National Regulatory
Research Institute

The Electric Industry at a Glance

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November 2008

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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 makes up about 35% of the total, industrial consumption about 26%, and transportation less than 1%. The remainder (about 4%) is self-generated, primarily by large commercial and industrial establishments.

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[1] See www.eia.doe.gov/basics/quickelectric.html for an overview of U.S. electricity statistics.

[2] 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.

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 more. Energy sources for electric generation include renewables (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 70% of that energy. Nuclear power and conventional hydroelectric generation provide most of the rest, with other renewables delivering a small but steadily growing amount. 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. 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 is 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 the transmission and distribution is complicated in some instances and is discussed further in Sections II.A.4 and III, below. Transmission primarily takes the form of alternating current at voltages from a few thousand volts to around 750,000 volts.[6] 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 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, below.

Electricity comprises about 12% of the total energy consumed in the United States.[7] Since the electric industry requires capital investments for production and delivery on top of the cost of fuels used to generate current, retail electricity expenditures in 2005 were over 28% of all retail energy expenditures (about $296 billion).

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[6] 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.

[7] For 2005. U.S. EIA, *2007 Annual Energy Review* (hereafter, AER 2007), Table 3.5, available at www.eia.doe.gov/aer/pdf/aer.pdf. Percentages of total energy are based on amounts produced or consumed as measured in British Thermal Units.

Transmission and distribution losses for the U.S. are about 9% of the gross generation from power plants.[8]

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 67% of the nation's airborne mercury emissions, and large amounts of sulfur dioxide and nitrogen oxide emissions, mainly from coal.[9] 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 well as the disposal of ash, nuclear waste, and other materials used or produced by generator operations.

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.[10] This section briefly sketches the main changes.

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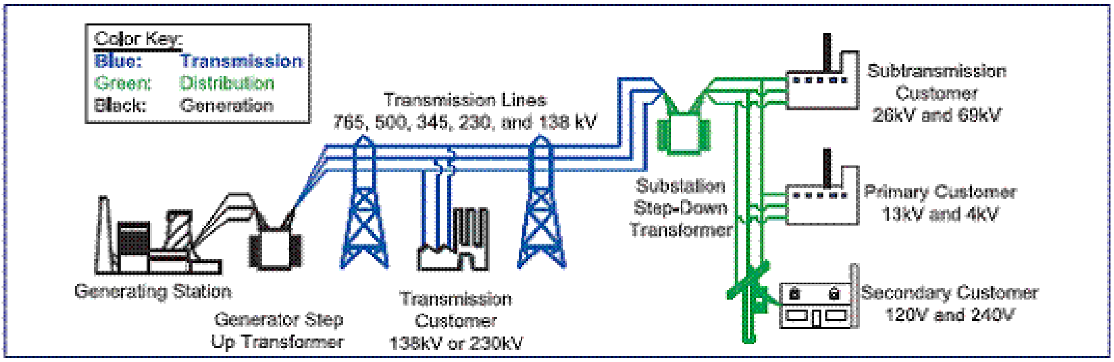
[8] AER 2007, Table 3.5 and Diagram 5

[9] AER 2007, Tables 12.7a and 12.2; U.S. EPA, *2004 TRI Public Data Release Report*, p. 13, available at www.epa.gov/tri/tridata/tri04/ereport/2004eReport.pdf

[10] 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.

Fig. 1. The Electricity Industry from Generator to Customer



Source: http://www.oe.energy.gov/information_center/electricity 101.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.[11]

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.

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.[12] Several federal power

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

[12] The difficulty of a single state regulating multi-state holding companies led to 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

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.[13] 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.[14] 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. 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. A QF had to be 50% or less owned by a traditional utility and had to be a renewable generator or a co-generator, but a firm could own QFs in any (or many) locations because QFs did not need to be part of an integrated and contiguous system.[15] The new law required utilities to connect QFs with the grid and to purchase

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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

[13] 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.

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

[15] 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 (space and heating or an industrial process) and for producing electricity so as to obtain more useful energy from a given amount of

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. Notwithstanding PURPA's introduction of independent QFs, most generation in the U.S. was 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 FERC acted forcefully to create competitive markets for wholesale electricity and to spur entry into the generation business by new players.[16]

1. Congress created another new class of generators, the "exempt wholesale generator" (EWG), which were exempt from the 1935 requirement for electrical integration of multiple generators owned by one holding company.[17] 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.

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

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fuel. More recently the term "combined heat and power" (CHP) has been applied to co-generation, especially for non-industrial applications.

[16] 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.

[17] 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.

transmission service and wholesale sales in interstate commerce. FERC oversight of ISOs and RTOs concentrates on transmission 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. 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.[18] 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 as discussed above, 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.[19] In states that established 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

[18] 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 component of a resource plan. DSM is discussed further in Section II.D, below.

[19] 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.

or by transferring those assets to affiliates.[20] Retail restructuring is discussed in Section II.C.

2. Generation

Electric energy output in the U.S. reached an all-time high of 4.2 billion megawatt-hours (MWh) in 2007.[21] Another 31 million MWh was imported, mainly from Canada.[22] The installed net summer capacity of generating plants in the U.S. in 2006 was 986,215 megawatts (MW), representing 16,924 plants. Traditional vertically integrated utilities owned 58% of that capacity (9249 plants); non-utility generators, including qualifying facilities, owned 36% (4585 plants). Customers owned the remaining 7% (3090 plants).[23] In the summer of 2006, the available capacity in the contiguous 48 states was 906,155 MW, while the peak load was 760,108 MW. The reserve margin, or available capacity in excess of need, was 16%, a value in the range of experience since the mid-1990s.[24]

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[20] 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.

[21] AER 2007, 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.

[22] This amount is the net of 51 million MWh of imports and 20 million MWh of exports.

[23] U.S. EIA, *Electric Power Annual*, Table 2.3. 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.

[24] 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.

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 construction cost at the expense of reduced efficiency and higher variable cost.[25] 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 has been roughly flat since 2000. 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—made up the difference, with annual gas-fired output growing by about one-third from 2000 to 2006.[26] Non-utility owners built many of those plants.

Nuclear generation, less than one percent of total U.S. generation in 1967, grew steadily in both aggregate output and percentage of total generation during the 1970s and 80s. Since 2000, a combination of capacity increases and reduced outage time at existing plants has led to further increases in annual output.[27] Nuclear power produced between 20 and 21.5% of total output since 1990.

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[25] There are no specific numerical cut-offs dividing the three categories of operating regimes, but one can think of base plants running, perhaps, 75% or more of the time, peaking plants as running up to about 10% of the time, and intermediates filling in the remainder.

[26] AER 2007, Table 2.1f.

[27] 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.

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.[28] 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.

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 a turbine), 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).[29] Non-renewable wastes, e.g., municipal solid waste, and other technologies provide a small fraction of one percent of total U.S. generation.[30]

Many hydroelectric generators can store energy, a rare and valuable capability in the electric world. This can be done 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" 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, 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 prices are at their highest, water is allowed to flow down from the upper reservoir through 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. Various other technologies for storing electric energy have been tried or are being developed. These include compressed air, flywheels, batteries, superconducting rings, and supercapacitors. Commercially feasible electricity storage would reduce costs,

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[28] 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 2007, Table 2.1f.

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

[30] AER 2007, Table 8.2a

increase reliability, and make intermittent renewables more useful, but decades of research and development have resulted in only a few small demonstration units in commercial service, aside from pumped storage units.[31]

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. A few states have adopted portfolio standards for acquisition of energy efficiency or demand response.[32]

3. Transmission, control, and storage 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.[33] 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.

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.

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[31] For information on storage technologies, see www.eere.energy.gov/de/energy_storage.html

[32] 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.

[33] 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 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.[34] 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.[35]

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.[36] 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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[34] 16 U.S.C. 824 et seq.

[35] 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.

[36] 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.[37] 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.[38]

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."[39] Adequacy focuses on forecasting load and adding needed generation, demand-side, or transmission resources. Security considers proper maintenance and operation of both generation and transmission, as well as minute-by-minute control and adjustment.

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. 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-

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[37] 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.

[38] 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.

[39] 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

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.[40] 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 creating vibrations in the rotating shafts of generators—or trigger cascading blackouts such as occurred in 1965 and again in 2003.[41] Security issues have 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.[42]

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[40] Rotating 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 failure of the whole grid.

[41] 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 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.

[42] *Electricity Transmission: A Primer* (Brown and Sedano, 2004) provides an overview of the history of the U.S. transmission system and the challenges it faces.

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 transmission system to retail customers.[43] 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.[44] 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

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Available at www.raponline.org/Pubs/ELECTRICITYTRANSMISSION.pdf. See also www.ncouncil.org for additional resources on transmission issues.

[43] 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.

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

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.[45] Those standards seek to set up simple but safe procedures and standards to smooth the way for the development of distributed 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 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.[46] For example, utility rate regulation is

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

[46] 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

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).[47] 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 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.

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/.

[47] 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.

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. Then 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.

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, consumers, and regulators alike.

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.[48] (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

[48] 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.

took advantage of cheaper idle capacity, and the utilities would split the savings in operating costs.[49]

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.[50]

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

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[49] 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.)

[50] 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.

auctions to obtain needed ancillary services.[51] 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. 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.[52] 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.[53] FERC does some market monitoring and has the authority to sanction non-competitive behavior.

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[51] For examples of RTO/ISO markets and the products they procure, see www.caiso.com/docs/2005/09/23/2005092315310610481.html (the California ISO) and 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.

[52] 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.

[53] 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

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, are used by some RTOs.[54]

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,

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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.

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

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.[55] 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 2006, 16 states and the District of Columbia allowed retail access for all customer groups. Two others allowed retail access only for large customers. Six states had adopted retail access legislation, but later delayed, repealed, or indefinitely postponed implementation. Customer participation in retail competition (called "shopping") varies widely by state and customer class. 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. Default service rates were often capped for a period and have risen considerably after those caps expired.[56] 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

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

[56] See Rose and Meeusen, *2006 Performance Review of Electric Power Markets* for post-restructuring participation rates and retail prices. Available at www.ipu.msu.edu/research/pdfs/2006_rose_1.pdf

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.[57] 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.[58]

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.[59] Demand-side management (DSM) programs are activities designed to promote greater energy efficiency or to reduce loads during peak load hours (called demand response programs).[60] 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

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

[58] 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.

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

[60] 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 (www.epa.gov/cleanenergy/energy-programs/napee/index.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.

rates or via cost recovery riders.[61] 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 1700 MW in 2006.[62]

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 2000, U.S. electric utility expenditures on energy efficiency increased slightly, to about $1.1 billion in direct costs.[63] Load management expenditures followed a similar pattern.[64]

Many electric energy efficiency measures cost significantly less per kWh than generating, transmitting and distributing electricity. Demand response programs can cost less per kW than building new generators and transmission lines. Properly designed and implemented DSM programs reduce system-wide electricity costs and reduce 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.[65]

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[61] 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.

[62] U.S. EIA Electric Power Annual, 2006, Table 9.3.

[63] York and Kushler, 2002, *State Scorecard on Utility and Public Benefits Energy Efficiency Programs: An Update*, American Council for an Energy Efficient Economy (ACEEE). For the current edition, see http://www.aceee.org/pubs/e075.htm.

[64] U.S. EIA Electric Power Annual, 2006, Tables 9.1 and 9.7.

[65] For more on DSM benefits, see Biewald, et al., *Portfolio Management: How to Procure Electricity Resources to Provide Reliable, Low-Cost, and Efficient Electricity*

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.[66] Cost-benefit testing is crucial to 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.[67] 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.[68]

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 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

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Services to All Retail Customers, Synapse Energy Economics; 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); 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.

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

[67] 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.

[68] 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.

as an energy efficiency utility, independent of the electric utilities in the state, and solicits competitive bids to provide that function.[69]

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.[70] 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.[71]

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[69] 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

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

[71] 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*

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 to integrated resource planning (IRP) that puts extra emphasis on uncertainty and risk relative to the weight given to expected costs. Portfolio management requires 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.[72] Portfolio management can be important for both restructured and vertically integrated utilities.[73]

Program Impact Evaluation Guide, available at www.epa.gov/cleanenergy/documents/evaluation_guide.pdf.

[72] 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.

[73] Portfolio management also can apply to gas and transportation procurement by utilities. Gas utilities increasingly have 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.

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;

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).[74]

Some environmental concerns, such as land use and aesthetics, are addressed in siting reviews of power plants and transmission lines. These reviews usually are conducted by state commissions. Other environmental requirements are set by environmental regulators, 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 tighter 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.[75] Environmental regulations limiting emission

[74] 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.

[75] An externality is a cost of an action that is not borne by the decision maker. 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

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, that will reduce SO_2 emissions 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.[76] 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 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 CO2 emissions rates per kWh are roughly one-half of those for coal-fired generation.

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.[77]

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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.

[76] Electric Power Annual, 2007, Table 1.1

[77] 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.

III. Economic regulatory jurisdiction in the U.S. electric industry[78]

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.[79])

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

[79] 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

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 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.[80]

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by certain public utilities and utility holding companies. That SEC authority no longer exists.

[80] There are three states in which transmission transactions remain outside of "interstate commerce": Alaska and Hawaii (because neither state is part of or

The table on page 33 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.

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.

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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).

Economic Regulatory Jurisdiction in the U.S. Electric Industry

What Action is Regulated?	*Who* is Regulated?	What *Subject Matter*?	*Jurisdiction* 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, to 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 to 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.[81]

2. The nation's financial crises, emerging in fall 2008, will affect utility finance in uncertain ways.[82] 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.[83] The appearance of non-utility participants in wholesale power markets during the 1990s had the unexpected and novel effect of requiring utilities to post significant collateral for trades in power markets. A

[81] 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.

[82] At least three RTOS (PJM, NE-ISO and CA ISO) have declared LBCS (a subsidiary of Lehman Bros.) in default and have suspended them from power trading in the markets administered by those RTOs. See, www.platts.com/Electric%20Power/News/6971984.xml.

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

major change in utility accounting standards is in the making in the U.S. and Canada.[84] 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 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 higher and more volatile prices for oil and natural gas. Even coal prices—long stably priced—have begun to exhibit increased prices and price fluctuations. Availability is also an issue, as demonstrated in the past few years 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. 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 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 beginning to face 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.[85] Further, the uncertainty in new nuclear plant cost estimates will affect investors' outlook for those utilities choosing this route. 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.

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.

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[84] J. Westbrook, "SEC May Let Companies Abandon U.S. Accounting Rules," *Bloomberg*, Aug. 27, 2008, available at http://www.bloomberg.com/apps/news?pid=20670001.

[85] Recent nuclear power plant construction estimates by some utilities are several times 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.

This trend has been furthered by gradual increases in the cost-effectiveness of renewable and energy efficiency technologies. Both 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, while 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.[86] 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 waste). Regulators will need to consider whether and how those concerns should guide choices between different types of generation and DSM investment.

9. Several technologies under the heading of the “smart grid” are beginning to affect state regulation of transmission and distribution. 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.[87] 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

[86] 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.

[87] For more information on smart grid concepts, see www.oe.energy.gov/DocumentsandMedia/DOE_SG_Book_Single_Pages.pdf.

proposed benefits, are a concern. 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.[88] Even brief outages can be disruptive, too. 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 face decision making that has huge and long-lived effects on the economy and society.

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[88] For a sample utility power quality specification, see www.rockymountainpower.net//Navigation/Navigation1891.html