DOE/EIA-0623
Distribution Category UC-950

Challenges of Electric Power Industry Restructuring for Fuel Suppliers

September 1998

Energy Information Administration
Office of Coal, Nuclear, Electric and Alternate Fuels
Office of Oil and Gas
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

Contacts

This report, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, was prepared jointly by the Office of Coal, Nuclear, Electric and Alternate Fuels (CNEAF), the Office of Oil and Gas (O&G), and the Office of Integrated Analysis and Forecasting (OIAF) in the Energy Information Administration.

General information concerning the report may be obtained from B.D. Hong (202/426-1126) of CNEAF, who coordinated the preparation of this report, and technical information about the preparation and contents of the report may be obtained from the following analysts:

Introduction	Rebecca McNerney	rebecca.mcnerney@eia.doe.gov	202/426-1251
Coal	B.D. Hong	byungdoo.hong@eia.doe.gov	202/426-1126
Nuclear	Kenneth Wade	kenneth.wade@eia.doe.gov	202/426-1248
Uranium	William N. Szymanski	william.szymanski@eia.doe.gov	202/426-1177
Natural Gas	William A. Trapmann	william.trapmann@eia.doe.gov	202/586-6408
Oil	Charles P. Shirkey	charles.shirkey@eia.doe.gov	202/586-6567
Renewables	Fred Mayes, Jr.	fred.mayes@eia.doe.gov	202/426-1166
	Mark Gielecki	mark.gielecki@eia.doe.gov	202/426-1141
Quantitative Impacts	Robert T. Eynon	robert.eynon@eia.doe.gov	202/586-2315

Preface

Section 205(A)(2) of the Department of Energy Organization Act of 1977 (Public Law 95-91) requires the Administrator of the Energy Information Administration (EIA) to carry out a central, comprehensive, and unified energy data and information program that will collect, evaluate, assemble, analyze, and disseminate data and information relevant to energy resources, reserves, production, demand, technology, and related economic and statistical information.

The purpose of this report, *Challenges of Electric Power Industry Restructuring for Fuel Suppliers*, is to provide an assessment of the changes in other energy industries that could occur as the result of restructuring in the electric power industry. This report is prepared for a wide audience, including Congress, Federal and State agencies, the electric power industry, and the general public.

The legislation that created the EIA vested the organization with an element of statutory independence. The EIA does not take positions on policy questions. The EIA's responsibility is to provide timely, high-quality information and to perform objective, credible analyses in support of deliberations by both public and private decisionmakers. Accordingly, this report does not purport to represent the policy positions of the U.S. Department of Energy or the Administration.

This report can be accessed from EIA's World Wide Web site at http://www.eia.doe.gov.

Contents

Tables

Page

Figures

Figures (continued)

Page

Executive Summary

The current movement to restructure U.S. electricity generation markets and make them more competitive may lead to changes in the financial risks and demands on the supply and transportation infrastructures for the fuels used in electricity generation. This report examines the potential impacts of restructuring of the U.S. electric power industry on the markets for electricity generation fuels—coal, nuclear, natural gas, petroleum, and renewable energy.

Included in this report are a brief review of electric power industry restructuring already in progress at the Federal and State levels, detailed discussions of the major qualitative issues for each of the major fuel supply markets, and a presentation of a range of possible quantitative results, based on the Energy Information Administration's (EIA) National Energy Modeling System (NEMS).

The following paragraphs summarize the discussions of issues related to the markets for coal, nuclear, natural gas, petroleum, and renewable fuels, followed by the quantitative analysis of electric power industry restructuring on fuel markets.

Coal

The U.S. coal and electric power industries are tightly linked: more than 87 percent of total domestic coal consumption is used for generation by utilities, and coal accounts for more than 56 percent of utility power generation. Thus, competitive electricity generation markets will have far-reaching implications for the coal industry. Power generators will attempt to pass on market risks to coal producers and carriers (primarily railroads) wherever they can. As a result, coal purchase contracts will likely become shorter in duration and lower in price. The traditionally stable coal market may absorb some of the volatility of electricity markets.

Electric power industry restructuring is expected to result in renewed pressure for cost cutting and consolidation in the coal industry, extending the trend of the past decade or more. Future gains in productivity will result from the computerization of administrative tasks and continuing improvements in production technology. Taking advantage of economic returns to scale will be another important component of the cost reduction effort. Small firms may be forced out of business, and large firms are likely to continue increasing in size through acquisitions and mergers. In addition, the trend toward shorter contract durations and an uncertain customer base will lead financial institutions to evaluate coal mines on a "balance sheet" basis rather than on the traditional project financing basis, increasing the pressure for industry consolidation.

Risk management will become an important new tool for coal producers. Coal futures markets, already being developed in some areas, will provide a mechanism for risk hedging and for price discovery. Risk reduction may also be accomplished by vertical integration, alliances with railroads or power producers, or the creation of multi-fuel conglomerates. Restructuring will change the business relationships among coal producers, railroads, and power generators, creating incentives for new alliances and the convergence of energy markets.

Emerging changes in the structure of the railroad industry may also affect the economics of both the coal and electric power industries. Transportation costs are a major component of the delivered price of coal to electricity generators, and over half of all coal consumed by them is delivered by rail. As the demand for low-sulfur western coal increases in the coming years, the importance of railroads will become even greater. The full effect on rail rates of the recent and ongoing consolidation of major railroads remains to be seen: the railroads may continue to lower rates as they achieve greater economies of scale, or they may be unwilling to lower rates once they establish their market power, as many coal shippers are concerned will be the case.

Nuclear Power

Nuclear power accounts for about 13 percent of current U.S. electricity generating capacity and about 19 percent of total electricity generation. As the States restructure electricity markets over the next few years, however, some nuclear power plants are expected to become uneconomical. Competitive electricity prices may be so low that nuclear power plant operators will not see enough income to enable them to recover the costs of operating and maintaining the plants and the costs of capital improvements, such as steam generator replacements. In the immediate future, some nuclear power units will be at risk of early retirement as a result of restructuring.

The additional inability of plant operators to cover a plant's full costs, including capital costs, under restructuring produces "stranded costs." The stranded cost recovery issue will not, however, be the major factor in retirement decisions. Ultimately, the long-term viability of nuclear power generation lies in the industry's ability to keep its operating costs competitive with new sources of generation. For nuclear plants, operating costs after deregulation will be driven mainly by plant size, age, capacity factors, and requirements for new capital improvements. Issues surrounding the recovery of future decommissioning costs remain to be resolved. In the long run, however, the market value for long-term firm capacity and for electricity in each region of the country will determine the value of nuclear power plants.

Average fuel costs make up only about one-fourth of the operating costs for nuclear power plants, but the competitive environment created by a restructured electric power industry will encourage nuclear power plant operators to reduce all operating costs, including the costs of purchasing and managing nuclear fuel. Moreover, if early retirements of nuclear power plants result from competition in electricity markets, the demand for nuclear fuel will be reduced. To compete, suppliers in the nuclear fuel industry will be forced to reduce prices or improve efficiency. In an industry that has already seen significant contraction during a decade of depressed prices, further consolidation is likely as companies seek to pool resources and spread risks.

Natural Gas

Natural gas, used for about 9 percent of electric utility generation, is primarily used during peak demand periods and is the preferred energy source for new generating capacity. The electric power and natural gas industries are both network industries, in which energy sources are connected to energy users through transmission and distribution networks. As the restructuring of electricity markets proceeds, the development of institutions, such as futures contract markets and electronic auction markets, could lead to greater integration of the electricity and natural gas industries and the emergence of competitive energy markets.

The availability of market information and public markets for natural gas and electricity will be a key to the development of an integrated energy market for those commodities. Price volatility for gas and electricity will spur the growth of futures markets and promote the efficient allocation of resources. Challenges for the natural gas industry include the development of shorter term contracts with standard terms and low transaction costs, improvements in deliverability and flexibility, and the synchronization of same-day nominations for deliveries of gas and electricity. Metering and measuring of gas flows throughout the industry are also likely to become more important as more frequent exchanges of energy take place among market participants.

Oil

Restructuring of the U.S. electric power industry should have little overall impact on crude-oil-derived fuels (distillate and residual). In 1996, for example, petroleum, which fueled 2.2 percent of electric utility generation, accounted for only 2.3 percent of the Nation's petroleum consumption. With the deregulation of electricity generation and the resulting incentive for power generators to lower fuel costs, the use of relatively expensive residual fuel oil for electricity production is likely to decline even further. As a result, petroleum refiners may be faced with a growing problem: how to dispose of "leftover" residual fuel and petroleum coke. Among other options, two possibilities are related to electricity markets: (1) selling petroleum coke to electricity generators for use as a fuel blending component, and (2) gasification at the refinery by using integrated gasification combined-cycle (IGCC) technology to produce steam for process heat and for electricity production.

Finally, electricity deregulation may provide oil companies with opportunities to expand synergistically into a related business. A number of oil companies have gained experience in electricity production as a means of exploiting their natural gas holdings in other countries, and they could become important players in the U.S. market as capacity needs grow in the future. Meanwhile, as economic considerations increasingly dictate when distillate fuel oil (and other fuels) will be purchased and at what price, electricity generators will be relieving the pressure on both available supply and the marginal price in the very volatile heating oil market that characterizes the Northeast during severe cold snaps.

Renewables

Because electricity generation from renewable sources (other than hydropower) generally is more expensive than power from conventional sources, unconstrained competition in electricity generation would likely result in a reduced role for renewable energy facilities. As a result, a variety of proposals under consideration by State legislatures and by the U.S. Congress include specific provisions to support the continued development and use of renewable energy. Renewable portfolio standards and system benefits charges are among the programs being considered. Green marketing and pricing programs, already being implemented by electric utilities, may also provide a means to increase consumer demand for electricity from renewable fuels.

The role of renewable energy sources in competitive electricity markets will also depend on the cost and performance of the individual renewable fuels: biomass (primarily wood), geothermal, solar, and wind. In addition, because renewable energy generating facilities generally depend on the availability of energy resources at specific sites—often at sites remote from major electricity grids—transmission issues will affect the penetration of renewable fuels in the electricity generation market.

Quantitative Impacts on Fuel Markets

A quantitative analysis was conducted to determine the impacts that competitive electricity generation markets could have on fuel supply industries. To capture the uncertainty about the conditions under which a competitive electricity market will operate, EIA prepared a range of possible outcomes (i.e., analysis cases) based on different assumptions about key electricity and energy variables. Two full competition cases (assuming low and high fossil fuel consumption), in addition to a partial competition case (the reference case from EIA's *Annual Energy Outlook 1998* (*AEO*)), were compared with a no competition case in order to illustrate the possible impacts of competition.

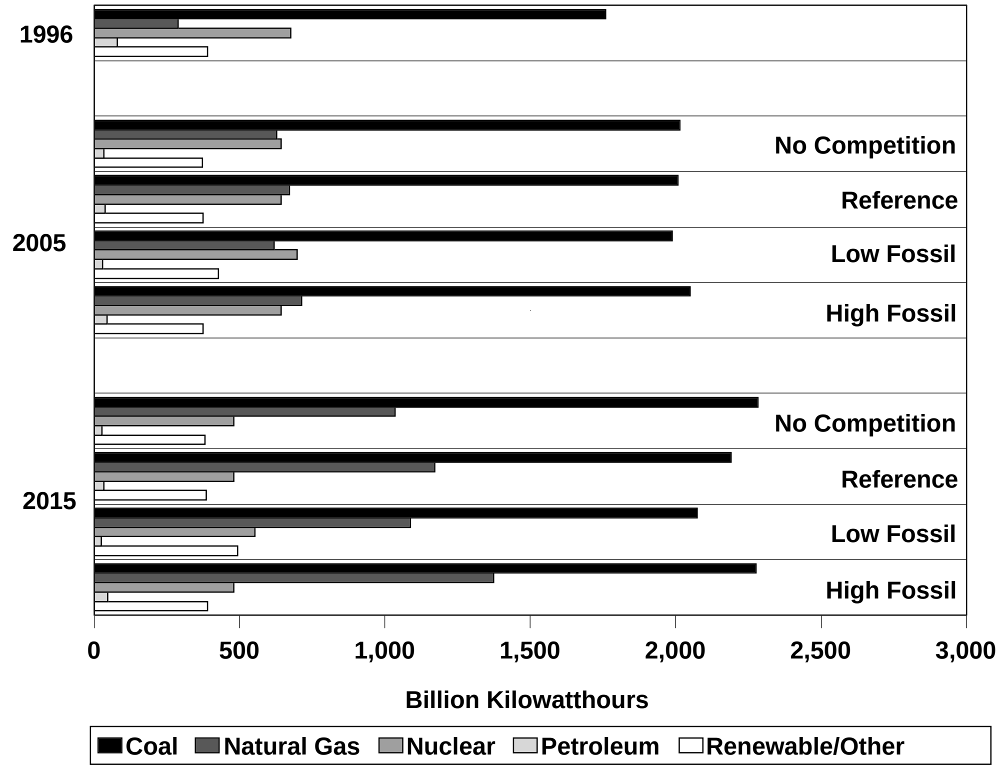
In all the cases, natural-gas-fired turbines and combined-cycle plants garner most of the market for new generating capacity when more competition was assumed. From 1996 to 2015, additions of coal-fired capacity are projected to range from about 20 gigawatts in the low fossil fuel case to 49 gigawatts in the no competition case, whereas additions of natural gas turbine and combined-cycle capacity range from about 256 gigawatts in the no competition case to 324 gigawatts in the high fossil fuel case. In all the cases, natural gas is projected to have an increasing share of electricity generation as demand levels grow (Figure ES1).

Unless required by Federal policies, the restructured electricity market is not projected to stimulate renewable energy technologies. Overall, the cases analyzed suggest that renewable resources will remain more costly than fossil fuel alternatives through 2015 and will penetrate electricity markets only to the extent compelled, such as by a renewable portfolio standard that mandates generation from renewable sources. If policies require increased use of renewable energy, the cases suggest that average electricity prices will increase slightly. Biomass, wind, and geothermal would be the most likely technology choices for expanded use of renewable energy.

In the competition cases examined, natural gas production is projected to range from 0.8 percent lower to 2.2 percent higher than in the no competition case in 2005 and from 0.3 percent to 6.0 percent higher in 2015. The projected average natural gas prices at the wellhead range from a low of $2.05 per thousand cubic feet in 2005 to a high of $2.61 per thousand cubic feet in 2015 (all prices expressed in real 1996 dollars). Overall, the results from all the cases suggest that restructuring in the electric power industry will stimulate demand for natural gas and that rising demand will lead to higher wellhead prices as the discovery process progresses from larger and more profitable fields to smaller, less economical ones. The projected price increases also reflect more production from higher-cost sources, such as offshore conventional recovery and onshore unconventional gas recovery from such sources as tight sands, Devonian shales, and coalbed methane. Electricity restructuring is not expected to have a significant impact on crude oil production because petroleum-based generation is a small share of overall electricity generation.

In the national coal market, two factors lead to significant changes: (1) the environmental regulations creating a national market for sulfur emissions credits, which encourages minimization of sulfur emissions and, thus, fuel sulfur content; and (2) the competitive electricity generation market, which rewards the minimization of generation fuel costs. The impacts of both changes are seen in the cases analyzed here. Across the cases, competition tends to favor the use of natural gas over coal for electricity generation because natural-gas-fired power plants are generally projected to be more economical than coal-fired plants. The exception is the high fossil case, which assumes higher demand for electricity than in the *AEO* reference case, no renewable portfolio standard, and continued operation of relatively higher-cost generating plants (up to 6 cents per

Figure ES1. Electricity Generation by Fuel Type in Four Cases, 1996, 2005, and 2015



Note: Data do not include nonutility generation for own use, cogeneration, or electricity imports. Renewable/other includes pumped storage hydroelectric.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

kilowatthour). The cases vary in their projections of consumption shares for low-, medium-, and high-sulfur coals, regional production shares, and minemouth prices. Production of high-sulfur coal is relatively stable across the competition cases and declines by about 19 million tons in the low fossil case in 2010. In contrast, low-sulfur coal production is more volatile and increases by as much as 80 million tons in 2015 in the high fossil case due to increased demand for coal while requirements to limit sulfur dioxide emissions are tightening.

Total energy consumption for electricity generation is projected to grow from 1996 to 2015 in all the cases analyzed. Consumption levels increase for all fossil fuels and renewable sources, whereas consumption of nuclear electricity generation declines as a result of retirements and the lack of new construction. There is little variation in total energy consumption among the competition cases, except when higher demand levels are assumed. There are, however, variations in the levels of consumption of natural gas and coal across the cases, with natural gas tending to gain and coal to lose market share as the industry moves from a regulated to a competitive environment.

The average price of fuel used for electricity production in 2015 is projected to be about the same as in 1996 in all but the high fossil case (Table ES1). In the high fossil case, an increase of about 11 percent in the average price is projected because of higher natural gas prices resulting from assumed higher drilling costs for onshore production. Natural gas prices increase slightly in the other cases but are offset by an almost 30-percent decline in coal prices between 1996 and 2015.

Electricity prices are projected to decline from 1996 levels, even in the case of no competition, because of lower coal prices and modest additions of new capacity. In the competition cases, prices fall even further as a result of efficiency improvements in plant operations and fewer additions of capital-intensive coal plants. Prices in competitive markets are based on marginal costs, which tend to be lower than the current average embedded costs.

Table ES1. Energy Consumption and Prices for Electricity Generation

Projection	1996	2005 No Competition	2005 *AEO98* Reference	2005 Low Fossil	2005 High Fossil	2015 No Competition	2015 *AEO98* Reference	2015 Low Fossil	2015 High Fossil
Energy Consumption by Electricity Generators (Quadrillion Btu per Year)									
Distillate Fuel	0.08	0.07	0.07	0.07	0.08	0.07	0.07	0.07	0.09
Residual Fuel	0.67	0.28	0.30	0.22	0.36	0.20	0.25	0.16	0.37
Petroleum Subtotal	0.75	0.34	0.37	0.28	0.44	0.27	0.32	0.23	0.46
Natural Gas	3.04	5.39	5.69	5.23	6.01	7.98	8.71	8.02	10.06
Steam Coal	18.36	20.60	20.55	20.35	21.04	23.16	22.29	21.21	23.21
Nuclear Power	7.20	6.87	6.87	7.45	6.87	5.12	5.12	5.90	5.12
Renewable Energy	4.45	4.37	4.37	5.06	4.31	4.44	4.53	6.25	4.59
Electricity Imports	0.39	0.39	0.34	0.37	0.37	0.28	0.28	0.30	0.30
Total	34.20	37.96	38.19	38.75	39.03	41.25	41.26	41.91	43.75
Energy Prices to Electricity Generators by Source (1996 Dollars per Million Btu)									
Fossil Fuel Average	1.54	1.46	1.49	1.44	1.51	1.49	1.60	1.51	1.71
Petroleum Products	3.27	3.61	3.57	3.76	3.46	4.13	4.00	4.27	3.77
Distillate Fuel	4.90	5.17	5.16	5.15	5.14	5.45	5.47	5.42	5.40
Residual Fuel	3.07	3.23	3.20	3.34	3.09	3.67	3.60	3.79	3.36
Natural Gas	2.64	2.58	2.63	2.56	2.72	2.80	2.98	2.85	3.32
Steam Coal	1.29	1.14	1.14	1.11	1.13	1.01	1.03	0.97	0.97

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

Introduction

The movement toward a competitive electricity generation market has been underway for several years. Many consumers, producers, and regulators see increased competition as a key to more efficient production of power and lower end-use prices. With the electric power industry accounting for more than $210 billion in annual sales, the implications of deregulated electricity generation markets for capacity choice, operating costs, and fuel choice are significant. This report examines potential impacts of restructuring and deregulation of the electric power industry on the markets for electricity generation fuels—coal, nuclear, natural gas, petroleum, and renewable fuels.[1]

The U.S. electric power industry is in the midst of a transition that is changing electricity generation operations from regulated monopolies to entities that operate in competitive markets. As the transition progresses, the competitive pressure for lower electricity prices could alter the Nation's power generation fuel mix. The possible ramifications vary in likelihood and complexity. Generating companies may change their fuel purchase arrangements and inventory practices. Higher cost generating plants may be retired in favor of more efficient, low-cost power plant technologies, and the shares of electricity generation from different fuels may change. (For example, legislation may be enacted to ensure some level of market share for renewable fuels in the generation mix.)

Electric power industry restructuring may lead to new financial risks and demands on the supply and transportation infrastructure of the fuels used for electricity generation. This report analyzes issues that electricity restructuring creates for each fuel market.

Major Restructuring Changes Already in Progress

Numerous structural changes in the electric power industry are yet to come. Already, however, there has been significant progress by regulators, legislators, and the utilities themselves toward a competitive electricity market.

FERC Actions

Perhaps the single most sweeping change so far has been the outcome of recent actions taken by the Federal Energy Regulatory Commission (FERC), which has the responsibility for regulating the Nation's interstate trade in electric power. Pursuant to guidelines set forth in the Energy Policy Act of 1992 (EPACT) regarding open access to transmission services at equitable rates, the FERC issued Orders 888 and 889 in 1996. These orders were designed to remove impediments to competition in wholesale electricity trade and are expected to bring more efficient, lower cost power to the Nation's electricity consumers. On February 26, 1997, in response to various rehearing requests, the FERC announced a number of minor adjustments to the rules, to become effective 60 days after they appeared in the *Federal Register*.[2]

Order No. 888, entitled *Promoting Wholesale Competition Through Open Access Nondiscriminatory Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, requires all public utilities that own, control, or operate transmission facilities to provide nondiscriminatory open access transmission

[1] Renewable fuels are hydroelectric (conventional), geothermal energy, biomass (wood, wood waste, peat, wood sludge, municipal solid waste, agricultural waste, straw, tires, landfill gases, fish oils, and / or other waste), solar energy (solar thermal and photovoltaic), and wind energy.

[2] For further details concerning FERC actions regarding electric power industry regulatory reform, refer to Energy Information Administration, *The Changing Structure of the Electric Power Industry: An Update*, DOE-EIA-0562(96) (Washington, DC, December 1996), Chapter 7. In addition, EIA has recently published a report entitled *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*, that updates information on restructuring activities by the FERC, Congress, and the States.

services by filing tariffs that offer others the same transmission services they provide to themselves. In addition, it provides for a stranded cost mechanism to aid in the transition to a more competitive industry. Stranded costs are those that utilities prudently incurred to serve customers under a regulated environment, which could go unrecovered if customers switch to other suppliers. The FERC stressed that providing for stranded cost recovery would ensure the financial viability of utilities that provide reliable, essential electric service.

Order No. 889, *Open Access Same-Time Information System and Standards of Conduct (OASIS)*, further ensures nondiscriminatory transmission service by requiring public utilities that own, control, or operate transmission facilities to develop an Internet-based bulletin board system that provides same-time information about electricity prices and the availability of transportation capacity on transmission lines. This rule requires public utilities to obtain information about their transmission system for their own wholesale power transactions in the same way their competitors do—through the Internet OASIS system, which began commercial operation in January 1997. It also requires them to separate their functions of wholesale power marketing and transmission operation.

As a result of the FERC Orders, many investor-owned utilities that own transmission lines have begun to establish independent system operators (ISOs) to manage and operate the transmission systems in their regions. Eleven ISOs have been approved, proposed, or are under discussion, covering all parts of the United States except the Southeast. Utility participation is fragmented, however, and issues have arisen regarding participation by Federal and other publicly owned utilities. As of April 1998, four ISOs were operating: California ISO; ISO-New England; Pennsylvania, New Jersey, Maryland Interconnection; and the ERCOT ISO. Each has procedures for pricing transmission services—in particular, when congestion occurs in the transmission system. It is too early to determine what, if any, changes may be seen in generation patterns and fuel consumption as a result.

Congressional Actions

While no Federal legislation that applies directly to electric power industry restructuring has been enacted, a number of bills have been introduced in recent years, and Congress has been actively pursuing the matter (see Appendix A). Electricity workshops and Congressional Committee hearings have been and are being held to investigate the issues and impacts and to hear industry views on the role the Federal Government should play in restructuring the industry. Restructuring legislation was introduced but not passed during the 104th Congress. Revised legislative proposals have been introduced and are being debated in the hopes of mandating a federally guided approach to restructuring before the end of the 105th Congress. On June 26, 1998, the Secretary of Energy submitted to Congress the Administration's proposed legislation to implement the Comprehensive Electricity Competition Plan that was released by the Administration on March 25, 1998.

The common theme among the proposals is to set forth guidelines that will benefit and protect electricity consumers by giving them the right to choose among competitive suppliers while securing lower rates and higher quality service. Some proposals encourage energy conservation and efficiency programs and the use of renewable sources of energy. One bill that contains the most proactive measures concerning renewables, H.R. 1359 introduced by Congressman Peter A. De Fazio (D-OR), instructs the Secretary of Energy to establish a National Electric System Public Benefits Board to fund programs related to renewable energy sources, universal electric service, affordable electric service, energy conservation and efficiency, or research and development in each of these areas. The bill also provides for a renewable energy portfolio standard and for renewable energy credits. Two bills set forth a date certain for retail competition. H.R. 655, the Electric Consumers' Power to Choose Act of 1997, introduced by Congressman Dan Schaefer (R-CO), specifies December 15, 2000; and S. 237, the Electric Consumers' Protection Act of 1997, introduced by Senator Dale Bumpers (D-AR), specifies December 15, 2003, as the date by which all retail customers will be able to choose their electricity providers.

Also included in the Federal proposals are bills to repeal the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Public Utility Holding Company Act of 1935 (PUHCA), both of which are being identified as impediments to a truly market-driven electric power industry. Some groups believe that PURPA and PUHCA repeal should be instituted, but only as part of legislation that would comprehensively address the many issues associated with restructuring. Additional issues—including privatization of the Federal Power Marketing Administrations, Federal Power Act amendments prescribing State parameters relative to instituting retail competition, the recovery of stranded costs, and the role that the Federal Government should play in restructuring the electric power industry—are addressed in various bills.

Appendix A summarizes pending Federal legislation and the Administration's plan[3] for the restructuring of the electric power industry, including an overview of the major issues contained in each.

State Actions

Retail competition is being deliberated on a State-by-State basis. The utility regulatory commissions and the legislatures of nearly all 50 States and the District of Columbia are in different stages of the implementation process, from informally studying the idea to passing legislation that specifies the date and conditions of full retail competition. In order for a State to make the transition to a fully competitive market, its legislature must first pass legislation that authorizes the conversion to deregulation. Only then can the State regulatory commission proceed with approved implementation plans. Six States, however, have been able to initiate competition through regulatory orders only. Figure 1 shows the progress being made throughout the United States toward establishing full retail competition. As of July 1, 1998, 12 States had enacted restructuring legislation.

On March 31, 1998, California became the first State to open its retail electricity market to competition. Retail access pilot programs are also underway in a number of States, including Idaho, Illinois, Massachusetts, Michigan, Missouri, Montana, New Hampshire, New Jersey, New Mexico, New York, Ohio, Oregon, Pennsylvania, Texas, and Washington. While there are similarities among them, each pilot program contains specifications (regarding size and duration, flexibility, billing and metering, targeted customers, etc.) that vary from one program to another.[4] Pilot programs are being instituted to provide insights into the workings of retail access. The lessons learned will serve as the building blocks for full retail competition.

Also being examined by those involved in formulating retail competition guidelines are Federal and State jurisdictional issues. Some groups believe that, while States may be in a position to direct certain aspects of full retail competition, the Federal Government is in the best position to address broader aspects, such as the environment, rules of reciprocity, and a date certain for customer choice. The rules of the game have been and will continue to be redefined by Federal and State regulators and legislators.

Some of these issues are discussed in more detail in two other Energy Information Administration reports, *The Changing Structure of the Electric Power Industry: An Update* and the recently released *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*.

The Role of Fuel Markets in Electricity Generation

More than one-third of the primary energy consumed in the United States is used to generate electricity. In 1996, the Nation produced 3,447 billion kilowatthours of electric power. Of that amount, utilities accounted for 3,077 billion kilowatthours and nonutilities generated the remaining 370 billion kilowatthours.[5] Coal-fired generation has been and continues to be the largest contributor to the supply of electricity, followed by nuclear, natural gas, renewables, and petroleum. In 1996, utility purchases accounted for 87 percent of the U.S. coal market, 53 percent of the renewables market, 12 percent of the natural gas market, 2 percent of the oil market, and virtually all the uranium available in the commercial market.[6] Investor-owned utilities spent approximately $22.8 billion on coal in 1996, $7.4 billion on natural gas, $3.0 billion on nuclear fuels, and $2.4 billion on petroleum.[7] Because fuel costs account for two-thirds of utility power production expenditures,[8] the future price of fuels is a critical issue for utilities facing the change to a competitive market.

Since 1986, there has been a downward trend in fuel costs. In the coal industry, increased productivity, lower transportation rates, and changing market conditions have produced a steady decline in coal prices. Average prices for natural gas to electric utilities have generally

[3] U.S. Department of Energy, *Comprehensive Electricity Competition Plan* (Washington, DC, March 1998).

[4] Energy Information Administration, *The Changing Structure of the Electric Power Industry: Selected Issues, 1998*, DOE/EIA-0620 (Washington, DC, May 1998), Chapter 4.

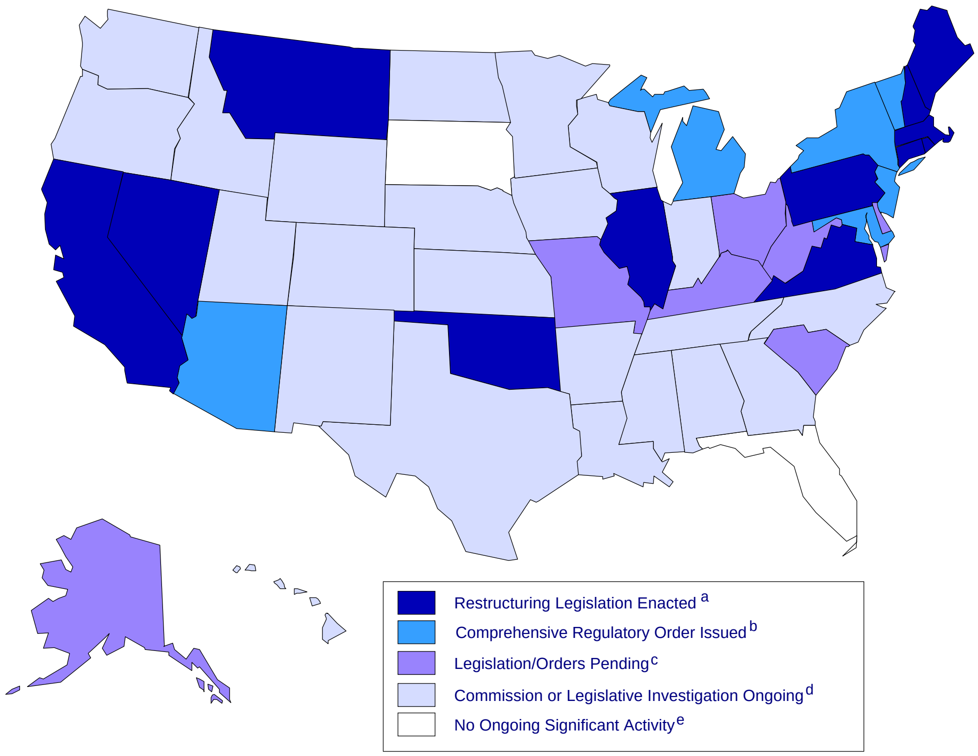
[5] Energy Information Administration, *Electric Power Annual 1996*, Volume II, DOE/EIA-0348(96/2) (Washington, DC, December 1997), pp. 13-14.

[6] Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), pp. 211, 265, 195, 161, and 259, respectively.

[7] Energy Information Administration, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants" (1996); FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others" (1996); and estimates made by the EIA Office of Coal, Nuclear, Electric and Alternate Fuels.

[8] Energy Information Administration, *Financial Statistics of Major U.S. Investor-Owned Electric Utilities 1996*, DOE/EIA-0437(96/1) (Washington, DC, December 1997).

Figure 1. Status of State Electric Utility Deregulation Activity as of July 1, 1998



[a]California, Connecticut, Illinois, Maine, Massachusetts, Montana, Nevada, New Hampshire, Oklahoma, Pennsylvania, Rhode Island, and Virginia.
[b]Arizona, Maryland, Michigan, New Jersey, New York, and Vermont.
[c]Alaska, Delaware, Kentucky, Missouri, Ohio, South Carolina, and West Virginia.
[d]Alabama, Arkansas, Colorado, District of Columbia, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Louisiana, Minnesota, Mississippi, Nebraska, New Mexico, North Carolina, North Dakota, Oregon, Tennessee, Texas, Utah, Washington, Wisconsin, and Wyoming.
[e]Florida and South Dakota.

Note: Texas allows competitive wholesale wheeling as authorized by SB 373, enacted in 1995. Legislation authorizing retail wheeling will be revisited in 1999. California, Massachusetts, and New Hampshire each have regulatory orders and legislation in place.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

trended downward from a 1983 peak to a 16-year low in 1995, although they recovered somewhat in 1996.[9] A large worldwide surplus of uranium has also caused its prices to decrease precipitously over the past decade or more.

Keeping fuel costs down is a major goal for electricity producers in maintaining competitive prices. As a consequence, fuel suppliers will be faced with many challenges to cope with the coming changes to their industries and remain competitive. Chapters 1 through 5, on the fuel markets, examine some of the challenges and opportunities brought about by electric power industry restructuring. Each fuel market is addressed in a separate chapter, where issues important to that particular market are discussed. Because the fuels vary widely in their economic and technological characteristics and in their alternative power uses, there is no consensus set of issues applying to all markets. As a result, the individual fuel chapters vary in the depth and scope of their analysis. Chapter 6 presents the results of a quantitative analysis conducted to estimate the magnitude of the impacts that competitive electricity generation markets could have on the fuel supply industries, based on model projections from EIA's National Energy Modeling System.

[9] Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), p. 181.

1. Impacts of Electric Power Industry Restructuring on the Coal Industry

The U.S. coal and electric power industries are tightly linked. Over 87 percent of all the coal consumed in the United States is for electricity generation by utilities, and coal is the primary fuel for more than 56 percent of utility power generation (Table 1). Deregulation of the electric power industry, therefore, has a potentially profound impact on the coal industry. Moreover, that impact will be compounded by a concurrent consolidation of the rail industry, which is the largest carrier of coal and a major determinant of the price of coal delivered to electric power generators.

Implications of Electric Power Industry Deregulation

The deregulation of electricity markets will have far-reaching implications for the coal industry. In the electric power industry itself, deregulation is expected to result in intensified price competition, growing price volatility, shorter-term wholesale electricity transactions, and industry consolidation and structural changes. Today, as the electric power industry is moving rapidly toward retail competition, the wholesale electricity market is already reaching full-scale, open competition. The deregulated wholesale market is proving to be highly dynamic; prices tend to be volatile and transactions short term. The electric power industry is undergoing consolidation through mergers and acquisitions and, at the same time, has started unbundling its generation, transmission, and distribution functions from an integrated structure.

Dynamics of a Deregulated Power Generation Industry

With open competition and electric industry unbundling, most U.S. electricity generators in the future are likely to function as "merchant" plants, much like oil and gas producers, with no guaranteed market for their output. These merchant plants will be in constant competition for sales of their output. Plant operators will look to cut costs wherever they can and to manage risks in both the fuel and electric power markets. The electric power industry has already started a consolidation, and it is expected to continue. At the same time, convergence between electric power, natural gas, and coal markets is also taking place.

All these developments reflect strong incentives for electricity generators to become lower cost producers, expand market share, and remain profitable in a deregulated environment. In a fully competitive retail electricity market, only those generators with costs low enough to produce electricity at market prices, as opposed to costs that are simply low enough to meet regulatory oversight, will be able to sell electricity profitably and remain viable.

Electric power generators will face new risks in a deregulated environment, and they must manage their operations to cover their costs in more competitive markets. Yet, greater uncertainty will prevail in virtually every aspect of their operations. Most notably, they will operate without a guaranteed market or price for their electricity. As retail competition unfolds, the market for their electricity will become even more uncertain in magnitude, timing, and price.

Risk management in power generation and in fuel purchasing will focus primarily on managing the spread between electricity and fuel prices, known as the "spark spread." Power generators will use various physical and financial techniques, such as futures or options contracts, to manage risks in both electricity and fuel markets. They will also attempt to pass on risks to fuel suppliers wherever possible. Such risk management techniques are well established in the oil and gas markets and recently have begun to emerge in electricity markets. In the near future, they will become important in coal markets as well.

Uncertainties in power markets will lead power generators to change their coal purchasing practices. They will shift from long-term to shorter term contracts to remain flexible in coal purchasing, and their contracts for coal purchases will include terms and conditions

Table 1. Electric Utility Net Generation and Coal Receipts by NERC Region, 1996

NERC Region	Coal	Other Fuel	Total Generation	Coal	Appalachian Receipts	Interior Receipts	Western Receipts	Total Receipts
	Billion Kilowatthours			Percent Share	Million Short Tons			
ASCC	0.2	4.8	5.0	4.6	NA	NA	NA	NA
ECAR	467.8	56.8	524.6	89.2	123.0	41.5	35.7	200.2
ERCOT . . .	104.2	117.7	221.8	47.0	0.0	51.3	29.1	80.5
FRCC	59.8	79.1	138.8	43.1	13.4	7.7	0.7	21.8
MAAC	106.7	98.1	204.7	52.1	43.5	0.0	0.0	43.5
MAIN	136.4	95.7	232.0	58.8	1.8	17.5	56.9	76.2
MAPP	115.6	44.3	159.9	72.3	0.0	1.3	70.6	72.0
NPCC	37.7	141.8	179.4	21.0	12.9	0.0	0.0	12.9
SERC	358.4	228.2	586.6	61.1	100.4	30.2	18.9	149.5
SPP	166.2	122.4	288.6	57.6	0.0	5.6	91.6	97.2
WSCC	184.7	344.8	529.5	34.9	0.0	0.0	104.3	104.3
Total[a]	**1,737.5**	**1,333.6**	**3,071.0**	**56.6**	**295.0**	**155.1**	**407.8**	**858.0**

[a]Excludes 6.4 billion kilowatthours of electricity generated in Hawaii, all from other fuels.
NA = Not available.
Source: Energy Information Administration Form EIA-759 for electric utility net generation by fuel type and Federal Energy Regulatory Commission Form 423 for coal receipts by coal-producing region.

enabling them to react to unanticipated changes in the coal market.

Complicating the above scenario is the regional disparity in coal dependence (Table 1). While 56.6 percent of all utility generation in the United States is coal-fired, regional dependence on coal varies widely, ranging from less than 5 percent for Alaska (ASCC) to almost 90 percent for the ECAR region (Figure 2). Further complications will arise from a consideration of the source of the coal used in power generation. For example, the SPP and MAAC regions are similar in their levels of coal dependence, but generators in the SPP obtain their coal mostly from suppliers in the West, whereas the MAAC region relies primarily on Appalachian coal. The difference in their coal sources may result in very different responses to deregulation.

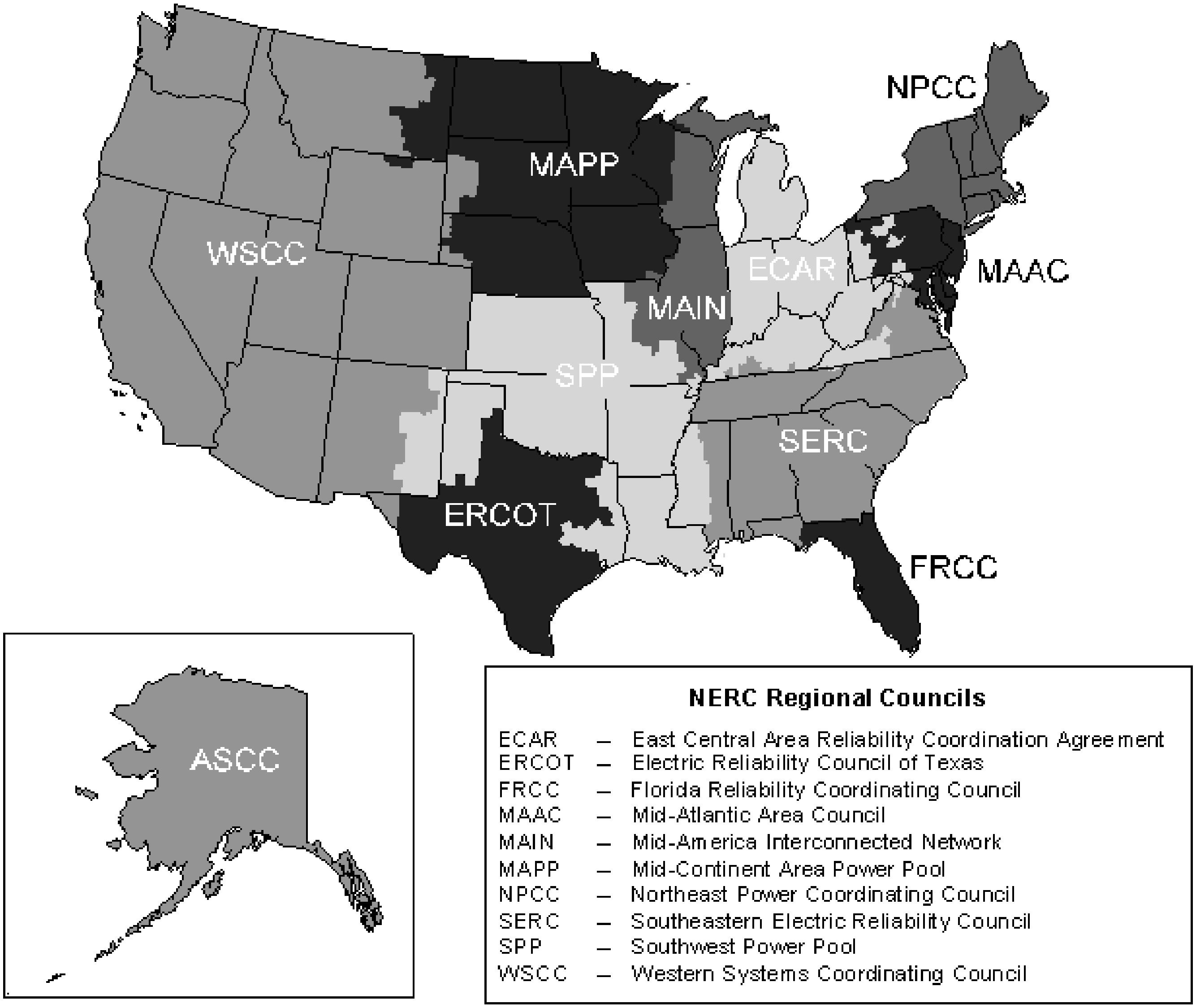
The Link to Coal Prices

The dependence of coal producers on the electricity generation market closely ties them to developments in the electric power industry. Once electricity markets are deregulated, power generators will try to cut fuel costs by putting pressure on both minemouth and delivered coal prices. Among the many strategies to cut costs, power generators will focus on reducing fuel costs, which are seen as being manageable and are the largest component of production costs at coal-fired power plants—over 75 percent. Power generators generally have less opportunity to cut nonfuel (operation and maintenance) costs (Figure 3). The importance of fuel costs is clearly reflected in today's incremental wholesale power sales, which are largely based on relative fuel costs.

Over the past decade, coal costs for electricity production have declined substantially. For example, between 1991 and 1996, they declined by 21 percent—from $17.84 to $14.08 per megawatthour (MWh) (in 1996 constant dollars)—while operation and maintenance costs remained flat. Much of the recent decline in coal costs is attributable to falling coal prices. Coal producers and carriers (primarily railroads) have improved their productivity and competed for utility coal business. In a deregulated electricity market, power generators are certain to look for still lower coal costs, adding pressure on both minemouth and delivered coal prices.

To remain competitive, power generators will intensify pressures on coal producers for lower coal prices, but will not be willing to make long-term commitments for coal purchases. This will mark a significant departure from past practices, with far-reaching impacts on the coal industry.

Figure 2. North American Electric Reliability Council (NERC) Regions for the Contiguous United States and Alaska



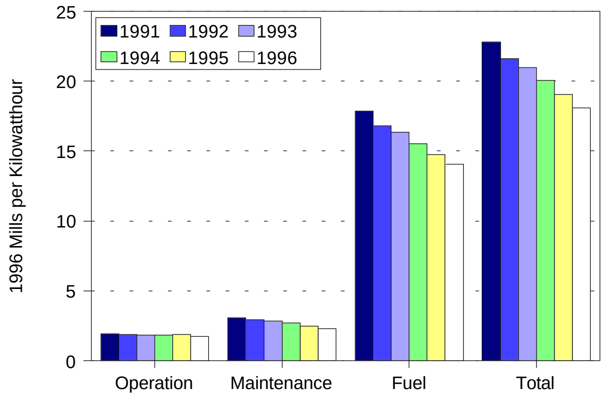
Note: The Alaska Systems Coordinating Council (ASCC) is an affiliate NERC member.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

Because coal-fired power plants are mostly baseload, their average capacity utilization rate is relatively high (for example, 63 percent in 1996, compared with only 20 percent for natural gas and 11 percent for oil, which in many situations are largely used for peaking generation[1]). Coal-fired power plants operate most of the time with a high degree of certainty, and their steady, large volume of electric output in the past has allowed power generators to make long-term contractual commitments to coal suppliers. Coal mines were usually opened with secured, long-term contracts in place, guaranteeing a market for their output that would provide a stream of (future) revenue. Even where long-term commitments were not made, coal producers at least knew that a well-defined market existed for power generation. Much of this certainty for coal producers, however, will disappear in unbundled, deregulated power markets populated with power generators functioning as merchant plants.

Power generators will attempt to pass on the pressures and risks in electricity markets to coal producers and

[1] Energy Information Administration, *Electric Power Annual 1996, Volume I*, DOE/EIA-0348(96)/1 (Washington, DC, August 1997), Table 1.

Figure 3. Average Power Production Expenses for Major U.S. Investor-Owned Coal-Fired Electric Utility Plants



Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

carriers wherever they can. This has already resulted in significant reductions in coal contract prices and duration. Price pressures mean lean profits for coal producers and new challenges to find ways to cut costs to remain viable. In addition, volatility in electricity markets may well be reflected in the coal markets. With the greater use of short-term transactions for coal and increasing market uncertainty, coal producers, like power generators, could well find themselves subject to considerable price and volume volatility and risks, which they will need to hedge.

The Coal Industry Response

Changing Industry Structure

Coal Production Trends

The result of a competitive, deregulated electricity market will likely be further consolidation in the coal industry. Pressure from electric power generators for lower coal prices will mean reduced revenues and, hence, profits, which will drive out smaller, inefficient coal producers. This will benefit larger companies, as larger size generally results in lower overhead and mining costs through economies of scale, diversification of business, and the availability of financial resources to make new investments in mines and to improve productivity.

Coal may also be included in attempts by energy companies to integrate their operations across energy sources. Combining electricity and gas in transactions is already a common business practice. This is one aspect of the widely discussed phenomenon termed "convergence" of the energy industry. Some coal producers today are packaging coal and sulfur emission allowances. Convergence could expand to include coal, as well as emission allowances, along with electricity and gas.

Only those coal producers with the ability to obtain financing and manage risks will survive. They must be able to face the challenge of investing with lower and less certain revenues per ton. Small coal producers may not have the financial resources to do this. Increasingly, balance-sheet financing of companies, based on the company's overall financial strength, will replace project financing of specific mining ventures. This, in turn, will favor the larger companies and may act as an incentive for further consolidation.

Coal Industry Concentration. The coal industry has been undergoing consolidation for some time, creating fewer but larger mines and firms and producing more coal (Table 2). Two basic forces have been driving consolidation in the coal industry. In the 1960s and 1970s, more stringent mine safety and reclamation laws forced many small mines out of operation. Then, in the 1980s, falling coal prices caused small, inefficient producers to close down or be bought out, and pressure to reduce costs motivated producers to seek economies of scale by forming larger units.[11] Under deregulated electricity markets, power generators will further increase the pressure on coal producers to lower prices, intensifying the recent trend toward increasing consolidation and concentration of mining operations and firms.

Nationally, concentration among coal producers has increased. The top four coal producers had a market share of 32.9 percent in 1996, up from 19.6 percent in 1986.[12] In coal reserve holdings, a key indicator of future production, concentration among the four largest reserve holders fell from 10 percent in 1985 to 7.2

[11] Electric Power Research Institute, *Structural Change in the Coal Industry: Coal Industry Concentration Trends, 1970-1994*, TR-105026 (May 1995).

[12] Energy Information Administration, *The Changing Structure of the U.S. Coal Industry: An Update*, DOE/EIA-0513(93) (Washington, DC, July 1993), Table 13; and *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997), Table 15.

Table 2. Coal Production Trends

Industry Characteristics	1970	1980	1990	1996
Number of mines	5,601	3,969	2,707	1,903
Number of surface mines	2,662	2,082	1,285	1,018
Number of underground mines	2,939	1,887	1,422	885
Average production per mine, surface.	102	236	471	642
Average production per mine, underground	116	179	299	463
Percent of production east of the Mississippi River	93	69	61	53
Percent of production west of the Mississippi River	7	31	39	47

Source: Energy Information Administration, Form EIA-7A, "Coal Production Report," and *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997).

percent in 1990.[13] However, a recent survey indicates that the concentration of reserve holdings may also be increasing. In 1996, the four largest reserve holders held 8.7 percent of total U.S. coal reserves.[14]

Increasing concentration in coal production can be seen in the Powder River Basin (PRB), the Nation's largest and fastest growing coal-producing region. Coal production in the PRB is dominated by a small number of large surface mines, which currently include 14 of the Nation's 15 largest mines, and is becoming increasingly concentrated. In 1986, the top 4 producers in the PRB accounted for 48 percent of its total output: Amax (14 percent), Arco (14 percent), Exxon (12 percent), and Nerco (8 percent). By 1996, the top 4 producers represented 77 percent of the Basin's total output: Peabody (33 percent), Kennecott (17 percent), Arco (15 percent), and Cyprus Amax (12 percent).[15]

The number of both surface and underground mines fell dramatically between 1970 and 1996, increasing the average production from both types of mines (Table 2, Figure 4). Surface mines on average produced six times more in 1996 than they did in 1970, due largely to the regional shift in coal production toward large western surface mines. Western coal production accounted for 47 percent of the U.S. total in 1996, up from only 7 percent in 1970. Deregulation of the electric power industry is likely to bolster this trend.

The coal industry is also increasingly becoming international. Foreign-affiliated coal firms made up only 1.4 percent of total production in 1976.[16] By 1995, three of the top five U.S. coal producers had foreign affiliations, and production by foreign-affiliated firms had risen to 30.7 percent.[17]

Another clear trend is that the coal industry is largely becoming composed of companies focusing almost exclusively on the coal business. Companies that currently have long-term interests in the coal industry tend to have more significant expansion plans; in fact, most recent acquisitions have been made by companies that have coal as their main business. Such firms also tend to operate mines more efficiently and reliably. Other types of companies—such as electric utilities, steel manufacturers, and oil companies—have mostly left the coal industry. For example, between 1989 and 1994, six petroleum companies sold or offered to sell their coal divisions.[18] It is noteworthy that such companies brought large amounts of capital to the coal industry, yet they failed to attain the same level of expertise and commitment as those dedicated primarily to the coal industry.[19] Kerr-McGee, one of the remaining major

[13] Energy Information Administration, *The Changing Structure of the U.S. Coal Industry: An Update*, DOE/EIA-0513(93) (Washington, DC, July 1993), Table 10.

[14] National Mining Association, *Facts About Coal*, 1996 (data compiled from a National Mining Association survey of major producers may not be all inclusive), p. 14.

[15] Energy Information Administration, Form EIA-7A, "Coal Production Report."

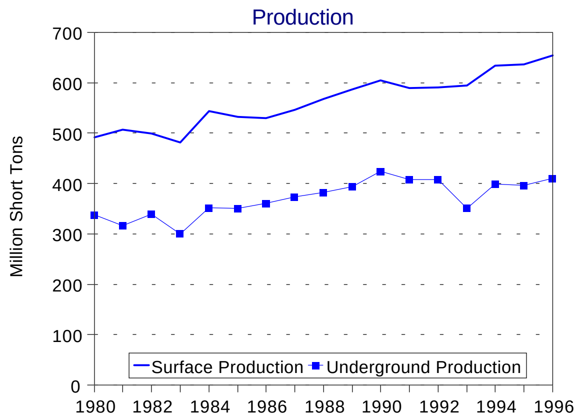
[16] Energy Information Administration, *The Changing Structure of the U.S. Coal Industry: An Update*, DOE/EIA-0513(93) (Washington, DC, July 1993), Table 13.

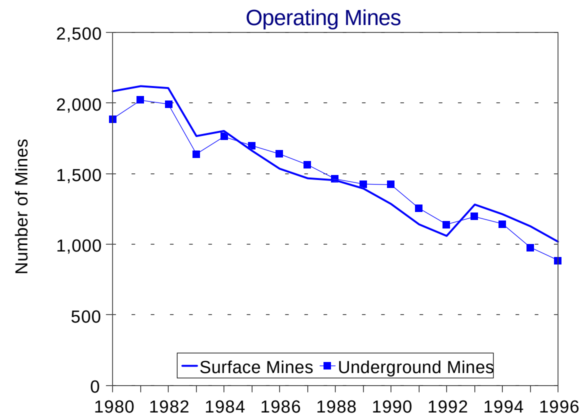
[17] Energy Information Administration, *Performance Profiles of Major Energy Producers 1995*, DOE/EIA-0206(96) (Washington, DC, January 1998), p. 82.

[18] *Ibid.*, p. 54.

[19] Electric Power Research Institute, *Fuel Management for Competitive Power Generation-A Guide to Managing Change*, TR-107890 (April 1997), pp. 6-13.

Figure 4. Production and Number of Operating U.S. Coal Mines





Sources: Energy Information Administration, Form-EIA-7A, "Coal Production Report."

petroleum companies with significant coal holdings, recently sold its coal assets.[20]

On the other hand, the deregulation of electricity markets may drastically affect the current composition of the coal industry, if many multi-fuel conglomerates are formed to maximize the flexibility and reliability of their fuel supply options. Competitive pressures in the electric power industry will provide incentives to coal producers to reduce costs through mergers and acquisitions. This option will appeal to those producers who hope to take advantage of economies of scale and achieve greater flexibility in managing supply contracts with electric power generators. In the short run, this will increase concentration, but will also lead to further reductions in coal prices, increases in productivity, and larger mine operations. In the long run, however, increasing concentration in the industry could result in less competitive pressure among producers, at which point prices may level off or rise.

One way to reduce costs is to shift production to larger, more efficient, low-cost mines. This is reflected in the trend of mine closings over the past three decades. Between 1980 and 1996, the total number of coal mines fell by more than half, with the average mine in 1996 producing more than 2.5 times the 1980 level (Table 2). In addition, production at the largest mines is becoming increasingly concentrated (Table 3). By 1996, mines producing more than 1 million short tons represented nearly three-quarters of total output, and the largest 20 mines were responsible for 30 percent of total coal production. Mine closures also show relatively more underground mines than surface mines being closed. The resulting shift toward surface mines, coupled with the shift toward predominantly large surface mines in the West, increased the market share of surface-mined coal (Figure 4).

Surface mines have lower production costs per ton than underground mines, as can be seen in the lower minemouth prices of coal from these mines (Figure 5). For surface mines in the 500,000 to 1,000,000 short-ton range, prices at the minemouth in 1996 were 18 percent lower than those of underground mines. The difference was even more dramatic for surface mines that produced more than 1 million tons. Overall, the production cost per short ton for surface mines is less than half that for underground mines, reflecting the economies of scale of larger mines, the highly productive thick seams, and the low overburden ratios (cubic yards of overburden per ton of coal in the seam) of western surface mines.

Coal Industry Investment Trends

Opening a large coal mine requires a substantial investment. Also, planning, acquiring property rights, developing access, purchasing capital equipment, developing the mine and support facilities, and covering startup costs extend over several years before the mine is fully operational. Thus, potential investors in new mines face the challenge of recovering and earning a return on their invested capital.

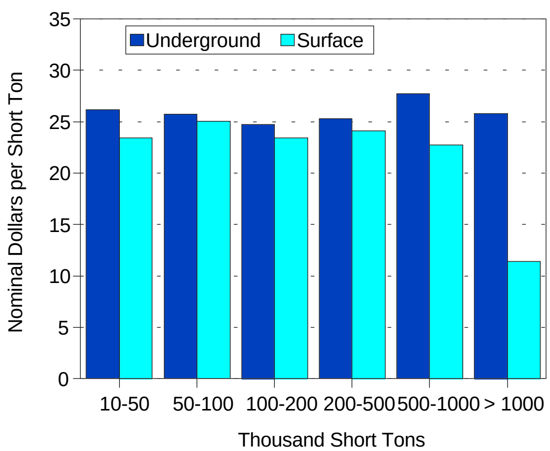
[20] Fieldston Publications Inc., *Coal Daily*, Vol. 2, No. 112 (June 9, 1998), p. 1.

Table 3. Coal Production by Mine Size
(Percent of Total Production)

Mine Production (Short Tons)	1970	1980	1990	1996
1,000,000 and over	--	44.4	63.5	74.3
500,000 to 999,999	59.6	15.3	11.1	10.5
200,000 to 499,999	14.0	16.7	12.8	8.9
199,999 and below	26.3	23.6	12.7	6.2

-- = Not applicable.
Note: Components may not add up to 100.0 percent due to independent rounding.
Sources: U.S. Department of the Interior, Bureau of Mines, *Mineral Yearbook 1970*, "Coal—Bituminous and Lignite" (Washington, DC, 1972), Table 8; Energy Information Administration, *Coal Production 1980*, DOE/EIA-0118(80) (Washington, DC, May 1982), Table 5;*Coal Production 1990*, DOE/EIA-0118(90) (Washington, DC, September 1991), Tables 1 and 4; and *Coal Industry Annual 1996* (DOE/EIA-0584(96) (Washington, DC, November 1997), Table 6.

Figure 5. Average Minemouth Price per Ton by Mine Type and Mine Size, 1996



Sources: Energy Information Administration, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997).

The traditional method of financing coal mines is "project finance." By this debt financing method, each mine is treated as a separate business entity that must stand on its own financially. Lenders have limited or no recourse to the mining company itself. The mine entity obtains a loan based on projections of its expected future revenues and costs. A basic requirement for project finance is a contract (or contracts) with customers monetarily able to repay the debt. The financing agreement with the mine dedicates a certain portion of revenues from the contract(s) to repay the loan. The assurance of the revenues from the contract gives the mine entity its financial credibility. Project financing of coal mines has typically been based on long-term coal sales contracts with electric utilities.

Power generators now want contract terms that are shorter, with frequent re-openers to adjust the price of coal to the market, making the use of project finance techniques much more difficult. This problem is analogous to that of merchant power plants, which have no guaranteed market for electricity. In this new business environment, most financing will be done on a corporate balance sheet basis rather than through project finance. Investors—both equity and debt—will most readily fund mining companies that are large, diversified (even international), low cost, and financially strong. Such companies are likely to invest only in proposed new coal mines that offer production costs so low that they are viable under most future market scenarios.

Only about a dozen financial institutions specialize in financing coal mines, and these institutions see project finance as increasingly difficult for new mines. Investors also face higher risks due to the increased uncertainty facing coal producers. Those firms that are able to obtain debt financing will generally use more balance sheet financing, which favors the large and most profitable companies. Smaller firms will find it difficult to secure financing or to use balance sheet financing, leading to a further consolidation of the coal industry, which many analysts had considered to be nearly complete.

Effective risk management tools may help to provide the needed revenue stability to assist in securing financing for new investment. The amount of equity required will increase, and a broader set of investors, perhaps including international investors, may enter the market. One bond rating agency predicts that, during the next several years, mining projects will attempt to raise rated debt (bonds) in the broader markets as an alternative to specialized lending sources.[21]

These financing considerations are likely to provide even more pressure to accelerate the consolidation of the coal industry. As mines become larger and more capital intensive, more capital will be needed for each mine. Also, small- and medium-sized coal producers will find it increasingly difficult to obtain financing, as their operations are too small to cover the increased capital investments. This, in turn, will favor the larger coal producers that have greater resources.

Not all financial analysts agree with this perspective, however. Some question whether the consolidation of the coal industry can go any further, arguing that additional gains from consolidation may not be feasible.[22] Some say that smaller operations, where the mine management has an ownership interest, have a stronger incentive to be profitable and may be run better than a mine operated by a large corporation.[23]

Changing Coal Prices

Whatever the outcome of coal industry consolidation, coal producers will increasingly face tough, ongoing competition based on low but volatile prices. They must respond to this challenge by finding ways to sell coal profitably at lower prices and to address emerging price and volume risks. Their efforts will focus on (1) cutting costs, (2) managing risks, and (3) redefining customer relationships. Some coal producers will be able to do this better than others, and they will have a competitive advantage.

Cutting Costs

Several methods are available for coal producers to reduce costs. First, they may improve the management of coal mining operations to increase efficiency. Second, mining firms may invest in more productive equipment to lower production costs. Third, consolidation may reduce costs through economies of scale and, at the same time, increase the producer's negotiating power to deal with large power generation and transportation counterparts. Another strategy to cut costs is to close down high-cost mines and/or to restructure some of them to be more economical. Efficient companies may be presented with opportunities to buy inefficient mines for a low price, make the necessary restructuring investments, and turn them into financially viable operations.

Such cost-cutting measures are not new. The coal industry has resorted to these measures to remain competitive and viable over the past decade to survive previous shakeouts. The coal industry’s ability to change the way it structures its operations, utilizes labor, and adopts new technologies has resulted in substantially lower mine costs, which, when coupled with lower coal transportation costs, explains why coal prices to power generators have declined steadily in both nominal and real dollar terms over the past decade (Table 4). The emerging electric power industry deregulation and restructuring add to the ongoing pressure for coal producers and carriers to reduce costs. The coal industry is certain to continue to use those cost-cutting measures that have worked in the past as well as other new measures (such as forging new business relationships with power generators and coal carriers).

Mine Productivity and Labor Issues. Mine productivity, measured in tons per miner hour, has increased significantly over the past decade and a half, by 6.9 percent per year from 1980 to 1996, with gains for surface mines being slightly higher than for underground mines (Table 5). The gains are attributable primarily to capital investment in more efficient technology, the closing of less efficient mines and the

Table 4. Average Coal Prices Delivered to Electric Utilities
(Dollars per Short Ton)

Price	1970	1975	1980	1985	1990	1996
Nominal	7.13	17.63	28.76	34.53	30.45	26.45
Real (1996 dollars)	25.78	46.16	52.54	48.46	35.85	26.45

Sources: **1970-1975:** Bureau of Mines, *Minerals Yearbook*, “Coal—Bituminous and Lignite” and “Coal—Pennsylvania Anthracite” chapters; **1980-1996**: Federal Energy Regulatory Commission, Form 423, “Monthly Report of Cost and Quality of Fuels for Electric Plants.”

[21] A. Simonson and D. Nayduch, “Project Finance Criteria: Mining Projects,” *Standard & Poor's Global Project Finance* (March 1997), pp. 18-21.

[22] Personal communication, Steve Fiscor, Executive Editor, *Coal Age* (July 3, 1997).

[23] Personal communication, Al Bertoni, National City Bank, Kentucky (July 28, 1997).

Table 5. Coal Mine Productivity by Mine Type
(Short Tons of Coal Produced per Miner Hour)

Year	Overall	Under-ground	Surface
1970	2.36	1.72	4.53
1975	1.83	1.19	3.26
1980	1.93	1.20	3.21
1985	2.74	1.78	4.24
1990	3.83	2.54	5.94
1996	5.69	3.57	9.05

Sources: **1970-1975:** Bureau of Mines, *Minerals Yearbook*, "Coal-Bituminous and Lignite" and "Coal-Pennsylvania Anthracite" chapters; **1980-1990:** Energy Information Administration, *Coal Production Report,* DOE/EIA-0118, various annual issues; and *Coal industry Annual 1996,* DOE/EIA-0584(96) (Washington, DC, November 1997), Table 48.

opening of more productive mines, and the regional shift of production toward western coal. A more experienced work force and more flexible working conditions have also contributed to productivity gains.

Coal prices and mine productivity are closely related. As prices fall, coal producers must make more efficient use of all assets—including labor—for improved productivity, or they will lose profits. Inefficient mines eventually close, improving the average productivity for the industry. Conversely, during periods of high prices, high-cost mines can be opened profitably, thus lowering average productivity. The relationship between coal prices and productivity gains is circular: productivity gains allow coal prices to be lowered and price declines induce actions by coal producers that raise productivity and cut costs.[24] This has been the case in recent years, and electric power deregulation is expected to reinforce this trend through price pressure on coal producers.

Labor composes roughly half of total mining costs, making it a major cost component for coal producers.[25] As a result, there has been substantial substitution of capital for labor in the coal industry over the years, yielding significant productivity gains and mine cost reductions. With increasingly efficient equipment and technologies applied to coal mining, the number of coal miners has declined over the years—by 5.8 percent per year, from 154,645 in 1986 to 83,462 in 1996.[26] During the same period, total coal output has increased on average by 1.7 percent per year.

The United Mine Workers of America (UMWA), the largest union of coal miners with nearly 33,000 members, is opposed to electric industry deregulation. The union is concerned that efforts by coal producers to cut costs in a deregulated electricity market will eventually lead to wage cuts and layoffs for miners (as power generators look to reduce coal prices).[27] Recently, the UMWA began a major lobbying effort to build grass roots opposition to any legislation in Congress to deregulate the electric utility industry by 2000.[28]

In the past decade, coal producers so far have moved to make capital investments that increase mine productivity and cut labor costs. Is there room for further reduction in labor costs? One possibility is that the similarity of operations between surface mines and the construction industry may create downward pressure on wages in some surface mines. An influx of workers from the construction industry moving into surface mining operations may create a wage structure that resembles the construction industry, with resulting lower average wages.[29]

Innovation in Mining Technology. Coal producers have been able to raise productivity and lower costs, in part, by adopting new, more efficient production technologies. Underground coal mining has advanced from the conventional "room and pillar" method to the more efficient continuous mining method. Since about 1980, highly productive longwall mining has greatly expanded in the United States, contributing significantly to productivity gains in underground mining (Table 6).[30] In surface mining, productivity gains have come from the use of progressively larger draglines to excavate coal, as well as larger trucks to haul it. The industry has a history of innovation and of moving quickly to adopt new, more efficient mining methods and technologies. Such innovation can be expected to continue in the future.

[24] Electric Power Research Institute, *Central Appalachia: Coal Mine Productivity and Expansion*, IE-7117 (September 1991).
[25] *Ibid.*
[26] Energy Information Administration, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997), Table 40.
[27] Personal communication, Doug Gibson, Director of Communications, United Mine Workers of America (June 24, 1997).
[28] N. Knox, "U.S. Electric Deregulation Loses Steam," *The Detroit News* (June 19, 1997).
[29] Personal communication, Leslie Coleman, National Mining Association (June 1997).
[30] Energy Information Administration, *Longwall Mining*, DOE/EIA-TR-0588 (Washington, DC, March 1995), Chapter 4.

Table 6. Coal Production by Mine Type
(Million Short Tons per Year)

Mine Type	1970	1975	1980	1985	1990	1996
Surface Mining	272	361	492	533	605	654
Underground Mining	341	294	338	351	425	410
Longwall Mining	7	9	26	61	115	194
Total	**613**	**655**	**830**	**884**	**1,029**	**1,064**

Sources: **1970-1975:** Bureau of Mines, *Minerals Yearbook*, "Coal—Bituminous and Lignite" and "Coal—Pennsylvania Anthracite" chapters; **1980-1990:** Energy Information Administration, *Coal Production Report,* (DOE/EIA-0118), various annual issues; and *Coal industry Annual 1996,* DOE/EIA-0584(96) (Washington, DC, November 1997).

Competitive pressures for lower coal prices will continue to encourage coal producers to take advantage of new technologies that increase productivity. The most promising new technologies currently on the horizon include further improvements in underground mining methods, the use of larger equipment in surface mining operations, and computerization applied to a wide range of administrative and mine maintenance activities.

Technological improvements in underground mining methods have been a major driving force for the substantial gains in productivity over the past decade, particularly the spread of longwall mining. Further gains may be obtained from more automated longwall operations (reducing labor requirements), faster advancing longwalls with deeper cutting shearers (to increase extraction rates), and more rapid and reliable conveyors (to speed coal haulage).[31] Increased use of computer controls with "expert systems" that draw upon human experience are also expected to improve longwall productivity. Real-time monitoring of the cutting blades can increase or reduce pressure to take full advantage of the equipment while reducing wear and increasing reliability.

Faster continuous miners also offer potential improvements in productivity. A mid-1970s continuous miner would produce at 5 tons per minute or less. Today's continuous miners can cut 10 tons per minute and load at 15 to 20 tons per minute.[32] Increased output and reliability can be achieved through improved drill bits and roof bolting technology. Increased reliability and more repairable equipment offer further gains in productivity. The use of self-diagnostic equipment that can direct repair personnel to the source of the problem will cut repair time.

In surface mining, increasing productivity is also closely tied to improvements in technology. Gains have come from the use of larger, more powerful draglines and dozers for strip mining and larger coal loaders and haulers to carry the coal. Manufacturers have noted that sales of trucks below 200 tons capacity have recently dropped, while sales of trucks above 200 tons have increased. Recently, the first 300-ton trucks have been introduced in the Powder River Basin.[33] New designs in buckets also offer improved performance for large draglines.

Technological innovation can also improve administrative and auxiliary work outside the mine. Using electronic data interchange (EDI), coal producers can speed the processing of purchase orders and billing. EDI can also interconnect the computer systems of coal producers, transporters, and power generators. The Rail-Utilities-Mining Group, formed in October 1996, is developing shipment, scheduling, routing, and payment standards for coal and coal transportation services.[34] Industry standards for coal quality analysis results and invoices are also under development.

Improvements in the technology for handling coal are also possible. One example is the on-line coal quality analyzer, which provides real-time sampling of coal quality. This ensures consistent coal quality and the ability to meet varying specifications for different customers—capabilities that will be valuable in a competitive short-term market. Real-time analysis of coal may also facilitate the creation of coal hubs, where

[31] *Ibid.*, Chapter 5.
[32] Electric Power Research Institute, *Central Appalachia: Coal Mine Productivity and Expansion*, IE-7117 (September 1991), pp. 2-11.
[33] R.A. Carter, "Battle of the Behemoths," *Coal Age* (January 1997), pp. 24-25.
[34] J.P. Bradshaw, "Doing Business in Cyberspace," *Mining Voice* (March / April 1997), pp. 20-25.

coals are blended to meet a wide variety of specifications. By interfacing with the accounting systems of the coal producer and power generator, on-line analyzers can also be used for payment purposes.[35] Their use will reduce laboratory and labor costs and ensure timely coal quality adjustments to the price of coal on the basis of coal quality.

Managing Risks

Coal producers will need to manage new risks arising from uncertainties in the deregulated electricity market. Power generators, facing increasingly uncertain electricity prices and sales volumes, will focus on managing the "spark spread"—the price differential between electricity and fuel—both to cover costs and to earn a return. They can manage the spread, to some extent, with risk management instruments, such as futures or options contracts. They will also try to manage their risks by sharing them with fuel suppliers, for example, by linking fuel purchase arrangements to electricity market conditions.

In addition to uncertainties arising from risk management efforts by power generators, coal producers must also deal with new uncertainties of their own. Coal contracts are growing shorter, more coal is sold on the spot market, and sales to power generators are becoming more uncertain. This uncertainty creates larger price volatility, and the resulting risks can have a significant impact on profitability unless steps are taken to manage them. A variety of methods or tools—financial, physical, and organizational—are available for coal producers to manage these new risks.

Coal producers may mitigate price risks by using financial risk management tools, such as forward or futures and options contracts. Although futures contracts for coal are not yet offered by any institutionalized exchange market, when offered, they will allow coal producers and power generators to lock in a coal price in the short to intermediate term. If the market coal price declines, the producer has the option either to sell the coal at the contract price or to sell the futures contract.

Because they are standardized in terms of quantity, quality, and delivery requirements, futures contracts are traded on commodity exchanges, allowing firms to use futures contracts markets as a means of price discovery as well as for hedging risk. Futures contracts have a small degree of flexibility in the contract specifications, but their homogeneity is the key to their usefulness.

The development of standard futures contracts for coal has lagged behind those for natural gas and electricity because coal prices are less volatile than those of other energy commodities and coal is more variable in quality. The New York Mercantile Exchange (NYMEX), a major futures exchange for oil, natural gas, and electricity, received approval from the Commodity Futures Trading Commission on May 11, 1998, for a Central Appalachia coal futures contract, which it hopes to offer in late 1998 or early 1999.[36] This contract will cover clean-burning coal with delivery to ports along the Big Sandy River and the Ohio River from Big Sandy, Kentucky, to Huntington, West Virginia. NYMEX is considering a Powder River Basin coal futures contract as well.

Until coal futures contracts are established, coal producers can use (non-standard) forward or options contracts to reduce price risk. Arco Coal Sales has offered call options on its coal, with delivery dates between 1999 and 2004.[37] Kennecott Energy is reported to have sold options to power marketers for delivery of PRB coal in 1999.[38] Zeigler Coal Holding is also rumored to be selling coal options, but Zeigler officials will say only that they are interested in the idea.

A coal producer can also purchase or sell an electricity or natural gas futures or options contract, a practice called "cross-commodity hedging." For example, a coal producer may purchase an option to buy electricity at a "strike" price of $25.00/MWh. The coal delivery contract may specify a price of coal that translates into $25.00/MWh. If the price of coal increases to a level that translates to $28.00/MWh, the producer can sell the coal on the spot market, realizing a profit of $3.00, and instead provide electricity to its customer through the futures contract.

The creation of regional "coal hubs," where coal can be blended and delivered to the ultimate consumer by multiple modes of transportation, has been proposed as a physical method to manage risks.[39] A coal hub would provide a common regional delivery point where coals

[35] R.C. Woodward and B. Lee, "On-line Analysis Evolves," *Coal Age* (March 1997), pp. 22-25.
[36] Pasha Publications, Inc., "Feds Approve Coal Futures Contract," *Coal Outlook* (May 18, 1998).
[37] Pasha Publications, Inc., "Arco Seeks Bids on Coal Option Contracts," *Coal Outlook* (March 9, 1998).
[38] Pasha Publications, Inc., "Kennecott Sells Options for Future PRB Delivery," *Coal Outlook* (January 26, 1998).
[39] M . Hyrnick, "Management of Coal Options Through Fuel Flexibility," 1995 EPRI Fuel Supply Seminar, New Orleans, LA.

can be traded and blended to meet the specifications of a wide variety of coal users, allowing coal producers and generators greater flexibility in transactions. The feasibility of coal futures contracts would also increase with the creation of hubs representative of specific markets. To date, however, no coal hubs have been created.

Coal producers may also reduce risks through diversification of their customer base, allowing them to reduce market risk by becoming less dependent on any one customer. For example, some producers export a portion of their output, reducing the risks associated with the domestic market. Exports traditionally make up a small part of U.S. production—only about 8.5 percent in 1996[40]—but increased uncertainty in the domestic U.S. market may make international markets more attractive. Exports may be a hedge against declining U.S. prices,[41] but they may not be an option for all producers. Indeed, export markets are highly volatile and have their own risks.

Other potential approaches to risk management create closer ties between companies. Kennecott Energy recently signed an alliance agreement with Enron Capital & Trade Resources making each the preferred provider of the other in joint coal/energy deals.[42] Traditional mergers, both with other producers (horizontal integration) and with customers (vertical integration), are also options. Each of these organizational methods allows parties with complementary needs and resources to share the new risks within the deregulated electricity market.

Changing Customer Relationships

The deregulation of electricity markets is already changing the relationship between coal producers and their power generation customers in significant ways: coal supply contract terms are changing in that (1) purchase arrangements are becoming shorter in duration and existing contracts above market price are being renegotiated; and (2) new types of business arrangements are emerging. Many of these new relationships differ greatly from the traditional arms-length relationships between electric utilities and their fuel suppliers.

Because both electricity generators and coal producers will need to focus on meeting the demands of the competitive electricity marketplace, both entities will have a greater commonality of interest than they had in a regulated marketplace. Cooperative relationships between fuel buyers and sellers are already emerging, with the objective of sharing opportunities and risks in the electric power marketplace. Vertical integration may even be an option.

Changing Contract Terms. The procurement of coal by power generators traditionally has involved a mix of contracts of various lengths as well as spot purchases. Deregulation of the electric power industry will create uncertainty about electricity and fuel prices and their volumes due to the lack of guaranteed markets for electricity. Electricity sales will vary over time and more widely across customer types. The result will be a dynamic market situation in which the parties involved must be able to respond quickly to changing market conditions. Faced with these uncertainties, committing to conventional long-term coal contracts will be increasingly difficult for power generators.

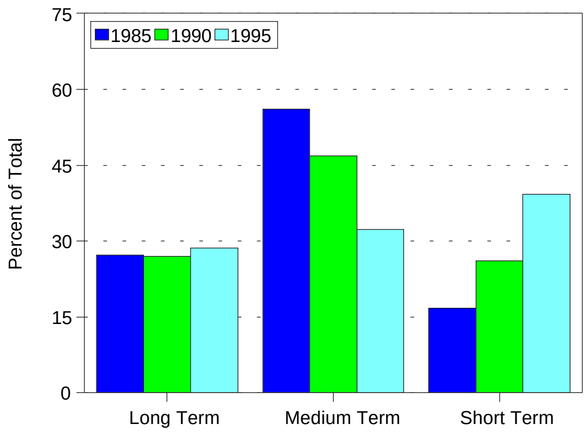
Large amounts of coal have traditionally been purchased under long-term contracts, some of which exceeded 30 years. However, contract durations have increasingly become shorter. In terms of tonnage share, deliveries of coal under contracts of shorter duration (less than 10 years) more than doubled from 17 to 39 percent between 1985 and 1995, while medium-term (11 to 30 years) deliveries shrank from 56 percent to 32 percent, and longer term (over 30 years) deliveries remained relatively unchanged from 27 percent to 29 percent during the same period (Figure 6). As coal prices have fallen over the past decade, and are expected to continue falling for some time to come, power generators have been shortening contract durations.

Uncertainties in deregulated markets will lead power generators increasingly toward shorter term, more flexible arrangements, including spot market purchases. (Spot market coal purchases currently account for less than 20 percent of all utility coal receipts. Their prices are substantially lower than contract prices.)[43] New coal contracts tend to have re-openers and other clauses that increase flexibility or pass on some of the electricity market risks to coal producers.

One new type of contract that has emerged over the past several years ties the price of coal to the price of

[40] Energy Information Administration, *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997), Table 76.
[41] A. Blumenfeld, "Exports to 'Swing' into Favor in the United States," *Coal Age* (July 1997), pp. 35-36.
[42] Pasha Publications, Inc., "Enron, Kennecott Form Alliance," *Coal Outlook* (March 9, 1998).
[43] Energy Information Administration, *Electric Power Monthly, September 1997,* DOE/EIA-0226(97-09) (Washington, DC, September 1997).

Figure 6. Distribution of Contract Coal Tonnage by Contract Duration



Source: Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October, 1995), Table 32, and the Coal Transportation Rate Data Base.

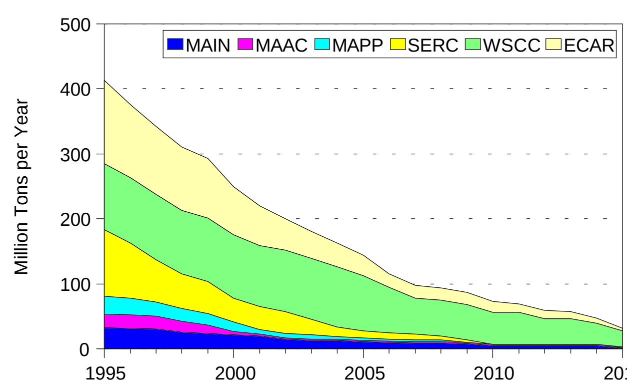
wholesale electricity. This is a way for power generators to ensure that their fuel costs will remain competitive. In some cases, the coal price is linked to specific electricity market transactions. Through this type of coal supply contract, the coal producer and the power generator share both the opportunities and the risks.

While new coal supply contracts are becoming increasingly short term, existing long-term contracts are also being renegotiated for lower prices. Many of the long-term coal contracts currently in force were signed when the electric power industry was regulated. The expectation at that time was that fuel costs under these contracts could be recovered from ratepayers through the normal ratemaking process. For many utilities, this included a "Fuel Adjustment Clause," which, subject to prudence review, automatically passed on all changes in fuel costs to customers. Since these contracts were entered, however, coal prices have declined substantially, making the price of coal under many remaining contracts higher than the current market price. It is no longer clear whether the cost of coal under these above-market priced contracts can be recovered from electricity customers once the industry is fully deregulated. Above-market contracts are making many generators uncompetitive in the current wholesale market. As a result, above-market contracts are considered to be potential "stranded liabilities" that may not be recovered.

What happens to above-market contracts will have an impact on power generators, their coal suppliers, and the overall coal market. Many will be renegotiated, bought out (as was done in the past), or will expire over the next several years. In order to avoid financial losses, power plant operators will need to ensure that these contracts are renegotiated or terminated before their plants are exposed to the full effects of open competition. Thus, timing is particularly important.

A recent analysis of coal supply contracts in the six National Electric Reliability Council (NERC) regions most dependent on coal shows that above-market contracts constitute a large portion of the coal contracts in force, but that over half will expire by 2005 (Figure 7).[44] At the beginning of 1995, 413 million short tons out of 492 million short tons under long-term contract in those regions were above market prices. This tonnage was estimated to decline to 342 million short tons by the end of 1997, but 144 million short tons will still remain in effect at the end of 2005. Of this, about 27 million short tons will be for coal from "captive" mining operations, mostly in the Western Systems Coordinating Council (WSCC), where the plant operators also own the mines.

Figure 7. Above-Market Contract Coal Returning to Market, 1995-2015



Source: Hill & Associates, Inc., *Generating Cost Study, 1996* (Annapolis, MD, 1996).

[44] Hill and Associates, Inc., *Generating Cost Study, 1996* (Annapolis, Maryland). The six regions are the East Central Area Reliability Coordination Agreement (ECAR), the Mid-Continent Area Power Pool (MAPP), the Mid-Atlantic Area Council (MAAC), Mid-American Interconnected Network (MAIN), Southeastern Electric Reliability Council (SERC), and Western Systems Coordinating Council (WSCC). "Above market" in this study is defined as above the price that would be obtained for a new coal contract—typically about 5 percent above the spot price. This premium reflects the added benefit in terms of reliability, security of supply, and coal quality assured by contract purchase.

Coal tonnage under above-market contracts and their expiration dates vary among the NERC regions. The East Central Area Reliability Coordination Agreement (ECAR) region originally had the most above-market contracts (128 million tons in 1995); however, all but 30 million tons will expire by 2005. Declines in all the other regions except WSCC are similarly precipitous. In WSCC, 85 million of the 101 million tons of above-market contract coal outstanding in 1995 will still not have expired by the end of 2005. This largely reflects the fact that many of the power plants in this region are located at the minemouth, and some are captive operations.

Pressures on both electricity generators and coal producers to renegotiate terms of above-market contracts (or to restructure captive mining operations) will be intense, as coal sales to power generators ultimately depend on the amount of electricity the generators can sell.[45] Coal producers may be more willing to renegotiate above-market contracts than before to avoid seeing their customers become uncompetitive and nonviable.

Coal contracts can be above market price due to high transportation rates. Thus, coal carriers may also feel pressure to renegotiate their transportation rates. If the carrier has a degree of market power (as discussed below), however, the generator's negotiating leverage may be more limited.

While above-market coal contracts will eventually cease to be a problem for most electric utilities, such contracts have been an important source of revenue for many coal producers. Expiration and renegotiation of these contracts, which have ensured profitability and stability for coal producers, may create financial difficulties for many coal producers. The renegotiation and expiration of above-market contracts in the past have already reduced the contract premiums substantially. For example, in the Southeastern Electric Reliability Council (SERC) region, contract premiums dropped from 23 percent in 1990 to 10 percent in 1996.[46] With fewer long-term contracts, coal producers will sell more coal on spot markets, which are more competitive than contract markets and bring lower prices (and profits) to the coal producers.

New Business Arrangements. Increasing competition is forcing many electricity generators to rethink how they deal with fuel suppliers. New cooperative relationships are, in some cases, replacing the traditional arms-length, adversarial purchasing practices. Opportunities are now emerging for coal producers, railroads, and electricity generators to develop new strategic relationships, causing new arrangements, such as strategic alliances, "coal-by-wire," "tolling," and "energy swaps" to emerge.

By working together, coal producers, carriers, and generators can coordinate their operations both to take advantage of opportunities and to create economies. For example, they can share market information and structure deals to realize specific opportunities. Coal producers and railroads can jointly schedule transportation to reduce downtime, and closer coordination can reduce the size of inventories and move the parties closer to "just-in-time" deliveries. Taken a step further, coal producers may be able to help manage coal inventories at some power plants. In addition, centralized rail fleet operations may allow carriers to reduce the number of cars they need, reducing capital costs, and master contracts that consolidate volumes over multiple plants may reduce rates and allow power generators to optimize shipments of coal among power plants.

Strategic alliances offer one avenue for cooperating to share opportunities and risks. A number of major coal companies and electricity generators are currently seeking such relationships. For example, Cyprus Amax Minerals Company has announced that it has formed strategic alliances with 12 of what it calls "leadership utilities," including coal tolling arrangements.[47]

In tolling, a power marketer (or fuel supplier) contracts with the operator of a generating plant to convert the power marketer's fuel 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 owns the electricity output and is responsible for selling it. Several coal tolling arrangements have recently been announced (Table 7). A power plant with underutilized generation capacity may generate greater revenues by tolling the available plant capacity, and the power marketer may have access to low-cost fuel and have power marketing opportunities.

Tolling as currently practiced is a temporary opportunity when the situation is right, not a permanent relationship. It is typically used when a plant operator's

[45] C. Seiple, "At-Risk Generation: Implications for the Coal Industry," *Coal Age* (March 1997), p. 28.

[46] T. A. Myers and B. O'Neill, "Converging Coal Prices in Retail Power Markets," *Coal Age* (June 1997), p. 42.

[47] R.D. Rosenberg, "Who Wins in a Competitive Power Market: Gas? Coal? Or Rail & Mining Interests?" *Public Utilities Fortnightly* (April 1, 1997), pp. 41-45.

Table 7. Announced Coal Tolling and Energy Swap Transactions

Toller	Utility	Size of Deal	Plant	Type of Deal
Vitol Gas & Electric (VGE)	Public Service Electric & Gas	750,000 tons	Hudson	Coal Tolling
VGE	Midwest utility	700,000 tons	NA	Energy Swap
VGE	Western utility	400,000 tons	NA	Energy Swap
VGE	Lower Colorado River Authority	200,000 tons	NA	Energy Swap
VGE	LCRA	500,000 tons	Fayette	Energy Swap
VGE	Commonwealth Edison	NA	NA	Energy Swap
Louisville Gas & Electric (LGE)	PSEG	750,000 tons	Hudson	Coal Tolling
LGE	Ohio Edison	945,000 tons	Burger	Coal Tolling
Entergy Services	Southern Co.	60,800 MWh	Crist	Coal Tolling
Carolina Power & Light	Appalachian Power	NA	Amos	Coal Tolling
Detroit Edison	Wisconsin utility	NA	NA	Coal-by-Wire
Cyprus Amax Coal	Ohio Edison	800,000 tons	Burger	Energy Swap
Zeigler Coal	NorAm Energy Services	100,000 tons	Springfield, IL	Coal Tolling
CINergy	East Coast utility (VA/MD)	800,000 tons	NA	Coal Tolling
Lakeland Electric & Water	NP Energy	9,000 tons	NA	Coal Tolling

NA = Not available.

Sources: **VGE:** *Coal Outlook*, 20:7; *Coal Outlook Supplement* (February 3, 1997);*Coal Outlook*, 20:47; *Coal Week*, 23:3; *Coal Outlook*, 21:20; *Coal Outlook*, 21:17; **LGE:** *The Energy Daily* (February 18, 1997); **LGE:** *Power Markets Week* (June 24, 1996); **Entergy**: *Power Markets Week* (February 12, 1997); **Carolina P&L:** *Coal Outlook Supplement* (August 5, 1996); *Coal Outlook*, 20:9; **Detroit Edison:** *Coal Outlook*, 20:21; **Cyprus Amax:** *Coal Outlook*, 23:2; **Zeigler Coal:** *Coal Outlook*, 21:10; **CINergy:** *Coal Outlook*, 20:27; **Lakeland:** *Coal Transportation Report*, 17:6.

access to power market information and/or low-cost fuel supplies is restricted in some way, or when the plant operator has a different tolerance for risk. A customer may also initiate the process, acquiring fuel and having it converted into electricity by a generator, buying the electricity at a lower price than the same generator could offer. "Reverse tolling" occurs when the value of the coal is greater in the spot market than in the electricity market. An electricity generator may have a stockpile of coal that, if burned, would receive a price in the electricity market that is less than needed to cover its generation cost. Through reverse tolling, the coal is sold on the spot market, and the generator can earn a profit without burning the fuel itself.

Energy swaps are a more flexible arrangement than tolling, in which the parties involved agree to exchange coal, electricity, gas, or cash. For example, a power marketer may arrange to supply a power generator with coal in exchange for electricity. Unlike a tolling deal, the power generator is not obligated to burn the coal, but is free to sell the coal to another party. Moreover, the timing and location of each part of the transaction may vary, provided that a method is agreed upon to assign value to each part.

Tolling, reverse tolling, and energy swap transactions are manifestations of the "convergence" of energy markets, which has emerged from a dynamic power marketplace just since 1995. These methods of doing business reflect the new fluidity in the market as well as the new characters of the players, all of whom are competing for market share and profit. These transactions also show how the inputs and outputs of electricity generation are becoming virtually interchangeable, providing mechanisms for fuel suppliers, electricity generators, and power marketers to operate in each other's markets.

The Role of the Railroads in Competitive Electricity and Coal Markets

The coal industry is facing a double challenge. Just when the major customers of the coal industry are being restructured, the railroads—the dominant transportation mode for coal—have been undergoing a significant consolidation. The role of the railroads in bringing coal to market is vital, and rail industry consolidation is controversial. Any changes in the structure of the railroad industry may affect the economics of both the coal and electric power industries.

Major railroads are merging to create larger companies, and concerns are being raised about their market power. Coal shippers—i.e., coal suppliers and power generators—are concerned that the railroads may seek to capture larger economic rents from them and, as a result, adversely affect their competitiveness. Some fear that by favoring the shippers that provide them with the most profitable traffic, railroads will charge discriminatory rates to others. The railroads contend that competition will be adequate, and they argue that larger operations will reduce costs and improve service and efficiency through economies of scale.

Importance of the Rail Industry to Coal

Although transportation modes differ among the regions, railroads are the most widely used mode of transportation for coal. Nearly 58 percent of all coal delivered to consumers in 1996 involved rail as the primary transport mode (Table 8). Further, average coal hauls are getting longer, reflecting the increased penetration of western coal carried by rail into southern and eastern utility coal markets. According to one study, the average haul of contract utility coal by rail lengthened by 33 percent, from 485 to 643 miles, between 1979 and 1995.[48] Coal is an important cargo for the railroads as well. In 1996, Class I railroads, defined as systems with operating revenues of more than $250 million, received 22.5 percent of their gross revenues from transporting coal, and coal composed 43.8 percent of the total tons of freight hauled by rail.[49]

While the distance coal travels has lengthened, average coal transportation costs have been declining for every mode over the past decade. Although rail rates for coal per ton mile increased slightly in nominal dollar terms, they declined by 51.0 percent in real dollar terms from 1985 to 1995.[50] Such declines (in rates per ton mile) have contributed to the increased competitiveness of more distant western coal sources in eastern markets. The competitiveness of different coal-producing regions is, therefore, sensitive to rail rates, and even small differences in rates can tip the balance in regional competition.

Because of differences in shipping distance and transportation mode, transportation costs vary greatly among different sources of coal. Eastern coal is costlier at the minemouth, but its transportation costs are lower, involving relatively shorter hauls to consumers not just by rail but also by low-cost barge. Low-cost western coal is shipped primarily by rail over great distances, thus involving a larger transportation cost. In 1995, coal transportation costs on average represented 11.8 percent of the delivered price for Interior region coal, 19.9 percent for Appalachian coal, and 51.4 percent for western coal.[51] For some western coal hauls, transportation costs account for up to 75 percent of delivered fuel costs.[52]

Increasing Rail Concentration and Concerns

The first single-company transcontinental railroad, the Canadian Pacific Railway, was completed more than 100 years ago, in 1887. All other North American railroads both before and since have provided only regional service. However, the present trend in the rail industry

Table 8. Coal Transportation by Mode, 1996

Mode	Rail	Water	Truck	Conveyor	Total[a]
Thousand Short Tons	611,674	247,935	99,941	98,934	1,059,892
Share of Total (Percent) . . .	57.7	23.4	9.4	9.5	100.0

[a]Total includes 1,408,000 short tons for which the transportation mode is not known.

Source: Energy Information Administration, Form EIA-6, "Coal Distribution Report." See *Coal Industry Annual 1996*, DOE/EIA-0584(96) (Washington, DC, November 1997), Table 65.

[48] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995), Table 34; and the Coal Transportation Rate Data Base.

[49] Association of American Railroads, *Commodity Freight Statistics* (1997).

[50] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995), Table 37; and the Coal Transportation Rate Data Base.

[51] Energy Information Administration, *Energy Policy Act Transportation Rate Study: Interim Report on Coal Transportation*, DOE/EIA-0597 (Washington, DC, October 1995), Table 50; and the Coal Transportation Rate Data Base.

[52] G. E. Vaninetti and J. J. Valentine, "Outlining the Impacts of Utility Deregulation on Railroads," *Coal Age* (December 1996), p. 51.

is toward increasing concentration, and the possibility that the U.S. rail market may be dominated by two major transcontinental railroads is even being discussed.[53]

In 1970, there were 71 Class I railroad companies. By late 1996, they had been combined into only nine.[54] Among western railroads, mergers over the past 16 years have resulted in only 2 major railroads, Burlington Northern-Santa Fe and Union Pacific-Southern Pacific. The most recent proposed development—the division of Conrail between CSX and Norfolk Southern—will leave only two major lines to serve the eastern part of the country. Currently, 5 companies—Burlington Northern-Santa Fe, Union Pacific-Southern Pacific, Conrail, CSX, and Norfolk Southern—combine to account for 90 percent of total railroad revenue from coal transportation.[55]

Perhaps an exception to the trend toward fewer, increasingly large railroads is a proposed plan by the Dakota Minnesota & Eastern (DM&E) Railroad to add a third railroad option to the PRB coal-producing region. This plan proposes to create a new railroad both by purchasing and upgrading existing track and by investing in new track. If it becomes a reality, the plan will create more railroad competition in the increasingly important PRB coal supply region. With this new railroad, DM&E Railroad hopes to capitalize on new business from utilities not yet using PRB coal in the Midwest and East.[56]

With the railroads carrying the largest share of coal shipments, coal shippers are concerned that the increasing rail concentration may weaken competitive pricing and affect them adversely through higher rail rates. Many coal shippers believe that the rail rates they receive depend on the intensity of competition among the carriers serving them. They argue that increasing concentration among railroads creates fewer choices for coal deliveries. Particularly concerned are "captive shippers," who have only one transportation option. Coal shippers also perceive that railroads can attempt to maximize their profits by favoring coal producers and power generators they think will give them the most profitable traffic.[57] They also claim that duopoly pricing could develop, with railroads implicitly colluding with each other to set prices at higher than competitive rates.[58]

The railroads, on the other hand, contend that competition will be adequate and that, to compete and survive, they need to take advantage of economies of scale through mergers and acquisitions. Reducing costs and improving performance, they argue, will ultimately benefit rail customers through lower transportation costs.[59] They also suggest that a larger geographic scope of company operations may broaden markets for coal producers and offer more coal supply choices for electricity generators.

New Rail Technologies for Moving Coal

The railroads have adopted many cost-cutting measures in the past. They have already reduced train crews where possible (for example, phasing out the brakeman position and leaving only the engineer and conductor to run a train[60]). Further cost savings from reductions in train personnel are unlikely. Future productivity gains are more likely to come from improvements in the capital stock. The old carbon steel cars are being replaced by ones made of lighter materials—stainless steel in the East, aluminum in the West.[61] Ultra-light, high-strength composites are being considered for use in the next generation of cars.[62] Increased use of alternating current locomotives will also improve productivity.[63]

Railroads are continuing to adopt technological innovations that offer more options to their customers and greater flexibility in operations. One such example is the "coaltainer," a specially designed container for

[53] C. Jones, "Whose Pound of Flesh is Extracted by Deregulated Markets?" *Power* (April 1997), p. 19.

[54] Electric Power Research Institute, *Railroad Consolidation and Market Power: Challenges to a Deregulating Electric Utility Industry*, TR-1107301 (December 1996), p. 3-1.

[55] *Ibid.*, p. 3-12.

[56] "Industry Reacts Cautiously to DM&E Project," *Coal Transportation* (June 16, 1997).

[57] Electric Power Research Institute, *Railroad Consolidation and Market Power: Challenges to a Deregulating Electric Utility Industry*, TR-107301 (December 1996), p. 2-2.

[58] R. D. Rosenberg, "Who Wins in a Competitive Power Market: Gas? Coal? Or Rail & Mining Interests?" *Public Utilities Fortnightly* (April 1, 1997), pp.41-45.

[59] Electric Power Research Institute, *Railroad Consolidation and Market Power: Challenges to a Deregulating Electric Utility Industry*, TR-107301 (December 1996), p. 3-2.

[60] D. M. Sawinski, ed., *U.S. Industry Profiles, The Leading 100* (first edition, 1995), p. 506.

[61] Chilton Publications, "Conrail Builds 600 Stainless-steel Rail Cars," *Iron Age New Steel* (September 1997).

[62] G. Welty, "Will Composition Enter the Mainstream?" *Railway Age* (August 1997).

[63] C. Deutsch, "Riding the Rails of Technology," *New York Times* (August 1, 1997).

intermodal transportation of coal. The containers can be transported both by rail and by truck, creating the equivalent of a rail spur without having to build one.[64] This and other new technologies may provide a competitive alternative for power generators who are captive to a single carrier.

Another innovation is the use of real-time satellite monitoring to improve the scheduling and routing of trains through computerized traffic management systems. Electronic data interchange (EDI), already extensively used by most railroads, can be expanded to offer potential improvements in many areas, such as better coordination among coal mines, railroads, and power generators for reduced cycle times and inventory levels. EDI will become increasingly important as more electricity generators move toward "just-in-time" inventory management. Norfolk Southern has already begun marketing this type of service.[65]

Options for Coal Shippers To Increase Rail Competition

Most rail rates are generally negotiated between the shipper and the railroad. As competitive pressures rise, coal shippers will seek to have as many options as possible for their shipments to give them greater leverage in rate negotiations. Such options for shippers include increasing access to alternative modes of transportation, forming new relationships, and using transactions that reduce transportation costs.

Consolidation of the electric utility industry may, in itself, create more choices for power generators. Larger companies, for example, may have more options in plant dispatch, which will enable them to dispatch those power plants getting the best rail rates. In addition, the larger size of the merged power companies may give them leverage to negotiate lower rail rates through volume discounts.[66] Many of the utility mergers that have taken place so far have been between utilities that predominantly use coal.

The most direct approach to fostering competition, where feasible, is to create new or extended tracks, called "spurs," from a power plant to a second railroad line, giving the power company access to a competitive delivery option. Several electric utilities have recently built or are building new spurs (Table 9). Sometimes, the mere threat of building a spur can force railroads to renegotiate prices.

Rates may also be reduced by cooperation among railroads, coal producers, and power generators to increase the efficiency of rail operations. Strategic alliances among coal producers, power generators, and railroads have the potential to control costs and risks in a deregulated market. Shippers and carriers can also work together to create economies of scale. For example, by creating a centralized operation for a group of plants, the railroad can reduce the number of cars in its rolling stock, resulting in lower capital costs.

Table 9. Recent Railroad Spur Development Activity

Utility	Plant	Original Carrier	Status	Connection
Grand Island Electric Dept., Nebraska	Platte	UP	Considering	Burlington Northern Santa Fe
Nebraska Public Power District	Gentleman	BN	Completed	Union Pacific-Southern Pacific
Omaha Public Power District.	Nebraska City	BN	Planned	Union Pacific-Southern Pacific
Houston Power & Light	Parish	ATSF	Completed	Union Pacific-Southern Pacific
Alabama Power Company.	Miller	CSX	Approved	Norfolk Southern
Savannah Electric & Power	McIntosh	CSX	Completed	Norfolk Southern
Western Farmers Electric Cooperative	Hugo	Kiamichi	Underway	Texas, Oklahoma & Eastern
Tennessee Valley Authority	Kingston	NS	Planned	CSX
Gulf States Utility	Nelson	Kansas City Southern	Completed	Union Pacific-Southern Pacific
Mid American	Council Bluffs	BN	Completed	Union Pacific-Southern Pacific
Wisconsin Electric	Pleasant Prairie	UP	Underway	Canadian Pacific Rail

Sources: *Coal Outlook*, 21:17, 21:19, 21:25, 21:29, 21:44, 21:46, and 22:33; *Coal Transportation Report*, 16:16; *Coal Week*, 23:19; *Journal of Commerce*, February 19, 1997.

[64] "A Whole New Way of Moving Coal," *Mining Voice* (March / April 1997), p. 9.

[65] H. J. Holcomb, "How to Break up Conrail in 14,810 Pages," *The Philadelphia Inquirer* (June 24, 1997).

[66] Electric Power Research Institute, *Fuel Management for Competitive Power Generation—A Guide to Managing Change*, TR-107890 (April 1997), pp. 4-8.

"Coal-by-wire" and tolling arrangements, as discussed above, offer new ways for coal producers, power generators, and power marketers to market their products in a competitive electricity market. If a reasonable rail rate is not available for its own plant, for example, a power generator may be able to send the coal to another plant and have the coal-generated electricity delivered through the transmission grid, reducing or saving coal transportation costs. It should be noted, however, that coal-by-wire is, to a great extent, limited by the availability of the transmission grid.

Summary

Electric power industry deregulation will open wholesale and, eventually, retail power sales to competition. Because coal is the major fuel used in electricity generation and electricity generators are the major consumers of coal, the coming changes will present a variety of challenges and opportunities to the coal industry.

Power generators will eventually be unbundled from the integrated electric utility structure and function as merchant plants, with no fixed customer base of present-day ratepayers. Competition among power generators will focus on price cutting and risk management. Attempts to cut prices will focus on fuel costs, the largest component of a power plant's production costs, which, in turn, will put pressure on coal prices. Power generators will not be willing to commit to new, long-term, fixed-price coal supply contracts, and they will seek to renegotiate existing high-price contracts to reduce fuel costs. Fluid electricity markets and increasing numbers of short-term coal transactions will increase the volatility of coal prices and the uncertainty of demand, requiring astute risk management by coal suppliers.

The coal industry has been cutting costs and consolidating production at both the mine and corporate levels for over a decade now. Electric power industry deregulation will continue, if not hasten, these processes. Productivity gains and cost reduction will result from improvements in technology, particularly the computerization of administrative tasks, as well as the use of bigger and more efficient mining machinery. Small firms, unable to take advantage of technological improvements and improve efficiency, will either go out of business or be bought out by larger firms, and large firms are likely to continue to increase in size through acquisitions of small firms or mergers with other large firms.

Coal industry financing will change dramatically under deregulation and will be a new challenge for coal producers, especially small producers who do not have large financial resources. The trend toward shorter contract durations and an uncertain customer base will lead financial institutions to evaluate coal mines on a "balance sheet" basis rather than the traditional "project financing," increasing the pressure on the industry to consolidate.

As coal contracts become shorter in duration and price volatility increases, risk management will be a crucial tool for coal producers to learn about and use in maintaining competitive viability. The most important development in this regard is the coming futures market in coal. Although coal's extreme variability in quality is a problem, NYMEX has one coal futures contract planned for Central Appalachian coal and is considering a Powder River Basin coal futures contract as well. Coal futures markets will not only allow risk hedging but also play the role of a coal price discovery mechanism. Other strategies for reducing risk include merging with other coal producers, creating alliances with customers (both railroads and power generators), vertical integration, and the formation of multi-fuel conglomerates.

The railroad industry, which will also figure prominently in any deregulation scenario, compounds the challenges faced by coal suppliers. Being the dominant carrier of coal, railroads can greatly influence coal transportation costs and, thus, the competitiveness of both coal producers and power generators. Of particular concern is that the increasing concentration of the railroad industry through consolidation may create the potential for the exercise of market power to extract large monopoly rents from coal shippers, with the possibility of changing the economics of coal production, distribution, and consumption at both the national and regional levels. On the other hand, the railroads may continue to lower their coal transportation rates through economies of scale and efficiency gains as they have done over the past years.

Deregulation will change the business relationships among coal producers, the railroads, and power generators. Coal producers may ally with railroads to provide delivered coal on a fixed schedule, allowing power plants to manage their inventories by less costly "just-in-time" methods. Coal producers and electricity generators may engage in profit- and risk-sharing alliances, such as coal tolling, a form of short-term alliance that allows plants to increase utilization rates and lower inventory costs. The strong incentives for the convergence of energy forms will expand to coal.

2. Impacts of Electric Power Industry Restructuring on the U.S. Nuclear Power Industry

Introduction

Nuclear power accounts for about 13 percent of the Nation's electricity generating capacity and about 19 percent of total electricity generation.[67] As the electric utility industry is restructured, the 105 commercial nuclear power plants currently in operation will face increasing competition.[68] The prospect of having to compete on the basis of market value of electricity threatens the continued operation of a number of units. From January 1997 through January 1998, utilities have announced the retirement of five units at four plants before the expiration of their operating licenses (Table 10). In each case, the utility owner calculated that continued operation was uneconomical given the costs of operating the plant, the market value of the electricity, and the long-term prospects for making the plant economical.

The continued operation of the remaining nuclear power plants depends on the ability of each plant owner to recover operating and capital improvement (i.e., capital additions) costs.[69] If revenues under competition exceed operating and capital improvement costs, the plant will probably continue to operate. Plant owners, however, may have stranded costs because of the inability of the plant to generate revenues that fully cover sunk capital costs. By contrast, if revenues do not exceed operating and capital improvement costs and the utility has no real prospect of changing this relationship, the plant will most likely be retired or, if possible, sold to another company that believes it can make the long-run operating costs economical. These decisions and relationships take place on a unit-by-unit basis according to the specific factors affecting the unit, State, and local power market.

This chapter discusses the potential impacts of electric power restructuring on the nuclear power industry. The issues facing the industry include stranded cost recovery, market competitiveness of plants, and the funds needed to cover decommissioning costs. Potential impacts on the nuclear fuel industry are also included.

Stranded Cost Recovery

Under the regulatory frameworks that have prevailed at the State and Federal levels, utilities are permitted to recover all their prudently incurred expenses and to earn a rate of return that fairly compensates the providers of capital.[70] In a competitive market, utilities will charge market rates for their electric power. The market rates will establish the value of the utilities' nuclear assets. If they cover operating expenses but not all the capital charges, the assets will essentially be devalued, but the plants may continue to operate. If the market rates fail to cover operating expenses, however, the plants will most likely be shut down or sold.

Over the past decade, several nuclear plants have been offered for sale in whole or in part. Before prematurely retiring the Rancho Seco plant in 1989, the Sacramento Municipal Utilities District was involved in discussions

[67] Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997), p. 113, and *Nuclear Power Generation and Fuel Cycle Report 1997*, DOE/EIA-0436(97) (Washington, DC, September 1997), p. 89.

[68] A plant comprises one or more units. In common usage, the units are individually and collectively termed "plants." Thus, one speaks of 105 operating nuclear power plants rather than the technically correct 105 operating nuclear units.

[69] Operating costs consist of fixed operations and maintenance costs, variable operations and maintenance costs, and fuel costs. Because of regulatory requirements and operational characteristics, the overhead and fuel costs of nuclear plants are highly fixed. Capital improvement costs cover long-lasting equipment, such as steam generators.

[70] The restructuring concepts discussed in this chapter apply to all investor-owned utilities. These utilities represent about three-fourths of the plant ownership and electricity sales in the United States. The same concepts may also apply to municipal utilities and cooperatives on a case-by-case issue. Municipal utilities and cooperatives self-regulate but are subject to Federal requirements for reciprocity in providing open access and may be subject to State proposals to permit retail choice. No current Federal or State restructuring plan applies to Federal agencies, such as the Bonneville Power Administration or the Tennessee Valley Authority.

Table 10. List of Recent Nuclear Plant Closings as of January 31, 1998

Plant[a]	Location	Size (MWe)	Date of Shutdown	Status
Haddam Neck	Haddam Neck, Connecticut	560	1/97	Following an economic analysis of operations, expenses, and the cost of inexpensive replacement power, the utility—Connecticut Yankee Atomic Power Co.—felt a shutdown was the best option.
Big Rock Point	Charlevoix, Michigan	67	8/97	The plant's small size made generating electricity very expensive. Consumers Energy felt that with only 36 months remaining on its operating license, improvements to the plant that would be needed to meet future regulatory requirements would be too expensive to be economical.
Maine Yankee	Wiscasset, Maine	870	8/97	Maine Yankee Atomic Power Company cited the rising cost of safety measures which made generating electricity too expensive in a market that is opening to deregulation and therefore provides no guaranteed customer base.
Zion 1 and 2	Zion, Illinois	2,080	1/98	Commonwealth Edison Co. cites deteriorating steam generators as the reason the plant was shut down. The company said that the two nuclear units would not be able to produce competitively priced power based upon projected costs of operating and supporting the plant, the amount of electricity it was expected to generate, and the projected price of electricity under deregulation.

[a]Since January 31, 1998, utility owners have announced the early retirement of two nuclear units—Oyster Creek (619 MWe) in Fork River, New Jersey, and Millstone 1 (641 MWe) in Waterford, Connecticut.

Source: **Haddam Neck**— NucNet, "The Operators of the Connecticut Yankee Nuclear Power Plant Have Taken a Final Decision to Close Down the Unit for Financial Reasons after 29 Years of Service" December 5, 1996, Internet – Nucnet@otagbe.ch.; **Maine Yankee**—Ross Kerber, "Owners of Maine Yankee Plant Say It May Be Closed Permanently," *Wall Street Journal* (May 28, 1997), Section B4; **Big Rock Point**—News Releases from Consumers Energy, "Rock Nuclear Plant Closing" (June 11, 1997), web site www.cpco.com/news/release_274.html; **Zion**—News Briefs, "ComEd to close Zion," *Ux Weekly* (January 19, 1998), pp. 3-4.

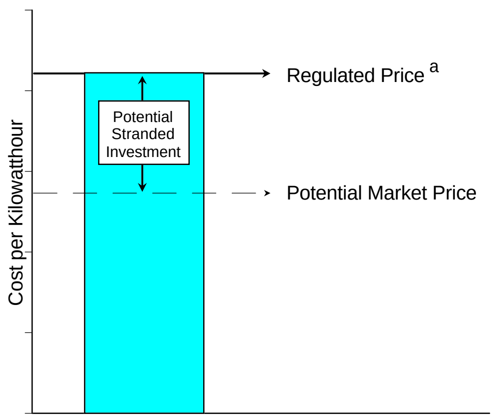
with Duke Power, Bechtel, and others about a potential sale. In the late 1980s, Consumers Power Company evaluated selling its Palisades plant, located in South Haven, Michigan, to a consortium led by Westinghouse. In 1996 and 1997, the owners of Maine Yankee plant held discussions about selling the plant to Philadelphia Electric Company (PECO). Ultimately, none of the plants was sold.

Currently, General Public Utilities (GPU) has offered for sale both its nuclear units, Oyster Creek and Three Mile Island-1.[71] On April 16, 1998, Boston Edison announced that it was seeking qualified buyers for its Pilgrim nuclear plant.[72] Potential buyers for nuclear plants are, in general, more aggressive utilities with large and successful nuclear plant operations, such as Duke Power and AmerGen, a joint venture of PECO and British Energy. As issues such as divestiture and mitigation of stranded costs become major factors in utility restructuring, more nuclear plants may be offered for purchase.

In the electric utility industry, the difference between full cost recovery under regulation and market-based income is "stranded cost." Figure 8 shows a simplified depiction of the potentially strandable nuclear cost components. With the advent of competition, utilities with high-cost nuclear units in States requiring retail competition may not be able to recover all the costs they have incurred to build the plants, the costs they are incurring to operate them, or the costs they are committed to incur to decommission them. To the extent that these costs would have been recoverable under

[71] "GPU In Serious Discussions Over TMI-1, Oyster Creek Sale," *Nucleonics Week* (September 18, 1997), p. 12.
[72] "Billing It As Hedge Against Fossil Costs, Boston Ed Puts Pilgrim Nuclear on Block," *Electric Utility Week* (April 20, 1998), pp. 11-12.

Figure 8. Simplified Depiction of Potentially Stranded Nuclear Cost



[a]Regulated market price includes: unrecovered capital cost, operating cost, fuel cost, unrecovered decommissioning cost, regulatory assets, and the cost associated with the generation of electricity.

Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

conventional cost-of-service regulation, the unrecoverable amounts will be stranded.[73]

The main assets at risk under competition are high-cost generating plants (especially, but not exclusively, nuclear), high-cost power purchase contracts, nuclear decommissioning costs, and regulatory assets.[74] Estimates of the potential size of such stranded assets range from about $30 billion to $150 billion.[75] Data Resources Incorporated estimates nuclear stranded costs at roughly $88 billion.[76] Moody's Investors Service estimates total stranded costs for 114 investor-owned utilities at $135 billion.[77] These estimates depend on many factors, including how the electric utility industry is restructured, when or if States allow retail competition, and what the current and long-term market value for power and energy is at the time of competition.

The nuclear stranded cost issue is a question of recovery—that is, how much can be recovered from ratepayers through the State procedures established through legislation or regulatory orders and how utility stock and bondholders will be affected by retail competition in electricity markets.

State Approaches to Stranded Costs

For the States that have approved retail competition, most allow full or substantial recovery of stranded capital assets, decommissioning costs, and regulatory assets incurred as of a specific date. In many cases, the accelerated recovery of stranded costs is timed to coincide with the introduction of competition at the State level. Recovery of stranded costs typically takes place over a period of about 4 to 9 years. Overall costs to ratepayers are reduced via "securitization" of the stranded cost income streams and through utility acceptance of reduced but accelerated cost recovery.[78]

All States with restructuring programs are attempting to mitigate stranded costs by aggressive cost cutting, staff reductions, and incentive pay plans. Another way to mitigate costs is to sell the stranded assets. In New England, for example, old and apparently uneconomical non-nuclear generating plants have brought much higher prices than valuations established by the selling utility or the book value of the assets. One way that this increased valuation can arise is if the acquiring utility places a high value on the land, site, and non-generating infrastructure (e.g., transmission connections) associated with the uneconomical generating assets. Because the higher value could not be realized by the continued use of the generating assets under regulation but could be realized under competition by replacing the plant with a new, more efficient plant, the revaluation of the non-generating assets may offset the devaluation of the generating assets. For nuclear assets, the primary way for the valuations to be increased is for a plant to be

[73] During the 1980s, regulators disallowed $16 billion in nuclear expenditures as imprudent (*Edison Electric Institute News,* March 6, 1997). These costs are not recoverable under regulation and thus are not strandable.

[74] Regulatory assets are assets created through the regulatory process. For example, a utility may have a portion of its plant balances ruled imprudent on the basis of the "used and useful" standard and thus excluded from the ratebase. Over time, the asset would be allowed into the ratebase as load growth made the plant "used and useful." Another example relates to "phase-in." If a regulatory commission had ordered a utility to phase-in the recovery of capital costs from a new, large power plant to avoid rate shock, the unamortized plant balances in excess of traditional amortization levels would be regulatory assets. In either case, regulatory assets are assets created by the regulatory process for later recovery by the utility.

[75] *Ibid.*

[76] Adam D. Thierer, *Electricity Deregulation: Separating Fact from Fiction in the Debate Over Stranded Cost Recovery* (The Heritage Foundation, March 11, 1997).

[77] *Ibid.*

[78] Securitization refers to the process of converting the regulatory-guaranteed stranded cost recovery income over a period of years into security, e.g., a bond that can be sold at a lower interest rate than the utility would otherwise enjoy due to the regulatory guarantee of repayment.

acquired by a more efficient operator—presumably, one with many nuclear plants and economies of scale, which can justify paying more for the asset than it is worth to the selling utility.

The following sections provide examples of State rulings on specific nuclear stranded cost items.

Capital Costs

Virtually all the more recently constructed nuclear plants, such as the Seabrook, South Texas, and Comanche Peak plants, have substantial stranded capital costs. Stranded capital costs exceeding $1 billion per unit are not unusual for units that originally cost $2 billion or more to construct. In general, States are treating stranded capital costs as fully or partially recoverable; however, no one clear theme has emerged among the States. The following approaches have been, or are about to be, implemented:

- In California, restructuring legislation passed in 1996 included recovery of transition (i.e., stranded) costs and provided for a 10-percent electricity rate reduction for residential and small commercial customers by March 31, 1998. The restructuring legislation authorized utilities to finance a portion of their transition costs with "rate reduction bonds." The maturity period of the bonds is expected to extend beyond the transition period at a below-market rate of return. In the case of Pacific Gas & Electric's (PG&E) Diablo Canyon nuclear power plant, sunken costs will be fully recovered over a period ending in 2001 at a return on common equity equal to 90 percent of PG&E's embedded cost of debt (7.52 percent in 1996).[79] For Southern California Edison (SCE), sunk costs at the Palo Verde nuclear power plant will be recovered over the same period at a 7.35-percent rate of return on ratebase.[80] Southern California Edison will also use a balancing account to pass through Palo Verde's incremental operating costs (considered reasonable so long as they do not exceed 30 percent of a baseline forecast and the site's gross annual capacity factor does not go below 55 percent). Recovery of San Onofre nuclear power plant operating costs will be on a fixed per-kilowatthour basis. This difference recognizes that SCE is the operator of San Onofre but only a minority partner of Palo Verde.[81]

- In Pennsylvania, recovery is limited to "just and reasonable" amounts, as determined prospectively by the State Public Utilities Commission (PUC). These costs, after mitigation by the utility, are to be recovered through the Competitive Transition Charge (CTC) approved by the PUC and collected from distribution customers for up to 9 years.[82]

- In New Jersey, the State is proposing that utilities have an opportunity for a limited number of years to recover stranded generating capacity costs through rates, with the intent to open the electricity market to all retail customers by July 2000. The determination of stranded cost recovery would be undertaken on a case-by-case basis—100 percent recovery of all eligible stranded costs would not be guaranteed. The opportunity for full recovery of such eligible costs would be contingent upon and may be constrained by the utility's meeting a number of conditions, including achieving the goal of delivering a near-term rate reduction to customers of 5 to 10 percent.[83] Public Service Electric & Gas (PSE&G) plans to reduce its rates by a combination of securitizing a portion of its strandable costs and extending the depreciation period of its distribution assets. Securitization involves the financing of stranded costs, up to a specified limit, by insurance of debt and subsequent liquidation of it through a surcharge on the utility's customers. The extension of the depreciation period for the distribution assets (to 45 years from 28 years) results in a theoretical increase in depreciation reserves, which PSE&G proposes to use as a partial offset for stranded generating assets.[84]

Decommissioning Costs

A large portion of the stranded costs for nuclear power plants is associated with the amount of unrecovered decommissioning costs. Currently, decommissioning costs appear to average slightly more than $400 million for a single-unit station and about $700 million for a

[79] *Ibid.*, p. 18.
[80] Southern California Edison Co., 1996 Form 10-K, p. 8.
[81] *Ibid.*
[82] PECO Energy Company, 1996 Form 10-K, p. 2
[83] Public Service Electric & Gas Co., 1996 Form 10-K.
[84] Public Service Electric & Gas Co., Form 10-Q for the quarter ended June 30, 1997.

two-unit station.[85] A major variable in decommissioning cost and timing is the cost of low-level waste (LLW) disposal, which has been increasing steadily over the past 10 years, with no clear abatement in sight.

The procedure for collecting decommissioning costs is through annual payments to a trust fund over the expected 40-year licensed operating life of the plant.[86] Because of the payment structure, utilities will not collect half of the required final balance until after the 30th year of contributions and accruals. Since more than half of the current capacity has 20 or more years of life remaining, the assets in decommissioning trusts are substantially below the estimated terminal requirements. On a national average basis, they are about one-third of the estimated terminal values.

In the past, regulatory authorities have permitted utilities to collect all or most of the decommissioning cost shortfall from ratepayers for the commercial reactors that were shut down before their operating licenses expired. Regulatory authorities generally recognize that the issue of decommissioning cost shortfalls is related in principle to the issue of unrecovered capital costs (i.e., liabilities of a plant no longer generating revenue), and they seem to treat such costs similarly.[87]

With the advent of restructuring, most States are treating decommissioning costs as fully recoverable stranded costs. For the most part, decommissioning costs that could not be covered by revenues would be recovered through a transmission charge or a charge on departing customers. The prospect for adjustments in decommissioning costs over time is unclear. Some States (e.g., Rhode Island) will allow decommissioning cost adjustments that reflect new information about the actual cost to decommission a unit. In Maine, a nuclear utility will have one opportunity to estimate and charge decommissioning costs under restructuring.[88] After that point, the utility will bear all the risk of cost increases.

Another issue in the debate over stranded nuclear decommissioning costs concerns the operating costs from the time a utility terminates commercial operation to the time it receives its possession-only license (POL). Nuclear power plant operators incur costs to maintain the plant at a commercial level. Aside from the defueling activity itself, other major cost areas are plant staffing, maintenance, security, and compliance with Nuclear Regulatory Commission (NRC) regulations.

Utilities currently treat these costs as operating costs, not decommissioning costs. For a typical operating plant with a staff of 500 to 1,500, annual transition costs could be in the range of $50 million to $150 million. Recently, POL transition periods have been on the order of 1 to 2 years. These periods should decline to 3 to 6 months for plants that shut down according to a planned retirement schedule. Plants that shut down abruptly, however, may continue to have transition periods of 2 years or more, and their transition costs could be $100 million to $250 million. Because these costs are part of nuclear operations (not decommissioning), they do not appear to be recoverable under any definition of stranded costs. Utilities will be able to recover these costs if plants are retired while still under rate regulation; however, if plants are retired in deregulated, competitive markets, the costs may not be recoverable.

Implications of Denying Stranded Cost Recovery

Although the States are establishing procedures for stranded cost recovery, those procedures may not result in full recovery of nuclear stranded costs because of time limits on recovery or the prescribed procedure for determining stranded costs. Without substantial stranded cost recovery, a significant number of nuclear utilities will suffer large losses in market value.

Three groups of nuclear utilities are at particularly high risk: utilities with heavy investments in relatively recent (and therefore relatively costly) nuclear plants; utilities with older, poorer performing units; and utilities with relatively concentrated nuclear exposure regardless of the vintage of the plants. At-risk utilities include a few very large investor-owned utilities, such as Commonwealth Edison, and a considerable number of municipal utilities and cooperatives. For example, large shares of the Catawba and McGuire plants in North Carolina and the River Bend plant in Louisiana are owned or have been owned by municipal utilities and cooperatives,

[85] Energy Information Administration, *Nuclear Power Generation and Fuel Cycle Report, 1996,* DOE/EIA-0436(96) (Washington, DC, October 1996), pp. 44-47.

[86] The fund operates like an annuity, growing over time as yearly annuity payments are made along with interest earnings.

[87] Energy Information Administration, *Nuclear Power Generation and Fuel Cycle Report 1996*, "Decommissioning U.S. Nuclear Plants," DOE/EIA-0436(96) (Washington, DC, October 1996), p. 51

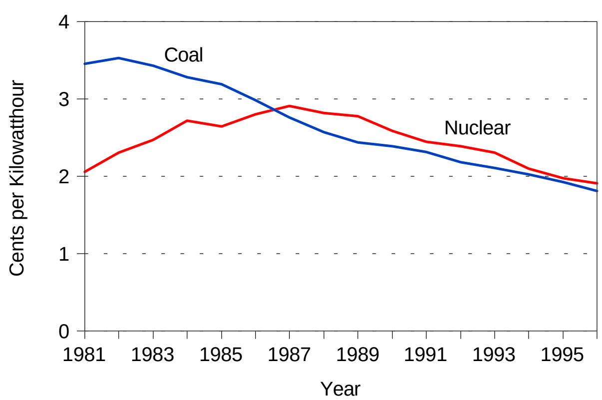
[88] "Energy Online Completes Review of Electric Deregulation Initiatives in All 50 States, Congress, Administration," www.energyonline.com/Restru..ng/news_reports/news/0819wrap.html, accessed October 23, 1997.

which are at risk as a result of asset concentration, independent of the absolute capital or operating costs of their nuclear plants.

Competitiveness of Nuclear Plants

Ultimately, the long-term viability of nuclear power generation lies in the industry's ability to keep its operating costs competitive with those for alternative forms of generation, primarily baseload coal-fired power plants. Over the past decade, the nuclear industry has succeeded in reducing average operation and maintenance (O&M) costs significantly.[89] In 1996, O&M costs, including fuel costs, reached an industry low of 1.91 cent per kilowatthour (Figure 9). Much of the decline is the result of a decade-long increase in unit capacity factors. The average capacity factor for the industry increased from 66.0 percent in 1990 to a high of 77.4 percent in 1995.[90] Over the same period, the nuclear industry continued to reduce the list of NRC issues requiring resolution, aggressively replaced steam generators and other major components causing difficulties, reduced refueling outage durations, extended operating cycles,

Figure 9. Comparison of Average O&M Costs for U.S. Nuclear and Coal-Fired Power Plants, 1981-1996

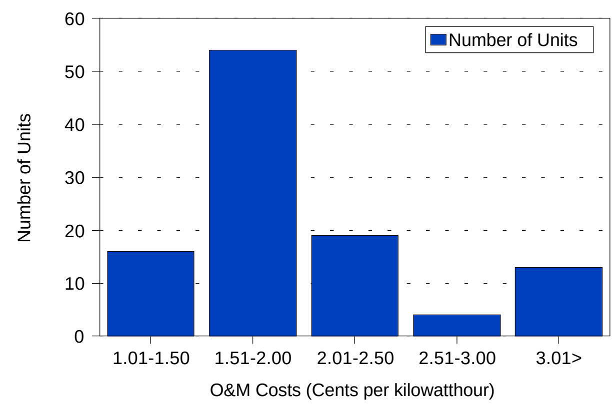


Note: Costs are in 1996 dollars. Fuel costs are included. Averages are generation weighted.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

and took other steps to improve cost and efficiency.[91] On average, O&M costs for U.S. nuclear power plants are now about the same as for U.S. coal-fired power plants, 1.81 cents per kilowatthour in 1996.[92]

Although nuclear plants are competitive with coal-fired plants on average, there are wide variations among individual nuclear units (Figure 10). For the 1994-1996 period, roughly 16 percent of the units had O&M costs exceeding 2.5 cents per kilowatthour. About 12 percent of the units had O&M costs exceeding 3.0 cents per kilowatthour. If significant additional costs must be incurred to ensure safety and reliability, some nuclear plants may cease to be competitive.

Figure 10. Variation in O&M Costs for U.S. Nuclear Plants, 1994-1996



Note: Costs are in 1996 dollars. Costs include fuel costs but exclude capital additions costs.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Units whose operating costs approach or exceed long-term firm capacity and energy prices are at risk of early closure. In regions with substantial surplus capacity, it is possible that nuclear plants will be at risk because their operating costs are above the costs for long-term non-firm energy, which is widely available at less than 2 cents per kilowatthour.[93] For all the units, a complex analysis of the long-range competitive market is required. Issues include the prospects for reducing O&M and capital improvement costs, the prospects for

[89] Energy Information Administration, *World Nuclear Outlook 1994*, DOE/EIA-0436(94) (Washington, DC, December 1994), pp. 43-44.
[90] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(97/03) (Washington, DC, October 1997), p. 105.
[91] Energy Information Administration, *Nuclear Power Generation and Fuel Cycle Report 1996*, DOE/EIA-0436(96) (Washington, DC, October 1996), and *World Nuclear Outlook 1994*, DOE/EIA-0436(94) (Washington, DC, December 1994).
[92] Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."
[93] Firm power is power that is intended to be available at all times, even under adverse conditions. Non-firm power does not have the guaranteed continuous availability of firm power.

increasing capacity factors, the likelihood that long-term firm power will remain available at low rates, decommissioning costs and scheduling, the projected O&M costs of competing fossil fuel generation, and cost recovery for prematurely retired units.

Many utilities, including GPU Nuclear Corporation (the owner of Oyster Creek), Commonwealth Edison (the owner of Dresden and Quad Cities), Wisconsin Public Service (the owner of Kewaunee), and Boston Edison (the owner of Pilgrim) have publicly addressed these issues, with varying results. In some cases (e.g., Oyster Creek), the utility has said that the plant will either be sold or closed, because the prospects for making it competitive are poor.[94] In other cases (e.g., Pilgrim), the utility has said that the plant will be brought up to competitive standards over the next few years and will not be retired prematurely.[95] The following section outlines some of the factors that go into these decisions.

Market Value

Under restructuring, the market value for long-term firm capacity and energy in each region of the country will determine the value of nuclear power plants. In the short term, firm capacity and energy will be available in most of the country for the incremental price of coal-fired energy from plants operated at less than baseload levels. This price is less than $20 per megawatthour in most of the country, although it is higher in some regions, such as New England. No utility, however, retires a plant with 10 to 20 years of remaining life because replacement power costs are low for the next year or two. Figure 11 shows the current average operating costs of nuclear power plants by North American Electric Reliability Council region.

Regional differences will play a major role in market value assessments. In New England, for example, coal-fired power is expensive because the coal sources are distant and the regulations governing air emissions and siting are stringent. Transmission of surplus coal-fired power from the Midwest and Mid-Atlantic would lower prices, but it is limited by the existing transmission capacity to New England, which is much less than would be optimal, given the differences in relative generating costs among the regions. Over the long term, new gas-fired combined-cycle capacity in New England and upgraded or possibly new transmission capacity to other regions, including Canada, may eliminate some of the regional pricing differences. In the Southwest, on the other hand, almost all these factors are reversed. Coal-fired power is available, transmission constraints are minimal, and surplus power is exported to Mexico. The net result is that the market value for power in the Southwest is much less than in New England.

As surplus coal-fired capacity available for baseload generation is used up in the first half of the next decade, prices may rise, making nuclear-powered generation more competitive. Prices may also rise in the early part of the next century as stringent sulfur dioxide emissions standards under the Clean Air Act take hold. New emissions standards for nitrogen oxides, as proposed by the U.S. Environmental Protection Agency in October 1997, would also significantly add to long-run operating costs. Limiting these increases in the long-run market price for baseload capacity and energy will be new combined-cycle gas-fired power plants, which can deliver power and energy at less than $40 per megawatthour, including capital recovery.

Operation and Maintenance Costs

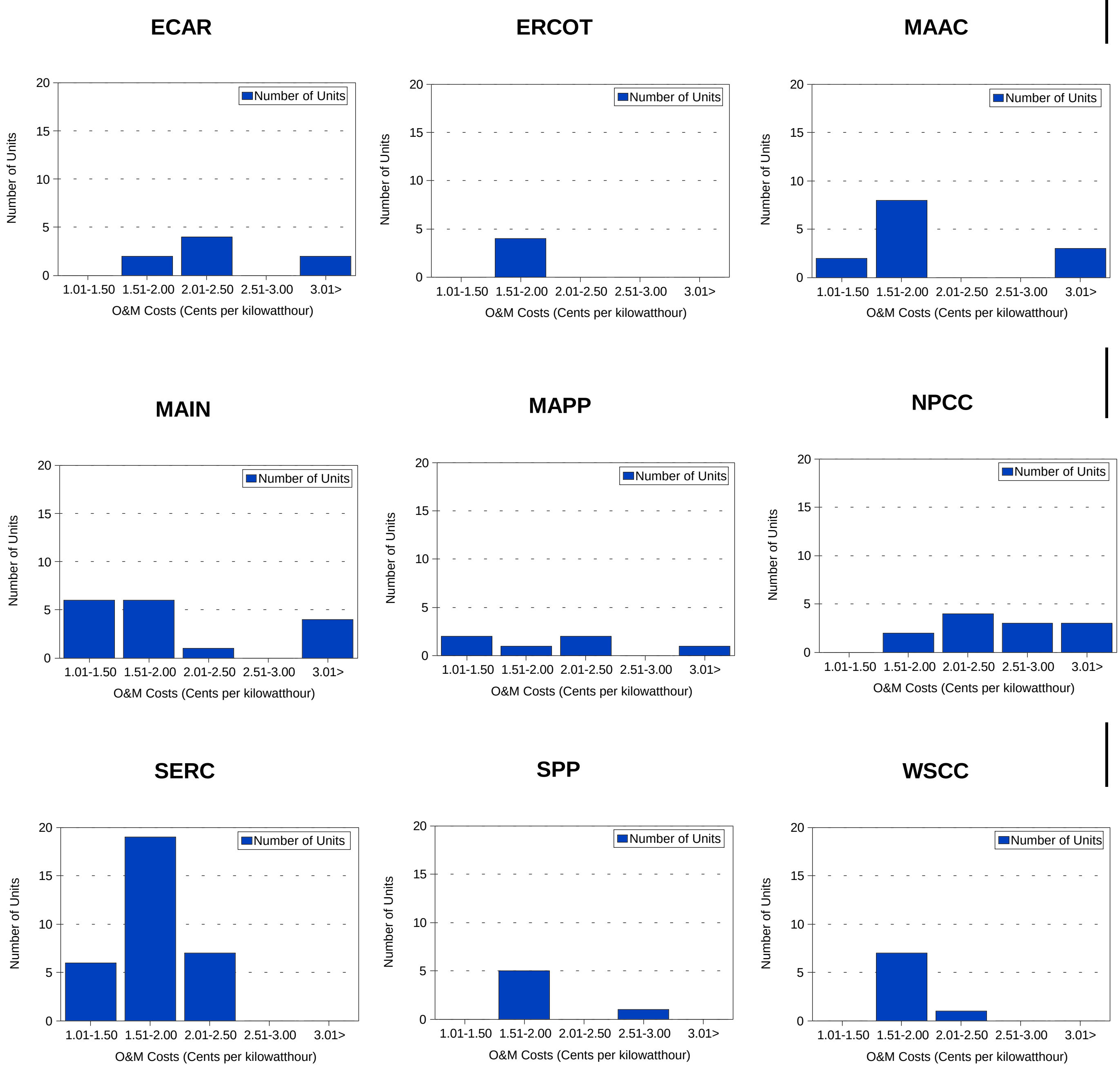
If nuclear power plants are to remain viable in deregulated electricity markets, their O&M costs will have to be maintained at the competitive levels achieved over the past decade. Factors contributing to nuclear O&M costs include plant size and age, required capital expenditures, and capacity factor.

Size

Roughly 70 percent of the O&M expenditures for nuclear units are for labor. Labor costs are largely fixed by regulatory requirements that do not relate to size. Moreover, multi-unit plants share a considerable amount of the labor relating to regulatory compliance, procurement, permitting, etc. Thus, larger units and multi-unit plants have the potential to be less costly to operate per kilowatthour than smaller units and single-unit plants. Most of the nuclear units prematurely retired or announced for premature retirement in recent years have been single-unit plants (e.g., Trojan, Rancho Seco, Maine Yankee, Big Rock Point, Oyster Creek, and Haddam Neck) and many are small units.

[94] D. Airozo, "Oyster Creek May Close in 2000, Unless a Buyer Can Be Found," *Nucleonics Week* (April 10, 1997).
[95] "Little Pilgrim Working To Avoid Fate of New England Neighbors," *Nucleonics Week* (June 19, 1997), p. 9.

Figure 11. Variation in O&M Costs for U.S. Nuclear Power Plants by NERC Region, 1994-1996



Note: Costs are in 1996 dollars. Costs include fuel costs but exclude capital additions costs.
Source: Federal Energy Regulatory Commission, Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Age

The age of a plant is significant for several reasons. First, as a plant passes 20 or 25 years of its 40-year license life, the remaining lifetime of the plant may be too short to permit competitive amortization of the costs of major capital improvements, such as steam generator replacements. Second, older plants are usually smaller, meaning that the fixed costs of replacements are spread over fewer kilowatthours of generation. Third, older plants have often required major upgrades because of their vintage rather than their operational performance. Several units (e.g., San Onofre 1, Yankee Rowe) have been prematurely retired because they could not economically be brought up to current standards while remaining economical. On the other hand, one unit—Robert Ginna, a 470-megawatt unit in Rochester, New York—had its steam generators replaced in 1995 because the utility, Rochester Gas and Electric Corporation, determined that the plant's long-run economics were favorable.

Large Capital Expenditures

Another major factor in determining a plant's competitiveness is whether significant capital expenditures will be needed in the near future for continued operation. Such capital expenditures are not sunk costs and, in a competitive marketplace, must be included in the cost of electricity generation. A plant that is currently competitive but is anticipated to require a large influx of capital in the next several years is a less desirable economic asset and may simply be operated until a large capital infusion is needed and then shut down.

The largest capital expenditure typically facing existing nuclear plants (pressurized-water reactors only) is the cost to replace degraded steam generators.[96] As a result of degraded steam generators, Commonwealth Edison announced in January 1998 that it was permanently shutting down its Zion plant.[97]

Capacity Factor

The capacity factor of a nuclear power plant has a significant impact on the cost of power from the plant. Although O&M costs usually are seen as variable costs, they are essentially fixed for any operational nuclear power plant. Nuclear fuel costs are also mostly fixed. Thus, most of the change in the capacity factor goes directly to the bottom line of the utility's income statement. For a 1,000-megawatt plant selling power at $25 per megawatthour, each capacity factor point generates $2.2 million in revenue per year and only slightly less in before-tax net income. The net present value of this percentage point change over a typical 20-year remaining life is $15 million to $20 million, depending on the discount rate. Not surprisingly, utilities are willing to make investments to improve plant performance. Similarly, the possibility of multi-point increases in capacity factors is a major influence on the retirement decision. For plants that have historically operated far below the industry average capacity factor (currently in the mid- to upper 70s), the prospect of a double-digit increase in capacity factors may justify expenditures to improve performance.

Decommissioning Assurance

Restructuring of the electricity industry introduces issues that concern the NRC and its relationship to utilities demonstrating financial assurance for decommissioning funds. The current NRC rule is based on the premise that the operator of a nuclear power plant will be an ongoing, capital-intensive concern with significant financial resources, including ratebase access, to cover any shortfall in the plant's decommissioning fund.[98]

With the advent of restructuring, utilities will no longer have a guaranteed customer base. Most State commissions have accepted full recovery for decommissioning costs, but it is unclear how the costs will be translated into rates or charged to existing and former customers. In addition, it is unclear how future increases in decommissioning costs could or would be passed on to former customers.

The NRC has statutory authority to regulate the decommissioning of its licensed nuclear facilities. On April 8, 1996, the NRC posted an announcement in the *Federal Register* soliciting public comment for a proposed rulemaking, stating it is considering rulemaking that would:

- Require that electric utility reactor licensees assure the NRC that they can finance the full estimated cost of decommissioning if they are no longer subject to rate regulation by State agencies or by the Federal Energy Regulatory Commission and do not have a guaranteed source of income.

- Require utility licensees to report periodically on the status of their decommissioning funds. The present rule has no such requirement because State

[96] The replacement of steam generators for a pressurized-water reactor between 1994 and 1995 cost between $125 million and $153 million.

[97] "ComEd To Close Zion," *The Ux Weekly* (January 19, 1998), p. 3.

[98] The NRC may require accelerated funding of a reactor's decommissioning fund if the operator's bond rating is below "A" by a national rating agency for a specific period of time. The NRC may consider other financial criteria in arriving at its decision. Energy Information Administration, *Nuclear Power Generation and Fuel Cycle Report 1996,* DOE/EIA-0436(96) (Washington, DC, October 1996), p. 49.

and Federal rate-regulating bodies actively monitor the funds. A restructured nuclear utility would have no such monitoring.[99]

The proposed rulemaking would assign financial oversight to the NRC by requiring licensees to report periodically the status of their decommissioning funds to the NRC. Whether the final rule does grant this authority to the NRC remains to be seen. In the past, however, the nuclear industry has resisted any proposals that would give NRC financial oversight responsibility.

Impacts on the Nuclear Fuel Industry

To produce fuel suitable for loading into a nuclear power plant's reactor core, naturally occurring uranium must undergo the following manufacturing steps: (1) extracting and processing ore to produce uranium concentrate (U_3O_8), (2) conversion, (3) enrichment, and (4) fuel fabrication (see textbox, p 35). These steps are referred to as the "front end" of the nuclear fuel cycle. In contrast, the management of spent fuel discharged from reactors is referred to as the "back end" of the nuclear fuel cycle. Products or services for each front-end stage are bought and sold in separate markets. Available capacity, inventory level, and the application of trade restrictions and other national policies differ from market to market. Consequently, trends in prices may show little correlation between markets. For example, the average annual spot-market price for the restricted U.S. uranium market increased by 36 percent from 1995 to 1996, compared with an increase of only 6 percent in the average annual spot-market price for the restricted U.S. enrichment market.[100, 101, 102]

The restructuring of the electric power industry is expected to affect the demand for nuclear fuel as uneconomical plants are retired early and the operators of the remaining plants focus on the marginal costs of power production. This section describes the potential impacts that the restructuring of the electricity industry will have on the nuclear fuel industry in the following areas: (1) changing emphasis on fuel costs, (2) declining demand for uranium and nuclear fuel services, (3) availability of uranium made surplus by plant closures, (4) decrease in inventories, (5) consolidation in nuclear fuel procurement, and (6) consolidation in the nuclear fuel industry.

Changing Emphasis on Fuel Costs

Unlike nonfuel O&M and capital additions costs, the cost of fuel has not been considered critical in determining the economic viability of existing nuclear power plants. Factors contributing to this view include: (1) fuel represents a relatively small share of power production costs; (2) fuel has been priced at historically low levels; and (3) utilities, operating as regulated monopolies, have generally been able to pass through fuel costs to customers. With the restructuring of the electric power industry, nuclear generating companies will be selling a commodity (electricity) in a highly competitive marketplace with little opportunity to differentiate their product other than by price. In this setting, they will be forced to focus on the incremental costs of production, including those for fuel, to remain competitive.

Fuel composed just 27 percent of the average nuclear power production expenses reported by major U.S. investor-owned utilities in 1996.[103] The remaining 73 percent of average nuclear production expenses was categorized as non-fuel O&M. In contrast, fuel contributed to a much greater share of the average power production expenses incurred by fossil steam, gas turbine, and small-scale plants (Figure 12).[104]

A general condition of oversupply has kept the prices of uranium and nuclear fuel cycle services at historically low levels (Figure 13).[105] The average annual spot-market price for the U.S. uranium market has declined to levels substantially lower than in the late 1970s, in sharp contrast to the substantial increases in nonfuel O&M

[99] NRC Press Release, NRC Electronic Bulletin Board on FEDWORLD, www.fedworld.gov (April 8, 1996).

[100] Historical uranium and enrichment spot-market prices used in this chapter are the Exchange and SWU Values, respectively, reported in TradeTech, *The Nuclear Review* (Denver, CO).

[101] In the spot market, transactions are made for the one-time delivery of the entire contract to occur within 1 year of contract execution. Term contracts are typically made for one or more deliveries to occur over a time period in excess of 1 year from contract execution.

[102] Due to restrictions on U.S. imports from republics of the former Soviet Union, a two-tiered market for uranium, consisting of restricted U.S. and unrestricted world components, was established in 1992.

[103] Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others" (1996).

[104] The gas turbine and small scale category includes gas turbine, internal combustion, photovoltaic, and wind plants.

[105] The nuclear fuel cycle includes the steps necessary for transforming naturally occurring uranium into fuel loaded into nuclear reactors.

Characteristics of Nuclear Fuel

1. Multiple Production Stages and Markets

Four major stages are involved in the transformation of naturally occurring uranium into the fuel assemblies that are loaded into a typical nuclear power reactor operating in the United States. These stages, collectively referred to as the "front end" of the nuclear fuel cycle, and their associated products, each sold through separate markets, are as follows:

- *Ore mining and processing*: production of uranium concentrate (U_3O_8 or yellowcake) from ores and solutions recovered from the earth.
- *Conversion*: U_3O_8 is converted into uranium hexafluoride (UF_6), a feedstock required for enrichment.
- *Enrichment*: the fissile content of natural uranium (0.7 percent ^{235}U) is increased to low-enriched uranium (generally 3.0-5.0 percent ^{235}U), suitable for reactor fuel. A utility typically contracts to have uranium enriched by a provider of enrichment services. The energy required for enrichment is measured in separative work units. Low-enriched uranium, known as enriched uranium product, also can be purchased directly from the marketplace.
- *Fuel Fabrication*: Fabricators manufacture fuel assemblies containing fuel rods loaded with uranium oxide (UO_2) pellets made from low-enriched uranium.

2. Five-year Useful Life

Nuclear fuel assemblies are designed to be used for up to 5 years, depending on the reactor operating cycle, burnup[a] rates, and other fuel management practices. The acquisition cost of nuclear fuel is accounted for as an asset on a utility's balance sheet, since nuclear fuel loaded into a reactor provides future economic benefit. A portion of the acquisition cost is allocated to each year in which the fuel provides benefit. This allocation, generally referred to as amortization, is deducted from the asset account on the balance sheet and added as a fuel expense to the income statement.

3. Internalization of Environmental Costs Incurred from Its Use

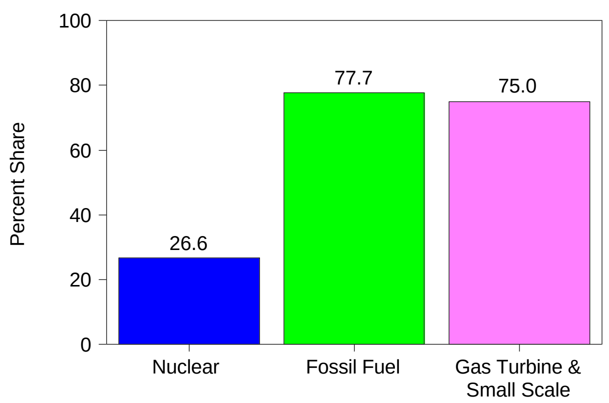
Nuclear fuel that has reached the end of its useful life is discharged from reactors during refueling in a manner that prevents contamination of the environment. This discharged fuel, termed "spent" fuel, is highly radioactive. It currently is being held by U.S. utilities at reactor sites, either under water in storage pools or in dry cask storage facilities, until a repository is made available for its permanent disposal. The management of spent fuel comprises the "back end" of the nuclear fuel cycle. Under the Nuclear Waste Policy Act of 1982, as amended, the U.S. Department of Energy (DOE) is to provide for the ultimate disposal of spent fuel waste. To fund the DOE's contractual obligations, each nuclear utility pays an ongoing fee, in addition to a one-time payment to cover disposal of fuel utilized prior to April 7, 1983. The annual fee is currently 1 mill per kilowatthour of net electricity generated and sold; it is included in the fuel expenses reported to the Federal Energy Regulatory Commission. Also, owners of nuclear power plants are required by the U.S. Nuclear Regulatory Commission to place funds into an external trust to provide for the cost of decommissioning the radioactive portions of plant and equipment. Thus, the costs incurred to ensure that nuclear waste does not contaminate the environment are included, or "internalized," in the cost of nuclear power.

4. Relationship to Nuclear Nonproliferation and Arms Reduction Programs

Critical components of nuclear weapons, especially highly enriched uranium (^{235}U content greater than 20 percent) and plutonium, can be produced in the same type of facilities used for the civilian nuclear fuel cycle. To provide safeguards against the spread of nuclear weapons, the United States and 185 other nations have signed a Non-Proliferation Treaty (NPT) with the International Atomic Energy Agency, an organization within the United Nations. The NPT requires detailed accounting of nuclear materials by signatory nations. With the end of the cold war, Russia and the United States have declared surplus a portion of their respective nuclear weapons arsenals. As a result of an agreement signed between the United States and Russia in 1993, the first fuel from highly enriched uranium (HEU) taken from dismantled Russian nuclear warheads was delivered to a U.S. electric power utility in November 1995. Nuclear fuel derived from U.S. HEU is scheduled to enter the market in 1998. In 1997, the DOE began selling surplus commercial-grade uranium that was intended for defense purposes. Plutonium from dismantled U.S. nuclear weapons could become available for use in commercial nuclear fuel after 2000.

[a]Burnup is a measure of the amount of energy obtained from fuel in a reactor.
Source: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels.

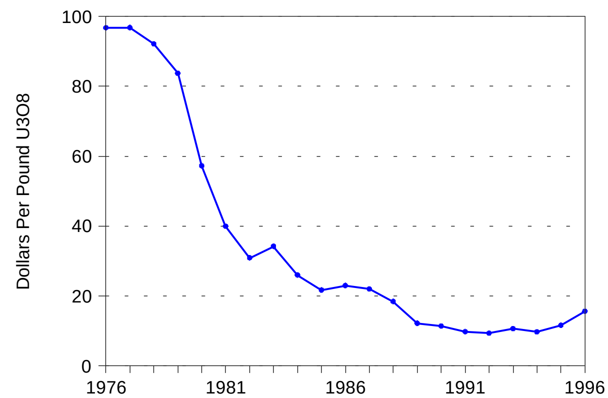
Figure 12. Fuel as a Share of Average Power Production Expenses for Plants Owned by Major U.S. Investor-Owned Electric Utilities, 1996



Notes: Power production costs include operating and maintenance (O&M) as well as fuel. Nuclear fuel expense includes payments for disposal of spent nuclear fuel waste.

Source: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees, and Others."

Figure 13. Spot-Market Price for the U.S. Uranium Market, 1976-1996



Notes: Price is in 1996 dollars. A two-tiered market developed at the end of 1992 as a result of agreements between the United States and the republics of the Former Soviet Union (FSU) that restrict U.S. imports of uranium from the FSU.

Source: The reported price is the Exchange Value for the restricted U.S. market reported in TradeTech, *The NUCLEAR Review* (Denver, CO, October 1997).

costs reported by nuclear power plants during the 1980s (Figure 9). There is excess production capacity in both the enrichment and fuel fabrication markets. The current world enrichment services capacity is estimated at 49.5 million separative work units (SWU), compared to 33.9 million SWU projected to be required by the world's nuclear reactors in 1998.[106, 107, 108] The current world capacity for light-water reactor fuel fabrication has been estimated at 150 percent of requirements.[109, 110] The market conditions responsible for low prices have enabled utilities to exercise a certain amount of leverage in negotiating favorable contract terms for the purchase of uranium and nuclear fuel cycle services.

- As regulated monopolies, utilities were able to pass through fuel costs to customers as long as such costs were determined to be prudent by State public utility commissions; however, the move toward full competition will make it increasingly difficult for nuclear generating companies to recover above-market generation costs. For example, some States have implemented performance-based ratemaking in exchange for allowing utilities to accelerate the recovery of their stranded costs as a transition to full competition (see text box on page 37). Performance-based ratemaking affects the profits of utilities by setting a level of operating revenues available to utilities for covering the day-by-day costs of generating electricity. To realize a profit, the utility must keep its production costs below the available revenue limit. However, the fixed portion of production costs, such as those for engineering and plant safety, are considered as unavoidable. Therefore, a nuclear generating company must focus on the variable portion of production costs, including fuel, to improve profit margins.

Declining Demand for Uranium and Nuclear Fuel Services

As nuclear capacity is retired prematurely for competitive reasons, the demand for uranium and nuclear

[106] Separative Work Unit (SWU) is the standard of measure for enrichment services.

[107] Enrichment plant capacity from NAC International, *Nuclear Industry Status Report on Enrichment, A Fuel-Trac Product* (Norcross, GA, February 1997), Table B-3.1.

[108] Energy Information Administration, *Nuclear Power Generation and Fuel Cycle Report 1997,* DOE/EIA-0436(97) (Washington, DC, September 1997), Table F3.

[109] The majority of the world's nuclear power reactors are light water reactors.

[110] Fuel fabrication capacity utilization from Energy Resources International, Inc., *1997 Nuclear Fuel Cycle Supply and Price Report* (Washington, DC, May 1996), p. 7.1.

California's Move to Competitive Electric Power Market Highlights Fuel Costs

The following description of legislation in California and its impact on a nuclear utility is presented to illustrate the changing focus on fuel costs as the electric power industry undergoes restructuring. The passage of Assembly Bill 1890 in 1996 provided the legal framework to establish a fully competitive electricity generation market in California by 2002. A key provision of the restructuring legislation authorizes utilities to recover certain generation-related costs that are likely to become stranded in a competitive marketplace. The recovery would take place during the transition period (1997-2001) preceding full competition. For example, Pacific Gas & Electric Company (PG&E) will accelerate the recovery of costs for its Diablo Canyon nuclear power plant over 5 years, instead of over the previous amortization period ending in 2016.

To provide for the accelerated recovery of costs considered as stranded, customers would continue to pay prices for electricity similar to those in effect before the adoption of the restructuring legislation. In return, PG&E would receive a reduced return on common equity for those costs. The lower return reflects the reduced risk associated with increased certainty of recovering costs over a shorter period. In addition to accelerated cost recovery, revenues would be unbundled for application to distribution, transmission, public purpose programs, generation, nuclear decommissioning, and other areas.

The revenues made available annually to PG&E for the recovery of ongoing operating costs and capital additions for Diablo Canyon will be based on the Incremental Cost Incentive Price (ICIP) established by the California Public Utilities Commission (CPUC) in May 1997. The ICIP is scheduled to increase periodically from 3.26 cents per kilowatthour in 1997 to 3.49 cents per kilowatthour in 2001. In determining the ICIP, the CPUC used an assumed capacity factor of 83.6 percent for Diablo Canyon and an escalation factor of 1.5 percent. The ICIP also contains a prudence disallowance of approximately $70 million for the undepreciated portion of costs attributed to unreasonable construction error.

The price paid by customers of PG&E in California for electricity generated by the Diablo Canyon plant peaked at around 11 cents per kilowatthour in 1994. At peak prices, the operating revenue for each reactor under 100 percent power was over $3 million per day. Because of the longer amortization period available prior to restructuring, much less revenue was applied on an annual basis to recovering costs that are now considered as stranded. Thus, the operation of Diablo Canyon provided a substantially greater margin of profit than is possible today. The cost of fuel, including interest and the spent fuel fee, was only about 3.5 percent of the price paid by customers in 1994.

Because the operation of Diablo Canyon realized a large profit margin, PG&E did not have to be overly concerned about cost management as long as the plant was producing electricity. In contrast, the accelerated recovery of costs and the imposition of the PCIP as a result of restructuring will inhibit Diablo Canyon's contribution to corporate profits. PG&E estimates that the operating revenue provided from each reactor will be reduced to only $0.8 million per day in 1997.

Diablo Canyon's production cost was about 2.9 cents per kilowatthour at the beginning of 1997, compared with the operating revenue of 3.26 cents per kilowatthour established by the PCIP for 1997. For Diablo Canyon to contribute to corporate profits during the transition period, it must keep production costs below the PCIP. Thus, considerable emphasis will be placed on the management of production costs. In this context, the cost of fuel, which currently makes up about 15 percent of Diablo Canyon's production costs, becomes increasingly relevant.

In 2002, the electric power generation market is expected to be fully competitive in California. With the completion of accelerated recovery of stranded costs, Diablo Canyon's asset value will have been depreciated to zero. With the exception of decommissioning costs, customers will no longer be subsidizing above-market generation costs. To improve the operating efficiency of Diablo Canyon, PG&E plans to increase the duration of each reactor's operating cycle, measured as the time between refueling outages, from 18 months to 24 months by 2001. With fewer planned outages, O&M costs are expected to be reduced. Although the overall cost of power production will decline, the cost of fuel will actually rise, because increased performance of nuclear fuel is required for the longer operating cycle. Thus, fuel will become an even more significant component of production costs.

Sources: Pacific Gas & Electric Corporation, 10-K Report to the Securities and Exchange Commission (March 5, 1998), pp. 23-25; J. Sellers, "Strategies for Competition and Nuclear Fuel," paper presented at the Nuclear Energy Institutes's FuelCycle 97 conference (April 1997).

fuel services will be reduced in the United States. For example, the closure of the Zion 1 and 2 nuclear power generating units, announced by Commonwealth Edison in January 1998, will reduce U.S. annual requirements for uranium and enrichment services by about 1.0 million pounds U_3O_8 and 250,000 separative work units (SWU), respectively.[111] Each Zion unit had a generating capacity of 1,040 net megawatt-electric (MWe) and was operated on an 18-month refueling cycle. Commonwealth Edison is expected to use uranium that was being held for future fuel reloads at Zion as supply for its reactors remaining in operation.[112]

Because of differences in the types of reactors and management policies, not all reactors are operated in the same way. For this analysis, fuel cycle requirements for the Zion units are assumed to approximate those for plants with a similar generating capacity. Based on this assumption, uranium and enrichment services requirements would be reduced by about 500,000 pounds U_3O_8 and about 125,000 SWU, respectively, for each 1,000-MWe increment of net generating capacity retired from service. Thus, the closure of a 1,000-MWe nuclear unit would have only a marginal impact on total U.S. requirements, which are projected to be 49.4 million pounds U_3O_8 and 11.1 million SWU for 1998.[113] Similarly, requirements for conversion and fuel fabrication services would be affected only marginally.

From the perspective of the U.S. nuclear fuel supply industry, however, each plant closure represents the loss of an actual or potential customer in a highly competitive marketplace. Plant closures could have a detrimental impact on suppliers that have relatively high marginal costs of production or have large shares of their business concentrated in the United States. The following discussion focuses on the U.S. uranium and enrichment service industries.

Because of differences in the quality of ore reserves, uranium concentrate (U_3O_8) is more expensive to produce in the United States than in such countries as Australia and Canada. In addition, to earn foreign exchange, the Commonwealth of Independent States and other countries have supplied uranium to utilities in the United States from mines that might not be economical to operate under U.S. accounting principles.[114] Driven by competitive pricing, imports have become the most important source of uranium for meeting U.S. requirements. The equivalent of 43.0 million pounds U_3O_8 was imported by U.S. suppliers and utilities in 1997.[115] [116] In contrast, domestic uranium concentrate production was 5.6 million pounds U_3O_8 in 1997.[117]

A decline in demand brought about by nuclear power plant closings could weaken the price of uranium, forcing producers with marginal production costs above the market price to suspend operations. Under a scenario of declining price, relatively higher cost U.S. production would be particularly susceptible to competitive pressures exerted by imports.

The United States Enrichment Corporation (USEC), the only domestic provider of enrichment services, reported that contracts with U.S. utilities accounted for more than 60 percent of its total worldwide sales in 1996.[118] It provided enrichment services to four-fifths of the domestic nuclear power generating industry in 1997.[119] Thus, USEC's earnings would be more sensitive to closings of U.S. nuclear power plants than would those of enrichers with less exposure to the U.S. market. Because enrichment services are sold under long-term contracts, USEC could be challenged to find new customers should the domestic market be substantially reduced.

Availability of Uranium Made Surplus by Plant Closures

With restructuring, some companies may completely exit the nuclear power generation industry. If they do, they are likely to sell inventories of uranium no longer needed to meet previously scheduled fuel reloads. For example, inventory equivalent to approximately 500,000

[111] *The Ux Weekly* (January 19, 1998), pp. 3-4.

[112] *Ibid.*

[113] Energy Information Administration, *Nuclear Power Generation and Fuel Cycle Report 1997*, DOE/EIA-0436(97) (Washington, DC, September 1997), Tables F1 and F3.

[114] Energy Information Administration, *Uranium Industry Annual 1991*, "The Uranium Industry of the Commonwealth of Independent States," DOE/EIA-0478(91) (Washington, DC, October 1992), p. 11.

[115] Energy Information Administration, *Uranium Industry Annual 1997*, DOE/EIA-0478(97) (Washington, DC, April 1998), Table 28.

[116] Uranium imports included U_3O_8, UF_6, and enriched uranium product (see text box, p. 35). For comparative purposes, the various forms of uranium are expressed as "equivalent" U_3O_8.

[117] Energy Information Administration, *Uranium Industry Annual 1997*, DOE/EIA-0478(97) (Washington, DC, April 1998), Table 5.

[118] United States Enrichment Corporation, *1996 Annual Report*, p. 22.

[119] United States Enrichment Corporation, "About USEC," website www.usec.com/about.html (accessed March 5, 1998).

pounds U_3O_8 became surplus as a result of the decision by Connecticut Yankee Atomic Power Co. (CYAP) to close the Haddam Neck nuclear power plant permanently. This quantity of uranium is equivalent to about 9 percent of the 5.6 million pounds of uranium produced in the United States during 1996.[120] In August 1997, Northeast Utilities, the parent company of CYAP, sold the uranium through an auction.

The sale of uranium made surplus by the closure of nuclear power plants displaces other sources of supply. The extent to which surplus uranium impacts the market depends on the timing and mechanism involved in selling the uranium. At the time that Northeast Utilities announced its intent to sell uranium made surplus by the closure of Haddam Neck, the uranium market had experienced a significant decline in price. The monthly spot-market price for the restricted U.S. market declined from $16.50 per pound U_3O_8 in July 1996 to $10.20 per pound U_3O_8 in August 1997. During the third quarter of 1996, the demand for uranium on the spot market reached a low not recorded since 1988.[121]

In addition to Northeast Utilities, the U.S. Department of Energy (DOE) announced plans to sell uranium that had been declared surplus.[122] The planned sales contributed to the downward pressure on price, with other sellers offering uranium at prices lower than the prevailing spot-market price in order to complete sales, before Northeast Utilities and DOE entered the market. By using an auction, however, Northeast Utilities was in a position to decline bids that were below the prevailing spot-market price. Buyers anticipating no further decline in spot-market price provided bids at or above the prevailing market to procure uranium at relatively low prices.[123] Prospective buyers apparently withheld demand until they perceived that the anticipated sales of surplus uranium would no longer push prices lower. Following sales of uranium by both Northeast Utilities and DOE, the spot-market price for the restricted U.S. market rose to $12.75 per pound U_3O_8 in October 1997.

Decrease in Inventories

In a competitive business environment, companies have historically sought to minimize inventory holding costs. For example, it is well documented that U.S. automobile manufacturers have met this goal by matching the delivery of parts from suppliers with assembly activities. This strategy has been popularly referred to as "just-in-time" delivery management. In contrast, nuclear utilities historically have favored the maintenance of inventories in excess of immediate fuel requirements.

Inventories of uranium are managed by utilities as part of work-in-process or "pipeline" materials required for the preparation of nuclear fuel to be loaded into the core of reactors.[124] In addition to the pipeline category, utilities also hold strategic inventories that could be used to minimize possible disruptions in supply, as well as hedging inventories used to take advantage of movements in uranium spot-market prices. Countries distant to uranium supply or nuclear fuel cycle services are more likely to hold strategic inventories. In contrast, some utilities in the United States, beginning in the 1980s, have held only inventories of the magnitude needed in the pipeline for a particular fuel reload.[125] Nevertheless, U.S. utilities have acquired excess inventories to hedge against a rise in prices. For example, discretionary purchases made in 1995 to hedge against a possible price rise contributed to an increased volume of spot-market transactions and the first increase in U.S. utilities' year-end inventories since 1983.[126]

As the electric power industry moves toward competitive retail markets, nuclear generating companies are likely to minimize inventory holding costs for both economic and regulatory considerations. Public utility commissions are likely to increase the regulatory oversight of fuel costs as they authorize nuclear utilities to recover potentially strandable costs before the onset of fully competitive markets while, at the same time, minimizing the impact on customers. As a result,

[120] Energy Information Administration, *Uranium Industry Annual 1997*, DOE/EIA-0478(97) (Washington, DC, April 1998), Table 5.

[121] "Third Quarter Spot U_3O_8 Review," *The Ux Weekly* (October 13, 1997), p. 1.

[122] Energy Information Administration, *Commercial Nuclear Fuel from U.S. and Russian Surplus Defense Inventories: Materials, Policies, and Market Effects*, DOE/EIA-0619 (Washington, DC, May 1998), p. 37.

[123] "The Auction Season (and Its Aftermath)," *The Ux Weekly* (September 8, 1997), p. 1.

[124] Some utilities sell nuclear fuel to another corporation and lease it back for use in reactors.

[125] R. McKeon, and J. Stefanko, "Uranium Procurement at Pennsylvania Power and Light Company (One Utility's Perspective)," paper presented at the U.S. Council of Energy Awareness International Uranium Seminar (September 1989).

[126] Energy Information Administration, *Nuclear Power Generation and Fuel Cycle Report 1997*, DOE/EIA-0436(97) (Washington, DC, September 1997), p. 22.

nuclear power plant operators may not be able to recover their traditional out-of-core inventory holding costs.[127]

To reduce inventory holding costs, the operators of nuclear power plants are expected to seek more flexible delivery schedules from nuclear fuel cycle vendors. Lead times for delivering uranium to each successive nuclear fuel cycle stage will be reduced. In a competitive marketplace, it will be important for fueling outages to coincide with low power market prices. This will require fuel deliveries to be flexible enough to meet the timing of the outages.

Enriched uranium product (EUP) is expected to be used in a just-in-time strategy. EUP can be purchased directly from suppliers for delivery to fuel fabricators.[128] This differs from traditional procurement practices, whereby the customer purchases uranium and delivers it first to a converter and then to an enricher. Since the customer does not hold title to the uranium contained in the EUP, the price of EUP includes both the cost of the uranium feed (uranium and conversion segments of the nuclear fuel cycle) suitable for enrichment and the enrichment service. By purchasing EUP, nuclear power plant operators no longer would carry the holding costs involved in owning the uranium through the enrichment stage, which would be transferred to the supplier and included in the price of EUP. The largest suppliers of EUP are expected to be enrichers with access to both competitively priced uranium feed and excess enrichment capacity.

Consolidation in Nuclear Fuel Procurement

A likely outcome of electric power industry restructuring is a consolidation in the ownership of nuclear power generation capacity. Consolidation is expected to take place through mergers, acquisitions, and plant closures. Also, some firms with successful nuclear operating experience will seek to provide operations management and related services to other owners of nuclear power plants. Corresponding to the consolidation in nuclear generating companies will be a decline in the number of buyers of uranium and nuclear fuel cycle services. In addition, individual utilities have developed working partnerships for the purpose of creating the economies of scale required to obtain nuclear fuel and other services at lower cost. One such partnership, the Utilities Service Alliance, was formed by 10 utilities.

Those fuel buyers remaining after industry consolidation are expected to engage in highly efficient procurement practices. They will be positioned to seek price discounts and other advantages from suppliers. Faced with oversupply and declining market prices, suppliers have been offering flexible contracts to utilities for many years. One such flexible contract arrangement offers the option to take delivery of additional quantities of uranium. The decision by a nuclear generating company whether or not to exercise such an option depends on market conditions and the contract price. The option is less likely to be exercised when the spot-market price is lower than the contract price. In this situation, a nuclear generating company could decrease its average cost by purchasing some uranium at a lower price on the spot market.

Consolidation in the Nuclear Fuel Industry

The dramatic decline in uranium prices since the late 1970s (Figure 13) has caused a number of companies to exit the industry. Large oil, metal mining, and nuclear services companies based primarily in the United States have divested significant holdings of uranium assets to concentrate on their core businesses.[129] The buyers generally have been either vertically integrated foreign nuclear fuel cycle companies with foreign government ownership or small domestic uranium mining companies. The consolidation of the uranium industry is continuing, although it is not as intense as it was between about 1985 and 1995.

Recently, the fuel fabrication industry has become the focus of significant consolidation that has been attributed to electric power restructuring. For example, a Siemens executive commented on the joint venture negotiations with British Nuclear Fuels, Ltd. (BNFL), initiated in October 1997, as follows: “These talks are aimed at strengthening the position of both BNFL and Siemens in a competitive market place. The deregulation of the world’s electricity markets is increasing the pressure on nuclear power plant operators to reduce their costs and increase plant availability. We want to explore whether a joint venture company will enable us

[127] J. Sellers, “Strategies for Competition and Nuclear Fuel,” paper presented at the Nuclear Energy Institutes’s FuelCycle 97 conference (Atlanta, GA, April 1997), p. 6.

[128] Energy Information Administration, *World Nuclear Outlook 1995*, DOE/EIA-0436(95) (Washington, DC, October 1995), p. 35.

[129] Energy Information Administration, *Uranium Industry Annual 1993*, “Uranium In Situ Leach Mining in the United States,” DOE/EIA-0478(93) (Washington, DC, September 1994), pp. x-xiii.

to better meet our customers' requirements by combining our technological and economic strengths."[130]

Fuel fabrication is less of a commodities business than uranium, conversion, or enrichment. Fabricators are involved in the design, manufacture, installation, and service of fuel assemblies for customers with a variety of reactor designs. With a goal of reducing costs, nuclear power generating companies are looking at fuel management practices, such as extending the time between refueling outages. To meet the needs of their customers' changing fuel management practices, fuel fabricators must develop innovative products and services. Facing the high cost of continuously improving the performance of reactor fuel in a potentially declining market, some companies have chosen to exit the business or seek joint venture partners. The remaining companies have one or more of the following strengths: (1) large market share, (2) manufacturing economies of scale, (3) technological innovation, or (4) overall financial strength.

Conclusion

As the States restructure generation markets over the next few years, utilities that cannot cover the operating costs of their nuclear power plants will be forced either to sell their nuclear units or to retire them prematurely. Nuclear units for which operating costs can be covered—including capital improvement costs—probably will remain in operation, but it is unlikely that all their sunk capital costs can be recovered. The inability of plant owners to cover the plant's full costs, including capital costs, under restructuring, produces "stranded costs."

How the States deal with stranded costs among utility shareholders, creditors, ratepayers, and taxpayers will determine whether nuclear utilities face bankruptcy. The stranded cost recovery issue will not, however, greatly influence whether certain nuclear plants remain in operation. The operational decision will be related primarily to the costs of operating the plant versus the costs of acquiring replacement power on the open market. Issues such as the long-run price of electricity, the supply of surplus capacity, the costs of compliance with Clean Air Act regulations, and the opportunities for greater savings in nuclear O&M costs will determine the outcome of the decision. At this point in time, it seems unlikely that the worst-case scenarios painted by observers of the nuclear energy market will come to pass. Most U.S. nuclear power plants currently are competitive with other sources of electricity, and deregulation probably will not cause them to become less competitive.

Average fuel costs make up just over one-quarter of the electricity generation costs for nuclear power plants. Nevertheless, the competitive environment created by a restructured electric power industry will provide the impetus for nuclear power generating companies to focus on reducing all costs, including fuel. In addition, if early retirements of nuclear power plants are brought about by the economics of electric power restructuring, the demand for nuclear fuel will be reduced. To compete, nuclear fuel suppliers will be forced to reduce prices or provide more efficient, customer-driven services. After enduring a prolonged period of depressed prices, many participants have already exited the nuclear fuel industry. Further consolidation is expected as companies seek to pool resources and spread the risks of operating in a highly competitive environment.

[130] BNFL, "Siemens and BNFL Agree Talks on Nuclear Co-operation," press release (October 15, 1997).

3. Challenges, Risks, and Opportunities for Natural Gas from Electric Power Industry Restructuring

Introduction

The electricity and natural gas industries are related in many ways. Historically, both have used coal to produce manufactured gas and to generate electricity, which they then distributed to end-use customers. Earlier this century, electricity was substituted for gas as a source of lighting. Starting in the 1920s and 1930s, electricity and gas competed for water heating, space heating, cooking, space cooling, refrigeration, and clothes drying services as the quality of home appliances improved.

Today, natural gas is used to generate electricity, especially during periods of peak demand, and it is the preferred source of energy for most new capacity. Both industries are also network industries, in which energy sources are connected to energy users through a sometimes complicated path of transmission and distribution lines. In the future, the two industries will not only be related but also interrelated by new institutions, such as futures[131] and spot contract markets. The degree to which natural gas will be a preferred energy source for peak electricity generation needs in the near future, or lose market share to electricity in the residential, commercial, and industrial sectors will be determined largely by these new institutions as well as the new business practices.

Natural gas supply has developed into a commodity market over the past 15 years, with active spot and futures markets. Electricity has been moving in the same direction during the past 5 years, with 2 futures contract markets established in 1996 and more expected by early 1998. Moreover, the number of generally recognized trading locations for electricity is growing.

The Federal Energy Regulation Commission (FERC) has begun opening up the electric transmission system in a way similar to that in which it opened up the interstate gas pipeline system. The electricity commodity and its transport are increasingly priced and provided as separate services. FERC has also proposed institutions for providing critical information—to be available to all interested parties in the industry electronically and in real time—about the price and availability of transmission space. Such information supports the development of competitive markets.

Institutions such as futures contract markets and electronic auction markets are important for greater integration of the natural gas and electricity industries. A principal challenge will be to improve the integration of the electricity and natural gas industries through these institutions to provide further support for the development of a competitive energy market.

This chapter discusses the importance of information and public markets for an integrated commodity market for gas and electricity and how electronic auction markets support integration. Price volatility is also examined, because it is both the source of growth for the futures market and a key motivator for the efficient allocation of resources. In addition, the growth of futures markets for electricity is illustrated. Some problems and challenges in the movement toward a more competitive market are also pointed out. The chapter ends with some general conclusions about expected changes in price and in capacity requirements for the gas industry as a result of electric power industry restructuring. A key point is that new institutions in both the natural gas and electricity industries are likely to affect suppliers of gas to electricity generators.

Market Evolution

New trading practices, institutions, and environments in the natural gas and electricity industries continue to develop and evolve as regulatory barriers to more open exchanges are removed. These new areas consist

[131] Futures trading is used in this chapter as an illustrative example representing the overall group of financial instruments available for managing price risk, such as options trading.

primarily of trading environments. For natural gas, the new institutions are futures markets, market centers or hubs—both at particular locations and along pipeline systems—and electronic auction markets. For electricity, the new institutions are futures markets, power exchanges, and the public reporting of prices and volumes traded at key locations.

The growth of the new institutions is a consequence of unbundling—of wholesale transmission and generation service on the electric side and of production, wholesale transmission, and storage on the gas side. These trading areas and institutions will continue to grow in importance and be modified, as electricity and natural gas unbundling is extended to the retail market. Innovations, such as electronic auction markets, have developed to improve the performance of cash markets. New institutions, such as futures contract markets, will both complement and compete with existing institutions, yet generally they will tend to improve the interrelatedness of markets for the two sources of energy.

Futures Contracts

The natural gas futures contract market has been a huge success, as indicated by the impressive growth in transactions. Every day there are about 200,000 contracts outstanding (open interest), which, in physical terms, translate into about 2 trillion cubic feet (Tcf) of natural gas—equivalent to almost 10 percent of the natural gas delivered in a year in the United States.

The growth of the futures contract market has provided several important benefits to the natural gas industry. First, it enables companies in the industry to manage unwanted price risk affecting expected gas transactions and thus protect themselves from some effects of price volatility. Second, it allows industry participants to discover readily the price of gas at any time, both for use in the negotiation of contracts for the commodity and as a clear reference point for price determination in transactions scheduled under a contract.

The typical market evolution for most industries is that active spot markets develop before futures markets are instituted. In contrast to this precedent, two electricity futures contract markets have been established even before a very active spot market has developed. This is a significant circumstance, because just as price discovery on the natural gas futures markets motivates exchanges of natural gas, price discovery on electric futures markets is expected to motivate exchanges of electric power both in kind and between natural gas and electric power. A major hindrance to the development of interfuel exchanges so far is that no electric futures market exists in the eastern part of the country to complement the highly successful gas futures contract market for delivery at the Henry Hub in Louisiana, which is well connected with many natural gas markets in the eastern United States.

Scheduling and Other Business Practices

Restructuring of the electric power industry in the United States is expected to influence business practices in the natural gas industry. For example, the scheduling of gas and transmission services (nominations) by wholesalers of gas will most likely be for increasingly shorter periods to better match operating and business practices in the electricity industry.

Although natural gas is used extensively for peaking service in electricity generation, gas contract terms often are not consistent with electric power needs. Hence, the amount of gas used for power generation is less than it could be only because it is much more timely and much easier to trade power than to purchase gas to generate power. At times, traded power is used rather than natural gas to satisfy a need even when generation from natural gas would have been the preferred choice.

Peak electricity prices can often be three times as great as nonpeak prices, and daily peak prices can increase several-fold over several days. Such large price fluctuations result in corresponding variation in the need to dispatch gas-fired generation because of the shifting relative economics. Consequently, rigidities in the flexible use of natural gas for power generation can cause significant lost opportunities for the industry. The continued opening up of the electricity industry and the increased availability of timely, reliable price information will provide a growing incentive for gas suppliers to shorten contract terms and increase the flexibility of scheduling practices to capture opportunities for expanded sales to the generation sector.

The Importance of Information in Competitive Markets

Liquid Markets and Price Transparency

Price transparency provides consistent, reliable information on market conditions to a wide number of market participants. This knowledge reduces transactional uncertainty and promotes a liquid market with ready buyers and sellers of the commodity. In the natural gas and electricity spot markets, the condition of liquidity is often inferred from the number of trades completed, since information on bid and ask prices is not yet available for many transactions. Simply stated, if a market has few or no trades on a day, it is considered an illiquid market. In an illiquid market, the amount of commodity exchanged can be very small, even though the amount of the commodity available to the market may be great. In fact, significant amounts of the commodity may lie idle when an illiquid market develops.

Price transparency is important for liquid markets and is especially important for markets that are inherently price volatile. Only if there is good price transparency will a sufficient number of buyers and sellers with different needs and preferences for risk be attracted to the market. A large number of candidate buyers and sellers with good market information and with ready access to transparent prices will be needed to support the development of liquid electricity and natural gas markets. Other things being equal, a significant number of transactions reduce the likelihood that market dominance will cause divergence between realized prices and a valid market clearing price.

The price spread between electricity and natural gas in markets with good information and many diverse participants is likely, on average, to be relatively constant. Exceptions will arise in periods of unexpected and significant shifts in demand and supply of the commodities. At such times, either the price of electricity or the price of natural gas will change significantly as demand for or supply of either fuel reacts. For example, if the electricity price increases significantly relative to that of natural gas because of a significant increase in power demand, there will be a tendency to purchase additional gas for the generation of electric power, thus raising the price of natural gas also. These changes in supply and demand will promote efficient increases in trade at critical times, as long as sufficient capacity is available to produce and deliver the energy.

Real-Time Information

When the demand for a commodity is highly variable between days (for example, because of difficult-to-predict weather changes) and the commodity is viewed as essential to quality of life, the relative value of real-time information about the commodity is enormous. In general, reliable market information supports the development of competitive markets with numerous exchanges between buyers and sellers. This includes not only reliable price information transparent to a wide number of industry participants in real time but also general market conditions.

Knowledge of the current market price is important because it promotes efficient behavior. FERC realized in developing Order 636[132] that readily available information would have great commercial and operational value and would also support the development of competitive markets. Thus, Order 636 prescribed that pipeline companies ". . . provide timely and equal access to all information necessary for buyers and sellers to arrange for capacity reallocation." Additionally, FERC itself provides electronic access to much data on jurisdictional gas pipelines. Despite the intent of this activity, its development to date has not met the original goal to provide timely, comprehensive data useful to promoting a competitive market for transmission services.

Information is made available by both the pipelines and the FERC.[133] The companies post their tariff[134] schedules, available released capacity, and operational available capacity on electronic bulletin boards (EBBs). The two types of capacity information are used by interested potential firm shippers in acquiring the associated rights.[135] The FERC maintains various information on its EBB, including information on pipeline tariffs, the index of customers, and the discount report. The index of customers is a quarterly report on the applicable tariffs and capacity used in firm transportation and firm storage services on the first day of each 3-month period. The discount report is a filing by transporters to FERC

[132] FERC Order 636, known as the Restructuring Rule, was issued on April 8, 1992, and was designed to allow more efficient use of the interstate natural gas transmission system by fundamentally changing the way pipeline companies conduct business.

[133] The present discussion is based on a representative description of available information. Any characterization of data posted on the EBBs by the companies or the FERC is subject to a number of exceptions, a number of which are identified. The general simplification is adopted for illustrative purposes.

[134] A tariff is a compilation of all effective and superceded rates, rate schedules, general terms and conditions of service and forms of service agreements. While it contains a set of pricing alternatives, the tariff generally does not indicate the actual price paid for any transaction.

[135] While a shipper may use operationally available capacity to move gas, an accurate measure of operationally available capacity will not be identified until the capacity release bidding and award processes are completed.

that provides the customer name, the rate schedule for service rendered, and the maximum and actual rates charged for each customer that received a discount in the previous billing period. The discount report does not, however, provide the amount of capacity that is discounted.

Since the tariffs do not specify charged transportation service rates, the FERC and pipeline company EBBs do not provide timely information on prices paid by primary holders of transportation capacity. Therefore, transportation market participants are unable to determine the actual price primary holders of capacity pay for capacity prior to the start of service. In addition, bids for released capacity are not required to be posted on EBBs. The successful and unsuccessful bidders are notified of the results the day before nominations for service may take place. Further, capacity trades at the maximum tariff rate or with terms of one calendar month or less are exempt from the bidding process. These capacity trades are not posted until the day nominations for service may take place. In all cases, the price information for natural gas firm transportation service is available only after the close of the auction process. Absent a comprehensive data source, the extent and quality of gas market information on price and transactions completed varies significantly between companies. These information limitations are serious impediments thwarting widespread, effective use of EBBs to facilitate active trading.

The value of information is likely to increase over time as the natural gas industry continues to shift toward more streamlined operations under competition from a regulated, cost-of-service business. As excess capacity is reduced, the allocation problem becomes more pressing. Price risks from bottlenecks or congestion increase as available capacity declines relative to expected demand, which is growing. As the electric power industry evolves along similar paths, its data requirements will expand correspondingly.

Electronic Auction Markets and Information

Technological innovation has advanced the evolution of markets in a number of ways. A recent development involves the use of electronic auctions to promote efficient transactions in the cash market. In the past several years, electronic auction markets for the natural gas commodity have become increasingly common for a large number of locations.

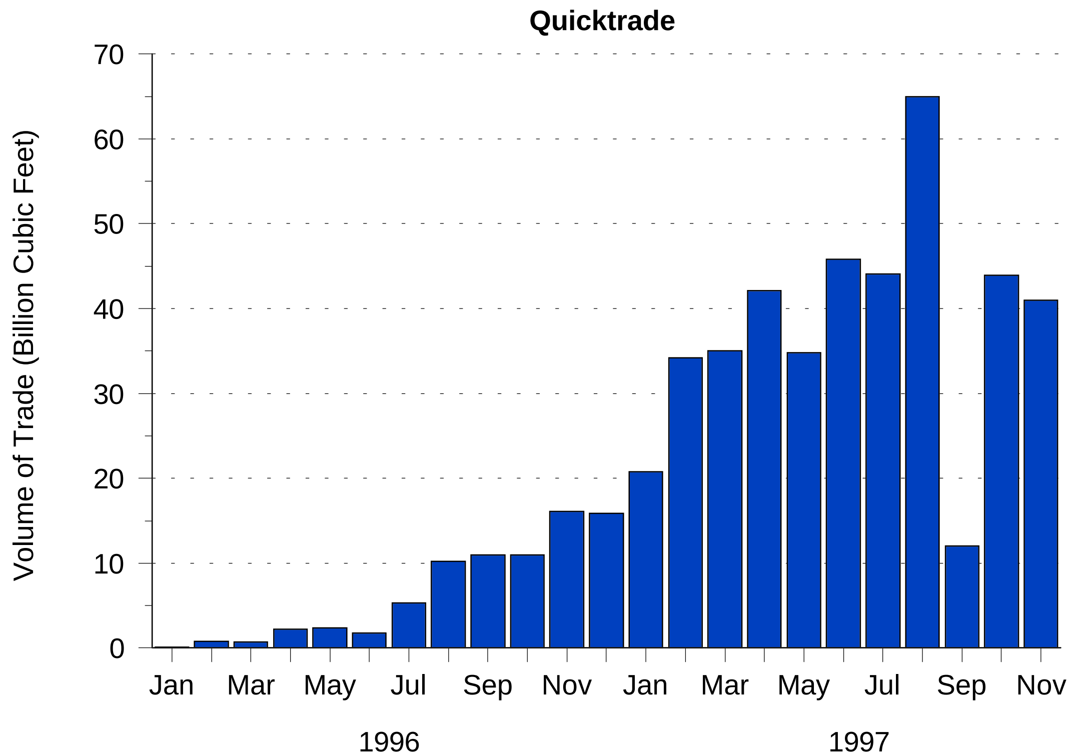
Prices are very transparent on auction markets. Throughout the trading day, bid and offer prices and quantities are posted. When a buyer accepts a seller's offer price or a seller accepts a buyer's bid price that completes the deal, it is clearly indicated by a visual cue. At the end of the trading day, the aggregate amount of gas traded and the volume-weighted price are computed and transmitted to the trade press. The press then sends this material in tabular and graphical form to its subscribers, often with some additional commentary. Reporting of summary data for a day looks very much like the reporting of summary statistics in the *Wall Street Journal* for commodities traded on futures contract markets. This information and the right to trade gas are available for any company that is willing to pay a fee to the company for access to the auction market trading platform.

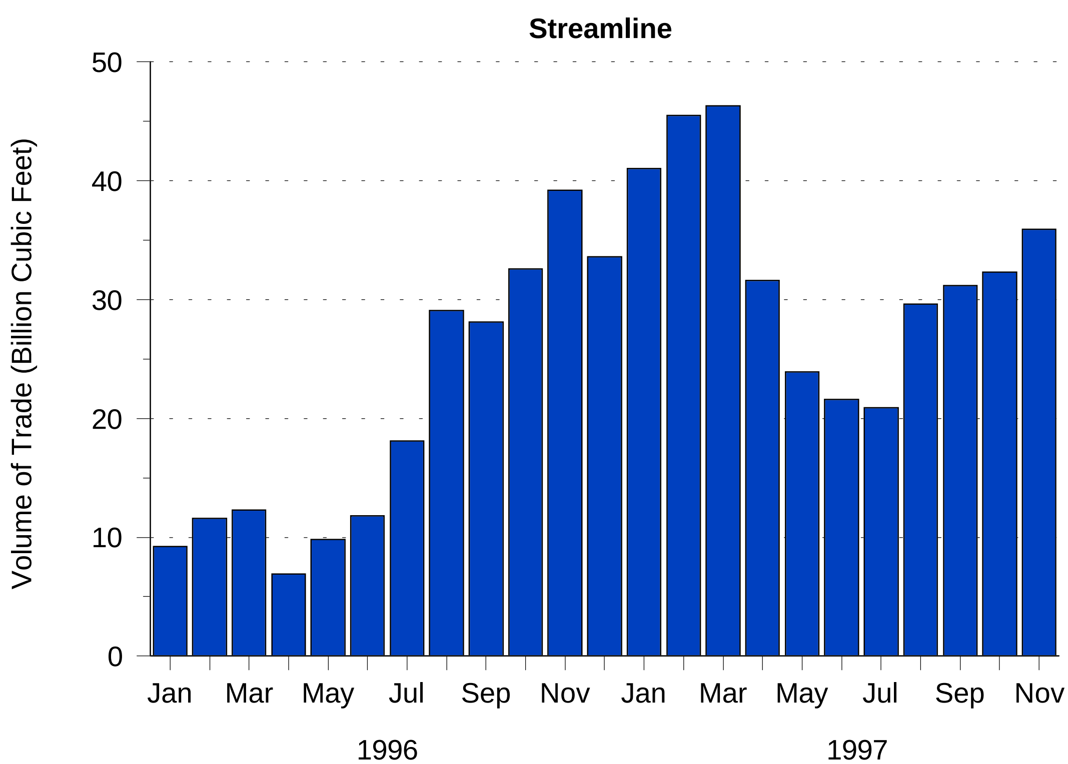
Companies are willing to pay a fee for participation in an auction market because it offers profit opportunities and, in some instances, a means of hedging price risk by fixing the price of gas (see box in the following section). Other companies are willing to pay a slightly reduced fee just to view the price information and not to trade. Some companies also subscribe to electronic data services, such as Bloomberg's, which provide price and other market information throughout the day from a wide variety of sources.

Before the advent of public auction markets, most companies in the industry relied on either futures market or trade press information for price discovery. This reliance had certain shortcomings. Futures prices represent the price at a particular location, which is not necessarily the location where a company would like to make or take delivery. If there is a uniform differential in futures prices between locations, changes in futures prices between days at one market may be thought also to represent price changes at other locations. However, the usual relative price structure between locations may not prevail under all circumstances, even for markets that are geographically near each other. At such times, the use of a single market price signal likely will lead to inappropriate supply or demand response in the other markets, distorting market behavior and often leading to profits or losses not commensurate with local market conditions. Nonetheless, futures markets are the most general and accessible source of price information, and there are ways to mitigate the impact of this source of price risk. Trade press data for particular locations also are subject to misreporting and measurement error.

Although public auction markets are just now being developed in the electric power industry, their significant growth in the natural gas industry (Figure 14) may inspire further development for electricity. Not

Figure 14. Auction Markets, January 1996–November 1997





Sources: **Quicktrade:** Quicktrade Canada Limited Partnership (Calgary Alberta, Canada); **Streamline:** Altra Streamline, L.L.C. (Houston, TX).

Price Risk Exposure in Auction Markets

A company having the capability to engage actively in both buying and selling a commodity, such as natural gas, must consider the price risk implications associated with activities in an auction market. Consider an electric utility using gas for power generation. The company assesses its daily requirements and signs a contract to acquire its average requirement for a specified time period at an agreed upon price. The company then buys natural gas whenever its current needs are above its average requirements and sells gas whenever its current needs are below its average level.

If the utility developed an unbiased estimate of its expected average requirements, those requirements are symmetrically distributed about that estimate, and the price the customer pays is independent of the utility's incremental demands, then the sums of the incremental amounts that it receives and pays by following this strategy should be equal. Thus, the price it pays for natural gas during the term of the "average requirements" contract is the contract price for gas. However, the necessary conditions are quite restrictive, and the utility remains open to other possible outcomes. If its price is negatively correlated with its incremental demands then there should be a net gain associated with this strategy.

The above strategy would be a disaster for a customer with incremental demands that are positively correlated with price, such as significant space heating demands. Further, if the estimate for its requirements is not unbiased with a symmetrical distribution, the incremental amounts from subsequent resales and purchases may not offset, thus shifting the average price for the utility up or down correspondingly.

These factors can be used as the basis for an acquisition strategy that attempts to optimize the expected return to the utility, but it involves a complex set of factors under uncertain conditions. Such strategies may mitigate potential price risk impacts, but they do not assure effective price risk protection.

surprisingly, companies involved in providing natural gas trading platforms (computer software support, credit rating checks, accounting and other services) have plans to provide similar platforms for the electricity industry. In fact, it is likely that electricity and natural gas will be trading on the same screen in a few years.

Price Volatility

Price volatility refers to rapid and significant price variability. Volatility can be measured as relative deviations around an average price value. Volatility is commonly higher for electricity and natural gas than for other commodities. Most commodities exhibit price volatility of less than 20 percent, whereas the average price volatility for natural gas and electricity generally exceeds 40 percent (Figure 15). For example, the average price variability during the 8-month period from November 1996 through June 1997 was about 45 percent for natural gas and for electricity, more than twice that for other commodities. The volatility for natural gas declined between December and May, but the volatility for electricity remained fairly constant.

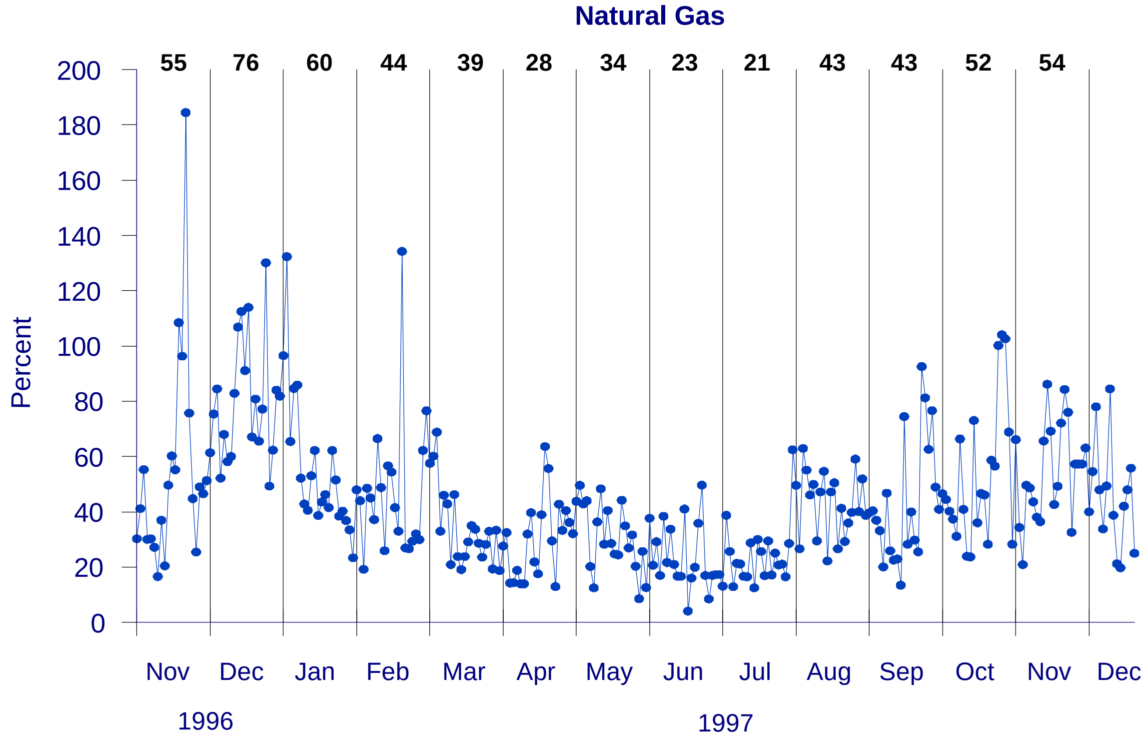
The decline in the volatility of natural gas prices in the spring could reflect the simple fact that natural gas prices are influenced greatly by temperature, the variability of which is at its lowest in the spring. Natural gas, much more than electricity, is used for space heating, which is a very temperature-sensitive use of energy. On the other hand, electricity price variability is influenced not only by temperature variability but also by unplanned outages of generators and a greater number of transmission problems. In addition, the inability to store electrical energy means that buffer stocks are not available to respond to unexpected contingencies throughout the year.

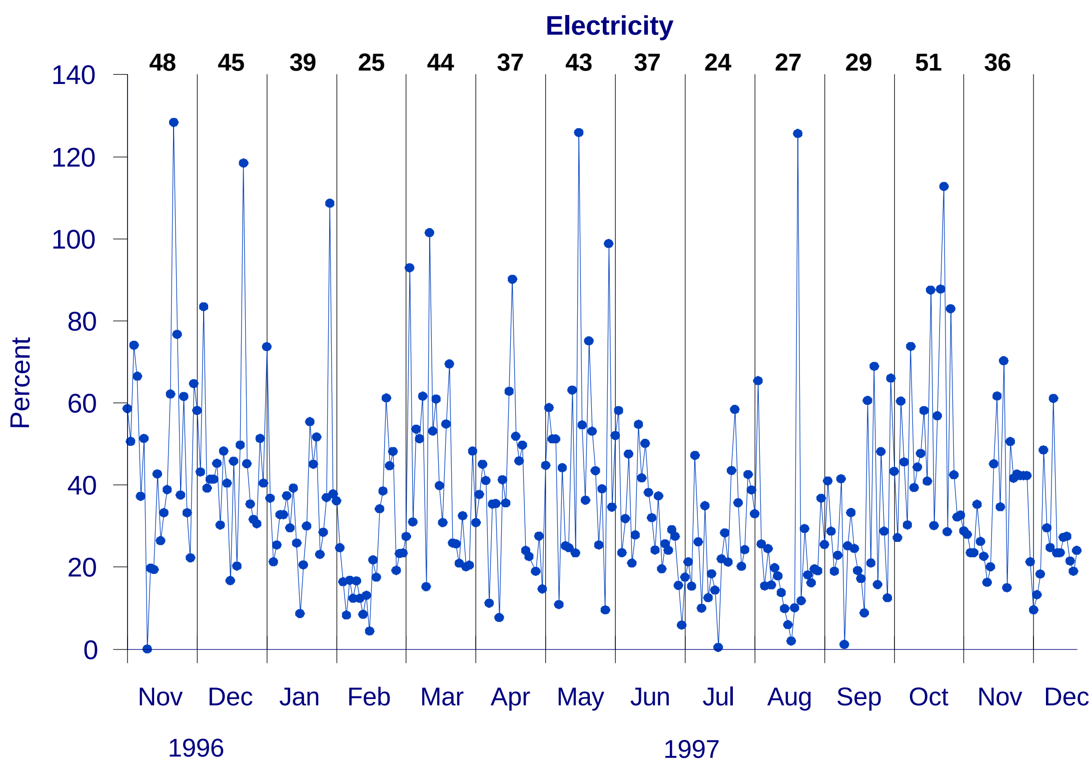
The Need for Futures Markets in Price-Volatile Spot Markets

Significant amounts of price volatility in a market support the development and growth of futures markets because of the great price risk in such markets. Price volatility is a fact of economic life in deregulated commodity markets, subject to the whims of nature and other forces outside an industry's control. Companies need to manage price risk so that they can both concentrate their energies on other aspects of their business and protect income streams for investments. Hence, futures markets have been developed as a way to manage price risk. Because of the great volatility in natural gas markets, the growth of the natural gas futures market has been phenomenal. Most recently, the growth in the electricity futures contract markets has also been impressive (Figure 16).

Important factors for the development of a futures contract market typically are the availability of a standardized product and an active spot market. Spot markets for natural gas have developed all across the

Figure 15. Volatilities for Natural Gas (Henry Hub) and Electricity (California-Oregon Border)

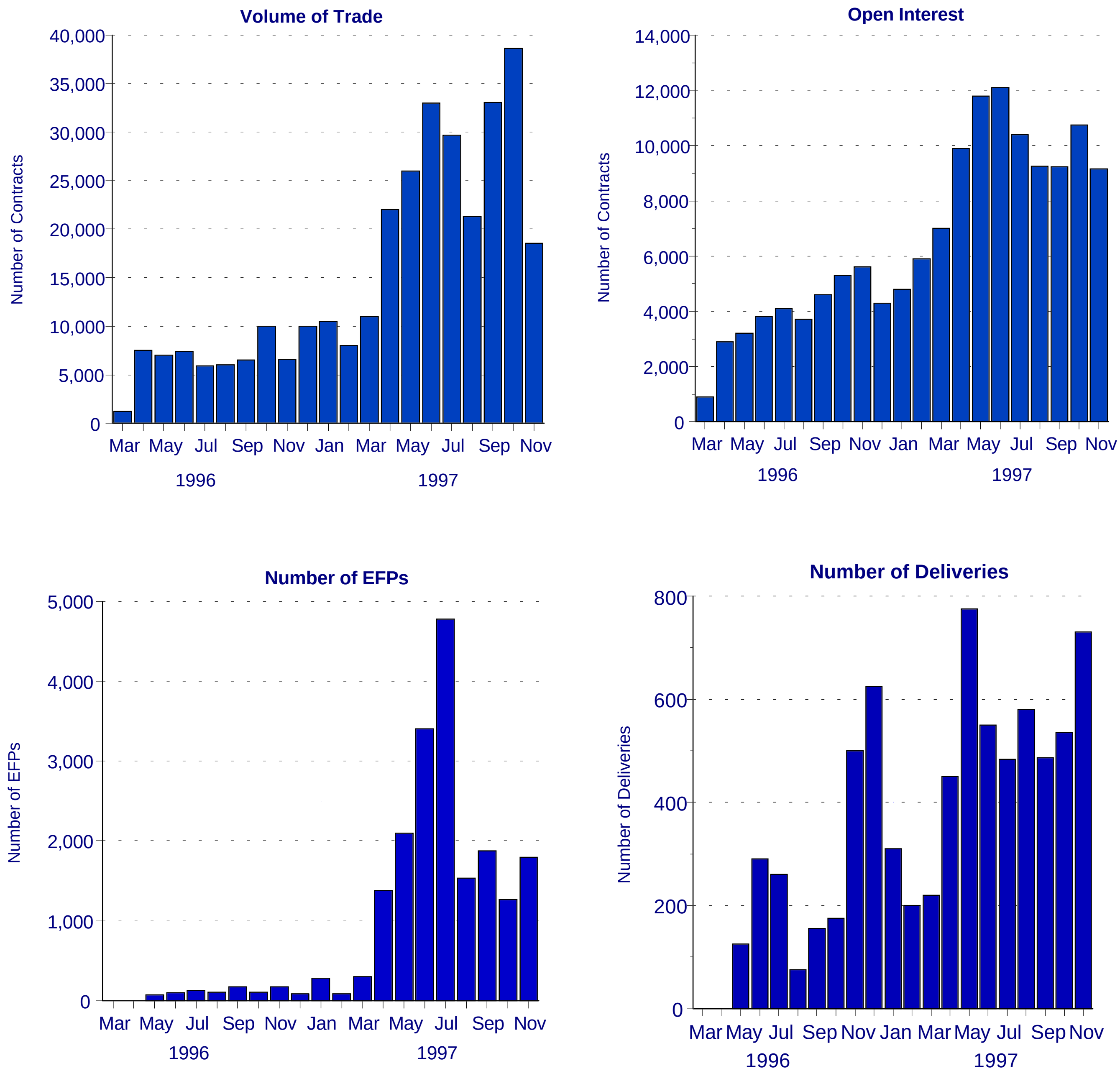




Notes: Volatility is an estimate of the annualized standardized deviation of daily price changes expressed in percentage terms. Volatility numbers for a month are indicated on the graphs.

Source: Energy Information Administration, Office of Oil and Gas, derived from Commodity Futures Trading Commission, Division of Economic Analysis.

Figure 16. Electricity Futures Contracts



EFPs = Exchanges of Futures for Physicals.

Notes: The volume of trade is the total number of contracts traded per month. Open interest is the number of contracts at the end of the month.

Source: Energy Information Administration, Office of Oil and Gas, derived from Commodity Futures Trading Commission, Division of Economic Analysis.

United States as the industry has become increasingly competitive. Natural gas and electricity are both highly standardized commodities. In fact, standardization is necessary in both industries to avoid operational problems. The characteristics of natural gas are similar in different markets scattered across the United States. This, in part, explains the growth in the volume of transactions on spot and futures markets for the commodity. There is usually much more variability in the characteristics of such well-known commodities as corn and wheat at different locations than there is for natural gas and electricity.

Because location is an important attribute even for a homogenous product, a delivery point must be established for futures trading. The location chosen for a delivery point for a futures market is usually where there is a very active spot market and where delivery problems are not likely to occur. Even though futures contracts are primarily financial instruments for price hedging or fixing the price of energy, deliveries through a futures contract do, in fact, occur, and when they do occur, the futures exchange has a great interest in maintaining ease of delivery.

Futures markets thrive on the frequent exchange of futures contracts. Frequent exchanges, in turn, are motivated by inherent price volatility and supported by market liquidity. An important objective of the futures contract market is to obtain broad and extensive involvement of the industry, which will support the liquidity of the market. Because participation is supported by the availability of information, futures contract markets are information-intensive markets. As new information is received about the condition of the markets, participants in the industry open and close out positions on the futures contract market, which again provides support for liquidity.

The futures exchanges want to involve every part of the industry—both buyers and sellers of the commodity—in hedging instruments, so that it will be easy for companies to open and close out futures positions at current prices. However, the futures exchange governing board understands that the industry participant will want to take delivery at times. In these arrangements, delivery capability should never be an issue or else the industry participants may lose interest in the futures contract market, which may reduce its liquidity.[136]

In fact, recent growth in the electricity futures market as measured by the number of contracts was influenced in a significant way by an increase in the number of deliveries through futures contracts and the number of "exchanges of futures for physicals" (EFPs) (Figure 16). In EFPs, companies use opposite futures positions to help complete deals in the cash market. In an EFP, a prospective buyer opens a long futures position (equivalent to buying a futures contract for forward delivery) and a prospective seller opens a short futures position (equivalent to selling a futures contract for forward delivery).

The great appeal of the futures contract market is the superb price discovery associated with it and the capability of a buyer and a seller to arrange delivery some distance from the location of the delivery point for the futures contract. They accomplish this by negotiating the difference between the price on the futures contract market and the price at the location where they would like to complete an exchange. This type of arrangement is possible because both parties at different locations have the same price information available to them. They also alert the futures exchange that they intend to do an EFP, documenting the planned exchange. They simultaneously close out their opposite positions on the futures contract market when they complete the deal on the cash or physicals market.

While growth in standard deliveries can be viewed as positive from the point of view of a market providing a service, it is also suggestive of the stage of development of the electricity spot markets. If the market for 1-month deliveries of peak service (the specifications for delivery under a futures contract) had broad market participation and the futures and cash prices were converging, then participants in the futures markets would close out their positions and not take delivery through the futures contract, because delivery through a spot contract ordinarily would allow them more flexibility in terms of delivery options. Moreover, if price discovery and the delivery mechanism for 1-month peak deliveries at a large number of locations were good and the number of market participants were large, then EFPs would generally not be used to effect exchanges.

[136] A company uses the futures contract market by opening a position on the futures market that is consistent with its position in the spot market. For example, if a company intends to sell power a month from now and wishes to fix the price today, it will sell a contract for forward delivery at a price quoted on the futures market for delivery in the forward month (called a short position on the futures contract market). If a company intends to buy power a month from now and wishes to fix the price today, it will buy a contract for forward delivery (i.e., open a long position). When a company opens a futures position, it has to pay a broker for handling the transaction and also has to post margin (a type of down payment) with the brokerage firm. The amount of margin varies with price volatility and also changes over time as the current price of the commodity on the futures contract differs from the price when the company opened its position.

Convergence of the Natural Gas and Electricity Markets

New Institutions

In the restructured electricity industry, the independent system operator (ISO) will be an institution for preserving the operational integrity of the electricity transmission system in the short term. The ISO will be independent of the transmission companies that use its services. In the natural gas industry, the pipeline company, which provides services similar to those provided by an electricity transmission company, is responsible for the operational integrity of the pipeline system.

The fact that the pipeline company remains responsible for the operational integrity of the pipeline system has created concern in some segments of the gas industry and complaints at FERC concerning possible affiliate abuse. Concern arises that a pipeline company has an extensive catalog of detailed transaction records regarding the gas requirements and purchasing practices of many, if not all, participants in the traditional markets served by the pipeline. The marketing affiliate of a pipeline, being staffed generally by former pipeline personnel, may have a sizeable competitive advantage in gaining market share. Further potential abuses can arise if the pipeline company and its affiliate do not operate at "arm's length." Some possible abuses stem from the pipeline company's possible access to certain real-time information on the utilization of the pipeline system. In addition, the pipeline company can impose penalties based on this and other information.[137] Other companies complain that this access to information and the right to impose penalties could result in benefits to the marketing affiliate of a pipeline company.

In the electricity industry, the open access same-time information system (OASIS) requires all bid and ask prices for transmission space to be posted, including the capacity contracted for under a transmission company's tariff (primary capacity) and the primary capacity leased to another party on a capacity release market (secondary capacity). Regulatory reform of the gas industry led to adoption of electronic bulletin boards (EBBs), which are that industry's precedent to the electric power industry's OASIS. However, as discussed previously in this chapter, the gas industry EBBs generally have suffered from a number of inadequacies related to their information content and associated processing capability. At best, actual rates paid by holders of gas transportation service are posted only after the fact, if at all. These information limitations are serious impediments thwarting widespread, effective use of EBBs to facilitate active gas trading.

The information available for the electric and gas industries is not equivalent in extent or quality. As the electricity and natural gas industries continue to move toward markets in which different types of energy are increasingly substituted for one another, depending on price, and where an increasing number of companies are regularly exchanging both types of energy to lower costs and remain competitive, this disparity in information may become a growing issue. On the one hand, more complete posting of information in electric power markets may encourage the gas industry to report similar, more complete information. The motivation for change in this case would arise if companies believe that there are significant profits to be gained from taking advantage of differences in current supply and demand conditions in various energy sectors by substituting energy sources whenever changes in relative prices indicate such action would be wise. On the other hand, companies in the gas industry may resist the release of more information because they perceive greater competitive advantage in exploiting other information while details regarding their own transactions remain confidential.

Exchanging Natural Gas and Electricity and the Nomination Process

In the past several years, natural gas companies generally have needed to nominate for specific amounts of pipe space a day ahead of time before they could ship gas. In the spring of 1997, the industry moved to allow for intra-day nominations, whereby a company could arrange for shipments of gas on the same day it purchased the gas. This is a major step forward, with clear advantages for market participants to respond with minimal delay as conditions warrant.

The electricity industry already has a sizeable daily market in which power is actively traded on an hourly basis as needs change. The greater frequency at which electricity is traded reflects both the larger size of the hourly loads faced by particular companies and a much

[137] The pipeline company has the right to impose imbalance penalties when a company has taken more or less gas than authorized under a contract. In theory, a pipeline might structure these penalties in such a way that it could penalize a group of customers substantially without impacting its marketing affiliate severely.

greater need to balance the loads on the electric system throughout the day to avoid operating the system beyond its limits.

The electricity industry has few options to adjust power supplies, in contrast to the gas industry, where the options include taking gas out of storage and changing compression within segments of the pipeline system. The inability to store electricity efficiently requires operators to meet consumption variations by dispatching fewer or more generation units. Broader tolerances for operating a gas system provide greater operating flexibility, which allows operators to prepare the system in a way that will allow them to better position themselves to serve anticipated demand or shifts.[138] For example, gas transmission and distribution companies can prepare for a demand rise by increasing line pressure, thus "packing" the lines with extra compressed gas. Additionally, deliveries can be drawn from gas stored in facilities stocked during the off-peak period.

Whether the gas supplies are stored in the line or in recognized storage sites, they are an important source of gas at peak. Flexible options are also available in case the demand does not develop as expected. The company can sell the gas on the spot market, divert it into an alternative storage site, or use "parking services" for the gas from a market center. A utility usually has some time to adjust its takes of gas to reduce any imbalance that develops on the pipeline system because of taking less gas than expected. These operational options do not exist for electricity transmission.

Market Centers and Exchanges of Gas and Electricity

Exchange of a commodity is naturally encouraged at a location where there are pipeline or electric transmission interconnections. The natural gas and electric industries have several locations at which many pipelines or transmission lines interconnect. In the natural gas industry, a good example of such a location is the Henry Hub in South Louisiana, where standard deliveries through futures contracts occur. Exchanges are also encouraged along those pipeline and transmission systems where a large number of users have complementary needs and where contract sizes are small, various contract terms can be readily accommodated, and the needs of the users change unexpectedly over time.

Contractual simplicity is an important factor influencing activity. For example, if several companies use a master contract in which only price, delivery, and receipt points need to be negotiated to complete a deal, it will encourage a much larger number of trades than there would be otherwise. Areas along pipeline or transmission systems where frequent exchanges of the commodity occur are often described as "pooling points" or "market centers."

Suppliers of natural gas and coal to electricity generators increasingly track the price of power at different locations in real time. When the price of electricity rises significantly at a location, they attempt to sell more gas or coal into a market near the location, sell gas to a particular generator near the location, or transport gas or coal to a particular generator and arrange to have the generator produce more power. In the latter case, the gas supplier may also arrange to sell the power—a practice known as "tolling." In a sense, these activities represent a race for generation, in which natural gas has the advantage over most other energy sources because of its greater operational flexibility and the ease with which incremental gas supplies can be moved to generators.

Another advantage of trading natural gas to generate power instead of trading power to satisfy demand is that it reduces the chance of congestion problems along transmission lines. Instead of moving power great distances over transmission lines, natural gas can be distributed to generators near markets experiencing significant unexpected shifts in demand for electricity. Since such shifts in electricity demand are more likely to occur in the summer, when significant space is available on gas transmission lines, this strategy implies a better use of industry infrastructure.

A good example of a market center along a pipeline system is Transco-Zone 6, which extends from Northern Virginia to New York City. Every day within this area many exchanges of gas are made between companies whose daily requirements vary from their daily rights to gas. Thus, a shipper who has an unexpected need for gas can balance it through exchange with a shipper who has an unexpected reduction in its requirements. Accordingly, the price statistics reported to the trade press for Transco-Zone 6 are considered to be reliable because they generally represent a large number of exchanges.

[138] In the case of unexpected demand or supply shifts, the operational flexibility often allows operators along the system to react to changes without requiring these responses to be immediate. Delayed reaction to variation in electricity consumption can result in system collapse.

A good example of a trading area for electricity is the area near the Pennsylvania, Maryland, and New Jersey borders, designated PJM. This location is accessible to many utilities and other large customers in the area. Many of the major consuming centers within the PJM area also are included in Transco Zone-6. The rough geographic coincidence of these markets allow a comparative analysis of gas and electric prices to assess the potential for interfuel trading opportunities for operators in these markets.

The prices for the two fuels in this area have striking differences (Figure 17). The electricity price series is more volatile than the natural gas series and, overall, tends to be higher. If the average difference is sufficient to compensate for conversion loss and additional capital charges, there would appear to be profit opportunities for companies that use natural gas to generate electricity in this area.

The largest price spikes for electricity occurred in June and July, which is a nonpeak period for gas prices, providing arbitrage opportunities favoring electricity over gas. The largest gas price spikes occurred in December 1996 and January 1997, when electricity prices also surged, but not to the same degree. An examination of weather data indicates that temperatures were significantly below normal at those times. This suggests that very low temperatures similarly affect both prices in this area, but gas prices so much so that the usual relation is reversed, with natural gas prices above electricity prices. Thus, it would be valuable for electricity generators that depend on natural gas for peak generation to avoid spot market purchases with their high associated prices at such times.

Power trading is likely to grow in importance as the electricity industry continues to be restructured at the wholesale and retail levels. As the market for power becomes more open, with broader industry participation and competition, sellers of power will be strongly motivated to seek out the least expensive supplies. The net impact of increased power trading on gas use for electricity generation remains to be seen. As more power is exchanged between parties to satisfy peak load demands, the demand for peaking generation—and for the natural gas that is used heavily for peak-load power generation—will be reduced. It does not necessarily follow, however, that reduced use of natural gas at one generation facility will result in the use of a different fuel elsewhere. The fluid exchange of fuels and power, both within and between the markets for each, will facilitate trades that can realize locational advantages in generating power from the same fuel but in different markets. Such trades may be the preferred outcome whenever the price differentials between markets are sufficient to compensate for the incremental transmission charges.

Challenges for the Natural Gas Industry

The trading of electricity and natural gas is not nearly as synchronized as it could be. The amount of trading in electricity and natural gas needed to enable these markets to take advantage of arbitrage opportunities is less than it could be, limiting the liquidity of both markets.

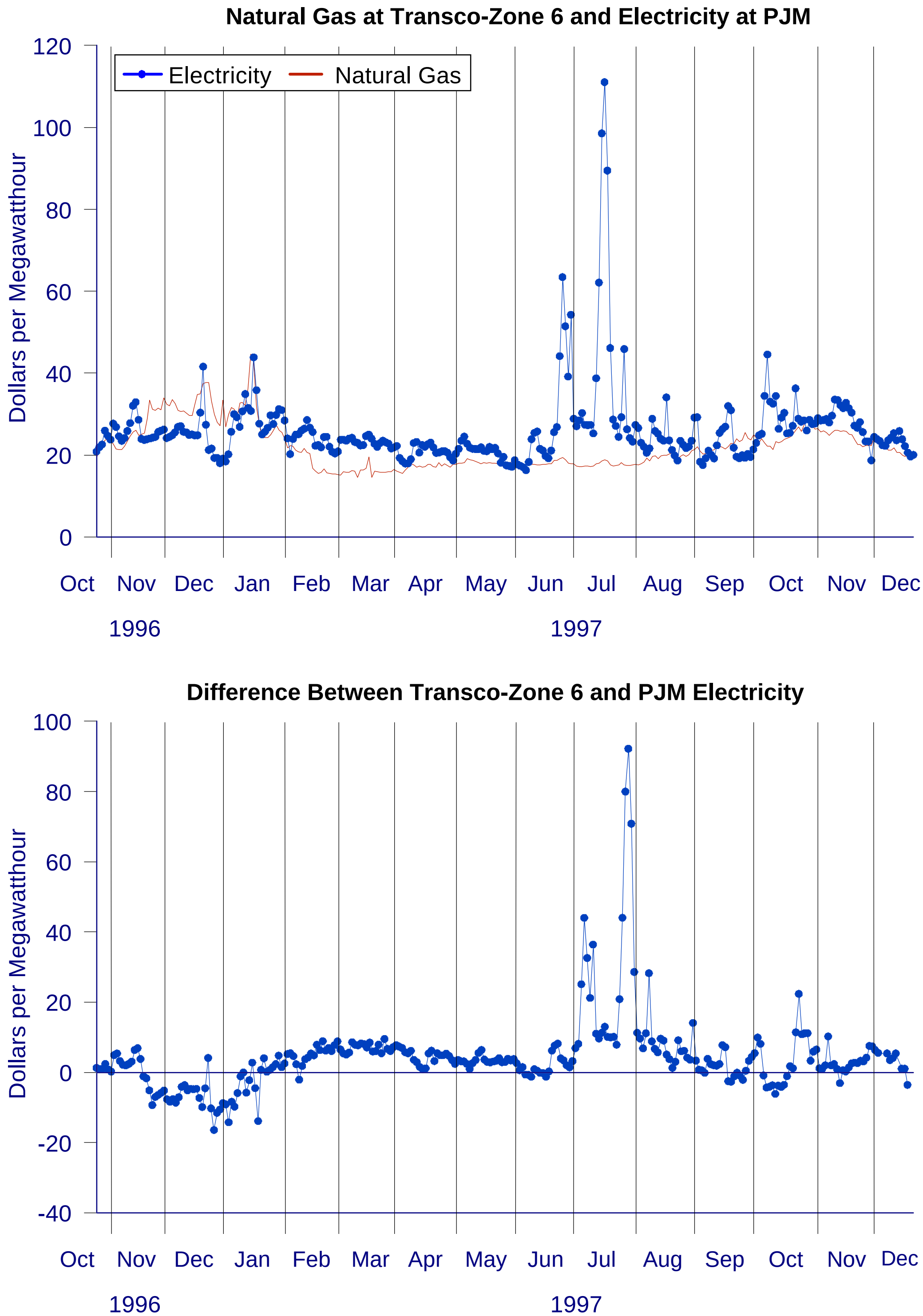
The terms of the shortest-term natural gas contracts tend to be much longer than the terms of the shortest-term electricity contracts. The difference in terms of trade is such that a difference in price that may have inspired a decision to purchase natural gas for electricity generation may erode significantly by the time the exchange agreement is completed. In the worst case, a company could be motivated to contract for large incremental supplies of natural gas because electric power is selling at a much higher price than natural gas; however, when the company began receiving the gas for power generation, it might discover that the price of natural gas has risen to a prohibitive level relative to the price of electricity.

When the terms of gas contracts become shorter, when deliverability and flexibility improve, and when nominations for gas and electricity are better synchronized within days, a greater number of trades can be completed. As a result, the level of price volatility could be reduced, and the chances of regular price convergence could be increased.

In order to promote exchanges, it is important that transaction costs be a small proportion of the cost of exchanging power and natural gas. Reduction in transaction costs will tend to occur when contracts become increasingly standardized across natural gas and electricity. Only when such standardization occurs will a Btu market with broad industry participation emerge.

Business practices for contracting exchanges of natural gas for electricity have changed extensively in the past 5 years. Prior to the 1990s, electricity prices were based on the cost of the energy needed to generate electricity plus any additional direct and indirect costs of getting the energy source to the generation plant. When electricity prices are based on current supply and

Figure 17. Spot Prices, November 1996–December 1997



Notes: PJM represents an area near the Pennsylvania, Ohio, and Maryland border where many power exchanges are made. Transco-Zone 6 represents the portion of Transco Pipeline Company from Northern Virginia to New York City. The heat rate used to convert the Transco-Zone 6 price to megawatthours (MWh) is 7.5 MMBtu per MWh.

Sources: **PJM:** The McGraw-Hill Companies, Inc. *Power Markets Week* (various issues). **Transco-Zone 6:** Pasha Publications, Inc., *Gas Daily* (various issues). **Differences:** Energy Information Administration, Office of Oil and Gas, derived from The McGraw-Hill Companies, Inc., *Power Markets Week,* and Pasha Publications, Inc., *Gas Daily.*

demand conditions, the most economical and operationally flexible energy source will be used for generation.

It is likely that metering and measuring gas flows throughout the industry will be increasingly important as more frequent exchanges of energy take place between participants in the marketplace. The increased importance of metering will also be a response to improved price information as price responds more to short-run shifts in demand and supply, especially because there will be more short-term contracts for natural gas and electricity being traded.

Peak load pricing likely will become increasingly common in the electricity and natural gas industries as market information is passed on to customers. When peak demand prices are much greater than average prices, this type of pricing should reduce electricity demand at peak times. If a significant portion of peak demand is satisfied from natural gas turbine generators, the demand for natural gas will increase.

Reliable information on price, available during the day to many participants in the industry, will lead to better allocation of the commodity. In the longer term, it will lead to better allocation of capital, because the industry will have additional price information for deciding where additional pipeline and transmission capacity should be placed. As a result, the average costs of transportation and services should be reduced, as well as the amount of planned generating capacity required as the electric power industry moves from a highly regulated market to a less regulated one. Thus, in general, both planned capacity and average prices for the natural gas and electricity industries are likely to be reduced in the future. These positive outcomes are likely to occur only if reliable information on current market conditions is readily available, prices are transparent, and market institutions for gas and electricity are designed to respond to short-run shifts in supply and demand.

4. Impacts of Electric Power Industry Restructuring on Crude-Oil-Derived Fuels

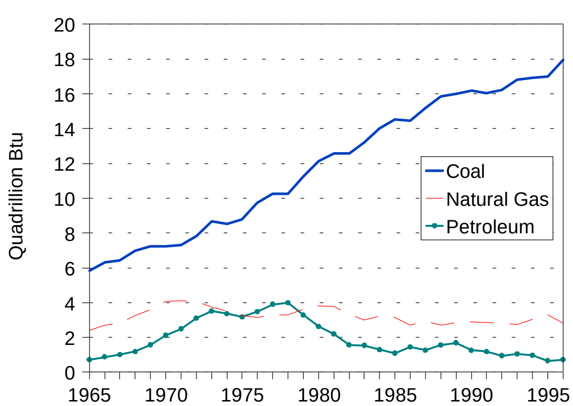
Introduction

Many products are derived from crude oil, and they serve many different markets. The transportation sector is the largest market for petroleum fuels (66.2 percent of petroleum consumed in 1997), followed by the industrial sector (25.5 percent of petroleum consumed), the residential sector (6.0 percent), and the utility sector (2.3 percent). Of the fuels produced from crude oil, distillate fuel oil, residual fuel, and petroleum coke are most likely to be affected by electricity deregulation. Overall, however, there should be little impact on crude-oil-derived fuels.

Petroleum use by utilities is small and has been diminishing (Figure 18). Similarly, petroleum fuels only about 2 percent of electric utility generation. Most of the petroleum fuel burned by utilities is residual fuel oil, which is a low-valued product whose markets are disappearing, making it economical for refiners to convert the fuel to other products. In 1997, residual fuel represented only 4.8 percent of all petroleum products consumed, and utilities accounted for about 38 percent of total residual fuel consumption. The small impact of deregulation on petroleum products will most likely be from:

- Utilities having more flexibility and stronger economic incentives to use the most economical fuels
- Oil companies having more options for dealing with their low-valued fuels, such as high-sulfur residual fuel and petroleum coke.

Figure 18. Utility Consumption of Fossil Fuels, 1965-1996



Source: Energy Information Administration, *Annual Energy Review 1996,* DOE/EIA-0384(96) (Washington, DC, July, 1997), Table 8.5.

Utility Use of Crude-Oil-Derived Fuels

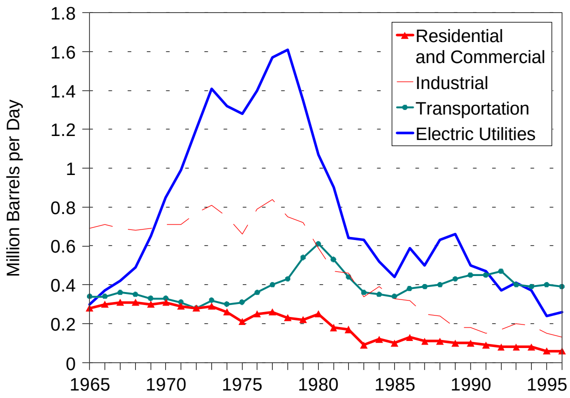
Once the utility industry is past the transition from a regulated to a deregulated industry, competition should increase. Fuel adjustment clauses will disappear, and utilities will be under more pressure to find ways of reducing their operating costs. Fuel costs, which represent more than 75 percent of production costs for fossil-fueled generating units, are a major target for cost efficiency improvements.

Utility Fuel Costs

Utilities' use of fossil fuels has changed over the years as economics and regulations among the fuels have changed. In general, coal has been the cheapest fossil fuel on a Btu basis and the major fossil fuel used by utilities. The utility sector is also the largest end-user for coal. Coal is burned in generating units serving base load. Petroleum in the form of two products, residual fuel oil and petroleum coke, is also used to serve base load, although petroleum coke comprises very little of the utility petroleum fuel being used (5.0 percent in 1997).

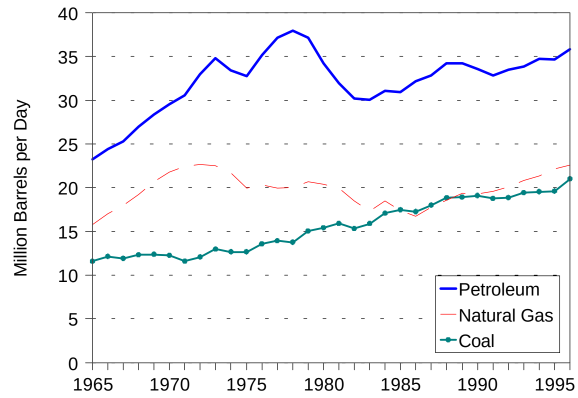
From the mid-1960s through the oil embargo of 1973, utility use of residual fuel oil grew from about 0.3 million barrels per day to 1.4 million barrels per day (Figure 19). The accessibility and relatively low price of

Figure 19. End Uses of Residual Fuel Oil, 1965-1996



Source: Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July, 1997), Table 5.12a.

Figure 20. U.S. Fossil Fuel Consumption, 1965-1996



Source: Energy Information Administration, *Annual Energy Review 1996*, DOE/EIA-0384(96) (Washington, DC, July 1997), Table 1.3.

residual fuel were attractive until the embargo sent prices spiraling upward. Utility consumption declined for several years, then began to grow again until the next crude oil price increase in 1979-1980. During the 1970s, natural gas curtailments during the winter, and even sometimes during the summer when winter stocks were being built, caused utilities to turn to petroleum, even though natural gas prices were more attractive.

After the crude oil price increases of 1979-1980, utility use of residual fuel plummeted. Although consumption showed some strength again after crude oil prices declined in 1986, utility consumption fell during the 1990s as residual fuel lost ground to other fuels, such as natural gas. The Powerplant and Industrial Fuel Use Act of 1978 discouraged use of natural gas, even though residual fuel prices outstripped natural gas prices. Natural gas use declined slightly while the Fuel Use Act was in force, but the Fuel Use Act was repealed in 1987.

Natural gas has become more appealing during the 1990s because of its low price, availability, and environmental attractiveness (Figure 20). It is used for all load applications from base load to peaking power, competing mainly with residual fuel, coal, nuclear, and hydropower for base load, and with distillate fuel oil for peak power needs. In addition to utilities, natural gas has been the fuel of choice for nonutility generators; more than 50 percent of the electricity being generated from nonutilities comes from natural gas.

Petroleum coke comprises a small part of utility fuel consumption, but increasing coke production, resulting from increasing residual fuel conversion and falling prices, is making this product attractive to some utilities. Supply is adequate for substantial utility growth. Utilities used only about 19.2 thousand barrels of petroleum coke per day in 1997, but 306 thousand barrels per day were exported, most of which were green coke (fuel-grade coke). The price of green coke[139] is reported to have fallen from as high as $50 per ton (nominal freight-on-board U.S. Gulf Coast) in the early 1980s to $6 per ton in 1996. The average delivered cost of petroleum coke to utilities in 1996 was 78.2 cents per million Btu, compared with the average delivered price of coal at 128.9 cents per million Btu.[140] Although coke's fuel properties are different from those of coal, it is being blended with coal in some facilities without the requirement of substantial equipment modifications.

[139] Different kinds of petroleum coke are produced and used in different markets. Green coke is the form of coke used as fuel. Some green coke is calcined (pyrolized above 2600° F) to remove the volatile materials and create a high carbon-to-hydrogen ratio material that can be used in producing graphite and carbon electrodes and anodes. Most of the coke consumed in the United States is used for anode manufacture. Less than 10 percent of the fuel-quality green coke produced domestically is burned as fuel domestically. In 1997, utility use of petroleum coke represented only 5.1 percent of total petroleum coke demand. Green coke is generally calcined or exported.

[140] Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1996,* DOE/EIA-0191 (Washington, DC, May 1997), Table 31.

One other factor affecting the price of residual fuel and petroleum coke relative to other fuels that is not evident in the aggregate figures is the environmental quality of the fuels. Utilities use little high-sulfur residual fuel oil. Generally, the share of residual fuel oil receipts containing more than 1 percent sulfur has remained less than one-third (32.5 percent in 1985, 29.0 percent in 1990, 27.8 percent in 1995, and 33.0 percent in 1996).[141] Because utility residual fuel use, including that of high-sulfur residual fuel, has been exhibiting a downward trend, and there is a general move to reduce sulfur in all fuels, the market for high-sulfur products is shrinking. The markets for fuels with low environmental quality are disappearing internationally as well as domestically, leaving refiners with products that are more difficult to sell at a profitable price.

Utility Actions To Reduce Fuel Costs Affecting Petroleum Fuels

The strategies employed by utilities to reduce fuel costs that could affect petroleum-based fuels include:

- Repowering old, underutilized, fossil-fuel plants
- Increasing fuel flexibility by installing technologies that allow for burning multiple types of fuel or by blending fuels, such as petroleum coke with coal, when it is economical
- Revisiting contracting and inventory policies to take the best advantage of market opportunities while balancing market risk.

Repowering

As utilities look ahead to increased competition, they are scrutinizing their old, underutilized facilities for cost improvements. Many old plants are not cost competitive on a marginal basis and therefore are run only at low capacity utilization. Utilities are determining what is the best cost strategy: continuing to run as is, refurbishing, retiring, or repowering. In the case of oil-fueled units, retiring or repowering would further reduce the demand for residual fuel.

Repowering involves replacing all or part of the steam supply system in a plant with a new steam supply system that is usually technologically different. Other portions of the plant are then refurbished and reused. The purpose behind repowering is to increase plant capacity at a competitive cost and to improve heat rate, thereby improving total plant efficiency while reducing emissions. For example, old coal-, oil-, or gas-fired boilers are candidates for replacement with efficient gas turbines and new heat-recovery steam generators in a combined-cycle system. The Electric Power Research Institute (EPRI) reports that, to date, gas repowering has been used heavily in areas where gas and oil are used for intermediate and baseload generators, such as California, Florida, and the mid-Atlantic States.[142] In 1996, these areas accounted for more than 56 percent of the petroleum fuel burned in steam turbine prime movers.[143] Most of the petroleum used was residual fuel oil.

Of the 263 thousand barrels per day of residual fuel oil consumed by utilities in 1996, about 127 thousand barrels per day was used in units that began commercial operation more than 25 years ago, including units that use residual fuel as an alternative fuel. The figure provides an upper bound on residual (fuel oil) demand that might disappear as a result of repowering or retiring. This potential “at risk” demand represents 15 percent of the total residual fuel consumption in 1996 in all sectors (848 thousand barrels per day). Although changes from repowering and retiring units would not occur quickly, electricity deregulation is likely to hasten the changes. The substantial amount of “at risk” utility residual fuel (oil) use reinforces the continuation of a diminishing market for this product.

Increasing Fuel Use Flexibility

Another means of saving on fuel costs is to make use of technologies that can burn multiple fuels, such as gasification units. Use of such technologies by utilities will serve only to depress the use of residual fuel as long as its price remains at a premium relative to the prices of other fossil fuels.

Fuel blending, however, is providing opportunities for petroleum coke, which can be more economical than coal. Utilities with pulverized coal plants or gasification units can make use of petroleum coke blended with coal. Florida utilities, which are located close to the major coke-producing refineries on the Gulf Coast, have been showing interest in burning coke blends. Tampa Electric

[141] Energy Information Administration, *Cost and Quality of Fuels for Electric Utility Plants 1996,* DOE/EIA-0191(Washington, DC, May 1997), Table 10.

[142] T. Moore, “Repowering as a Competitive Strategy,” *EPRI Journal*, Vol. 20, No. 5 (September/October 1995).

[143] Energy Information Administration, *Electric Power Annual 1996,Volume 1,* DOE/EIA-3048(96)/1 (Washington, DC, August 1997), Table 16.

Company has completed test burns and is soliciting fuel-grade petroleum coke to use in a 20-percent blend with coal in its Big Bend Units 3 and 4. Seminole Electric Cooperative received approval to burn coke blends of up to 30 percent in its generating station and began using some petroleum coke in 1997. Florida Power Corporation is also exploring the possibility of burning small blends of coke (5 percent) in its Crystal River Units 1 and 2. Florida Power feels that, even at that low blend percentage, it could save more than $1 million a year; however, the company is running into permitting problems over concerns that the coke is high in sulfur content and the Crystal River units do not have scrubbers. Outside Florida, coke blending is being used in other plants, including American Electric Power plants in Ohio and plants owned by Northern Indiana Public Service Company.[144]

Fuel Purchasing and Inventory Policies

As deregulation proceeds, utilities will be looking at their purchasing and inventory policies as a means of managing fuel-cost risk. The spur of competition is reasonably expected to result in the more economical use of inventories, with benefits for the electricity consumer. In addition, these managerial developments may benefit distillate fuel oil markets, especially in the Northeast. With the supply-demand balance under stress during peak winter months, fuel purchasing and inventory policies have encouraged some utilities to buy more than needed immediately and at uneconomical prices. What has concerned other users of distillate fuel, particularly the many residential users of heating oil, is how much utilities want to buy during such periods and what prices they are willing to pay for the last barrel. The consequences for available supply and marginal prices affect the entire heating fuel market.

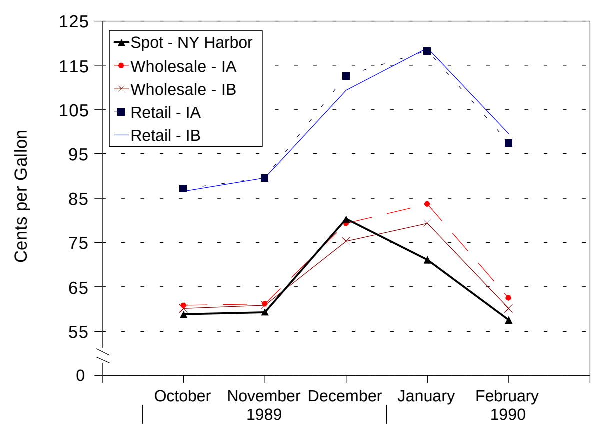
Utilities generally rely on distillate fuel to meet peak demand, competing with distributors supplying the residential and small commercial heating fuel markets at the same time. With interruptible natural gas contracts, the utilities must buy more distillate fuel during peak periods in lieu of curtailed natural gas. During the regulatory period, the inventory policies of some utilities have encouraged or even required purchases in excess of the immediate need to generate electricity to maintain minimum stock levels or at least slow down the net stock draw.

How much utilities are willing to pay for distillate fuel has been influenced by fuel adjustment clauses that allow utilities to pass fuel costs through to consumers without a full rate hearing. This has reduced the financial risk to utilities of bidding at high prices during peak demand periods, regardless of near-term weather and market prospects. Utilities also have more latitude than heating oil dealers to bid higher prices for distillate fuel, since the price of distillate represents a small part of the overall cost of generating electricity. Hence, end-use consumers of electricity are less affected by increases in the price of distillate than are heating oil customers.

Only the minimum stocking requirement and fuel adjustment clauses are expected to change given deregulation, but those changes should be sufficient for utility actions to change. In a deregulated environment, utilities will want to optimize how they buy and stock distillate fuel, using futures markets and financial devices for hedging and minimizing cost without jeopardizing their ability to meet customer needs.

In the past, how the utilities have purchased and stocked distillate fuel during periods of peak demand has reduced the volume of fuel available to meet immediate total demand and has put upward pressure on the spot price in the Northeast. This was particularly the case in the severe winter of 1989-1990 (Figure 21),[145] during

Figure 21. Prices of No. 2 Heating Oil, Winter, 1989-1990



Source: Energy Information Administration, *Petroleum Marketing Monthly* and Platt's *Oilgram Price Report*, the Computer Petroleum Corporation, and the Energy Information Administration Telephone Survey for Heating Oil Prices.

[144] C. Jones, "Fuel Management," *Power* (January / February 1997), p. 25.

[138] Energy Information Administration, *An Analysis of Heating Fuel Market Behavior 1989-1990*, SR / OG / 90-01 (Washington, DC, June 1990).

which the heating oil customers had to pay for a greater run up in the bills to heat their homes and small businesses than did electricity or natural gas users, in part because the heating oil customers had no capability to convert to another fuel. The changes in fuel purchasing and inventory management alone during normal market conditions should give utilities more incentive to avoid bidding prices up during periods of market stress.[146] As the behavior of utilities in distillate markets evolves, becoming more in line with other major wholesale purchasers, the uncertainty about the amounts and prices that some utilities are prepared to bid for on the spot market during periods of peak stress should be reduced. In turn, the potential for avoiding price spikes in the Northeast distillate market in the future should improve.

Options for Refiners

Refiners have already been taking advantage of the beginning of deregulation brought about by the Public Utility Regulatory Policies Act of 1978 (PURPA). Refineries are heavy users of electricity and steam, and they have already built many cogeneration facilities, some of which sell power to the grid. As described below, many oil companies are entering the power generation business as a result of their experience in building and running power generation units in other parts of the world as outlets for natural gas production.

Deregulation is also providing refiners with more options to deal with evolving heavy fuel and waste disposal problems. Refiners are producing more residual fuel and petroleum coke with high sulfur and high metals contents, but the market for these products is diminishing as environmental restrictions increase.

A Growing Dilemma

From a refiner's perspective, residual fuel is a "leftover." Refineries are run with a focus on the higher valued products, such as gasoline and distillate. Residual fuel oil in 1997 represented only about 5.4 percent of crude oil input to refiners, down from 7.1 percent in 1990, and from 12.0 percent at its share peak in 1977. Residual fuel is what is left after the higher valued products are removed from crude oil. The shrinking market for residual fuel, its low value, and an increasingly heavy crude oil slate[147] have caused refiners to install upgrading equipment that converts residual material to higher valued products. One such conversion process leaves refiners with petroleum coke. As more residual fuel is upgraded by using cokers, more petroleum coke is produced, some of which is used as fuel.

A large part of the diminishing market for residual fuel derives from the fact that the environmental qualities of residual fuel have been deteriorating as a result of the changing slate of crude oils being processed by refiners. Refiners have been using more high-sulfur crude oil and more crude oil with high heavy metal content. Most of the sulfur, metals, and inert material found in the crude oil are not removed as the oil is processed, but are concentrated in the residual fuel oil. Coking has been a standard process used to convert residual fuel with high sulfur and heavy metals content; however, coking further concentrates the sulfur and metals into the petroleum coke.

Metals content can be an even greater problem than sulfur content. Burning either residual fuel or coke containing high sulfur in a boiler can be handled with standard emissions control devices, but heavy metals content can result in hazardous airborne pollution and high-metal-content ash, which can become a disposal problem. In the future, high-sulfur, high- metals residual fuel and coke may even become "wastes" to be disposed of rather than fuels to be sold. Deregulation, however, is presenting more alternatives for the oil industry to dispose of such materials, as discussed below.

As the demand for low environmental quality fuels diminishes, refiners will have a harder time selling these products profitably. As the use of new, clean coal technologies for power generation grows, the market for low-quality fuels will expand, since many new technologies can burn dirty fuels safely. In the meantime, even export markets are disappearing as countries worldwide add more environmental restrictions to fuel combustion, including transportation use of residual fuels (bunker fuels). One source indicates that the "market for high-sulfur, high-metals coke has constricted to the point where some U.S. refiners are faced with negative netbacks on their coke production."[148]

[138] Competitive economics may dictate distillate fuel inventory levels for the long term that some utilities may regard as inadequate when faced with peak electricity demand. While a few utilities may seek to bid prices high enough to meet their needs, the impact their smaller volumes are likely to have on the overall supply-demand balance in the Northeast should be less than what has occurred historically.

[147] Heavy crude oils contain a higher percentage of high boiling point material, or "bottoms," than do light crude oils.

[148] D.L. Heaven, "Gasification Converts a Variety of Problem Feedstocks and Wastes," *Oil and Gas Journal* (May 27, 1996), pp. 49-54.

Options for Handling Low-Quality Residual Fuel and Petroleum Coke

To deal with high-sulfur, high-metals residual fuel oil or petroleum coke, refiners have the following options:

- Converting the residual fuel to other products through processes such as coking, catalytic hydrotreating, and hydrocracking

- Selling some or all of the residual fuel or fuel-grade coke they produce to utilities or others who can burn the fuel cleanly using air emission control systems

- Gasifying the fuel and removing the sulfur and metals before using the synthetic gas to create steam, liquid fuels, chemical products, and/or electricity.

Installing conversion equipment to reduce or eliminate the volume of residual fuel is expensive and still may not solve the refiners' dilemma of getting rid of high-sulfur, high-metals fuel. When coking is used to convert the residual fuel, the sulfur and metals are concentrated in the petroleum coke. Refiners look at their unique circumstances to determine whether conversion and upgrading investments are worthwhile, including a refinery's ability to treat the products resulting from the residual fuel conversion.

The paragraphs above on "Increasing Fuel Use Flexibility" discussed how the second option of selling the fuel to those that can burn it cleanly is providing opportunities for the petroleum coke market. As long as transportation costs do not remove the current price advantage that coke has over coal, high-sulfur coke can be burned economically with coal, particularly in plants already equipped with scrubbers. Although high-sulfur residual fuel also can be burned in plants with scrubbers, other fuels are more economical.

The third option for refiners eliminates the production of residual fuel oil or petroleum coke, presents some of the more interesting long-term solutions, and is an option that has been directly affected by deregulation. Refiners faced with a growing problem of getting rid of high-sulfur, high-metals residual fuel and coke along with waste disposal problems from other processes are looking more closely at gasification, a process in which electricity is one of the products. Before PURPA, refiners' choices to burn fuel and generate electricity were limited. Units had to be sized to produce only as much electricity as was needed internally. PURPA removed that restriction, requiring utilities to buy excess power from generators that met certain efficiency criteria, which refinery cogeneration facilities would generally meet. After PURPA, refiners could build units that generated electricity in excess of their own needs both to plan for future expansion and to earn extra revenue. The ability to size units for selling power to the grid adds another dimension to the economics of gasification that could not be considered prior to PURPA.

The Gasification Option

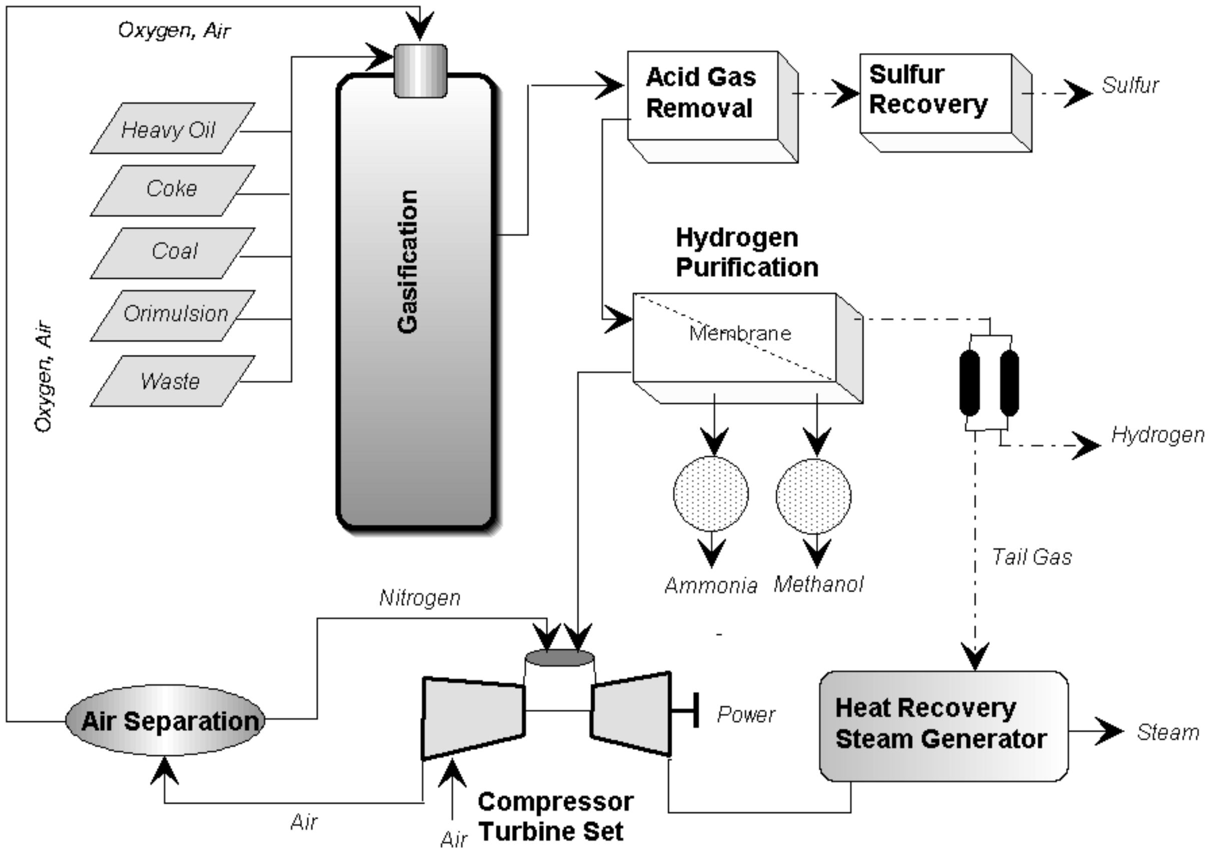
Gasification is a process that converts a variety of hydrocarbon feedstocks, such as coal or residual fuel, to a clean synthetic gas that can then be converted to other products, such as chemicals, electricity, industrial gases, or fuels. Figure 22 shows a process in which feedstocks are gasified and the sulfur is removed from the resultant gas product. Hydrogen is removed from the desulfurized synthetic gas for other applications. Some of the gas then is burned directly to create electricity and heat for further process use, and the remaining gas can be converted to chemicals. The steam from the heat recovery steam generator can be fed to a steam turbine instead of being directed to process use, which would create a combined cycle after the gasification unit instead of just a combustion turbine as shown. The configuration with a steam turbine added is called an integrated gasification combined-cycle unit (IGCC).

Generally, emissions form an IGCC unit using petroleum coke or residual fuel approach the low emissions profile of a natural-gas-fired combined-cycle unit. Solid waste from an IGCC is much less than from a boiler with flue gas desulfurization or from a circulating fluidized-bed boiler. Although IGCC produces more carbon dioxide (CO_2) than a natural-gas-fired combined cycle, IGCC has much lower CO_2 emissions than other solid fuel plants.[149]

Refiners probably are one of the best markets for gasification technology because of their ability to use the various products that can be produced and their need to dispose of materials that can be used as feedstock in gasification units. The refinery gasification application has been referred to as a "trigeneration system" that produces steam, power, and synthesis gas, which, in

[149] D.L. Heaven, "Gasification Converts a Variety of Problem Feedstocks and Wastes," *Oil and Gas Journal* (May 27, 1996), pp. 49-54.

Figure 22. Illustrative Schematic of a Gasification Power System



Source: Energy Information Administration, Office of Coal, Nuclear, Electric, and Alternate Fuels.

turn, can be used to produce hydrogen and/or chemicals, such as ammonia.[150] Gasification economics are driven by the following factors:

- The capital costs of the facility, including the need for an air separation plant to produce oxygen
- The trend toward heavier, and, in some cases, higher metal content, crude oils that result in high-sulfur, high-metals residual fuel or coke, which are facing more environmental restrictions
- The need to dispose of a variety of wastes
- The cost savings realized from the ability to produce some needed products in the refinery, such as hydrogen, industrial gas, steam, and electricity
- The revenue from producing additional products, such as ammonia, methanol, fertilizer, and excess electricity for sale to the grid.

Although the economics of gasification are specific to each plant, some general information is available. Fluor Daniels has indicated that the costs for a heavy-oil-based IGCC unit might be from $950 to $1,100 per kilowatt of generating capacity, compared with costs for a coal-based IGCC that might run from $1,300 to $1,500 per kilowatt.

Environmental factors play a large part in driving the latest interest in refinery gasification. The fuel for the gasification units is likely to be high-sulfur, high-metals residual fuel or coke, along with waste streams, such as off-spec chemicals, waste oils, sludge settled from refinery process water streams, and tower bottoms from phenol production units. At the Texaco El Dorado

[150] D.R. Simbeck, R.L. Dickenson, and A.D. Karp, "Markets for Gasification Technologies in the New World of Competitive Energy," Keynote presentation given at EPRI Gasification Conference (San Francisco, CA, October 1996), p. 4.

Refinery gasification facility, the U.S. Environmental Protection Agency (EPA) has authorized "exemption from hazardous waste permitting requirements and other hazardous waste regulatory requirements."[151] With the gasification unit being exempt from Resource Conservation and Recovery Act requirements, the EPA has distinguished between burning hazardous wastes in an incinerator and gasifying them to produce other products. This means that a refinery using gasification does not have to incur expenses for disposal of the hazardous waste and probably reduces long-term liabilities associated with storing and disposing of hazardous wastes.[152]

Gasification is beginning in the refinery industry without any government subsidies to use the new technology. Two refineries using gasification to create power and other products are the Texaco El Dorado refinery in Kansas, which started up its gasification project in the summer of 1996, and the large Shell Pernis refinery in The Netherlands, which started operating in 1997. Other combination refinery and power projects are being proposed worldwide, such as in Japan and Europe. Two projects in Italy have already secured financing and should soon begin construction.[153]

In summary, the ability of refiners to participate in the electricity generation business outside their own facilities has opened the door to the resolution of other issues. First, refineries are prime cogeneration markets because of their own steam and power needs. Furthermore, technologies such as gasification can resolve other refinery problems, and the economics are being driven by factors other than those associated with traditional cogeneration, including the need to dispose of waste and the ability to produce useful products besides electricity and steam.

Oil Companies as Electricity Generators

The impact of deregulation is probably affecting only a few crude-oil-based fuels, but it is providing oil companies with the opportunity for expanding synergistically into a related business. Oil companies have been moving into the electricity generation business for years. Within the United States, many refineries and oil field operations use cogeneration units. Many of the units that have been built since PURPA was enacted sell power to the grid as well as satisfying a facility's own needs. In 1996, the refining sector had 2,322 megawatts of capacity in operation, on standby, or under construction.[154] (Utilities reported 145,129 megawatts of petroleum- and gas-fired capability in 1996.[155])

Most recently, offshore opportunities are providing oil companies more experience with electricity generation. In many parts of the world with large natural gas reserves, power generation is the most economical use of the gas. It was a natural extension for the oil companies participating in developing those gas reserves to move into power generation to create a market for the gas production.

Royal Dutch Shell Group, Unocal, Mobil, and ARCO are exploring moves into power generation to make use of their unused gas discoveries.[156] [157] Exxon, which has been in the electricity generation business internationally for years, is moving into China through several joint ventures.[158] Texaco has indicated its intent to be as big in power generation as it is in gas production. Coastal Power, a subsidiary of Coastal, develops power projects, and Coastal Electric Services Company is involved in marketing power. Amoco also has a subsidiary set up to market power, although Amoco has not indicated any intention to go into the merchant electricity generation business.[159] This offshore activity implies that, with deregulation, the oil industry will be an important electric power player in the United States as capacity needs grow in the future.

Summary

Deregulation will serve to hasten the decline of an already disappearing market for residual fuel oil.

[151] F.C. Jahnke, J.S. Falsetti, and R.F. Wilson, "Coke Gasification Costs, Economics and Commercial Applications," Paper No. AM-96-54, National Petroleum Refiners Association Annual Meeting (1996), p. 10.

[152] W.E. Preston, "Texaco Gasification Power Systems, Status of Projects," Paper given at the EPRI Gasification Conference (San Francisco, CA, October 1996), p. 6.

[153] D.R. Simbeck, R.L. Dickenson, and A.D. Karp, "Markets for Gasification Technologies in the New World of Competitive Energy," Keynote presentation given at EPRI Gasification Conference (October 1996, San Francisco, CA), p. 7.

[154] Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report."

[155] Energy Information Administration, *Electric Power Annual 1996, Volume I*, DOE/EIA-0348(96)/1 (Washington, DC, August 1997), Table 6.

[156] "Shell Targets Electric Power for Unused Gas," *Oil and Gas Journal* (February 3, 1997), pp. 27-28.

[157] "Asia's Electric Gas Prices," *World Gas Intelligence* (August 9, 1996), p. 1.

[158] "Exxon Seeks Power Project in China," *Electric World* (May 1997), pp. 12 and 14.

[159] "US Gas Firms Weigh Need to Enter Power Business," *World Gas Intelligence* (December 13, 1996), p. 8.

Increasing competition is causing utilities to scrutinize their fuel costs ever more closely, and residual fuel is not competitive in today's markets. In addition, larger shares of residual fuel and petroleum coke with high sulfur and heavy metals content are being produced as a result of the changing slate of crude oil inputs to refineries; however, environmental restrictions are shrinking the potential markets for these fuels. Refiners may be faced with handling these products at a cost as hazardous wastes rather than as fuels.

As utilities increase their search for cheaper fuel options, fuel blending of petroleum coke has surfaced as an economical route in some cases. Petroleum coke prices currently are highly competitive with coal prices in some regions, such as Florida, which is near the large coke-producing refineries on the Gulf Coast. In these areas, coke is being blended with coal either in quantities small enough not to violate environmental restrictions or in plants that have adequate pollution control devices and waste handling to deal with the low-quality coke.

While deregulation, on the one hand, is hurting refiners by hastening the demise of the residual fuel market, it also is expanding opportunities for dealing with poor-quality fuels and wastes. Refiners are beginning to look to gasification as a means of using high-sulfur, high-metals residual fuel and coke, along with a number of refinery waste streams, as feedstocks to produce synthetic gas, which could then be used to produce power, steam, and a variety of chemicals (such as hydrogen and ammonia) of use to refineries. PURPA and subsequent legislation have increased the flexibility of sizing such units to make the most of a facility's economic situation. In addition, a recent EPA ruling on a Texas refinery allows the facility to treat the waste streams being used as gasification feedstocks as fuels rather than as hazardous wastes. The associated cost savings and potential liability reduction add positively to the economics of production. With wastes and high-sulfur, high-metals fuels as gasifier feedstocks, the feedstock costs for gasification projects might even become a negative cost. That is, it would cost the refinery more to dispose of the fuels by some other means.

In utilities' search for more economical fuel strategies, distillate fuel prices might be affected by deregulation, but whether for better or worse is unclear. Utilities are and will continue looking at their inventory and fuel purchasing policies as deregulation removes fuel adjustment clauses and eliminates requirements for minimum inventory levels. Distillate is used largely as a peaking fuel along with natural gas. Natural gas contracts to utilities and large industries are generally interruptible during times of large peak needs so that residential natural gas users will have adequate supplies. Utilities then rely more heavily on distillate fuel oil and even propane. Because they buy in large quantities, if utilities enter the market when supplies are tight and prices are rising, they can drive prices even higher. When evaluating the number of times that this may have occurred historically, compared with the carrying costs of extra inventory, some utilities may find it economical to carry less inventory and buy more distillate during times of market stress if necessary. Others may find it cost effective to carry more inventory to keep from having to pay market stress prices.

Finally, the petroleum industry has for some time played a role in domestic electricity markets as a result of its own cogeneration activities. The industry also has a growing role in the international power generation business. The increasing involvement of petroleum companies in power generation implies a potentially strong role for this energy industry in U.S. electricity markets in the future.

5. Issues for Renewable Fuels in Competitive Electricity Markets

Introduction

Restructuring of the U.S. electric power industry has refocused attention on renewable energy and the policies that affect it. Renewable energy sources include water, wind, solar, geothermal, and some combustible materials, such as landfill gas, municipal solid waste (MSW), and other forms of biomass. Public policies favoring renewable energy are nothing new. Policies including tax and financial incentives and guaranteed purchase power contracts, among others, have supported the development of renewable energy in the past. Such policies have sought to develop a sustainable energy future, reduce dependence on foreign oil, and reduce the environmental impacts of fossil-fueled electricity generation. These ends were deemed to be more important than the fact that alternative fuels cost more than fossil fuel sources of energy.

The advent of competition in electricity markets necessitates a reevaluation of renewable energy policies. Concerns about the use of renewable energy sources in a competitive environment can be outlined as follows. Competition in the electric power industry will encourage utilities to become more efficient and reduce costs in order to lower electricity prices. There will be a premium on short-term cost minimization. In this environment, renewable energy sources will be challenged to continue to penetrate electric power markets because they are generally higher-cost options for producing electricity. Proponents of renewable energy thus fear that renewables may be an inadvertent casualty in the transition to a competitive market. This chapter reviews the reasons for the historical interest in renewable electric power in the United States; the Federal and State plans to support renewables; the various mechanisms being implemented or discussed to provide that support; and issues specific to individual renewable energy resources and technologies.

Overview

The electric power industry and its regulators were unprepared for the social, political, and economic upheavals that followed the oil embargo of 1973. The tripling of oil prices precipitated a need for numerous rate increases by electric utilities because oil was being used to fuel many power plants. In the wake of the oil embargo, the goal of national energy policy was to foster an adequate supply of energy at reasonable costs. As a result, interest in renewable energy rose sharply during the 1970s. A strategy to achieve that goal was to promote a balanced and mixed energy resource system. The development of renewable energy—which reduces dependence on fossil fuels, does not need to be imported, and generally produces fewer and less toxic pollutants than fossil fuels—became a national priority.

The oil embargo of 1973 was a catalyst for the proposal and adoption of the National Energy Act of 1978, a compendium of statutes aimed at restructuring the U.S. energy sector. One objective of the Act was to reduce the Nation's dependence on foreign oil and its vulnerability to interruptions in oil supply through the development of renewable and alternative energy sources.

The most significant statute in the National Energy Act for the development of commercial markets for renewable energy was passed into law as the Public Utility Regulatory Policies Act of 1978 (PURPA). Among other things, PURPA encouraged the development of "nonutility" cogeneration and small-scale renewable-fueled electric power plants designated as "qualifying facilities."[160] Under PURPA, utilities were required to purchase electricity from certain qualifying facilities at the utilities' avoided costs, that is, the cost to the utility if it had generated or otherwise purchased the power. Some avoided cost purchase contracts, particularly in

[160] Essentially, PURPA defines two groups of "qualifying facilities": (1) "small power producers" with rated capacity less than 80 megawatts that obtain at least 75 percent of input energy from renewable sources and (2) renewable-based cogenerators. Utilities may not own more than 50 percent of a qualifying facility.

California, were very favorable to renewable technologies.

A second major factor influencing the development of renewables was State policies promoting renewable energy. California, in particular, promoted renewable energy strongly in the 1980s with renewable energy tax credits. By the late 1980s, however, California's renewable tax credits for wind energy had ended, and competition and pricing policies had begun to evolve in the electric utility industry. "Competitive bidding" became the predominant approach to defining avoided costs. By the end of the decade, with declining natural gas prices setting the value of avoided costs, renewable facilities had difficulty competing in electricity markets on the basis of price alone.

To spur renewable energy development, the Federal Government provided several tax incentives. By 1982, most renewable energy projects were eligible for a 10-percent investment tax credit, a 15-percent business renewable energy investment tax credit, a 40-percent residential tax credit for renewables, and a 5-year accelerated depreciation schedule. Taking advantage of these incentive packages, private industry responded by pioneering new renewable energy technologies and applications. In terms of Federal research and development budget appropriations, funding for renewables increased dramatically from fiscal year (FY) 1974 through FY 1979, stabilized for 2 years, dropped precipitously in FY 1982, then decreased further each year until rebounding in FY 1991. Funding increased to $391 million in FY 1995 before dropping to $268 million in FY 1996 and $244 million in FY1997. The appropriation for FY 1998 is $272 million.[161] This pattern of inconsistent funding, as well as the on-again, off-again availability of some incentives, has created an uncertain investment environment for renewables.

The Renewable Electricity Marketplace

Electric utility and nonutility power producers generated 446 billion kilowatthours in 1997, 13 percent of their total generation,[162] from renewable energy sources (Table 11). Including net imports, total available electricity from renewable resources was 467 billion kilowatthours.

Water from conventional hydroelectric power plants[163] is the major renewable energy source for electricity production in the United States. Conventional hydroelectric plants produced 360 billion kilowatthours of electricity (including exports), about 10 percent of total U.S. generation (81 percent of renewable generation), in 1997. Other renewables accounted for an additional 86 billion kilowatthours, or 2 percent of total U.S. electricity generation for the year. Excluding conventional hydroelectricity, biomass is the largest renewable source of electricity (75 percent), followed by geothermal (19 percent). Wind and solar account for the remainder (6 percent).

Of the 86 billion kilowatthours domestically generated from nonhydroelectric renewable energy sources,[164] nonutility power producers accounted for 91 percent and electric utilities 9 percent. Electric utilities have historically devoted few resources to nonhydroelectric renewable energy sources. This is because, in general, these facilities are small in size and more expensive per unit of output than large central generating stations. Federal and State incentives have, however, resulted in the development of some nonhydroelectric renewable power plants by electric utilities. In California, with State incentives and favorable climate conditions, electric utilities have developed geothermal, solar, and wind facilities.

Manufacturing processes and legislative incentives favor the production of electricity from renewable sources by nonutility power producers. A nonutility power producer includes a corporation, person, agency, authority, or other legal entity that owns generating capacity, but, unlike electric utilities, is without a franchised service area or an obligation to serve retail customers. Nonutility power producers include qualifying facilities (cogenerators and small power producers) under PURPA, exempt wholesale generators[165] under the Energy Policy Act of 1992 (EPACT), other commercial and

[161] U.S. Department of Energy, Office of Budget, DOE History Tables.

[162] Total generation for 1997 is estimated to be 3,533 billion kilowatthours. Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(98/03) (Washington, DC, March 1998), Table 7.1 states that renewables' share of total generation in 1997 was unusually high due to record high hydroelectric generation.

[163] Pumped storage plants are not considered renewable since energy is consumed to pump the water to the upper reservoir.

[164] Excluding electricity imported by utilities.

[165] An exempt wholesale generator (EWG) is a nonutility electricity generator that is not a qualifying facility under the Public Utility Regulatory Policies Act of 1978 (PURPA). EWGs were created by the Energy Policy Act of 1992 (EPACT), and made exempt from provisions of the Public Utility Holding Company Act of 1935 (PUHCA). The exemption of EWGs from PUHCA regulations eliminated a major barrier for utility-affiliated and nonaffiliated power producers who want to compete to build new non-rate-based power plants.

Table 11. Electricity Generation from Renewable Energy by Energy Source, 1993-1997
(Million Kilowatthours)

Source	1993	1994	1995	1996	1997
Nonutility Sector (Gross Generation)[a]					
Biomass	55,746	57,392	R57,514	R57,997	62,607
Geothermal	9,749	10,122	9,912	R10,198	11,212
Conventional Hydroelectric	11,511	13,227	14,774	R16,555	18,702
Solar	897	824	824	R903	994
Wind	3,052	3,482	3,185	R3,400	3,727
Total	**80,954**	**85,046**	**R86,208**	**R89,053**	**97,243**
Electric Utility Sector (Net Generation)[b]					
Biomass	R1,987	R1,985	R1,647	R1,912	1,867
Geothermal	7,571	6,941	4,745	5,234	5,469
Conventional Hydroelectric	269,098	247,071	296,378	R331,058	341,400
Solar	4	3	4	3	3
Wind	*	*	11	10	6
Total	**R278,660**	**R256,001**	**R302,785**	**R338,218**	**348,746**
Imports and Exports					
Geothermal (Imports)	877	1,172	885	650	10
Conventional Hydroelectric (Imports)	28,558	30,479	28,823	33,360	27,991
Conventional Hydroelectric (Exports)	3,939	2,807	3,059	2,336	6,791
Total Net Imports	**25,496**	**28,844**	**26,649**	**31,673**	**21,210**
Total Available Electricity from Renewable Sources	**R385,111**	**R369,891**	**R415,642**	**R458,944**	**467,199**

[a]Includes generation of electricity by cogenerators, independent power producers, and small power producers.
[b]Excludes imports.
* = Less than 0.5 million kilowatthours.
R = Revised.
Notes: Biomass includes wood, wood waste, municipal solid waste, and landfill gas. Totals may not equal sum of components due to independent rounding.
Source: Energy Information Administration, *Annual Energy Review 1997*, DOE/EIA-0384(97) (Washington, DC, July 1998), and Office of Coal, Nuclear, Electric and Alternate Fuels estimates.

industrial establishments that may generate electric power for their own use and buy backup or sell excess power to electric utilities, and independent power producers built solely to supply and sell power to electric utilities.

The major technology used in nonutility generation is cogeneration—the combined production of electric power and another form of useful energy (heat or steam). Many nonutility power producers use waste energy streams (principally heat) to produce electricity, and some manufacturing processes may produce renewable waste (e.g., sawdust) that can be burned to produce energy.

The distinction between the utility and nonutility sectors assumes additional significance under some restructuring proposals, notably in California. Under many plans, a firm must generate some high percentage (usually over 50) of its electricity from renewable sources to be classified as a “green power” provider. Such requirements will tend to limit utility ownership of renewable generating facilities and push future non-hydroelectric renewable development into the nonutility sector.

Most renewable energy systems (except perhaps for biomass) are not constrained by the same types of fuel supply infrastructure considerations as fossil-fueled power generating units. The constraints that renewable power systems face are related to geographic availability factors associated with particular wind, biomass, geothermal, and hydroelectric resources. To a great extent, renewable generating facilities are very region-and site-specific, which, depending on the circumstances, can be either a drawback or a significant advantage. Until recently, most nonutility renewable energy power generators and other nonutility generators have sold their power directly to local utilities, or used it on site, avoiding the need for nationwide transmission access. With deregulation opening access to electricity transmission, transmission pricing can affect the development of renewable power generating facilities.

Utility Generation

Electric utilities generated 338 billion kilowatthours from renewable resources in 1996 and 349 billion kilowatthours from renewable resources in 1997 (Table 11). Nearly 98 percent of utility generation came from conventional hydroelectric facilities in both 1996 and 1997. Access to water power by utilities in Washington made that State the leading producer of renewable energy, accounting for 29 percent of all renewable electricity produced in 1996 (Table 12).[166] Washington also leads the Nation in utility power produced from wood and wood waste. Electric utilities in Illinois, Connecticut, and Minnesota generated, respectively, 87 percent, 45 percent, and 31 percent of their renewable-based electricity from municipal solid waste and landfill gas. Virtually all utility geothermal energy comes from California.

In 1996, 14 percent of utility renewable generation nationwide occurred in California. (California's share of nonutility renewable electricity was even larger—over 23 percent (Table 13).) State policies promoting renewable energy have also influenced the development of renewables. California, for example, promoted renewable energy strongly in the 1980's with renewable tax credits. The combined effect of resource availability and energy policy makes California the second-largest producer of renewable electricity generation.[167]

Utilities in Oregon, which also has sizable water power resources, produced the third-largest amount of electricity from renewables—13 percent. Besides New York at 8 percent and Montana at 4.1 percent, no other State contributed more than 4 percent of total utility renewable generation.

Nonutility Production

Nonutility generators produced almost 86 billion kilowatthours of electricity in 1995 and 89 billion kilowatthours in 1996 (Table 13). Almost 17 billion kilowatthours (19 percent) of electricity was produced from conventional hydroelectric facilities in both 1995 and 1996. More than 42 percent of nonutility renewable electricity generation is produced from wood and wood waste.

Nonutilities in California produce by far the largest share of electricity, 23 percent. Nonutility renewable generation (outside California) is more evenly spread than is utility renewable generation. One reason is that nonutility plants are usually smaller than utility plants, having been built in many instances to service a single facility (e.g., pulp and paper manufacturing plants). Thus, many more resource locations—particularly for biomass and hydropower—are available. After California, the States with the most nonutility electricity generation from renewables in 1996 were Florida, Maine, Alabama, New York and Louisiana.

Federal Approaches to Supporting Renewables

Various electric power restructuring bills have been proposed in the U.S. Congress. All the proposals contain sections designed to promote the development of renewable energy. The Clinton Administration has also recently presented a proposal, the “Comprehensive Electricity Competition Plan,” as a blueprint for electric power restructuring. This plan and four legislative proposals are summarized below. The legislative proposals discussed were drafted prior to the Administration’s plan and were chosen for discussion because they include provisions which have attracted considerable interest.

Administration’s Comprehensive Electricity Competition Plan

The Administration’s “Comprehensive Electricity Competition Plan” was released in March 1998. The

[166] State-level data for 1997 were not available when this report was published.

[167] In California, qualifying facilities (QFs) typically enter pre-approved contracts called Standard Offer Contracts with utility companies. These contracts vary by the difference between short- and long-term costs based on the utility costs they displace. Short-term avoided costs are generally calculated to reflect the costs that would have been incurred to supply the energy otherwise. These costs are based on the utility’s marginal generating costs, varying with the fuel in use and seasonal demand. Long-term avoided costs are designed, in addition to reflecting marginal costs, to include the costs of a resource (capital cost) that the utility would have constructed in lieu of the QF resource.

Table 12. Renewable Electric Utility Net Generation by State, 1996
(Million Kilowatthours)

State	Conventional Hydro-electric	Geothermal	Solar/ Photovoltaic	Wind	MSW/ Landfill Gas	Wood and Wood Waste	Total	Percent of U.S. Total
Alabama	11,082	--	--	--	--	--	11,082	3.3
Alaska	1,266	--	--	--	--	--	1,266	0.4
Arizona	9,214	--	--	--	--	--	9,214	2.7
Arkansas	2,797	--	--	--	--	--	2,797	0.8
California	41,862	5,042	3	10	55	0	46,917	13.9
Colorado	1,705	--	--	--	--	--	1,705	0.5
Connecticut	530	--	--	--	437	--	966	0.3
Delaware	--	--	--	--	--	--	--	0.0
Dist. of Col.	--	--	--	--	--	--	--	0.0
Florida	216	--	--	--	--	--	216	0.1
Georgia	4,549	--	--	--	--	--	4,549	1.3
Hawaii	18	--	--	--	--	--	18	0.0
Idaho	12,236	--	--	--	--	--	12,236	3.6
Illinois	20	--	--	--	133	*	153	0.0
Indiana	448	--	--	--	--	--	448	0.1
Iowa	921	--	--	*	23	--	944	0.3
Kansas	--	--	--	--	--	--	--	0.0
Kentucky	3,497	--	--	--	--	--	3,497	1.0
Louisiana	--	--	--	--	--	--	--	0.0
Maine	2,116	--	--	--	--	1	2,116	0.6
Maryland	2,457	--	--	--	--	--	2,457	0.7
Massachusetts	921	--	--	--	--	--	921	0.3
Michigan	1,648	--	--	--	--	--	1,649	0.5
Minnesota	837	--	--	*	396	26	1,259	0.4
Mississippi	--	--	--	--	--	--	--	0.0
Missouri	1,314	--	--	--	31	--	1,345	0.4
Montana	13,741	--	--	--	--	--	13,741	4.1
Nebraska	746	--	--	--	12	--	758	0.2
Nevada	2,143	--	--	--	--	--	2,143	0.6
New Hampshire	964	--	--	--	--	--	964	0.3
New Jersey	--	--	--	--	--	--	--	0.0
New Mexico . . .	211	--	--	--	--	--	211	0.1
New York	27,116	--	--	--	--	40	27,156	8.0
North Carolina	4,176	--	--	--	--	--	4,176	1.2
North Dakota . .	3,151	--	--	--	--	--	3,151	0.9
Ohio	392	--	--	--	--	--	392	0.1
Oklahoma	2,158	--	--	--	--	--	2,158	0.6
Oregon	44,513	--	--	--	--	--	44,513	13.2
Pennsylvania . .	2,561	--	--	--	--	--	2,561	0.8
Rhode Island . .	--	--	--	--	--	--	--	0.0
South Carolina	3,064	--	--	--	--	--	3,064	0.9
South Dakota . .	8,833	--	--	--	--	--	8,833	2.6
Tennessee	10,579	--	--	--	--	--	10,579	3.1
Texas	954	--	*	--	--	--	954	0.3
Utah	1,014	192	--	--	--	--	1,206	0.4
Vermont	1,528	--	--	--	--	135	1,664	0.5
Virginia	1,617	--	--	--	--	--	1,617	0.5
Washington	98,079	--	--	--	--	360	98,439	29.1
West Virginia . .	219	--	--	--	--	--	219	0.1
Wisconsin	2,414	--	--	--	93	226	2,733	0.8
Wyoming	1,232	--	--	--	--	--	1,232	0.4
Total	**331,058**	**5,234**	**3**	**10**	**1,124**	**788**	**338,218**	**100.0**

* = Less than 0.5 million kilowatthours.

Note: Sum of components may not add up to the total due to independent rounding.

Source: Energy Information Administration, Form EIA-759, “Monthly Power Plant Report,” and Form EIA-860, “Annual Electric Generator Report.”

Table 13. Nonutility Gross Generation from Renewables by State, 1996
(Million Kilowatthours)

State	Conventional Hydro-electric	Geothermal	Solar/ Photovoltaic	Wind	MSW/ Landfill Gas	Wood and Wood Waste	Total	Percent of U.S. Total
Alabama	--	--	--	--	W	W	4,580	5.1
Alaska	--	--	--	--	W	W	123	0.1
Arizona	--	--	--	--	--	W	W	0.1
Arkansas	W	--	--	--	W	1,617	1,634	1.8
California	2,940	8,285	903	3,243	2,259	3,072	20,702	23.2
Colorado	W	--	--	--	W	--	120	0.1
Connecticut	97	--	--	--	1,736	--	1,834	2.1
Delaware	--	--	--	--	--	--	--	0.0
Dist. of Col.	--	--	--	--	--	--	--	0.0
Florida	--	--	--	--	3,496	2,586	6,082	6.8
Georgia	53	--	--	--	105	3,168	3,326	3.7
Hawaii	W	249	--	23	630	W	992	1.1
Idaho	W	--	--	--	W	526	1,585	1.8
Illinois	W	--	--	--	327	W	413	0.5
Indiana	--	--	--	--	104	--	104	0.1
Iowa	17	--	--	--	W	W	59	0.1
Kansas	11	--	--	--	--	--	11	0.0
Kentucky	--	--	--	--	--	W	W	*
Louisiana	974	--	--	--	99	3,025	4,097	4.6
Maine	2,173	--	--	--	590	3,075	5,838	6.6
Maryland	--	--	--	--	W	W	771	0.9
Massachusetts	W	--	--	--	2,073	W	2,486	2.8
Michigan	144	--	--	--	923	2,039	3,106	3.5
Minnesota	353	--	--	50	321	440	1,165	1.3
Mississippi	--	--	--	--	W	W	1,831	2.1
Missouri	--	--	--	--	W	--	W	*
Montana	W	--	--	--	--	W	W	0.1
Nebraska	--	--	--	--	--	--	--	0.0
Nevada	W	W	--	--	--	--	1,684	1.9
New Hampshire	503	--	--	--	188	921	1,613	1.8
New Jersey	W	--	--	--	W	--	1,217	1.4
New Mexico	--	--	--	--	--	--	--	*
New York	1,862	--	--	--	2,040	600	4,502	5.1
North Carolina	W	--	--	--	W	1,638	3,600	4.0
North Dakota	--	--	--	--	W	--	W	0.0
Ohio	W	--	--	--	W	433	444	0.5
Oklahoma	--	--	--	--	W	W	W	0.3
Oregon	W	--	--	--	W	522	993	1.1
Pennsylvania	455	--	--	--	1,867	709	3,031	3.4
Rhode Island	W	--	--	--	W	--	110	0.1
South Carolina	W	--	--	--	W	1,574	1,710	1.9
South Dakota	--	--	--	--	--	--	--	0.0
Tennessee	897	--	--	--	62	550	1,508	1.7
Texas	W	--	--	83	77	W	861	1.0
Utah	30	--	--	--	--	--	30	0.0
Vermont	W	--	--	--	--	W	390	0.4
Virginia	92	--	--	--	1,008	1,474	2,574	2.9
Washington	444	--	--	--	170	792	1,406	1.6
West Virginia	W	--	--	--	W	--	939	1.1
Wisconsin	292	--	--	--	172	646	1,110	1.2
Wyoming	--	--	--	--	--	--	--	0.0
Total	**16,555**	**10,198**	**903**	**3,400**	**20,449**	**37,549**	**89,053**	**100.0**

W = Data withheld to avoid disclosure of proprietary company data.
Note: Sum of components may not add up to the total due to independent rounding.
Source: Energy Information Administration, Form EIA-0867, "Annual Nonutility Power Producer Report."

components of the plan were designed to work together to provide the economic benefits of competition in a manner that is fair to all consumers and to enhance the environmental performance of the electric power industry. The plan has five basic objectives: (1) to encourage States to implement retail competition (i.e., end users may choose their electricity provider); (2) to protect consumers by facilitating competitive markets; (3) to assure access to and reliability of the transmission system; (4) to promote and preserve public benefits; and (5) to amend existing Federal statutes to clarify Federal and State authority.

The Administration's plan, with the objective of promoting and preserving public benefits, proposes policy mechanisms, such as a renewable portfolio standard, public benefit funding, and net metering, to promote the development of renewables. The terms renewable portfolio standard, public benefit fund, and net metering are defined and discussed below.

Renewable Portfolio Standard

A renewable portfolio standard (RPS) is a market-based strategy to ensure that renewable energy constitutes a certain percentage of total energy generation or consumption. An RPS could require electricity generators or sellers to cover a percentage of their electricity generation or sales, respectively, with generation from renewable technologies. It guarantees that a minimum percentage of generation comes from renewable sources. Under the Administration's proposal, the initial RPS requirement, based on electricity sales, would be set close to the existing ratio of renewable generation to total retail electricity sales, with an intermediate increase in 2005, followed by an increase to 5.5 percent in 2010. (In 1997, nonhydroelectric renewable generation represented 2 percent of total generation.) Retail sellers could meet the RPS requirement either by generating sufficient renewable electricity to meet the ratio, or by purchasing tradeable renewable electricity credits that would be created and tracked. The RPS would employ market prices through credit trading and spread the cost of supporting renewable generation more evenly across the retail electricity market than does PURPA's "must buy" provision (Section 210), which would be repealed under the Administration's plan. The RPS could be subject to a price cap.[168]

Public Benefit Fund

The Administration's plan supports the creation of a $3 billion Public Benefit Fund (PBF) to provide matching funds to States for low-income assistance, energy efficiency programs, consumer education, and the development and demonstration of energy technologies, particularly renewables. The PBF would be a 15-year program, funded through a generation or transmission interconnection fee on all electricity.[169] Since transmission will be regulated, the charge should be non-bypassable to ensure that all customers pay the charge and the charge is competitively neutral. The charge can be based on energy, demand, or a combination of both. In the Administration's plan, the charge would be capped at 0.1 cent (1 mill) per kilowatthour. States would have the option to seek funds and allocate the funds among public purposes. The States would compete for the funds on the basis of cost-effective proposals.

Net Metering

Net metering refers to the concept that a facility is permitted to sell any excess power it generates over its load requirement back to the electrical grid to offset consumption. (A more detailed discussion of net metering is provided later in this chapter.) Under the Administration's plan, all consumers would be eligible for net metering, and all distribution service providers would be required to assure the availability of interconnection. This provision would apply only to very small (up to 20 kilowatts) renewable energy projects and would be subject to a price cap determined at the State level.

Finally, in competitive markets, many different suppliers will offer a diverse menu of energy products and services with different pricing and billing plans. Under the Administration's proposal, consumers will have the option of choosing suppliers on the basis of their generation mix, including paying a premium for "green power" (renewable generation). To ensure consumers that they are purchasing green power, the Secretary of Energy would be authorized to implement a rulemaking to require all electricity suppliers to disclose reliable and easy-to-read information on prices, generation sources, and other information to enable consumers to make informed choices among various offers.

[168] A price cap is a value set on a credit that would be sold by the government to limit the price they would be traded for. The cap, in effect, limits the cost of renewable electricity to consumers. Monies collected by the government from the sales of credits could be used to support renewable technologies.

[169] The terms used to describe such a charge include public benefit charge, access charge, wires charge, systems benefit charge, and universal service charge. Although these terms differ, the concept is the same.

Senate Bill 237 (The Bumpers Proposal)

Section 110 of Title One of Senate Bill 237 has a requirement for a certain amount of renewable energy generation. Starting in 2003, 5 percent of total retail electricity sold must come from a renewable energy source (including partial credit for hydroelectricity). The amount increases to 9 percent in 2008 and 12 percent in 2013. Thereafter, the requirement remains constant until 2019, when it ends. Retail electric suppliers may satisfy the requirement by earning renewable energy credits under the National Renewable Energy Trading Program, depending on the type of renewable energy source used. Credits will be issued by the Federal Energy Regulatory Commission (FERC) to any facility using renewable resources for generation or for any power purchased by the facility from a generator using renewables. One half of one credit can be earned by any large hydroelectric facility that generates and then sells one unit of energy. One credit can be earned by any facility that generates and sells electricity from a renewable energy source other than hydro at a facility built before the enactment of the Act. Two credits can be earned by any facility built after the enactment of the Act that generates and sells electricity from a renewable energy source other than hydroelectric.

Senate Bill 687 (The Jeffords Proposal)

Section 5 of Senate Bill 687 instructs the Secretary of Energy to establish a National Electric System Public Benefits Board to fund programs related to renewable energy sources, universal electric service, affordable electric service, energy conservation or efficiency, or research and development in any of these areas. The money for the National Electric System Public Benefits Fund will be financed from transmission wire charges imposed by FERC and will be distributed to the States by the Board. States must provide matching funds. The Board will recommend eligibility criteria for disbursements from the Fund and will determine the amount needed every year for the fund. FERC will impose a nonbypassable, competitively neutral wires charge paid directly to the fund by the operator of the wire. The charge will be applied to all electricity carried through the wire, measured from the busbar at a generation facility, which has an impact on interstate commerce.

Section 6 of the bill provides a renewable energy portfolio standard imposed on any nonhydroelectric facility that generates electricity for sale. Starting in the year 2000, 2.5 percent of total electricity generated by all (nonhydropower) electricity generators must be generated from renewables. Renewable energy sources include wind, organic waste (excluding incinerated municipal solid waste), biomass, geothermal, solar thermal, and photovoltaics. The required renewables portfolio schedule after the year 2000 increases by approximately 1 percent a year until the year 2020 up to a total of 20 percent, which is the target level for beyond that time period. The bill also provides for renewable energy credits, to be issued by the Federal Energy Regulatory Commission (FERC) beginning in 2001. One credit will be given for each megawatthour of electricity sold by a facility in the preceding calendar year that was generated from a renewable energy source. Credits can be traded and used in lieu of generation to meet the generation requirement of the renewables portfolio standard.

House of Representatives Bill 655 (The Schaefer Proposal)

House of Representatives Bill 655 calls for a minimum renewable generation requirement (Section 113) by December 31, 2000. It directs the FERC to establish a program to issue renewable energy credits to electricity generators, providing for their sale and exchange. It would require each generator (excluding hydroelectric facilities) selling electric energy to submit such credits to FERC in an amount equal to the required annual percentage of the total renewable electric energy it generated in the preceding year. PURPA would be amended so that it would no longer apply to any electric utility whose customers are able to purchase retail services from any offeror on a competitively neutral and nondiscriminatory basis.

House of Representatives Bill 1359 (The DeFazio Proposal)

The intent of House of Representatives Bill 1359 is to amend PURPA to establish a means to support programs for energy efficiency, renewable energy, and universal and affordable service for electric customers. It would establish a National Electric System Public Benefits Fund, to be administered by the National Electric System Public Benefits Board, which would provide matching funds to States for the support of eligible public purpose programs. This program would not supersede other programs that support renewable energy.

State Approaches to Supporting Renewables

Much of the regulatory initiative to bring competition to the electricity industry is occurring at the State level. As at the Federal level, most States have formulated policy measures to preserve or promote renewables in a restructured electric power market. The States have been considering a number of regulatory mechanisms to promote renewable energy development, including a system benefits charge (SBC) or "wires charge," RPS, net metering, and green pricing (voluntary).

The SBC would be a fee that would be paid by users of distribution lines, either generators or consumers. It would be included in the cost of electricity to all consumers. Revenues from the charge could be pooled for use in a number of ways to fund the development of selected renewable energy projects.

By design, both the SBC and the RPS would be competitively neutral with respect to fuels and technology, and would put in place a minimum public obligation to support the development of renewable energy. Used singly or in combination, they will have differential effects on renewable energy development. The SBC provides for a regulatory agency with the latitude to promote specific renewable technologies or projects.

Given that the SBC is collected on a regular basis from wires usage, it would provide consistent support to renewables. By providing this consistent support, it would also have the effect of making the cost of capital lower for this type of project development. The biggest drawback of the SBC is the administrative cost and difficulty of decisionmaking. The RPS, on the other hand, does not have these administrative obstacles because the market is used to determine which projects are developed. The renewable portfolio standard would encourage the lowest cost, highest efficiency projects to be developed. There is, however, a risk of neglecting the development of those renewable technologies that have a longer development horizon. As of February 9, 1998, 6 States had enacted RPS provisions, 5 States had enacted SBC provisions, and 26 States had some form of green pricing program legislation (discussed below).

Net Metering

As mentioned above, net metering is an arrangement that permits users generating power to sell any electricity in excess of requirements back to the grid to offset consumption.[170] How excess energy (if any) from facilities under net metering is treated, and what rates are paid, are what differentiate State net metering policies. Some State initiatives require the utility to pay retail rates instead of avoided cost rates for the excess energy. States may apply certain capacity restrictions and, in some cases, fuel restrictions on facilities that qualify for net metering.

Most net metering programs are available to customer-owned small generating facilities only, and some programs further restrict the eligibility to renewable energy technologies. Net metering can increase the economic value of small renewable energy technologies for customers by allowing them to use the grid to bank their energy, producing electricity at one time and consuming it at another. This form of energy exchange is especially useful for such renewable energy technologies as wind turbines and photovoltaics, which transmit electricity to the grid intermittently (when the wind is blowing or the sun is shining) and, at other times, are consumers of electricity from the grid.

Green Pricing/Marketing

Green pricing or green marketing is an approach States have used to maintain or increase demand for renewable electricity. In green marketing programs, electricity suppliers offer consumers electricity produced from environmentally preferred resources consisting largely of renewable energy. Consumers who voluntarily choose to purchase their electricity under a green marketing program pay a premium above their normal electricity bills. This premium is then applied toward the additional costs incurred by electricity suppliers to develop and maintain a renewable power project that might otherwise not be cost-effective.

Initially,[171] the goal of green marketing was to provide customer-driven mechanisms for enabling the development of additional renewable energy power projects. Although the concept of green marketing originated in a regulated environment, a number of utilities and non-utilities are looking at green pricing programs as a way to differentiate their product in a more competitive market. Market research conducted to date suggests that there is a willingness among consumers to pay more for

[170] Net metering, in effect, measures the difference between the total generation of a facility and the electricity consumed by the facility with a single meter that can read electricity flows in and out of a facility. Hence, the meter will record the net energy received by the facility or, if the facility generated more than it consumed, the energy delivered to the grid.

[171] Green marketing programs were first introduced by companies like Detroit Edison, Gainesville Regional Utilities, Sacramento Municipal Utility District, Public Service of Colorado, and Traverse City Light and Power.

power from renewable energy up to a certain point.[172] Assuming that this remains true in the future, regardless of what shape the restructured electric industry takes, green marketing programs are likely to continue evolving as viable competitive strategies that electricity suppliers can use to aggregate customer groups, reach specific market segments, and retain existing customers.

As of March 1998, there were 17 State level green pricing programs in operation, 5 in active development, 7 that were pending formulation based on utility market research, and 4 in the planning stage. A current list of green pricing programs can be found at http://www.eren.doe.gov/greenpower/summary.html. A current list of utilities and power marketers involved in green power programs can be found at http://www.eren.doe.gov/greenpower/marketing.html. These Web sites are maintained and regularly updated by the Department of Energy's Office of Energy Efficiency and Renewable Energy.

The case of green marketing is illustrative of the types of issues associated with this strategy. With hundreds of nonutility "electric service providers" planning to offer electricity in the California market, fierce competition will likely produce a variety of claims about the electricity being offered. In order for customers to make informed choices, they must understand what really distinguishes one supplier from another. A criterion that some customers say they will use is the extent to which generation is environmentally acceptable. For most such customers, this means renewable sources.

Unfortunately, pilot programs in New England illuminated the potential for "green fraud," when some suppliers allegedly offered their customers electricity that they labeled as green but that in fact was no different from any other electricity in the New England Pool. To prevent such abuses in the future, legislatures, regulators, and private organizations have proposed measures to give electricity customers valid information on the renewable content of their electricity. To provide customers data on their suppliers, California's Assembly Bill (AB) 1305 legislation, enacted in 1997, requires all electric service providers annually to state the source of their electricity.[173] Categories include coal, large hydroelectric (greater than 30 megawatts), natural gas, nuclear, other, and eligible renewables (biomass and waste, geothermal, small hydroelectric, solar, and wind). In Illinois, the new Environmental Disclosure Law[174] requires every "electric utility and alternative retail electric supplier" to provide customers quarterly the known sources of electricity by fuel type, with corresponding emissions information.

To provide further assistance to customers in evaluating how "green" their electricity is, the non-profit Center for Resource Solutions in San Francisco will certify with its "Green-**e** Brand" that approved electric service providers:[175]

- Obtain at least 50 percent of total energy from "eligible renewable resource facilities" through performance obligation contracts

- Utilize fossil resources in the nonrenewable component of the electricity product that have equal or lower air emissions (for SO_x, NO_x, and CO_2) than the fossil portion of an equal amount of system power (from California's Power Exchange). Generate air emissions from waste renewable fuels, to the extent they are utilized, at a rate as low as or lower than would be generated by alternative waste disposal methods

- Refrain from using nuclear power beyond that contained in system power purchased for the eligible electricity product's portfolio.

The success of green marketing programs is related to the extent that consumers would choose to pay higher rates for renewable-based electricity.[176] Green marketing

[172] B.Fahrar and A. Houston, "Willingness to Pay for Electricity from Renewable Energy," *Proceedings of the 1996 ACEEE Summer Study on Energy Efficiency in Buildings* (August 25-31, 1996), pp. 2-6. However, a clearer indication of what people will actually pay can be determined by undertaking local-area market research. Only 10 percent of the respondents in one such local area survey indicate they would participate in a specific green pricing program. In fact, several local-area market research studies indicate that at the program's inception, only 1 percent will actually sign up.

[173] While over 100 nonutilities initially announced plans to service the California market, only 27 nonutilities had formally filed to offer electricity as of April 1, 1998.

[174] ILCS 5/16-127 (new) -- Public Act 90-561.

[175] Power marketers participating in the Green-**e** Branding Program as of November 1, 1997, were Edison Source, Foresight Energy, PacifiCorp, Enron Energy Services, Green Mountain Energy Resources, Electric Clearinghouse, Bonneville Power Administration/Environmental Resources Trust, and the Sacramento Municipal Utility District. Planning to enter the market by mid- to late 1998 were PG&E Energy Services and Cleen 'n Green.

[176] It should be noted that the premium paid by consumers for green power would be used to increase the amount of renewable-based electricity available on their system, or, powerpool. It is not a direct purchase of renewable-based electricity from supplier to consumer.

amounts to product differentiation, with the result that the demand for renewable-based electricity would have its own supply and demand functions. Absent system benefits charges (SBC) and renewable portfolio standards (RPS) in a competitive market, renewable electricity product differentiation is even more critical because it (ostensibly) increases the demand for renewable energy. However, some believe that in a competitive marketplace, both an RPS or SBC and green marketing are necessary and serve to complement each other.[177]

Current Economics

Renewable technologies are generally characterized by relatively high capital costs and low operation and maintenance costs. These characteristics make them attractive in the long run, but less so in a competitive setting where the premium is on near-term cost minimization. Renewable generating technologies continue to make advances, thereby increasing their efficiency and lowering cost; however, outside of some niche market applications, they still are not economically competitive with conventional sources of power.

One of the ways in which capital costs decrease is through "learning by doing." That is, as the number of units of a product are built, manufacturers learn more efficient production techniques and costs thereby decline. In the case of renewables, this can occur whether a company builds for the domestic market or for export. With American firms competing for foreign markets, costs are likely to decline further domestically. Capital costs and operations and maintenance (O&M) costs also decline through "economies of scale," that is, up to a certain (optimal) plant or project size.

Levelized Costs of Renewable Electric Technologies

When determining the fuel source to use in constructing a new generating plant, "levelized" cost is usually used to determine which technology and energy source will be least cost. Levelized costing considers all capital, fuel, and operating and maintenance costs. In levelized costing, capital costs are amortized over the expected power output for the life of the plant.[178]

EIA estimates the levelized costs of all generating technologies using its National Energy Modeling System, (NEMS). Tables 14 through 17 show decision year 2000 cost and performance information, based on NEMS, for fossil and renewable technologies for the major regions of the country best suited for renewables.

Although geothermal energy appears to be the least costly of the technologies compared in the California-Southern Nevada power area (CNV) (Table 14), there is very limited capacity available for development at 37.6 mills per kilowatthour. Wind power offers a 10-percent cost advantage over natural gas combustion turbine technology. However, wind technology is intermittent and therefore cannot be fully credited for firm capacity. The levelized cost of biomass power is about double that of wind and gas combustion turbines. The biomass power cost, however, does not include any credit for waste disposal costs that might be otherwise incurred.

In the Northwest (NWP) and the Southwest, except California (RA), the cost comparison is much the same, except that biomass is about one-fourth less expensive than in California.[179] In most of Texas (ERCOT), however, natural gas combustion turbines are 10 mills per kilowatthour cheaper than the next cheapest technology, wind power. Biomass in eastern Texas produces power for approximately the same cost as in NWP and RA.

It is worth reiterating that site-specific conditions are critical to the economic feasibility of renewable electric generating plants. NEMS does not assess generating plant feasibility on a site-specific basis.

A number of state public utility commissions (including Rhode Island and Massachusetts) have also studied levelized / life-cycle costs of renewables.[180]

[177] Actually, green pricing creates an increased risk in a competitive market that, should consumer preferences turn away from renewables, less renewable electricity might be demanded than if the utility under the existing "rate of return" rate making scheme rolled a small amount of higher-cost renewable-based electricity into its overall rates.

[178] In general, "levelized cost" is the present value of the total cost of building and operating a generating plant over its economic life, converted to equal annual payments. In the context of this report, levelized costs are the calculated average busbar costs per kilowatthour of generating electricity over the plant lifetime, including overnight capital costs per kilowatt, fixed operations and maintenance (O&M costs per kilowatt, variable O&M per kilowatthour, and fuel costs per kilowatthour, using a specified discount rate.

[179] The regions used in this chapter are based on EIA NEMS model Electricity Market Module regions as shown on p. xiv of Energy Information Administration, *Electricity Prices in a Competitive Environment*, DOE / EIA-0614 (Washington, DC, August 1997). These regions are synonymous with the NERC regions and subregions.

[180] C.T. Donovan Associates, Inc., *Scoping Study of Renewable Electric Resources for Rhode Island and Massachusetts, Volume 2: Life Cycle Cost Analysis* (Burlington, VT, November 1997).

Table 14. Cost and Performance Characteristics for Combustion Turbine and Renewable Generating Technologies, California-Southern Nevada (CNV)

Technology [a]	Capacity (megawatts)	Overnight Capital Cost (1995 $/kilowatt)	Variable Plus Fixed O&M[b] (1995 mills/kWh)	Capacity Factor (percent)	Construction Lead Time (Years)	Levelized Cost[c] (1995 mills/kWh)
Combustion Turbine						
(Conventional) . .	160	329	10.8	85	2	60.3
Combined Cycle						
(Conventional) . .	250	480	20.6	85	3	59.3
Biomass	100	2,630	11.3	80	4	84.3
Geothermal	50	1,765	10.8	80	4	37.6
Solar Thermal . . .	100	3,064	12.5	42	3	107.8
Solar PV	5	4,283	4.0	28	2	196.0
Wind	50	778	9.4	31	3	40.2

[a]Decision to build made in 2000. Plant assumed to enter service at end of construction lead time.

[b]Does not include fuel costs, which are included in the levelized cost. The cost of fuel per kilowatthour varies by fuel and the efficiency of that technology to transform energy to electricity.

[c]Includes various externality costs and credits.

Notes: CNV refers to the Electricity Market Module Region: California Southern Nevada Power Area, which includes most of California (it does not include the extreme eastern and northern parts) and the southernmost part of Nevada. The regions used in this chapter are based on EIA NEMS model Electricity Market Module regions as shown on p. xiv of Energy Information Administration, *Electricity Prices in a Competitive Environment,* DOE/EIA-0614 (Washington, DC, August 1997). These regions are synonymous with the NERC regions and subregions. Natural resource and other limitations may restrict number of units able to be built at these costs.

Source: Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997); National Energy Modeling System run AEO98B.D100197A.

Table 15. Cost and Performance Characteristics for Combustion Turbine and Renewable Generating Technologies, Southwest (RA)

Technology [a]	Capacity (megawatts)	Overnight Capital Cost (1995 $/kilowatt)	Variable Plus Fixed O&M[b] (1995 mills/kWh)	Capacity Factor (percent)	Construction Lead Time (Years)	Levelized Cost[c] (1995 mills/kWh)
Combustion Turbine						
(Conventional) . . .	160	359	10.8	85	2	43.8
Combined Cycle						
(Conventional) . . .	250	517	20.6	85	3	35.2
Biomass	100	2,863	8.7	80	4	62.9
Geothermal	50	1,869	17.7	80	4	39.9
Solar Thermal	100	2,998	14.2	37	3	119.2
Solar PV	5	4,163	4.3	30	2	175.9
Wind	50	756	9.1	31	3	39.1

[a]Decision to build made in 2000. Plant assumed to enter service at end of construction lead time.

[b]Does not include fuel costs, which are included in the levelized cost. The cost of fuel per kilowatthour varies by fuel and the efficiency of that technology to transform energy to electricity.

[c]Includes various externality costs and credits.

Notes: RA covers Arizona, virtually all of Colorado and Utah, eastern Wyoming, and extreme western Texas, South Dakota, and Nebraska. The regions used in this chapter are based on EIA NEMS model Electricity Market Module regions as shown on p. xiv of Energy Information Administration, *Electricity Prices in a Competitive Environment,* DOE/EIA-0614 (Washington, DC, August 1997). These regions are synonymous with the NERC regions and subregions. Natural resource and other limitations may restrict number of units able to be built at these costs.

Source: Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997); National Energy Modeling System run AEO98B.D100197A.

Table 16. Cost and Performance Characteristics for Combustion Turbine Technologies and Renewable Generating Technologies, Northwest (NWP)

Technology [a]	Capacity (megawatts)	Overnight Capital Cost (1995 $/kilowatt)	Variable Plus Fixed O&M[b] (1995 mills/kWh)	Capacity Factor (percent)	Construction Lead-Time (Years)	Levelized Cost[c] (1995 mills/kWh)
Combustion Turbine (Conventional) . . .	160	316	10.8	85	2	42.2
Combined Cycle (Conventional) . . .	250	463	20.6	85	3	30.0
Biomass	100	2,540	8.8	80	4	58.5
Geothermal	50	1,415	8.6	80	4	30.0
Solar Thermal	100	2,921	15.9	37	3	133.0
Solar PV	5	4,083	4.6	30	2	217.1
Wind	50	742	9.4	31	3	[b]38.6

[a]Decision to built made in 2000. Plant assumed to enter service at end of construction lead time.
[b]Does not include fuel costs, which are included in the levelized cost. The cost of fuel per kilowatthour varies by fuel and the efficiency of that technology to transform energy to electricity.
[c]Includes various externality costs and credits.

Notes: NWP includes Washington, Oregon, Montana (excluding easternmost port), Nevada, Utah, the western part of Wyoming, and extreme eastern California. The regions used in this chapter are based on EIA NEMS model Electricity Market Module regions as shown on p. xiv of Energy Information Administration, *Electricity Prices in a Competitive Environment,* DOE/EIA-0614 (Washington, DC, August 1997). These regions are synonymous with the NERC regions and subregions. Natural resource and other limitations may restrict number of units able to be built at these costs.

Source: Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997); National Energy Modeling System run AEO98B.D100197A.

Table 17. Cost and Performance Characteristics for Combustion Turbine and Renewable Generating Technologies, Electric Reliability Council of Texas (ERCOT)

Technology [a]	Capacity (megawatts)	Overnight Capital Cost (1995 $/kilowatt)	Variable Plus Fixed O&M[b] (1995 mills/kWh)	Capacity Factor (percent)	Construction Lead Time (Years)	Levelized Cost (1995[c] Mills/kWh)
Combustion Turbine (Conventional) . .	160	316	10.8	85	2	38.5
Combined Cycle (Conventional) . .	250	459	--	85	3	33.6
Biomass	100	2,519	9.6	80	4	62.9
Geothermal	N/A	N/A	N/A	N/A	4	N/A
Solar Thermal . . .	100	2,863	16.4	32	3	137.3
Solar PV	5	4,003	4.3	26	2	202.6
Wind	50	727	11.7	25	3	48.3

[a]Decision to build made in 2000. Plant assumed to enter service at end of construction lead time.
[b]Does not include fuel costs, which are included in the levelized cost. The cost of fuel per kilowatthour varies by the fuel and the efficiency of that technology to transform energy to electricity.
[c]Includes various externality costs and credits.

Notes: ERCOT, which includes most of Texas, is a region of the Electricity Market Module. The regions used in this chapter are based on EIA NEMS model Electricity Market Module regions as shown on p. xiv of Energy Information Administration, *Electricity Prices in a Competitive Environment,* DOE/EIA-0614 (Washington, DC, August 1997). These regions are synonymous with the NERC regions and subregions. Natural resource and other limitations may restrict number of units able to be built at these costs.

Source: Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997); National Energy Modeling System run AEO98B.D100197A.

Transmission Issues for Renewable Energy Technologies

The tariffs[181] for transmission access and services are coming under review as the electric power industry evolves from a regulated to a competitive environment. The structure of the transmission tariff will determine the allocation of transmission costs to the users of the transmission system, and ultimately, to the respective consumers. The structure of the transmission tariff can impact the prices of transmission for different generation technologies and energy sources, which could affect the economics of these technologies.

The transmission tariff is designed to recover both the marginal and fixed costs of the transmission system. The marginal cost of transmission for completing any given power transfer, including losses, ancillary services (i.e., capacity reserves), and any congestion cost, is typically a small fraction of the embedded cost included in transmission tariffs. The transmission tariff also sets prices well above the marginal cost to recover the fixed cost of the transmission system. The methodology used to recover fixed costs (in excess of marginal cost) can impact the price of electricity, thereby potentially affecting competition among generation suppliers. For example, certain transmission tariffs could result in a distant generation supplier paying "pancaked" transmission rates[182] to several transmission providers, the sum of which greatly exceeds the marginal cost of transmission.

The most common type of transmission tariff is postage stamp pricing. A postage stamp rate is a fixed charge per unit of energy transmitted within a particular zone, irrespective of the distance that the energy travels. Other transmission tariffs include megawatt-mile and congestion pricing. Megawatt-mile rates explicitly reflect the cost of transmission based on both the quantity of power flow and the distance between the receipt and delivery points. Congestion pricing is used to allocate the available transmission capacity by increasing the price to users of the transmission lines as maximum transmission capacity is reached.

Currently, transmission tariffs are based on contract path pricing. A contract path rate is one that follows a fictional transmission path agreed upon by transaction participants. However, contract path pricing does not reflect actual power flows through the transmission grid, including loop and parallel path flows. Flow-based pricing schemes can be used as an alternative to contract path pricing.

Tariffs that include charges for firm (take-or-pay) transmission capacity or transmission distance will increase the cost of transmission for generating units having low capacity factors (e.g., due to intermittency of operation, as with wind-powered facilities) or with increasing transmission distance (e.g., remotely located facilities, as with biomass powered facilities). Under these tariffs, technologies utilizing certain renewable energy technologies having inherently low capacity factors, large distance from load centers, and intermittent operation will incur relatively higher transmission costs than other technologies.

Historically, renewable energy technologies have received Federal and State incentives to make them more price-competitive with fossil-fueled technologies. In competitive markets, advocates of renewable energy resources, in addition to promoting incentives (e.g., renewable portfolio standards), are also promoting green pricing programs where consumers pay a premium for electricity from renewables. How competitive renewable technologies ultimately become will depend on the cost of renewable technologies to produce electricity, including transmission prices, incentives that mandate consumption or reduce the cost of renewable generation, and the price elasticity of consumers' demand for green power. High prices for transmission services, added to the cost of renewable generation, could reduce the demand for renewables even with green pricing programs. However, a transmission tariff that results in high transmission prices in certain geographic areas may create an opportunity in those areas for distributed generation by using renewable technologies to compete with central station power plants.

Distributed Generation

During the early development of the electric power industry, electricity was provided using distributed generation, sometimes called distributed resources, where generation occurs near or at the site of electricity demand. Although distributed generation has been

[181] Tariff is a set of schedules filed with the regulatory authority specifying lawful rates, charges, rules, and conditions under which service is provided.

[182] "Pancaked" transmission rates refer to paying multiple rates on top of one another. For example, if postage stamp transmission rate schedules are in effect, then a firm which had transmission facilities outside a single "zone" would have to pay for crossing into another "zone"; hence, the term "pancaked."

replaced by large central-station power plants—made possible by the development of an adequate, reliable, and efficient transmission system—it may be staging a comeback under deregulation.

Generation will be priced competitively under deregulation, but transmission and distribution (T&D) will continue to be regulated. T&D regulation is undergoing substantial changes, with transmission owners required to open access to transmission lines, and the transmission services undergoing a transition to "unbundling" of services and prices. Under unbundled services, transmission owners must provide a clear and specific tariff for a variety of transmission access services (e.g., point-to-point vs. network related, interruptible vs. non-interruptible charges) and a variety of dispatching and power management services (e.g., capacity reserves, voltage control, and administration). Distributed generation may have opportunities in niche markets to be competitive with the cost of electricity from central stations, which includes cost of transmission (including losses and ancillary reserves), operating power substations, and distribution lines and equipment for delivery to end users.

T&D costs can vary greatly among locations with the unbundling of rates. T&D costs may be relatively low for customers receiving power from plants close to major transmission lines or substations. For customers located far away from main transmission lines, or in constrained areas of the grid, T&D costs may be a multiple of the average costs. Distributed generation may prove to be attractive in areas where it can defer T&D investment or where it can improve reliability to the consumer. Small-scale renewable generation technologies that have seen significant cost reductions and improvements in operating characteristics may be competitive and provide benefits (e.g., environmentally friendly, minimum land use) not available from large central generating stations. In the future, fuel cells, wind turbines, solar panels, and some biomass technologies may meet these criteria.

Renewable Energy Resources

Each of the renewable resources and technologies is different with regard to resource location, markets, and infrastructure. Therefore, each may be differentially affected by deregulation. This section discusses the possible effects of competitive markets on each of the renewable sources.

Biomass[183]

Biomass produced 75 percent of nonhydroelectric renewable electricity in 1997, with wood comprising the largest component of biomass energy. Clearly, the success of any restructuring provision attempting to increase substantially renewable-based electricity in the near term will require more generation from biomass sources. A major issue in this section is the availability of additional biomass resources, especially wood and wood waste, which are the principal biomass products used to produce electricity. Their use is greatest in the forest products industry, which consumes about 85 percent of all wood and wood waste used for energy and is the second-largest consumer of electricity in the industrial sector (Figure 23).[184] Electric utilities have historically relied on fossil fuels and consumed very little biomass. Of the more than 500 U.S. biomass power production facilities (with total capability near 10 gigawatts), fewer than 20 are owned or operated by electric utilities.

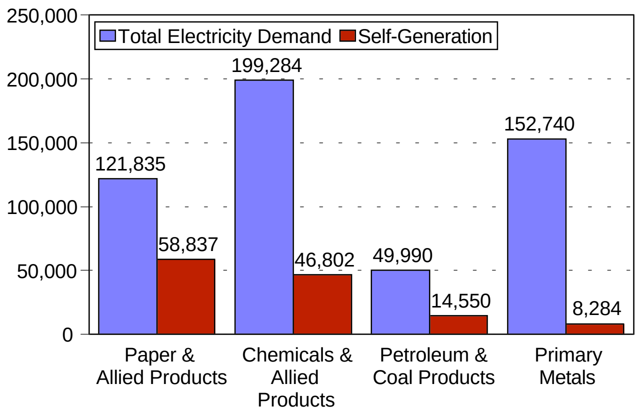
Almost all industrial firms that generate biomass-based electricity do so to achieve multiple objectives. First, most of these firms are producing biomass-related products[185] and have waste streams (e.g., pulping liquor) available as (nearly) free fuel. This makes the cost of self-generation cheaper in many cases than purchasing electricity. Despite the fact that the Forest Products Industry self-generates a substantial portion of its electricity demand, its sizeable power requirements leave plenty of room for additional competitively priced self generation, if such is possible. Second, combusting waste to generate electricity also solves otherwise substantial waste disposal problems. Thus, the net cost of generation is much lower to the forest products industry than it would be if its generating facilities were used only to produce electricity, because a sizable waste disposal cost is being avoided. The use of waste-based fuel by some industrial generators to reduce waste disposal costs while simultaneously providing power is an example of synergy among industrial production, environmental concerns, and energy production.

[183] Biomass includes wood, wood waste (e.g., black liquor from paper pulping operations), municipal solid waste, manufacturing wastes, ethanol, and "other biomass" (e.g., used tires, utility poles, and various combustible gases which are byproducts of manufacturing.)

[184] Based on sector analysis of data in Energy Information Administration, *Manufacturing Consumption of Energy, 1994,* DOE/EIA-0512(97) (Washington, DC, December 1997), Table A43.

[185] These are usually wood waste streams but can be from a wide variety of sources, such as rice hulls or bagasse from sugar harvesting.

Figure 23. The Largest Electricity-Consuming Industries and Their Generation, 1994
(Million Kilowatthours)



Source: Energy Information Administration, *Manufacturing Consumption of Energy 1994*, DOE/EIA-0512(94) (Washington, DC, December 1997).

Although many people envision substantial increases in biomass power for the future with "energy crop" plantations forming a primary supply base,[186] this is not feasible in the near term. Presently, "closed-loop" (i.e., sustainably supplied) biomass power projects are at the research and demonstration phase.[187] This reemphasizes the fact that significant near-term increases in biomass-produced power will need to come from sectors currently producing power from biomass.

If the principal source of biomass for power is waste streams, then industrial company biomass generation beyond current levels will require changes in basic industrial operating conditions which generate those waste streams. That is, the synergy referred to above must be maintained. A decision by an industrial company to increase electricity generation would be based on (1) how increasing generation would affect industrial operations, i.e., existing processes and products; (2) anticipated costs and supply implications for additional primary biomass fuel; and (3) the cost of self-generated versus purchased electricity.

One industrial operating condition which could change is the character of the biomass fuel used. If primary fuel (e.g., dedicated crops and trees) rather than waste-based fuel were used to support increased generation, fuel costs would change. Another is that increased industrial biomass generation could require alteration or addition of fuel storage, material handling, and generating equipment (e.g., for cofiring retrofits). Third, increased demand would be placed on the fuel supply infrastructure. While some biomass fuel resources are owned by industrial companies,[188] in other cases companies purchase from private or government landowners. The availability of additional biomass fuel from noncaptive suppliers is thus uncertain. Hence, prices paid for electricity would have to be sufficiently high to motivate forest product generators to become net sellers beyond current levels for there to be a significant impact on U.S. biomass-generated electricity from the industrial sector.

It is generally perceived that, absent mandatory incentives to promote and preserve public benefits (e.g., RPS, wire use charges), electricity restructuring will exert competitive market pressures that will (on a macro scale) tend to reduce, rather than increase, the price of electricity. It is, therefore, not reasonable to anticipate a substantial increase in industrial output of biomass electricity solely due to market restructuring. Even with a mandatory RPS, it is unclear that the cost of new biomass power would be less than for other renewables—particularly wind—in the near term.

The effect, on the other hand, of green power marketing programs, voluntary or State-mandated, is an altogether different matter. During the past year, there has been a steadily increasing demand for renewable-based electricity as a result of retail marketing programs and State production mandates and incentives. Whether or not demand for green power is beginning to outstrip initial supply, there is clear evidence of new interest and participation by both forest products and energy companies, and public attitude and corporate image play no small role in this change. Utilization of additional primary biomass resources, such as timber, for energy may be constrained somewhat in the short term by available generating capacity. The potential of the wood resource base for energy use is large, however, under qualified conditions.

One major qualification is that noneconomic factors, such as public perceptions regarding land use, will play a major role in how much of the wood resource base may be used for energy. There may be a conjunction at

[186] "Energy crops" are any crops grown and dedicated for energy production, with the intent that the generating facility can be "sustainably supplied" by these crops.

[187] For example, a 75-megawatt generating plant, which will be fueled by a sustainable alfalfa supply grown by regional farmers, is being built in Minnesota.

[188] The ownership of resources by an entity using that resource is known as "captive ownership."

the present time, however, between public attitude toward use of timber resources for energy and the potential of biomass-based power.

A recent analysis of the press by the Forest Service indicated that 75 percent of the stories on the subject expressed a favorable attitude and growing acceptance that forest ecosystem management is necessary. In recent decades, cutting practices on timberland have been a contentious public issue. Thinning of forest understorey[189] is a component of this issue. The study noted that attitudes have shifted regarding the thinning of understorey since the lives of over a dozen firefighters were claimed a few years ago in their attempt to control a raging forest fire. While understorey wood is of limited commercial use otherwise, it is a good source of hogged fuel (woodchips). Slash (tops, stumps, and limbs) left over from general timber harvesting are related in nature. It is now perceived that balanced ecological practice leaves sections of slash and understorey for support of habitat and natural reforestation but removes part to reduce the risk of fire and allow remaining healthier trees to grow larger than they would otherwise.

Use of understorey, slash, poor quality timber, and mill wastes for energy may now even represent an opportunity for some companies to "hit a home run." If these products are replanted with new biomass, use of these forest wastes for energy is a sustainable practice and a strategy for mediation and sequestration of carbon. A primary motive for forest product companies to thin understory and remove slash is to replace this poor quality biomass with more commercially viable trees. This may be not only a profitable but also an ecologically popular practice if biodiversity can be maintained. It may now become possible for companies simultaneously to acquire both a "green" corporate ecological image in their resource operations and a "green energy" image in their production operations.[190]

Although the increased availability of understorey for fuel would represent an increase in the biomass resource base, any sizable short- to mid-term increase in commercially viable resources is not feasible. Trees require 20 to 40 years to reach full maturity, and while crops such as switchgrass and alfalfa can be grown quickly, the infrastructure for utilizing them for energy is limited, as mentioned previously. Thus, in evaluating the potential for large increases in renewable-based electricity generation from a resource point of view, the conclusion is the same as previously—heavy reliance upon the existing biomass resource base and the generating capability of the Forest Products Industry.

In addition to the potential for traditional forest product companies to participate in the green power phenomenon, one must evaluate the degree of success which nontraditional participants in the national fiber market will experience. The principal nontraditional participant would likely be an electric utility considering cofiring biomass with coal. Scenarios for large increases in biomass-based power usually assume that some fraction of this electricity will come from cofiring. About 15 percent of a cofiring fuel mix can be biomass in theory. In practice, workable proportions may be closer to 5 percent. At the utility sector level, this scenario might imply that a big increase in biomass electricity subsumes participation by many buyers making relatively small, scheduled fiber purchases.

The viability of the utility cofiring scenario, at first glimpse, does not appear favorable. Forest product industries are usually located in close proximity to timber resources. In contrast, utility generating facilities are located according to a number of considerations: water availability, land acquisition capability and costs, environmental and safety issues, transmission and distribution costs, and proximity to population centers, among others. These considerations often do not put utility plants within an economically feasible range (generally 50 miles) of biomass resources; the amount of wood required to satisfy only 5 percent of fuel requirements is far too small to transport wood in a manner similar to that of coal. Thus, some utilities that might wish to cofire wood are faced with difficulties accessing fuel resources in a cost-effective manner.

Finally, a major limitation on the use of wood for energy within the Forest Product Industry is the fact that wood has a higher value for its primary end uses (e.g., paper, packaging, structural components, insulating materials, panels, composite materials, chemical feedstocks, mulch, animal bedding, sanitary products, components for automobiles, etc.) than for fuel. Using more wood for fuel would place upward pressure on the cost of primary products, unless additional forest resources are available near current costs.

[189] Understorey is composed of the noncommercial timber and scrub vegetation growing amid commercial-grade timber.

[190] Some companies go a step further and now offer the retail pubic "green tagged" building products, reflecting that they have been manufactured by use of sustainable and environmentally responsible practices.

The reality is, however, that there are many constrictions on the supply of forest resources. For many years, harvests outstripped timber production, and while supply has recovered somewhat in recent decades, significant pressures on supply sometimes develop. Also, the amount of cutting allowed on Federal lands has fallen drastically in recent years, largely for ecological reasons. Additionally, forest product companies enjoy long-established fiber supply relationships, contract arrangements, and sometimes own or lease timberland directly. Therefore, utilities and nontraditional generators would appear to be at a disadvantage with respect to obtaining significant additional wood supply.

About 50 percent of the national timber resource base is privately owned, however, with millions of acres in noncommercial hands. Some of it cannot be accessed by virtue of such factors as aesthetic considerations and buffer value, but a large quantity can. Buyers can contract directly with private landowners to harvest poor commercial quality trees or to thin understorey. Frequently, however, such activities are conducted by brokers who deal with all wood grades. Also, independent consulting foresters represent both individuals and groups of landowners and provide the reforestation knowledge and services that would be handled by the staff of large forest product companies and corporate timberland owners. Therefore, an infrastructure is already in place that can be used to advantage by nontraditional wood generators.

As mentioned earlier, large diversified forest product companies sometimes own "captive" timber resources. However, many of these companies are still not self-sufficient in fiber supply. Businesses that fall into the partly or wholly fiber-dependent category can be expected to oppose any changes in markets that introduce new demand and price pressures on the timber supply. Businesses that have excess timber reserves can be expected to favor increased biomass-based power output. In this respect, the market conditions for wood supply facing any nontraditional wood generator are dependent on local conditions and ownership characteristics.

These are some of the obstacles and opportunities which confront new biomass electricity generation. The structure of the Forest Products Industry reflects that, although there are only 500 to 1,000 very large corporate businesses, there are nearly 40,000 smaller businesses involved in forestry, logging, and sawmilling. Biomass-based power could develop into a huge new market for some of these businesses—eventually. From a national perspective, the potential opportunities of increased biomass electricity generation are great. Winners include small business, rural development, national energy security, and climate goals. In the immediate future, however, any substantial increases in power from biomass will come from the large Forest Products Industry firms, whose use of biomass for power is linked to their overall production of major products.

Geothermal

Producing electricity from geothermal resources involves a mature technology. The time from which a site is confirmed as having the potential (i.e., with sufficient water at temperatures high enough to drive turbine blades using a binary or flash system) to the time a facility can produce electricity is short—less than 3 years. However, due to the remote locations of geothermal resources, the cost of transmission may make the venture more expensive than a facility that does not need miles of transmission lines. Constructing transmission lines requires extensive environmental permits, the acquisition of which may stretch out for years before a permit is granted. Currently, two potential areas of geothermal resources are known to remain without a facility, both in Northern California. However, only one-third of the potential capacity estimated in 1992 is currently built.

The Northwest region has an abundant supply of electricity, most of it coming from the Bonneville Power Administration (BPA). The BPA recently backed out of contractual arrangements to purchase geothermal electricity from Northern California for this very reason. It is possible, however, that if consumer demand for "green energy" is sufficient, geothermal energy will be among the resources used.

Solar

The solar industry, especially the photovoltaics (PV) segment, has reduced product prices substantially in recent years. The industry has made major progress in all areas of performance, reliability, and costs, as well as consumer acceptance. For many years, State and Federal governments, as well as environmentalists and utilities, have strongly supported the use of solar energy—especially in the U.S. Department of Energy's research and development budget. However, attaining competitiveness with conventional fuels has been slowed by factors that affect the viability of all[191] renewables, including declining though still relatively high capital costs for solar operations, the decline in the price of natural gas, the surplus of coal-fired energy, and the planned deregulation of electricity. In most cases, solar energy systems currently are not economical for grid-interactive applications.

As generation becomes deregulated, the solar energy industry will have to emphasize its niche market applications and newly derived opportunities (subscription to renewable energy power supplies, net metering, rooftop PV systems, and portfolio standards) in order to continue its technological and cost-reducing developments. Solar energy can fill many niche applications because of its unique characteristics of generally low maintenance costs, modularity, portability, and adaptability.

Distinct market niches with differing promise emerge in distributed generation, depending on market structure. Solar energy is consistent with the concept of the distributed utility. At present, utilities are the major market niche for distributed generation. They use distributed generation at substations to place generation closer to areas with new high load demand and, thereby, to minimize infrastructure costs associated with the construction of new transmission lines and generation facilities. The Hedge substation plant, for example, was completed by the Sacramento Municipal Utility District in 1995 for transmission and distribution support. It consists of four PV systems, totaling 527 kilowatts. In addition, distributed generation units are small and, as full retail access becomes a reality, smaller generators (from 2 megawatts up to 50 megawatts capacity) are likely to be in demand. Solar / PV stations fit well into this structure.

Currently, rooftop PV systems are benefitting from net metering. Under some net metering proposals, the customer's PV system offsets the retail electric rates rather than wholesale avoided costs, a plus to the consumer. Rooftop PV systems also have no-cost land for siting. The Sacramento Municipal Utility District is planning the installation of 1,000 such rooftop systems in its district. About 15 States, including California and all of the New England States, allow homeowners essentially to become small-scale solar power plants, running their electric meters backward and sending power back to their utilities when they generate more than they use (net metering). In a separate initiative, on June 26, 1997, in his speech before the United Nations Session on Environment and Development, President Clinton announced a national plan to install PV rooftop systems in 1 million homes by the year 2010.

Under most restructuring proposals, however, new grid-connected rooftop PV installations with net metering are unlikely because competitive pressures will eliminate mechanisms supporting higher cost generation. Utilities under restructuring, for example, will no longer be in the role of making low-interest loans for the rooftop equipment. On the other hand, the use of rooftop installations in remote areas to avoid construction of distribution lines should be economically viable. Also, solar energy is treated very favorably in many of the States that have passed renewable portfolio standards. For example, New York has set-asides totaling $750,000 per year for renewable projects; in 1996, 90 percent went to PV projects.

Wind

The greatest advantage of wind power is its potential for large-scale, though intermittent, electricity generation without emissions of any kind.[192] In addition, over the years, wind energy's production cost has benefitted from improvements in technology and better reliability.[193] Wind power plants can be built in small, modular units (less than a megawatt each) within a relatively short time frame (2 years), so they offer power suppliers greater flexibility than plants that can be built only in large sizes and over longer periods of time. As noted below, this would be an advantage only in deregulated markets where major transmission investments are unnecessary.

About 1,700 MW of wind capacity operate in the United States, most of which is located in California because of utility incentives offered there in the 1980s.[194] This pattern is shifting, however, as other States develop wind power plants with a variety of local initiatives.

[191] R&D expenditures for solar energy activities (solar thermal and photovoltaic) account for about 31 percent of the DOE proposed FY 98 R&D budget. See U.S. Department of Energy, *Solar and Renewable Resources Technologies Program*, GAO / RCED-97-188 (Washington, DC, July 1997) Table 1.

[192] D.L. Elliot and M.N. Schwartz, "Wind Energy Potential in the United States," National Renewable Energy Laboratory (Golden, CO, 1997), Figure 3. See Web site www.nrel.gov / wind / potential.html.

[193] "Wind Industry Criteria for Restructuring the Electric Industry" in American Wind Energy Association, AWEA Compilation on Electric Industry Restructuring (Washington, D C, Spring 1997)

[194] Energy Information Administration, *Electric Power Annual 1996, Volume II*, DOE / EIA-0348(96) / 2 (Washington, DC, December 1997).

Wind power facilities are now operating or under construction in Minnesota, Texas, Colorado, Iowa, Vermont, Hawaii, Wyoming, Michigan, New York, Montana, North Dakota, Oregon, and Wisconsin.

Analysis indicates that good wind resource areas with accessibility to nearby transmission lines do exist,[195] although it is perhaps more common that wind resources are located some distance from adequate transmission lines.[196] Larger wind developments (several hundred megawatts) are more likely to be able to justify investments in transmission.

Fixed, investment-related charges are the largest component of wind-based electricity costs. Improved designs with greater capacity per turbine have reduced investment costs to a quarter of what they were a decade ago, so that the cost per kilowatt of installed capacity is currently around $1,000 (1996 dollars).[197] Wind power plants incur no fuel costs, however, and their maintenance costs have also declined with improved designs.[198]

At good sites, electricity generation from wind power now costs around 4 cents per kilowatthour (levelized) including the EPACT credit.[199] This is still higher than the cost anticipated from combined-cycle, natural gas-fired plants with present gas prices. If natural gas prices rise much, however, wind power will become competitive in selected markets.

Due to the intermittent nature of wind, a wind power plant's economic feasibility strongly depends on the amount of energy it produces. Capacity factor[200] serves as the most common measure of a wind turbine's productivity. Estimates of capacity factors in 1997 ranged from 26 percent to 36 percent.[201]

In the United States, wind power has a lower delivered cost than other new nonhydroelectric renewable electricity resources. Virtually all exploitable and economical hydroelectric sites have already been developed. Therefore, if the electricity supply industry moves toward a higher renewable fraction, wind power can be expected to play a significant role. While wind power has no air emissions, it does have other impacts on the environment. These are visual obstruction, bird kills, and noise pollution. Mitigation measures are frequently taken to resolve these problems.

Another major issue regarding wind intermittency is that wind power can offer energy, but not on-demand capacity. Even at the best sites, there are times when the wind does not blow sufficiently and no electricity is generated. Existing hydroelectric power offers the greatest complementarity with new wind power facilities in that it provides capacity but only limited energy. As the market is deregulated and becomes more competitive, ownership of dispatchable resources together with wind will be of greater value than either alone.

Related to intermittence is wind's unpredictable nature. Weather forecasting has improved markedly over the past several decades, so wind power plant operators can predict, to some extent, what their output will be by the hour. But that ability is imperfect at best. In the past, unpredictability was not as important because a large vertically integrated utility—particularly one with excess capacity—was able to dispatch whatever was needed at the time it was needed. As that capability is dispersed to competitors in the new deregulated industry, the problem will be exacerbated by market rules that require operators to bid into the exchange at least 24 hours in advance. Therefore, wind power plants will be at a disadvantage unless they are allied with suppliers offering appropriate levels of firm capacity.

Conclusion

The continued use of renewable-based electricity faces strong challenges in a competitive electricity market. Renewable energy sources, while relatively benign

[195] See National Renewable Energy Laboratory, *U.S. Wind Reserves Accessible to Transmission Lines, Review Draft* (Golden CO, August 1994).

[196] J. P. Doherty, Energy Information Administration, "U. S. Wind Energy Potential: The Effect of the Proximity of Wind Resources to Transmission Lines," *Monthly Energy Review* DOE/EIA-0035(95/02) (Washington, DC, February 1995), pp. vii-xiv.

[197] Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997), p. 217.

[198] Energy Information Administration, *Renewable Energy Annual 1996*, DOE/EIA-0603(96) (Washington, DC, March 1997), p. 47.

[199] By comparison, the American Wind Energy Association estimates the cost at 3 cents per kilowatthour. See "Renewables in a Competitive Environment," in American Wind Energy Association, *AWEA Compilation on Electric Industry Restructuring* (Washington, DC, Spring 1997).

[200] Capacity factor is the ratio of the electrical energy produced by a generating unit for the period of time considered to the electrical energy that could have been produced at continuous full-power operation during the same period.

[201] Electric Power Research Institute and the U.S. Department of Energy, *Renewable Energy Technology Characterizations*, EPRI TR-10946 (Palo Alto, CA, December 1997), pp. 6-12.

environmentally, are generally higher cost options for generating electricity. In order to maintain renewables as a generating option, a number of strategies have been put in place or proposed. One or more of these mechanisms—renewable portfolio standard (RPS), system benefits charge (SBC), public benefit fund (PBF), net metering, green marketing—are generally part of Federal and State proposals to support renewables while their costs continue to decline.

6. Quantitative Impacts of Electric Power Industry Restructuring on Fuel Markets

This chapter presents a quantitative analysis of the likely impacts that competitive electricity generation markets could have on fuel supply industries. The primary tool used for the analysis is the National Energy Modeling System (NEMS), a comprehensive model of energy markets that projects energy supply, demand, and prices. NEMS is an integrated model that represents the supply, conversion, and end-use demand sectors in domestic energy markets. By balancing energy supply and demand, NEMS projects production, imports, consumption, and prices of energy in the mid-term forecast horizon (in this analysis, through 2015). Because restructuring affects all energy consumers and producers, all the demand and supply modules within NEMS were used in the analysis.

Case Descriptions and Assumptions

In order to explore the potential impacts of a competitive electricity market on fuel markets, several cases were constructed. The regulatory, legislative, and environmental policies that will eventually emerge are currently being debated in a number of different forums. Therefore, there is considerable uncertainty about the conditions under which a competitive electricity market will operate. In order to capture this uncertainty, a range of possible outcomes was prepared, each based on different assumptions about key electricity and energy variables. Although these cases are not forecasts, they do represent potential outcomes that could occur under the range of assumptions analyzed. Two full competition cases in addition to a partial competition case (the *AEO98* reference case) are compared with a no competition case in order to illustrate possible impacts of competition.

The first case (no competition) represents a market in which there are no further competitive initiatives and in which participants assume that no further move toward competition will occur. This case was developed to provide a base against which the competition cases and the *AEO98* reference case could be compared. While the *AEO98* reference case assumes that only three regions (California, New England, and New York) will move to full competition over the next decade, it also assumes that electricity market participants will anticipate the onset of full competition.[202] To develop the no competition case, EIA modified the following assumptions from the *AEO98* reference case:

- Heat rates for new plants are assumed to improve less over the forecast horizon than in the *AEO98* reference case, because there would be less incentive for vendors to improve them if electricity markets remained regulated. For example, while heat rates for new advanced combined-cycle plants were assumed to be 6,350 British thermal units (Btu) per kilowatthour in the *AEO98* reference case, the no competition case assumes that they would be only 6,668 Btu per kilowatthour by 2015, an efficiency that is 5 percent lower (Table 18).

- The capital costs of new generating plants are assumed to be 15 percent higher than those assumed in the *AEO98* reference case. In regulated electricity markets with full cost passthrough, plant equipment manufacturers are assumed to be less aggressive in lowering costs to maintain market share. In addition, it is assumed that equipment would be tailored to meet individual customer needs, thus reducing cost savings that could be realized if more factory construction and modular design were employed.

- Capital costs for new construction are assumed to be based on the regulated utility cost of capital, rather than on the project cost of capital used in the *AEO98* reference case. In a regulated environment, utilities are allowed to recover their capital costs

[202] Assumptions used for competitive electricity markets in the *AEO98* reference case are described in Energy Information Administration, *Annual Energy Outlook 1998*, DOE/EIA-0383(98) (Washington, DC, December 1997), Appendix G.

Table 18. Comparison of Selected NEMS Assumptions

Assumption		Case			
		No Competition	*AEO98* Reference	Low Fossil	High Fossil
Capacity	Nuclear retirement	Same as *AEO98* reference case	Retire 24 nuclear plants prior to end of operating license	Retire 6 nuclear units that have announced early retirement dates	Same as *AEO98* reference case
	Fossil retirement	Same as *AEO98* reference case	Retire fossil plants with operating costs > 4 cents per kWh	Same as *AEO98* reference case	Retire fossil plants with operating costs > 6 cents per kWh
	Upper bound on new plants	Same as *AEO98* reference case	Up to 3 percent above optimal reserve margin in competitive regions; 1% elsewhere	Up to 10 percent above optimal reserve margins in all regions	Up to 10 percent above optimal reserve margins
	Renewable portfolio standard (RPS)	None	None	2 percent RPS by 2000 increasing to 4 percent by 2010	None
Electricity Demands	End use sector growth	Same as *AEO98* reference case	1996-2015 Residential 1.6% Commercial 1.3% Industrial 1.5% Total 1.5%	Same as *AEO98* Reference	1996-2015 Residential 2.0% Commercial 1.8% Industrial 1.6% Total 1.9%
Competitive Electricity Prices	Regions	None	New York, New England, California (phased in by 2005)	All regions (phased in by 2005)	All regions (phased in by 2005)
Electricity Trade	Regions	Same as *AEO98* reference case	Adjoining regions that have traded historically	Allow trading between all regional pairs with connecting transmission capability	Allow trading between all regional pairs with connecting transmission capability
Fuel Supply	Oil and gas drilling costs	Same as *AEO98* reference case	1.3 percent annual reduction in onshore drilling costs	Same as *AEO98* reference case	1.6 percent annual reduction in onshore drilling costs
	Coal productivity	Same as *AEO98* reference case	2 percent average annual increase in productivity	2.5 percent average annual increase in productivity	2.5 percent average annual increase in productivity
New Generating Plants	Heat rates	5 percent higher than the *AEO98* reference case	Based on analysis of reports and discussions with industry, government, and the National Laboratories	Same as *AEO98* reference case	Same as *AEO98* reference case
	Capital costs	15 percent higher than the *AEO98* reference case	Based on analysis of reports and discussions with various sources from industry, government, and the National Laboratories	Same as *AEO98* reference case	Same as *AEO98* reference case
	Capital recovery	30 years	20 years	Same as *AEO98* reference case	Same as *AEO98* reference case

Table 18. Comparison of Selected NEMS Assumptions (Continued)

Assumption		Case			
		No Competition	*AEO98* Reference	Low Fossil	High Fossil
Generating Plant Costs	General & administrative and operation & maintenance costs	Decline by 5 percent from historical levels by 2005	Decline by 25 percent from historical levels by 2005	Same as *AEO98* reference case	Same as *AEO98* reference case

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

over 30 years. The *AEO98* reference case assumes higher costs of capital based on project financing by unregulated investors. In a competitive market, new capacity additions are riskier and investors are assumed to plan for a 20-year recovery for capital costs.

- Both general and administrative costs, as well as operation and maintenance costs, are assumed to decline by 5 percent, compared with the 25-percent decline assumed for the *AEO98* reference case. Much of the incentive to cut staff and reduce costs comes from the anticipation of competitive electricity markets. In a regulated market, these costs are paid by consumers, dampening the incentive to reduce them.

The competition cases described below contain varying assumptions on how a deregulated electricity market may evolve. Two full competition cases are considered, combining assumptions about low fossil fuel use with the *AEO98* reference case electricity demand and about high fossil fuel use coupled with higher electricity demand. While both cases assume full competition, they differ from each other in assumptions about consumer responses to prices, technological progress for oil and natural gas production, legislation promoting generation from renewable sources, and retirement decisions for fossil and nuclear generators. These competition cases are designed to characterize the effects of competition that is more intense than is assumed in the *AEO98* reference case. While the cases may overstate the intensity of competition, they provide an outer boundary on the effects on electricity markets. Assumptions common to all the cases are as follows:

- Both the reference case and the competition cases assume that California, New York, and New England will become fully competitive within the next decade. Electricity prices for commercial and industrial customers in California are assumed to remain at 1996 levels between 1998 and 2001, with residential customers receiving a 10-percent reduction from 1996 prices during the same period. After a transition period between 2002 and 2007, California markets are assumed to be fully competitive by 2008. This transition period reflects the time needed to establish the institutions for a competitive market and to allow for recovery of stranded costs to the extent permitted by the State. New York and New England have a similar transition period between 1998 and 2007. In the competition cases (unlike the *AEO98* reference case), all other regions are assumed to move to competitive markets beginning in 1998 with the same transition period and to become fully competitive beginning in 2008. Full competition, in addition to the cost and efficiency gains assumed, means that electricity prices will be driven by competition among electricity generators rather than by regulatory proceedings.[203]

- Limits on power transmission are relaxed in three regions from those assumed in the *AEO98* reference case. For the competition cases, it is assumed that Texas, New York, and New England can transmit more power to adjacent regions than they could in the *AEO98* reference case. Texas is assumed to have an incentive to build new transmission connections to neighboring States in order to allow its low-cost fossil plants to sell electricity

[203] For a description of the competitive pricing methodology, see *Electricity Prices in a Competitive Environment: A Preliminary Analysis Through 2015*, DOE/EIA-0614 (Washington, DC, August 1997).

outside the State. In New York and New England it is assumed that new transmission connections to Canada will be built, allowing additional sales of electricity from Canada to the United States.

- Investments in new generating capacity are assumed to exceed the levels that would be expected on the basis of optimal economic efficiency alone. This could occur if suppliers invest in new capacity in order to increase their market share. The level of overbuilding to reflect this investment behavior is assumed to be 10 percent above that which would occur under assumptions of economic efficiency.

- Because of competitive pressures to maintain market share, a higher rate of improvement in coal mining productivity is assumed in the competition cases—2.5 percent annually compared with 2 percent in the *AEO98* reference case.

In order to represent outcomes from restructuring that result in higher or lower fossil fuel consumption, additional assumptions were made in the competition cases. The following assumptions were made for the high fossil case:

- Optimistic technological progress rates that lower costs for oil and natural gas supply are assumed because of competition. Compared with the 1.3-percent annual reduction in the *AEO98* reference case, technological improvements are assumed to reduce onshore drilling costs by 1.6 percent per year. The impact of technology on costs is offset by other factors, including rig availability and drilling levels. Improvements in technology are assumed to result from pressure exerted by electricity markets on oil and gas producers to lower their costs to maintain (or to increase) their market shares.

- Retirements of existing fossil-fueled power plants are reduced to address the uncertainty in the price of generation services in competitive markets. It is assumed that existing fossil-fueled power plants will be retired if their operating costs are greater than 6 cents per kilowatthour. In the other cases, plants with current operating costs greater than 4 cents per kilowatthour are assumed to be retired early because they would not be competitive given the costs and performance of new generating sources. The higher cost criterion used in this analysis allows more fossil plants to be available over the projection period. This assumption reflects the uncertainty about market prices for generation services in a competitive market as well as the value of having higher cost capacity available to provide ancillary services such as voltage stability and reactive power.

- Based on estimates of elasticities observed in regulated markets, a higher level of electricity demand is assumed to capture the uncertainty of predicting the effects that lower electricity prices would have on consumption. In addition, the potential reduction in regulatory oversight could cause demand-side management programs to be deemphasized, resulting in an increase in electricity demand above what it would be if such programs were in effect. New pricing structures, such as time-of-day pricing, could also increase demand. The growth rate for electricity sales (1.9 percent) is assumed to be close to the growth rate for the gross domestic product (GDP), which averages 2.1 percent per year from 1996 through 2015. In the *AEO98* reference case, electricity consumption is projected to grow by 1.5 percent per year. In the high fossil case, residential and commercial sector consumption of electricity was adjusted to mirror GDP growth.

In the low fossil case, the additional assumptions include the following:

- The low fossil case assumes that legislation mandating a renewable portfolio standard (RPS) will be enacted. The standard is based on H.R. 655, Electric Consumers' Power to Choose Act of 1997 (Title I Section 113) submitted by Congressman Dan Schaefer (R-CO). This bill requires that 2 percent of new generation be produced from renewable sources by 2000, increasing to 3 percent by 2005 and 4 percent by 2010. The RPS results in higher levels of generation from renewable sources than projected in the *AEO98* reference case. Higher generation from renewable sources dampens the demand for fossil fuels for a given level of electricity demand. (In March 1998, the Department of Energy announced the Administration's Comprehensive Electricity Competition Plan, which recommends an RPS calling for 5.5 percent of generation from renewable sources by 2010. This is about 20 billion kilowatthours more than is assumed in the low fossil case.)

- This case also assumes no additional retirements of nuclear capacity before their operating licenses expire beyond those already announced. It is assumed that uncertainty about the price of generation services in a competitive market will encourage utilities to postpone the decision to retire plants early. In the *AEO98* reference case, about 18 gigawatts are retired 2 to 10 years before the plant licenses expire, based on the expected need to invest additional capital to refurbish major systems. In this analysis it is assumed that only Big Rock (1997), Haddam Neck (1997), Maine Yankee (1997), Browns Ferry (1997), and Zion 1 & 2 (2004),[204] for which retirements already have been announced, will be retired early.

There are likely to be many innovative approaches to providing electricity services that develop under competition. For example, power from environmentally benign sources (i.e., green power) is currently offered in California. Because the quantitative impacts of these programs and others that improve the efficiency of delivering electricity services are not well understood at this time, they were not considered in the low fossil case.

Results

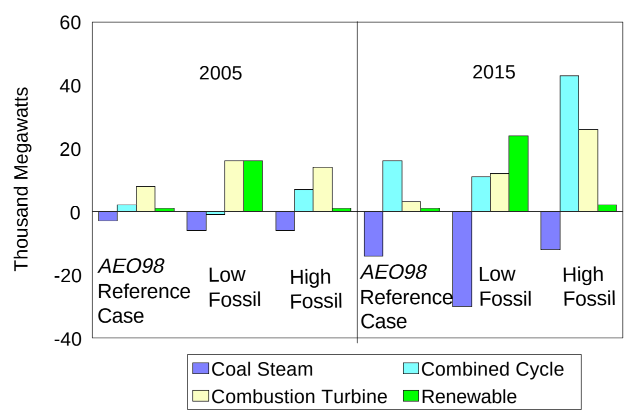
Electricity Capacity and Generation

Decisions about capacity additions are based on assumptions about capital investments, cost of capital, the economic life of the plant, operating efficiency, and fuel expenditures that determine costs over the life of the plant. Using those criteria as a basis for decisions results in natural-gas-fired turbines and combined-cycle plants garnering most of the market for new generation in all the cases analyzed. This outcome is driven by the high efficiency of gas-fired turbines and the expectation that natural gas prices will grow moderately over the next 20 years. Gas-turbine technologies are also attractive over the next several years because they are competitive during shoulder and peak periods of electricity demand. These are the periods for which most of the new capacity will be needed.

Currently there is more than sufficient baseload capacity to meet electricity demand, and new baseload capacity will not be needed in significant quantities for several years. From 1996 to 2015, additions of coal-fired capacity range from about 20 to 49 gigawatts for all the cases analyzed. In contrast, additions of natural-gas-fired turbine and combined-cycle capacity range from about 256 to 324 gigawatts; however, the impact of new natural-gas-fired turbines (132 to 158 gigawatts) is less than the level of capacity additions would indicate because, unlike coal-fired plants, these units operate at low capacity factors.

Even with the dominance of gas-fired capacity additions in mind, there are variations in capacity choice among the cases of this study (Figure 24). For example, coal-fired capacity additions in the no competition case are higher by 2.7 gigawatts than those in the *AEO98* reference case by 2005 (Table 19) because capital investment costs are assumed to be recovered over 30 years instead of 20 years. This assumption improves the economics of more capital-intensive projects, such as coal-fired plants, compared with less capital-intensive projects, such as natural-gas-fired turbines and combined-cycle plants. The higher level of coal capacity additions lowers gas-fired capacity additions by about 10 gigawatts, most of which is turbines. This trend continues through 2015, when there are about 14 gigawatts more of coal capacity additions than in the *AEO98* reference case. The higher coal capacity offsets gas-fired capacity, which is more than 19 gigawatts lower. By 2015, most gas capacity additions are combined-cycle units. The generation from coal- and natural-gas-fired capacity follows similar patterns (Table 20). Coal-fired generation in 2015 is 4 percent more than in the *AEO98* reference case, and gas-fired generation is almost 12 percent lower (Figure 25).

Figure 24. Differences in Capacity Additions from the No Competition Case



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

[204] Commonwealth Edison announced on January 15, 1998, that Zion 1 & 2, temporarily shut down on February 21, 1997, will not reopen.

Table 19. Electricity Generating Capability
(Thousand Megawatts)

Projection	1996	2005 No Competition	2005 *AEO98* Reference	2005 Low Fossil	2005 High Fossil	2015 No Competition	2015 *AEO98* Reference	2015 Low Fossil	2015 High Fossil
Electricity Generators									
Capability									
Coal Steam	305.3	304.8	302.1	299.3	304.8	330.3	316.0	300.7	325.0
Other Fossil Steam	138.1	103.6	103.6	103.6	116.3	97.1	97.1	97.1	109.8
Combined Cycle	15.3	69.2	71.3	68.7	76.7	139.0	154.9	150.3	182.4
Combustion Turbine/Diesel	76.7	168.2	176.2	184.4	182.2	206.8	210.1	218.7	232.3
Nuclear Power	100.8	86.8	86.8	96.1	86.8	63.9	63.9	70.7	63.9
Pumped Storage	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9	19.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	88.6	92.2	92.9	108.3	92.7	93.5	94.7	117.9	95.4
Total	**744.7**	**844.7**	**852.7**	**880.3**	**879.3**	**950.5**	**956.7**	**975.3**	**1,028.7**
Cumulative Planned Additions									
Coal Steam	2.4	3.2	3.2	3.2	3.2	4.7	4.7	4.7	4.7
Other Fossil Steam	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Combined Cycle	2.0	2.7	2.7	2.7	2.7	3.0	3.0	3.0	3.0
Combustion Turbine/Diesel	3.8	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2
Nuclear Power	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Pumped Storage	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.7	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2
Total	**11.3**	**16.6**	**16.6**	**16.6**	**16.6**	**18.5**	**18.5**	**18.5**	**18.5**
Cumulative Unplanned Additions									
Coal Steam	0.0	16.0	13.3	10.4	9.7	46.4	32.1	16.8	34.8
Other Fossil Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	52.6	54.7	52.1	60.1	122.2	138.1	133.4	165.5
Combustion Turbine/Diesel	20.2	111.1	119.1	127.3	125.1	151.2	154.5	163.1	176.7
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.5	1.3	2.0	17.4	1.8	3.0	4.2	27.4	4.8
Total	**20.7**	**181.0**	**189.1**	**207.3**	**196.7**	**322.7**	**328.9**	**340.7**	**382.0**
Cumulative Total Additions	32.0	197.6	205.6	223.9	213.2	341.2	347.4	359.2	400.5
Cumulative Retirements	14.4	80.1	80.1	70.7	62.6	117.1	117.1	111.1	99.6
Cogenerators									
Capability									
Coal	7.1	7.5	7.5	7.5	7.5	7.7	7.7	7.7	7.7
Petroleum	1.0	1.1	1.1	1.1	1.1	1.2	1.2	1.2	1.2
Natural Gas	28.0	31.6	31.6	31.6	31.6	32.7	32.7	32.7	32.7
Other Gaseous Fuels	1.2	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
Renewables	5.8	6.5	6.5	6.5	6.5	6.6	6.6	6.6	6.5
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	**43.0**	**47.9**	**47.9**	**47.9**	**47.9**	**49.3**	**49.3**	**49.3**	**49.2**
Cumulative Additions	8.1	12.9	12.9	12.9	12.9	14.4	14.3	14.4	14.3

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

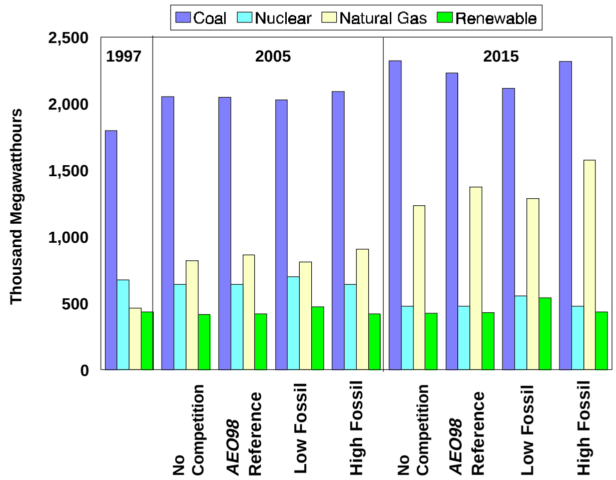
Table 20. Electricity Supply, Disposition, and Prices
(Billion Kilowatthours, Unless Otherwise Noted)

Projection	1996	2005 No Competition	2005 *AEO98* Reference	2005 Low Fossil	2005 High Fossil	2015 No Competition	2015 *AEO98* Reference	2015 Low Fossil	2015 High Fossil
Generation by Fuel Type									
Electricity Generators									
Coal	1,758	2,014	2,007	1,987	2,050	2,282	2,190	2,073	2,277
Petroleum.	80	34	37	28	44	27	33	23	47
Natural Gas	288	628	671	618	714	1,034	1,171	1,088	1,373
Nuclear Power	675	643	643	698	643	480	480	553	480
Pumped Storage	(2)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
Renewable Sources	392	375	377	431	377	383	388	497	392
Total	**3,191**	**3,691**	**3,732**	**3,758**	**3,824**	**4,203**	**4,258**	**4,230**	**4,566**
Nonutility Generation for Own Use	26	26	26	26	26	26	26	26	26
Cogenerators									
Coal	39	38	38	38	38	39	39	39	39
Petroleum	6	6	6	6	6	6	6	6	6
Natural Gas	174	192	192	192	192	201	200	200	200
Other Gaseous Fuels	7	7	7	7	7	7	7	7	7
Renewable	41	43	43	43	43	43	43	43	43
Other	3	3	3	3	3	4	4	4	4
Total	**270**	**289**	**289**	**289**	**289**	**299**	**299**	**299**	**298**
Sales to Utilities	121	125	125	125	125	127	127	127	127
Generation for Own Use	149	163	163	164	163	172	172	171	171
Net Imports	38	38	33	36	36	27	27	29	29
Electricity Sales by Sector									
Residential	1,079	1,252	1,258	1,265	1,296	1,443	1,449	1,449	1,593
Commercial	988	1,120	1,125	1,132	1,155	1,260	1,268	1,271	1,395
Industrial	1,014	1,164	1,186	1,199	1,206	1,306	1,343	1,316	1,363
Transportation	17	32	32	32	32	55	55	56	55
Total	**3,098**	**3,568**	**3,601**	**3,628**	**3,689**	**4,064**	**4,115**	**4,091**	**4,406**
End-Use Prices (1996 cents/kWh)									
Residential	8.4	7.8	7.5	7.2	7.1	7.2	7.0	6.9	7.0
Commercial	7.6	7.1	6.8	6.4	6.4	6.5	6.1	6.0	6.2
Industrial	4.6	4.3	4.1	3.8	3.8	3.9	3.6	3.5	3.7
Transportation	5.2	5.1	4.7	4.5	4.5	4.8	4.3	4.3	4.4
All Sectors Average	6.9	6.4	6.1	5.8	5.8	5.9	5.6	5.5	5.7
Price Components (1996 cents/kWh)									
Capital Component	3.3	3.1	2.7	2.4	2.4	2.7	2.3	2.2	2.3
Fuel Component	1.2	1.0	0.8	0.8	0.8	1.1	0.6	0.6	0.6
O&M Component	2.0	1.9	1.7	1.7	1.7	1.8	1.5	1.5	1.4
Wholesale Power Cost	0.4	0.4	0.9	1.0	0.9	0.4	1.2	1.2	1.3
Total	**6.9**	**6.4**	**6.1**	**5.8**	**5.8**	**5.9**	**5.6**	**5.5**	**5.7**

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

In the high fossil case, where capital costs are assumed to be recovered over a shorter period, coal-fired capacity additions are about 6 gigawatts less in 2005 than in the no competition case. In this case, gas-fired additions are about 22 gigawatts higher and are shared between turbines (14 gigawatts) and combined-cycle plants (8 gigawatts). By 2015, coal-fired additions are almost 12 gigawatts less than in the no competition case, and

Figure 25. Electricity Generation by Fuel Type, 1997, 2005, 2015



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

gas-fired additions are about 69 gigawatts higher. These changes in capacity additions indicate that the assumptions about competitive markets used in this case have a significant impact on fossil-fired capacity additions in the later years of the projection period.

The low fossil competition case (where the RPS is imposed and nuclear capacity is assumed not to be retired before operating licenses expire) reduces the need for fossil-fueled plants even with a higher level of electricity sales than in the no competition case. By 2015, coal-fired capacity is about 30 gigawatts lower and gas-fired capacity is about 23 gigawatts higher than in the no competition case. As a result, coal-fired generation is about 9 percent lower than and gas-fired generation is about 5 percent above the no competition case (Table 20).

It is interesting to note that the need for turbines is higher by about 12 gigawatts in the low fossil case compared with the no competition case because the higher level of generation from nondispatchable renewable sources requires that additional backup capacity be made available to meet peak requirements. These cases indicate that natural gas is expected to have an increasing share of electricity generation as demand levels grow and that coal-fired generation will be lower than would occur in regulated electricity markets, absent the assumption about additional demand growth under competition.

Electricity trade levels across the NEMS regions change modestly across the cases analyzed. Incentives for regional trade are driven by differences in regional generation sources and region-specific characteristics. The assumptions about increased transfer capability of the transmission network in the low and high fossil cases do not cause trading patterns to change because the cost differences are not sufficient to make trading economical. This analysis does not address the potential changes in electricity trade within a region that could occur in competitive markets.

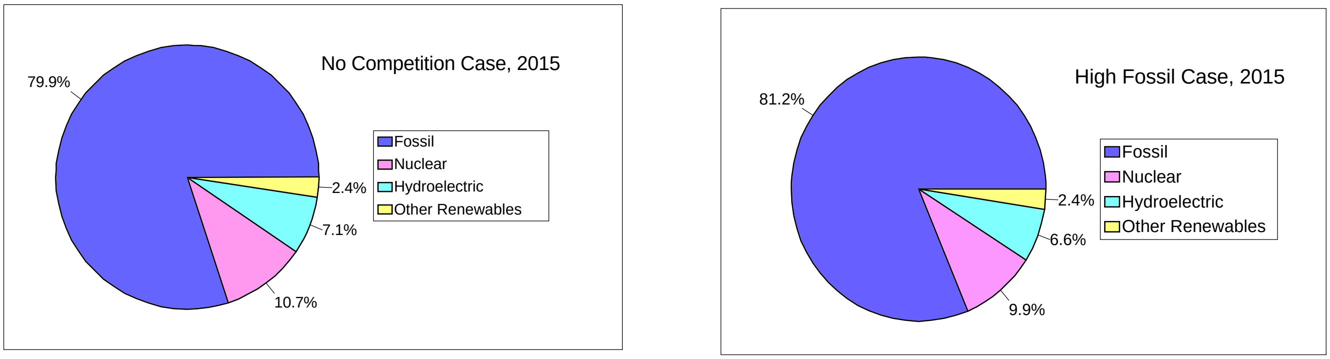
Renewable Sources

Unless required by policies, the restructured electricity market is not expected to stimulate central station renewable energy technologies. Overall, the scenarios suggest that renewable sources will remain more costly than fossil-fueled alternatives through 2015 and will penetrate electricity markets further than they do in the reference case only to the extent compelled, such as by an RPS that mandates generation from renewable sources. The cases suggest that, if policies require increased use of renewable sources, average electricity prices will increase slightly. Under the assumed RPS (HR 655), most of the growth in renewable generation will be from biomass, geothermal, and wind.

The results suggest that renewable sources will garner only a minor overall portion of electricity supply under a range of electricity market conditions. In the absence of an RPS, nonhydroelectric renewable sources (including municipal solid waste) hold only a 2.4-percent share of total U.S. electricity generation in 2015; the hydropower share falls as low as 6.6 percent (Figure 26). Although increased overall electricity demand also raises generation from renewable sources, significant growth occurs only under an RPS. Whereas generation by RPS-qualifying renewable sources (biomass, geothermal, solar, and wind) is 74 billion to 76 billion kilowatthours by 2005 and reaches as much as 85 billion kilowatthours by 2015 with no RPS, it increases to 130 billion kilowatthours in 2005 and to 190 billion kilowatthours in 2015 with an RPS (Table 21).

In the high fossil case, defined renewable sources remain barely changed from their no competition case market share. If renewable sources are to expand more rapidly, the results suggest a need for some significant market change, such as accelerated improvements in renewable energy technologies, an RPS, successful green pricing programs (where consumers choose electricity suppliers based on their impacts on the environment), subsidies, or higher costs for competing technologies.

Figure 26. U.S. Electricity Generation Shares by Energy Source, 2015



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

Finally, the results suggest that renewable sources are highly vulnerable to improvements in competing fossil-fuel technologies, as shown by the high fossil case. Compared with the no competition case, renewable sources fare about the same under competition absent a policy mandating higher shares.

The results also show the likely technology choices for expanded use of renewable sources under more rapid growth or RPS conditions. Biomass, wind, and geothermal are the likely "winners" among renewable energy technologies. Biomass-powered generation increases most, more than doubling from 46 billion kilowatthours in 1996 to 97 billion kilowatthours in 2015 in the RPS case; its capacity also increases significantly, adding more than 7 gigawatts of new capacity by 2015. Geothermal generation increases from 16 billion kilowatthours in 1996 to 52 billion kilowatthours in 2015 in the RPS case; its capacity also increases significantly, far more than doubling by 2015. Wind-powered generation also increases from 3 billion kilowatthours in 1996 to 38 billion kilowatthours in 2015, a leap of nearly 14 gigawatts of capacity by 2015 in the RPS case. Because biomass capacity operates a much greater proportion of the time than wind power and can compete in more regions than geothermal, biomass-fueled generation appears the most likely source for increased electricity generation under policies encouraging use of renewable sources. However, significant issues of cost and land use could arise if the growth of biomass becomes a reality (see Chapter 5).

Because they remain more expensive than both fossil and other renewable alternatives, solar technologies are minor contributors in all the cases and do not increase significantly. Further, because neither solar thermal nor photovoltaic technologies operate as intensively as fossil technologies (they have lower capacity factors), their contribution to total generation remains small. The use of photovoltaic technologies could grow much more rapidly if their cost declined or if electricity prices were higher than those projected in this analysis.

Electricity Prices

Electricity prices are projected to decline from 1996 levels for all of the cases analyzed, including the no competition case. Prices will decline even in a "no competition" market because investments in new capacity will be relatively modest compared with historical levels and because of expected decreases in the price of coal. Prices in the competition cases are further reduced due to improvements in the efficiencies of both plant operations and the labor force. An additional factor contributing to lower electricity prices in the competition cases is less construction of capital-intensive coal plants (Table 20). In competitive markets, electricity prices are expected to be sensitive to the price of natural gas because it is projected to be used to meet demand during peak periods.

Electricity Fuel Consumption

In comparing the cases, EIA found that total energy consumption for electricity generation essentially follows the overall demand for electricity, although the composition of the fuel demands is important in explaining differences. The *AEO98* reference case has slightly higher overall consumption in the electricity sector in 2005 than in the no competition case, but the two cases are virtually the same in 2015 (Table 22), despite the fact that

Table 21. Renewable Energy Capacity and Generation

Projection	1996	2005				2015			
		No Competition	*AEO98* Reference	Low Fossil	High Fossil	No Competition	*AEO98* Reference	Low Fossil	High Fossil
Net Summer Capability (Thousand Megawatts)									
Electricity Generators									
Conventional Hydroelectric	78.58	80.65	80.65	80.65	80.65	80.71	80.71	80.71	80.71
Geothermal	3.02	2.93	2.93	4.28	2.95	2.72	2.87	7.73	3.22
Municipal Solid Waste	2.91	3.46	3.46	3.46	3.46	4.26	4.26	4.26	4.26
Wood and Other Biomass	1.91	2.02	2.02	3.98	2.02	2.02	2.28	8.66	2.53
Solar Thermal	0.36	0.38	0.40	0.38	0.38	0.48	0.51	0.49	0.48
Solar Photovoltaic	0.01	0.08	0.08	0.38	0.08	0.38	0.38	0.68	0.38
Wind	1.85	2.68	3.31	15.19	3.18	2.96	3.68	15.36	3.79
Total	**88.64**	**92.20**	**92.86**	**108.30**	**92.72**	**93.54**	**94.69**	**117.90**	**95.37**
Cogenerators									
Municipal Solid Waste	0.41	0.45	0.45	0.45	0.45	0.47	0.47	0.47	0.47
Biomass	5.41	6.05	6.06	6.06	6.06	6.09	6.08	6.11	6.07
Total	**5.81**	**6.50**	**6.50**	**6.51**	**6.50**	**6.57**	**6.56**	**6.58**	**6.55**
Generation (Billion Kilowatthours)									
Electricity Generators									
Conventional Hydroelectric	346.30	318.10	318.20	318.20	318.20	318.70	318.80	318.70	318.90
Geothermal	15.70	17.34	17.34	26.76	17.45	16.87	17.92	51.96	20.38
Municipal Solid Waste	18.85	23.13	23.14	23.14	23.14	28.67	28.68	28.67	28.70
Wood and Other Biomass	7.27	9.48	9.48	23.17	9.48	9.48	11.24	55.93	13.02
Solar Thermal	0.82	0.96	1.04	0.98	0.96	1.30	1.39	1.32	1.30
Solar Photovoltaic	0.00	0.20	0.20	0.94	0.20	1.00	1.00	1.75	1.00
Wind	3.17	5.98	7.70	37.68	7.39	6.88	8.86	38.13	9.20
Total	**392.11**	**375.20**	**377.10**	**430.80**	**376.80**	**382.90**	**387.80**	**496.50**	**392.40**
Cogenerators									
Municipal Solid Waste	2.09	2.22	2.22	2.22	2.22	2.34	2.34	2.34	2.34
Biomass	39.17	40.46	40.48	40.52	40.49	40.61	40.55	40.72	40.47
Total	**41.25**	**42.68**	**42.70**	**42.74**	**42.71**	**42.95**	**42.89**	**43.06**	**42.81**

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

electricity demand in the *AEO98* reference case is higher by 51 billion kilowatthours in 2015, up from only 33 billion kilowatthours in 2005 (Table 20). In part this reflects the lower efficiencies for coal-fired generation. In the no competition case, the assumptions with respect to the cost of capital provide an incentive for more coal-fired and fewer gas-fired capacity additions than in the *AEO98* reference case. Because of the lower efficiencies for coal-fired generation, this translates into roughly the same consumption in the two cases in 2015, despite the higher demand in the *AEO98* reference case. The trade-off between coal and natural gas in the two cases leads to a slightly higher efficiency in total electricity production in the *AEO98* reference case.

In the low fossil case, coal consumption is lower by almost 2 quadrillion Btu in 2015 compared with consumption in the no competition case. Consumption of renewable and nuclear fuels is higher based on the assumptions used in the low fossil case, and natural gas consumption is about the same as it is in the no competition case. In the high fossil case, both coal and gas consumption are higher in 2015 than they are in the no competition case in 2005, but by 2015 coal consumption is about the same as it is in the no competition case. Natural gas consumption is about 2 quadrillion Btu greater because of higher electricity demand levels.

The average price of fuel used for electricity production in 2015 is projected to be about the same as in 1996 in all but the high fossil case (Table 22). In the high fossil case, an increase of about 11 percent in the average price is projected because of higher natural gas prices resulting from assumed higher drilling costs for onshore

Table 22. Energy Consumption and Prices for Electricity Generation

Projection	1996	2005 No Competition	2005 *AEO98* Reference	2005 Low Fossil	2005 High Fossil	2015 No Competition	2015 *AEO98* Reference	2015 Low Fossil	2015 High Fossil
Energy Consumption by Electricity Generators (Quadrillion Btu per Year)									
Distillate Fuel	0.08	0.07	0.07	0.07	0.08	0.07	0.07	0.07	0.09
Residual Fuel	0.67	0.28	0.30	0.22	0.36	0.20	0.25	0.16	0.37
Petroleum Subtotal	0.75	0.34	0.37	0.28	0.44	0.27	0.32	0.23	0.46
Natural Gas	3.04	5.39	5.69	5.23	6.01	7.98	8.71	8.02	10.06
Steam Coal	18.36	20.60	20.55	20.35	21.04	23.16	22.29	21.21	23.21
Nuclear Power	7.20	6.87	6.87	7.45	6.87	5.12	5.12	5.90	5.12
Renewable Energy	4.45	4.37	4.37	5.06	4.31	4.44	4.53	6.25	4.59
Electricity Imports	0.39	0.39	0.34	0.37	0.37	0.28	0.28	0.30	0.30
Total	**34.20**	**37.96**	**38.19**	**38.75**	**39.03**	**41.25**	**41.26**	**41.91**	**43.75**
Energy Prices to Electricity Generators by Source (1996 Dollars per Million Btu)									
Fossil Fuel Average	1.54	1.46	1.49	1.44	1.51	1.49	1.60	1.51	1.71
Petroleum Products	3.27	3.61	3.57	3.76	3.46	4.13	4.00	4.27	3.77
Distillate Fuel	4.90	5.17	5.16	5.15	5.14	5.45	5.47	5.42	5.40
Residual Fuel	3.07	3.23	3.20	3.34	3.09	3.67	3.60	3.79	3.36
Natural Gas	2.64	2.58	2.63	2.56	2.72	2.80	2.98	2.85	3.32
Steam Coal	1.29	1.14	1.14	1.11	1.13	1.01	1.03	0.97	0.97

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

production. Natural gas prices increase slightly in the other cases but are offset by an almost 30-percent decline in coal prices between 1996 and 2015.

Oil and Natural Gas

Restructuring the electric utility industry is expected to open up new opportunities and challenges for the natural gas industry. The electric and gas industries are moving toward a more integrated market through mergers or strategic alliances and the development of new financial instruments, such as spot and futures contract markets.

Even without electricity restructuring, substantial growth in natural gas consumption is expected, driven primarily by the addition of new turbines and combined-cycle facilities. Relatively low capital costs and projected improvements in gas turbine efficiencies make the cost of gas-generated electricity competitive with the cost of electricity from new coal-fired generators even with increases in natural gas prices projected to occur in the later years of the analysis. The extent to which restructuring further affects gas demand depends on other fuel industries. The expected retirements of nuclear and fossil-fueled plants, the implementation of an RPS, and the growth in coal mine labor productivity will have significant effects on gas demand.

Key results on natural gas supply and disposition for all the cases analyzed are shown in Table 23. Electricity is not projected to reduce or displace natural gas sales in the residential and commercial sectors across the cases. Changes in gas consumption patterns compared with those in the no competition case are seen primarily in the industrial and electricity generation sectors, where fuel substitution is more common. Because of the changes in gas demand in the competition cases, natural gas production ranges from 0.8 percent lower to 2.2 percent higher than in the no competition case in 2005 and from 0.3 percent to 6.0 percent higher in 2015 (Figure 27).

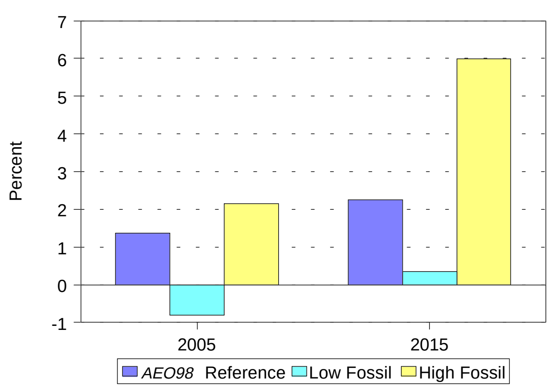
Average natural gas wellhead prices range from a low of $2.05 per thousand cubic feet in 2005 to a high of $2.61 per thousand cubic feet in 2015 (Figure 28). In 2005, the variation from the no competition case in the average wellhead price ranges from 2.4 percent lower in the low fossil case to 4.8 percent higher in the high fossil case. By 2015, average gas wellhead prices differ from the no competition case much more significantly, ranging from 4.5 percent lower to 17.6 percent higher. The higher gas wellhead prices reflect higher demand for natural gas

Table 23. Natural Gas Supply and Disposition
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Projection	1996	2005 No Competition	2005 *AEO98* Reference	2005 Low Fossil	2005 High Fossil	2015 No Competition	2015 *AEO98* Reference	2015 Low Fossil	2015 High Fossil
Lower 48 Average Wellhead Price									
(1996 Dollars per Thousand Cubic Feet)	2.24	2.10	2.15	2.05	2.20	2.22	2.38	2.12	2.61
Production									
Dry Gas	19.02	21.95	22.25	21.77	22.43	25.54	26.12	25.63	27.08
Supplemental Natural Gas	0.12	0.11	0.11	0.11	0.11	0.05	0.05	0.05	0.05
Net Imports	2.72	4.05	4.02	4.04	4.11	4.57	4.64	4.53	4.88
Total Supply	**21.86**	**26.11**	**26.39**	**25.92**	**26.65**	**30.16**	**30.81**	**30.21**	**32.01**
Consumption by Sector									
Residential	5.23	5.32	5.31	5.34	5.30	5.69	5.66	5.71	5.58
Commercial	3.20	3.52	3.52	3.52	3.52	3.76	3.74	3.75	3.73
Industrial	8.60	9.43	9.39	9.38	9.33	9.82	9.75	9.81	9.63
Electricity Generators	2.98	5.28	5.57	5.12	5.88	7.81	8.52	7.84	9.84
Lease and Plant Fuel	1.25	1.44	1.45	1.43	1.46	1.65	1.68	1.66	1.74
Pipeline Fuel	0.71	0.81	0.82	0.81	0.83	0.93	0.96	0.93	0.99
Transportation	0.01	0.15	0.15	0.15	0.15	0.29	0.29	0.29	0.29
Total	**21.99**	**25.94**	**26.22**	**25.75**	**26.47**	**29.96**	**30.61**	**30.00**	**31.80**
Discrepancy	-0.12	0.17	0.17	0.17	0.18	0.20	0.20	0.21	0.21

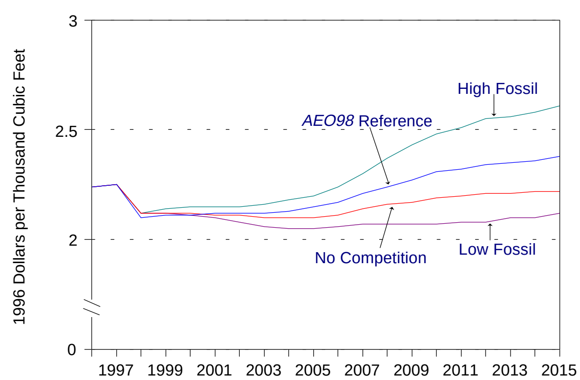
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

Figure 27. Variation from No Competition Case Projections of Natural Gas Production



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

Figure 28. Lower 48 Average Natural Gas Wellhead Prices, 1996-2015



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

and more production from higher cost sources, such as tight sands, Devonian shales, and coalbed methane.

The variation in gas production across the cases is due to the changes in the assumptions defining each case. In the low fossil case, where there are no early nuclear retirements and an RPS is implemented, more electric generator demand is met by nuclear power and renewable energy than in the *AEO98* reference, no competition, and high fossil cases. This results in overall lower natural gas production in the low fossil case through 2005 than in the other cases, because nuclear power and renewable energy sources displace natural gas in electricity generation despite relatively low natural gas prices. By 2015, natural gas demand, and hence production, in the low fossil case is slightly higher than in the no competition case, because the low capital costs associated with gas-fired electricity generation, combined with low end-use prices, make gas a cheaper alternative for electricity generation than new coal-fired generators.

In the high fossil case, where assumptions about nuclear and renewable energy are the same as in the no competition case, tradeoffs in electricity generation are only between natural gas and coal. To further promote fossil fuel use, electricity demands in the residential and commercial sectors were adjusted upward, and the rates of technological improvement affecting coal labor productivity and oil and gas exploration, development, and production were increased as previously described. As a result, natural gas production in 2005 is projected to be almost 0.5 trillion cubic feet higher than in the no competition case. By 2015, natural gas production in the high fossil case is over 1.5 trillion cubic feet higher than in the no competition case. The natural gas market share is slightly higher in 2015, whereas coal's market share is lower in both the low and high fossil cases compared with coal's market share in the no competition case, despite a significant increase in the price of gas and a decrease in coal prices. This is because coal costs are a smaller part of total costs for coal-fired generation than natural gas costs are for gas-fired generation.

Overall, the results from all the cases suggest that the restructuring of the electric utility industry will stimulate natural gas demand. Rising demand for natural gas contributes to the increases in wellhead prices as well as the natural progression of the discovery process from larger and more profitable fields to smaller, less economical ones. Price increases also reflect more production from higher-cost sources, such as offshore conventional recovery and onshore unconventional gas recovery. Despite the significant increases in the price of gas, the use of gas turbines and combined-cycle facilities in electricity generation is still less costly than the use of coal-burning generators. Even with substantial improvements in coal mine productivity and technological progress, natural gas fares better than coal in a restructured environment.

While it may significantly affect natural gas production, electric power industry restructuring is not expected to have a meaningful impact on crude oil production. Currently, very little petroleum is used in electricity generation, and the amount is projected to decrease even more by 2015 in all the cases. Crude oil production is roughly the same in the low fossil case as in the reference and no competition cases. The higher levels of production in the high fossil case compared with the levels of production in the *AEO98* reference case are not a result of restructuring but are due to the reduction in costs as a result of the change in the oil and gas technological impact assumption.

Coal

Comparison of the No Competition and AEO98 Reference Cases

National coal production is 6 million tons[205] less in the *AEO98* reference case than in the no competition case in 2005 (Table 24). Approximately one-third of this difference is accounted for by slightly lower coal demand in the *AEO98* reference case (0.172 quadrillion Btu), and the remainder by lower use of western coals, which are 13 million tons below the no competition case level (eastern coal production is 8 million tons higher) (Table 24). In 2015, total coal production in the *AEO98* reference case is 41 million tons lower than in the no competition case, a difference attributable to a 3-percent lower demand in the *AEO98* reference case. Again, the larger part of this difference—24 million tons—is in western coal production.

An examination of these two cases in 2005 also reveals a shift from low-sulfur to medium-sulfur coal production in the *AEO98* reference case. In general, whenever coal demand increases under Phase II of the Clean Air Act Amendments of 1990, sulfur allowance restrictions encourage most of the additional production to be low in sulfur, and the least expensive source of low-sulfur coal for most of the United States is western production. The impact of increased low-sulfur demand

[205] In this chapter, the terms "tons" and "short tons" are used interchangeably.

Table 24. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

	1996	2005 No Competition	2005 *AEO98* Reference	2005 Low Fossil	2005 High Fossil	2015 No Competition	2015 *AEO98* Reference	2015 Low Fossil	2015 High Fossil
Production									
Appalachia	452	498	506	476	474	522	505	451	455
Interior	173	176	176	177	177	167	167	166	175
West	439	539	525	556	602	678	654	676	778
East of the Mississippi	564	600	608	579	578	626	609	556	564
West of the Mississippi	500	612	599	630	675	741	717	737	843
Total	**1,064**	**1,213**	**1,207**	**1,209**	**1,253**	**1,367**	**1,326**	**1,293**	**1,407**
Net Imports									
Imports	7	8	8	8	8	8	8	8	8
Exports	90	104	104	104	104	119	119	121	121
Total	**-83**	**-96**	**-96**	**-96**	**-96**	**-112**	**-112**	**-113**	**-113**
Total Supply	**981**	**1,116**	**1,111**	**1,113**	**1,157**	**1,255**	**1,215**	**1,180**	**1,294**
Consumption by Sector									
Residential and Commercial	6	6	6	6	6	7	7	7	7
Industrial	70	77	77	77	78	81	81	81	83
Coke Plants	32	28	28	28	28	24	24	24	24
Electric Generators	896	1,005	1,000	1,004	1,045	1,144	1,103	1,070	1,183
Total	**1,003**	**1,117**	**1,112**	**1,116**	**1,157**	**1,255**	**1,215**	**1,182**	**1,296**
Discrepancy and Stock Change	-23	0	-1	-3	0	0	0	-2	-2
Average Minemouth Price									
(1996 dollars per short ton)	18.50	16.02	16.18	15.25	14.95	13.95	13.99	12.44	12.04
(1996 dollars per million Btu)	0.87	0.76	0.76	0.73	0.72	0.67	0.67	0.60	0.59
Delivered Price (1996 dollars per short ton)									
Industrial	32.28	29.96	29.92	29.51	29.50	28.87	28.90	27.66	27.64
Coke Plants	47.33	45.90	45.90	45.47	45.34	44.90	44.78	43.38	43.26
Electricity Generators									
(1996 dollars per short ton)	26.45	23.28	23.37	22.58	22.67	20.51	20.72	19.21	18.98
(1996 dollars per million Btu)	1.29	1.14	1.14	1.11	1.13	1.01	1.03	0.97	0.97
Average	27.52	24.32	24.40	23.65	23.69	21.52	21.76	20.29	19.99
Exports	40.77	36.38	36.40	36.16	36.10	33.76	33.75	32.88	32.78
Coal Production									
Low Sulfur	434	541	532	551	599	685	661	662	765
Medium Sulfur	457	483	487	472	470	471	465	439	431
High Sulfur	173	188	188	186	184	210	200	192	211

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

is felt more by medium-sulfur than by high-sulfur coal producers, since most high-sulfur coal has a stable market in units with operating flue-gas scrubbers. Thus, in 2005, comparison of the two cases shows that medium-sulfur coal production is 4 million tons higher, low sulfur is 9 million tons lower, and high-sulfur production is unchanged in the *AEO98* reference case. By 2015, low-sulfur production in the *AEO98* reference case is 25 million tons lower than it is in the no competition case, but medium- and high-sulfur demand are also lower (by 6 and 10 million tons, respectively) as a result of the increased use of scrubbers in the no competition case to meet the requirements of the progressively more restrictive sulfur allowance cap.

Relatively lower use of western coal in the *AEO98* reference case causes slightly higher minemouth prices. In addition to containing less sulfur, western coal is less costly at the minemouth than eastern coal. Because the difference in regional production is small compared with total production, the difference in average minemouth prices is less than 1 percent. In 2005, the *AEO98* reference case has a national minemouth price of $16.18 per ton, compared with the no competition case price of $16.02. By 2015, the minemouth price is still higher in the *AEO98* reference case, $13.99 per ton as opposed to $13.95 per ton in the no competition case.

In both cases, the market share of eastern coalfields declines by about 4 percent to 46 percent of the national total between 2005 and 2015, and the share of low-sulfur coal increases by almost 6 percent to 50 percent. The increase in low-sulfur coal consumption exceeds the decline in eastern production because some of the growing demand for low-sulfur coal is met by Central Appalachian production.

Comparison of the No Competition and Low Fossil Cases

Coal production in the low fossil case in 2005 (1,209 million tons) is 4 million tons lower than in the no competition case. This difference is greater when measured by heat content (quadrillion Btu) than by tons, indicating that, as demand increases in the no competition case, it is met by a higher proportion of western coal—with its lower heat content per ton—than in the low fossil case. Increasing demand for coal under an inflexible sulfur emissions cap mandates the use of progressively lower sulfur coal.

In 2005, the no competition case uses less western and less low-sulfur coal than the low fossil case. Most of the difference reflects higher medium-sulfur coal use in the no competition case, as the consumption of high-sulfur coal does not vary significantly. In 2005, the difference in total coal demand between the two cases is small, only 4 million tons. By 2015, however, the difference between the cases increases to 74 million tons, of which 23 million tons are low-sulfur coal, 32 million tons are medium-sulfur coal, and 18 million tons are high-sulfur coal.

The relative market shares of eastern and western coals differ only by about 1 percent in 2005, but the eastern share is 3 percent larger in the no competition case in 2015, a difference of 70 million tons. Because a higher proportion of western coal is used in the low fossil case, it shows lower minemouth prices than the no competition case. The low fossil case shows minemouth prices of $15.25 and $12.44 per short ton in 2005 and 2015, respectively, whereas the no competition case reaches $16.02 and $13.95 per short ton during the same period.

Comparison of the No Competition and High Fossil Cases

In 2005, coal production in the high fossil case (1,253 million tons) exceeds that in the no competition case by 40 million tons. The high fossil case benefits from 0.44 quadrillion Btu greater demand, nearly 2 percent higher. The production difference exceeds 3 percent, however, indicating higher use of coal with lower heat content. Western production is 63 million tons higher and low-sulfur coal production is 58 million tons higher. Part of the increased demand is met by medium-sulfur coal from the West. By 2015, the difference in demand between the high fossil and no competition cases narrows to 0.05 quadrillion Btu, but the 40-million-ton difference in production remains. This indicates substantially higher use of low heat content coals in the high fossil case (western coal production is 102 million tons higher than in the no competition case, and low-sulfur production is 80 million tons higher).

There is little difference between the high fossil and no competition cases when the production of medium- and high-sulfur coal is compared. Progressive tightening of the sulfur emissions limit per ton of coal as total consumption increases causes most new and some old consumption to be met from low-sulfur sources, chiefly low-cost western coals. High-sulfur coal consumption, chiefly at scrubbed units that continue to operate throughout the forecast period, remains stable, and most production losses fall on medium-sulfur coal. This result is strongly suggested by the shifting market shares between the cases. The high fossil case shows a larger western market share than the no competition case—a difference that grows higher with demand by 2015.

Because of the higher production of western low-rank, low-sulfur coal in the high fossil case, minemouth prices are substantially lower. In fact, the higher the coal demand, the lower the mine price, a seemingly counter-intuitive result produced by the coincidence that the least-cost coal available (at the mine) is also the lowest in sulfur content—subbituminous coal from the Powder River Basin in Wyoming and Montana. Thus, as the stringency of sulfur emission limitations is increasingly felt with growing coal consumption, the market share of low-cost western coal increases and the average mine price declines accordingly. The price advantage of western coal is not great in most regions after the transportation cost is factored in, but western coal is still the most desirable because of its low sulfur content.

Two factors are changing the entire national coal market: (1) the creation of a national market for sulfur emissions encourages minimization of sulfur emissions and, thus, fuel sulfur; and (2) the deregulation of electricity generation rewards minimization of the cost of generation fuels. Both changes are recent, but their impact is visible in the cases reviewed here.

Energy Consumption and Production

Total energy consumption is projected to grow from 1996 to 2015 in all the cases analyzed (Table 25). Consumption increases for all fossil fuels and renewable sources, while nuclear consumption declines because of retirements and no new construction. Total energy consumption is relatively unchanged for the competition cases analyzed except when higher demand for electricity is assumed; however, there are changes in the levels of consumption of natural gas and coal across the cases, while consumption of petroleum products remain relatively unchanged.

The changes in the shares of natural gas and coal are due to consumption by electricity providers described earlier. In the low fossil case, coal consumption is almost 2 quadrillion Btu less than in the no competition case, because assumptions about nuclear plant relicensing reduce the need for new capacity. In the high fossil case, natural gas consumption is almost 2 quadrillion Btu greater than in the no competition case because of higher demand levels for electricity, which are met by construction of more gas-fired generators. In all the cases, natural gas and coal production increase significantly, while domestic petroleum production declines (Table 25). The natural gas and coal production levels are consistent with the consumption patterns described above.

Regional Projections

In addition to the quantitative results at the national level, detailed results at the regional level are summarized in figures and bullets by the National Electricity Reliability Council (NERC) region and appended to the end of the chapter. These regional summaries focus primarily on the potential changes from 1996 to 2005 and 2015 in electricity demand, electricity generation, additions to generation capacity, and fuel consumption by fuel type for the low fossil and high fossil cases—the two full competition cases.

Conclusions and Caveats

The cases analyzed in this chapter that assume full competition in electricity markets vary in their assumptions about improvements in technological progress in fossil fuel production, policies concerning renewable generation requirements, retirements of nuclear and coal generating units, and demand for electricity. The full competition cases and the *AEO98* reference case are compared with a case that assumes no further competition in electricity markets beyond current policies.

For the cases considered, it is likely that natural gas will enjoy a greater role in electricity generation, given the assumptions about financial costs for new investments and the range of electricity demand growth considered. Competitive electricity markets will result in more additions of natural-gas-fired turbines and combined-cycle units, which are relatively less capital-intensive than coal-fired technologies. The assumption that investors face higher risks in a competitive market than they would under regulation leads to this result. Consequently, gas-fired electricity generation could be from 5 to 33 percent higher in 2015 under competition. The rapid expansion of gas-fired turbines and combined-cycle installations could result in bottlenecks if manufacturing capability is insufficient to meet this growth.

In contrast, coal-fired generation is a less attractive option for new capacity under competition, because it is relatively more capital intensive than gas-fired generation. As a result, coal-fired generation could be as much as 9 percent lower than it would be if electricity generation services continued to be regulated. The projected changes in coal production and consumption vary, depending on the assumptions about electricity demand in the competition cases. When *AEO98* reference case demands are assumed, coal consumption in the competition case is lower than in the no competition case because the choice of new electric generating capacity favors natural gas.

Neither renewable nor nuclear electricity generation would be expected to benefit from full competition in

Table 25. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

	1996	2005 No Competition	2005 *AEO98* Reference	2005 Low Fossil	2005 High Fossil	2015 No Competition	2015 *AEO98* Reference	2015 Low Fossil	2015 High Fossil
Production									
Crude Oil & Lease Condensate	13.71	12.32	12.32	12.43	12.44	11.10	11.09	11.34	11.38
Natural Gas Plant Liquids	2.46	2.59	2.63	2.57	2.66	3.04	3.12	3.06	3.24
Dry Natural Gas	19.55	22.57	22.88	22.38	23.06	26.25	26.85	26.34	27.84
Coal	22.64	25.67	25.62	25.36	26.13	28.60	27.73	26.66	28.70
Nuclear Power	7.20	6.87	6.87	7.45	6.87	5.12	5.12	5.90	5.12
Renewable Energy	6.89	7.11	7.12	7.81	7.06	7.49	7.59	9.31	7.65
Other	1.33	0.55	0.55	0.55	0.55	0.47	0.47	0.47	0.47
Total	**73.79**	**77.68**	**77.98**	**78.57**	**78.77**	**82.07**	**81.97**	**83.07**	**84.40**
Imports									
Crude Oil	16.30	21.99	22.01	21.88	21.90	24.36	24.36	24.11	24.07
Petroleum Products	3.98	5.53	5.47	5.37	5.40	8.86	9.01	9.00	8.87
Natural Gas	2.93	4.42	4.39	4.41	4.49	4.96	5.04	4.93	5.28
Other Imports	0.57	0.63	0.58	0.61	0.61	0.54	0.54	0.57	0.57
Total	**23.78**	**32.57**	**32.45**	**32.27**	**32.40**	**38.72**	**38.96**	**38.61**	**38.79**
Exports									
Petroleum	2.04	1.73	1.73	1.74	1.74	1.88	1.89	1.88	1.88
Natural Gas	0.16	0.28	0.28	0.28	0.28	0.30	0.30	0.30	0.30
Coal	2.37	2.64	2.64	2.64	2.64	3.03	3.03	3.07	3.07
Total	**4.57**	**4.65**	**4.65**	**4.66**	**4.66**	**5.21**	**5.21**	**5.25**	**5.25**
Net Petroleum Imports	**18.25**	**25.80**	**25.75**	**25.52**	**25.56**	**31.33**	**31.48**	**31.23**	**31.06**
Consumption									
Petroleum Products	36.01	41.23	41.32	41.25	41.42	46.12	46.20	46.12	46.34
Natural Gas	22.60	26.66	26.93	26.46	27.20	30.77	31.44	30.81	32.65
Coal	20.90	23.25	23.21	23.00	23.71	25.81	24.95	23.86	25.91
Nuclear Power	7.20	6.87	6.87	7.45	6.87	5.12	5.12	5.90	5.12
Renewable Energy	6.89	7.12	7.12	7.82	7.06	7.51	7.62	9.33	7.67
Other	0.39	0.42	0.37	0.40	0.40	0.40	0.40	0.43	0.43
Total	**93.99**	**105.54**	**105.82**	**106.38**	**106.65**	**115.73**	**115.72**	**116.45**	**118.11**
Discrepancy	**0.99**	**-0.06**	**0.04**	**0.20**	**0.15**	**0.15**	**0.00**	**0.02**	**0.18**
Prices (1996 Dollars)[a]									
World Oil Price	20.48	20.19	20.19	20.11	20.17	21.49	21.48	21.35	21.29
Gas Wellhead Price	2.24	2.10	2.15	2.05	2.20	2.22	2.38	2.12	2.61
Coal Minemouth Price	18.50	16.02	16.18	15.25	14.95	13.95	13.99	12.44	12.04
Average Electricity Price	6.9	6.4	6.1	5.8	5.8	5.9	15.6	5.5	5.7

[a]Price denominations are as follows: oil, dollars per barrel; natural gas, dollars per thousand cubic feet; coal, dollars per ton; electricity, cents per kilowatthour.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, National Energy Modeling System runs nocomp.d010698a, aeo98b.d100197a, complo3.d031298b, and comphiD3.d031398b.

electricity markets without changes in policy. Renewable generation is more costly than coal and natural gas and is not expected to penetrate significantly without policy changes, such as an RPS. No additional nuclear generating capacity is expected through 2015, but retirements of existing capacity could be affected by competition, depending on the operating costs of nuclear power plants and the costs of new competing capacity. Finally, competition does not appear to lead to significant incentives to transmit power across geographic regions beyond the levels currently traded.

Electricity prices are projected to decline from 1996 levels even in the case of no competition because of lower coal prices and modest additions of new capacity. In the competition cases, prices fall even further as a result of efficiency improvements in plant operations and fewer additions of capital-intensive coal plants. Prices in competitive markets are based on marginal costs, which tend to be lower than the average costs used by regulators.

As in any modeling exercise, there is considerable uncertainty concerning both the input assumptions and results from these cases. The main uncertainties include:

- Technological improvements beyond those in the *AEO98* reference case are assumed for coal (in the low and high fossil cases) and natural gas (high fossil case). The exact nature and timing of such improvements is unknown. Much of the outcome in these cases depends on the relative costs of these two energy sources. To the extent that one or the other realizes greater technological improvements in production than assumed here, a different set of fuel shares could result.

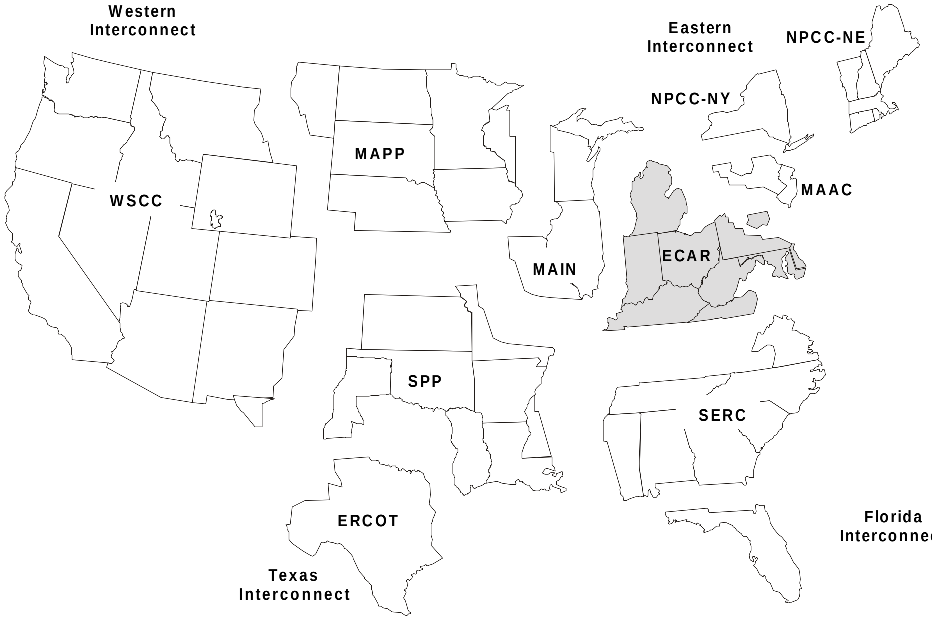
- The response of consumers to changes in electricity prices is also highly uncertain. To the extent that the response is fairly small, as assumed in the *AEO98* reference case and in the low fossil case, there will be less change in overall consumption of fuels for electricity generation. To the extent that the response is more robust, as assumed in the high fossil case, even for reasons other than price, there will be more room for growth in fuel consumption by electricity generators. This variable will be key to determining the response of fuel markets to restructuring.

- The rules for restructuring have not yet been determined, and they will have a significant impact on the outcome. For example, the inclusion of an RPS (as in the low fossil case) would reduce the contribution of fossil fuels but would likely raise prices. Other policy uncertainties include the treatment of stranded costs (assumed here to be recovered during a 10-year transition period), treatment of transmission and distribution costs, and carbon mitigation. Any changes from currently assumed policy would change the results discussed in this analysis.

Appendix to Chapter 6: Projected Changes in Regional Electricity Markets, 1996-2015

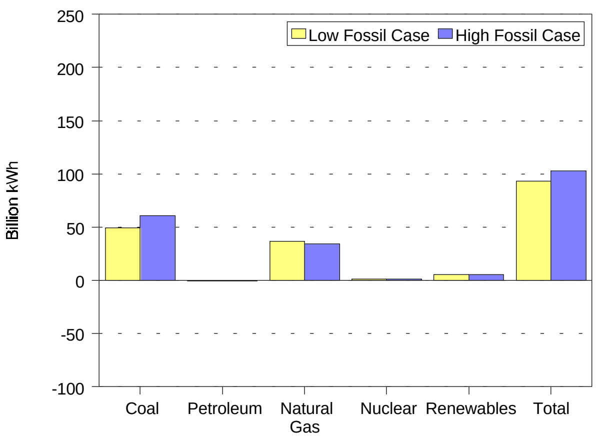
The following pages provide summary results from the NEMS model, showing projected changes in electricity demand, electricity generation, additions to generating capacity, and fuel consumption between 1996 and 2005 and between 1996 and 2015. Results are shown for the low fossil and high fossil cases—the two full competition cases—for the following NERC regions: ECAR, ERCOT, FRCC, MAAC, MAIN, MAPP, NPCC-NE, NPCC-NY, SERC, SPP, and WSCC.

East Central Area Reliability Coordination Agreement (ECAR)

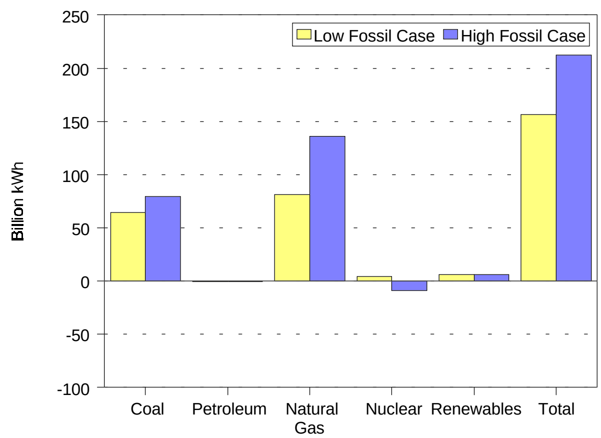


Projected Change in Electricity Generation from 1996 for Full Competition Cases

1996-2005



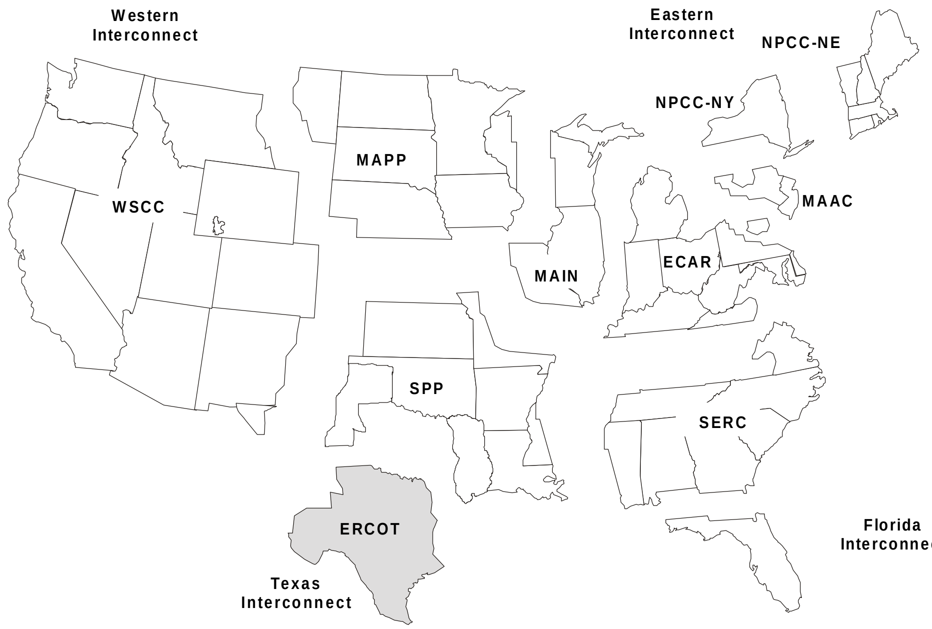
1996-2015



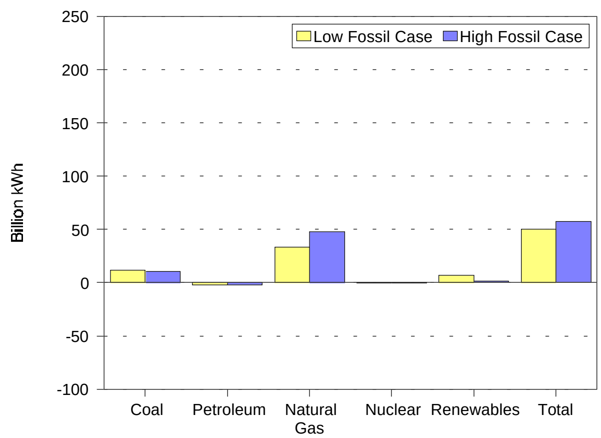
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

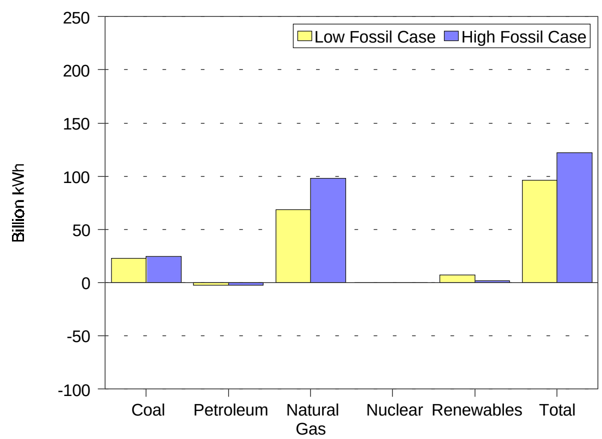
- Electricity sales are projected to grow between 1.3 and 1.7 percent per year from 1996 through 2015.
- The growth in generation occurs primarily in coal- and gas-fired plants.
- Coal-fired generation increases through greater utilization of existing power plants (63 percent capacity factor in 1996 and 77 percent in 2015). No new coal-fired plants are projected to be built.
- Additional gas-fired generation is produced by new gas-fired combustion turbines and combined-cycle units(30 Gigawatts of turbines and 6 to 11 Gigawatts of combined-cycle units built between 1996 and 2015). Variation in the level of increase in gas-fired generation in 2015 is due to uncertainty about the growth in demand for electricity.
- In 2015, natural gas consumption is between 0.6 and 1.0 quadrillion Btu above 1996 levels, and coal consumption is between 0.6 to 0.7 quadrillion Btu higher than in 1996.

Electric Reliability Council of Texas (ERCOT)



Projected Change in Electricity Generation from 1996 for Full Competition Cases

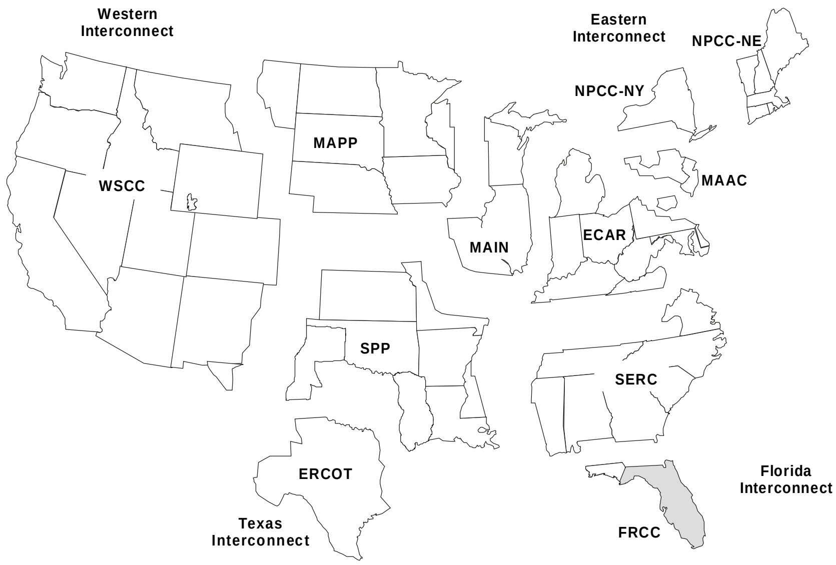




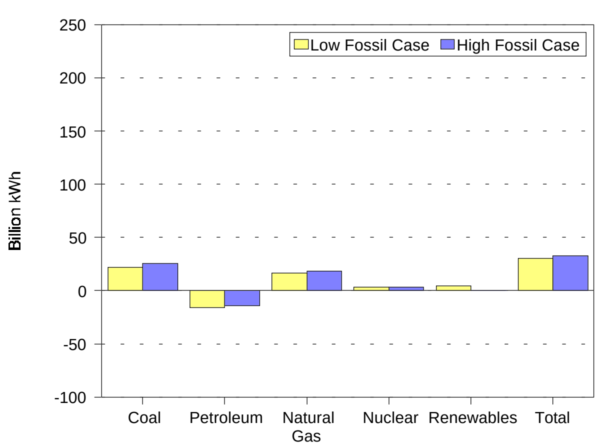
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

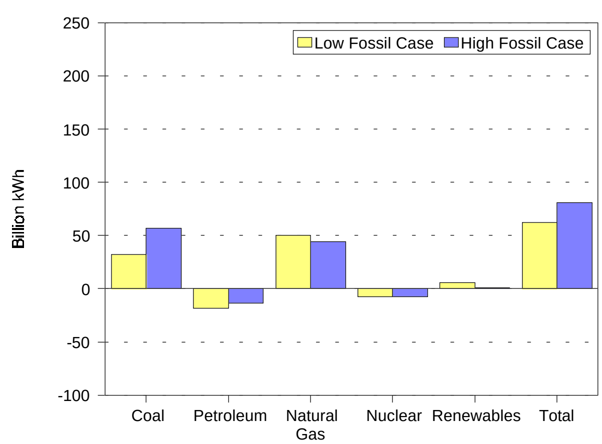
- Electricity sales are projected to grow between 1.7 and 2.1 percent per year from 1996 through 2015.
- Four planned coal units (2.4 gigawatts), scheduled for completion between 2000 and 2006, account for most of the increase in coal-fired generation.
- The increase in gas-fired generation is lower in the low fossil case because of the growth of renewable sources (wind) when a renewable portfolio standard is assumed, as well as the difference in demand for electricity.
- In 2015, natural gas consumption is between 0.2 and 0.4 quadrillion Btu higher than 1996 levels. Coal consumption is approximately 0.3 quadrillion Btu higher than in 1996.

Florida Reliability Coordinating Council (FRCC)



Projected Change in Electricity Generation from 1996 for Full Competition Cases

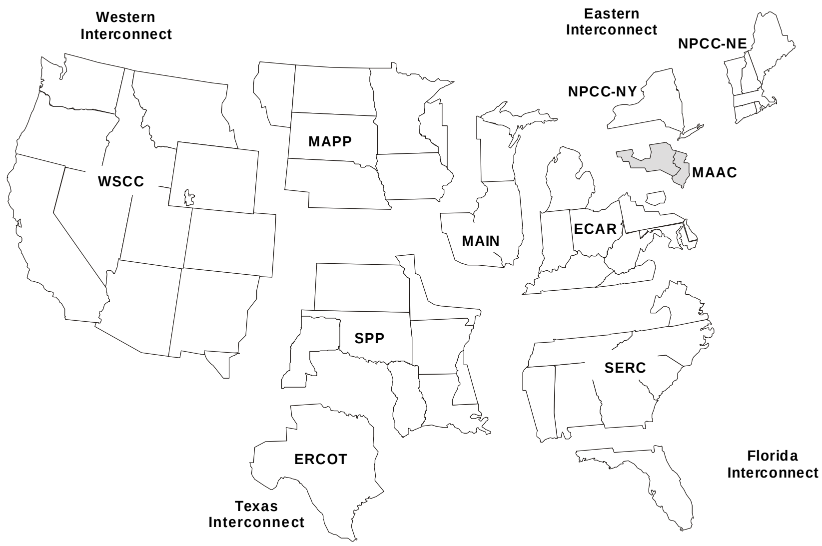




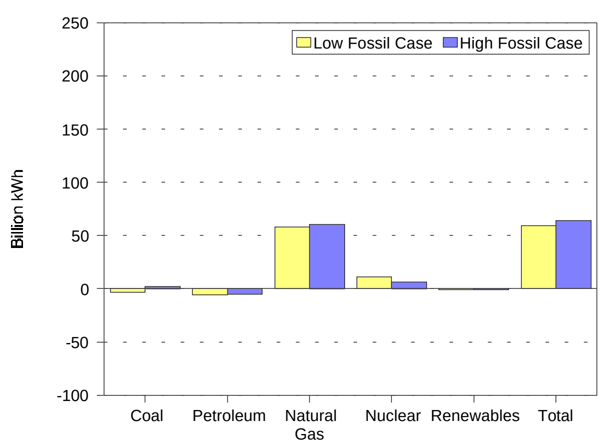
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

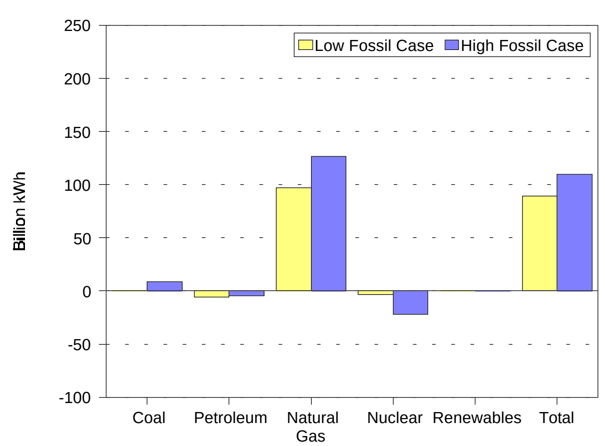
- Electricity sales are projected to grow between 1.8 and 2.2 percent per year from 1996 through 2015.
- New coal- and gas-fired power plants are projected to be built by 2005 to meet the growth in electricity demand and to replace power from retired oil-fired power plants. In 2015, replacement power is also needed for retired nuclear plants.
- In 2015, fewer oil-fired power plants retire in the high fossil case, resulting in a smaller increase in gas-fired generation.
- The renewable portfolio standard results in an increase in generation from biomass in the low fossil case.
- In 2015, natural gas consumption doubles, with an increase of 0.3 quadrillion Btu above 1996 levels, and coal consumption increases by 0.3 to 0.6 quadrillion Btu.

Mid-Atlantic Area Council (MAAC)



Projected Change in Electricity Generation from 1996 for Full Competition Cases

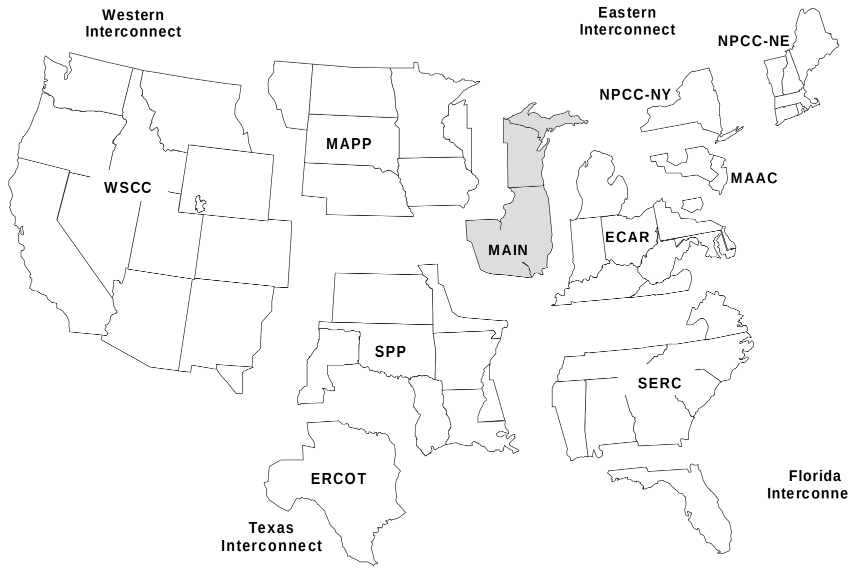




Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

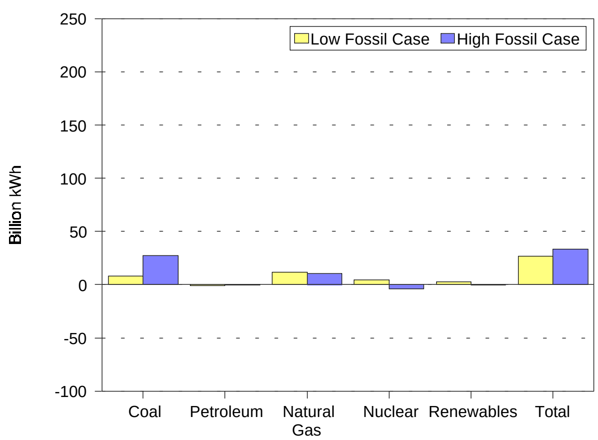
- Electricity sales are projected to grow between 1.2 and 1.7 percent per year from 1996 through 2015.
- Almost all the increased generation of electricity is projected to be produced by natural gas. In addition, gas-fired generation could be higher to provide replacement power for nuclear units retired early in the high fossil case. This significantly changes the share of generation by fuel type. In 1996, almost 90 percent of the region's electricity was produced by coal-fired and nuclear power plants.
- Coal-fired generation remains at 1996 levels. There are more retirements of coal-fired plants than additions of new plants, but increases in capacity utilization offset the reduction in capacity.
- Nuclear generation increases through 2005 with improved capacity factors. By 2015, however, nuclear generation declines in the high fossil case, with five large nuclear units assumed to be retired early.
- In 2015, natural gas consumption is between 0.7 and 0.9 quadrillion Btu higher than 1996 levels. Coal consumption remains the same or increases by 0.1 quadrillion Btu.

Mid-America Interconnected Network (MAIN)

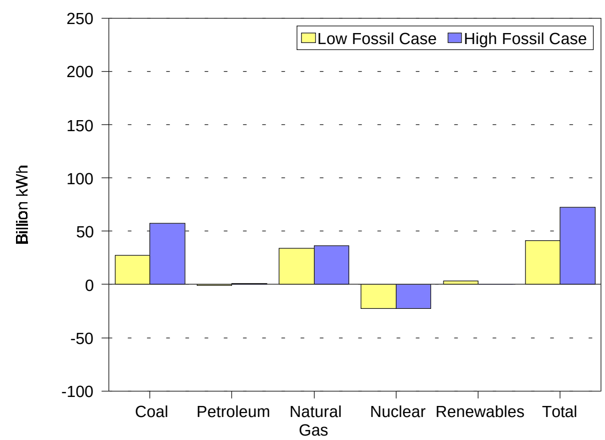


Projected Change in Electricity Generation from 1996 for Full Competition Cases

1996-2005



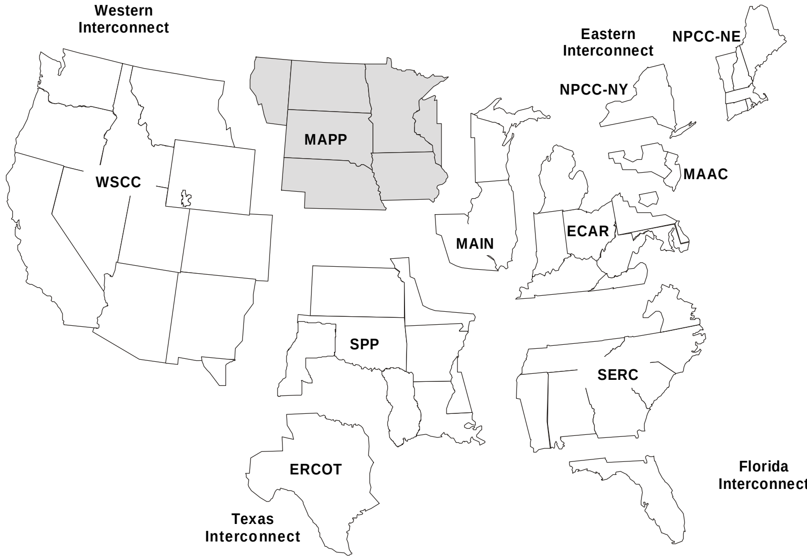
1996-2015



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

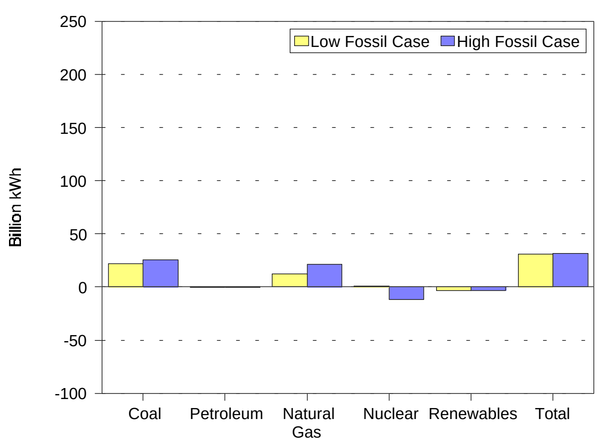
- Electricity sales are projected to grow between 1.2 and 1.7 percent per year from 1996 through 2015. The increased demand is met in part by an increase of over 20 billion kilowatthours in net power purchases from other regions.
- There is uncertainty in the level of growth in coal-fired generation. In 2005, the early retirement of four nuclear units assumed in the high fossil case results in an increase in coal-fired generation. In the low fossil case, increased generation from biomass power plants as a result of the assumed renewable portfolio standard results in a smaller increase in coal-fired generation. By 2015, the projected range of coal-fired generation is primarily due to uncertainty about electricity demand growth.
- The building of almost 4 gigawatts of new coal-fired capacity combined with increasing capacity utilization (from 57 percent in 1996 to about 80 percent in 2015) produces the increased generation.
- Gas-fired generation increases, with capacity increases of 17 gigawatts of new gas-fired combustion turbines and 9 gigawatts of combined-cycle units.
- In 2015, natural gas consumption is 0.2 quadrillion Btu higher than 1996 levels, and coal consumption is 0.2 to 0.5 quadrillion Btu higher than in 1996.

Mid-Continent Area Power Pool (MAPP)

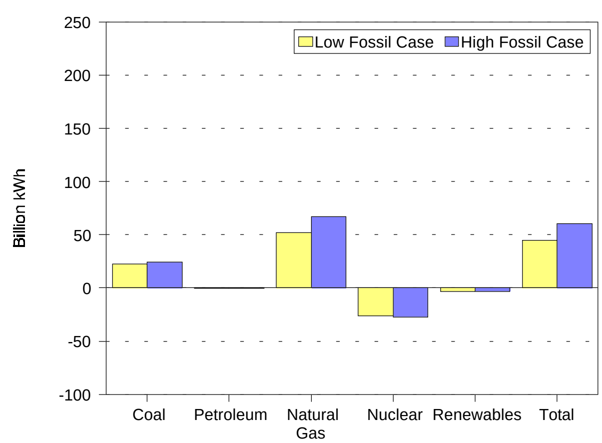


Projected Change in Electricity Generation from 1996 for Full Competition Cases

1996-2005



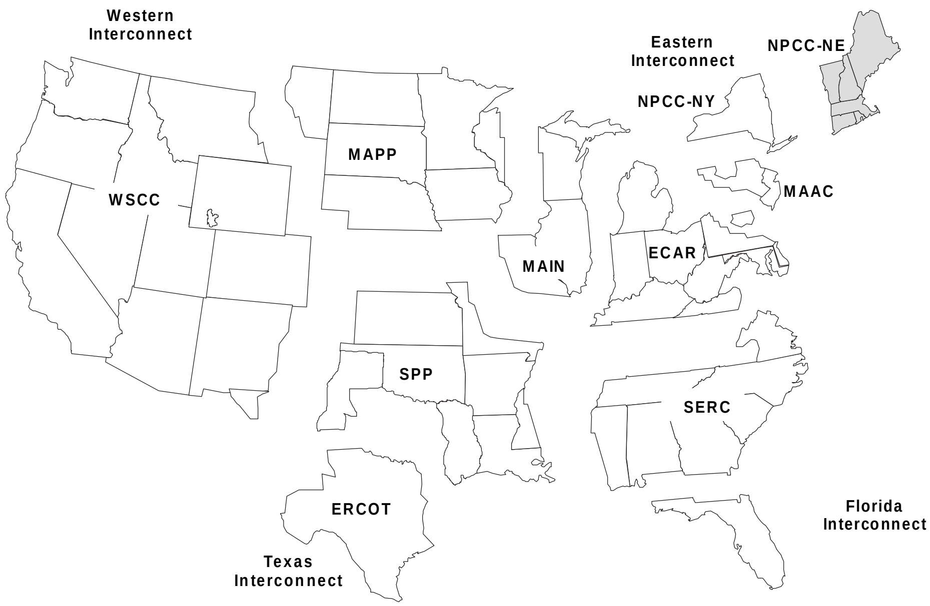
1996-2015



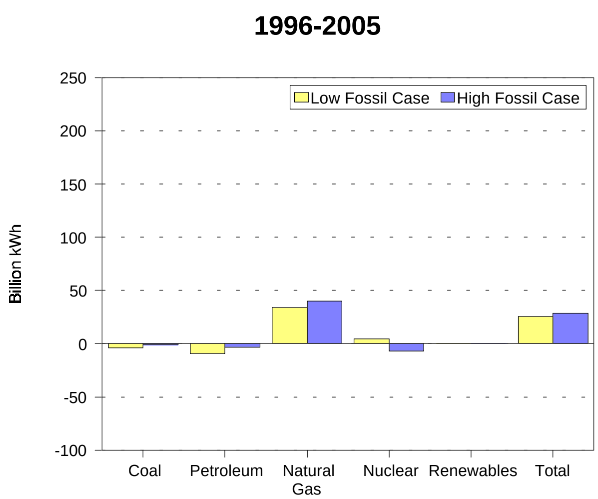
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

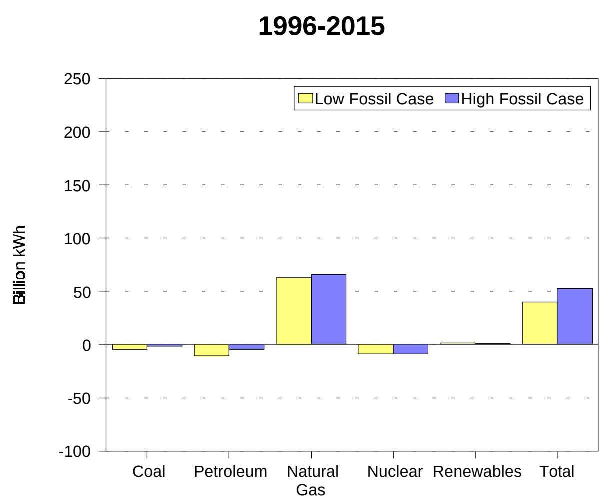
- Electricity sales are projected to grow between 1.3 and 1.8 percent per year from 1996 through 2015.
- All of the increases in coal-fired generation occur by 2005 as a result of greater utilization of existing coal-fired power plants (60 percent in 1996 compared with 77 to 79 percent in 2005). There is little additional change between 2005 and 2015, and no new coal-fired plants are projected to be built.
- Natural-gas-fired turbines and combined-cycle units are built to meet the need for additional generation. The amount of additional generation required will depend on the level of demand for electricity and the assumed early retirement of two nuclear power plants.
- In 2015, natural gas consumption is 0.4 to 0.5 quadrillion Btu above 1996 levels, and coal consumption is 0.1 to 0.2 quadrillion Btu higher than in 1996 levels.

Northeast Power Coordinating Council-New England Region (NPCC-NE)



Projected Change in Electricity Generation from 1996 for Full Competition Cases

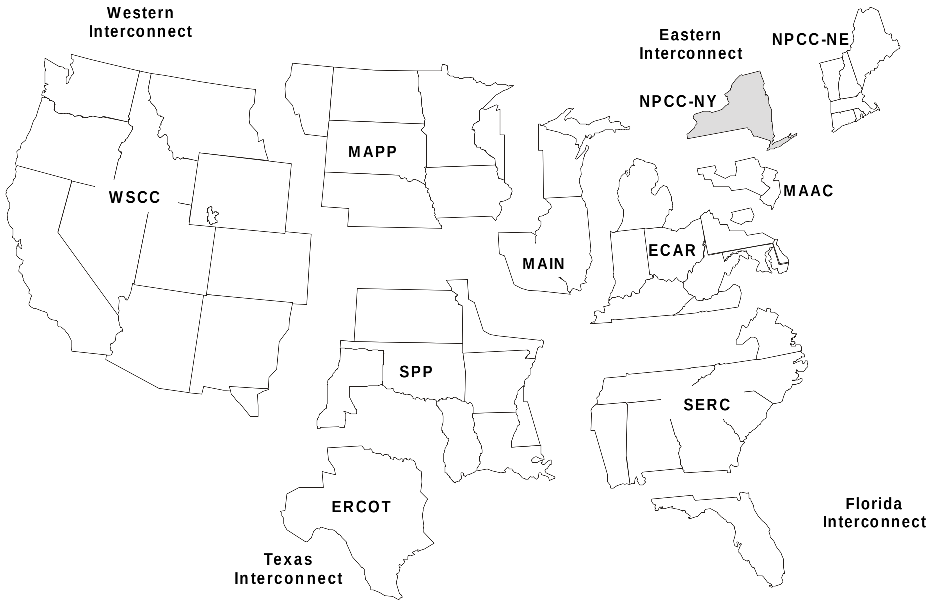




Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

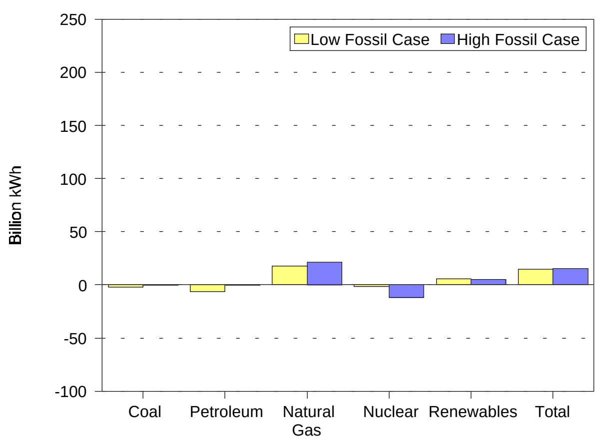
- Electricity sales are projected to grow between 0.9 and 1.4 percent per year from 1996 through 2015.
- Gas-fired generation is projected to increase to replace power from retired coal, oil, and nuclear units and meet increased demand for electricity.
- The higher demand in the high fossil case results in fewer retirements of oil-fired power plants and a small increase in capacity utilization for existing coal-fired power plants.
- The assumed early retirement of nuclear plants in the high fossil case results in a decline in the nuclear share of total generation from over 30 percent in 1996 to 20 percent in 2005.
- In 2015, natural gas consumption is 0.5 quadrillion Btu higher than the 1996 level, whereas coal consumption is 0.01 to 0.05 quadrillion Btu lower than in 1996.

Northeast Power Coordinating Council-New York Region (NPCC-NY)

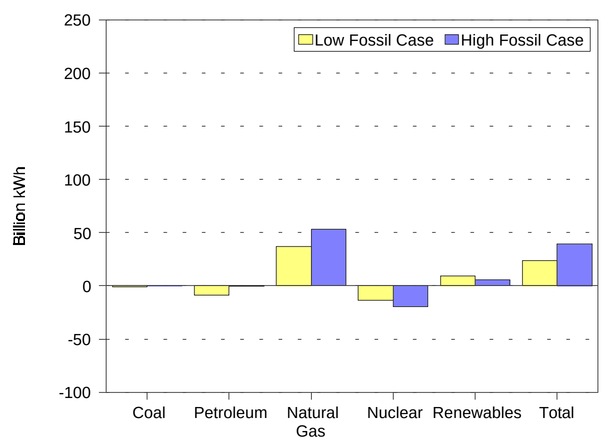


Projected Change in Electricity Generation from 1996 for Full Competition Cases

1996-2005



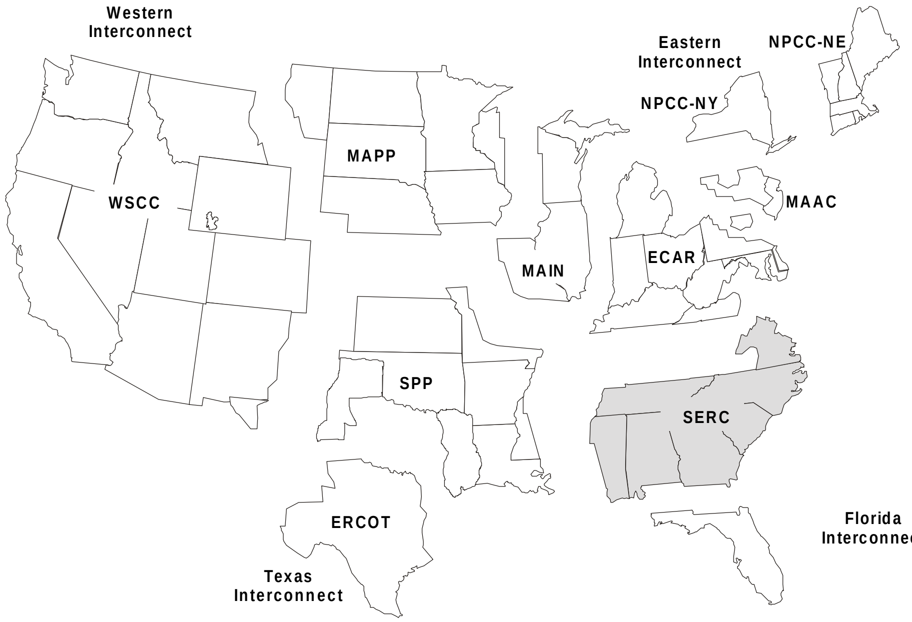
1996-2015



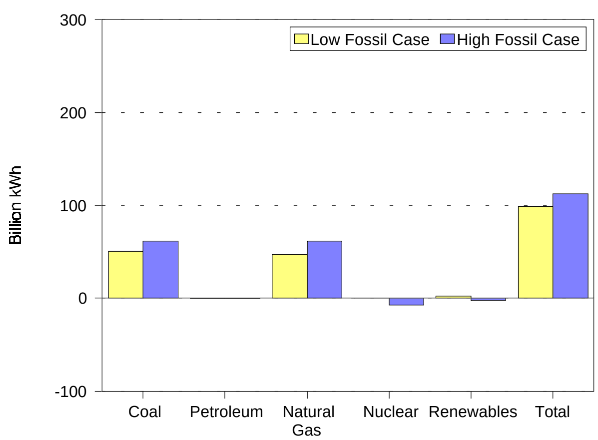
Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

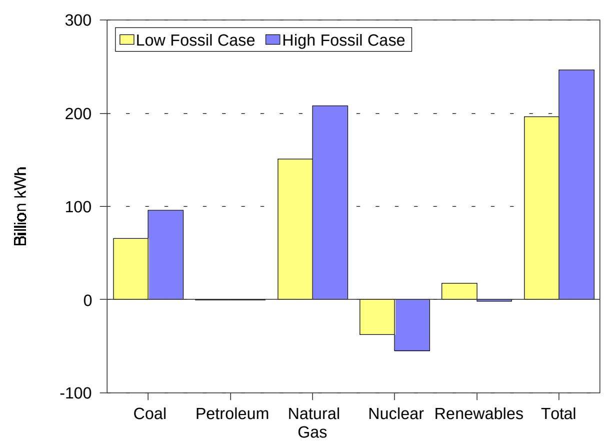
- Electricity sales are projected to grow between 0.9 and 1.4 percent per year from 1996 through 2015.
- Gas-fired generation and renewable generation increase to replace power from retired coal, oil, and nuclear units and to meet increased demand for electricity.
- The renewable portfolio standard results in a small increase in generation from biomass.
- In 2015, natural gas consumption is 0.2 to 0.3 quadrillion Btu above 1996 levels, whereas coal consumption is 0.04 quadrillion Btu below its 1996 level.

Southeastern Electric Reliability Council (SERC)



Projected Change in Electricity Generation from 1996 for Full Competition Cases

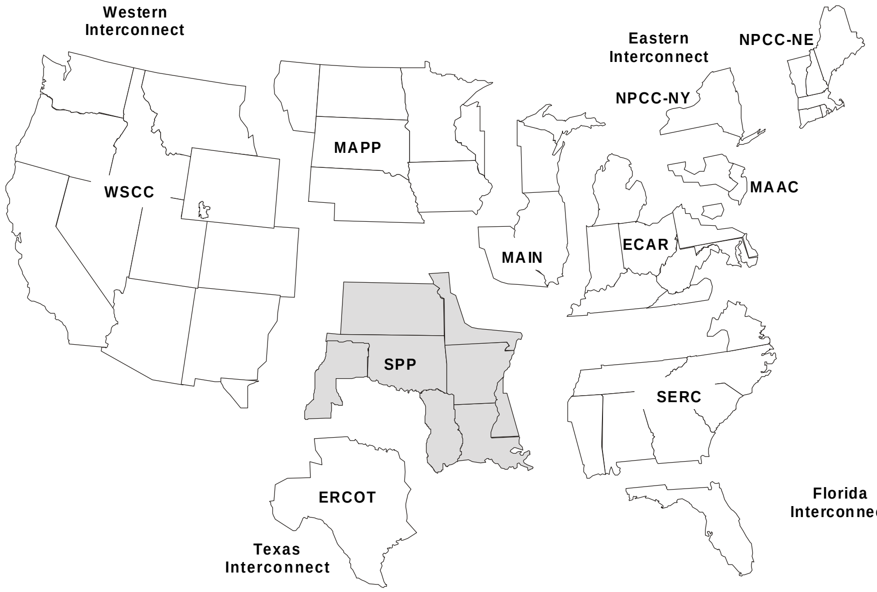




Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

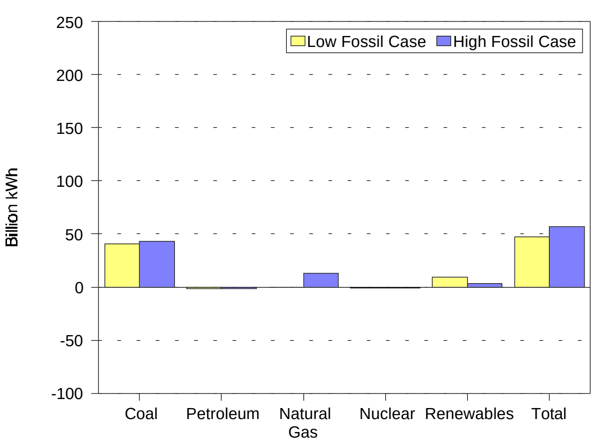
- Electricity sales are projected to grow between 1.7 and 2.1 percent per year from 1996 through 2015.
- Coal-fired generation increases as a result of the higher utilization of existing power plants (64 percent capacity factor in 1996 and 81 percent in 2015). In addition, 4.5 gigawatts of new coal-fired capacity is built in 2015 to replace nuclear power plants retired early in the high fossil case.
- New gas turbines provide the increased generation from natural gas in 2005. By 2015, additional combustion turbines and combined-cycle units are built to meet demand.
- The renewable portfolio standard leads to increased generation from biomass resources and wind in the low fossil case.
- In 2015, natural gas consumption is by 1.0 to 1.5 quadrillion Btu above 1996 levels, and coal consumption is 0.6 to 0.9 quadrillion Btu higher than in 1996.

Southwest Power Pool (SPP)

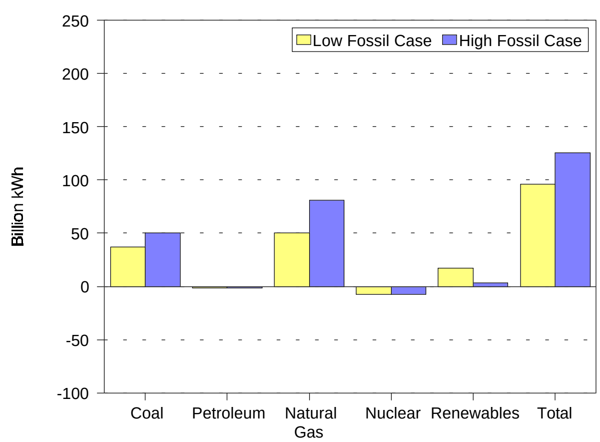


Projected Change in Electricity Generation from 1996 for Full Competition Cases

1996-2005



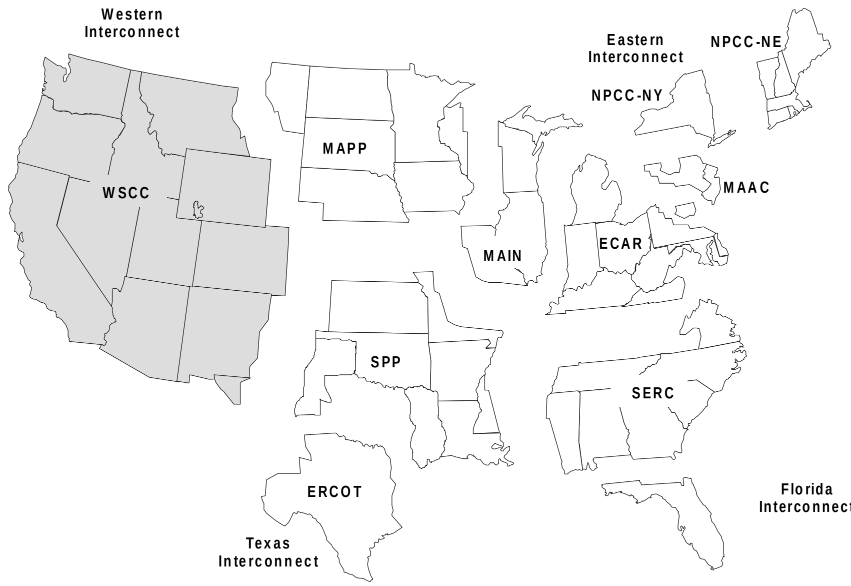
1996-2015



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

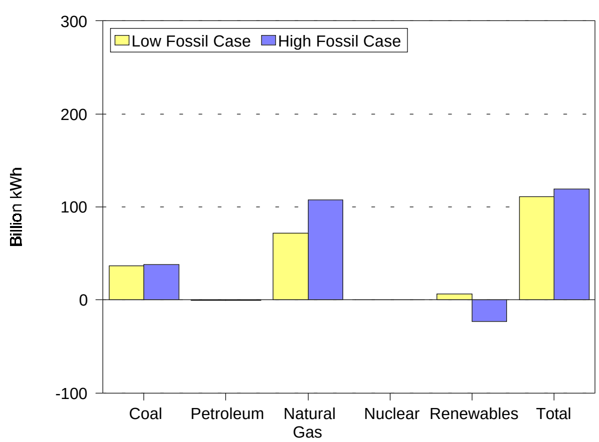
- Electricity sales are projected to grow between 1.6 and 2.0 percent per year from 1996 through 2015.
- Coal is the main fuel for the increased generation in 2005. Almost 3 gigawatts of new coal-fired capacity is built, and capacity utilization increases from 70 percent in 1996 to 81 percent in 2005. By 2015, new coal-fired capacity reaches 5 gigawatts.
- Between 2005 and 2015, natural gas-fired generation increases significantly. By 2015, 17 to 21 gigawatts of new gas-fired combined-cycle units are built to meet the varying levels of electricity demand in the two competitive cases.
- With the renewable portfolio standard in the low fossil case, generation of electricity from renewable sources is over 3 times the 1996 levels. The growth comes from biomass and wind and reduces the need for increased coal and gas-fired generation.
- In 2015, natural gas consumption is 0.1 to 0.3 quadrillion Btu above 1996 levels, and coal consumption is by 0.4 to 0.5 quadrillion Btu higher than in 1996.

Western Systems Coordinating Council (WSCC)

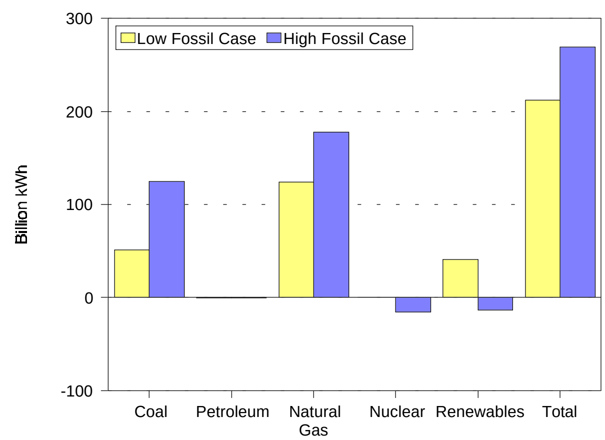


Projected Change in Electricity Generation from 1996 for Full Competition Cases

1996-2005



1996-2015



Source: Energy Information Administration, Office of Integrated Analysis and Forecasting, NEMS runs complo3.d031298b and comphiD3.d031398b.

- Electricity sales are projected to grow between 1.6 and 2.0 percent per year from 1996 through 2015.
- Coal-fired generation is projected to be higher in 2005, with greater utilization of existing power plants (82 percent capacity factor in 2005, compared with 73 percent in 1996). By 2015, almost 15 gigawatts of new coal-fired capacity is projected to be built in the high fossil case to replace generation from two large nuclear units assumed to be retired early, to replace some of the reduction in hydroelectric generation, and to meet increased demand for electricity. In the low fossil case, 4 gigawatts of new coal-fired capacity is built.
- Much of the increased generation in the region comes from new natural gas-fired turbines and combined-cycle units. The level of gas-fired generation varies with the outlook for renewable generation.
- With the renewable portfolio standard in the low fossil case, generation of electricity from is 6.5 billion kWh higher than 1996 levels in 2005 and 40.5 billion kWh higher in 2015. This growth, which results from geothermal, biomass, solar, and wind resources, more than offsets the decline in hydroelectric generation.
- In 2015, natural gas consumption increases by 0.8 to 1.1 quadrillion Btu above 1996 levels and coal consumption is 0.6 to 1.2 quadrillion Btu higher than in 1996.

Appendix A

Pending Federal Legislation Relative to the Restructuring of the Electric Power Industry

Appendix A

Pending Federal Legislation Relative to The Restructuring of The Electric Power Industry

Senate Bills

S. 237 - Electric Consumers Protection Act of 1997

Introduced by: Senator Dale Bumpers (D-AR)
Date: January 30, 1997
Purpose: To provide for retail competition among electric energy suppliers for the benefit and protection of consumers, and for other purposes.
Summary: **Title I: Retail Competition**
Sets December 15, 2003, as the date beginning which : (1) each consumer shall have the right to purchase retail electric energy from any offeror; and (2) all sellers of such energy shall have reasonable and nondiscriminatory access on an unbundled basis, to the local distribution and retail transmission facilities of retail electric energy providers and all related services. Section 110 of Title One of the bill has a requirement for a certain amount of renewable energy generation. Starting in 2003, 5 percent of total retail electricity sold must come from a renewable energy source (including hydroelectricity). The amount increases to 9 percent in 2008 and 12 percent in 2013; the requirement ends in 2019. Retail electric suppliers may satisfy the requirement by earning renewable energy credits under the National Renewable Energy Trading Program depending upon the type of renewable energy source used.
Title II: Public Utility Holding Companies
Repeals the Public Utility Holding Company Act of 1935.
Title III: Public Utility Regulatory Policies Act
Declares the Public Utility Regulatory Policies Act of 1978 governing cogeneration and small power production inapplicable to public utility facilities beginning commercial operations after the enactment of this Act.
Title IV: Environmental Protection
Instructs the Environmental Protection Agency to report to the Congress on the implications of differences in air pollution emissions standards for wholesale and retail electric generation competition and for public health and the environment.

S. 621 - Public Utility Holding Company Act of 1997

Introduced by: Senator Alfonse M. D'Amato (R-NY)
Date: April 22, 1997
Purpose: To repeal the Public Utility Holding Company Act of 1935.
Summary: Prescribes procedural guidelines for both FERC and State access to records of a holding company of a public utility or natural gas company; precludes such State access to any person that is a holding company solely by reason of ownership of one or more qualifying facilities under PURPA; instructs FERC to promulgate a final rule to exempt specified holding companies from such access requirements; requires FERC to exempt any person or transaction from such access requirements if it finds that regulation of such person or transaction is irrelevant to the jurisdictional rates of a public utility or natural gas company; retains the jurisdiction of FERC and State commissions to determine whether a public utility company or natural gas company may recover in rates any costs of affiliate

transactions; grants FERC certain FPA enforcement powers; transfers from the SEC to FERC all books and records that relate primarily to the functions vested in FERC by this Act; authorizes appropriations and amends the FPA to repeal its conflict of jurisdiction guidelines.

S. 687 - Electric System Public Benefits Protection Act of 1997

Introduced by: Senator James M. Jeffords (R-VT)
Date: May 1, 1997
Purpose: To enhance the benefits of the national electric system by encouraging and supporting State programs for renewable energy sources, universal electric service, affordable electric service, and energy conservation and efficiency, and for other purposes.
Summary: Directs the Secretary of Energy to establish a National Electric System Public Benefits Board to establish accounts known as the "National Electric System Public Benefits Fund" at financial institutions in order to provide matching funds to States to support programs relating to renewable energy sources, universal electric service, energy conservation, and other public purposes; prescribes guidelines for funding, distribution, and wires charges; prescribes a minimum schedule for the total amount of electricity sold by non-hydroelectric facilities and generated by renewable energy sources. Prescribes procedural guidelines for renewable energy credits; amends PURPA to repeal its cogeneration and small power production provisions; prescribes procedural guidelines for emissions standards and allocations, a monitoring system for pollutants and emissions credits; directs the Secretary of Energy to establish a disclosure system to allow retail consumers to knowledgeably compare retail electric service offerings (including comparisons based on generation source portfolios, emissions data, and price terms), and to promulgate regulations accordingly; declares that failure of a retail company to provide accurate disclosure shall be treated as a deceptive act in commerce under the Federal Trade Commission Act.

S. 710 - (No short title)

Introduced by: Senator John Breaux (D-LA)
Date: May 7, 1997
Purpose: To amend the Internal Revenue Code of 1986 to extend the credit for producing fuel from a nonconventional source to taxpayers using biomass fuel sources in the generation of electricity through the use of a suspension burning process.
Summary: Amends the Internal Revenue Code to make the credit for producing fuel from a nonconventional source applicable to fuel produced from (1) gas produced from geopressured brine, Devonian shale, coal seams, or a tight formation, and (2) gas or steam produced from biomass.

S. 722 - Electric Utility Restructuring Empowerment and Competitiveness Act of 1997

Introduced by: Senator Craig Thomas (R-WY)
Date: May 8, 1997
Purpose: To benefit consumers by promoting competition in the electric power industry, and for other purposes.
Summary: Amends the Federal Power Act to prescribe parameters within which a State may: (1) exercise jurisdiction over retail electric supply or distribution service provided to retail customers within its borders; (2) establish and enforce electric energy performance standards; (3) exercise authority over retail transactions (including the imposition of surcharges); and (4) require electric energy suppliers to provide wholesale and retail reciprocity with respect to open, nondiscriminatory transmission access and local distribution access; grants the States exclusive jurisdiction over electric energy sales to a Federal facility or to a federally chartered corporation within their borders; retains State prerogative to require electricity retailers to assist in providing universal service; removes wholesale sales of electric energy from Federal regulatory purview; retains State authority over retail electric energy sales; grants FERC jurisdiction over wholesale electric transmission services; instructs the

Inspector General of the Treasury to report to the congress regarding the impact of specified tax provisions upon the promotion of a competitive retail electricity market; amends PURPA to exempt an electric utility beginning commercial operation after the date of enactment of this Act from the requirement to enter into a new contract or obligation to purchase or sell electric energy or capacity pursuant to the provisions governing cogeneration and small power production; repeals PUHCA; prescribes procedural guidelines for both FERC and State access to records of a holding company of a public utility or natural gas company; instructs FERC to promulgate a final rule to exempt specified holding companies from such access requirements; requires FERC to exempt any person or transaction from such access requirements if it finds that regulation of such person or transaction is irrelevant to the jurisdictional rates of a public utility company; retains the jurisdiction of FERC and State commissions to determine whether a public utility company may recover in rates any costs of affiliate transactions; grants FERC certain FPA enforcement powers; transfers from the SEC to FERC all books and records that relate primarily to the functions vested in FERC by this Act; amends the FPA to repeal its conflict of jurisdiction guidelines.

S. 1276 - Federal Power Act Amendments of 1997

Introduced by: Senator Jeff Bingaman (D-NM)
Date: October 8, 1997
Purpose: To amend the Federal Power Act, to facilitate the transition to more competitive and efficient electric power markets, and for other purposes.
Summary: Clarifies FERC jurisdiction over regulation of transmission and distribution; places transmission systems of Federal power marketing agencies (including TVA), municipal utilities, and rural electric cooperatives under FERC's jurisdiction; limits FERC's authority to order retail wheeling unless permitted or required by State law; clarifies States' authority to require retail competition and unbundled local distribution service, and to require nondiscriminatory service or reciprocity in implementing competition; instructs FERC to establish and enforce transmission reliability standards; broadens FERC authority to order a transmitting utility to enlarge, extend, or improve its transmission facilities; authorizes FERC to designate a national electric reliability council and regional reliability councils, which must meet certain requirements; provides protection of existing PURPA Section 210 power purchase contracts by precluding nonrecovery of related costs; authorizes FERC to order formation of regional transmission systems and appoint an oversight board to oversee such systems. This board shall appoint independent system operators to operate these systems.

S. 1401 - Transition to Electric Competition Act of 1997

Introduced by: Senator Dale Bumpers (D-AR) and Senator Slade Gorton (R-WA)
Date: November 7, 1997
Purpose: To provide for the transition to competition among electric energy suppliers for the benefit and protection of consumers, and for other purposes. (This bill modifies S. 237.)
Summary: **Title I: Retail Competition**
Sets January 1, 2002, as the date from which (1) each consumer shall have the right to purchase retail electric energy from any offeror; and (2) all sellers of such energy shall have reasonable and nondiscriminatory access, on an unbundled basis, to the local distribution and retail transmission facilities of retail electric energy providers and all ancillary services.
Title II: Public Utility Holding Companies
Repeals the Public Utility Holding Company Act of 1935, except with respect to (1) the United States; (2) a State or local government; (3) any foreign governmental authority not operating in the United States; (4) any agency, authority or instrumentality of any of the foregoing; or (5) any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty.
Title III: Public Utility Regulatory Policies Act
Declares the Public Utility Regulatory Policies Act of 1978 governing cogeneration and small power production inapplicable to public utility facilities beginning commercial operations after the enactment of this Act. States that no public utility shall be required to enter into a new contract or obligation to

purchase or sell electric energy after the effective date of this title or, if earlier, the date on which retail electric competition is implemented in all of its service territories.

Title IV: Environmental Protection

Instructs the Environmental Protection Agency to report to the Congress on the implications of differences in air pollution emissions standards for wholesale and retail electric generation competition and for public health and the environment.

Title V: Bonneville Power Administration

Place BPA transmission services under FERC rules on nondiscriminatory open access to transmission services provided by public utilities.

Title VI: Tennessee Valley Authority

Sets a date from which: (1) all electric energy suppliers shall have the right to sell retail and wholesale electric energy to persons currently purchasing such energy directly or indirectly from the Tennessee Valley Authority (TVA); (2) TVA may sell wholesale electric energy to any person; (3) TVA wholesale power customers may sell such power to any person; and (4) customers may terminate their contracts to purchase TVA power.

S. 1483 - (No short title)

Introduced by: Senator Frank Murkowski (R-AK)
Date: November 8, 1997
Purpose: To amend the Internal Revenue Code of 1986 to provide for the treatment of tax-exempt bond financing of certain electrical output facilities.
Summary: Amends the Internal Revenue code to set forth provisions concerning the treatment of tax-exempt bond financing of certain electrical output facilities.

S. 2182 - Private Use Competition Reform Act of 1998

Introduced by: Senator Slade Gorton (R-WA)
Date: June 17, 1998
Purpose: To amend the Internal Revenue Code of 1986 to provide tax-exempt bond financing of certain electric facilities.

S. 2187 - Electric Consumer Choice Act

Introduced by: Senator Don Nickles (R-OK)
Date: June 18, 1998
Purpose: To amend the Federal Power Act to ensure that no State may establish, maintain, or enforce on behalf of any electric utility an exclusive right to sell electric energy or otherwise unduly discriminate against any consumer who seeks to purchase electric energy in interstate commerce from any supplier.

S.2287 - The Comprehensive Electricity Competition Act

Introduced by: Senator Frank Murkowski (R-AK)
Date: July 10, 1998
Purpose: To provide for a more competitive electric power industry, and for other purposes.
Summary: All electric consumers would be able to choose their electricity supplier by January 1, 2003, but a state may opt out of retail competition if it believes its consumers would be better off under the status quo or an alternative state-crafted plan. The Secretary of Energy would be authorized to require all retail electric suppliers to disclose, in a uniform format, information on prices, terms, and conditions of service; type of energy resource used to generate the electric energy, and the environmental attributes of the generation (including air emissions characteristics). A Renewable Portfolio Standard would be established to ensure that by 2010 at least 5.5 percent of all electricity sales are covered by generation from renewable energy sources. A Public Benefit Fund would be established to provide matching funds of up to $3 billion to States for low-income assistance, energy-efficiency programs, consumer

information, and the development and demonstration of emerging technologies, particularly renewable energy technologies. The Federal Energy Regulatory Commission (FERC) would have the authority to require transmitting utilities to turn over operational control of transmission facilities to an independent system operator. States would be encouraged to allow the recovery of prudently incurred, legitimate, and verifiable retail stranded costs that cannot be reasonably mitigated. All participants in transactions on the transmission grid would comply with mandatory reliability standards. FERC would approve and oversee a private, self-regulating organization that would develop and enforce these standards. Federal electricity law would be modernized to achieve the right balance of competition without market abuse, including repealing laws like the Public Utility Holding Company Act of 1935 and the "must buy" provision of the Public Utility Regulatory Polices Act of 1978, and giving FERC authority to address market power.

House Bills

H.R. 296 - (No short title)

Introduced by: Congressman John Shadegg (R-AZ)
Date: January 7, 1997
Purpose: To privatize the Federal Power Marketing Administrations, and for other purposes.
Summary: **Title I: Establishment of Corporations and Transfer of Facilities**
Establishes the following Government corporations to operate, maintain, and market the electric power transmission and generation facilities transferred to them under this Act: (1) the Southeastern Power Corporation; (2) the Western Area Power Corporation; and (3) the Southwestern Area Power Corporation.
Title II: Privatization of Corporations
Instructs the Secretary of the Treasury to retain the services of investment banking firms to serve jointly as co-lead managers of the public offering for each such Corporation and to establish a syndicate to underwrite the public offering.

H.R. 338 - Ratepayer Protection Act

Introduced by: Congressman Cliff Stearns (R-FL)
Date: January 7, 1997
Purpose: To prospectively repeal section 210 of PURPA
Summary: Amends the Public Utility Regulatory Policies Act of 1978 to declare its provisions governing cogeneration and small power production inapplicable to any facility placed in service after enactment of this Act, except with respect to power purchase contracts entered into pursuant to such provisions which were in effect on the repeal date; declares that after January 7, 1997, no electric utility shall be required to enter into a new contract or obligation to purchase or sell electric energy or capacity pursuant to the provisions of the PURPA governing cogeneration and small power production; directs FERC to promulgate and enforce regulations to assure that no utility shall be required to absorb the costs associated with electric energy or capacity purchases from a qualifying facility executed prior to January 7, 1997, and governed by such provisions; provides that such regulation shall be treated as a rule enforceable under the FPA.

H.R. 603 - Tennessee Valley Authority First Step Reform Act of 1997

Introduced by: Congressman Bob Franks (R-NJ)
Date: February 5, 1997
Purpose: To amend the Tennessee Valley Authority Act of 1933 to prohibit appropriations after FY 1998.
Summary: Instructs the Director of the Office of Management and Budget to report to the Congress on (1) the historical and current costs to the Federal Government of TVA subsidies, and (2) how TVA plans to

make the transition from receiving Federal subsidies to an organization generating, transmitting, and distributing electric power on an open and competitive market.

H.R. 655 - Electric Consumers' Power to Choose Act of 1997

Introduced by: Congressman Dan Schaefer (R-CO)
Date: February 10, 1997
Purpose: To give all American electricity consumers the right to choose among competitive providers of electricity, in order to secure lower electricity rates, higher quality services, and a more robust U.S. economy, and for other purposes.
Summary: **Title I: Competitive Retail Electric Energy Service**
Sets December 15, 2000, as the deadline by which all electric utility retail customers shall have the right to purchase retail electric energy services from any person offering them.
Title II: Public Utility Holding Company Act of 1935
Declares that the Public Utility Holding Company Act of 1935 ceases to apply to any gas or electric utility company (including its respective holding company) when each State in which such company provides retail distribution service notifies FERC and the Securities and Exchange Commission of its determination that the pertinent retail customers are able to purchase such services at retail from any offeror on a competitively neutral and nondiscriminatory basis.
Title III: Public Utility Regulatory Policies Act of 1978
Amends the Public Utility Regulatory Policies Act of 1978 to declare that its requirements that electric utilities offer to purchase electric energy from qualifying cogeneration and small power production facilities at specified costs shall cease to apply to any electric utility if the State notifies FERC of its determination that the utility's retail customers are able to purchase retail electric energy services from any offeror on a competitively neutral and nondiscriminatory basis.

H.R. 718 - Federal Power Asset Privatization Act of 1997

Introduced by: Congressman Mark Foley (R-FL)
Date: February 12, 1997
Purpose: To privatize certain Federal power generation and transmission assets, and for other purposes.
Summary: Directs the Secretary of Energy to sell, at the highest possible price, all Federal electric power generation and transmission facilities supervised by, or coordinated with, the Federal Power Marketing Administrations; restricts such sales to domestic entities or U.S. citizens. Requires the Secretary to terminate Federal Power Marketing Administration operations upon completion of the sales. Directs the Secretary to retain a private sector firm through a competitive bidding process to serve as financial advisor with respect to such sales.

H.R. 1230 - Consumers Electric Power Act of 1997

Introduced by: Congressman Tom DeLay (R-TX)
Date: April 8, 1997
Purpose: To give all American electricity consumers the right to choose among competitive providers of electricity in order to secure lower electricity rates, higher quality services, and a more robust U.S. economy, and for other purposes.
Summary: Declares that each person has the right to purchase electric service from any electric service provider; prohibits a governmental authority from: (1) denying or limiting a person's right to purchase such energy from an electric service provider at a price and on terms and conditions freely arrived at, (2) discriminating or authorizing discrimination against any person exercising the right to purchase such energy, or (3) granting any preference or protection from competition to any electric service provider (including subsidies, exit fees, and other penalties on exercising choice of electric purchases); permits electric energy purchasers to choose alternative arrangements for the delivery of electric energy; prohibits any State from establishing discriminatory requirements or other obligations for certification

of electric service providers within that State; authorizes a State to establish rules for initial, nondiscriminatory assignment of retail customers who fail to select an electric service provider; enumerates objectives to be achieved through the operation of transmission and distribution systems; grants FERC the authority to provide for nondiscriminatory prices and conditions to transmission and distribution services; sets a deadline by which FERC must promulgate and make effective rules which provide nondiscriminatory access to transmission and distribution service, and which eliminate barriers to competitive electric service presented by existing contracts and arrangements involving transmitting utilities and distribution facilities; directs FERC to (1) ensure that existing electric utilities are not permitted to exercise market power in the sale of electric service, (2) initiate proceedings to determine the extent to which existing utilities have such market power, and (3) determine the means for mitigating it; authorizes FERC to enforce such determinations by (1) restricting the ability of an electric utility to sell such services at market-determined rates, and (2) ordering the divestiture of assets and functions which are the source of market power; declares that PUHCA, as well as the PURPA requirement that electric utilities offer to purchase electric energy from qualifying cogeneration and small power production facilities at the incremental cost to the utility of alternative electric energy, shall cease to apply to an electric utility if each State in which it is providing electric services notifies FERC of its determination that retail customers can purchase such services in accordance with this Act; prohibits Federal, State, and local government authorities from regulating (1) pricing, terms, or conditions of service offerings by electric service providers, or (2) who may engage in selling electric energy (except as provided in this Act).

H.R. 1359 - (No short title)

Introduced by: Congressman Peter A. DeFazio (D-OR)
Date: April 17, 1997
Purpose: To amend PURPA to establish a means to support programs for electric energy conservation and energy efficiency, renewable energy, and universal and affordable service for electric consumers.
Summary: Amends PURPA to establish a National Electric System Public Benefits Fund, administered by the National Electric System Public Benefits Board, to provide matching funds to States for the support of eligible public purpose programs; confers oversight responsibility over the Board upon the Secretary of Energy; requires each electric power generation facility owner or operator, as a condition of transmitting power to any transmitting utility, to contribute funds determined by the Board to be necessary to generate revenues in each calendar year equal to one-half of the aggregate cost of implementing certain public purpose programs; requires the Board to institute a rulemaking proceeding governing creation and administration of a Public Benefits Program; authorizes any State to establish one or more public purpose programs and apply for matching funds under the Public Benefits Program; emphasizes State discretion to elect participation in such Program; expresses the sense of the Congress that such Program shall not replace or supersede any other existing programs that support or encourage conservation and energy efficiency, renewable energy, universal and affordable service, or research and development.

H.R. 1401 - (No short title)

Introduced by: Congressman Bill Thomas (R-CA)
Date: April 17, 1997
Purpose: To amend the Internal Revenue Code of 1986 to provide a 5-year extension of the credit for producing electricity from wind.
Summary: Amends the Internal Revenue Code to extend, for five years, the credit for producing energy from wind or a closed-loop biomass.

H.R. 1910 - Electric Utility Nitrogen Oxide Limitation Act of 1997

<u>Introduced by</u>: Congresswoman Julia Carson (D-IN)
<u>Date</u>: June 17, 1997
<u>Purpose</u>: To establish minimum nationwide nitrogen oxide pollution standards for fossil-fuel fired electric powerplants.
<u>Summary</u>: Makes it unlawful for any fossil-fuel fired utility unit with a nameplate capacity of greater that 25 megawatts of electrical output to emit nitrogen oxides in excess of a maximum allowable emission standard of 0.35 pounds per million Btu; cites circumstances under which the owner of several electric utility units within a single State may elect to use alternative contemporaneous annual emission limitations and receive operating permits accordingly; directs the Administrator of the Environmental Protection Agency to issue implementation and enforcement regulations; sets a deadline after which no unit under this Act may operate without a permit subject to the Clean Air Act; declares that the requirements of this Act shall be treated as an emission limitation under the Clean Air Act.

H.R. 1960 - Electric Power Competition and Consumer Choice Act of 1997

<u>Introduced by</u>: Congressman Edward J. Markey (D-MA)
<u>Date</u>: June 19, 1997
<u>Purpose</u>: To modernize PUHCA, the Federal Power Act, the Fair Packaging and Labeling Act, and PURPA to promote competition in the electric power industry, and for other purposes.
<u>Summary</u>: **Title I: Standards of Competition - Subtitle A: Application of PUHCA and PURPA**

Declares PUHCA inapplicable to holding company systems which are in compliance with certain specific standards and requirements of competition and public benefits programs under PURPA; exempts utilities which obtain certification of competition from PURPA requirement to purchase electricity from qualified cogenerators and small power production facilities.

Subtitle B: Mergers, Acquisition, Market Concentration, Affiliate Relationships and Diversifications

Conditions acquisition of an interest in a public utility that results in effective control or ownership upon (1) certain FERC findings, (2) submission to FERC of certain public utility certifications regarding effective competition and substantial electric service cost reductions; and (3) transactions executed on an arms-length basis; directs FERC to establish the parameters governing such transactions.

Subtitle C: Electric Energy Transmission and Distribution Policies

Amends the FPA to direct FERC to promulgate rules establishing tariffs applicable in the largest regions feasible to (1) ensure development of competitive electricity markets, while encouraging economical use of existing generating facilities and the economical location of future generating facilities, (2) ensure full recovery by transmission facilities' owners of prudent transmission costs, (3) prevent multiple charges for transmission service based on the number of transmission owners, and (4) prevent a seller of energy from gaining advantage over competitors by reason of ownership or control of electric power transmission or distribution facilities.

Title II: Reliability

Amends the FPA to direct each electric utility and transmitting utility to join an electric reliability council, which shall promote the reliability of electricity supply and systems; requires FERC to oversee the operations of such councils.

H.R. 2909 - (No short title)

<u>Introduced by</u>: Congressman Frank Pallone, Jr. (D-NJ)
<u>Date</u>: November 7, 1997
<u>Purpose</u>: To amend the Federal Power Act to establish requirements regarding the operation of certain electric generating facilities, and for other purposes.
<u>Summary</u>: Amends the Federal Power Act with respect to procedures and administrative provisions to direct the Federal Energy Regulatory Commission (FERC) to: (1) calculate a generation performance standard (equal to a certain statutory tonnage cap) for oxides of nitrogen, sulfate fine particulate matter, and

any other pollutant released in significant quantities by electric generating units; (2) set forth schedules of statutory tonnage caps for emissions of oxides of nitrogen and sulfate fine particulate matter from covered electric generating units; and (3) promulgate by rule a national limit on total annual emissions of any other pollutant from covered electric generating units, expressed in tons. Prescribes procedural guidelines for: (1) allocation and trading of allowances; (2) penalties for excess emissions; and (3) periodic publication by FERC of its estimate of the total electric generation by covered electric generating units. Provides for citizen suits to enforce this Act.

H.R. 2988 - The Federal Power Marketing Act of 1997

Introduced by: Congressman John T. Doolittle (R-CA)
Date: November 9, 1997
Purpose: To facilitate the operation, maintenance, and upgrade of certain federally owned hydroelectric power generating facilities, to ensure the recovery of costs, and to improve the ability of the Federal Government to coordinate its generating and marketing of electricity with the non-Federal electric utility industry.
Summary: Amends the Federal Power Act with respect to procedures and administrative provisions to direct the Federal Energy Regulatory Commission (FERC) to: (1) calculate a generation performance standard (equal to a certain statutory tonnage cap) for oxides of nitrogen, sulfate fine particulate matter, and any other air pollutant released in significant quantities by electric generating units; (2) set forth schedules of statutory tonnage caps for emissions of oxides of nitrogen and sulfate fine particulate matter from covered electric generating units; and (3) promulgate by rule a national limit on total annual emissions of any other pollutant from covered electric generating units, expressed in tons. Prescribes procedural guidelines for: (1) allocation and trading of allowances; (2) penalties for excess emissions; and (3) periodic publication by FERC of its estimate of the total electric generation by covered electric generating units. Provides for citizen suits to enforce this Act.

H.R. 3548 - Environmental Priorities Act of 1998

Introduced by: Congressman Robert E. Andrews (D-NJ)
Date: March 25, 1998
Purpose: To establish a Fund for Environmental Priorities to be funded by a portion of the consumer savings resulting from retail electricity choice, and for other purposes.
Summary: Effective for a consumer sector in any State in the first year after all of a State's regulated and nonregulated electric utilities have established retail electric service choice for customers in such sector, but no earlier than 2001. Requires providers of retail electric services to contribute to the fiscal agent for the Environmental Priorities Board (established by this Act) ten percent of the total consumer savings for the consumer sector for that calendar year. Defines: (1) "consumer savings" as the amount by which the potential rate for electric energy provided to a consumer sector exceeds the current rate for the sector, multiplied by the sector's total consumption (in kilowatthours) during a calendar year; and (2) "potential rate" as the average kilowatthour rate paid by the provider's customers in that sector during the 12-month period preceding the date on which retail electric service choice was established, adjusted for inflation. Requires the Administrator of the Environmental Protection Agency to establish a National Environmental Priorities Board. Directs the board to: (1) establish regulations governing creation of an Environmental Priorities Program, to include criteria and methods of selecting State projects to receive support; and (2) enter into arrangements with a non-federal fiscal agent to receive and disburse contributions described by this Act. Authorizes States in which retail electric service choice has been established for any consumer sector to establish public purpose programs and apply for matching funding to support environmental priorities programs. Requires the fiscal agent to distribute contributions to States to carry out such programs.

H.R. 3927 - (No Short Title)

<u>Introduced by</u>: Congressman Phil English (R-PA)
<u>Date:</u> May 21, 1998
<u>Purpose:</u> To amend the Internal Revenue Code of 1986 to restrict the use of tax-exempt financing by governmentally owned electric utilities and to subject certain activities of such utilities to income tax.
<u>Summary</u>: Narrows the Internal Revenue tax code definition of circumstances under which governmentally owned electric utilities may finance utility facilities with tax exempt bonds. Subjects utility-related income of governmental entities to Federal income tax, in situations where the income is derived from sources outside a limited area.

H.R. 3976 - (No Short Title)

<u>Introduced by:</u> Congressman W. J. "Billy" Tauzin (R-LA)
<u>Date:</u> May 22, 1998
<u>Purpose:</u> To repeal the Public Utility Holding Company act of 1935, to enact the Public Utility Holding Company Act of 1998, and for other purposes.
<u>Summary:</u> Repeals the Public Utility Holding Company Act of 1935; enacts the Public Utility Holding Company Act of 1998 to support the continuing need for limited Federal and State regulation and to supplement the work of State commissions for the continued rate protection of utility customers.

Summary of the Administration's Comprehensive Electricity Competition Plan

The Administration' s Comprehensive Electricity Competition Plan will result in lower prices, a cleaner environment, increased innovation, and government savings. The Department of Energy estimates that retail competition will save consumers $20 billion a year on their electricity bills. This translates into direct savings to the typical family of four of $104 per year and indirect savings, from the lower costs of other goods and services, of $128 per year. Thus, total savings for a typical family are $232 a year.

Competition will also produce significant environmental benefits through both market mechanisms and policies that promote investment in energy efficiency and renewable energy. For example, we estimate that the Competition Plan will reduce greenhouse gas emissions by 25 to 40 million metric tons in 2010. A generator that wrings as much energy as it can from every unit of fuel will be rewarded by the market. More efficient fuel use means lower emissions. In addition, competition provides increased opportunities to sell energy efficiency services and green power. The Competition Plan also makes possible new policies, such as the renewable portfolio standard and enhanced public benefit funding, which will guarantee substantial environmental benefits.

Competition will also spark innovation in the American economy, creating new industries, jobs, products and services just as telecommunications reform spawned cellular phones and other new technologies. Finally, Federal, State, and local governments will also benefit from lower electricity prices, with savings of close to $2 billion a year.

The components of the Administration' s Plan work together to obtain the economic benefits of competition in a manner that is fair to all Americans and improves the environmental performance of the electricity industry. The various components in our Plan fall into five basic categories: (1) encouraging States to implement retail competition; (2) protecting consumers by facilitating competitive markets; (3) assuring access to and reliability of the transmission system; (4) promoting and preserving public benefits; and (5) amending existing Federal statutes to clarify Federal and state authority.

I. Encouraging States to Implement Retail Competition

A. Retail Competition – Flexible Mandate

Proposal: Support customer choice through a flexible mandate that would require each utility to permit all of its retail customers to purchase power from the supplier of their choice by January 1, 2003, but would permit States or non-regulated utilities to opt out of the competition mandate if they find, on the basis of a public proceeding, that consumers in the State would be better served by an alternative policy, such as a State-crafted retail competition plan or the current monopoly system.

Federal legislation with a flexible retail competition mandate is the best means to obtain the economic benefits of competition while ensuring that States have the opportunity to tailor their utility systems to meet their unique needs.

B. Stranded Cost Principle

Proposal: The Administration endorses the principle that utilities should be able to recover prudently incurred, legitimate, and verifiable retail stranded costs that cannot be reasonably mitigated. States would continue to determine recovery of investments, including stranded cost recovery, under State law. FERC would have "backup" authority to establish a stranded cost recovery mechanism if a State lacks such authority.

Federal policy should encourage States to provide for recovery of stranded costs because resolution of this issue is one of the key stumbling blocks which must be surmounted in order to provide choice to consumers. At the same time, the authority of States to address this difficult issue should be preserved.

II. Protecting Consumers by Facilitating Competitive Markets

A. Consumer Information

Proposal: The Secretary of Energy would be authorized to conduct a rulemaking to require all suppliers of electricity to disclose information on price, terms, and conditions of their offerings; the type of generation source; and generation emissions characteristics.

In a competitive market, consumers will need reliable information so they can compare the products and prices offered by suppliers. Uniform and easy to understand labeling along the lines of the Food and Drug Administration's highly successful nutritional labeling system will help consumers get the best price possible on electricity and facilitate the development of a vigorous market for environmentally beneficial power technologies.

B. Authority to Address Market Power

Proposal: Authorize the Federal Energy Regulatory Commission (FERC) to remedy wholesale market power if FERC finds market power in wholesale markets. Authorize FERC, upon petition from a State, to remedy market power in retail markets if the State is implementing retail competition, finds market power, and has insufficient authority to remedy the market power. FERC would be authorized in these circumstances to require generators with market power to submit a plan to mitigate market power, which FERC could approve with or without modification. FERC would be authorized to order divestiture to the extent necessary to mitigate market power.

In order to assure that competition benefits all consumers, the Competition Plan provides regulatory authorities the tools they need to protect against the abuse of market power in the new market. Existing authorities, such as antitrust statutes and other Federal and State law, can be used to help protect consumers in a competitive market. However, these authorities alone do not provide sufficient assurance that markets will remain competitive in all areas of the nation. Accordingly, the Administration plan contains additional consumer protection provisions to address market power.

C. Public Utility Holding Company Act (PUHCA) Repeal

Proposal: Repeal of substantive requirements of PUHCA. Provide FERC and State Commissions with additional access to the books and records of holding companies and affiliates of public utilities within holding companies to assist them in guarding against increased interaffiliate abuse following repeal of PUHCA, in combination with the other reforms, such as additional merger and market power authority.

D. Merger Review

Proposal: Endow FERC with jurisdiction over the merger or consolidation of electricity utility holding companies and generation-only companies. FERC's review of mergers should be streamlined.

III. Assuring Access to and Reliability of the Transmission System

A. Strengthen Electric System Reliability

Proposal: The Federal Power Act should be amended to require FERC to approve the formation of and oversee a private self-regulatory organization that prescribes and enforces mandatory reliability standards.

Reliability and competition can-- and must-- go hand in hand. To ensure reliability in the new market, we propose to build upon the industry's tradition of self-regulation by requiring key market participants to join an organization which would establish reliability standards and enforce those standards subject to the oversight of FERC.

B. Authority to Establish and Require Independent System Operation

Proposal: Amend the FPA to provide FERC with the authority to require transmitting utilities to turn over operational control of transmission facilities to an independent system operator.

Separation of the operation and control of transmission facilities from generation through participation in an independent system operator (ISO) structure would greatly reduce the risk that operation of the transmission system could favor some generators or customers over others.

IV. Promoting and Preserving Public Benefits

A. Secure the Future of Renewable Electricity Through a Renewable Portfolio Standard

Proposal: Adopt a Federal Renewable Portfolio Standard (RPS) to guarantee that a minimum level of additional renewable generation is developed in the United States. The RPS would require electricity sellers to cover a percentage of their electricity sales with generation from non-hydroelectric renewable technologies, such as wind, solar, biomass, or geothermal generation. The RPS requirement would be initially set close to the ratio of RPS-eligible generation to retail electricity sales projected under baseline conditions. There would be an intermediate increase in RPS requirement in 2005, followed by an increase to 5.5 percent in 2010. The RPS should be subject to a cost cap.

Repeal prospectively the “must buy” provision of section 210 of PURPA, but preserve existing contracts and exemptions.

Retail competition itself has the potential to significantly increase renewable energy's share of the electricity market, because it will allow environmentally-conscious consumers to support green energy technologies with their wallets. Nonetheless, the inherent uncertainty of the transition to competition and the important environmental and energy diversification benefits from renewables dictate that the future of renewable energy be secured.

B. Encourage and Support Continued Funding for Public Benefit Programs

Proposal: Create a $3 billion Public Benefit Fund (PBF) to provide matching funds to States for low-income assistance, energy efficiency programs, renewable energy, and consumer education.

A number of States that plan to open their electricity markets to retail competition are already planning to recover the costs of certain public benefit programs through a non-bypassable distribution charge on all electricity customers. A Federal PBF will both encourage and support the creation of these programs at the State level and can be structured to give States the flexibility to allocate such funding in a manner that addresses unique State or local needs.

C. Net Metering

Proposal: Make all consumers eligible for net metering and require that all distribution service providers assure the availability of interconnection, subject to appropriate nondiscriminatory safety standards. The provision should apply only to very small (up to 20 kW) renewable energy projects and be subject to a cap determined at the State level.

Net metering provides an incentive for electricity users to install small-scale on-site renewable generation sources (such as the rooftop solar photovoltaic panels featured in the President's Million Solar Roofs Initiative announced in June 1997) in order to reduce electricity generation from conventional sources.

D. Nitrogen Oxide Trading Authority

Proposal: Clarify EPA authority to require a cost-effective interstate trading system for nitrogen oxide (NOx) pollutant reductions addressing the regional transport contributions needed to attain and maintain the Primary National Ambient Air Quality Standards (PNAAQS) for ozone. No change is proposed to existing EPA authority to determine geographic coverage or level of reductions required in addressing regional transport contributions.

Our restructuring proposal is likely to provide net benefits to the environment by reducing emissions of nitrogen oxides and carbon dioxide relative to baseline projections for 2010. Notwithstanding these benefits, the work of the Ozone Transport Assessment Group (OTAG), a multi-year consultative process that included representatives from States, public interest groups, and electric utilities throughout the Eastern United States, suggested that a further substantial reduction in NOx emissions over a wide area is needed to attain the ambient standard for ozone in the Northeast. Electric generators are a major source of NOx emissions. Our proposal will allow these NOx reductions to be achieved through efficient market-based mechanisms.

E. Air Emissions

The Administration believes that retail competition will deliver cleaner air and a down-payment on greenhouse gas emissions reductions. We estimate that our Competition Plan will reduce greenhouse gas emissions by 25 to 40 million metric tons by the year 2010. These reductions result from the specific provisions outlined above that support renewable energy sources and efficiency, as well as the incentive provided by retail competition itself, to improve efficiency both in the supply and use of electricity. We intend to coordinate across Federal agencies regarding data on emissions from the utility sector and with the Congress to ensure that any unanticipated adverse consequences are addressed quickly and in keeping with the Administration's climate change policy.

F. Rural Safety Net

The Administration is confident that a properly structured retail competition system will benefit consumers in all parts of the nation, including those in rural areas. Nevertheless, we are mindful of the possibility that in certain cases competition could have adverse impacts in rural areas where the cost of delivering electricity to consumers is relatively high. Accordingly, a “rural safety net” should, if necessary, be established to address any unintended consequences arising from the transition to retail competition.

V. Amending Existing Federal Statutes to Clarify Federal and State Authority

The existing Federal regulatory framework for the electric power industry was established early in the New Deal with the enactment of the Federal Power Act and the Public Utility Holding Company Act. The State regulatory structure, for the most part, preceded these Federal statutes. This regulatory framework has remained essentially unchanged: vertically-integrated utilities enjoy the advantages of monopoly franchise territories and authorized rates of return on investment, in exchange for an obligation to serve all customers within their respective service territories at regulated rates.

The Federal statutory framework does not readily accommodate individual State initiatives to institute competition among retail suppliers. In fact, certain Federal statutes which were drafted in the context of cost-of-service regulation may prove unworkable in a restructured market. Moreover, FERC may be unable to fully implement its open-access policy absent increased authority under the Federal Power Act. Amendments to the Federal Power Act will be necessary in order to enable both FERC and the States to implement competition effectively.

A. Clarify Federal Jurisdiction

Proposal:

- Provide FERC with clear authority to order retail transmission in a transmission system other than where the end user is located to complete an authorized retail sale.
- Reinforce FERC jurisdiction over rates, terms, and conditions of unbundled retail transmission.
- Reinforce FERC authority relied upon to promulgate Order 888.
- Provide that FERC's open access rules apply to municipal utilities, cooperatives, the Tennessee Valley Authority (TVA), and Federal power marketing administrations (PMAs), with the provision that, with respect to the PMAs, TVA, and cooperatives financed by the Rural Utilities Service, it may be necessary in some instances to adopt special stranded cost mechanisms to take into account the unique facts and circumstances surrounding these Federal investments or loans.

B. Clarify State Jurisdiction to Implement Retail Competition

Proposal:

- Amend the Federal Power Act (FPA) to clarify that it does not preempt States from ordering retail competition.
- Amend the FPA to clarify that it does not preempt States from imposing a charge on the ultimate consumer’s receipt of electric energy.

C. Clarify State Authority to Impose Reciprocity Requirements

Proposal: Provide States that have implemented retail competition with the authority to preclude an out-of-State utility with a retail monopoly from selling within the State unless that out-of-State utility permits customer choice.

VI. Miscellaneous Provisions

A. Taxes

(1) Nuclear Decommissioning Costs

Proposal: Amend the Internal Revenue Code relating to deductions to a qualified nuclear decommissioning fund.

(2) Tax-Exempt Bonds

Proposal: Amend the Internal Revenue Code to provide that (1) private use limitations are inapplicable to outstanding bonds for publicly-owned generation, transmission, or distribution facilities if used in connection with retail competition or open access transmission, and (2) tax-exempt financing is unavailable for new generation or transmission facilities. Tax-exempt financing would continue to be available for distribution facilities, subject to current law private use limitations.