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The Electric Industry at a Glance

William Steinhurst, Ph.D.
Senior Consultant, Synapse Energy Economics

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I. Some Basic Facts about Electricity

This paper provides basic information on the U.S. electric industry.[1] It assumes only a basic understanding of the nature and purpose of utility regulation.[2] While it addresses issues related to ratemaking, it is not an introduction to rate setting.[3] This section reviews the overall nature of the industry and of power production and use. Section II breaks down the industry into segments and discusses their recent and current status and organization. Section III covers regulatory jurisdiction, while Section IV identifies some of the critical issues facing the industry and its regulators.

Electricity is used to light homes, businesses, and streets; to operate appliances, machinery, and electronic equipment; to heat and cool buildings and water; to process, preserve and cook food; to provide heat or motive power for industrial processes and municipalities; in transportation; and to operate electric power plants themselves.[4] Electricity usage in most sectors of the economy has grown over time, although total U.S. industrial consumption of electricity has been roughly constant in absolute terms since the mid-1990s.[5] Residential and commercial use each make up about 38% of the total respectively, industrial consumption about 25%, and transportation less than 1%. The remainder (about 1%) is self-generated, primarily by large commercial and industrial establishments.[6]

Electricity is produced using many different energy sources and technologies. Originally generated on a small scale and close to consumers, electricity is now produced on all scales, from home solar panels able to serve the needs of one household to multi-unit central generating stations that supply the electric needs of half a million households. The distance from source to consumer can range from a few feet to a thousand miles or

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[1] This is an update of the November 2008 version previously issued by NRRI. Sections I, II, and IV have been updated. An appendix of acronyms and abbreviations has been added, and web links have been updated.

[2] See www.eia.doe.gov/basics/quickelectric.html for an overview of U.S. electricity statistics. For an introduction to utility regulation, see NRRI, 2003, *A Primer on Public Utility Regulation for New State Regulatory Commissioners*, available at nrri.org/pubs/electricity/public_regulator_primer_03.pdf, as well as the Glossary of Utility Terms at www.globalregulatorynetwork.org/Resources/Glossary.htm.

[3] A classic reference for utility ratemaking is Phillips, 1984, *The Regulation of Public Utilities*, recently reprinted. A detailed review of utility accounting for rate setting may be found in the NARUC 2003 *Rate Case and Audit Manual*, available at www.globalregulatorynetwork.org/resources.cfm.

[4] Many, but not all, generators need electricity to run fans, pumps, and controls during start-up and operation. Utilities carefully prepare "black start" plans that take those needs into account when restarting their systems after an outage.

[5] When discussing an amount of electric energy produced (e.g., the number of megawatt-hours produced in a given year), the terms "generation," "generated," or "electric output" will be used. Amounts of electric energy used or consumed (e.g., the number of megawatt-hours consumed by commercial and industrial customers in a given year) will be referred to as "consumption" or "usage." The amount of electric power produced or consumed at a given moment or that can be produced at a given moment will be referred to as "capacity" and "demand," respectively.

[6] U.S. EIA, "2009 U.S. Electricity Sales," *Electricity Explained: Electricity in the United States*, www.eia.doe.gov/energyexplained/index.cfm?page=electricity_in_the_united_states.

more. Energy sources for electric generation include renewable sources (the sun, biomass, flowing rivers, geothermal sources, wind, and tides), fossil fuels (natural gas, petroleum, and various forms of coal), and nuclear fission. In the U.S., fossil fuels generate 69% of that energy.[7] Nuclear power and conventional hydroelectric generation provide most of the rest, with other renewables delivering a small but steadily growing amount.[8] Sources of U.S. electric generation are discussed in more detail in Section II.A.2, below. A crucial fact about electricity production and use is that storing electric energy is quite difficult and expensive, and only tiny amounts of electricity can be stored for later use. In essence, the industry can only deliver as much power as the available generating plants can produce at a given instant, although significant investments are being made in storage R&D. A driving force behind all types of utility planning is the need to ensure that generation and transmission capacity sufficient to meet instantaneous customer needs are available at all times.

Transmission, sometimes referred to as "bulk transmission" or "wholesale transmission," means the transmission of wholesale electricity from generators to the point in the electric system where delivery to retail customers begins. Delivery to retail customers is usually called "distribution," but distinguishing between transmission and distribution is complicated in some instances and is discussed further in Sections II.A.4 and III. Transmission primarily takes the form of alternating current at voltages from a few thousand volts to around 750,000 volts.[9] The higher the voltage of a transmission line, the more it costs per mile to build; however, the higher the voltage of a line, the greater its capacity to carry power and the lower the energy losses from the electrical resistance of the wires. Also, higher-voltage lines of a given capacity usually cost less to build than lower-voltage lines with the same capacity. For long distances or very large amounts of power, high-voltage lines are more economical. Transmission and distribution are discussed in more detail in Sections II.A.3 and II.A.4.

Electricity comprises about 18% of the total energy consumed in the United States.[10] Since the electric industry requires capital investments for production and delivery (on top of the cost of fuel used to generate power), retail electricity expenditures in 2007 were over 28% of all retail energy expenditures (about $340 billion). Transmission and distribution losses for the U.S. are about 7% of the gross generation from power plants.[11]

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[7] U.S. EIA, *2009 Annual Energy Review* (hereafter, AER 2009), Table 8.2a, available at www.eia.doe.gov/aer/pdf/aer.pdf.

[8] The term "renewables" is commonly used to mean renewable generation technologies.

[9] Voltage is a measure of electromotive force or the pressure of electricity. This is analogous to the pressure in a waterline. It is measured in volts (abbreviation: V). Direct-current transmission is used in some special situations.

[10] Computed from data in AER 2009, Tables 2.1b-e. Percentage of total energy is based on amounts produced or consumed as measured in British Thermal Units and represents end-use energy consumption, i.e., excluding electric system losses in conversion and transmission. Including those losses, the value would be 40%.

[11] AER 2009, Table 3.5 and Diagram 5.

The environmental effects of electricity production vary greatly among energy sources and technologies and also depend on the age of the generator, operating and maintenance practices, and pollution controls installed. Electricity production may affect air and water quality, greenhouse gas levels, radiation levels, land use, wildlife, crops, and human health. Electric generation accounts for about 40% of U.S. greenhouse gas emissions, as well as 71% of the nation's airborne mercury emissions and large amounts of sulfur dioxide and nitrogen oxide emissions, mainly from coal.[12] Transmission and distribution construction, too, have environmental effects through land clearing and herbicide application. The environmental effects of producing and delivering fuels for generators are also a concern, as are the disposal of ash, nuclear waste, and other materials used or produced by generator operations.

[12] AER 2009, Tables 12.7a and 12.2; U.S. EPA, 2009 Toxic Releases Inventory National Analysis Overview, p. 6, available at www.epa.gov/tri/tridata/tri09/nationalanalysis/overview/2009TRINAOverviewfinal.pdf

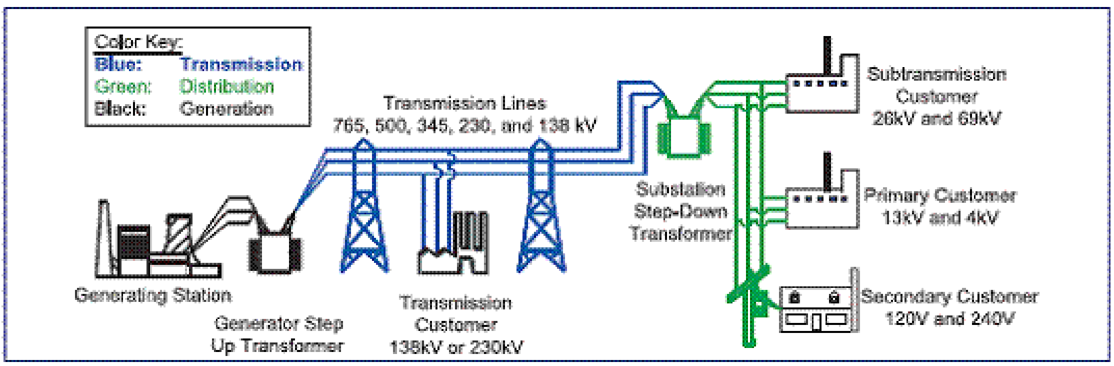
II. The Electricity Industry

A. Industry functions and structure

1. Overview and evolution of industry structure

Figure 1 shows a schematic overview of the electricity sector's functions. The sector has four major segments: generation, bulk transmission, local distribution, and retail sales. While the physical "set-up" remains the same, successive waves of change since the 1970s have altered the organization, ownership, and regulation of these segments, and the transactions among them.[13] This section briefly sketches the main changes.

Fig. 1. The Electricity Industry from Generator to Customer



Source: http://www.oe.energy.gov/information_center/electricity101.htm

For a variety of reasons, states granted monopoly franchises to electric utilities in the early twentieth century, and state commissions generally relied on ratemaking based on embedded cost as a substitute for competitive forces.[14]

The vertically integrated utility characterized the early history of the industry. Inter-city transmission was technically and economically impractical. Each utility, by necessity, owned and operated generators and distribution lines, making retail sales directly to customers. Some were municipal "light departments," and others were privately owned. As technological advances made larger generators and inter-city transmission feasible, consolidation took place, either by merging local utilities into new regional utilities or through the purchase of local companies by interstate holding companies.

[13] A detailed review of those changes is beyond the scope of this report. For a detailed discussion, see Brown and Sedano, *A Comprehensive View of U.S. Electric Restructuring with Policy Options for the Future*, *National Council on Electric Policy*, Ch. II "Policymakers Pursue Restructuring," available at www.ncouncil.org/Documents/restruc.pdf.

[14] For references to discussion of those reasons, see fn. 12 and 81, below.

Local, state, and federal regulation of utilities evolved in several waves, responding to evolving corporate structures, culminating in two major changes during the mid-1930s. One condensed the industry's pattern of scattered holding-company properties into vertically integrated utilities serving single, integrated, and contiguous service territories. The second was the creation of rural electric cooperatives to serve sparsely populated areas not attractive to private firms.[15] Several federal power authorities (in essence, multi-state generation and transmission utilities owned by the U.S. government) were also created during the 1930s, such as the Tennessee Valley Authority and the Bonneville Power Administration.[16] From that time through the 1990s, electric utilities were mainly vertically integrated utilities in the form of for-profit corporations (some as part of holding companies), municipally owned utilities, rural cooperatives, and federal power authorities. Municipal utilities formed a number of joint action agencies to purchase power in bulk, or even to facilitate the construction of power plants. Likewise, rural cooperatives formed generation and transmission cooperatives for similar purposes.

The next major type of actor, the power pool, began to emerge in 1971. Following a blackout in the northeastern U.S. on November 9, 1965, utilities in some regions formed power pools to improve the management and reliability of generation and transmission. Power pools were multi-utility contractual arrangements under which the signatories coordinated operations and maintenance outages, set standards, and arranged money-saving exchanges between members and with neighboring systems.[17] At the same time, the nation's utilities voluntarily created "regional reliability councils" for additional coordination for economic and reliability purposes.

The oil price shocks of the 1970s led Congress to enact the Public Utility Regulatory Policies Act of 1978 (PURPA). One prominent feature of PURPA, relevant to electric industry structure, was its Section 210. In that section, Congress there created a new category of electricity generator called the "qualifying facility" (QF). Congress's goals were to diversify the types of companies generating electricity and to reduce the nation's dependence on fossil fuels. To that end, Congress required that a traditional utility not own 50% or more of any QF, and that any QF had to be a renewable generator or a co-generator. However, a firm could own QFs in any (or many) locations, and QFs

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[15] The difficulty of a single state regulating multi-state holding companies led to the passage of the Public Utility Holding Company Act in 1935. For further information on this transition, see NRRI, *A Primer on Public Utility Regulation for New State Regulatory Commissioners*, 2003, p. 7 ff., available at nrri.org/pubs/electricity/public_regulator_primer_03.pdf. Congress repealed the Act in 2005. For a discussion of the implications of this repeal for state regulators and the industry as a whole, see "Testimony of Scott Hempling before the U.S. Senate Committee on Energy, 2008," available at nrri.org/pubs/electricity/hempling_senate_testimony_5-08.pdf. The Rural Electrification Act of 1936 (49 Stat. 1363) provided federal funding for installation of electrical distribution systems in rural areas. See 7 U.S.C. 31 at www4.law.cornell.edu/uscode/html/uscode07/usc_sup_01_7_10_31.html

[16] See 16 U.S.C. 12A at www.law.cornell.edu/uscode/uscode16/usc_sup_01_16_10_12A.html. These authorities serve some large industrial customers directly and sold power at wholesale to municipal and cooperative utilities. See, for example, www.tva.gov/abouttva/keyfacts.htm.

[17] See, for example, www.iso-ne.com/aboutiso/co_profile/history/index.html.

did not need to be part of an integrated and contiguous system.[18] The new law required utilities to connect QFs with the grid and to purchase their output at a state-set price equal to the power cost a utility saved by purchasing from the QF rather than taking other measures, known as its "avoided cost." Notwithstanding PURPA's introduction of independent QFs, most generation in the U.S. continued to be owned by vertically integrated utilities, by federal power authorities, or by groups of municipal or cooperative utilities until the mid-1990s.

During the 1990s, Congress and the Federal Energy Regulatory Commission (FERC) acted forcefully to create competitive markets for wholesale electricity and to spur entry into the generation business by new players.[19]

1. Congress created another new class of generators, the "exempt wholesale generator" (EWG), which was exempt from the 1935 requirement for electrical integration of multiple generators owned by one holding company.[20] This meant that one firm could own generators in geographically separate regions, breaking the link between owning generation and owning a retail service territory. Both utilities and non-utilities were allowed to enter fully into the wholesale power business with unlimited numbers of EWGs, in any location, under any corporate and financial structure.

2. FERC allowed most generation owners to use "market pricing" rather than cost-based pricing. Formerly, all sellers under FERC jurisdiction (i.e., wholesale sellers) had to price their power based on each plant's actual cost of production (including return of and on capital). Under market pricing, once FERC determines that the seller lacks "market power" (the ability to sustain a price above competitive levels without losing sales), the seller is free to charge whatever price it can negotiate or to sell the power into an organized auction market, such as those described below.

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[18] A renewable resource is one that is naturally replenished at a rate greater than or equal to the rate at which it is consumed. Renewable energy sources for electricity generation include the sun, wind, rivers, tides, geothermal (underground) heat, and biomass (wood or other crops used for fuel). A co-generator is a facility that uses the energy from burning fuel both for direct heat (e.g., space and water heating or an industrial process) and for producing electricity so as to obtain more useful energy from a given amount of fuel. More recently the term "combined heat and power" (CHP) has been applied to co-generation, especially for non-industrial applications.

[19] FERC Order 888, available at ferc.gov/legal/maj-ord-reg/land-docs/order888.asp, and FERC Order 2000, available at ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf. Also, the Energy Policy Act of 1992, available at ferc.gov/legal/maj-ord-reg/epa.pdf, and Energy Policy Act of 2005, available at ferc.gov/legal/fed-sta/ene-pol-act.asp.

[20] See discussion of PUHCA in fn. 12, above. PURPA had sidestepped this requirement twenty years earlier, but only for renewable generation and co-generators. EWGs could be, and to date usually have been, fossil-fueled power plants.

3. FERC, in its 1996 Order 888, required investor-owned utilities who owned transmission facilities to make them available to their competitors, so that they could compete on comparable terms.

FERC also encouraged utilities to create corporations called independent system operators (ISOs), which were later converted into regional transmission operators (RTOs). ISOs and RTOs in the U.S. are regulated by FERC because they provide transmission service and wholesale sales in interstate commerce. FERC oversight of ISOs and RTOs concentrates on transmission access rules, reliable real-time operation of the electric grid, independence from market participants, the competitiveness of power markets, and ensuring adequate supply. ISOs took over many of the functions of power pools in those parts of the country that had them but were open to all generation owners, not just utilities, and were required to treat all generation owners equally. ISO membership is also open to non-generators such as customers and state public advocates, as they can have as large a stake in the operation of markets as generators and transmission owners. FERC also required ISOs to establish and run auction markets into which any generation owner could sell its output. ISOs and RTOs are discussed further in Sections II.A.3 and II.B below.

Two other important trends developed during the 1990s—integrated resource planning in the early 1990s and retail competition in the latter part of the decade. Sensitized by over a decade of oil price shocks, as well as unprecedented delays and cost overruns in the construction of coal and nuclear plants, in the 1980s, some states began to require vertically integrated utilities to prepare long-range, least-cost plans. Least-cost planning (also known as "integrated resource planning" or IRP) involves a consolidated review of long-range resource needs and emphasizes equal consideration of all generation, transmission, and demand-side options.[21] IRP also sought to carefully consider the long-term strategic and financial impacts of the available resource options. Another motivation for IRP was growing concern for the environmental effects and risks from the generation and transmission of electricity.

As mentioned above, traditional electric utilities had state-granted monopoly franchises. In the mid- to late 1990s, while FERC and Congress were addressing wholesale restructuring, some states considered or established retail competition—that is, authorizing entities other than the incumbent utility to sell at retail. The process of conversion to retail competition is often called "retail restructuring" or just "restructuring," and approaches to restructuring varied widely.[22] In states that established

[21] Demand-side here means "on the customer's side of the electric meter." Demand-side management (DSM) is a broad term for programs implemented by a utility or another party in order to procure energy efficiency or load reductions as a component of a resource plan. DSM is discussed further in Section II.D, below.

[22] Some refer to wholesale restructuring, retail restructuring, or both as "deregulation." This is a misnomer. Wholesale sale of electric power remains regulated by FERC; what have changed are the nature and organization of the sellers permitted and their ability to apply for permission to sell at market prices instead of at cost. Likewise, retail restructuring permitted new kinds of vendors to sell power at retail and authorized them to set their own prices and terms. Those competitive retail sellers, however, must be licensed and are still regulated by state commissions in certain ways.

retail competition, incumbent utilities were often required or encouraged to divest themselves of most or all of their generation assets, either by sale to another party or by transferring those assets to affiliates.[23] Retail restructuring is discussed in Section II.C.

2. Generation and storage of electricity

Electric energy output in the U.S. reached an all-time high of 4.2 billion megawatt-hours (MWh) in 2007, declining to 4.0 billion MWh in 2009.[24] Another 34 million MWh was imported, mainly from Canada.[25] The installed net summer capacity of generating plants in the U.S. in 2009 was 1,025,400 megawatts (MW), representing 17,876 plants, up from 986,215 MW and 16,924 plants in 2007. Traditional vertically integrated utilities owned 53% of that capacity (9,428 plants); non-utility generators, including qualifying facilities, owned 31% (5,531 plants). Customers owned the remaining 16% (2,917 plants).[26] In the summer of 2009, the available amount of capacity resources was 916,449 MW, while net internal demand was 713,106 MW.[27] The reserve margin, or available capacity in excess of need, was 22%, a value significantly higher than the typical range experienced since the mid-1990s.[28]

Broadly, electric generators tend to be used in one of three operating patterns, depending mainly on variable operating cost: base load, peaking, and intermediate. Base load plants are expensive to build because they are engineered for maximum efficiency; as their variable cost is relatively low, they are in use many hours of the year, and, for engineering reasons, some types are slow to reach full output or change their level of output. Peaking plants are intended to run only when load is at its highest and to start and stop quickly; since they will not run for many hours per year, they are engineered for low

[23] See NRRI, *A Primer on Public Utility Regulation for New State Regulatory Commissioners*, 2003, p. 9 ff. Rose and Meeusen's 2007 *Bibliography on Market Power and Performance* offers references to a broad range of opinions both positive and negative concerning competitive market reforms in the electric industry. See www.ipu.msu.edu/research/pdfs/Rose%20Bib%20on%20Markets%20(2007).pdf.

[24] AER 2009, Table 8.1. The amount of electric energy produced or consumed over a period of time is expressed in kilowatt-hours (kWh). A kWh is the energy required to operate ten 100-W bulbs for one hour or a common microwave oven for 40 minutes. The average U.S. household uses about 900 kWh/month. Electric energy use is often reported in terms of megawatt-hours (MWh), each of which is 1000 kWh, or even gigawatt-hours (GWh), each of which is 1000 MWh or 1,000,000 kWh.

[25] This amount is the net of 52 million MWh of imports and 18 million MWh of exports.

[26] U.S. EIA, *2009 Electric Power Annual* (hereafter, EPA 2009), Table 1.3. The amount of electric energy produced or consumed at a given moment is expressed in kilowatts (kW), a measure of power similar to horsepower. It is used to express the "size" or capacity of generating plants, as well as the load on the system at a given time, such as the peak load for a year. A kW is the power required to operate ten 100-W bulbs at the same time. Electric capacity and load are often reported in megawatts (MW), each of which is 1000 kW, or even gigawatts (GW), each of which is 1000 MW or 1,000,000 kW. System loads vary by season, time of day, and region. The capacity of power plants and transmission lines varies with season because ambient air and water temperatures affect the efficiency of heat transfer to the environment; this can have important effects on reliability in summer peaking systems.

[27] EPA 2009, Table ES1.

[28] The summertime balance is often singled out in discussions about load and generating capacity balance, because the summer surpluses are narrower in most parts of the U.S. One reason is the large growth in air conditioning load over the past 20 years.

construction cost at the expense of reduced efficiency and higher variable cost.[29] The third type, intermediate plants, sometimes called cycling plants, run more often than peakers, but less often than base load plants; they are usually older base load plants that are no longer the most fuel-efficient available.

Overall, about 70% of U.S. electric generation is from fossil fuels, down from about 80% in the 1960s, despite increased total annual output. Electric output from petroleum is down by almost one-half over the past decade, and output from coal was roughly flat from 2000 to 2008, but dropped 12% in 2009 (compared to a drop of only 4% in total output). Rapid construction of natural gas power plants—driven by increasing environmental pressures, technological advances in the efficiency of gas-fired plants, and relatively low prices for gas in the 1990s and again more recently—made up the difference, with annual gas-fired output growing by about 44% from 2000 to 2009.[30] Non-utility owners built many of those plants.

Nuclear generation, less than 1% of total U.S. generation in 1967, increased gradually in both aggregate output and percentage of total generation during the 1970s and 80s, gaining about 10% from 1999 to 2007 and then leveling off through 2009.[31] Since 2000, a combination of capacity increases and reduced outage time at existing plants has led to further increases in annual output.[32] Nuclear power produced between 20 and 21.5% of total output since 1990.

Total renewable generation in the U.S. rose gradually from 1960 to 1997 while declining steadily as a percentage of total output, dropping from about 29% in 1950 to about 8.6% in 2005, rebounding slightly to 9.2% in 2008, largely due to a near quadrupling in wind capacity online.[33] Since 1997, when hydroelectric output represented about 10% of total generation, the amount of U.S. hydroelectric generation declined by almost one-third, now supplying about 6% of total generation. Aside from a small spurt following the creation of PURPA "qualifying facility" status in the 1980s, there has been relatively little new hydroelectric generation built. The most attractive sites were already developed, and environmental effects on river habitats led to FERC and state environmental agencies imposing new operating restrictions on some dams; a few have even been decommissioned.

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[29] There are no specific numerical cut-offs dividing the three categories of operating regimes, but one can think of base plants running, perhaps, 60% or more of the time, peaking plants as running up to about 10% of the time, and intermediates filling in the remainder.

[30] EPA 2009, Table ES1.

[31] Ibid.

[32] The U.S. Nuclear Regulatory Commission (NRC) has approved "uprates" for a number of plants, increasing their maximum allowed operating capacity, sometimes by as much as 20%. Also, while implementing retail competition, some states allowed or required utilities to sell off nuclear power assets, putting more plants in the hands of specialized owners able to sell some or all of the power at whatever price the wholesale market would bear, rather than to retail customers at the cost of production, as was the case under traditional rate setting. Greater specialization, economies of scale, and greater exposure to market forces may have contributed, then, to the observed increase in output.

[33] This trend reflects a drop in hydroelectric output since the mid-1990s and steady gains in solar, wind, and biomass generation since the late 1980s. AER 2009, Table 2.1f; EPA 2009, Table ES1.

Other sources of renewable generation are growing, but remain modest. Actively developing technologies include wind turbines, geothermal power (use of deep underground heat to run turbines), solar photovoltaics (PV), concentrating solar thermal (where mirrors concentrate sunlight onto a heat engine), and biomass (combustion of plant matter, either directly or after gasification).[34] Non-renewable wastes, e.g., municipal solid waste, and other technologies provide a small fraction of one percent of total U.S. generation.[35]

The past few years have seen significant deployment or approval of new, utility-scale renewable generation. In 2010, California approved construction of ten concentrating solar-thermal projects totaling about 3680 MW.[36] The Arizona Corporation Commission authorized Arizona Public Service to build photovoltaic plants in 2010 through 2014, initially in the 15 to 20 MW range and totaling about 100 MW.[37] Cape Wind, a 468 MW, 130-turbine offshore wind farm, to be located in Nantucket Sound off the southern shore of Cape Cod, received its final permit on January 7, 2011.[38] According to the American Wind Energy Assoc. (AWEA), "14 states have installed over 1,000 MW of wind. . . . [and] Iowa . . . got an estimated 20 percent of its electricity from wind in 2010 . . . , an increase from 14 percent in 2009. In addition, U.S.-based capacity for manufacturing of renewable generation equipment is being expanded. New photovoltaic manufacturing plants are being built in Mississippi and South Carolina. New wind turbine manufacturing plants are being built in Michigan, Kansas, Arkansas, and Texas.[39]

Many hydroelectric generators can store energy, a rare and valuable capability in the electric world. This can be accomplished in two ways. The most common is to hold water behind a dam or series of dams for use when power is most expensive or needs are greatest. This "ponding" process can store huge amounts of energy and feed it into the grid on short notice at low cost, but causes reservoir levels to fluctuate, sometimes greatly, possibly causing environmental damage to shorelines. The other is called pumped storage and uses two reservoirs that are located close to each other, one higher than the other. When power is inexpensive, it is used to pump water from the lower reservoir to the higher one; when power is more expensive, pumping is halted; and when costs are at their highest, water is allowed to flow down from the upper reservoir through

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[34] For further information on these and other renewable technologies, see www.nrel.gov/learning.

[35] AER 2009, Table 8.2a

[36] California Energy Commission, http://www.energy.ca.gov/siting/solar/index.html, accessed 1/7/2011.

[37] ACC, "Commission Approves New Energy Efficiency and Renewable Projects to Benefit APS Customers," 3/3/10, available at http://www.cc.state.az.us/Divisions/Administration/news/100303APS%20projects.pdf

[38] Cape Wind, "Cape Wind Completes Permitting Process," http://www.capewind.org/news1174.htm, accessed 1/7/11.

[39] AWEA, "American Wind Power Surmounted Challenges In 2010," 1/6/11, available at http://awea.org/rn_release_01-06-11.cfm. Todd Woody, "Solar Start-Up Plans Big Factory in South Carolina," *New York Times*, 1/6/11, available at http://green.blogs.nytimes.com/2011/01/06/solar-startup-plans-big-factory-in-s-c; Candace Lombardi, "Solar Panel Maker Stion to Create 1,000 Miss. Jobs," *CNet News*, 1/5/11, available at http://news.cnet.com/8301-11128_3-20027356-54.html.

a generator. Pumped storage provides benefits similar to ponding in a reservoir. Pumping water uphill, however, uses more energy than is returned when the water flows back downhill through the generator. In addition, two reservoirs must be flooded, not just one, and the water levels in those reservoirs fluctuate so greatly as to severely impact both of them environmentally.

Many states have adopted policies to promote renewable generation. Some require that each electric utility's portfolio contain at least a set percentage of renewable power, often according to a gradually increasing schedule over a decade or more. Such requirements are called renewable portfolio standards (RPSs). The magnitude of standards and the definitions of what qualifies vary. Many RPSs rely on a system of tradable renewable energy credits (called TRECs or RECs, depending on the jurisdiction) for compliance. TRECs are certificates representing a certain amount of renewable energy production; they are usually issued to renewable generators by an RTO. TRECs can be traded separately from the electric energy produced. TRECs ease compliance burdens and reduce the overall cost of compliance. A national RPS has been debated in Congress. Others provide tax incentives, production incentives, grants, loans, or financing, as well as supportive zoning, easement, and access provisions. Another policy for promoting renewable generation is the feed-in tariff (FIT), which may require utilities to purchase electricity from eligible renewable generators under a standard power purchase contract with a guaranteed payment ($/kWh) for a guaranteed period of time (typically 15-20 years). FIT prices may be based on the total lifetime cost of building and operating the given type of generation (depending on the technology, on-line date, size or other properties) or the value of the power (as was the case under PURPA).[40]

As of the end of 2010, all but thirteen states had a state or local RPS in place. "Expectations are rising that the electric industry in North America will begin to reduce carbon emissions and integrate higher percentages of renewable resources into its generation mix over the coming years." The federal government has extended and improved the investment tax credit (ITC) for renewable generation through 2016, and federal stimulus bills have appropriated about one billion dollars to state energy offices for renewables development. As of late 2009, there were 39 production-based incentives for renewable energy in 28 states (excluding feed-in tariffs), 11 feed-in tariffs (FITs), and 14 REC-purchase programs (through which RECs are purchased separately from electricity).[41] In addition, a number of states provide for "green pricing" or "net

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[40] Karlynn Cory, Toby Couture, and Claire Kreycik, *Feed-in Tariff Policy: Design, Implementation, and RPS Policy Interactions*, NREL/TP-6A2-45549 March 2009, available at http://www.osti.gov/bridge. For discussion of design recommendations for Commissions, see Adam Pollock and Edward McNamara, *What Is an Effective Feed-In Tariff for Your State? A Design Guide*, 4/15/10, available at http://www.nrri.org/pubs/multi-utility/NRRI_FIT_design_april10-07.pdf. For discussion of the available legal foundations for FITs, see Scott Hempling, Carolyn Elefant, Karlynn Cory, and Kevin Porter, *Renewable Energy Prices in State-Level Feed-in Tariffs: Federal Law Constraints and Possible Solutions,* NREL/TP-6A2-47408 January 2010, available at http://www.osti.gov/bridge.

[41] For current information on state RPS and DSM portfolio standard laws, see www.dsireusa.org. In retail competition jurisdictions, retail competitors usually must meet the same RPS requirement for their sales. For statistics and quotes, see DSIRE database summary, available at http://www.dsireusa.org/summarytables/rrpre.cfm; North American Electric Reliability Corporation, "Key

metering" to support retail customers who, respectively, wish to pay a premium rate to support renewable generation or install their own on-site renewable generation—typically small wind turbines or photovoltaics—and feed any excess generation back to the grid. As of 2009, over 1.1 million customers had chosen green pricing and about 96,500 participated in net metering.[42]

Many renewable generation technologies are intermittent, that is, their output depends on external conditions, such as sunshine or wind. As a result, the value and timing of their output is not controllable. Various other technologies for storing electric energy have been tried or are being developed and are receiving renewed attention because progress in storage would significantly increase the economic and strategic value of renewable technologies. Electric storage technologies fall into two strategic categories. One is high-volume storage, such as ponded hydropower or pumped storage, discussed above, and thermal storage of heat from the sun (e.g., in molten salt). The other type is the limited energy storage resource (LESR)—technologies such as flywheels, capacitors, and batteries. The "key difference is that while energy production from a pumped storage facility is typically measured in hours, the duration of energy production from a LESR is measured in minutes."[43] Compressed air storage operates in a similar manner, but occupies an engineering and economic niche between hydropower-based storage and LESRs. Until recently, decades of R&D have resulted in only a few small demonstration units in commercial service, aside from large pumped storage units. Recently, utility-scale electric storage projects (aside from pumped storage) have begun significant deployment. Several MW of flywheel plant have been used to supply frequency regulation in New England since 2008, a 20 MW flywheel storage plant is being installed in New York, and three 20 MW battery storage units have been proposed for construction in upstate New York. R&D on these and other storage technologies is active and shows signs of promise.[44]

Similarly, extensive R&D efforts to find new or improved low-carbon generation technologies are underway. While the field is in rapid flux, a few recent examples will

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Issues: Renewables," available at http://www.nerc.com/page.php?cid=4|53|60, accessed 1/7/11; and Interstate Renewable Energy Council, 10/26/09, available at http://www.dsireusa.org/documents/PolicyPublications/IREC_2010_report.pdf.

[42] EPA 2009, Table 7.5.

[43] New York ISO, *Energy Storage in the New York Electricity Markets*, March 2010, p. 8, available at http://www.electricitystorage.org/images/uploads/docs/Energy_Storage_in_the_NY_Electricity_Market_March2010.pdf.

[44] NY-ISO, op. cit.; Beacon Power Form 10-Q, 11/9/10, p. 30, available at http://phx.corporate-ir.net/phoenix.zhtml?c=123367&p=irol-sec&secCat01.1_rs=11&secCat01.1_rc=10. One example of technical progress in storage is lab-scale demonstrations of the use of nanomaterials such as graphene (tubes or sheets of pure carbon, similar to the more widely known "buckyballs"), which show promise in increasing the durability and charge-recharge times for lithium-ion batteries, as well as in improving the energy-storage-to-weight ratio of capacitors. Angstron Materials, "Angstron Materials and K2 Energy Solutions Selected by Department of Energy to Develop Hybrid Nanomaterial for Lithium-Ion Batteries," 7/17/10, available at http://angstronmaterials.com/in-the-news/angstron-and-k2-to-develop-hybrid-nanomaterial/; "Graphene-Based Supercapacitor with an Ultrahigh Energy Density," Chenguang Liu, et al., Nano Lett., 2010, 10 (12), pp 4863–4868, available at http://pubs.acs.org/doi/abs/10.1021/nl102661q.

demonstrate the variety and potential of those efforts. Research advances are being made in the efficiency and cost-effectiveness of photovoltaic panels and wind turbines, as well as better methods for integrating intermittent renewables into the grid.[45] Substantial investments are being made in new or enhanced technologies for using fossil fuels, especially coal gasification, carbon capture, and sequestration (CCS).[46] Numerous proposals exist for new nuclear reactor designs, some of which are proposed in the U.S. and are under construction in other countries.[47]

3. Transmission and control of electricity

The next major function of the electricity industry after generation is transmission. Physically, transmission systems consist of poles and wires, substations, transformers, and other equipment used to move power from generators to the distribution system (discussed in Section II.A.4, below). The Federal Energy Regulatory Commission (FERC) has jurisdiction over the provision of unbundled transmission service in interstate commerce—including all transmission service except that provided in Alaska, Hawaii, and most of Texas.[48] Commencing with its 1996 Order 888, FERC has required owners of transmission facilities to make those facilities available on a non-discriminatory basis to all generators at embedded cost-based prices regulated by FERC.

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[45] The use of nanotechnology to "funnel" light to small PV cells may improve efficiency from the mid-20% range of today's best single crystal cells to the mid-30% range or higher. S. Kurtz, *Opportunities and Challenges for Development of a Mature Concentrating Photovoltaic Power Industry*, NREL/TP-520-43208, 11/09, available at http://www.nrel.gov/pv/pdfs/43208.pdf. Laser measurement of oncoming wind speeds can help optimize the adjustment of turbine blades in real time for greater output, and deployment of turbine blades with "wavy" edges like the fins of certain whales can increase the power output of both wind and tidal power turbines. M. Murray, T. Gruber, and D. Fredriksson, "Effect of Leading Edge Tubercles on Marine Tidal Turbine Blades," *Bull. Am. Physical Soc., 63rd Annual Meeting of the APS Div. of Fluid Dynamics*, 55: 16, available at http://meetings.aps.org/link/BAPS.2010.DFD.HC.6. Several ISOs are working to improve wind speed forecasts to more cost-effective integration of wind into the grid. G. Hinkle, et al., *Final Report: New England Wind Integration Study*, ISO NE, 2010, available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf.

[46] See, for example, http://www.fossil.energy.gov/programs/powersystems/cleancoal/index.html.

[47] The current U.S. nuclear fleet was built with 1960s and 1970s technology. Improvements at the 104 currently operating U.S. plants have enabled them to increase power output. Most of the current nuclear power plants have received or are expecting to receive 20-year operating-license extensions. New plants constructed before 2020 will be "evolutionary" plants, based on modifications of existing plant designs and using technologies that are largely ready now. New plants will use alternative, perhaps radically different, plant designs, but significant R&D would be needed. One study suggests that "by 2020, as many as five to nine new evolutionary nuclear plants could be built in the United States. . . . By combining new power plants with capacity from modified plants, an increase of 12–20 percent in U.S. nuclear capacity is possible by 2020." National Acad. of Sciences, *Overview and Summary of America's Energy Future: Technology and Transformation*, 2010, p. 26, available at http://www.nap.edu/catalog/12943.html.

[48] Most of the Texas grid is electrically isolated from the rest of the country. In this context, "unbundled transmission" means transmission service available separately from the purchase or sale of the power being transmitted. See Section III for discussion of this concept.

The lower 48 states have about 164,000 miles of bulk high-voltage transmission lines rated 230 kilovolts (kV) and above. Thousands of miles of additional FERC-regulated transmission facilities rated at 115 kV, 138 kV, and 161 kV serve smaller regions.

The U.S. transmission system is composed of three major electrically interconnected grids, each spanning many states: the Eastern Interconnect, spanning the entire eastern and central states; the Western Interconnect, comprised of the Pacific, Rocky Mountain, and southwestern states; and the Electric Reliability Council of Texas (ERCOT) interconnect, including most of Texas. Within each interconnect, the transmission system is operated by local utilities and RTOs. Under provisions of the U.S. Energy Policy Act of 2005, FERC has designated the North American Electric Reliability Corporation (NERC) as the "electric reliability organization" (ERO) for the United States.[49] NERC coordinates reliability with Canadian utilities under NERC-signed Memorandums of Understanding with the Provinces of Ontario, Quebec, and Nova Scotia and with the National Energy Board of Canada. NERC delegates its authority to monitor and enforce compliance with NERC Reliability Standards in the United States to eight Regional Entities, with NERC continuing in an oversight role.[50]

FERC Order 888 set out the principle of open access to the grid under non-discriminatory tariffs. This landmark order required transmission-owning entities to file tariffs with FERC making transmission service available to other utilities, independent generators, municipal and rural cooperative systems, and power marketers, under the detailed terms and conditions set forth in those tariffs. This new access to the transmission grid allowed for the development of wholesale power markets in which all those entities could participate. FERC's companion Order 889 mandated that providers of transmission service create web-based, public information systems, so that all transmission customers would have equal and simultaneous access to information about transmission capacity. The purpose of those information systems is to prevent a vertically integrated owner of transmission from using knowledge of capacity availability to favor its own generators.[51] Those orders have been updated, most recently in FERC Order 890, which established, among other things, more detailed planning principles for transmission owners or RTOs to follow. These included the use of transparent analyses in determining the extent to which new transmission would be supported by reliability or economic needs.

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[49] 16 U.S.C. 824 et seq.

[50] Those Regional Entities are: Florida Reliability Coordinating Council (FRCC), Midwest Reliability Organization (MRO), Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool, RE (SPP), Texas Regional Entity (TRE), and Western Electricity Coordinating Council (WECC). For more information and a map of the Regional Entities, see http://www.nerc.com/page.php?cid=1|9|119. Canadian provinces and small portions of northern Mexico also belong to these councils. For a map of the three interconnects, see www.eia.doe.gov/cneaf/electricity/page/fact_sheets/transmission.html.

[51] Each of these information systems is called an "OASIS," or open-access same-time information system.

FERC's Order 2000 encouraged utilities to establish RTOs. RTOs exist today in California and in most of the Eastern Interconnect, covering approximately two-thirds of the load of the lower 48 states.[52] The premise of Order 2000 is that transmission systems and power markets are regional. An RTO is legally a "public utility" under the Federal Power Act, subject to FERC's jurisdiction over all its activities. Each RTO acts as the provider of transmission service, responsible for operating, planning, and selling access. The RTO era also has ushered in spot markets for electric energy, as well as markets for ancillary services and generation capacity.[53]

During 2008 and 2009, FERC issued a series of orders (719, 719-A, and 719-B) setting out regulations to "strengthen the operation and improve the competitiveness of organized wholesale electric markets through the use of demand response and by encouraging long-term power contracts, strengthening the role of market monitors and enhancing regional transmission organization (RTO) and independent system operator (ISO) responsiveness."[54] For example, the Order requires RTOs/ISOs to accept bids from demand response resources in markets for certain reserves and ancillary services on a basis comparable to any other resources and states that RTOs/ISOs must support marketing of long-term contracts. Also, RTOs/ISOs must provide for an independent market monitor with certain "core functions"—duties FERC finds necessary to proper monitoring and mitigation of market power.

Planning, construction, maintenance, and operation of transmission systems were traditionally the responsibility of vertically integrated utilities. Today, these functions are carried out by those utilities and by RTOs where they exist. Two aspects of reliability drive those functions: adequacy and security. Adequacy means having sufficient generation connected to the bulk transmission system in the right places to meet the instantaneous needs or "demand" of customers. Security is "the ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements."[55] Adequacy focuses on forecasting load and adding needed generation, demand-side, or transmission resources. Security considers proper maintenance and operation of generation and transmission, as well as minute-by-minute control and adjustment.

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[52] Those RTOs/ISOs are CAISO (California), ERCOT (portions of Texas), SPP (portions of the central southern U.S.), MISO (upper Midwestern states and Manitoba), PJM (mid-Atlantic states, Pennsylvania, Virginia, West Virginia, and portions of Ohio, Indiana and Michigan), NYISO (New York state), and ISO-NE (New England). Ontario and Alberta have also formed Independent System Operators. For more information and a map, see http://ferc.gov/industries/electric/indus-act/rto.asp.

[53] Ancillary services are those services that are necessary "to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission system. . . ." FERC Order 888, Final Rule, 5 FERC 61,080, p. 206 ff. Examples of ancillary services include various types of reserves, scheduling and dispatch, voltage control, and voltage regulation.

[54] Available at http://www.ferc.gov/industries/electric/indus-act/competition.asp. For demand response, see § 35.28(g)(1)(i). For long-term contracts, see § 35.28(g)(2). For market monitoring, see § 35.28(g)(4)(ii).

[55] For a general discussion of these concepts, see www.nerc.com/page.php?cid=1|15|123. For details, see NERC Standard 51 — Transmission System Adequacy and Security, available at www.nerc.com/docs/standards/sar/Planning%20Standards%20Clean.pdf

To maintain adequacy, system planners at utilities and on the staff of RTOs/ISOs carry out studies and projections to assess the need for supply- and demand-side resources and new or reconfigured transmission.[56] System operators at utilities and RTOs/ISOs have day-by-day, hour-by-hour responsibility for decisions affecting security and for actions during emergencies to minimize loss of customer load while protecting generators and the grid from damage. A critical part of that responsibility is making on-the-spot decisions to keep power flowing to customers. Those decisions may be made by RTO/ISO system operators and implemented by them or by utility staff. To preserve reliability, operators may order owners to start up or shut down generators, arrange additional imports from neighbors, direct that retail utilities invoke demand response agreements with retail customers, issue or request the issuance of public appeals, and, as a last resort, order voltage reductions or rotating blackouts.[57] Operators also have the ability to call on quick-start units, ramp online units up or down, and use other generation and load flexibilities to cope with sudden system changes; these capabilities, called "ancillary services," are discussed further in Section II.B.1, below.

Over time, monitoring and control of load, generation, and transmission have become more automated, often using SCADA (Supervisory Control and Data Acquisition) systems that provide remote control of and telemetry for the grid. System operators must protect the equipment on the grid, which represents investments of billions of dollars and which would require years to replace. A critical part of that responsibility is to maintain precisely the balance between generation and consumption on the electrical system at all times and to protect the system as a whole from instabilities that can be caused by unplanned or uncontrolled interruption of power flow (say, by failure of a large generator or the transmission lines to a specific area). If not compensated for quickly, such events can cause voltage swings, similar to the screeching of audio feedback in a public address system, or other unstable behavior in the grid. Such uncontrolled conditions can damage equipment—for example, by causing the rotating shafts of generators to vibrate and damage the bearings on which they rotate—or trigger cascading blackouts such as occurred in 1965 and again in 2003.[58] Security issues have

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[56] Resource adequacy has recently been the subject of various rulemakings and studies regarding metrics for the performance of RTOs/ISOs including, among other factors, comparison of their planned reserve margins to the actual margins obtained. For an example of a resource adequacy rulemaking, see FERC NOPR "Planning Resource Adequacy Assessment Reliability Standard," 10/27/10, available at http://federalregister.gov/a/2010-27132. For RTO/ISO performance metrics, see FERC, *ISO/RTO Performance Metrics*, Commission Staff Report AD10-5-000, 10/21/10, available at http://www.ferc.gov/legal/staff-reports/10-21-10-rto-metrics.pdf.

[57] Rotating (or rolling) blackouts means the disconnection of electrical service to a few distribution lines at a time, typically for 20 to 30 minutes, after which those lines are reconnected and another set disconnected, continuing as long as needed to avoid the failure of the whole grid.

[58] A "cascading" blackout is a grid failure that grows over a period of time, usually a few minutes to a few hours. In such an event, an initial failure in one part of the grid overloads other parts to the extent that they must be shut down to avoid being damaged. Those shutdowns then overload additional facilities, causing them to shut down. After a certain point, the shutdowns result in the failing portion of the grid being isolated from the rest of its interconnect, resulting in a blackout of that region until it can restart and stabilize its equipment. For an analysis of one severe blackout, see *Final Report on the August 14, 2003*

become more important as wholesale trade in power over longer distances has grown and as households and businesses have become more dependent on electronic equipment.[59]

A complex of technologies, commonly called "smart grid," has begun to affect T&D systems in many parts of the U.S. While smart grid has no one definition, broadly speaking, it means "an interconnected system of information and communication technologies and electricity generation, transmission, distribution and end-use technologies that has the potential to enable consumers to manage their usage and choose the most economically efficient energy service offerings, enhance delivery system reliability and stability through automation, and improve system integration of the most environmentally benign generation alternatives, including renewable resources and energy storage." Advanced metering infrastructure (AMI)—solid-state digital meters with two-way communications between the meter and utility—is part of the smart grid. Smart grid technologies also includes sensing and measurement technologies, advanced T&D components (superconductivity, storage, power electronics, and diagnostics), distribution automation systems, end-use technologies like appliances that can communicate with smart grid and advanced control systems for buildings, distributed generation, and communication systems permitting these devices to interact.[60]

Roughly $3.5 billion was made available under the American Recovery and Reinvestment Act of 2009 (ARRA, Pub.L. 111-5) for rapid deployment of smart grid by utilities.[61] Some jurisdictions are attempting to deploy certain smart grid technologies (often AMI) universally and immediately; others are moving more slowly. Twenty-four states and the District of Columbia have smart metering policies or legislation.[62] Since smart grid technologies can be quite costly, likely in excess of $100 billion over the next 20 years for U.S. utilities, ratemaking issues, including magnitude of rate impacts, rate treatment of T&D and metering assets supplanted by smart grid and AMI, allocation of risk for smart grid investments and decisionmaking, and preapproval, are emerging issues

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Blackout in the United States and Canada: Causes and Recommendations, U.S.-Canada Power System Outage Task Force, 2004, available at www.nerc.com/filez/blackout.html.

[59] Brown and Sedano, *Electricity Transmission: A Primer* provides an overview of the history of the U.S. transmission system and the challenges it faces. Available at www.raponline.org/Pubs/ELECTRICITYTRANSMISSION.pdf. See also www.ncouncil.org for additional resources on transmission issues.

[60] D. Moskowitz and L. Schwartz, *Smart Grid Or Smart Policies: Which Comes First?*, Regulatory Assistance Project, 7/09, available at http://www.raponline.org/docs/RAP_IssuesletterSmartGridPolicy_2009_07.pdf. [bullets omitted] See, also, http://www.naruc.org/Publications/NARUC%20Smart%20Grid%20Factsheet%205_09.pdf for a glossary and overview. Appliances capable of smart grid communication have just begun to reach the consumer market, although it remains unclear how popular or capable they will be. See, for example, Martin Lamonica, "CES: LG touts grid-aware smart appliances at CES 2011," Cnet.com, 1/5/11, available at http://ces.cnet.com/8301-32254_1-20027448-283.html.

[61] For ARRA smart grid awards, see http://www.energy.gov/recovery/smartgrid.htm.

[62] National Council of State Legislatures, http://www.ncsl.org/default.aspx?tabid=20672, accessed 1/7/11.

in some jurisdictions.[63] For example, the Maryland Public Service Commission approved Baltimore Gas & Electric's application for a proposed smart metering program only on the condition that the company agree to rely on the creation of a regulatory asset and the recovery of prudent costs in a future base rate case, rather than the preapproval it had requested.[64]

Regional transmission planning and approval has become an issue of some interest. From 2001 to 2008, Edison Electric Institute (EEI) members invested over $57 billion in infrastructure improvements and projected spending at least another $56 billion from 2009 through 2020. The DOE has concluded that "[s]ignificant expansion of the transmission grid will be required under any future electric industry scenario. Expanded transmission will increase reliability, reduce costly congestion and line losses, and supply access to low-cost remote resources, including renewables." In 2007, FERC "stated that particularly in an era of increasing transmission congestion and the need for significant new transmission investment, it could not rely on the self-interest of transmission providers to expand the grid in a not unduly discriminatory manner." FERC amended its rules to specify the role of customers and other stakeholders in transmission planning, requiring that transmission planning processes be coordinated, open, and transparent, among other changes. In 2010, FERC initiated Rulemaking RM10-23-000 to reform transmission planning and cost allocation processes further and "to address remaining deficiencies in transmission planning and cost allocation processes so that the transmission grid can better support wholesale power markets and address new public policy imperatives." In these various proceedings, FERC has sought to address cost allocation for regional transmission projects. Another issue for such projects is the question of cost recovery, specifically whether or not preapproval of cost recovery should be considered and, if so, how. A number of states have confronted or will confront this regulatory issue.[65]

4. Distribution and sub-transmission

The distribution system also consists of poles and wires, substations, transformers, and related equipment. Its function is to move power from the bulk

[63] For costs and funding issues, see Richard Cowart, *Financing the Smart Grid: Costs, Rates, and Public Policy*, Regulatory Assistance Project, 9/10, available at http://www.raponline.org/docs/RAP_Cowart_FinancingtheSmartGridIEAMadrid_2010_09_28.pdf.

[64] MD PSC, *In the Matter of the Application of Baltimore Gas & Electric Co. for Authorization to Deploy a Smart Grid Initiative and to Establish a Surcharge for Recovery of Costs*, Case No. 9208, Order No. 83531 (August 13, 2010).

[65] EEI, *Transmission Projects: At a Glance Order*, 2/10, available at http://www.eei.org/ourissues/ElectricityTransmission/Documents/Trans_Project_lowres.pdf. (U.S. DOE) Electricity Advisory Committee, *Keeping the Lights On in a New World*, at 45, 1/09. FERC Order No. 890, FERC Stats. & Regs. ¶ 31,241. For the current rulemaking, see 131 FERC ¶ 61,253. Regarding preapproval issues, see, S. Hempling and S. Strauss, Pre-*Approval Commitments: When And Under What Conditions Should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects?*, NRRI, 11/08, available at http://www.nrri2.org/index.php?option=com_content&task=view&id=140&Itemid=48.

transmission system to retail customers.[66] Distribution has traditionally been the responsibility of retail electric utilities. In states with vertically integrated utilities, this is still the case. In jurisdictions that established retail competition, distribution utilities remain in place to perform those functions.[67] Sub-transmission is a term used in some jurisdictions for facilities that are physically similar to bulk transmission, but that move power within a given utility's service territory, either to different regions of that utility's distribution system or to small utilities embedded in its service territory.

The distribution function is both physical and commercial. The physical aspect consists of the construction and operation of the poles, wires, customer meters, and other equipment used for retail delivery of power. The commercial aspects include metering usage by retail customers, billing and collection, and customer service (opening new accounts, initial handling of complaints, and the like). In the absence of retail competition, the distribution utility performs both aspects. Where retail competition exists, the distribution utility provides the physical aspects of distribution and usually provides the commercial aspects as well, even for customers whose power is provided by a competitive retailer. A few very large customers take service at high voltage directly from the transmission or sub-transmission system, but are still metered and billed in a similar manner. Under retail competition, the function of buying power for retail customers who have not "shopped" is usually carried out by the distribution utility, as well.

Another function of the distribution and sub-transmission systems is to interconnect small generators, allowing them to sell their output to utilities or other wholesale market participants. These generators include qualifying facilities, other non-utility generators, and small generators owned by utilities, such as small hydroelectric plants along a river course. Co-generators and combined heat and power (CHP) systems also interconnect to the distribution system. The increasing prevalence of dispersed renewable generation and CHP creates challenges for distribution systems. FERC in its Order 2003, and many states through their own rules, have paid close attention to interconnection standards for such generators.[68] Those standards seek to set up simple but safe procedures and standards to smooth the way for the development of distributed

[66] Precisely defining the line of division between transmission and distribution is difficult. FERC discussed this question at length in its Order 888 75 FERC 61,080 at page 400 ff., available at ferc.gov/legal/maj-ord-reg/land-docs/order888.asp. In that Order, FERC adopted a seven-indicator test of local distribution. Those indicators are: (1) local distribution facilities are normally in close proximity to retail customers; (2) local distribution facilities are primarily radial in character; (3) power flows into local distribution systems—it rarely, if ever, flows out; (4) when power enters a local distribution system, it is not reconsigned or transported on to some other market; (5) power entering a local distribution system is consumed in a comparatively restricted geographical area; (6) meters are based at the transmission/local distribution interface to measure flows into the local distribution system; and (7) local distribution systems will be of reduced voltage. Order at 402. Not only is that test complicated, but FERC "recognize[d] that in some cases the Commission's seven technical factors may not be fully dispositive and that states may find other technical factors that may be relevant." Order at page 438.

[67] This subsection deals with retail competition only as it affects the distribution function. Retail competition itself is discussed in Section II.C, below.

[68] Available at http://ferc.gov/legal/maj-ord-reg/land-docs/order2003.asp.

generation. They also standardize the process of studying and negotiating interconnection arrangements so that the utility that owns the distribution system does not favor its own generators over those of its competitors.

Utilities owning distribution systems conduct or participate in long-range planning and engineering studies, as described above under transmission, to ensure both the adequacy and the stability of the grid. This planning evaluates the economics of investments, balancing initial construction cost against life cycle operating costs, especially the costs of providing power to make up for losses in the transmission and distribution system. SCADA monitoring and automation, as well as power electronics, are becoming important design options at this level, too.

5. Retail rate setting

Part of regulating a vertically integrated electric utility is rate setting. Even in the presence of retail competition, rate setting is still required for the distribution function. Each jurisdiction has its own goals, precedents, and laws for rate setting, and U.S. constitutional law has set certain broad limits within which state rate setting must operate. While this report is not a primer on rate setting, a few basic aspects of rate setting and some recent trends will be mentioned here.[69] For example, utility rate regulation is intended to substitute for the discipline of competitive markets, but full-scale rate proceedings are sometimes expensive and time-consuming, imposing a certain amount of uncertainty and delay in cost recovery by utilities. Some states have attempted to address those concerns through mechanisms (sometimes called riders or adjustment clauses) that allow utilities to flow certain costs into rates without a rate case. Such efforts, however, reduce the scope of oversight and relax the reviews that are intended to serve as a substitute for market discipline. Commissions may be faced with proposals to adopt, modify, or repeal such mechanisms.

Traditionally, rate setting is a two-step process: determining the allowable revenue amount and establishing specific tariffs designed to be capable of producing that revenue (under sound and economic management by the utility).[70] Rate design, in turn, has two parts: allocating costs among rate classes and designing the structure of the tariff itself. For each of these different tariff designs, the costs allocated to that customer class

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[69] The issues, including cost of service, rate design and cost allocation, discussed in this subsection are set out in detail in three treatises: Bonbright, Danielsen, and Kamerschen, 1988, *Principles of Public Utility Rates* (recently reissued); Phillips, 1993, *The Regulation of Public Utilities*, Public Utilities Reports; Kahn, *The Economics of Regulation: Principles and Institutions*, MIT Press, 1988, Reissue Edition. The Phillips reference has recently been reprinted. For a practice-oriented review of cost-of-service determination and "the most common, basic regulatory principles, processes, and procedures used by many regulatory commissions to examine and investigate general rate applications," see *Rate Case and Audit Manual*, prepared by NARUC Staff Subcommittee on Accounting and Finance, 2003, available at http://www.naruc.org/Publications/ratecase_manual.pdf. Methods for cost allocation are covered in NARUC, 1992, *Electric Utility Cost Allocation Manual*, available at www.naruc.org/Store/.

[70] In this context, a tariff is a regulator-approved written statement of the terms, conditions eligibility, and charges for a service, such as electricity, made publicly available so that customers may know the charges to which they are subject.

needed to be divided up among the different parts of the tariff. These steps are central to rate setting for vertically integrated utilities, but apply equally to the rates charged by distribution utilities in the presence of retail competition. They may also be relevant to charges for wholesale transmission.

As an example of tariff structure, a utility and its regulators can choose between one-part, two-part, and three-part rates. A one-part rate simply charges a flat fee each month; this would be appropriate for an end use such as street lighting where the monthly energy usage and peak demand are quite predictable. One advantage of a one-part rate is that it avoids the cost of installing and reading a meter. A two-part rate might charge a certain amount each month, plus a usage charge that depends on the number of kilowatt-hours consumed. Using a two-part rate requires making an estimate of the peak load per customer for the affected customer class and determining when that occurs so that they can be assigned a suitable portion of the utility's fixed costs. When a customer's usage is large enough or the time and size of peak usage is unpredictable, a three-part rate can be adopted. It would include the components of a two-part rate, plus a charge that depends on the peak load of the customer. Measuring a customer's peak load requires a more expensive meter, but that may be justified by more accurate billing for a large customer. Then there are real-time rates that require meters able to record usage each quarter-hour through the month. Other types of rates may include different charges for different times of day or seasons of the year, and charges for special equipment provided (such as industrial-size transformers or street lights). Some tariffs provide discounts for customers who allow the utility to control air conditioners or water and space heaters.

These issues of rate setting and rate design are relevant to this report because they have policy implications for utility regulators beyond simply giving the utility an opportunity to earn a fair return on its investment and ensuring that different customer classes are treated fairly. Specifically, the design of tariffs has implications for utility resource needs, economic efficiency, consumer protection, and other aspects of utility regulation. For example, suppose that a two-part rate is offered. A decision must be made about how much of the cost of service will be collected via the fixed monthly charge and how much from the variable usage charge. Shifting costs to the fixed charge decreases the customer's incentive to conserve but increases the certainty of revenue collection for the utility. One approach to this problem is to try to set the usage charge close to the variable cost of providing electricity (sometimes called a "straight fixed-variable rate"); however, short-run variable costs are easy to estimate but would not signal consumers about the high cost of new generators and power lines. On the other hand, long-run variable costs are more difficult to estimate. A variety of approaches can be considered for setting rates in ways that are proper and also encourage efficient use of electricity.[71]

In an era of rising power costs, difficult environmental challenges, and financial stress, rate setting and rate design are increasingly important and challenging to utilities,

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[71] For discussion of ratemaking options for promoting efficient electricity consumption, see Adam Pollock and Evgenia Shumilkina, *How to Induce Customers to Consume Energy Efficiently: Rate Design Options and Methods*, NRRI, 1/10, available at www.nrri.org/pubs/electricity/NRRI_inducing_energy_efficiency_jan10-03.pdf.

consumers, and regulators alike. One avenue being explored in some states is called "alternative regulation." While examples can be found as early as the 1900s, alternative regulation began to take off in the 1980s when the telecommunications industry was being restructured and incumbent utilities were concerned about competition. Instead of rates being set on a strict cost-of-service basis, some telephone companies were allowed to set rates flexibly within certain constraints, including a cap on either prices or revenue. Some such plans adjusted the caps for inflation and performance on preselected criteria (e.g., technology investments) and often required the cap to ramp down to force cost efficiencies. More recently, as electric retail and wholesale competition surfaced in the 1990s, interest in alternative regulation for electric utilities has spread.[72]

B. Wholesale markets and products

1. Products

As described in Section II.A.1, regulation of the production, sale, and transmission of wholesale power was changed significantly during the 1990s to make wholesale generation and trade more competitive. This transition is referred to as "wholesale restructuring." Before wholesale restructuring, utilities acquired electric power for their customers by one or more of three methods: (a) building, owning, and operating generators; (b) owning a share in the output of a generator built and operated by another utility; or (c) purchasing power from other generation owners through bilateral contracts, usually long-term contracts.[73] (Such bilateral contracts were negotiated between the utility and the generation owner and then approved by FERC, which has jurisdiction over the sale of power at wholesale in interstate commerce. Regulatory jurisdiction over the various segments of the electricity industry is described below in Section III.) System operators frequently made less formal daily, weekly, or monthly deals, often on the telephone. Short-term purchases were sometimes made to augment generation reserves to ensure adequacy, but more often were "economy exchanges" that took advantage of cheaper idle capacity, and the utilities would split the savings in operating costs.[74]

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[72] For an early view of alternative regulation, see Paul R. Joskow and Richard Schmalensee (1986), "Incentive Regulation for Electric Utilities," 4 *Yale J. of Regulation*. For a brief summary of alternative regulation formats, see M. N. Lowry and L. Kaufmann, Alternative Regulation for North American Electric Utilities," *Electricity J. June 2006,* 19:5, pp. 15-26.

[73] In the first half of the twentieth century, manufacturers that had built hydroelectric or fossil-fueled generators for their own purposes produced much of the country's electricity, often as co-generation, selling their surpluses to retail utilities.

[74] In a "split savings" transaction—a common type of economy exchange—between two generation-owning utilities, the price would be the midpoint between the buyer's incremental cost (i.e., that of the generator it would have had to run but for the exchange) and the seller's decremental cost (i.e., that of the least generator it had to run because of the exchange). Assume that in a particular hour, the running cost for the buyer's next most expensive generating unit was 7 mils per kWh, while the seller's next most expensive generating unit had a running cost of 5 mils. The purchase price would then be 6 mils. Both buyer and seller would be better off, in the amount of 1 mil, compared to no transaction. (A mil is 1/10 of a cent.)

As power pools came into being (see Section II.A.1, above), they expanded organized trading of economy transactions by applying to the whole power pool the form of power plant scheduling that most electric utilities had previously followed operating their own resources. The process would work as follows: The system operators of the power pool reviewed the operating costs of all generators in the region and scheduled the least expensive set of generators that met reliability needs. This practice is called "security-constrained economic dispatch" or "least-cost dispatch." Thus, to serve a region's load, the pool would dispatch that least-cost set of generators selected from around the region, regardless of who owned them. The result is a lower total cost than if each utility ran its own resources, in isolation, to serve its own load. The savings were shared among the participants.[75]

ISOs and RTOs continue the dispatch functions of power pools, except that dispatch is no longer based on the actual variable operating costs of plants, but on prices bid by plant owners or the entity with rights to the output of a plant. Generally, all successful bidders are paid the highest winning bid, a so-called "clearing price." This approach greatly changed the profit margins of plants with low operating costs. Whether bid-based or cost-based, economic dispatch refers to producing electric energy—kilowatt-hours—in order of increasing variable production cost. Other aspects of electric power also need to be available to keep the system reliable. These include capacity (kilowatts), several types of reserves (capacity that is idling or is available to start up if needed), and more. These extra products (except for capacity) are called ancillary services. ISOs and RTOs procure ancillary services in different ways; some conduct auctions to obtain needed ancillary services.[76] The design and operation of these markets is critical to reliability and controlling costs.

An emerging feature of RTO markets is locational marginal pricing (LMP). LMPs represent the differences among locations in the cost of generating or delivering power that result from transmission congestion and line losses. Congestion is any limit on the flow of otherwise economic power movements due to transmission constraints. That is, an RTO may need to dispatch high-cost generators in some locations because lower-cost power is unable to flow into that region. The extra generation cost is the congestion cost.

[75] The engineering of generators and the system complicates economic dispatch. Some plants need start-up durations of hours or days and cannot shut down quickly without damaging equipment, for example. Therefore, operators need to schedule some units that can respond rapidly to load changes, even if there are cheaper alternatives. Dispatch schedules are prepared in advance (e.g., in the morning of the previous day) and updated as needed to reflect actual loads, unplanned outages, and other events.

[76] For examples of RTO/ISO markets and the products they procure, see Section 1.3 of ISO New England's *2007 Annual Markets Report*, available at www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/2007/amr07_final_20080606.pdf. FERC has recently ordered RTOs/ISOs to accept demand response bids when procuring ancillary services during certain periods of capacity shortages. See 125 FERC ¶ 61,071 at para. 15 et seq., available at http://www.ferc.gov/whats-new/comm-meet/2008/101608/E-1.pdf. A number of RTO/ISO markets have or are considering opening up markets for one ancillary service—frequency regulation—to a novel technology, flywheel storage. Beacon Power Form 10-Q, 11/9/10, p. 30, available at http://phx.corporate-ir.net/phoenix.zhtml?c=123367&p=irol-sec&secCat01.1_rs=11&secCat01.1_rc=10.

The cost of line losses as electricity flows through the transmission lines also affects the LMP. A load far from the power source incurs greater line losses than one close to the source.

2. Competitiveness and market monitoring

A central feature of the wholesale restructuring described above was the introduction of competition into wholesale electricity markets.[77] That restructuring brought with it the potential for the exercise of market power due to concentration of ownership or collusion among market participants. An example of market power is the ability of a firm that owns enough capacity to cause a shortage to bid an arbitrarily high price because its resources are essential to adequate service. As part of its effort to prevent the exercise of market power, FERC requires each RTO to monitor the RTO-managed markets for manipulation. There are both internal market monitors (employees of the RTO) and external monitors (outside contractors retained by the RTO). Monitors examine the markets and transactions for signs that competitiveness is compromised. Internal market monitors also investigate specific transactions.[78] FERC does some market monitoring and has the authority to sanction non-competitive behavior.

Several measurements are used to check that the RTO-administered market for each product is competitive, as well as to detect the presence of non-competitive behavior. While no single test works in all cases, several are widely used. Perhaps the simplest is whether any supplier owns more than, say, 20% of the available capacity. A more sensitive test, the Herfindahl-Hirschman Index (HHI), measures the lumpiness of ownership of resources. A value of zero means no concentration, while a value of 10,000 means one supplier owns all the capacity. Another measurement considers whether any one supplier is pivotal, i.e., indispensable. A supplier is pivotal if it controls more capacity than the surplus capacity available. That is, a pivotal supplier is one who controls enough capacity so that if it withholds some or all of that capacity, there is not enough capacity available on the market to meet the load. So, if in a particular market and a particular hour, demand is 800 MW and total capacity is 1000 MW, a supplier owning 250 MW is pivotal. That supplier is pivotal because withholding its capacity (or at least 201 MW of it) would cause a blackout. Because a pivotal supplier is indispensable, it is able to exercise market power—raising its bid price above competitive levels without a loss of revenue. The three pivotal suppliers test, which determines whether any three suppliers, as a group, are pivotal, is used by some RTOs.[79]

[77] As discussed above, competition in this sense means that (1) non-utility sellers of electricity may participate, (2) bulk transmission is open to all sellers of wholesale electricity without discrimination, and (3) most wholesale sellers of power (i.e., those whom FERC has found have "no market power") may charge market-based rates rather than embedded cost prices.

[78] For a sample internal market monitoring report, see PJM's 2006 *State of the Market Report*, available at www.pjm.com/markets/market-monitor/som-reports.html. On October 17, 2008, FERC issued its Order 719 imposing additional market-monitoring requirements on RTOs. See, 125 FERC ¶ 61,071 at para. 310 et seq., available at http://www.ferc.gov/whats-new/comm-meet/2008/101608/E-1.pdf.

[79] See PJM's *2006 State of the Market Report*, Appendix J, for further details of these tests.

Market designs and rules change frequently to align incentives with competitive outcomes for all of the different regional operators. Most RTO/ISOs continue to develop and refine aspects of LMP, scarcity pricing, ancillary service markets, capacity markets, integration of demand resources, and regional system planning. "Work in progress" is still the best way to view wholesale market structures.

C. Retail competition

Electricity markets have changed rapidly since the mid-1990s. Alongside wholesale market changes, retail competition has been implemented or considered by a number of states. Under retail competition, the vertically integrated utility's legal monopoly, i.e., an exclusive franchise to serve retail customers, historically granted by state statute or state commission decision, is set aside, in whole or in part. The typical state retail competition statute maintains transmission and distribution as monopolies, while opening the retail sale of electricity to competition for some or all customer classes. Firms wishing to compete at retail first must obtain a license from the state commission, then sign up customers and notify the distribution utility (the former incumbent monopoly). The competitive retailer enters into business arrangements with the distribution utility under which (a) the retailer provides the power for that customer (known as "generation service"), and (b) the distribution company meters the customer, bills the customer at the retailer's rate, and hands over money received from that customer to the retailer. These arrangements are complex, but have largely been standardized and are usually done electronically.[80] Some aspects of these business arrangements vary among states or are still evolving, such as treatment of partial payments by retail customers and arrearages.

State statutes allowing retail competition have established a "default service provider" who delivers *generation service* (as distinct from *transmission and distribution services*) for any customer who, for whatever reason, does not have a competitive retail provider. Default service is also referred to as "standard offer service" and "basic generation service," and the default service provider is sometimes called the "provider of last resort." The default service provider is often the distribution utility. In most retail competition states the supermajority of residential customers have not switched to a competitive supplier, and, as a result, continue to be served under default service. Legislators and regulators have to decide what type of default service procurement best serves those customers and what level of price stability should be provided. Some states that implemented retail competition repealed (and a few later reinstated) long-range resource planning with regard to procurement of power for default service.

As of 2009, 16 states and the District of Columbia allowed retail access for some or all customer groups. Seven states had adopted retail access legislation, but later delayed, repealed, or indefinitely postponed implementation.[81] Customer participation in

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[80] For one example of how those business practices were worked out, see www.dps.state.ny.us/98m0667.htm.

[81] U.S. EIA, http://www.eia.doe.gov/cneaf/electricity/page/restructuring/restructure_elect.html, accessed 1/7/11.

retail competition (called "shopping") varies widely by state and customer class. For example, as of 2006, in the residential class, Texas had about 40% participation. Massachusetts, New York, and Ohio participation ranged from about 7 to 19%, with all other retail choice states seeing participation of less than 5%. In the larger commercial and industrial classes, participation is higher. In 2009, for the U.S. as a whole, 2.3% of customers were served by an "energy only" provider, typically a competitive retail provider, with 2.1% of the residential class and 2.7% of the industrial class doing so.[82] Default service rates were often capped for a period and have risen considerably after those caps expired.[83] Some legislatures, such as those in Ohio, Illinois, and California, have revised their retail competition statutes due to the paucity of retail suppliers and the small percentage of shoppers. Other legislatures, like Pennsylvania's, are revisiting their statutes as of this writing.

Some state retail competition statutes, or their implementing regulations, required or encouraged divestiture of generation assets by utilities to promote competition among generators. "Stranded cost" refers to ongoing costs (mainly capital recovery for power plants and the charges from must-take power contracts) that were incurred by utilities prior to restructuring and that the utilities would not or might not be able to recoup or avoid under retail competition. The stranded cost is the portion of those prior commitments in excess of competitive market prices. Recovery of those stranded costs was often contentious, but generally allowed, at least in part. Between 1998 and 2002, about 20% of U.S. generation facilities changed hands as a result of divestiture under restructuring, either sold to unregulated companies or transferred to unregulated affiliates of the utility.[84] The specifics of restructuring (or lack thereof) in each state depended on local political, regulatory, and economic issues. A detailed understanding of each state's experience is best obtained from its public utilities commission.[85]

D. Demand-side management

Throughout the United States there is significant untapped potential to improve the efficiency with which consumers use electricity. Electricity customers with aging, lower-efficiency equipment could replace it with newer, more efficient models or select a high-efficiency model when purchasing a new piece of electric equipment.[86] Demand-side management (DSM) programs are activities designed to promote greater energy

[82] EPA 2009, Table 7.1.

[83] See Rose and Meeusen, *2006 Performance Review of Electric Power Markets* for post-restructuring participation rates and retail prices. Available at http://www.kenrose.us/sitebuildercontent/sitebuilderfiles/2006_Performance_Review.pdf.

[84] Interlaboratory Working Group, 2000, *Scenarios for a Clean Energy Future*, Oak Ridge National Laboratory, Lawrence Berkeley National Laboratory.

[85] For a review of results and issues through 2003, see Brown and Sedano, *A Comprehensive View of U.S. Electric Restructuring with Policy Options for the Future*, National Council on Electric Policy. Available at www.ncouncil.org/Documents/restruc.pdf. See also Electric Energy Market Competition Task Force, *Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy Pursuant to Section 1815 of the Energy Policy Act of 2005*, available at www.ferc.gov/legal/fed-sta/ene-pol-act/epact-final-rpt.pdf.

[86] Interlaboratory Working Group, op. cit.

efficiency or to reduce loads during peak load hours (called demand response programs).[87] These programs usually involve targeted rebates towards the purchase of energy-efficient equipment or appliances, and incentives plus educational efforts to move the building trades towards use of energy-efficient practices.

Electric utilities began DSM programs in the early 1980s. In the late 1980s and early 1990s, utility investments in DSM increased and were generally recovered in base rates or via cost recovery riders.[88] Under integrated resource planning (discussed in Section II.A.1, above), DSM programs are treated as resources available to meet customer demand on an equal footing with building power plants. With the introduction of (or the prospect of) retail competition in the 1990s, utility DSM offerings shrank as the attention of regulators and utilities focused on other issues. In 1993, U.S. electric utility investments in energy efficiency peaked at roughly $1.6 billion. By 1997, utility DSM outlays were roughly $900 million, down about 44%—a sharp turnaround from previous growth. In terms of amount of energy saved, utility energy-efficiency programs saved about 8000 MWh in 1995, about one-fourth of one percent of retail sales that year. The additional savings achieved each year declined from that level, bottoming out at about 3000 MWh in 2003. Incremental savings in 2006 had climbed back, but only to about 5400 MWh. Peak load savings from load management followed a similar but more erratic pattern, dropping from about 5100 MW in 1996 to about 1000 MW in 2000, and then rising again to just under 3,000 MW in 2008.[89]

In response, some states introduced a new policy—the system benefits charge (SBC)—to ensure that efficiency efforts would continue despite retail competition. An SBC is a charge collected from all distribution customers, regardless of generation service provider, to fund DSM programs (and in some cases other activities that offer public benefits). SBC policies have been primarily responsible for a turnaround in the decline in utility investment in energy efficiency. Between 1998 and 2009, U.S. electric utility expenditures on energy efficiency increased significantly, from $0.9 billion to about $3.4 billion in direct costs.[90] Load management expenditures followed a similar pattern.[91]

Many electric energy-efficiency measures cost significantly less per kWh than generating, transmitting, and distributing electricity. Demand response programs can cost

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[87] For a wide range of reports on DSM programs, options, and policies, refer to the web sites of ACEEE (aceee.org), the National Action Plan for Energy Efficiency (http://www.epa.gov/cleanenergy/energy-programs/suca/resources.html), and the Alliance to Save Energy (www.ase.org). NAPEE is a public-private partnership of the U.S. EPA and DOE, gas and electric utilities, state agencies, energy consumers, energy service providers, and environmental/energy efficiency organizations.

[88] A rider is a provision in (or affecting) a rate tariff that adjusts the rate up or down for some purpose, often to collect a cost that is not predictable in advance.

[89] EPA 2009, Table 9.3.

[90] York and Kushler, 2010, *The 2010 State Efficiency Scorecard*, American Council for an Energy Efficient Economy (ACEEE). For the current edition, see http://www.aceee.org/research-report/e107/.

[91] EPA 2009, Tables 9.1 and 9.7.

less per kW than building new generators and transmission lines. Properly designed and implemented DSM programs reduce system-wide electricity costs and lessen customer bills. In addition, energy efficiency reduces risks from fossil fuel dependence and environmental impacts while increasing reliability and wholesale market competitiveness, cutting stress on transmission and distribution (T&D) systems and promoting local economic development, competitiveness, and energy independence.[92]

Three DSM policy issues are central for regulators: (1) what savings are available and cost-effective and should be acquired, (2) how to deliver programs, and (3) how to treat programs in ratemaking.

Determining the available cost-effective savings and deciding which savings should be acquired begins with a study of the technical, economic, and achievable potential in each customer group and type of use. Potential studies lay a solid foundation for decision-making.[93] Cost-benefit testing is crucial to the proper design of DSM programs (just as it is in the choice of generation and T&D options). Standardized definitions of those tests are available, but care is needed to ensure proper use and input assumptions.[94] Choices about which test or tests to use often inspire disagreement. The Total Resource Cost Test measures the impact of a measure or program on the life cycle cost of electric service as a whole, and is widely used. Some states supplement that test with an estimate of the costs of environmental impacts.[95]

DSM delivery mechanisms vary. Most states rely on distribution or vertically integrated utilities to plan and deliver programs. Some jurisdictions (Maine, the District of Columbia, Illinois, Ohio, Wisconsin, and New York) assigned some or all of the

[92] For more on DSM benefits, see Biewald, et al., *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers*, Synapse Energy Economics, http://www.synapse-energy.com/Downloads/SynapseReport.2003-10.RAP.Portfolio-Management.03-24.pdf; Nadel, Gorden, and Neme, 2000, *Using Targeted Energy Efficiency Programs to Reduce Peak Electrical Demand and Address Electric System Reliability Problems*, American Council for an Energy Efficient Economy (ACEEE), http://www.aceee.org/node/3078?id=525; and Cowart, 2001, *Efficient Reliability: The Critical Role of Demand-Side Resources in Power Systems and Markets*, Regulatory Assistance Project (RAP) prepared for the National Association of Regulatory Utility Commissioners, http://www.raponline.org/Pubs/General/EffReli.pdf; *Quantifying Demand Response Benefits in PJM*, 2007, The Brattle Group, http://sites.energetics.com/MADRI/pdfs/brattlegroupreport.pdf; U.S. EPA, *Assessing the Multiple Benefits of Clean Energy: A Resource for States*, 2/10, available at http://www.epa.gov/statelocalclimate/documents/pdf/epa_assessing_benefits.pdf.

[93] For a discussion of current best practices in DSM potential studies, see the NAPEE *Guide for Conducting Energy Efficiency Potential Studies*, available at http://www.epa.gov/cleanenergy/documents/suca/potential_guide.pdf.

[94] For definitions of DSM cost-benefit tests, see the *Standard Practice Manual* of the California PUC and Energy Commission, 2002, available at www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF.

[95] For a discussion of each of the tests and their appropriate use, see Chapter 6 of Biewald, et al., *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers*, Synapse Energy Economics, available at www.synapse-energy.com/Downloads/SynapseReport.2003-10.RAP.Portfolio-Management.03-24.pdf. Chapter 5 discusses the specifics of load forecasting, as well.

responsibility to state government. Oregon established an independent, non-profit agency, the Energy Trust of Oregon, Inc., to administer the energy-efficiency programs there. Vermont established a new function, the Vermont Energy Efficiency Utility, to act as an energy-efficiency utility, independent of the electric utilities in the state, and solicits competitive bids to provide that function.[96]

Ratemaking treatment of DSM programs is also varied and fluid. The main issues are: (1) recovery of costs of programs, (2) recovery of lost revenue, and (3) performance incentives for utility shareholders. Utilities are generally provided with some mechanism for recovering the costs of their DSM programs, such as an adjustment rider, authorization to book and defer the costs for possible future recovery (if the commission permits), or, as mentioned above, a system benefit charge. Recovery of lost revenue arises as a ratemaking issue because DSM reduces retail electricity sales. Some short-run expenses are avoided (less fuel burned, for example), and very large savings are reaped in the long run. However, under typical retail tariffs, where at least some of the fixed-cost revenue collection is based on kWh consumption, the utility still loses the portion of its rate that was meant to cover fixed costs (interest and depreciation, for example) and its return to stockholders (the “net lost margin”). Some states track net lost margins and allow their recovery. Some adopted “decoupling” as a means of preventing lost margins. One version of decoupling adjusts rates to make the utility’s net revenue constant, independent of the amount of electricity sold, rather than just to eliminate net lost revenue from DSM programs. Finally, some states have determined that utilities should be rewarded, over and above cost recovery and lost revenue recovery, for DSM performance. Performance incentives can be a share of the power costs saved, a share of the DSM budget, a sliding scale, or other mechanisms.[97] Decisions about recovery of net lost revenue or decoupling and about shareholder incentives may be strongly contested.

DSM programs require specialized monitoring, verification, and evaluation (MV&E). Due to the variety of measures and programs, these activities are more complex than for supply-side measures. Regulators pay attention to process evaluation (assessment of how programs function and may be improved) early during implementation and at intervals thereafter. Regular monitoring systems, including a tracking database, are needed, as well as validation of recorded costs and savings. Impact evaluation should be done regularly, including assessment of how programs have affected market practices in construction and purchasing. Some states require evaluation by an independent party.[98]

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[96] Harrington and Murray, 2003, *Who Should Deliver Ratepayer-Funded Energy Efficiency? A Survey and Discussion Paper*, Regulatory Assistance Project (RAP), available at raponline.org/Pubs/RatePayerFundedEE/RatePayerFundedEEFull.pdf.

[97] For discussion of lost revenue and incentive issues, see NAPEE’s *Aligning Utility Incentives with Energy Efficiency Investment*, available at http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf.

[98] For guidelines on DSM program evaluation, see NARUC’s 1997 *Evaluating Energy-Efficiency Programs In a Restructured Industry Environment: A Handbook for PUC Staff*, available at www.naruc.org/Store/, and NAPEE’s *Model Energy Efficiency Program Impact Evaluation Guide*, available at http://www.epa.gov/cleanenergy/documents/suca/evaluation_guide.pdf.

As with low-carbon generation technologies, extensive R&D efforts to find new or improved energy-efficiency technologies and policies are underway. For example, while compact fluorescent lights, a flagship technology of DSM in the 1990s, are beginning to be displaced by light emitting diode (LED) equipment due to its efficiency, absence of mercury, size and lifetime, research continues to better balance light color and further improve cost and efficiency. During the 1990s, DSM planners began to raise concerns about rapid growth in power demand from "plug loads," appliances and electronic equipment that plug into wall outlets. While often modest individually, their proliferation in the modern home and office has created a substantial effect. In particular, many modern plug loads are "always on" even when turned off, including "instant on" televisions and power adaptors for computers and the like. These "vampire" loads are now the subject of R&D and energy standards.[99] One technology recently announced is said to electronically disconnect a power supply or other vampire load in to which it is built. On the program design front, rather than the technology side of DSM, programs are exploring the concept of "deep retrofit," seeking to obtain the maximum possible cost-effective savings in a structure all at once to help meet long-term savings goals as well as to avoid costly revisits to the same structure.

While some states have had substantial DSM programs since about 1990, a number of others have recently become engaged in DSM policy and program deployment. Oklahoma and a number of other states have recently adopted new DSM rules.[100] Demand response has received significant policy attention in the past few years, as well.[101]

E. Portfolios and risk management

Volatile fuel prices and the need for large investments in utility plant or power contracts create uncertainties that utilities and their regulators must address. Portfolio and risk management are approaches to doing so.

The portfolio approach to resource planning offers electric utilities and their regulators a disciplined approach to risk management. Portfolio management is an extension of integrated resource planning (IRP) that puts extra emphasis on uncertainty and risk relative to the weight given to expected costs. Portfolio management requires

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[99] Recently announced technologies claim to electronically disconnect a power supply or other vampire load it is built into. Martin LaMonica, "CES: Freescale chip chops vampire draw to zero," 1/3/11, available at http://news.cnet.com/8301-11128_3-20026972-54.html, and "CES: Green Plug plugs digital, efficient power supply," 1/5/11, available at http://news.cnet.com/8301-11128_3-20027316-54.html.

[100] See, for example, Oklahoma Corporation Commission T. 165, Ch. 35, Sub-chapter 41, adopted 12/4/08, especially section 165:35-41-4(b)(10) regarding "hard-to-reach customers." Available at http://www.occeweb.com/rules/2010Ch35ElectricpermanentMasterRuleseff7-11-10searchable.pdf. Other jurisdictions that have moved or considered moving on DSM rules in recent years include Mississippi, Florida, Virginia and South Carolina.

[101] See, for example, FERC Order No. 890, FERC Stats. & Regs. ¶ 31,241 and RM10-23-000 at 131 FERC ¶ 61,253. For discussion of the current context for demand response, see Scott Hempling, *Demand Response and Aggregators of Retail Customers: Legal, Economic, and Jurisdictional Issues*, http://www.nrri.org/pubs/electricity/NRRI_demand_response_issues.pdf.

several key steps on the part of electric utilities or default service providers. Starting with a load forecast, portfolio managers assess available options for meeting customer demand, including new power plants, DSM procurement, wholesale spot markets, short-term and long-term forward contracts, derivatives, distributed generation, building or purchasing renewable resources, and adding or upgrading transmission and distribution. The most challenging step in portfolio management is to develop the optimal mix of these resources that will best achieve various objectives identified by the utility and promoted by the regulators. This step includes quantifying the uncertainties in the projected costs of the various resources and of candidate portfolios as a whole. Resource decisions are then based on choosing the portfolio strategy that delivers the desired degree of risk control at the lowest long-term cost.[102] Portfolio management can be important for both restructured and vertically integrated utilities.[103] Driven in part by portfolio management opportunities and climate change concerns, as well as the slowdown of transitions to retail competition, there has been a revival of interest in integrated resource planning, with an emphasis on clean energy portfolios.[104]

F. Environmental issues

Production and delivery of electric power generation have many different direct and indirect environmental impacts. These can include:

1. Air emissions (including sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulates, mercury, lead, other toxins, and greenhouse gases), with associated health and ecological damages;

2. Fuel-cycle impacts of front-end activities, such as mining, transportation, and waste disposal;

3. Water use and pollution, including thermal pollution;

4. Land use and post-operation cleanup issues;

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[102] For a review of these concepts and tools for implementing them, see Biewald, et al., *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity Services to All Retail Customers*, Synapse Energy Economics, available at www.synapse-energy.com/Downloads/SynapseReport.2003-10.RAP.Portfolio-Management.03-24.pdf, and Steinhurst, et al., 2006, Portfolio Management: Tools and Practices for Regulators, available at www.synapse-energy.com/Downloads/SynapseReport.2006-07.NARUC.Portfolio-Management-Tools-and-Practices-for-Regulators.05-042.pdf.

[103] Portfolio management also can apply to gas and transportation procurement by utilities. Gas utilities have increasingly shifted from a least-cost paradigm to behavior that recognizes the price and supply risks associated with gas and pipeline purchases from various sources. Gas utilities recognize the value of diversification in giving them more flexibility and protection from uncertain futures events. See Ken Costello, *Gas Supply Planning and Procurement: A Comprehensive Regulatory Approach*, NRRI 08-07, 2008, available at nrri.org/pubs/gas/Gas_Supply_Planning_and_Procurement_jun08-07.pdf.

[104] See, for example, David Boonin, *Clean Energy Scenario Planning: Thoughts on Creating a Framework*, http://www.nrri.org/pubs/electricity/NRRI_clean_energy_scenario_planning.pdf.

5. Aesthetic impacts of power plants and related facilities, including visual, noise, and odor impacts; and

6. Radiological exposures related to nuclear power plant fuel supply and operation (both in routine operation and in possible accident scenarios).[105]

Some environmental concerns, such as land use and aesthetics, are addressed in siting reviews of power plants and transmission lines. State commissions usually conduct those reviews. Environmental regulators set other environmental requirements, but utility regulators supervise the resulting costs, risks, and resource choices as part of overseeing utility planning and operations, supervised by utility regulators. For example, compliance with air emissions regulations can be a major consideration in electric utility resource planning since they influence the relative operating costs of resource options, and because major capital investments can be necessary for emissions control equipment to meet increasingly tight regulations over time. System operations can also play a role in air emissions compliance, since generating unit dispatch can influence system emissions, and since some caps are set for specific time periods (e.g., NO_x regulations that focus on ozone-season emissions only).

Some utility regulators have addressed environmental costs to society that are not reflected in prices, referred to as "externalities," by requiring that utility planning impute monetary values for certain air emissions.[106] Environmental regulations limiting emission levels have forced suppliers and buyers to consider at least a portion of those costs in their production and use decisions, thereby internalizing a portion of those costs. One example is the Clean Air Interstate Rule, passed by Congress in March 2005, requiring reduction of SO_2 emissions by about 73% from 2003 levels.

An important recent environmental development in electric power—one accompanied by much uncertainty—is the emergence of climate change policy as a planning issue. In 2004, electric power production caused 39% of total U.S. carbon dioxide (CO_2) emissions. Over four-fifths of that was from coal-fired power plants.[107] Recent Congresses have considered several approaches, some imposing caps on total emissions of greenhouse gases. Among the fossil fuels, coal emits the most CO_2 per kWh of electricity produced due to the high carbon content of the fuel and the relatively low efficiency of steam-fired generation. The carbon content per unit of available energy is lower for natural gas than for coal, and modern natural gas-fired power plants are relatively fuel-efficient, so CO_2 emissions rates per kWh are roughly one-half of those for coal-fired generation.

[105] There are also a number of non-environmental effects that can be associated with electricity, including economic effects (generally focused on employment), energy security, and others.

[106] An externality is a cost of an action that is not borne by the decisionmaker. An environmental externality is an environmental effect whose cost is borne by someone other than the person who creates that effect. For example, buildings and crops downwind from a power plant that emits SO_2 suffer the effects of acid rain. Because the generator owner does not compensate affected owners, the cost of that damage is an environmental externality of running the power plant. Compliance with environmental regulations does not mean the environmental externalities are eliminated.

[107] *Electric Power Annual*, 2007, Table 1.1.

One of the most important and challenging aspects of electric system planning is figuring out how to incorporate future carbon dioxide regulations into the analysis. Some form of carbon regulation seems inevitable, but the timing, stringency, and implementation details are all quite uncertain. Governmental agencies and private consulting firms have conducted modeling studies and carbon dioxide price forecasts that can be helpful.[108]

Greater attention has been paid in recent years to certain other environmental concerns from electric generation. One of these is the "once-through cooling" (OTC) issue. All thermal power plants require constant cooling to protect the equipment and maximize thermal efficiency. One of the most convenient and cheapest technologies for that is OTC, where water is taken from a river, lake, or ocean, used to cool the plant, and then discharged. This has thermal effects on the discharge destination and may have effects on the intake source, as well. In California, this has been identified as a significant threat, and a ban on once-through cooling is being phased in.[109]

Another environmental issue drawing renewed attention is coal combustion waste (CCW or coal combustion byproducts). In the wake of the December 2008 release of more than 5 million cubic yards of waste from a coal ash storage pond at TVA's Kingston Fossil Plant into the Emory River, public and regulatory pressure to address the disposal of CCW is high. This public pressure stems from not only the concerns that the ash ponds which are sometimes used to store CCW, as was the case at the Kingston Plant, are inadequate to physically contain the CCW, but from knowledge of the toxic content of the CCW. In the aftermath of the Kingston spill, elevated levels of arsenic and mercury have been found in the river water and sediment near the site. It is now commonly appreciated that the toxicity problem may worsen as emissions controls become more common.[110] Commissions regulating utilities with significant coal exposure may expect issues to arise regarding the need for and cost and risks of CCW disposal.

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[108] See, for example, Schlissel, et al., *Synapse 2008 CO2 Price Forecasts*, available at www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.2008-Carbon-Paper.A0020.pdf, for a review of carbon costs and recent federal legislation proposals.

[109] "OTC can cause adverse impacts when aquatic organisms are trapped against a facility's intake screens (impinged) and cannot escape, or when they suffer contact injuries that increase mortality. Likewise, smaller organisms, such as larvae and eggs, can be drawn through a facility's entire cooling system (entrained) and subjected to rapid pressure changes, chemical treatment systems, and violent sheering forces, only to be discharged along with the now heated cooling water and other facility wastewaters. . . . OTC systems . . . present a considerable and chronic stressor to the State's coastal aquatic ecosystems by reducing important fisheries and contributing to the overall degradation of the State's marine and estuarine environments." (CA) State Water Resources Control Board, *Water Quality Control Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling: Final Substitute Environmental Document*, 5/4/10, available at http://www.waterboards.ca.gov/water_issues/programs/npdes/docs/cwa316may2010/sed_final.pdf. For final policy, see http://www.waterboards.ca.gov/water_issues/programs/npdes/docs/cwa316may2010/otcpolicy_final050410.pdf.

[110] U.S. GAO. *Letter to the Chairman of the Senate Committee on Environment and Public Works and Chairman of the House of Representatives Committee on Oversight and Government Reform RE: Coal Combustion Residue: Status of EPA's Efforts to Regulate Disposal*. October 30, 2009.

III. Economic Regulatory Jurisdiction in the U.S. Electric Industry[111]

A. In general

Regulatory jurisdiction addresses nouns and verbs: a defined entity performing a defined activity. In the electric industry, focusing on economic regulation, the relevant activities—the verbs—are:

- selling electricity at wholesale and at retail
- transmitting wholesale power and retail power
- distributing wholesale power and retail power
- merging with others and divesting or acquiring assets
- issuing equity or debt
- siting transmission facilities
- siting generation facilities
- operating nuclear power plants

What entities—what nouns—perform these activities? The answer is defined by federal and state statutes. Under the Federal Power Act, the regulated entity is, in most cases, a "public utility," defined as any entity that sells power at wholesale in interstate commerce or transmits electricity in interstate commerce. In federal law, a public utility thus can be a traditional vertically integrated utility, an independent generating company, an independent marketer, a regional transmission organization, or simply a "person." Under state law, the answers will vary, but in most cases a "public utility" will be a person or company that sells electricity to the public.

Turning to jurisdiction: The two main players are the Federal Energy Regulatory Commission, acting under the Federal Power Act; and state commissions, acting under state law. The other players include the U.S. Department of Energy, the U.S. Nuclear Regulatory Commission, the U.S. Department of Justice, and the Federal Trade Commission. (The Securities and Exchange Commission reviews certain public issuances of debt and equity, but since that jurisdiction applies to all companies, not just utilities, we will omit further discussion of it here.[112])

The main economic regulatory jurisdiction is divided between FERC and the state commissions. The statutory basis for the jurisdictional divide is Federal Power Act Section 201(b)(1):

> The provisions of this Part [16 USCS sec. 824 et seq.] shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided

[111] Scott Hempling, Esq., Executive Director of NRRI, wrote Section III of this paper.

[112] Prior the its 2005 repeal, the Public Utility Holding Company Act of 1935 obligated the SEC to review the appropriateness of certain issuances of debt and equity by certain public utilities and utility holding companies. That SEC authority no longer exists.

> in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have jurisdiction, except as specifically provided in this Part [16 USCS sec. 824 et seq.] and the Part next following [16 USCS sec. 825 et seq.], over facilities used for the generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter.

This language, and decades of judicial interpretation, tell us that jurisdiction over particular entities performing particular activities can be vested either in FERC exclusively, in states exclusively, or concurrently in both levels of government. Where the jurisdiction is concurrent, there can be several different results. In the context of the reliability of the electric "bulk power system," Section 215(i)(3) allows state jurisdiction unless state decisions are "inconsistent with" federally approved standards; state decisions inconsistent with federal standards are preempted. In the merger context, in contrast, there is no preemption: if FERC approves a merger but a state disapproves the merger, and vice versa, the merger fails.

Interstate commerce: Decisions by the Federal Power Commission (FERC's predecessor) in the late 1960s established that because (a) the entire continental U.S. is electrically interconnected, and (b) electrons from electricity production originating in different states commingle within the interconnected grid, therefore transmission of electricity within the continental U.S. is deemed to be transmission in interstate commerce, even if as a matter of contract the origin and destination of the transmitted electricity lie within the same state. The U.S. Supreme Court has upheld these FPC decisions. The interstate commerce criterion applies to wholesale sales also. A wholesale sale from Florida Power & Light to a Florida municipal is in "interstate commerce," and thus FERC-jurisdictional, even though the contractual origin and destination are in the same state.[113]

The table on page 37 entitled "Economic Regulatory Jurisdiction in the U.S. Electric Industry" tracks the foregoing discussion. The first column lists activities (verbs); the second column lists do-ers of those activities (nouns). The subject matter comes next. Then come three columns related to jurisdiction: FERC-exclusive, state-exclusive, and concurrent. In a few cases, other entities get involved.

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[113] There are three states in which transmission transactions remain outside of "interstate commerce": Alaska and Hawaii (because neither state is part of or interconnected with the rest of the interstate grid); and part of Texas (because until the late 1970s there was no interconnection between that portion of Texas; there is a minor interconnection now, but there is a special federal statutory provision that limits FERC jurisdiction to service provided over that interconnection but otherwise keeps all internal Texas transmission service outside of FERC jurisdiction).

B. A word on transmission service

Because the jurisdiction over entities providing transmission service is complicated, we offer a narrative description here.

An entity providing transmission service can provide transmission of wholesale power or retail power. Transmission of wholesale power is always subject to FERC jurisdiction. Transmission of retail power is a different story. In its Order No. 888 (1966), FERC established that transmission of retail power is subject to FERC jurisdiction, if the transmission service is "unbundled" from the sale of the power. “Unbundled” means that the seller of transmission service sells it separately from its generation products, meaning in turn that a customer can buy its transmission service from one entity and its generation from another. As of this writing, unbundled transmission service, for the transmission of retail power, occurs in two contexts. The first context is in those states that have authorized competition to provide retail electric service. In those states, retail customers (or the marketers that serve them) can buy generation from one source and transmission from another source. FERC's Order 888 deemed such transmission service to be subject to its jurisdiction. The U.S. Supreme Court upheld FERC's Order 888 in *New York v. United States*.

The second example of unbundled, FERC-jurisdictional transmission of retail power occurs when a transmission-owning utility has joined a "regional transmission organization" (RTO). An RTO enters into a contract with a region's transmission-owning utilities. That contract leaves ownership of the transmission facilities with the utilities, but transfers functional control of the transmission assets to the RTO. The RTO thus becomes the legal provider of transmission service, subject to FERC jurisdiction as a "public utility." FERC has determined that RTO-provided transmission service is FERC-jurisdictional service, even when the power transmitted is retail power, because the provision of the service by the RTO rather than the transmission facility owner means that the transmission service is "unbundled" service.

Economic Regulatory Jurisdiction in the U.S. Electric Industry

			Jurisdiction			
What Action is Regulated?	***Who* is Regulated?**	**What *Subject Matter*?**	**FERC Exclusive[a]**	**State-Exclusive**	**Concurrent FERC and State**	**Other**
Sale of electricity at retail	public utility	Rates		FPA 201		
Sale of electricity at wholesale	public utility	Rates	FPA 201, 205			
Transmission of retail electricity, bundled[b]	public utility	Rates		FPA 201		
Transmission of retail electricity, unbundled[b]	public utility	Rates	FPA 201, Order 888, New York v. U.S.			
Transmission of wholesale electricity, bundled	public utility	Rates	FPA 201			
Transmission of wholesale electricity, unbundled	public utility	Rates	FPA 201			
"Local" distribution of retail electricity	public utility	Rates		FPA 201		
"Non-local" distribution of wholesale electricity[c]	public utility	Rates	FPA 201			
Merge with utility; acquire utility or utility assets	public utility, person	corporate structure			FPA 203, PUHCA 2005	DoJ, FTC (antitrust)
Issue equity or debt[d]	public utility	Finance				FPA 204
Own, use, or operate bulk power system[e]	owner, user, or operator of the bulk power system	Reliability			FPA 215	
Site transmission[f]	Person	transmission need, siting				FPA 216
Site generation	Person	generation need, siting		FPA 201		
Construction and operation of nuclear plants	plant owner	nuclear safety				NRC

Notes:

[a] Section 201 restricts FERC's authority to regulate transactions in interstate commerce. Court, FPC, and FERC cases have found that due to the interconnectedness of the grid, all electricity transactions are in interstate commerce, regardless of their contractual origin or destination, with the exception of transactions in Alaska, Hawaii and Texas.

[b] FERC and the U.S. Supreme Court have determined that when, as a result of state or federal law, transmission service becomes "unbundled" (meaning that the customer can purchase other products, like generation, from other sellers while buying transmission service from the transmission owner, then the jurisdiction over rates, terms and conditions is exclusively FERC jurisdiction. In a traditional sale of retail electricity, transmission remains bundled with the electricity itself, thus the state retains jurisdiction over the associated transmission cost. In two situations presently recognized by FERC, the transmission of retail power becomes unbundled: (a) where the state has authorized retail customers to shop for power among competing retail sellers; and (b) where the utility has joined a regional transmission organization, because in that situation the utility is buying transmission service from the RTO.

[c] Section 201(b)(2) denies FERC jurisdiction over "local" jurisdiction. FERC has found that distribution of wholesale power is non-"local" distribution. This unusual situation arises when a buyer of wholesale power is connected to a transmission service provider at distribution voltage.

[d] Federal Power Act Section 204 provides that FERC has jurisdiction only if the state does not.

[e] Federal Power Act Section 215(i)(3) provides that State regulation is preempted if "inconsistent with" federal standards. Note: Section 215 does not apply to Alaska or Hawaii. See Section 215(k).

[f] Before 2005, states had exclusive jurisdiction over transmission facility siting. Concerned that one state might block projects necessary to serve other states, Congress in 2005 added Section 216 to the Federal Power Act. This section grants FERC the power to award an applicant a preemptive siting right, if the state has withheld approval, disapproves, or has no jurisdiction to grant siting permission. Three contiguous states may form a compact to oust FERC. Note: Section 216 does not apply to Alaska or Hawaii.

IV. Current Industry and Regulatory Issues

This section briefly presents some of the important challenges facing the U.S. electric industry and its regulators. The order in which they are presented does not reflect any kind of prioritization.

1. With the granting of monopoly franchises to electric utilities in the early 20th century, state commissions relied on ratemaking based on embedded cost as a substitute for competitive forces. Traditional ratemaking, especially rate-base/rate-of-return regulation, had been honed over many decades, by commissions, utilities, and regulatory practitioners, into a system that, on balance, was accepted by industry professionals as consistent with the multiple interests and values at stake in utility regulation. Since the mid-1990s, regulators and, in some cases, legislatures have introduced, or received proposals for, new forms of ratemaking and cost review. Performance-based ratemaking, contract regulation, battles over prudence and used-and-useful standards, special provisions for DSM ratemaking, demands for rates that promote demand response or economic development or renewable generation, and many more trends have overlapped and interacted. The same time period saw heightened levels of advocacy and increasingly technical issues that have changed the conduct of hearings and the necessary content in commission orders. Integrating fundamental ratemaking concepts and goals with those new concepts and pressures is likely to challenge regulators for some time.[114]

2. The nation's financial crises, emerging in fall 2008, will affect utility finance in uncertain ways. The electric industry is highly capital-intensive and will need huge amounts of new capital in the coming decades for expansion and replacement of outdated equipment, as well as for meeting new challenges such as climate change.[115] Utilities have faced weakened demand and higher debt costs, plus some disruption of access to capital.[116] The industry has encountered rough financial waters before. High interest rates in the late 1980s burdened some nuclear plant owners during plant construction. In the 1990s, changes to the formulae used in setting bond ratings for utilities made it more challenging for utilities with large, long-term power purchase contracts to maintain high credit ratings. Late in the 1990s, bank financing for natural gas exploration became harder to obtain, increasing equity requirements for natural gas drillers among other effects that rippled through the electric industry.[117] The appearance of non-utility participants in wholesale power markets during the 1990s had the unexpected and novel effect of

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[114] Some treatises that set out those fundamentals are Bonbright, Danielsen, and Kamerschen, 1988, *Principles of Public Utility Rates* (recently reissued); Phillips, 1993, *The Regulation of Public Utilities,* Public Utilities Reports; Kahn, *The Economics of Regulation: Principles and Institutions*, MIT Press, 1988, Reissue Edition. The Phillips reference has recently been reprinted. For discussion of ratemaking options for promoting efficient electricity consumption, see Adam Pollock and Evgenia Shumilkina, op. cit., fn 71 above.

[115] One estimate foresees a need of up to $2.0 trillion in the next two decades. Marc W. Chupka, Robert Earle, Peter Fox-Penner, and Ryan Hledik, *Transforming America's Power Industry: The Investment Challenge 2010-2030*, The Brattle Group, 11/08.

[116] Julie Cannell, *The Financial Crisis and Its Impact On the Electric Utility Industry*, 2/09, available at http://www.eei.org/ourissues/finance/Documents/Financial_Crisis_and_Industry.pdf.

[117] M. Popper, "Wildcatters Face a Dry Financial Field," *Business Week*, Nov. 20, 2000.

requiring utilities to post significant collateral for trades in power markets. A major change in utility accounting standards is in the making in the U.S. and Canada.[118] These and other novel financial issues will challenge utilities and regulators for some time.

3. There is considerable controversy about the future need for electricity and how to meet it. International competition for the raw materials, specialized manufactures, and skilled labor needed to build generation is rising. Both fossil fuels and nuclear power remain problematic, with strong promoters and serious detractors. Much of the nation's fossil fuel-generating fleet is aging, inefficient, increasingly unreliable, and environmentally damaging. Regulators and utilities will need to face all of these concerns and determine the best choices for consumers in terms of both economics and risk.

4. Fossil fuels remain central to power production in the U.S. Utilities and regulators must find ways to address the seemingly permanent fact of volatile prices for oil and natural gas. Current low prices for natural gas make coal less attractive, and even coal—long stably priced—has begun to exhibit increased prices and price fluctuations. Availability is also an issue, as demonstrated by Hurricane Katrina and occasional railroad shipping limitations for coal. New or heightened environmental concerns, such as greenhouse gas and mercury emissions, will need to be addressed. Shale gas plays are being developed at a rapid pace, but may face environmental challenges due to the controversial and highly secretive hydraulic fracturing fluids being used. Novel and capital-intensive technologies will be needed if coal is to continue to be used on anything like the current scale.

5. The nuclear power industry also faces major decisions. Public concerns about safety, radiological pollution, and terrorism remain and are in tension with the claimed climate-change benefits of nuclear power. Disposal of radioactive waste remains challenging, particularly for spent fuel. The leading edge of the existing fleet of nuclear plants is in the midst of retirement or relicensing, raising concerns about longevity and reliability. Many nuclear power plants have changed hands, leading to increased concentration of ownership, economies of scale, and materially increased output. Relicensing applications may require significant capital investments to refit them for another 20 years of operation, but those costs are minor compared to the current estimates of the cost of new nuclear plants.[119] Further, the uncertainty in new nuclear plant cost estimates will affect investors' outlook for those utilities choosing this route. Internationally and in the U.S., there are numerous new nuclear plants of various designs, not yet seen by most utility regulators, proposed or under construction. Regulators will need to consider what level of assurance of cost recovery utilities or bankers will demand before committing ratepayers to outlays of many billions of dollars.

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[118] J. Westbrook, "SEC May Let Companies Abandon U.S. Accounting Rules," *Bloomberg*, Aug. 27, 2008, available at http://www.bloomberg.com/apps/news?pid=newsarchive&sid=azXvW6B6aINg&refer=home.

[119] Recent nuclear power plant construction estimates by some utilities are several times the estimates from the industry even a few years ago. For a review of recent and current estimates, see Schlissel and Biewald, 2008, *Nuclear Power Plant Construction Costs*, available at www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.Nuclear-Plant-Construction-Costs.A0022.pdf.

6. For reasons of energy independence, long-term cost savings and price stability, and climate change concerns, DSM and renewable energy policies have come to the fore. This trend has been furthered by ongoing R&D and steady increases in the capability, consumer acceptance and cost-effectiveness of renewable and energy-efficiency technologies. A recent driver of energy-efficiency R&D has been a sharp increase in interest by the armed services regarding energy efficiency and renewables, both for U.S. bases and for deployed troops, planes, and ships. Such trail blazing by the military has a history of engaging private R&D leading to economies of scale, rapid technological advances, and commercialization for civilian use.[120] R&D aside, regulators can be confident that expansion of DSM programs is not going to hit a "wall" and exhaust the available potential.[121] However, utility DSM and renewable energy development raise issues that will require careful balancing of values by utility regulators. Aesthetic and wildlife impacts, for instance, are common concerns in mountainous terrain, but wind turbines are most effective when located on ridgelines. Advancing DSM program delivery will require resolution of questions about regulation, funding, and delivery modes.

7. Transmission is key to wholesale trade in electric power. The wholesale cost of electricity in some regions is high because less expensive power cannot be transmitted to those locations. There are also concerns about the regulatory and permitting challenges of building new transmission across multiple jurisdictions. The Energy Policy Act of 2005 granted FERC authority to issue permits, preemptive of state law, to entities seeking to build transmission lines used for interstate commerce if they are located in corridors designated by the U.S. Department of Energy (DOE) as being "in the National Interest." The FERC permit is available if a state commission has withheld approval, delayed approval for more than a year, or lacks authority to grant approval.[122] Commissions of states in such corridors will face challenges in protecting the interests of their states.

8. All fossil fuel resources (gas, coal, and oil) make significant direct contributions to the total carbon output of society, which increasingly appears to be the largest challenge humanity has ever faced. Other technologies (including nuclear resources) contribute to the overall carbon footprint of society through indirect uses of fossil fuel (this includes the nuclear industry in the mining, processing, and transportation of uranium fuel and

[120] One compelling reason for this interest is that "[Seventy] percent of the tonnage moved when the Army deploys is fuel and water. . . [and] about half of current casualties in theater are associated with convoys." Andrew Bochman, "Case for Operational Energy Metrics," Joint Forces Q., Issue 55 (4^{th} q. 2009), 113-119. Specifically, "the fully burdened cost of fuel was estimated to be as much as $400 per gallon." Michael E. Canes, "The Peculiar Economics of Energy in Defense Operations," USAEE *Dialogue* 16, no. 1 (March 2008). Each of the armed services has set ambitious goals for energy efficiency and conversion to renewable energy, including net-zero goals for some bases and alternative fuel capability for combat aircraft and ships.

[121] Kenji Takahashi and David Nichols, *The Sustainability and Costs of Increasing Efficiency Impacts: Evidence from Experience to Date*, 2008 ACEEE Summer Conference August 20, 2008, available at http://www.synapse-energy.com/Downloads/SynapsePresentation.2008-08.0.Sustainability-and-Costs-of-Efficiency-Impacts.S0051.pdf.

[122] This new authority is set forth in Section 216 of the Federal Power Act, added by the Energy Policy Act of 2005. See ferc.gov/industries/electric/indus-act/siting.asp. The circumstances under which preemption is possible are an issue in a pending judicial review of the FERC order implementing Section 216.

waste).[123] Regulators will need to consider whether and how those concerns should guide choices between different types of generation and DSM investment. Some states have adopted policies or programs to address the likelihood of future constraints on emissions of greenhouse gases (GHG), either in general or from electric generation. A group of ten northeast states have established the Regional Greenhouse Gas Initiative (RGGI) with the goal of reducing carbon dioxide (CO_2) emissions from the electricity sector via a cap-and-trade approach. RGGI has held seven successful auctions of pollution permits.[124] California and Oregon have set targets for GHG emission reduction.[125] The Western Governors' Association has identified a need for "appropriate actions . . . to reduce greenhouse gas emissions," but has focused on promoting renewable generation, potential technologies to reduce GHG emissions from coal plants, and adaptation to climate change.[126] While still controversial in some quarters, this issue has received attention from each successive Congress for some time and is likely to do so in the future. For example, a bill passed by the U.S. House established a Global Warming Pollution Reduction Program with goals for a 20% reduction below 2005 levels in 2020, 42% below 2005 levels in 2030, and 83% below 2005 levels in 2050, plus a very wide range of energy-efficiency and renewable energy program provisions.[127] The prospect of operating in a carbon-constrained world must be taken into account in electric utility planning and policymaking.

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[123] For discussion of the range of generation technologies, see Joe McGarvey, Ken Costello, R. Scott Potter, Michael Murphy and Paul Laurent, *What Generation Mix Suits Your State?: Tools for Comparing Fourteen Technologies across Nine Criteria*, NRRI, 2/07, available at http://nrri.org/pubs/electricity/07-03.pdf

[124] RGGI is an agreement among the six New England states, Delaware, Maryland, New Jersey, and New York to reduce electric industry GHG emissions 10% by 2018 using a market-based mechanism. A set quantity of allowances is auctioned quarterly, totaling no more than 188 million tons per year through 2014. After 2014 the amount of allowances shrinks gradually by 2.5% per year over four years for a total reduction of 10% by 2018. Generators must submit allowances equal to their emissions after each three-year compliance period or pay a cash penalty. Surplus allowances may be sold. Revenue from the auctions is distributed to the states to fund clean energy technologies and energy efficiency. RGGI website at http://www.rggi.org/design; Sean Pool, "The Proof Is In the Pudding: Regional Greenhouse Gas Initiative Shows Pollution Pricing Works," Center for American Progress, 3/22/10, available at http://www.americanprogress.org/issues/2010/03/rggi_roadmap.html.

[125] California has established a standard that 33% of the electricity sold in the state by 2020 come from renewables, and its *Climate Change Scoping Plan* is designed to reach the greenhouse gas reduction goals required in the (CA) Global Warming Solutions Act of 2006 (AB 32), a reduction to 1990 levels, about 30% from business-as-usual emissions levels projected for 2020, or about 15% from current levels. Available at http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm. Oregon's 2007 House Bill 3543 codifies GHG reduction goals of 10% less than 1990 levels by 2020 and 75% below 1990 levels by 2050. See http://www.oregon.gov/ENERGY/GBLWRM/HB3543.shtml.

[126] Western Governors' Association, *Policy Resolution 09-3 Regional and National Policies Regarding Global Climate Change*, available at http://westgov.org/index.php?option=com_joomdoc&task=doc_download&gid=70&Itemid=53. See, also, http://westgov.org/index.php?option=com_content&view=article&id=128&Itemid=62 for an overview of the Association's activities.

[127] H.R. 2454, "American Clean Energy and Security Act" was approved by House on a 219-212 vote. While not enacted into law, the bill is indicative of the many issues affected by climate change policy making. It covered topics ranging from forestry to building codes, vehicle efficiency standards, DSM goal setting by utilities, transmission planning and siting, net metering, R&D, smart grid, and many more.

9. Several technologies under the heading of the “smart grid” are rapidly being implemented in some states and considered in others. The term “smart grid” encompasses four components: advanced metering infrastructure (AMI), automated distribution operation (ADO), automated transmission operation (ATO), and automated asset management (AAM). Each of these intends to further automate one portion of the grid, respectively customer metering, distribution facilities, transmission facilities, and maintenance of equipment. The National Association of Regulatory Utility Commissioners (NARUC) and FERC have established a collaboration to develop and promote smart grid technologies. The U.S. DOE is also active in this field. Benefits claimed for the “smart grid” are improvements in economy and reliability. “Smart grid” costs, in relation to proposed benefits, and the associated ratemaking issues are a concern. The DOE itself states that implementing a smart grid will be a “colossal task.”

10. The ubiquity of electronic devices in homes, businesses, and factories is driving concern for reliability and power quality to new levels. (Reliability is the measure of how likely a customer is to have power when it is wanted. Power quality measures how well that power will fit within the specifications.) Large or lengthy departures from power quality standards can disrupt the operation of motors, electronic devices, and computers and can even harm that equipment.[128] Even brief outages can be disruptive. Customer demands in this area will likely drive considerable utility investment. Regulators will need to develop and enforce standards and measurement tools to track and improve reliability and power quality, and will have to decide how to allocate among customer classes the costs for any needed improvements.

11. The electricity industry is important to both national and local economies. Utilities and non-utility power producers are major employers, key purchasers of fuel and other goods and services, and huge consumers of investment capital, and their every action can affect the environment, consumer spending, and public well-being. In some states, utility regulators serve as gatekeepers for “economic development discounts” on utility rates. Utility DSM programs and renewable energy procurements are drivers for those growing sectors of local economies. In states where utility regulators have authority to approve or disapprove siting of new generation and new or renewed power purchase contracts, they make decisions with immense aftereffects on the economy and the environment, decisions that dictate resource balances for many decades to come. Regulators face and will continue to make decisions that have huge and long-lived effects on the economy and society.

12. While still in its infancy, electrification of the transportation fleet may become a key driver of electric demand. All-electric, battery-driven vehicles are just now and plug-in hybrid electric vehicles will soon enter widespread commercial distribution, but forecasts of the speed and extent of their penetration vary widely.[129] The timing of electric vehicle

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[128] For a sample utility power quality specification, see http://www.rockymountainpower.net/con/pqs.html.

[129] For example, one EPRI research project is evaluating the economic and electric generation impacts of penetrations of plug-in hybrids ranging from 6% to 30% in 2030. Electric Power Research Inst., *Electric Transportation - Program 18 Program Overview*, available at http://mydocs.epri.com/docs/Portfolio/PDF/2010_P018.pdf.

charging will affect not only the amount but also the types of generation needed in the future. Since timing of load is a key determinant of electric rate design, novel tariffs may be needed, even more so if the batteries and generators of all-electric or plug-in hybrid vehicles come to be a resource for the grid to draw on at peak hours, as is predicted by some. As was the case with the spread of domestic electric water heaters rented by utilities in the 1950s and later, the deployment of charging devices in homes, offices, or parking spaces may be expected to bring up questions about what electric vehicle services, if any, should be either competitive or “below the line” in ratemaking. Load growth from electric vehicles may have significant implications for other aspects of rate setting such as the need for decoupling and allocation of fixed costs.

Appendix: List of Abbreviations and Acronyms

Item	Translation
AAM	Automated Asset Management
ADO	Automated Distribution Operation
AER	Annual Energy Review
AMI	Advanced Metering Infrastructure
CAISO	California ISO
CCS	carbon capture and storage
CCW/CCB	coal combustion waste (or byproduct)
CHP	combined heat and power
CO_2	carbon dioxide
DoE	Department of Energy
DoJ	Department of Justice
DSM	Demand Side Management
EEI	Edison Electric Institute
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
EWG	Exempt Wholesale Generator
FERC	Federal Energy Regulatory Commission
FIT	feed in tariff
FPC	Federal Power Commission
FRCC	Florida Reliability Coordinating Council
FTC	Federal Trade Commission
GHG	greenhouse gas
GW	Gigawatt
GWh	Gigawatt-hour
HHI	Herfindahl-Hirschman Index
IRP	Integrated Resource Planning
ISO	Independent System Operator
ISO-NE	ISO New England
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LBCS	Lehman Brothers Commodity Services
LED	light-emitting diode
LERS	Limited energy storage resource
LMP	Locational Marginal Pricing (or Price)
mil	1/10 of a cent
MISO	Midwest ISO
MRO	Midwest Reliability Organization
MV&E	Monitoring, Verification, and Evaluation
MW	Megawatt
MWh	Megawatt-hour
NAPEE	National Action Plan for Energy Efficiency

NARUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Council
NO_X	nitrogen oxides
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Council
NYISO	New York ISO
OASIS	Open-Access Same Time Information System
OTC	once-through cooling
PJM	Pennsylvania, New Jersey and Maryland Interconnection
PUC	Public Utility Commission
PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act
PV	photovoltaic
QF	Qualifying Facility
R&D	research and development
RFC	ReliabilityFirst Corporation
RGGI	Regional Greenhouse Gas Initiative
RPS	renewable portfolio standard
RTO	Regional Transmission Operator
SBC	system benefit charge
SCADA	Supervisory Control and Data Acquisition
SEC	Securities and Exchange Commission
SO_2	sulfur dioxide
SPP	Southwest Power Pool
T&D	transmission and distribution
TRE	Texas Regional Entity
TREC/RECs	(tradable) renewable energy credits
U.S.	United States
V	Volt
WECC	Western Electricity Coordinating Council