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DOMESTIC ENERGY POLICY IN THE ERA OF ELECTRIC INDUSTRY DEREGULATION: THE FUTURE OF GAS, COAL, RAILROAD, NUCLEAR POWER, RENEWABLES, AND OIL INDUSTRIES . . . AND THEIR EXECUTIVES AND LAWYERS

Suedeen G. Kelly

Chapter 1
DOMESTIC ENERGY POLICY IN THE ERA OF ELECTRIC INDUSTRY DEREGULATION: THE FUTURE OF GAS, COAL, RAILROAD, NUCLEAR POWER, RENEWABLES, AND OIL INDUSTRIES . . . AND THEIR EXECUTIVES AND LAWYERS

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Synopsis

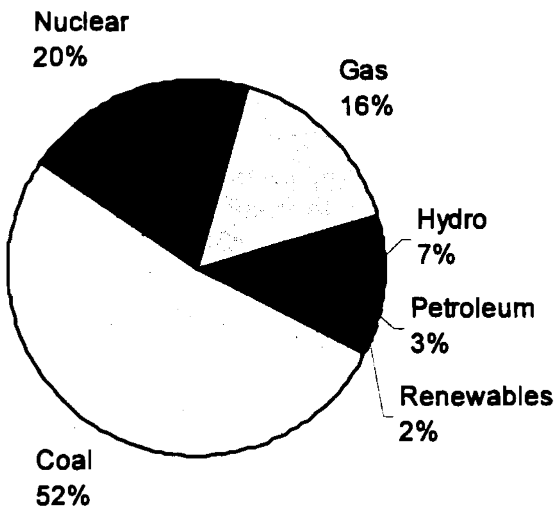
§ 1.01 Background on Electric Industry Deregulation

[1] Electricity Market Structure and Demand

[a] Overview of Electricity Supply and Demand

Americans are the largest electricity consumers and producers in the world. Domestic production of electricity totaled 3,792 billion kilowatt hours in 2000.[1] Coal, natural gas, nuclear fuel, falling water, and oil power about 98% of all electricity generation. Specifically, coal makes up about 52% of generation, while nuclear totals about 20%, natural gas accounts for 16%, hydroelectric sources account for 7%, and petroleum makes up about 3%. The other 2% of generation comes from alternative sources such as wind, solar, geothermal, and biomass production.

Net Generation by Source in 2000
(of 3,792 Billion kilowatt hours)



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[1] Generation data is from Energy Information Administration (EIA), *Electric Power Monthly: March 2001, Table 2: U.S. Electric Power Industry Summary Statistics,* http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html (visited June 19, 2001).

The 2000 production total was up 2% from 1999. Both coal generation and nuclear generation were up 4%, gas-fired generation was up 7%, and generation from wind sources was up 10% from 1999. Petroleum generation fell 12% from 1999. Hydroelectric power and renewable generation sources such as geothermal and biomass also fell in 2000. The Energy Information Administration's forecasts predict that demand growth for electricity in the United States will slow to an average of 1.8% annually between now and 2020.[2] Slower growth will not preclude the need for new generation capacity, however. The EIA estimates that 27% of the nuclear generation now in operation and 8% of fossil-fuel generation will be retired by 2020. Plant retirements and increasing demand mean that more than 1300 new generating plants, producing a total of about 393 gigawatts of capacity, will be needed in the next 20 years. Currently, 92% is forecast to be gas-fired generation.

[b] Electricity Fuel Cycle

All electricity generation including gas-fired, coal burning and distributed generation uses the same basic process to generate electricity. This process is referred to as the fuel cycle since electric energy itself is not a primary natural resource. This fuel cycle is comprised of three distinct phases: generation, transmission, and distribution. In the United States the federal and state governments have jurisdiction over different portions of this cycle.

[i] Generation

The electricity used by the United States is generated regionally, nationally, and internationally. Generation is the largest sector of the electricity business and often accounts for half of an electric utility's assets. In addition, it can make up half of the cost of producing and delivering electricity to consumers. Electricity can be generated from a variety of fuel sources, each with its own economic strengths and weaknesses.

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[2]Forecasting data is from EIA, *Annual Energy Outlook 2001,* http://www.eia.doe.gov/oiaf/aeo (visited June 19, 2001).

Economic differences aside, most fuels go through the same basic process to be converted into electricity. Additionally, no matter what fuel is used, all electricity generation produces waste heat. New technology is allowing this waste heat to be captured, and either used to generate additional electricity or sold to an end user for other energy applications, such as space heating or cooling. The most efficient process for generating additional electricity from heat is combined-cycle generation, which utilizes both a gas turbine and a steam turbine sequentially to produce 50% efficiency, far above the 35% efficiency of traditional steam turbines.

Because there is no effective method to store electricity once it is generated, utilities must use a varied supply portfolio to meet fluctuating demand. Normally, utilities will operate their most efficient plants to meet their *base load* (or minimum demand), and will then speed up operation of low-level constant operation plants, or *spinning reserves,* to meet increases in demand. In times of a severe demand increase, utilities will utilize their *cold reserves*, or *peaking plants*, which are normally the least efficient plants in the portfolio and are kept offline unless needed.

Utilities normally will keep a reserve margin of capacity, known as their *capacity margin*, to shield them from unexpectedly high demand. While under traditional regulation utilities would normally build their own generation to meet demand, in today's competitive wholesale market utilities can meet their demand through a number of methods, including long-term contracts with independent power producers, or short-term purchases in spot markets. Utilities are also experimenting with tools such as *demand side management* to shave their peak load. Recently, California has been forced to implement a stringent version of demand side management, with regulators passing steep retail rate increases in the hope that the price signal will encourage conservation in the state, and forestall future blackouts while new generation is being built.

[ii] Transmission

Generated electricity gets to distributors or end-users via transmission lines. Higher voltage transmission lines are used to carry it long distances with higher efficiency. But as distances increase so do electromagnetic radiation and line losses. Line losses inevitably reduce the electricity available to consumers. The physical layout of regional transmission lines (in a grid) can also impact the transmission systems' efficiency. The laws of physics dictate that electricity travels on the path of least resistance. The path of least resistance may not always be the shortest distance between point A and point B.

Regional coordination of utility generation mix helps keep the grid operational and power scheduled cost-effectively. Coordination also reduces the amount of generation needed on a regional basis because utilities' peaking resources can be shared. Currently, regional reliability councils and power pools coordinate the supply and transmission in many electric systems. Through interconnections every utility is either connected or capable of being connected with its neighbor. The United States has three large power grids; one west of the Rocky Mountains, one east of the Rocky Mountains, and one in Texas.

Regional reliability councils maintain the reliability, adequacy and, to some degree, the cost-effectiveness of interconnected regional electricity supplies. There are nine voluntary regional reliability councils across the country, as well as a national reliability council (created after the 1968 New York City blackout), each with diverse members. Members often hold opposing points of view on many issues, making grid coordination issues sometimes difficult to resolve.

Power pools are formal and informal agreements by groups of utilities to plan and operate their electric systems. Formal pools consist of two or more members that coordinate planning and operation of bulk power facilities, pursuant to a contract, in order to increase reliability and economy, while informal pools rely on voluntary adherence to certain agreed-upon principles of operation. Formal pools can be either tight or loose. Tight power pools have a central dispatch system that operates the grid and enforces reserve requirements, while loose power pools provide coordination services but generally do not dispatch or enforce requirements.

[iii] Distribution

Distribution of electricity normally occurs through local distribution companies (LDCs). A local distribution company is a local utility such as Pennsylvania Power and Light or Pacific Gas and Electric. These local utilities typically are regulated by state public utility commissions (PUCs). Usually, the state gives a utility a set territory within which it has an exclusive franchise, and, in return, the utility is obligated to serve all the customers in that territory.

LDCs handle numerous different categories of consumers: residential, commercial, and industrial and, perhaps, irrigators and other special groups. Each class puts different demands on the system for the amount of electricity it consumes, the number of plants necessary to generate that electricity, and the level of service required from the LDC.

[c] Market Structure Under Current Law[3]

Today's electricity transactions take place in two distinct but interconnected markets. Wholesale sales and the interstate transmission market are subject to regulation largely by the U.S. Federal Energy Regulatory Commission (FERC). Retail sales and the distribution market are regulated by the states. The most important pieces of federal legislation affecting the wholesale sales and interstate transmission market are the Federal Power Act of 1935,[4] the Public Utility Regulatory

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[3]For a more in-depth discussion of the development of electricity regulation, see generally *The Electric Industry: Opportunities and Impacts for Resource Producers, Power Generators, Marketers, and Consumers* (Rocky Mt. Min. L. Fdn. 1996); Suedeen G. Kelly, "Electricity," *in* The Energy Law Group, *Energy Law and Policy for the 21st Century* (Rocky Mt. Min. L. Fdn. 2000); Joseph P. Tomain, "Electricity Restructuring: A Case Study in Government Regulation," 33 *Tulsa L.J.* 827 (1998).

[4]Title II of the Public Utility Act of 1935, 16 U.S.C.A. §§ 791a-825r (2000), made the Federal Water Power Act (which was enacted in 1920 to create the Federal Power Commission and provide it with authority to license private hydroelectric projects located on navigable waters of the United States) Part I of the Federal Power Act and added Parts II and III to the Federal Power Act.

Policies Act of 1978 (PURPA),[5] and the Energy Policy Act of 1992 (EPAct).[6]

The Federal Power Act regulates electric companies in their engagement in interstate commerce. Under the Federal Power Act, the FERC, and its predecessor the Federal Power Commission, has exercised traditional economic regulatory control over the transmission and wholesale sale of electricity in interstate commerce, consistent with the monopoly nature of the electric business. It regulates rates for interstate transmission and wholesale sales of electricity.[7] It assures adequate interstate electric service.[8] It authorizes purchase and abandonment of utility assets.[9] It regulates the securities issued by public utilities under its jurisdiction.[10] It approves mergers and acquisitions.[11] It is also responsible for directing the interconnection and coordination of electric facilities, such as transmission lines, across the United States.[12]

The thirty years between 1935 and 1965 saw the growth and demand for electricity grow steadily. Vertically integrated utilities were able to capture economies of scale and the average cost of production stayed relatively constant for a long period of time. This changed in the 1970s as technological advances and economies of scale flattened and the energy crises unfolded. In the 1970s electric utilities saw costs increase. Labor costs rose and inflation increased. With the rise of the international cartel called the Organization of Petroleum Exporting Countries (OPEC) in 1973, oil supplies available to the United States fell, and the cost of oil soared.

[5]Pub. L. No. 95-617, 92 Stat. 3117 (codified as amended in scattered sections of titles 15, 16, 42 & 43 U.S.C.A.).

[6]Pub. L. No. 102-486, 106 Stat. 2776 (codified as amended in scattered sections of titles 15, 16, 25, 30, 40, 42 & 49 U.S.C.A.).

[7]Federal Power Act § 205; 16 U.S.C.A. § 824d (2000).

[8]Federal Power Act § 207; 16 U.S.C.A. § 824f (2000).

[9]Federal Power Act § 203; 16 U.S.C.A. § 824b (2000).

[10]Federal Power Act § 204; 16 U.S.C.A. § 824c (2000).

[11]Federal Power Act § 203; 16 U.S.C.A. § 824b (2000).

[12]Federal Power Act § 213; 16 U.S.C.A. § 824a (2000).

Oil-fired electric generators sought to switch to gas or coal. However, domestic interstate supplies of natural gas, which had been subject to stringent federal price caps since about 1960, were not available. Conversion of plants to burn coal was expensive and took time. Congress looked for ways to stimulate the production of U.S. natural gas and other forms of energy. One of its vehicles for achieving this, which related directly to electric utilities, was the passage of PURPA.

PURPA was designed to promote the growth of generation not owned by utility companies. PURPA sought to achieve this by requiring the local electric utility to buy the power produced by certain types of non-utility generators, which PURPA calls "qualifying facilities" (QFs).[13] There are two types of QFs: small (80 megawatts or less) generators powered by renewable resources and cogenerators. A cogenerator is an electric generator that also produces another form of energy (steam or heat, for example) which is put to use. A qualifying cogeneration facility is one that meets certain efficiency standards.[14] While QFs could sell their power to the local utility, they did not have access to the utility's transmission lines to wheel their power to any other utility. Although their market reach was not broad, the establishment of QFs marked the formal reintroduction of competition into generation, which had ended by 1920 with state establishment and regulation of electric utilities as monopolies. From 1989 through 1993, the number of QFs grew from 576 to 1200 and installed QF capacity increased from 27,429 megawatts to 47,774 megawatts.[15]

Between 1970 and 1985, electric rates increased substantially. Nuclear plants constructed in the 1970s and 1980s generally came in over budget and behind schedule. The United States experienced high interest rates, a

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[13] 16 U.S.C.A § 796 (2000).

[14] *Id.*

[15] Preamble to Federal Energy Regulatory Commission (FERC) Final Rule Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Order No. 888, 61 Fed. Reg. 21,540, 21,545 (May 10, 1996) (codified at 18 C.F.R. pts. 35 & 385) [hereinafter FERC Order 888].

recession, and a fall-off in demand for electricity. Nevertheless the glut of expensive generation capacity had to be paid for. Industrial electric rates quadrupled in nominal terms and saw an 86% increase after adjustment for inflation. Residential rates tripled in nominal terms with a 25% increase after adjustment for inflation.[16] New generation in the 1980s could be built for substantially less than the average price of existing generation. Political pressure mounted to expand competition in generation. There were two primary factors limiting the increase in competition in the wholesale market. Non-utility generators, other than QFs, found it difficult to enter the market because they had no exemption from the ownership restrictions of the Public Utility Holding Company Act (PUHCA).[17] These generators seemed particularly desirable because they could provide new generation capacity, which promised to supply electricity at a lower cost.[18] The second constraint on market expansion was FERC's lack of authority to mandate wheeling over transmission lines. In 1992, Congress passed EPAct and eliminated both these constraints.

EPAct eliminated the PUHCA constraint by authorizing persons "engaged exclusively in the business of selling energy at wholesale," to be exempt from PUHCA's ownership restrictions. These generators are called exempt wholesale generators (EWGs).[19] EPAct also authorized FERC to order utilities that own transmission facilities (including intrastate utilities, federal power marketing agencies, and QFs) to transmit wholesale power over their systems.[20] Significantly, EPAct prohibits FERC from ordering access to transmission

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[16] *Id.* at 21,544.

[17] 15 U.S.C.A. §§ 79-79z (1997).

[18] State-mandated competitive bidding processes for new electric generation capacity showed that the cost of new generation based on new technologies could supply new capacity at a lower cost than existing capacity. Robert E. Burns, "Electric Industry Restructuring: Finance, Mergers, and Acquisitions, Two Years In Review," *Year-in-Review* (ABA Sec. of Nat'l Res., Energy & Env't, ed., 1999).

[19] 15 U.S.C.A. § 79z-5a (1997).

[20] Federal Power Act §§ 211-212; 16 U.S.C.A. §§ 824j-824k (2000).

for unbundled retail power sales. That power is left to the states.[21]

After using its wholesale transmission authority under EPAct aggressively on a case-by-case basis, in 1996, FERC promulgated its open access rule, which is commonly called "Order 888."[22] The goal of this rule is to create a more robust competitive market in wholesale power by allowing all wholesale buyers and sellers of electricity access on a non-discriminatory basis to transmission in the United States. The rule requires all public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce to have on file with FERC open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service. Traditionally, public utilities had provided electricity at wholesale and the transmission of that electricity as a bundled service at a single price. Order 888 requires utilities to unbundle their transmission service function from their generation and power-marketing functions, and to sell them separately. In fact, a transmission-owning utility must buy transmission service from itself under the same tariff that applies to outside users of its transmission.

Order 889,[22.1] issued with Order 888, requires utilities to participate in an electronic open-access same-time information system (OASIS), which provides information to the public about the transmission system, including its cost and availability. Order 889 requires utilities to adhere to standards of conduct designed to prevent transmission-

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[21]The FERC's recent exercise of its EPAct transmission authority, in the form of the Order 888 rulemaking (see *infra*), is now on appeal before the U.S. Supreme Court from the U.S. Court of Appeals for the District of Columbia, which upheld the order. The Court will hear opposing arguments asserting that Order 888 either exceeds FERC's jurisdiction, or does not do enough to provide for open access to interstate transmission. *See* Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *cert. granted*, New York v. FERC, No. 00-568 (U.S. Feb. 26, 2001).

[22]FERC Order 888, *supra* note 15.

[22.1]FERC Final Rule on Open Access Same-Time Information Systems and Standards of Conduct, 61 Fed. Reg. 21,737 (May 10, 1996) (codified at 18 C.F.R. pt. 37).

owning utilities from favoring their wholesale generation business with information or access to transmission that is not available to generators that compete with them.

There are three significant things that Orders 888 and 889 did not do. First, they did not require public utilities to establish separate corporate affiliates to manage their unbundled services. However, FERC indicated it was interested in accommodating voluntary utility corporate restructuring, including divestiture of generation or transmission assets. Second, FERC did not require utilities to set up independent system operators (ISOs) of their transmission systems to prevent undue discrimination or to mitigate the market power of utility-owned wholesale generators. However, as discussed below, in 2000, FERC issued another order strongly encouraging utilities to join with others in the region to set up a regional transmission organization (RTO) run by an independent board. Finally, FERC did not provide generically for market-based rates for the wholesale sale of electricity. As has been recently publicized in the popular press in connection with high electricity prices in California, FERC has the authority to regulate wholesale power rates; however, FERC policy has been to allow market-based rates where there is an open market or a contract negotiated at arm's length. Generator requests to sell wholesale power at market-based rates are still decided by FERC on a case-by-case basis. However, as discussed in more detail below, pursuant to Order 888, a generator wishing to sell wholesale power from new generation capacity enjoys a presumption that it lacks market power, although any party objecting to a market-based rate may rebut this.

[d] Retail Markets

The retail electricity market historically has been regulated by the states. Generally, states create public utility commissions and give them expansive power to regulate the retail rates charged by public utilities, their entry and exit into the retail market, and the terms and conditions of retail electric utility service. Typically, state regulators grant an electric utility an exclusive franchise to provide both electricity and its distribution to consumers within a specific geographic area within the state. In return for receiving this monopoly, the utility is obligated to serve all customers in the area. State regulators have also taken on the responsibilities of assuring adequate service by the utility, protecting the parties who furnish the money for utility construction, and supervising the utility's service "in every material particular."[23]

Competition in the provision of retail electricity can be accomplished legally by the states in much the same way as the federal government has accomplished competition in the provision of wholesale electricity. First, states can eliminate the monopoly held by the incumbent utility on the sale of retail electricity and allow other generators, whether owned by other utilities or by independents, to sell electricity directly to the consumer. Second, states can mandate that the utilities providing distribution service to the consumer open access to their distribution lines to all sellers and buyers of retail electricity. Today, 25 states have changed their laws in just this way to allow for competition in their retail electricity markets,[24] and several have already implemented competition to a greater or less extent.

[i] Competition in the Sale of Electricity Has Been Extended to the Retail Market in Some States

California was the first state to mandate retail competition, opening its entire market to competition in 1998.[25] New England followed, with New Hampshire and Connecticut also beginning retail competition in 1998.[26] Other states, such as

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[23]Idaho Power & Light Co. v. Blomquist, 141 P. 1083 (Idaho 1914).

[24]For a monthly update on the status of state deregulation efforts, and a list of states that have deregulated their electricity markets by law, see EIA, *Status of State Electric Industry Restructuring Activity*, *at* http://www.eia.doe.gov/cneaf/electricity/chg_str/tab5rev.html.

[25]California's restructuring legislation, AB 1890, is at 1996 Cal. Stat. ch. 854.

[26]*See* N.H. Rev. Stat. Ann. §§ 374-F:1 to 374 F:7 (Supp. 2000); Conn. Gen. Stat. Ann. §§ 16-244 to 16-244i (West 1998 & Supp. 2001). New Hampshire's market was later closed by order of the federal district court in *Public Service Co. v. Patch*, 167

Pennsylvania and Arizona, and most recently Texas, have instituted "pilot programs" that allow certain classes of customers or a percentage of customers to shop for power on the open market, in an effort to "experiment" with competition.[26.1] Each of the states that has either completely opened its market to competition or has taken significant steps to do so has first had to resolve numerous rather difficult issues. Some of these include whether to (1) allow incumbent utilities to recover their stranded costs and, if so, how;[27] (2) require their incumbent utilities to divest their generation assets to eliminate their potential market power in the newly-formed retail competitive market;[28] (3) freeze retail rates during a transition period in order to reassure consumers that competition will achieve the desired goal of

F.3d 15 (1st Cir. 1998), because the legality of the actions of the New Hampshire Public Utilities Commission (NHPUC) was questioned. Public Service Company of New Hampshire and the PUC recently reached a settlement and planned to re-open the market to competition in Spring 2001.

[26.1] *See* 66 Pa. Cons. Stat. Ann. § 2806 (West 2000); Ariz. Rev. Stat. Ann. § 40-202 (West Supp. 2000); Tex. Util. Code Ann. § 39.104 (West Supp. 2001).

[27] To date, most states have allowed their utilities the opportunity to collect all their stranded costs. Typically, they are recovered through a temporary surcharge levied on the distribution of kilowatt-hours of electricity to all consumers in the jurisdiction. In some states the actual recovery of stranded costs is more difficult than in others. For example, in Connecticut, Maine, and Massachusetts only "unmitigable" stranded costs can be recovered. Conn. Gen. Stat. Ann. § 16-245e (West Supp. 2001); Me. Rev. Stat. Ann. tit. 35-A, § 3208 (West Supp. 2001); Mass. Gen. Laws Ann. ch. 164, § 1G (West Supp. 2000). Several states have conditioned stranded cost recovery on divestiture of some or all of the utility's generation. See, for example, Connecticut, which required its utilities to divest all non-nuclear generation. In Rhode Island, utilities must divest 15% of their generation assets within three years. R.I. Gen. Laws § 39-1-27.4 (West 1997). Maine will require its utilities to divest all their generation. Me. Rev. Stat. Ann. tit. 35-A, § 3204 (West Supp. 2000).

[28] Most states are not requiring divestiture of generation assets. Although this is an advantage for aiding the development of a retail competitive market, it is opposed by the incumbent utilities and frequently by the labor unions and non-unionized utility employees who wish to see the same ownership continue. In addition, consumers are often anxious about what new electricity providers will mean for the reliability of their service and the level of solicitude for them as consumers. This concern has increased with California's recent experience with high prices and shortages on the spot wholesale market.

lowered rates;[29] (4) set up programs to continue state jurisdiction over the environmental externalities associated with the generation and distribution of electricity;[30] (5) mandate that their publicly- and cooperatively-owned utilities participate in retail competition;[31] and (6) make other services, which have typically been provided by utilities, open to competition.[32]

§ 1.02 The U.S. Electric Industry in 2001: Where It Is and Where It Is Headed

Today, the domestic electric industry is much more competitive than it was even five years ago. Independent generators are producing an increasing amount of the wholesale power sold in the United States. In 2000, independent generators produced 28% of all wholesale

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[29] One of the primary political forces behind the passage of legislation in the states to open electricity to retail competition is the belief that it will result in lower electric rates. Some states are reluctant to rely on a nascent competitive market to achieve this and have enacted programs and temporary regulatory controls designed to assure it. California did this and, although the freeze protected consumers from sharp increases in 2000, it has led to the bankruptcy of Pacific Gas & Electric, the near-bankruptcy of Southern California Edison, and the financial distress of San Diego Gas & Electric. It also prevented California consumers from feeling the price signals that would have counseled conservation and might have ameliorated the shortage situation that occurred in June 2000 in California.

[30] About half the states that have provided for retail competition have set up a program to fund efforts designed to promote electricity efficiency, demand-side management, research and development of renewable fuels, environmental improvement, universal electricity service, low income assistance, and utility employee health, retirement, and retraining programs. Some states have a renewable resource portfolio requirement that must be met by electricity providers seeking to be licensed to do business in their jurisdictions. For example, Maine will require licensed power marketers to generate a minimum of 30% of the power offered for sale in Maine from renewable energy resources. Me. Rev. Stat. Ann. tit. 35-A, § 3210 (West Supp. 2000).

[31] Only a few states have required their publicly- and cooperatively-owned utilities to participate. Arizona is one, which has made retail wheeling applicable to its rural electric cooperatives and the Salt River Project, a publicly-owned water and electric utility, although Arizona has exempted municipally-owned utilities from the program. Ariz. Rev. Stat. Ann. § 40-202 (West Supp. 2000).

[32] For example, Massachusetts' utilities must open up their billing and collections, metering, and meter reading services to competition. Mass. Gen. Laws Ann. ch. 164, § 1D (West Supp. 2000).

power.[33] Even traditional integrated utility monopolies have become more free-market oriented than before. Obviously they must compete with other generators in those states where competition has reached the retail level. Even in the other states, however, more regulators are employing performance-based regulation to encourage lower costs and greater efficiency. Also, many utilities have affiliates that build and operate independent generation. In the current state of low supply and high demand in many regional electricity markets, including the West's, independent generation has become a more profitable business than ever before.

Independent generation, also known as "merchant generation," differs from utility- owned generation in that it is built as a speculative venture. No regulator guarantees it a revenue stream or captive customers. The merchant generator typically sells the plant's expected electricity output by contracts of varying lengths to one or more wholesale purchasers. The generator may also sell capacity on the spot wholesale market. As states open up their retail markets to competition, assuming they do, the market into which the merchant generator can sell will expand.

As long as the competitive market in electricity continues or expands, a primary goal for electricity generators will be producing electricity at the lowest possible cost. This lowest-cost principle will have a direct impact, then, on the type of generators that are built, i.e., gas-fired, coal-fired, etc., and on the contractual arrangements that generators will seek with resource producers.

There are numerous questions pending in legislative and regulatory arenas, the answers to which will affect the costs of the competing sources of electricity generation. For example, will President Bush's newly-announced national energy policy with its emphasis on producing electricity from fossil and nuclear fuels be enacted, thus giving these sources some cost advantages? Will all states be willing to site new

[33]EIA, *Electric Power Monthly* (Apr. 2001), http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html.

generation within their boundaries or will the number of available sites be limited, thus driving up costs and potentially narrowing the choices for the type of generation appropriate to the site? Will states require their utilities to build more transmission, thereby decreasing the amount of generation, particularly distributed generation that will otherwise be built? Will existing federal and state environmental and land use regulations affecting electricity be stiffened or weakened? Will Congress and state legislatures increase or decrease the support they currently give to the development and use of renewable resources to produce electricity? Will foreign governments make their fuel resources more or less available to the United States?

Unknowns under the control of private parties will also affect the future of the electric industry. For example, will fuel cell technology advance rapidly and significantly displace the generation/transmission/distribution system of electricity? Will new transmission technology advance and lower the costs of transmitting electricity?

The year 2001 finds us with an electric industry structured considerably differently from the industry of even five years ago, but the future portends even more change. This industry likely will continue to evolve in fits and starts, and not necessarily along a straight and predictable path, for decades to come. Predicting the future direction of the industry would be relatively straightforward if all one had to do was apply the lowest-cost principle to today's electricity market data. However, the old adage—that nothing is ever as simple as it appears to be—applies here as well. There are many uncertainties looming in the future of the electric industry, the resolution of which may decrease the otherwise strong applicability of the lowest-cost principle to traditional electricity generation, or may dramatically affect the costs of generating electricity. An example of the former is the uncertainty surrounding the country's commitment to competition in electricity generation. While the federal government is still evidencing a commitment to enhancing competition in wholesale power markets, the crisis in California has caused many states to step back from their plans to introduce competition at the retail level. Additionally, publicly-owned utilities and federal power marketing entities currently have a great degree of freedom to choose whether to participate in the competitive marketplace for electricity, and they have been largely cautious about doing so. The choices they make in the future will impact the competitiveness of the market, too. Less reliance on the competitive market for the generation of electricity will attenuate the importance of lowest-cost generation.

The future of the electricity industry will also be affected by actions taken by local, state, federal, and other countries' governments. Governmental actions can have radical impacts on the costs of producing electricity. Thus, what may be least-cost today may not be so tomorrow, and vice-versa.

[1] Will Competition in Electricity Generation Continue to Expand?

[a] Continuing Federal Commitment to Enhancing Competition in the Wholesale Electricity Markets

In issuing Orders 888 and 889, FERC advanced the process of transition to a competitive wholesale market for electricity that had started in the late 1970s.[34] Since issuing those orders, FERC has continued to promote wholesale competition by easing access to the grid for new generation sources, and by granting authority to new, independent generation sources, to sell power at market-based rates, instead of cost-based rates.

[i] Interconnection of Independent Generation

For the past two decades, the federal government has encouraged the development and connection to the grid of new generation operated by independent, non-utility entities. As discussed in § 1.01[1][c] above, PURPA attempted to encourage the development of independent generation not only by requiring public utilities to buy power from small

[34] *See* § 1.01[1][c] *supra*.

power producers, but also by giving FERC the authority to order interconnection of facilities when requested by generators.[35] EPAct gave FERC the additional power to order utilities to open their transmission lines to allow independent generators to deliver power at wholesale.[36] These statutory changes allowed FERC to require transmission-owning entities to provide open access outside of merger and market-based rate proceedings.

Under these statutes, FERC has directed its energy at easing the interconnection of new, independent generation sources. While PURPA only obligated utilities to purchase power from qualifying facilities, FERC went one step further and enacted regulations under the authority of the statute that *obligate* transmitting utilities to interconnect with qualifying facilities.[37] FERC has also issued a statement of policy regarding good faith requests for transmission services and good faith responses by transmitting utilities.[38] While the EPAct gave FERC the authority to order a utility to provide transmission service, it conditions the authority by allowing an order only if the applicant for transmission service has made a request to the transmission-owning utility for transmission service at least 60 days prior to filing for an order.[39] In the policy statement, however, FERC set only minimum guidelines for what constitutes a "good faith request." For example, the policy requires only that generators requesting transmission service provide "the character and nature of the services requested," and only requires an estimate of certain other information about the delivery the requesting entity wishes to make.[40] FERC has accepted requests that even lack these estimates, and instead

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[35] 16 U.S.C.A. § 824i (2000).

[36] 16 U.S.C.A. § 824j (2000).

[37] 18 C.F.R. § 292.303 (2000).

[38] *See* 18 C.F.R. § 2.20 (2000).

[39] *See* 16 U.S.C.A. § 824j (2000).

[40] 18 C.F.R. § 2.20 (2000).

only include a request for a meeting with the transmitting utility.[41]

FERC has also not been afraid to use its authority to issue orders directing interconnections and transmission under PURPA and EPAct.[42] Recently, however, the Commission has determined that Order 888 eliminates the need for specific orders directing interconnection of new facilities. Specifically, FERC has determined that "interconnection is an element of open access transmission service required to be provided by public utilities pursuant to Order No. 888."[43]

[ii] Market-Based Rates for Sales from Independent Generators

Beginning in the early 1980s, FERC began to experiment with allowing generators to set their own "market-based" rates, instead of setting the generator's rates according to their costs in producing the power, plus a reasonable rate of return (often referred to as "cost-plus" pricing). Under this experiment, the Commission would grant a generator's request to sell power at market-based rates only if it could show that it could not exercise undue market power in generation and transmission markets, and that there would be no potential for anticompetitive favoring of affiliates.[44] The Commission acted under a presumption that the requesting generator has undue market power, and the generator was then required to defeat the presumption by making a specific showing to the contrary.

In 1994, FERC determined that in light of industry and statutory changes that resulted in an easing of market entry by new generation, no new facility could have market power

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[41] *See, e.g.*, Suffolk County Electrical Agency, 77 F.E.R.C. ¶ 61,355, 62,551 (1996).

[42] *See, e.g.*, Illinois Municipal Electric Agency v. Illinois Power Co., 86 F.E.R.C. ¶ 61,045 (1999).

[43] Laguna Irrigation Dist., 91 F.E.R.C. ¶ 61,340, 62,152 (2000), citing Central Maine Power Co., 90 F.E.R.C. ¶ 61,214, 61,707 (2000).

[44] For a discussion of FERC market-based ratemaking activities, see Joseph T. Kelliher, "Comment: Pushing the Envelope: Development of Federal Electric Transmission Access Policy," 42 *Am. U.L. Rev.* 543, 563-68 (1993).

in generation.[45] In Order No. 888, FERC codified this determination. Specifically, the Commission changed its presumptions about market power when a generator requests market-based rate authority for a new facility by dropping the requirement that the generator prove lack of generation market dominance.[46] Lack of market power is now presumed, and opposing parties must come forward and prove that market power exists for the Commission to deny a request for market-based rate authority.

While voicing its continued commitment to market-based rates, FERC has nevertheless implemented a "price mitigation plan" to constrain prices in all spot market sales in the Western Systems Coordinating Council (WSCC).[47] FERC explained that it was ordering market-based caps, not cost-based rate caps, because it feared cost-based rates would squelch development of new supplies in the West and thus perpetuate the shortage that currently exists. It characterized its price mitigation plan as one that ensures that rates are not unreasonable but also encourages new supplies needed in the West.[48] At the time FERC adopted this plan it faced an announced move by the U.S. Senate Energy and Natural Resources Committee to bring to hearing a bill directing

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[45]Kansas City Power & Light Co., 67 F.E.R.C. ¶ 61,183 (1994).

[46]*See* FERC Order 888, *supra* note 15, at 21,553. If a generator wishes to sell at market-based rates from an existing facility, it is still required to prove lack of market dominance.

[47]When generation operating reserves fall below 7% in California (a "reserve deficiency"), a market-clearing price will apply to all spot market sales in California and in the rest of the WSCC. All bidders in the California Independent System Operator (ISO) spot market will receive the market-clearing price without further price justification. All sellers in other spot markets in the WSCC will receive up to the clearing price without further price justification. The market clearing price will be based on the bid of the highest cost gas-fired unit located in California that is needed to serve the California ISO's load on any day in which a reserve deficiency exists. When a reserve deficiency period ends and generation operating reserves rise to 7%, the maximum price that can be charged for spot market sales in California and the rest of the WSCC, absent cost justification, will be 85% of the highest hourly price that was in effect during the most recent reserve deficiency period called by the California ISO.

[48]News Release, Federal Energy Reg. Comm'n, "Commission Extends California Price Mitigation Plan for Spot Markets to All Hours, All States in Entire Western Region" 7 (June 18, 2001).

FERC to set a cost-based rate for the California power market.[49] Previously FERC had established target prices at which it believed energy should be selling in the California ISO spot market, and then ordered electricity providers to refund any charges they initiated over the cap during specific situations or justify the prices they did receive. For example, in March 2001, FERC issued an order compelling 13 electricity providers to refund $69 million for transactions in California that occurred over the $273 MWh target price in January 2001.[50]

[iii] Formation and FERC Conditional Approval of Regional Transmission Organizations

The latest evidence of the continued federal commitment to competition in wholesale energy markets is the recent FERC initiative to form Regional Transmission Organizations (RTOs). An RTO is an entity that controls all of the transmission facilities within a given region, similar to the current Independent System Operator (ISO) structure operating in some markets. On December 20, 1999, the Commission issued its final rule on RTOs, stating, "appropriate RTOs could successfully address the existing impediments to efficient grid operation and competition."[51] The Commission hoped that the rule would encourage transmission owners to place their transmission facilities under the operational control of RTOs "voluntarily and in a timely manner."[52]

An RTO is essentially a new form of the old ISO structure, but is more flexible in the types of governance and business forms the new entities may take. While each of the five ISOs approved by FERC after Order 888 and before its RTO

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[49] *See* S. 764, 107th Cong. (2001), offered by Senators Dianne Feinstein, D-Cal., and Gordon Smith, R-Or.

[50] *See* San Diego Gas & Electric Co. v. California ISO, 94 F.E.R.C. ¶ 61,245 (2001).

[51] Regional Transmission Orgs, Order 2000, 65 Fed. Reg. 810, 811 (Jan. 6, 2000) (codified at 18 C.F.R. § 35.34); *petitions for review pending*, Pub. Utility Dist. No. 1 of Snohomish County, Wa. v. FERC, No. 00-1174 (D.C. Cir.).

[52] 65 Fed. Reg. at 812.

rulemaking proposal are not-for-profit organizations,[53] the RTO rulemaking explicitly declined to "propose to require or prohibit any one form of organization for RTOs."[54] The rule requires that any proposed RTO meet four minimum characteristics, and carry out eight minimum functions. The four minimum characteristics are: (1) the RTO must be independent, (2) the RTO's scope and configuration must be regional, (3) the RTO must have operational authority over the facilities under its control, and (4) the RTO must provide for short-term reliability in the region.[55] The eight minimum functions of an RTO include grid congestion management, market monitoring, determination of system availability, and capacity and interregional coordination.[56] FERC also established an open architecture policy with regard to the governance structure of RTOs, to allow for flexibility and rapid changes in scope and operations should the market demand them.[57]

To date, FERC has given conditional approval to three RTOs: the Alliance RTO (containing mostly Midwestern states, and including the Midwest ISO in a "super-region"), GridSouth Transco LLC (containing Southeastern states), and GridFlorida LLC (a one-state-only RTO).[57.1] The Commission has given something less than conditional approval to a fourth entity, RTO West, containing portions of Northwestern and Western states.[58]

In contrast to the currently existing ISOs, all of the RTOs that have been established have a for-profit governance

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[53] *Id.* at 815.

[54] *Id.* at 811.

[55] *Id.*

[56] *Id.*

[57] *Id.* at 811-12.

[57.1] *See* Illinois Power Co., 95 F.E.R.C. ¶ 61,183 (2001) (Alliance order); Carolina Power & Light Co., 94 F.E.R.C. ¶ 61,273 (2001) (GridSouth order); GridFlorida LLC, 94 F.E.R.C. ¶ 61,363 (2001) (GridFlorida order).

[58] While the conditionally-approved entities have passed what FERC calls its Stage Two proceeding, RTO West has passed only through Stage One of the approval process. *See* Avista Corp., 95 F.E.R.C. ¶ 61,074, 61,114 (2001) (RTO West order).

structure. The entities will operate essentially as transmission companies, or Transcos. Since RTOs will be considered "public utilities" under law, they will be subject to the requirements of Order 888 and therefore must still provide open access to the transmission they will control. Under each of the conditionally-approved RTOs, participating utilities will transfer control and operational authority of their transmission facilities to the governing body of the RTO. In some cases, the RTO will purchase the transmission facilities and control all aspects of them, while in other cases the RTO will hold only operational authority, and in at least one case, there is a combination of the two. In one instance, a transmission company will purchase all the transmission facilities in the region, and then transfer operational authority to the RTO.

FERC has focused its concentration thus far in the process on ensuring that RTOs are independent of the transmission owners. The independence standard is designed to cure the problem of transmission-owning utilities giving their affiliates preference in granting access to their transmission. FERC has expressed concern over RTOs that contain utilities hesitant to transfer operational control.[59]

The next issue the Commission will have to tackle is how these entities will price their transmission services. Currently, the debate is over whether an RTO will charge one rate for its entire region, or whether the rate it charges will be dependent upon the delivery point in the system (also called a "license plate rate"). This issue is likely to be significant, given that a main goal of FERC in creating RTOs is to eliminate the "pancaking" of rates that currently occurs; that is, a transmission customer is charged separately by each transmission-owning utility whose lines the power travels over to its delivery point. The Commission likely prefers a flat rate for all transmission within the RTO's region, given its recent acceptance of a settlement that ties the Alliance RTO

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[59]Southwest Power Pool, Inc., 94 F.E.R.C. ¶ 61,359, 62,291 (2001).

and the Midwest ISO, creating the electric utility industry's first "super-region" under one transmission rate.[60]

[b] Hesitation in Many States About Extending Competition to the Retail Electricity Market

While the federal government continues to steer along the wholesale electric competitive road, state-level policymakers have become more cautious about extending competition into the retail market. Halting expansion of competition to the retail market does not mean that the competitive and cost-cutting approach to electricity generation will be halted, but how big an issue it continues to be will be decided in large part by state regulators. If integrated monopoly utilities continue to provide the electricity to their consumers, state regulators will decide how these monopolies will provide electricity as the demand in their territory grows. Traditionally, these utilities have built most of the generation they needed, but state regulators can direct them to obtain their supplies differently. For example, utilities could be directed to purchase power from independent generators or to outsource their need for a new generator to the lowest bidder. Even if integrated monopoly utilities continue to build for themselves, state regulators could work to make lowest cost the driving force behind new generation. However, state regulators may not always wish to make this the primary goal, and this is one significant area where their control differs from the "control" of the competitive market place. Often regulators have multiple goals in mind when they approve new generation for their monopolies; for example, firing new generation with a fuel source that is produced within the state or building generation that uses a renewable energy resource. Whether retail competition expands among the states will have an impact on the future direction the electric industry takes.

Just as many states rushed to follow California in restructuring their electricity markets, many have rushed to back off deregulation after watching the California energy

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[60] *See* Illinois Power Co., 95 F.E.R.C. ¶ 61,183, 61,641 (2001).

morass unfold. This development is extremely important to the future of the industry, because electricity markets can be opened to retail competition only by regulators at the state level; FERC currently has no jurisdiction to open retail markets to electricity competition. While bills have been introduced in Congress to extend competition nationwide to retail electricity markets, they have not advanced through any committees.

To date, 21 states have remained on schedule to deregulate their electricity markets.[61] Some of those states, however, are considering delaying the start of competition. Oregon, whose electricity restructuring law only allows industrial and large business users to shop for power, is currently debating whether to delay the start of its retail electricity market.[62] The North Carolina Legislature was expected to adopt a report by a legislative study commission that would have full retail access in the state by 2006, but it has taken no action to do so in the wake of the recent turmoil in the West.[63]

Three state legislatures have taken action this year to amend their restructuring laws to delay the start of statewide retail access. Arkansas was the first, enacting legislation in late February that delays electric deregulation until at least October 1, 2003.[64] The law gives the Arkansas Public Service Commission the power to delay the start of competition in the state until as late as October 1, 2005, if the Commission finds that customers would not receive price benefits or that "demonstrably effective market structures are not in place."[65] New Mexico later followed suit, enacting a law that delays restructuring of the state electricity industry until 2007.[66]

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[61] *See* Kenneth Rose & Selina Lim, *The Status of Electric Deregulation Following The California Meltdown* (Nat'l Regulatory Research Inst., Mar. 2001).

[62] *See* Jeff Mapes, "Future Remains Cloudy for Oregon Deregulation Laws," *The Oregonian*, May 10, 2001.

[63] *See* Paul B. Johnson, "Electric Deregulation Movement in North Carolina Gets Unplugged," *High Point Enterprise*, May 15, 2001.

[64] 2001 Ark. Acts 324.

[65] *Id.*

[66] S.B. 266, 45th Leg., 1st Sess. (N.M. 2001).

That measure, however, does allow utilities in the state to continue to file transition plans (including business separations) and allows utilities to invest in, construct, or acquire unregulated generation not intended to serve customers in the state.[67] Oklahoma also moved legislatively in 2001 to delay its start date for retail access until at least 2003.[68] The legislation states that electric competition may not begin in the state until a seven-person task force created by the measure studies the issues and makes a recommendation in November 2002, and enabling legislation is enacted in 2003, at the earliest.[69]

Nevada has taken the furthest step away from deregulation, completely reversing its restructuring law indefinitely. Governor Kenny Guinn, after halting deregulation indefinitely several times in the past two years, signed into law a measure that re-regulates electric utilities in the state and bars them from selling power plants until July 1, 2003.[70] The bill also requires that retail electricity rates remain at April 2001 levels until early in 2002.[71]

There are still several states that are not interested in deregulating their electricity markets. The National Regulatory Research Institute (NRRI) has classified 14 states as those that are a "no go" on electricity restructuring, with no action likely.[72] Many of the states that are a "no go" have refused deregulation in large part because costs for energy in those states are already relatively low. Colorado, for example, instituted a legislative study which found that costs for power in the state were low, and that competition would likely increase rates, especially among low income, residential, and

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[67] *Id.*

[68] S.B. 440, 48th Leg., 1st Sess. (Okla. 2001).

[69] *Id.*

[70] A.B. 369, 2001 Leg., 71st Sess. (Nev. 2001).

[71] *Id.*

[72] Rose & Lim, *supra* note 61.

small business users.[73] The Colorado study also found that the transmission system in the state was limited in its ability to import power into the state, significantly reducing its ability to obtain any advantages from electricity restructuring.[74] A similar fact also explains why isolated states such as Alaska and Hawaii, far away from any available power to establish a competitive market, have not opted for competition.

Of the states that are currently considering legislation or regulations to restructure their electric industries, some are pushing legislation that is more limited in scope. In Missouri, for example, legislation is being considered that would allow utilities to separate their generation assets into a separate generation company (or GENCO) from the rest of their utility assets.[75] The bill would also allow certain larger industrial and commercial customers to shop for power on the open market.[76] Louisiana, another state with electricity costs below the national average, has issued a study report recommending a "slow and cautious" approach to industry restructuring.[77] Virginia, while not repealing or delaying the start of its retail choice program, has acted to provide a safety net, passing legislation that allows the state corporation commission to require incumbent public utility franchises to provide default service to customers if a competitive market does not develop in the state.[78]

[c] Will Publicly- and Cooperatively-Owned Utilities Opt for Competition?

Public-power systems, which are most often municipal- and city-run utilities, and cooperative utilities, serve over 32

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[73] *See Colorado Electricity Advisory Panel, Evaluation Study Report* (Colo. Pub. Utilities Comm'n, Nov. 1, 1999), http://www.dora.state.co.us/puc/euir/euir.htm.

[74] *See id.*

[75] S.B. 455, 91st Gen. Assem., 1st Reg. Sess. (Mo. 2001).

[76] *Id.*

[77] La. P.S.C., "*In re* An Investigation Into Whether Electric Industry Restructuring and Competition in the Provision of Retail Electric Service are in the Public Interest, Docket No. U-21453," *Staff Report and Recommendations* (May 1999).

[78] 2001 Va. Acts ch. 748.

million customers, or just over 25% of the total number of customers served by electric utilities.[79] As these statistics clearly indicate, public power and cooperative utilities and their customers represent a significant portion of the potential market for competitive energy suppliers.

Most state restructuring laws give cooperative and municipal utilities the choice of whether or not to open their service territories to competition.[80] Arizona is one of only a handful of states that requires cooperative utilities and municipal utilities, including the publicly-owned Salt River Project, to participate in competition.[80.1] Only municipal utilities that serve less than 75,000 customers are exempt, although they may choose to opt in to competition. Oklahoma and Pennsylvania have required their cooperatives to open their transmission and distribution facilities to competition, but have exempted municipal utilities unless they chose to opt in.[80.2] Montana requires cooperatives to participate, unless they specifically inform the state that they wish to opt out.[81]

Most cooperative and publicly-owned entities are likely to use these exemptions to remain regulated until a viable retail market develops, and the turmoil in the wholesale markets subsides. In states where competition has been extended to the retail market, almost no municipal or cooperative utilities have opted to extend competition to their service areas.

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[79] American Pub. Power Ass'n, *2001 Annual Directory & Statistical Report* 11 (2001), http://www.appanet.org/general/issues/stats.htm.

[80] See, for example, Texas and Massachusetts. Tex. Util. Code Ann. § 39.002 (West Supp. 2001); Mass. Gen. Laws Ann. ch. 164, § 1 (West Supp. 2000).

[80.1] *See* Ariz. Rev. Stat. Ann. § 40-202 (West Supp. 2000).

[80.2] *See* Okla. Stat. Ann. tit. 17, § 190.3 (West 1999); 66 Pa. Cons. Stat. Ann. § 2804 (West 2000).

[81] Mont. Code Ann. § 69-8-311 (1999). For more information, see Suedeen G. Kelly, "Electricity," in The Energy Law Group, *supra* note 3, at 12-36.

[d] Will Federal Power Marketing Administrations and TVA Opt for Competition?

The federal government owns hydroelectric and other generation facilities as well as transmission facilities. These facilities are organized into four federal Power Marketing Administrations (PMAs)—Western Area Power Administration (WAPA), Southwestern Power Administration, Bonneville Power Administration, and Southeastern Power Administration—and the Tennessee Valley Authority. These PMAs have remained relatively quiet on their prospects in a deregulated industry.

The U.S. Secretary of Energy has the authority to market the power produced by the federal facilities within the PMAs. The PMAs set the power and transmission rates for the facilities within their jurisdictions, using cost-of-service ratemaking principles. The PMAs sell most of their electricity at wholesale to publicly- and cooperatively-owned utilities and sell some power at retail to industrial customers. Although FERC has no jurisdiction over the PMAs' rates, EPAct allows FERC to order them to provide transmission service so long as the order is consistent with other laws. However, FERC's open access Order 888 does not apply to them.[82] TVA is a bit different from the PMAs. Its mission includes economic development of the Tennessee Valley region. It cannot sell its power, or compete outside the region,[83] but it has the right to serve all the distribution utilities within its region. TVA sets its own power and transmission rates. FERC can order it to transmit power on a case-by-case basis, but TVA is not subject to Order 888.

[82] *See* FERC Order 888, *supra* note 15, at 21,668-69.

[83] *See* Jeffery D. Watkiss & Douglas W. Smith, "The Energy Policy Act of 1992—A Watershed for Competition in the Wholesale Power Market," 10 *Yale J. on Reg.* 447, 461 n.58 (1993).

[2] Will the Executive and Legislative Branches Change Today's Costs of Generating Electricity?

[a] President Bush's Newly Announced National Energy Policy Emphasizes Enhancing Supply of Electricity

While federal regulators have continued to support competition in electricity markets, and state legislators and regulators have grown shy of extending competition into their retail markets, the new Administration has instead attempted to focus on encouraging new supplies of energy. This White House policy can be interpreted either as one supporting competition (because without adequate supplies of energy, competition is likely to fail consumers), or as a policy simply to avert what President Bush has described as an impending energy crisis. Under either interpretation, the ability of the President to implement the new policy will significantly impact the future course of the industry.

Of foremost importance in the new Administration energy policy is its focus on increased production of fuels used in electricity generation, especially natural gas. The Administration estimates in its report that natural gas electricity generation will grow from 16% of total generation to 36% of total generation by 2020, and that the total wells drilled for natural gas will need to double by that time in order to meet increased demand.[84] To respond to this issue, the Administration has focused its policy on increased exploration for oil and natural gas on federal lands and on the Outer Continental Shelf (OCS). The administration policy recommends that restrictions on federal oil and gas leasing be reviewed and eased where possible, and that economic incentives be provided and royalties be reduced for offshore oil and gas development.[85] The report also contains the extremely controversial recommendation that a portion of the Arctic National Wildlife Refuge (ANWR) be opened for oil and gas

[84] Nat'l Energy Policy Dev. Group, "Reliable, Affordable and Environmentally Sound Energy for America's Future," 5-10, 5-14 (Report to the President May 2001).

[85] *Id.* at 5-7.

exploration and development.[86] Unlike the former recommendations, however, the latter will require congressional approval, which appears quite unlikely with the recent shift in power in the Senate.

The policy additionally encourages an increase in supply through the expedited siting and permitting of new generation facilities. Since the federal government can do little to expedite siting of new gas- or coal-fired plants, which is largely within the exclusive jurisdiction of the states, the Administration policy focuses on development of new nuclear, hydroelectric, and geothermal and combined heat and power (CHP) projects. These projects still may be subject to state siting jurisdiction, but they need federal approvals as well. Specifically, the policy recommends that nuclear energy become a "major component" of national energy policy, that existing nuclear sites which can accommodate more reactors than are currently operating be updated, and that existing nuclear plants which meet or exceed safety standards be relicensed.[87] The policy also recommends that the much-debated licensing and relicensing process for hydroelectric facilities, directed by FERC, be reformed.[88] Finally, the policy makes a blanket recommendation that the President, by executive order, direct federal entities to expedite permitting and actions necessary to gain approval of "energy-related projects."[89]

Another key component of the administration energy policy is the easing of regulatory restrictions, and development of alternative regulatory plans, that affect plant development and production. The policy calls for a program to regulate three pollutants from power plant emissions (sulfur dioxide, nitrogen oxides, and mercury) through a market-based program, which will presumably become an emission credits

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[86] *Id.* at 5-10.

[87] *Id.* at 5-15 to 5-17.

[88] *Id.* at 5-18.

[89] *Id.* at 3-12 to 3-13.

trading program.[90] Such a program would allow power plants that do emit more than the allowed amount of pollutants to buy credits from plants that emit less than they are allowed, to avoid reducing their emissions and possibly their output. This recommendation is significant because it fails to regulate a fourth pollutant, carbon dioxide, which was expected as recently as January 2001 to be part of any electric generating emissions standard. The policy also recommends that the current new source review environmental regulations, and enforcement actions under the regulations, be reviewed to determine their effect on investment in new generation capacity.[91]

Finally, the policy recommends that the Energy Star efficiency-rating program be expanded to include schools, homes, and hospitals in addition to businesses, and to increase the use of the Energy Guide labeling system to new products.[92] This recommendation, if approved, could increase the supply of energy by promoting more conservation within the home. While conservation is only a minor part of the Bush plan to increase national energy supply, this recommendation does insert conservation into the agenda.

These policy recommendations, if ultimately implemented by the federal government, would decrease the costs that will otherwise pertain to the future generation of electricity by gas, hydropower, coal, and nuclear. Adoption of the President's Energy Policy would advance the prospects of these fuels in relation to their competitors, on a cost basis, from where they are today in the hierarchy of desirability for electricity generation.

[b] Will States be Willing to Work Cooperatively to Site New Generation and Transmission Within Their Boundaries?

A functional, competitive market in electricity can be maintained only if new generation can be built when it is

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[90] *Id.* at 3-3.

[91] *Id.* at 7-14.

[92] *Id.* at 4-5.

needed and connected to the transmission grid, and if the transmission infrastructure can be planned, constructed, and financed efficiently. Whether this goal can be achieved involves many issues, including the preliminary question of who is going to have the responsibility and incentive to make decisions regarding where and when to build. But an equally significant question is whether the states, which currently have de facto veto power over these types of decisions through their siting authority, will be able to resolve the enormous potential for conflict that these issues pose. Obviously, almost no one wants a power plant or transmission line in his backyard, but the conflict will only escalate when it becomes clear that in a broad regional marketplace the costs and benefits of siting decisions may not accrue to the same individuals.

Currently, some states have power plant siting laws that effectively prevent the siting of power plants that export electricity out of state. A Florida siting law, for example, has been interpreted to require a significant amount of power from any new generating facility to be committed to be sold to in-state utilities. The Florida Supreme Court found that the state siting law would not allow an out-of-state company to be granted a determination of need to build a new power plant when only 30 megawatts of the 514-megawatt capacity were committed to in-state use.[93]

On the other hand, some states recently have shown an interest in expediting the siting of new generation, although their actions may be based on the belief that the benefits of new power plant sitings will accrue in state. California has recently enacted a law that accelerates timelines for review of applications for permits for new generation facilities, limits the public hearing process and appeals process for siting decisions, and limits the approval process for repowering existing plants to six months and peaking projects to four

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[93]Tampa Elec. Co. v. Garcia, 767 So. 2d 428 (Fla. 2000), *cert. denied*, 121 S. Ct. 1227 (2001).

months.[94] As an incentive for local communities to allow power plants to be built, the bill permits cities and counties to retain all money received in property tax assessments from the plants.[95] New Mexico has also acted legislatively, requiring the state's Public Regulation Commission to approve or deny an application for a new generation or transmission facility within six or sixteen months, respectively, of the filing of the application.[96]

In New York, a recent state appeals court decision could prove to be the impetus for an easing of the siting of large power plants within the state. In *In re Citizens for the Hudson Valley v. New York State Board on Electric Generation Siting and the Environment*,[97] the court upheld the ability of the state siting board to override local zoning laws. In that case, the board used a section of the New York Public Service Law, known as "Article X," to override local zoning ordinances in granting approval to the plant.[98] The petitioners sought review of this decision, claiming that the language of Article X which allows the board to refuse to apply local zoning laws that are "unreasonably restrictive" was both a violation of state constitutional home-rule provisions and unconstitutionally vague.[99] The court ruled that the provision does not violate home-rule because it is "general law," which "applies alike to . . . all cities, all towns or all villages," and that the language "unreasonably restrictive" was not unconstitutionally vague because of the qualifying language that the "board may refuse to apply any local ordinance [or] law . . . if it finds that as applied to the proposed facility such is unreasonably restrictive in view of the existing technology

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[94] S.B.X.1 28, 2001-2002 Leg., 1st Extraordinary Sess. (Cal. 2001). The bill was signed by Governor Gray Davis (D) on May 22, 2001.

[95] *Id.*

[96] S.B. 452, 45th Leg., 1st Sess. (N.M. 2001).

[97] 723 N.Y.S.2d 532 (N.Y. App. Div. 2001).

[98] *Id.* at 535; the provision of law in question is at N.Y. Pub. Serv. Law § 168(2)(d) (2001).

[99] 723 N.Y.S.2d at 536.

or the needs of or costs to ratepayers whether located inside or outside of such municipality."[100]

A sub-issue inherent in this discussion is whether Congress will give FERC eminent domain authority to site transmission facilities over the objections of state officials. Currently, FERC has no authority over electricity transmission facility siting, even though it does have authority over the siting of interstate natural gas pipelines.[101] Policymakers, most notably FERC Commissioner William Massey, have advocated giving the Commission power to site transmission facilities used in interstate transport of electricity.[102] The new Administration's energy policy, while not using the exact phrase "eminent domain," does recommend that legislation be developed to "grant authority to obtain rights-of-way for electricity transmission lines, with the goal of creating a reliable national transmission grid."[103]

[c] Will Transmission and Generation, Particularly Distributed Generation, Become Better Substitutes?

The problem of insufficient supply of electricity to an area can sometimes be solved either by building more transmission to the area or more generation near the area. In other words, transmission and generation can sometimes be substitutes for the supply of electricity. "Distributed generation" is a new group of smaller generation technologies, some still in their infancy and some still on the drawing board. Some distributed generation is simply re-engineered back-up generators that produce power more efficiently; others employ new technologies such as microturbines, reciprocating engines,

[100] *Id.* at 536-37; N.Y. Pub. Serv. Law § 168(2)(d) (2001).

[101] 15 U.S.C.A. § 717f(h) (1997).

[102] "FERC Commissioner Massey Tells State Regulators That Sustained High Energy Prices May Spur Consumer Revolt," *Foster Elec. Rep.* No. 212, Mar. 14, 2001, at 17.

[103] *Supra* note 84, at 7-7 to 7-8.

fuel cells, and even wind and photovoltaics.[104] They are sized from about 1 megawatt downwards. The majority of distributed generation today is fueled with natural gas. Distributed generation can be interconnected to the utility's distribution system or connected just to a particular consumer. Distributed generation could be bi-directionally connected to allow power to go directly to the consumer when it was needed and otherwise to the grid. Distributed generation could be used to generate power on-peak, to provide voltage support for the transmission grid, and as an alternative to expansion of the grid or the distribution system.

Making distributed generation a viable generation or transmission alternative will take a commitment by state regulators to its deployment. Regulators must develop standards for the interconnection of distributed generation and determine who may own and operate them.[105] For example, under current regulations in most states, utilities could refuse to interconnect distributed generation owned by others but install their own distributed generation. The Public Utility Commission of Texas (PUCT) is in the forefront among the states in encouraging the deployment of distributed generation. It has developed guidelines for the interconnection of distributed generation units[106] and issued rules setting safety and operating standards and pre-certification requirements for them.[107] The rules allow any customer to interconnect up to 10 megawatts of capacity to the grid.

While it may seem far-fetched to expect that residential consumers, producing power in their own homes and selling the excess back to the grid, can become a viable alternative, there is reason to believe it can be. For example, a recent survey found that a majority of higher income utility

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[104]Fred Bosselman, Jim Rossi, Jacqueline Lang Weaver, *Energy, Economics and the Environment* 699 (2000).

[105]*See generally* William M. Smith, "Digital Mobility: Toward a Fluid Electric Infrastructure; Why Deregulation Needs a Technology Reboot," *Pub. Util. Fort.*, May 1, 2001.

[106]*See* 16 Tex. Admin. Code § 25.211 (2001).

[107]*See* 16 Tex. Admin. Code § 25.212(b)(2) *et seq.* (2001).

customers would rather supply their own electricity during shortfalls, and move power back into the grid when able, than support the construction of new power plants.[108] Congress has also lent some credibility to the prospects of distributed generation. This session has seen the introduction of the Home Energy Generation Act, intended to require utilities to provide "net metering" services to customers who have installed energy generation units and wish to move power back to the grid, and to require FERC to develop model standards for the interconnection of independent generation.[109]

[d] Will Existing Environmental Regulations Affecting Electricity be Stiffened or Weakened?

Today, the future of the electric industry is determined as much by environmental policy as any other factor. Environmental regulation plays a key role in where and when generation and transmission can be built. It also helps determine what is used to fuel new generation. The stiffening or weakening of environmental laws will have a significant impact on how the competitive electric industry matures.

As noted earlier, the new Administration energy policy contains two environmental initiatives that, if implemented, will affect the electric power industry. First, the policy calls for the introduction of legislation to regulate three pollutants from electric generating plants. The proposal calls for a "flexible, market-based program to significantly reduce and cap emissions of sulfur dioxide, nitrogen oxides, and mercury from electric power generators."[110] This proposal, while a stiffening of current law, is actually a weakening of the environmental regulation that the utility industry was expecting the Administration to propose, because it fails to regulate carbon dioxide emissions. Utilities had even been

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[108] *See* Dennis Wamsted, "Consumers: Distributed Generation, Yes; New Power Plants, No," *Energy Daily*, Feb. 28, 2001.

[109] H.R. 954, 107th Cong. (2001).

[110] *Supra* note 84, at 3-3.

rumored to be spending millions to develop a trading market in carbon dioxide emission credits, in anticipation of new regulations. Democrats in Congress, with significant bipartisan support, are introducing air quality legislation that includes standards for carbon dioxide emissions from power plants.[111] With the recent shift in power in the Senate, regulation of carbon dioxide emissions may have become more viable. This legislation might even get a boost from Massachusetts' recent announcement of its plan to regulate carbon dioxide emissions from power plants. It may be that industry participants would prefer to have a uniform, comprehensive federal program than individual, state-by-state regulation.

The Administration energy policy also contains proposals regarding the Environmental Protection Agency's new source review program, under which the agency sets standards for allowable emissions from new or modified sources. The statute requires EPA to set standards that "reflect the degree of emission limitation achievable through the application of the best system of emission reduction."[112] The new Administration energy policy calls for a comprehensive review of these rules and their impact on "investment in new utility . . . generation."[113] A relaxation of new source review could speed the approval and construction of new generation, especially coal generation.

There also has been significant action in several state legislatures to ease environmental permitting requirements for new power plants. The recent legislative action in California to expedite the siting of new generation in the state also contains provisions reducing the environmental regulations otherwise affecting new power plant construction. The new law contains provisions to allow for the banking, trading, and purchasing of emission reduction credits by generation plants, and to ease the process for an owner of new

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[111] *See, e.g.*, Clean Power Plant Act of 2001, H.R. 1335, 107th Cong. (2001).

[112] 42 U.S.C.A. § 7411 (1995); EPA's regulations are at 40 C.F.R. pt. 60 (2000).

[113] *Supra* note 84, at 7-14.

generation to purchase emission offsets for the facility when none are available in the area where the plant will be located.[114] California Governor Gray Davis has also used his executive authority to lessen the clean air requirements on electric generation, issuing two separate orders that allow generation plants to operate beyond their allowable emissions, provided they pay a mitigation fee to local authorities.[115] In Connecticut, the legislature passed a measure containing new pollution control requirements for power plants, which provides for expedited approval of pollution control equipment installation on facilities that are being repowered, makes the installation of the equipment not subject to local laws, and allows for the suspension of emission limits under certain circumstances.[116]

On the other hand, the U.S. House of Representatives recently passed by a significant majority a moratorium on the lease sale proposed by the U.S. Department of the Interior in the Eastern Gulf in water about 100 miles off the coast of Florida.[116.1] And, as mentioned above, Massachusetts plans to regulate carbon dioxide from power plants within its borders.[116.2]

[e] Will Congress and State Legislatures Support Continued Development and Use of Renewable Energy?

The sources of energy classified as renewable generally are considered to be solar, wind, geothermal, biomass, and ocean thermal energy, as well as hydroelectric power under some definitions.[117] The future of these resources as viable

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[114] *Supra* note 94.

[115] *See* Exec. Order No. D-24-01 (issued Feb. 9, 2001).

[116] 2001 Conn. Acts 01-107 (Reg. Sess.).

[116.1] *See* House Amend. 107 to Dep't of the Interior Appropriations Bill for 2002, H.R. 2217, 107th Cong. (2001).

[116.2] Mass. Regs. Code tit. 310, § 7.29 (issued Apr. 2001).

[117] For more information on renewable energy fuel cycles and markets, see Suedeen G. Kelly, "Alternative Energy Sources," 13-3 to 13-10 & 13-16 to 13-24, *in* The Energy Law Group, *supra* note 3.

alternative energy sources to meet future demand will depend greatly on making them more affordable and reliable. Government support of research is one way to make these sources more viable.

Whether the government will continue to fund and support research into the use of alternative energy sources, however, is in doubt. In the Department of Energy budget for fiscal year 2002, a 27% cut in renewable energy research and energy-efficiency is proposed.[118] The budget redirects much of this money to clean-coal technology research initiatives, following the stated Administration support of increasing clean-coal generation. The new Democratic leadership in the Senate is expected to fight this proposal.

Several state legislatures, when restructuring their electricity markets, displayed support for renewable power sources by imposing portfolio requirements on energy suppliers who intend to sell at retail in their markets. These provisions normally require retail electric suppliers who intend to compete in the state to gather from renewable sources a specific portion of the total amount of energy sold. Maine has instituted the most aggressive portfolio requirement, mandating that licensed retailers in the state obtain 30% of the power they sell from renewable sources.[119] Arizona has instituted a portfolio requirement that begins with 0.2 % in 2001, and increases to 1.1% by 2007.[120] Additionally, a number of states providing for retail competition have plans to provide financial support for the use of renewables and conservation. They have imposed a surcharge on the distribution of electricity, sometimes called a "competitive transition charge" or "systems benefit charge," to fund programs to promote electricity efficiency, demand

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[118] A summary and highlights of the proposed budget can be found at http://www.energy.gov.

[119] *See* Me. Rev. Stat. Ann. tit. 35-A, § 3210 (West Supp. 2000).

[120] Ariz. Corp. Comm'n, *In re* Proposed Rulemaking for the Environmental Portfolio Standard, Docket No. RE-00000C-00-0377, Dec. No. 63364 (Feb. 8, 2001).

side management, and research and development of renewable fuels.[120.1]

[f] Will Foreign Fuel Sources Become More or Less Available?

A key issue for the future of United States electricity production is the availability of the fuels used to generate electricity. In particular, steady growth in natural gas demand is occurring. The average growth rate for gas demand in 2000-2002 is expected to be 3.4% per year, as compared with just 0.9% per year from 1994 to 1999.[121] The increased demand is due in large part to significant amounts of new gas-fired electric generation. A 12.4% increase in growth in gas demand for electricity generation is expected in 2002.[122] Domestic natural gas production is expected to increase more slowly than consumption over the next 19 years. Therefore, the importance of natural gas imports is expected to grow over this time. Indeed, much of the pipeline construction of the past several years has been focused on expanding import capacity for Canadian gas into the Midwest and Northeast regions of the country. The completion of the Maritimes and Northeast, Portland Gas Transmission, and Alliance Pipeline systems has contributed a 15 % increase in U.S. natural gas import capacity since 1998. In 1999, natural gas imports accounted for 3,397 billion cubic feet (Bcf), or 16% of total U.S. natural gas consumption.[123] This will need to increase to allow the U.S. to meet the projected demand for gas.

Given the projected growth in demand for gas and the likelihood that gains in supply will not increase immediately, the price for gas at the wellhead is expected to stay relatively high, with an annual average wellhead price for 2001 projected to be about $5.18 per thousand cubic feet ($4.85 per

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[120.1] *See, e.g.*, N.M. Stat. Ann. § 62-3A-13, 62-3A-15 (2000).

[121] EIA, *U.S. Natural Gas Markets: Recent Trends and Prospects for the Future* xii (May 2001).

[122] *Id.*

[123] EIA, *Natural Gas Monthly*, Feb. 2000, at xi.

million Btu).[124] However, with increases in supply, the price is expected to decline, though not significantly, during 2002.

Mexico is believed to have large supplies of natural gas that are currently untapped. However, a provision in the Mexican Constitution prevents private investment in oil and natural gas production, granting it exclusively to a state-owned oil and gas company. While Mexican President Vincente Fox did propose a privatization of the state-owned oil company early in his campaign, he has since remained quiet on the issue, and the constitutional provision is not expected to be changed in the near future.[125]

Canada may begin exporting more electric power, as well as natural gas, into the large cities of the Northeast. Under a proposal recently filed at FERC, Neptune Regional Transmission System LLC is seeking approval to construct an undersea merchant transmission line linking generation in Nova Scotia and New Brunswick, Canada, with Boston, New York City, and New Jersey.[126]

[3] Will the Fuel Cell Displace the Traditional Generation/Transmission/Distribution System of Electricity?

The fuel cell converts liquid fuels into electricity through a chemical reaction, instead of through combustion. Although they have been available for more than 100 years, fuel cells have been so expensive that they have seemed practical only for very specialized uses. While still expensive, fuel cells have improved in technology and design, and may become a serious competitor to traditional power generation.[127]

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[124] EIA, *U.S. Natural Gas Markets: Recent Trends and Prospects for the Future* xii (May 2001).

[125] *See* "Mexico Unlikely to Send Gas North for Years, New CRE Chief Says," *The Energy Report*, Feb. 19, 2001.

[126] *See* Application of Neptune Regional Transmission System LLC For Approval of Merchant-Based Open Access Transmission Tariff, FERC Docket No. ER01-2099 (filed May 23, 2001).

[127] For a more in-depth description of fuel cells, see Suedeen G. Kelly, "Alternative Energy Sources," 13-13 to 13-15, in The Energy Law Group, *supra* note 3.

Fuel cells are being considered more frequently in large new construction projects. The largest fuel cell power plant in the world, rated at 1.2 megawatts, is being installed at a juvenile training center in Connecticut—clear evidence that the fuel cell is now becoming a viable source of electricity.[128] While it is likely to be quite some time before fuel cells compete with central station electricity generation in a big way, entities may elect to invest in them if power shortages and tight supplies continue.

§ 1.03 What a Restructured Electricity Industry Means for the Gas, Coal, Railroad, Nuclear, Renewables, and Oil Industries

[1] Summary

The electricity industry's ongoing restructuring will affect the preferability of particular fuels for electric generation and inevitably will lead to changes in the relationships among fuel producers, their supply lines, and electricity generators. New market pressure arising from wholesale competition and retail choice will make it necessary for merchant generators to cut their costs wherever possible. More market pressures will mean more risk—risk they will want to pass on to their fuel suppliers. Fuel is a significant cost for most types of generation—up to 80% of the cost of generation.[129] Therefore, electricity producers will pressure fuel suppliers, including existing ones, to lower prices.

Due to the pressure to lower costs for fuel, suppliers and transporters will search for any economies of scale or integration advantages they can find. In some instances this search may even lead industry participants to cooperate with each other via strategic alliances or consolidation. In turn, alliances and consolidation could give large financially-secure suppliers an advantage in the new market because they have

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[128] "IFC Building Biggest Fuel Cell Power Plant," *Energy Daily*, Apr. 4, 2001.

[129] Judith M. Matlock, "Impact of the Restructuring of the Electric Power Industry on Oil, Gas, Coal, and Other Mineral Producers," 43 *Rocky Mt. Min. L. Inst.* § 1.15[1] (1997).

the money and the leverage to enter into beneficial alliances or to acquire smaller companies.[130]

The risk-management techniques necessary to deal with greater unpredictability also probably favor large companies, which are more likely to have experience with sophisticated risk-management tools. Often, these companies are also more efficient and more profitable. Not all analysts agree that this is the case. Some suggest that as the competition gets stiffer some of the smaller owner-managed companies will do better because they have more at stake and may be more nimble. In any event, the increased risk and the wider variety of tools required to manage it will lead to new markets in some of the supply areas. These new markets will need price transparency and easily accessible market information in order to remain liquid and functioning.

Because the restructuring of the industry is occurring at the same time that new generation needs to be built, new opportunities exist for most resources used to fuel generation. The challenge will be to find ways to make the electricity produced by the target resource the lowest cost supply of electricity. To the extent the targeted resource produces electricity at a higher price, this disadvantage can be overcome if it possesses other desirable characteristics that are highly valued by consumers ("green power," for example), or consumers are given a valuable incentive to consume them despite their higher price (tax credit, for example).

[2] Natural Gas

[a] Preferred Energy Source for New Generation Capacity

The restructuring of the electricity market already has had an impact on natural gas. Natural gas has been the favored fuel for meeting peak demand. Currently, it is also the preferred fuel for new generation capacity.[131] The Energy

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[130] EIA, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers* 8 (Sept. 1998), http://www.eia.doe.gov/cneaf/electricity/chg_str_fuel/ execsumm.html.

[131] Even if gas-fired generation remains the least-cost alternative for new capacity, there still will be demand for new generation fueled by other sources.

Information Administration projects that of the 1005 competitive, non-utility generation units expected to be built by 2004, 799 (or about 80%) will be natural gas-fired.[132] If this occurs, gas-fired generation as a percent of total U.S. electric generation capacity will triple, rising from 16% today to 45% in 2005. The continuation of relatively high natural gas prices might temper this expectation; however, continuing advances in gas-fired generation technologies can offset some gas cost increases.

[b] Price Incentive to Produce More

Over the winter an increase in demand, fueled by cold weather and California's power woes, combined with a relatively low supply to push prices to record highs. The low supply was brought on by a decline in drilling precipitated by low gas prices in the 80s and early 90s. High demand and low supply created last winter's natural gas price-spike. Winter 2000 prices at Henry Hub were quadruple their 1999 levels.[132.1] In California, where there are border and intrastate pipeline capacity problems, the NYMEX price was six times greater than in 1999.[133] Because gas supply still is not predicted to catch up with demand over the next two years, prices are not expected to decline until 2002. The Energy Information Administration predicts a 2001 average wellhead price of $5.18 per thousand cubic feet and a 2002 price of about $4.82 per thousand cubic feet.[134]

As expected, higher prices and forecasts predicting continued demand growth have resulted in increased production in the United States. And a further increase in

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[132] *See* EIA, *Table 6:Existing Capacity and Planned Capacity Additions at U.S. Nonutilites by Energy Source and State, 1999, at* http://www.eia.doe.gov/cneaf/electricity/ipp/html/ippv2t06p1.html.

[132.1] *Id.* EIA, *International Energy Outlook: 2001* at 48 (Mar. 2001), http://www.eia.doe.gov/oiaf/ieo/nat_gas.html. The Henry Hub is the centralized point for natural gas futures trading in the United States interconnecting with nine interstate and four intrastate pipelines.

[133] *Id.*

[134] EIA, *U.S. Natural Gas Markets: Recent Trends and Prospects for the Future* xii (May 2001).

production is anticipated. The EIA predicts a 5.4% increase in domestic natural gas production in 2001, representing an increase of approximately one trillion cubic feet from 2000.[135] The U.S. natural gas rig count has also risen significantly in the past two years. Today 900 rigs are being operated in the United States, up from a low of about 370 in 1999 and the highest number since the mid-1980s.[136] The American Gas Association recently predicted that by the end of 2001 gas reserves would have grown to at least 170 trillion cubic feet, the most since 1987.[137] Over the next twenty years, the EIA predicts that natural gas consumption by U.S. power producers alone will triple to 11.3 trillion cubic feet a year by 2020.[138] Of course, these predictions assume no change in current laws and policies. As discussed above in § 1.02, there are numerous ways these laws and policies might change to advantage or disadvantage natural gas as the leading fuel choice for new generation.

[c] Development of an Integrated Energy Market for Gas and Electricity

The natural gas and electricity industries are similar in many ways. Traditionally, both used coal to generate electricity and to produce manufactured gas, which they then deliver to end-use customers. Electricity replaced gas as a source of lighting early in the 20th century. As the quality of home appliances improved in the 1920s and 1930s, gas and electricity competed for clothes drying, refrigeration, space cooling and heating, cooking, and water heating.

In the future, it is likely that new institutions such as spot contract and futures markets will closely tie the electricity and gas industries. These new institutions and new business practices likely will determine the degree to which natural gas

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[135] EIA, *Short Term Energy Outlook: February 2001* at 6, http://www.eia.doe.gov/emeu/steo/pub/outlook.html.

[136] Jeff Beattie, "AGA Expert Sees Gas Reserves Building Faster Than Expected, But Little Price Relief," *Energy Daily*, May 2, 2001.

[137] "El Paso, Marathon Mulling New Pipeline for Maritime Gas," *Energy Daily*, May 7, 2001.

[138] EIA, *Annual Energy Outlook 2001*, *supra* note 2, at 84.

is used for generating electricity during peak periods, or whether it will lose market share to the electricity industry in the industrial, commercial, and residential sectors. Similarly, the electricity industry established two futures contract markets in 1996. The number of recognized trading locations for electricity is also increasing.

Greater integration of the electricity and natural gas industries requires institutions such as electronic auction markets and futures contract markets. These institutions are necessary to support the development of a competitive energy market. The development of a competitive energy market will require increased integration of the natural gas and electricity industries through these institutions.

If a market player trades gas to generate power instead of trading power to satisfy demand, it reduces the possibility of encountering congestion on over-burdened long-distance electrical transmission lines and the higher prices for peak time transmission. The advantages of generation over trading electricity have resulted in an effort by fuel suppliers to sell into a market near a location with high real time electricity prices. If demand for electricity continues to outpace construction of more transmission capacity, substitutions like this likely will happen more and more frequently with the eventual result of convergence into a single market.

[d] Deliverability Challenges

Until 1997, natural gas companies generally had to nominate set amounts of pipe space 24 hours in advance of shipping gas. This shipping period contrasts with that of the electricity industry, where there is a sizeable hourly, ten-minute and real-time market. In 1997, the industry began allowing intra-day nominations, so gas shipments can be arranged on the same day gas is purchased. Changing volumes within the 24-hour period can occur through gas balancing though it adds to the cost. Clearly, a challenge for the gas industry will be to have the nomination process for pipeline capacity synchronize with the short-term fluctuations in electricity demands. Introduction of same-day nominations was a step in the right direction, but the process will need to come into line with hourly, ten-minute ahead and real-time electricity market structure. Once this happens the two fuels could be virtually interchangeable allowing producers to capitalize on the relative price advantages of either commodity.

Increased domestic demand for natural gas also affects the natural gas transportation infrastructure. As seen in the California example from the 1999-2000 winter, inadequate transportation capacity can drive the price of natural gas up relative to areas that are not congested. The demonstrated and projected increases in demand for both foreign and domestic natural gas has led to a considerable amount of pipeline expansion in the United States, as discussed above. Pipeline capacity has increased 15% since 1998. Between 1990 and 2000 an additional 22 interstate pipelines came online, and pipeline investment is estimated to have been $2 billion in 1999, with further large investment numbers expected in 2001.[139] However, more expansion will be needed to keep up with the projected increases in demand over the next 20 years.

[e] Price Volatility and the Growth of Futures Markets

While interchangeability has advantages, the close ties between natural gas and electricity markets could result in increased volatility all around as natural gas producers encounter more and more power generators trying to offload risk. Volatile prices and the close link between natural gas and electricity will probably result in the creation of new futures markets. In the past three years futures markets for electricity have come online, and it is possible that interfuel exchanges will become equally common.[140]

Better price transparency will promote the liquidity that is incident to a market with more potential for volatility, in this

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[139] *Id.* at 34.

[140] *Id.* at 44; New York Mercantile Exchange, *Cinergy and Entergy Futures Launch*, *at* http://www.nymex.com/news/ce_index.htm (visited June 22, 2001).

case from the crossover effects of the electricity markets.[141] For example, the natural gas market will become more liquid if information on prices paid by holders of pipeline transportation capacity is made available sooner.

[f] New Contracting Standards

The shortest-term natural gas contracts are generally longer than the shortest-term electricity contracts. With the emergence of more electricity-related demand, natural gas sellers likely will feel pressure to accommodate the shorter-term contracts that electricity generators prefer. After the recent spike in natural gas prices and the problems that have arisen from California's "detrimental reliance" on short-term contracts for power, it is also possible that power generators will want standardized contracts that are longer than those currently in place. Natural gas producers can add value to their product by improving management of both price and capacity risk.[142]

[3] Coal

[a] Tightly Linked to Electricity Markets

Because the coal and the power generation markets are highly interdependent, the changes in the electricity market will have an enormous impact on the coal industry. Power generators consumed almost 91% of all the coal used in the United States in 2000.[143] About 52% of all domestic electric generation in 2000 was fueled by coal.[144] In some regions of the United States, coal-fueled generation is considerably higher than this. For example, in the East Central Area (Michigan, Indiana, Ohio, Kentucky, West Virginia, and parts of New York and Virginia) almost 90% of the generation is coal-fueled. In the Mid-Continent Area (North Dakota, South Dakota, Nebraska, Minnesota, and parts of Iowa, Wisconsin,

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[141] New York Mercantile Exchange, "Commercial Applications for Electricity Futures," *in Cinergy and Entergy Futures Launch*, *supra* note 140.

[142] *See* Matlock, *supra* note 129, § 1.17[5].

[143] EIA, *U.S. Coal Supply and Demand: 2000 Review* 1 (Apr. 2001), http://www.eia.doe.gov/cneaf/coal/page/special/feature.html.

[144] EIA, *Electric Power Monthly: March 2001*, *supra* note 1, at 1.

and eastern Montana), 72% is coal-fueled. In some regions, coal plays a less-than-average role in generation. These include Alaska (5%), New England (21%), and the Western states lying west of the Rocky Mountains (35%).[145] These regions also receive their coal from different areas. For example, generators in the Southwest use mostly western coal while the Middle Atlantic states use predominantly Appalachian coal. These differences may result in different responses to a competitive electricity market.

The coal industry is also affected, of course, by the environmental standards applicable to electric generators. For example, as emission standards have tightened, the quality distinctions between different regional coal reserves with respect to sulfur and nitrogen content have shifted patterns of demand, primarily in favor of western coal.[146] Low-sulfur coal supplies also benefit from a rise in the price of sulfur dioxide emission credits. These credits increased by over 50% in the first quarter of 2001 to about $200 per unit. Some project the price to continue to rise over the next few years.[147] President Bush's decision not to regulate carbon dioxide emissions also may have a favorable impact on the coal market.

With the overall demand for electricity rising and the decreased availability of hydropower this past year, the coal industry has seen a rising demand for coal. This is likely to continue in the short-term because many coal-fired generators have been depleting their coal stockpiles. Utilities reportedly began 2001 with stockpiles approximately 35% lower than last year.[148] In response to the rising demand, the spot price

[145]EIA, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, *supra* note 130, at 6.

[146]Thaddeus J. Huetteman & Kevin B. Cardwell, *With Coal Futures Looming, the Cash Market Starts Hopping* (Spring 1999), *at* http://www.nymex.com/news/ein/12/12.htm.

[147]Tina Davis, "Energy Crisis Gets New Flavor: Not Enough Coal," *Energy Daily*, Apr. 24, 2001.

[148]*Id.*

of delivered coal has multiplied in some regions, and as of May 2001 was around $1.30 per mmBtu.

The longer-term prospects for coal also appear promising. There are 20,000 megawatts of announced new coal-fired capacity plants, which, if built, will consume an extra 60 million to 80 million tons of coal annually.[149] The Tennessee Valley Authority announced in April 2001 that it is beginning an environmental assessment of a proposed 1,500 megawatt integrated coal gasification combined-cycle plant to be located in Hollywood, Alabama. If built, it would be the largest integrated coal gasification plant in commercial operation. These plants are somewhat more efficient than a conventional coal-fired plant, but their real advantage is in cutting sulfur dioxide and nitrogen oxide emissions.[150] Given the tight link between electricity and coal markets, the coal industry has already begun to change the way it does business, and it will feel even more pressure to do so, as the electricity market becomes more competitive. These changes will include pressures to reduce costs and shoulder more risk.

[b] Pressure to Reduce Costs

Faced with pressures to reduce costs, coal providers will likely look to consolidation, investing in productivity-enhancing technology, and increasing the efficiency and size of mines.

[i] Consolidation

Consolidation and concentration of mining operations and firms within the coal industry has been occurring for some time. The pressure to reduce costs and, as discussed below, manage more risk will likely spur a continuation of this trend. The top four coal producers in the United States had a market

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[149] *Id.*

[150] Chris Holly, "TVA Mulls Monster Coal-Gas Power Plant," *Energy Daily*, Apr. 12, 2001. Another attention-getting announcement was the one in February 2001 to develop in Minnesota two huge wind projects backed by coal-fired generation with a combined capacity of 6,400 megawatts and a cost of $15 billion. Chris Holly, "Hot Air Or Real Deal? Minnesota Pol Pushes Huge Wind-Coal Projects," *Energy Daily*, Feb. 5, 2001.

share of 32.9% in 1996, up from 19.6% in 1986.[151] In the Powder River Basin, the country's largest (14 of the country's 15 largest mines) and fastest-growing coal-producing region, the top four companies produced 77% of the Basin's output in 1996 compared with 48% in 1986.[152] Consolidation is appealing because it promises increases in productivity, reductions in cost due to economies of scale, larger mine operations (with concomitant lower costs), and increased ability to access financing.[153]

[ii] Investing in Productivity-Enhancing Technology

Historically, coal producers have been innovative and able to raise productivity, and thus lower costs, by adopting new, more efficient production technologies. For example, longwall mining has contributed to significant productivity gains in underground mining.[154] Greater productivity in surface mining has been achieved by using larger draglines for excavation and by employing larger hauling trucks. In the future, underground mining productivity may be enhanced by more automated longwall operations, faster advancing longwalls with deeper cutting shearers, more rapid and reliable conveyors, and increased use of computerized systems.[155] In surface mining, new designs in buckets offer improved dragline performance. Improvement in the handling of coal is also possible, including the use of online coal quality analyzers.[156]

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[151] EIA, *The Changing Structure of the U.S. Coal Industry: An Update,* Table 13 (July 1993) and *Coal Industry Annual 1996,* Table 15 (Nov. 1997).

[152] EIA, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers, supra* note 130, at 9.

[153] Not all industry participants agree that consolidation can go further or that it will provide more benefits than a smaller operation with a stronger incentive to be profitable. *Id.* at 12.

[154] *See* EIA, *Longwall Mining* ch. 4 (Mar. 1995).

[155] *Id.* at ch. 5.

[156] EIA, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers, supra* note 130, at 14.

In the 1990s the Clean Coal Technology Program sponsored by the Department of Energy sought to upgrade the environmental performance of coal-fired power plants while keeping costs down by using innovative technologies. When the program was begun, coal was the fuel of choice for large, base-load electric generation. Today this has changed, and it is unclear what place clean coal technology will have in future electric generation. At least one commentator argues that it will find niche markets, perhaps large ones, in repowering existing coal plants, and adding components to existing plants to treat coal prior to its combustion or to treat stack gases after combustion.[157] There is less optimism about the adoption of clean coal technologies for new electric generation in the face of the current cost advantages of new natural gas turbines and particularly if tougher environmental regulations affecting coal burning are not enacted.

[iii] Increasing the Efficiency and Size of Mines

Another way to reduce costs is to produce coal from more efficient and larger mines. This is not a new notion. Mine productivity, measured in tons per miner hour, has increased significantly over the last twenty years—by 6.9% per year from 1980 to 1996. In fact, coal prices to electricity generators have declined steadily over the past fifteen years due to the coal industry's continuing ability to increase its efficiency.

In 1996, the largest 20 mines produced 30% of total U.S. coal output, and mines producing more than 1 million short tons were responsible for 75% of the total output. In 1996, the average mine produced more than two and one-half times the 1980 average.[158] Surface mines have lower production costs per ton than underground mines. In 1996, for surface mines producing 500,000 to 1,000,000 short tons, the prices at the

[157] Verne W. Loose, "Clean Coal Technology Diffusion; The Impact of Electric Power Industry Restructuring," *Electricity J.*, Dec. 1998.

[158] EIA, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, *supra* note 130, at 10.

mine mouth were 18% lower than those of underground mines.[159]

[c] Pressure to Shoulder More Risk

Coal providers already have been pressured to renegotiate existing contracts with electricity generators to make them shorter with more frequent price re-openers. This injects more uncertainty into the coal marketplace, thus adding to the risk. The industry is beginning to respond by using financial and physical risk-management instruments and by entering into some cooperative arrangements with their coal purchasers. This added risk is also changing the nature of available financing for coal projects (financing on a corporate balance-sheet basis rather than project financing), adding to the otherwise existing incentives to consolidate.

[i] Contract Changes

Traditionally, coal was purchased under long-term contracts, sometimes exceeding thirty years in length. Over time they have become shorter, and spot markets for coal have developed. Spot coal transactions are generally contracts expiring in one year or less. Between 1985 and 1996, deliveries of coal (by tonnage) under contracts of ten years or less went from 17% to 39%.[160] In April 2001, at least one coal producer reported that generators were reversing an earlier trend toward shorter contract periods, and now were asking for contracts longer than one to three years.[161] It is the generators' uncertainty of market and price that leads to the pressure for shorter, more flexible coal contracts. In response to this situation, one new type of contract-pricing provision that has emerged ties the price of coal to the price of wholesale electricity.

Significant changes in the spot-coal market were made in anticipation of the New York Mercantile Exchange's introduction of a coal futures contract in 1999. Although much

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[159] *Id.*

[160] *Id.* at 16.

[161] Davis, *supra* note 147.

of the spot coal still is bought and sold in a two-party relationship between coal producers and electricity generators, with the intent of accepting physical delivery at the generator's facility, other parties are getting involved in some sales. These other parties are generally energy traders and entities that manage positions related to other energy commodities, including companies such as Euro Brokers; Natsource, Inc.; and TFS Energy. Additionally, coal production companies have formed new trading arms offering new products in an evolving market.[162]

In 1996, the National Electric Reliability Council analyzed coal supply contracts and concluded that significant amounts of coal were being purchased under contracts with prices above the current market price for coal. (Traditionally, regulated integrated utilities were able to pass increases in fuel on to the retail electricity consumer with relative ease and often with little delay, through the mechanism of a "purchased fuel adjustment" clause in their tariffs.) Half of these contracts will expire by 2005. Of the 144 million short tons that still will remain under above-market priced contracts in 2005, 27 million short tons will be for coal from "captive" mining operations mostly in the Western states.[163]

[ii] Risk Management

The revenue instability and price volatility brought about by more sales on the spot market, shorter contract terms, and, sometimes, indexed prices can be managed to an extent with financial and physical instruments. Financial instruments include futures and options contracts. The New York Mercantile Exchange has responded to the increase in demand for coal futures and in 1999 began offering a Central Appalachian coal futures contract. A coal producer can also engage in "cross-commodity hedging" by buying or selling electricity or natural gas futures or options contracts. Diversification of customer base, for example, by exporting

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[162]Huetteman & Cardwell, *supra* note 146.

[163]Hill & Assocs, Inc., *Generating Cost Study* (Annapolis, Md. 1996). "Above market" was defined as above the price that would be obtained for a new coal contract, typically about 5% above the spot price.

output, can also reduce the risks associated with the U.S. domestic coal market.

Coal producers are also entering into new, cooperative arrangements with power generators and coal carriers that aim to reduce risk by sharing it with the other parties. These arrangements are furthering the convergence of energy markets.

For example, Kennecott Energy and Enron Capital and Trade Resources have agreed to make each the preferred provider of the other in joint coal/energy transactions.[164] Vertical integration may also be an option to spread risk. One form of vertical integration is the conversion of coal by the producer to electricity prior to sale of the coal, known as "coal-by-wire."[165] The conversion can take place at a coal-fired mine mouth power plant or by a "coal tolling" relationship. In tolling, the coal producer (or power marketer) contracts with a generator (usually one with excess capacity) to convert the coal into electricity, which is delivered over a transmission line to an agreed-upon location. The generator does not take title to either the fuel or the electricity, but is paid a tolling fee for its services. The power marketer (or coal producer) owns the electricity output and is responsible for selling it. This arrangement typically is used when the generator's access to power market information or low-cost coal is restricted or the operator has less interest in risk. "Reverse tolling" occurs when the value of the coal is greater in the spot market than in the electricity market. Coal-by-wire, coal tolling, and energy swaps are products of strategic relationships between coal producers and electric generators. Energy swaps are more flexible than tolling, and allow the parties involved to exchange coal, electricity, natural gas, or cash. Unlike in tolling, the generator can sell the coal to another party rather than burning it itself, and the timing and location of each part of the transaction may vary.

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[164] "Enron, Kennecott Form Alliance," *Coal Outlook*, Mar. 9, 1998.

[165] Matlock, *supra* note 129, § 1.16[4].

[d] Linked to Railroad Rates

In addition to its tight link to electricity markets, coal is also tightly linked to the railroads that transport the vast majority of coal to its buyers. In 1996, 58% of all coal delivered to customers was transported by rail, and this accounted for 22.5% of the gross revenues of Class I railroads that year.[166] The average distance traveled by coal on railroads has increased, reflecting the greater use of western coal in southern and eastern markets, while average coal transportation costs have declined over the last fifteen years. The competitiveness of each region's coal is sensitive to rail rates. In 1995, coal transportation costs represented, on average, 51.4% for western coal (and up to 75% of the total delivered cost), 19.9% for Appalachian coal and 11.8% for interior region coal.[167] Coal producers will be looking to railroads to continue to lower their coal transportation rates through economies of scale and efficiency gains. The railroads have been successful at this in the past. For example, they have reduced labor costs and adopted new technology (like the "coaltainer"—a container designed to be transported by both rail and truck, and the electronic data interchange—use of satellite monitoring to improve the computerized scheduling and routing of trains).[168] Other options for coal shippers to effect lower transportation rates include increasing access to alternative modes of transportation, supporting the building of spurs from power plants to second rail lines (thereby increasing the competitive pressure on railroads to lower their rates) and working cooperatively with shippers and generators to create economies of scale (for example, by creating more centralized operations for groups of coal-fired power plants).

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[166]EIA, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, *supra* note 130, at 21.

[167]EIA, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation* 73, Table 50, http://www.eia.doe.gov/cneaf/coal/coal_trans/backissues.html; EIA, Coal Transportation Rate Data Base, *at* http://www.eia.doe.gov/cneaf/coal/ctrdb/database.html.

[168]EIA, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, *supra* note 130, at 23.

[4] Nuclear

Currently there are 103 commercial nuclear power plants operating in 31 states. Improvements in the efficiency and safety of many of them have resulted in a large increase in electricity production from them. The future of nuclear power in a competitive electricity generation marketplace is best described in two parts—the future of existing plants and the likelihood of new nuclear generation being built in America.

[a] Incumbent Plants

A number of nuclear plants have low and improving operating costs, sometimes below those of their fossil-fuel counterparts, and high capacity factors. Some improvements have come about from technological advances (for example, Baltimore Gas and Electric's replacement of steam generators at Calvert Cliffs with new units).[169] Nuclear fuel prices have dropped considerably in the last few years. Enrichment prices and fuel fabrication prices also have dropped. Kazakstani uranium and an oversupply of fuel from retired plants are some of the factors that have combined to push prices down from their highs in 1996.[170] The cost of labor at nuclear plants is relatively high and fairly stable. These trends are improving the value of these nuclear plants, and on a per kW-hour basis, many can be competitive. When compared to the costs of, and barriers to, siting new generation, these plants might well have an incumbency advantage. In fact, owners of nearly half of the operating plants have been reported to say they will seek a 20-year license renewal for their plants to keep them running beyond their initial 40-year licenses.[171] Chairman Richard Meserve of the Nuclear Regulatory Commission (NRC) recently stated he expects between 85% and 100% of U.S. nuclear plants to seek re-licensing.[172] Thirty-

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[169] Nainish K. Gupta & Herbert G. Thompson, Jr., "The Market Value of Nuclear Power," *Electricity J.*, Oct. 1999.

[170] EIA, *U.S. Uranium Market*, *at* http://www.eia.doe.gov/cneaf/nuclear/special/uranmark.html (visited June 22, 2001).

[171] H. Josef Hebert, "Nuclear Power Allies Fired Up Over Future," *Albuquerque J.*, May 17, 2001.

[172] Jeff Beattie, "Kerry Smiling On Nuclear?," *Energy Daily*, Apr. 27, 2001.

six applications for license renewals have been filed with the NRC. The NRC has approved 20-year license extensions for two utilities, covering five reactors. Re-licensing costs have been estimated to amount to between $10 million and $50 million per plant for an estimated production cost of $10 to $50 per kW.[173] It may be economic for nuclear plants to incur these costs and extend their useful lives, even in a competitive environment.

The economics of existing plants in states that have deregulated retail sales of electricity is also affected by the stranded cost recovery awarded to them. To the extent they are not awarded full stranded cost recovery, their economics become more problematic. Ultimately, nuclear generation will be in head-to-head competition with other types of generation. To be successful, nuclear power producers must be price competitive. In areas where electricity supplies are tight, the competitive price will be the price of long-term, firm capacity. In areas with a healthy surplus of power, nuclear power will have to match the price of long-term, non-firm capacity.[174] The cost of long-term capacity will vary from region to region because of the location of different natural resources.

In the East, long-term coal-fired capacity has become more expensive because of its distance from coal sources; this makes prospects for incumbent nuclear generation located there better than in other areas. In the Southwest, long-term coal-fired capacity is inexpensive, but the recent supply crisis in California will allow nuclear power in that region to compete, at least while prices are high.

[b] New Nuclear Generation

The President's energy policy speaks encouragingly of new nuclear generation, and rumors even have circulated about an impending application to the NRC for a site license for a new

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[173] Nainish K. Gupta & Herbert G. Thompson, Jr., "The Market Value of Nuclear Power," *Electricity J.*, Oct. 1999.

[174] EIA, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, *supra* note 130, at 30.

reactor in the United States.[175] (No applications for new nuclear plants have been filed in the last 25 years.) However, most commentators are not optimistic about a significant role for nuclear power in future electric generation in the United States. The issues include cost, air emissions, safety, and radioactive waste.

Proponents of nuclear power argue that a new approach, the pebble-bed modular reactor, will be cost-effective. A pebble-bed reactor is much smaller than current large nuclear plants. It promises to be safer, cheaper, and faster to build than existing plants. It will have to be in order to have any hope of being able to compete on the basis of cost. In today's market no one is prepared to take the risk of investing the amount of money that would be needed (in the billions) to build a nuclear reactor along the lines of those that exist in the United States today. As the Chairman of Pacific Gas and Electric Co. was reported recently to have said, "To order a new nuclear plant today, you'd have to be crazy."[176]

To the extent global warming and the release of carbon dioxide from fossil fuel-fired generators becomes a weighty issue in U.S. public policy, nuclear power may be part of the debate. However, at this point in time, the President has disavowed the Kyoto Protocol and eschewed carbon dioxide regulation, so it seems unlikely this will be a significant policy issue in the foreseeable future. Even if it is, nuclear will have to compete with generators fueled by renewable sources that do not carry the same perceived safety risks.

Nuclear power's history, including its mishaps, at a minimum heightened the perception of risk associated with it. This decreases the value of the product; safety advances will have to be sold persuasively to ameliorate the risk factor. Radioactive waste disposal still remains unsolved. This uncertainty increases the direct cost of doing business in the nuclear arena and also increases risk, and thus, indirectly,

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[175] "Idaho, Home of Nation's Next Nuclear Plant?," *Energy Daily*, May 8, 2001.

[176] Tom Redburn, "Nuclear Power: A Debate Renewed," *The New York Times*, May 13, 2001.

increases cost. It certainly seems that any long-term revival of nuclear power will have to be preceded by a resolution of these uncertainties.[177] In the long run, the new natural-gas-fired base load plants that are poised to take over in most regions will present formidable competition to new nuclear plants.

[5] Renewables

[a] State-Mandated Renewable Portfolio Standards and System Benefits Charges Will Help Support Continued Use of Renewables for Generation

As noted in section 1.02[2][e] above, some states have tried to shield renewable technologies from the perils of the open market by including niches for renewable energy in their deregulation plans. One of these niches is a requirement that a surcharge be collected on distribution, often called a "competitive transition charge" or "system benefit charge," to help fund a variety of programs, including renewable technologies research. As of January 2000, about twelve states have implemented these surcharges.[178]

States are also creating a niche market for renewables by imposing renewable portfolio standards on new independent generators entering the market.[179] In this system the market chooses which renewable technologies it will employ, which presumably will be the most efficient and the least costly. In practice though there is a significant risk that technologies with a longer development period will be neglected by the

[177]This is, in effect, what John Holdren, Harvard professor of environmental science and former chairman of the White House science and technology advisory panel in the Clinton administration is reported to have said. *Id.* Clearly, some members of Congress are trying to address these issues. Senator Domenici (R-NM), for example, has introduced a bill, the Nuclear Energy Assurance Act, that would increase spending by $406 million to support nuclear energy initiatives. S. 472, 107th Cong. (2001).

[178]Bosselman, *supra* note 104, at 698.

[179]*See* § 1.02[2][e] *supra*.

market in its rush to meet the standards required by law, and for short-term profitability.[180]

[b] Green Marketing and Pricing Programs May Increase Consumer Demand for Electricity From Renewables

Green marketing is another approach that states are using to spur the development and use of renewable energy. Green marketing programs offer consumers the option to buy electricity generated from renewable sources, and in return consumers agree to pay an additional charge.[181] This additional revenue is then used to supplement the increased cost of the renewable generation project, which otherwise might be un-economic.[182] There are several large electric generating companies that are also pursuing green marketing programs on their own as a business strategy.[183]

[c] Transmission Issues Will Affect the Penetration of Renewable Fuels in the Electricity Generation Market

In addition to its higher costs, renewable electricity will face significant transmission obstacles in a deregulated environment. Given the current structure of most transmission tariffs, which normally charge higher rates for longer distances traveled and include charges based on capacity factors, renewable generation is bound to cost more to deliver.[184] Most renewable resources have a low capacity factor. Additionally, many renewable technologies, such as wind and solar power, are by their nature intermittent. Renewable generation also is often located far away from peak demand centers. The current RTO development process at FERC could assuage the higher cost of transmission for

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[180] EIA, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, *supra* note 130, at 75.

[181] *Id.*

[182] *Id.*

[183] Bosselman, *supra* note 104, at 927.

[184] EIA, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, *supra* note 130, at 80.

renewable generation, however, if more RTOs opt to price transmission services at a flat rate for delivery within their system.[185]

[6] Oil

[a] Likely Further Decline in Use for Electricity Generation

In general, utility use of crude oil and its by-products is expected to continue to decline. In 2000, less than 2% of all electricity generated was produced from oil.[186] Historically, utilities have used crude oil products such as residual fuel oil, distillate fuel oil, and petroleum coke in generation. It is these resources that will suffer the effects that electric utility deregulation will have on the oil industry.

Residual fuel oil, or that left over after higher-valued products such as distillate fuel oil and gasoline are produced, was the main crude oil product used by utilities to serve base load. Utility use of residual fuel oil rose sharply from the 1960s until the oil embargo of 1973 forced a decline in its use.[187] Its use rose again slightly in the late 1970s and early 1980s, but has essentially been on a steady decline as most electricity generators have opted for natural gas.[188] Most of the electricity generation units that continue to use residual fuel are more than 25 years old.[189] As competitive markets for electricity expand, and generators look to cut costs to make themselves more competitive, older plants will be scrutinized and either repowered or retired. Under current trends, most generators that opt to repower older oil burning units are expected to switch to natural gas, in order to take advantage of the higher heat rates and combined-cycle systems to

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[185] *See* § 1.02[1][a][iii] *supra*.

[186] EIA, *Electric Power Monthly: April 2001*, *supra* note 33, at 15.

[187] EIA, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, *supra* note 130, at 57-58.

[188] *Id.*

[189] *Id.* at 59.

improve efficiency, while at the same time garnering significant environmental benefits.[190]

Distillate fuel oil generally has been relied on by utilities to fuel peak demand, instead of base load. In areas such as the Northeast, utilities would compete with purchasers of home heating oil to serve peak winter demand, thus driving up costs. Utilities would even buy more than was necessary during these times at high prices in order to keep a minimum stock required by law.[191] Utilities, however, could pass on these costs to ratepayers by virtue of fuel adjustment clauses. If the retail electricity market is opened to competition, fuel adjustment clauses and minimum stock level requirements should vanish, thus encouraging utilities to act more efficiently. This could result in fewer heating oil price spikes during the winter months.[192]

Petroleum coke, created when utilities "coke" high-sulfur, high-metal residual fuel, historically represented a very small fraction of the fuels used to generate base load of electricity.[193] Historically, and even currently, its biggest problem has been its environmental externalities. As refiners are faced with more low-quality residual fuels (and a smaller market of electric utilities wishing to purchase it), they are increasingly using coking to dispose of residual fuel, and thus creating larger stocks of petroleum coke. As a result, its price has dropped significantly over the past two decades, attracting the attention of utilities.[194] Some utilities are experimenting with blending coke with other fuels such as coal, especially in areas where there are large supplies of coke nearby.[195]

In addition to the blending of fuels, gasification is another new technology that may allow utilities to utilize oil products

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[190] *Id.*

[191] *Id.* at 60.

[192] *Id.* at 61.

[193] *Id.* at 57.

[194] *Id.* at 58.

[195] Florida utilities are one example, where refineries on the Gulf Coast produce large amounts of coke. *Id.* at 59-60.

more cost-effectively. Gasification converts coke and other resources to a synthetic gas that is much cleaner, and can be used to produce electricity, among other items.[196] Gasification is attractive not only because it makes use of what was previously considered a waste product, but also because it can use combined cycle technology to utilize heat for further electricity generation or other uses.[197]

A final crude oil product that could be impacted by electricity deregulation is diesel fuel. In a purely competitive market, prices for electricity at the retail level could fluctuate substantially. As noted in section 1.02[2][c] above, higher income consumers may elect to purchase their own generation to utilize during times of short supply and high prices, and sell excess power back into the grid through distributed generation. While natural gas is currently the most popular fuel for distributed generation units,[198] continued high prices for that resource could allow for diesel fuel to increase in popularity. Thus, if distributed generation becomes more viable, diesel fuel could find an increased market.

§ 1.04 Conclusions

Even with the trouble in the California electricity market over the past year, the competitiveness of the electricity market does not show signs of lessening. The pace of competition's expansion into the retail sector of the market may have slowed, but Texas is scheduled to open its retail market to competition next year. The primary goal for independent electric generators, which today make up more than 28% of the market, is producing electricity at the lowest possible cost. Even traditional, regulated utility generators have become more free-market oriented and more concerned about cost and efficiency. This is having an impact on the industries that produce the fuel for generators—the gas, coal, nuclear, renewables, and oil industries.

[196] *Id.* at 62.

[197] *See id.* at 63, fig. 22.

[198] *See* Bosselman, *supra* note 104, at 699.

Because the restructuring of the electric industry is occurring at the same time that new generation needs to be built, new opportunities for most resources exist. Natural gas is predicted to be the fuel of choice for new generation, all things remaining the same. But, of course, things never do remain the same. There are many questions pending in legislative and regulatory arenas, the answers to which will affect the relative prospects of the fuels available for powering new electric plants. Outside of government arenas, in the businesses themselves, new market pressures are leading to changes in technology and to changes in the relationships among fuel producers, their supply lines, and electricity generators.

Fuel is a significant cost for most electric generators—up to 80% of the cost of generation. Electricity producers will pressure fuel suppliers to lower their prices. Today's generators face more uncertainty about their likely revenue stream than they have in the past. They are looking to divide up this risk with their fuel suppliers. The energy resource industries are already moving to respond to these pressures by seeking new economies of scale and integration advantages, including even new strategic alliances with the generators. They also are beginning to employ new risk-management strategies, including new types of futures contracts and cross-hedging. There is movement toward more convergence of the energy industries.

The electric industry is staid no longer. It and the energy industries that support it will likely be in the vortex of change for many years to come. They need perceptive, creative executives and lawyers now more than ever.