NOVEMBER 1995

The Implications for Coal Markets of Utility Deregulation and Restructuring

THE NATIONAL COAL COUNCIL

THE IMPLICATIONS FOR COAL MARKETS

OF

UTILITY DEREGULATION AND RESTRUCTURING

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The National Coal Council

November 1995

THE NATIONAL COAL COUNCIL

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U.S. DEPARTMENT OF ENERGY

Hazel Rollins O'Leary, Secretary

The National Coal Council is a Federal Advisory Committee to the Secretary of Energy.

The sole purpose of the National Coal Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to coal or the coal industry.

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November 16, 1995

The Honorable Hazel R. O'Leary
Secretary of Energy
1000 Independence Avenue, SW
Room 7A-257
Washington, DC 20585

Dear Madam Secretary:

On September 28, 1995, you requested that we conduct a study and report to you on the potential impact on coal of the many changes now underway affecting the electric generating industry. To this end, a working group was constituted under the leadership of Mr. Rene Males, and they in turn generated the enclosed report entitled, "The Implications on Coal Markets of Utility Deregulation and Restructuring." We are pleased to transmit this report to you.

The Council believes that the method of regulating electric utilities is likely to change substantially in the near term. As a consequence of this change and other forces as well, it is likely that the structure of utilities and the way they operate will also be transformed. The exact form of this transformation is uncertain, but it is clear that competition among electric suppliers will be much more aggressive.

In turn, the Council believes these changes will affect coal markets. In the short term, it may increase coal consumption as low marginal cost coal units are used more intensely. Longer term, coal consumption for the domestic utility market will stabilize or decline unless: 1) the price of alternate fuels, primarily natural gas, rises; 2) new organization partnering among coal chain entities is created and substantially reduces costs; 3) new coal technologies decline sharply in cost and in time to construct.

The Council believes that the DOE can help assure an appropriate role for coal in the nation's energy future by: 1) helping to assure that regulatory changes affecting the utility industry does not put existing or new coal plants at a disadvantage; 2) continuing to encourage development and deployment of new, competitive coal using technologies; 3) participating to assure that sound science and appropriate cost/benefit assessments be used such that unnecessary environmental legislation or regulation do not impede the use of coal.

Madam Secretary, we are confident that his report meets your request and that it provides information that will prove useful to you in your policy decisions. We once again appreciate the opportunity to be of service to you.

Yours very truly,

Joseph W. Craft III
Chairman

Enclosure

PREFACE

The National Coal Council is a private, nonprofit advisory body, chartered under the Federal Advisory Committee Act.

The mission of the Council is purely advisory: to provide guidance and recommendations as requested by the Secretary of Energy on general policy matters relating to coal. The Council is forbidden by law from engaging in lobbying or other such activities. The National Coal Council receives no funds or financial assistance from the Federal Government. It relies solely on the voluntary contributions of members to support its activities.

The members of the National Coal Council are appointed by the Secretary of Energy for their knowledge, expertise, and stature in their respective fields of endeavor. They reflect a wide geographic area of the United States, representing more than 30 states, and a broad spectrum of diverse interests from business, industry, and other such groups as:

- *Large and small coal producers*
- *Coal users such as electric utilities and industrial users*
- *Rail, waterways, and trucking industries as well as port authorities*
- *Academia*
- *Research organizations*
- *Industrial equipment manufacturers*
- *Environmental interests*
- *State government, including governors, lieutenant governors, legislators, and public utility commissioners*
- *Consumer groups, including special women's organizations*
- *Consultants from scientific, technical, general business, and financial specialty areas*
- *Attorneys*
- *Special-interest groups that are regional or state in concentration*
- *Indian tribes*

The National Coal Council provides its advice to the Secretary of Energy in the form of reports on subjects requested by the Secretary and at no cost to the Federal Government.

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Executive Summary

Approach

The National Coal Council has been asked to consider the effects of possible changes in the electric utility industry on domestic coal markets in the next decade. To respond to this question, the Coal Policy Committee of the Council created a Working Group charged with evaluating the effect on coal markets of such changes as FERC's proposed mandatory access to the transmission systems by all wholesale electric customers, the possibility of deregulation of certain parts of the electricity market currently regulated, and the entry of new entities into the electricity supply sector. The possible changes to be considered are to be based on these and other regulatory/legislative events of the last decade.

The report of these considerations of the Council is divided into four parts:

Part 1 *Executive Summary.* Reviews the rationale for the report, describes the approach taken, summarizes the primary conclusions, and presents the Council's recommendations.

Part 2 *History of Regulatory, Legislative, and Market Forces Affecting the Electric Utility Industry.* Provides the background of the changes which have taken place since the dawn of the industry, relates these changes to the regulatory/ legislative/market forces at work during the various periods, and highlights the forces currently affecting the industry.

Part 3 *Implications for Utilities.* Reviews the likely change in utility structures and operations resulting from the changes described in Part 2.

Part 4 *Implications for Coal Markets.* Lists the six primary implications for utility operations and evaluates their likely effect on coal use in both the short and long terms. Finally, the Council integrates its assessment of these six implications into overall directions for the coal markets.

Conclusion

The National Coal Council recognizes the high degree of uncertainty about the future of the electric utility sector and the even greater uncertainty about its effect on coal use by the electric industry. The

Council evaluated the direction of the impact on coal use in each of the following major implications for the industry:

1. Increased competition.
2. More customer choice.
3. Less protection by regulatory oversight.
4. Generation/transmission/distribution unbundling.
5. Decreased cost of alternative technologies.
6. Partnering.

After evaluation on domestic coal use (see Table 1), the National Coal Council believes the following:

1. In the short term (two to five years), there may be a significant increase in coal demand, stemming from higher utilization of existing facilities with access to low-cost coal but offset by the closing of older non-competitive plants.
2. Over the next five years, most of the increasing demand for electricity will be met by other fuels.
3. In the mid term (five to ten years for this analysis), and continuing into the longer term, there is a potential for coal use to grow if one or more of several events occur:
   a) The price of alternate fuels, primarily natural gas, rises or is perceived as likely to rise very substantially relative to the price of coal.
   b) New organizational partnering among coal suppliers, transporters, and users is developed to reduce coal's cost relative to other fuels.
   c) Either existing or new coal technologies decline sharply in cost and in the time required to construct such projects.

The National Coal Council believes that these changes may affect the rate at which clean coal technologies are being developed. Increased competition among electric utilities will encourage a focus on reducing costs. It will also reduce their willingness to make capital investments in new technologies because regulatory protection of these investments through a guaranteed return is unlikely. Combined, these changes are likely to delay development and deployment of clean coal technologies. This, in turn, will reduce coal's competitive ability to fuel new generation facilities and delay the expected improvements in the environment available through employment of clean coal technology.

Table 1: Summary of Utility Deregulation Impacts on Coal Usage

Implication	Next Five Years	Five to Ten Years
Increased Competition	⇑ early ⇓ late	⇔
More Customer Choice	⇔	⇔ to ⇑
Less Protection by Regulatory Oversight	⇓	⇓ or ⇑ (a.)
Generation, Transmission and Distribution Unbundling	⇓	⇓
Decreasing Cost of Alternate Technologies	⇓	⇓
Partnering	⇔ (b.)	⇑
Total	⇑ early ⇓ late	⇓ (c.)⇔⇑ (d.)
(a.) Dependent on nuclear plant license extensions (b.) Because of lead time (c.) If severe environmental restrictions or other negative forces are applied (d.) If dominated by a positive force such as a natural gas price rise, partnering, or improved technologies using coals		

Of particular note is the impact of the development of improved gas-fired, combined-cycle/ combustion turbine (CC/CT) technology on coal-fired generation prospects. (The combined-cycle mode is used here to refer to steam recovery to generate electricity through a steam turbine, to provide steam for process use in industry or for the heating of buildings.) This technology, coupled with the availability of competitively priced gas, has already affected the market for coal-based capacity and will continue to do so during the period of study. Other small-scale technologies may have impacts, but they are likely to be dwarfed by those of the CC/CT-based option.

The National Coal Council believes that such an assessment is helpful for the Department of Energy and for all parts of the interested industries: coal suppliers, equipment and service suppliers, transporters, and users. It provides an early indication, as the electric industry begins responding to these proposed changes in legislation and regulation, as to whether coal markets are likely to be called upon to supply increased volumes, stable volumes, or declining volumes.

One important implication of changes in the use of coal has been highlighted in other National Coal Council reports. As demand for coal changes, it affects employment in coal mining, which in turn affects employment in related industries, such as transportation, and in the local economy around the mines.

Recommendations

The National Coal Council recognizes that the institutional/regulatory changes discussed above are likely to take place, although the exact outcomes remain unclear. The Council believes that maintaining coal as a major fuel for generating electricity is of primary importance to national economic health if coal is, in fact, the lowest overall cost alternative. Also, to the extent that coal is primarily a domestic resource as compared, for example, to oil, maintaining coal as a fuel source is important to national security. Therefore, the National Coal Council makes the following recommendations:

I. The Federal Government, together with the private sector, should participate actively in the formulation of the transition strategy and the final institutional design decisions regarding electric utility deregulation with the objective of assuring that:

   A. Existing coal facilities are not put at an unfair disadvantage compared to other sources of electricity.

   B. New coal-based electric generating facilities can compete fairly with other new facilities for electric generating business.

II. The Department of Energy has championed the next generation of coal-based generating facilities particularly through the clean coal technology program. The National Coal Council encourages DOE to help catalyze the commercialization of clean coal technologies by the private sector and to focus on lowering the capital cost and the lead time of such facilities.

III. The National Coal Council is concerned that unnecessary environmental regulations may reduce coal's competitive position. Therefore, the Council urges DOE and other federal and state agencies involved in setting environmental regulations to insure that sound science and appropriate cost/benefit analysis are applied to environmental decision making.

IV. The National Coal Council believes that the several industry sectors involved in the coal chain and others, such as technology developers and regional development groups, can reduce costs by coordinating their individual interests. Therefore, the Council encourages industry to develop such strategic alliances and urges regulators, to the extent they have oversight, to permit such institutional arrangements.

PART 2
History of Regulatory, Legislative, and Market Forces Affecting the Electric Utility Industry

The Early Years (Before 1920)

The industry was born over 100 years ago as the technology developed by Edison was exploited. Early ventures were typically limited to a small area of a city, to a small town, or to a single factory. But as the technology for transporting electricity improved, the early ventures combined into municipal utilities under private or public ownership.

As transmission technologies continued to improve, and as the technology benefited from economies of scale, many of these early municipal systems were integrated into larger operating companies. Eventually, these financial economies of scale encouraged the integration of many of these systems into large holding companies.

The industry, as it evolved, recognized the economies of a single service provider reducing needless duplication of physical facilities. As a trade-off for exclusive service rights, the investor-owned industry, after considerable debate, agreed to state or local oversight of service and of the level of charges. This created the state or local "public service" or "public utility commissions." The evolving compact between commissions and utilities developed an implicit agreement for fair compensation for expenditures prudently taken in the public service. This implicit understanding continues today, although it has been severely strained during periods of rapid change, such as the 1970s and 1980s.

Electrical generation's energy source for these first 30 years of the industry was either coal or water power, where a dam was available nearby. The scale for both of these technologies, compared to today, was relatively small.

The Middle Years (1920-1970)

During the 1920s, there was a period of rapid growth in electricity usage. This provided an opportunity for the financial consolidation of the more successful investor-owned entities providing electric service. Neighboring municipal utilities were acquired and integrated into existing larger systems, as were generating facilities for individual manufacturing plants. Also, far-flung properties were acquired and consolidated into a few large holding companies.

Where financial structures of utility holding companies used excessive financial leverage, there was substantial risk. When the growth period came to an end, many of those risky structures collapsed. This led, in 1935, to passage of the Federal Power Act, which brought new federal oversight to the operation of utilities. Also in 1935, the Public Utility Act was passed by the United States Congress. It included the Public Utility Holding Company Act (PUHCA) and was followed in 1938 by the Natural Gas Act. These pieces of legislation established the model that was to determine the structure of the electric and gas industries until the late 1960s and the 1970s.

During the 1930s, service began to be extended to more rural areas through the Rural Electrification Administration. Through federal support of capital investment, nearly the entire U.S. population was connected to the electric grid over the next two decades. Many of the publicly owned systems benefited from low-cost electricity by buying power from federal projects that were designed to control flood waters as well as generate electricity.

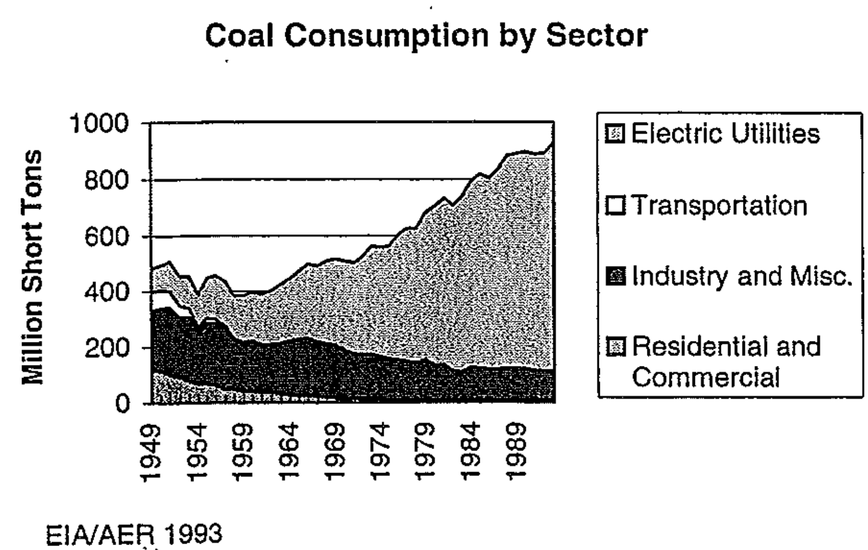


Figure 1: Coal Consumption by Sector

During World War II, civilian-directed power use was limited in growth. After the war, the utilities experienced a period of rapid growth, averaging a doubling of electricity consumption every 10 years.[1] It was during this time that there was a large growth in coal-based generation, making electric utilities the principal users of coal. Utility coal use went from 19 percent of total U.S. coal

[1] Energy Information Administration, Annual Energy Review (EIA/AER), 1993, p. 239.

consumption in 1950 to 61 percent in 1970 (Figure 1).[2] During this period, coal sales to many of the other users, such as the transportation, commercial, and residential sectors, declined. Electric utility growth on the East Coast and in Arizona and California was also fueled with oil, and in the gas-rich regions of the country, such as Texas, Louisiana, and Oklahoma, with natural gas.

Cooperation and coordination were limited by more than technical feasibility because of concerns about ownership of distribution systems and concerns about national policy, such as the creation of a national, publicly owned transmission grid. The Northeast blackout of 1965 demonstrated the need for greater reliability of the grid. The industry responded by creating a system for coordination among various entities and by formalizing the relationship under councils and the umbrella of the North-American (originally National) Electric Reliability Council (NERC).

During these decades, the scale and efficiency of coal-fired technologies improved greatly. This resulted in reductions in the real cost of electricity. From 1960 to 1970, the average price in cents per kwh went from 1.8 to 1.7, or a 6 percent decrease equivalent to a reduction of 30 percent in real terms (Figure 2).[3] The lower price for electricity fueled additional demand, thus increasing the use of coal. By 1970, coal-fired power plants produced approximately 46 percent of the net electrical generation (Figure 3).[4]

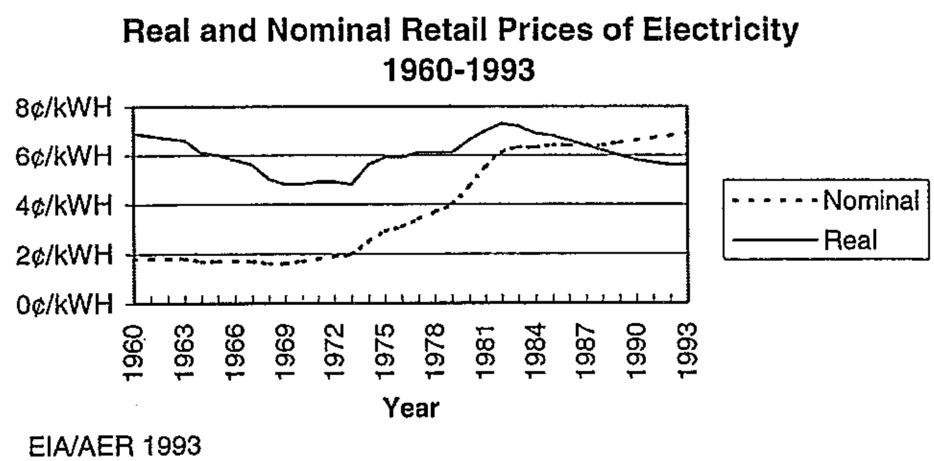
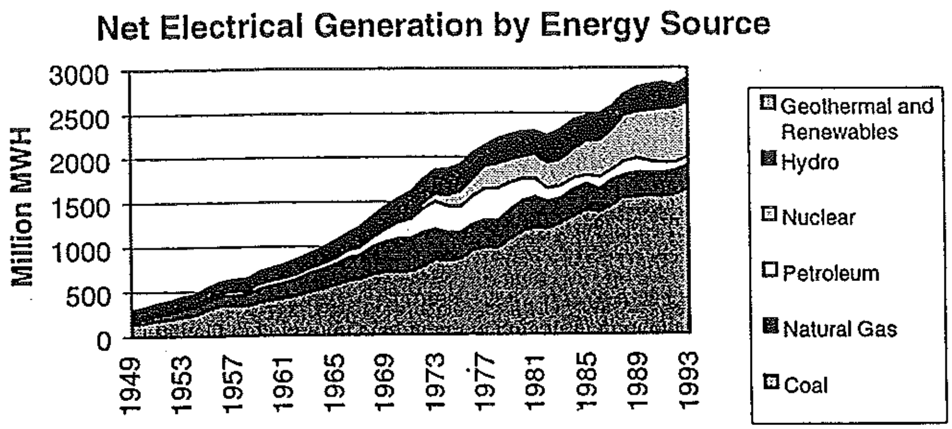


Figure 2: Real and Nominal Retail Prices of Electricity

[2] *Ibid.*, p. 215.
[3] *Ibid.*, p. 249.
[4] *Ibid.*, p. 235.



EIA/AER 1993

Figure 3: Net Electrical Generation by Energy Source

The Crisis Years (1970-1990)

The 1970s brought radical change to the energy industry generally and to the electric utilities specifically. It was a time when long-term trends, such as falling electricity prices, began to change. It was a time when sudden crises, such as the oil embargo, dramatically shifted the way the country perceived energy issues. Electric utilities, the government, and the nation embraced nuclear technology as the response to meet rapidly increasing demand, to avoid the environmental impacts of combustion processes, and to provide fuel security. By the end of the decade, many of these benefits were more than offset by the rising costs of nuclear technology, delays in construction, and unexpected regulatory constraints. Nevertheless, by 1980, nuclear technology provided approximately 9 percent of the industry's capacity and 11 percent of its net generation (Figure 3).[5]

Natural gas and petroleum-fired plants, which were built during the 1960s, stabilized and declined in total output, primarily because of changed perceptions of the availability of these fuels and consequent regulatory or price constraints on their use. The seminal factors were the fivefold increase in Middle Eastern oil prices[6] and the subsequent oil embargo. These traumas caused the nation to think about energy and fuels differently than it had in the past.

[5] *Ibid.*, pp. 233, 243.
[6] *Ibid.*, p. 179.

Conservation of energy, improved efficiency, and avoidance of scarce or unreliable fuels became the policy basis for much subsequent legislative and regulatory action. During the period, many state agencies imposed requirements on utilities to develop and put conservation programs into action that became known as demand side management (DSM) programs. Such programs provided incentives, payments, or subsidies for such things as higher efficiency equipment, insulation to reduce heat loss or gain, free energy audits of premises, and integrated energy system designs. DSM programs were judged on the basis of their savings to utility customers through the utility's deferral of building additional capacity or reductions in the amount of fuel used. Some jurisdictions used more globally oriented tests, which included the value of reductions in emissions from fuel conversion or the value of reduced resource use, such as decreased mining of coal or pumping of oil. Also, programs were instituted for open solicitations to meet additional capacity needs in order to ensure consideration of non-traditional sources of electricity. The Federal Government restricted the use of scarce fuels and for a period of time forbade utilities to build new gas-fired boilers. The Powerplant and Industrial Fuel Use Act of 1978 had as an objective the reduction of electric utility use of gas to zero by 1990.

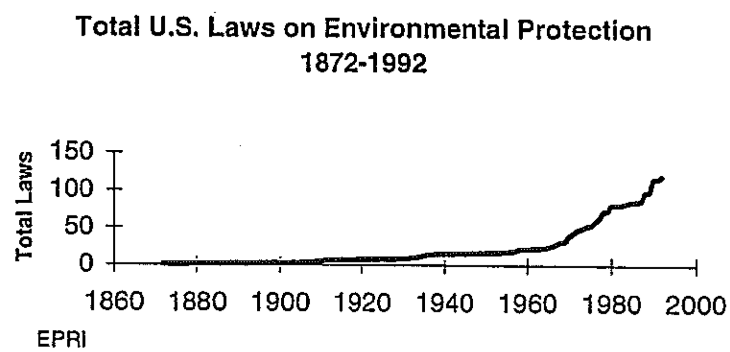


Figure 4: Quantity of Environmental Legislation and Regulation

Another important force changing the trends in utility decision making was the increasing value society placed on environmental improvement. Emotionally ignited by Rachel Carson's *Silent Spring*, published in 1954, and focused by creation of the Environmental Protection Agency (EPA) in 1970, the concern for environmental protection and improvement spawned an exponentially expanding list of legislative and regulatory initiatives (Figure 4). These rules created challenges to traditional utility practices and increased the cost of generating electricity. The capital costs of new coal plants that were required to include substantial additional environmental control equipment were particularly affected. Also, many existing plants had to retrofit improved emissions control equipment to meet new and stricter environmental standards. The cost of operating these new and existing plants increasingly reflected the operating cost of the environmental equipment and the more costly disposal of residuals, such as coal ash or thermal effluents.

Two major trends in the generation of electricity were derived from the energy crises of the 1970s. First, there was a drive to conserve energy resources through promotion of non-utility generation utilizing newer, more efficient technologies. Non-traditional generation based on wind, solar energy, geothermal, refuse/waste derived fuels, and agriculture-based fuels was also promoted. Second, a push to encourage competition in power generation through support of cogeneration and small power producers was begun. At a time when social and environmental agendas required utilities to meet additional rules imposed by regulation, competitors received relatively light regulatory oversight and were favored with special rate treatment.

This philosophical change in attitude toward energy was embodied in federal legislation. The Energy Policy Act of 1978 contained a section labeled the Public Utility Regulatory Policies Act (PURPA) which, among other effects, changed the relationship between utilities and other potential generators. This ushered in an increased role for non-utility generators (NUGs). If capacity were needed, PURPA mandated states to force regulated utilities to buy from alternate suppliers at the utility's avoided cost, which was deemed to include the capital cost of generating equipment as well as operating and maintenance expands (O&M) and fuel costs. This capital cost was often evaluated using a hypothetical future plant. In addition, states were allowed to place a premium value on the use of renewable resources or the high-efficiency conversion of resources to electricity. Utilities could be mandated to buy electricity from these qualifying facilities (QFs) at prices higher than their marginal cost of production. The legality of this premium value is now being questioned both in the courts and in the regulatory arena.

In the same year, the Natural Gas Policy Act of 1978 began to lift federal price controls on wellhead gas. This attempt to introduce free markets and competition into the natural gas markets laid the groundwork for later phases of deregulation and the phased elimination of Fuel Use Act restrictions on natural gas use for electric generation. The Federal Energy Regulatory Commission (FERC) concluded that, as long as pipelines were allowed to provide services as vertically integrated companies, full competitive forces would not drive the industry. FERC Order No. 436 required pipelines to provide transportation on a non-discriminatory and equal basis, and Order No. 636 mandated the unbundling of services provided and restricted pipelines from providing certain of these services. Pipelines were required, on average, to file four to five tariffs before the Commission deemed them to be in full compliance with Order No. 636. This progression shares many similarities with current Commission efforts to deregulate interstate wholesale electric power markets.

The net result of PURPA on the electric sector, after it passed legal challenges in 1983, is that NUGs increasingly were building and putting new generation into service supported by long-term contracts with utilities. By 1990, over half of the annual new electric generating capacity added was from these NUGs, and much of that capacity was gas-fired, of which a substantial fraction was operated in a cogeneration mode. This trend continues today with approximately 70 percent of planned new capacity being owned by NUGs of various sorts.[7]

While the cost of electricity in both nominal and real terms had fallen during most of the history of the industry, this trend was reversed during the 1970s and early 1980s (Figure 2). This was a time when commissions allowed utilities to recoup the past inflationary increases as well as real cost increases, such as escalation in equipment cost. The average price in cents per kwh went from 1.7 in 1970 to 6.4 in 1985. This is a 276 percent nominal increase but only a 42 percent increase in real terms.[8]

Notwithstanding the substantial increase in price for electricity, electricity consumption continued to grow at about the rate of growth of the economy. While slower than the 7 to 8 percent growth of the halcyon period, it was more rapid than total energy consumption (Figure 5). Other fuels were losing market share to fuels converted to electricity. Electricity served an increasing fraction of total energy consumption, from 24 percent in 1970 to 38 percent in 1990.[9] This trend of electricity gaining market share predated this period and has continued for a very long time (Figure 6).[9] This increasing penetration has resulted from the declining relative cost of electricity and the continuing increases in efficiency of electro-technologies.

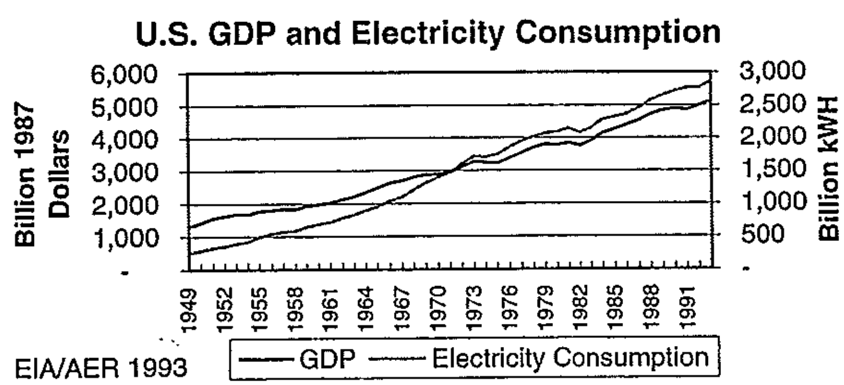


Figure 5: U.S. GDP and Electricity Consumption

[7] Edison Electric Institute, *Electricity Futures, America's Economic Imperative*, 1993.
[8] EIA/AER, 1993, p. 249.
[9] Sam H. Schurr, Burwell, Devine & Sonenblum, *Electricity in the American Economy*, Greenwood Press, 1990.

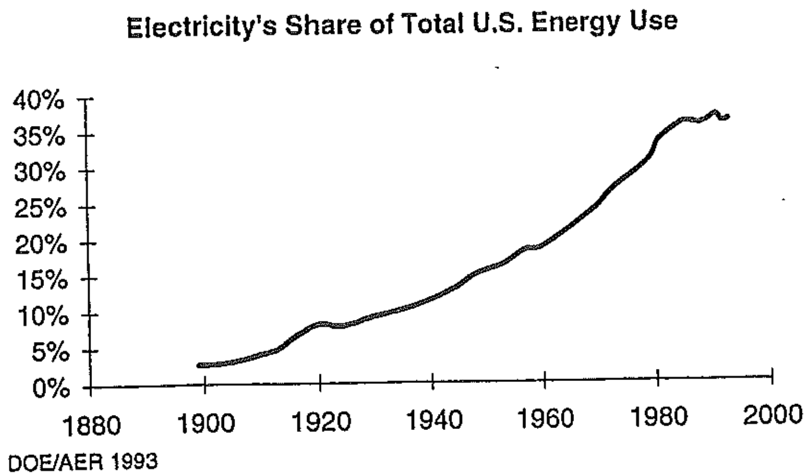


Figure 6: Electricity's Share of Total U.S. Energy Use

Nevertheless, during this period, coal production rose dramatically, from 600 million short tons per year in 1970 to 1 billion tons in 1990.[10] Even though productivity in the progressive underground mines rose dramatically, virtually the entire net increase in coal production came from surface mines (Figure 7). This reflects the closing of the older marginal underground mines and the opening and expansion of new, huge surface mine operations, particularly in the West. At the same time, a growing share of the coal production was used for electricity production.

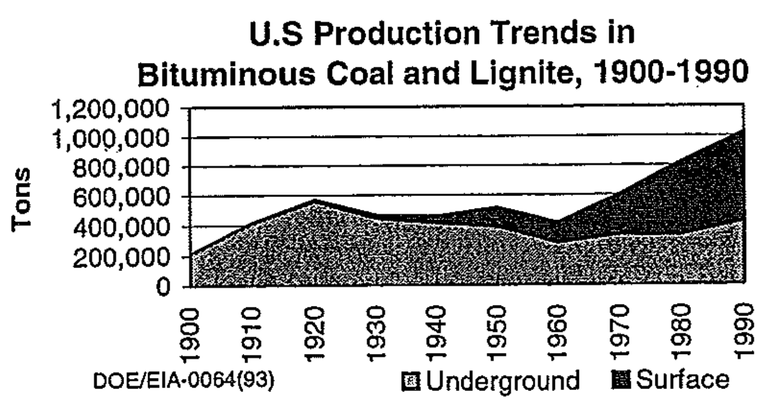


Figure 7: Bituminous Coal and Lignite Production Trends

[10] EIA/AER, 1993, p. 213.

Other uses declined from 203 million short tons per year in 1970 to 122 million tons in 1990 (Figure 1).[11] Clearly, coal's success was entirely related to the growth in electric consumption and coal's increased penetration of the generation market (Figure 3).

The Present (Since 1990)

By the late 1980s, a rethinking of the optimum structure for the electric utility sector began to take place. One initial factor was the concern by environmental activists that existing utility organization and regulation did not provide the right incentives for appropriate environmental stewardship, particularly implementation of conservation technologies. Another factor was regulators' and academics' belief that the cost increases which had occurred during the past decade were caused in part by regulations which created insufficient incentives for utilities to maximize efficiency and minimize costs. Consumer pressure to obtain lower priced electricity also was an important factor.

The traditional paradigm suggested that electricity could best be provided through monopoly service. This avoids the costly duplication of retail service facilities and provides for the efficient planning, implementation, and operation of generation and transmission systems. This paradigm began to change, at least in the generation sector, as academics and policymakers began to think that competition might provide a more effective and efficient model. The United Kingdom, with the breakup of the Central Electric Generating Board (CEGB) in the late 1980s, pioneered this new idea of competition in the electric sector. A number of countries--Australia, Argentina, New Zealand, Columbia, Chile, *et al.*--are following this model.

In the U.S., PURPA created an opportunity for entities other than utilities to build new generating capacity. But direct delivery of electricity to customers was limited to a utility function unless customers provided their own generating facility. Even the sale of NUG-produced energy could be made only to the local utility or to a single customer for whom the NUG facility was built.

With the direction indicated by the National Energy Strategy in 1991, the Energy Policy Act of 1992 (EPAct) directed FERC to allow utility ownership of independent power producers (IPPs) and expanded FERC's authority to order wheeling for wholesale power transactions. While the EPAct facilitates wholesale wheeling, it specifically precludes FERC from ordering retail wheeling, although it does not preclude FERC's agreeing to it. EPAct also instructed the SEC to remove PUHCA's restrictions on U.S. utility ownership of foreign electric utility assets and relaxed PUHCA requirements on a new class of power supplier, the exempt wholesale generator (EWG). An EWG is any owner of generating resources, including utilities, which are exempt from typical regulations.

On March 29, 1995, FERC approved a Notice of Proposed Rule-Making (NOPR) addressing open access for wholesale power transactions and utility stranded cost recovery. This is FERC's attempt to

[11] *Ibid.*, p. 215.

implement the EPAct requirements on access to the utility transmission system. The so-called "Mega NOPR" or "Giga NOPR" proposes that FERC require utilities who own transmission facilities to file open-access wholesale tariffs. Initially, FERC will set rates through generic tariffs based on utilities' FERC Form 1 filings. These tariffs will provide both Network and Point-to-Point services for wholesale customers. Utilities then can modify these tariffs by obtaining FERC approval of their individual open-access tariffs. This parallels FERC action on interstate pipelines under Order No. 436.

Ancillary services comparable to those which a utility provides to itself must be offered by the transmission provider, although the physical connections may be closest to the generator. These services include loss compensation, load following, system protection, energy imbalance, reactive power/voltage control, and scheduling and dispatch services. These services also can be provided by another supplier. There are several definitional issues yet to be clarified under the interpretation of the Giga-NOPR. One of these is what constitutes the demarcation between the transmission and distribution systems. This will define the potential extent of FERC's reach into the electric system and the degree of responsibility held by state regulators. Another of these issues is the definition of wholesale versus retail wheeling. Wheeling, or the transmission of electricity from one point to another point, can be differentiated by type of seller at the initiating end or buyer at the receiving end, and by the type of ancillary services provided. Retail wheeling is the transmission of electricity purchased directly by that customer from a supplier other than the local utility.

The issue of how to compensate for the stranded costs some utilities will be faced with also remains unresolved. Such costs can come from utility plants, at the current accounting value on the books, which are no longer economically competitive; or they can be costs incurred earlier by a utility but deferred for later recoupment by commission order (called a regulatory asset); or they might be contractual obligations (such as power purchase contracts) which are no longer competitive. FERC is proposing stringent criteria for establishing "legitimate and verifiable" costs as stranded. For example, were a wholesale buyer to terminate its contract with a utility to buy power, leaving the utility with unneeded generating assets, FERC will demand proof that the utility had a reasonable expectation that such a contract would not be canceled. FERC has implied that the same sort of stringent definition should be applied to stranded costs relating to retail services.

In summary, FERC is maintaining a position with respect to wholesale electric wheeling consistent with its deregulation of the natural gas industry. Its sensitivity to "market power" issues and insistence on comparability tests for tariffs demonstrate its awareness of the means by which utilities might attempt to mediate or slow the effects of deregulation. As of this writing, FERC has yet to make final determinations on the specific rules to be imposed. There is general consensus that wholesale wheeling will be mandated, and some measures will be taken to ease the transition. Meanwhile, some states are taking independent action to initiate competition in their electric sector and may do so before FERC puts its proposed rules into effect.

As required by law, FERC must provide an Environmental Impact Statement predicting the effect of the new rules. FERC staff have been so directed, and they suggest that the proposed rules may cause such changes as:

- In the near term, changes in dispatch and operation of generators. Some regions may experience changes in fuel use, which would have both economic and environmental consequences.
- In the long term, a different pattern of newly constructed generating plants and transmission lines.

Some utility analysts question the impact of FERC's ruling on the grounds that it is limited to wholesale transactions. As long as utilities control local distribution, they say, the impact of wholesale wheeling can be diluted. This assumes that wholesale transactions take place largely between utilities, depriving the industrial customers, deregulation's strongest advocates, of immediate maximum benefit. However, this limitation could be circumvented in three ways:

1. Municipalities qualify as wholesale power purchasers and therefore gain access to the grid under FERC's plan. Municipalization could be given new impetus as communities recognize their interests in attracting new businesses through access to competitive power costs. Recently, a spokesperson for General Motors applauded West Valley City, Utah, for creating a municipal to serve an industrial park. The Wing Group of Woodlands, Texas, is earning fees for devising and setting up municipal utilities in upstate New York. However, FERC's requirement that such newly created municipals pay stranded cost exit fees has provided some disincentive for this strategy.
2. Power generators also qualify for access to the grid. This could push groups of industries in a centralized area to support some level of self-generation in order to escape high local electric rates.
3. Just as small businesses can support levels of internal services previously obtainable only in large, highly centralized companies, advances in information technologies will lower the hurdles for providers of ancillary services. FERC is facilitating this process through its pursuit of real-time information networks or electronic bulletin boards as a means of promoting wholesale energy transactions under open-access tariffs.

Market Forces

Regulatory and legislative forces alone cannot account for all of the movement toward deregulation. In today's utility environment, market-driven factors like the improved efficiencies of electric power generation technologies, such as combined-cycle/combustion turbine (CC/CT) units, continue to have a significant impact on an increasingly competitive generation market.

These CC/CTs produce steam that can be used to drive conventional steam turbines, provide process steam for a manufacturer, or supply space heating needs. In each of these configurations, the improved thermodynamic efficiencies available through such synergistic combinations achieve much more cost-effective energy use. The many applications for such technologies have driven utilities, IPPs, and manufacturers seriously to consider acquisition of or conversion to such facilities. Declining capital costs and higher efficiencies (lower heat rates) available with this equipment have made it feasible for IPPs to build increasingly competitive CC/CTs in any part of the country and offer electricity to neighboring utilities. Further ensuring the economic viability of the IPPs are their historically lower financing costs when compared to a utility. This is because many utilities must pay higher property tax rates, do not qualify for economic incentives provided by state or local agencies, are not allowed to benefit from leveraged financing beyond their capital structure, and may have to pay special "utility taxes" on revenue. Also, utilities are obligated now to buy IPP-generated power under PURPA regulations. (However, one should recognize that, until now, utilities have had a largely captive market for the output of their generators.) Declining capital costs and improved efficiencies have also played a key role in the rise of cogeneration as large customers have found self-generation a more feasible option.

Other major market forces likely to affect electricity markets include information technology improvements, which can now be applied to trading markets. This implies that buying and selling of power for the next hour or day, as is done currently among utilities, can be expanded to include many players. In addition, it is likely that a full futures market, similar to the existing markets for many commodities, including natural gas, will be created to meet the needs of both buyers and producers of electricity. Even now, such markets are being created. In some cases, this market is the expansion of existing reliability organization functions; in others, the markets are being created by other organizations, such as financial or trading companies.

With retail wheeling, there will be access to power from almost anywhere in the country. Qualifying customers will have more choice in selecting suppliers, and utilities will be able to market to a much broader range of customers. One implication associated with this expansion of choices is that franchises may become less relevant. This would further drive changes in the way electricity is supplied.

Current Outcomes of These Changes

As of mid-95, the changes permitted by PURPA and EPAct 92 in the traditional way of supplying electricity, and the changes in technologies available, have had a substantial impact:

- About 70 percent of new capacity is being built by NUGs.[7]
- On average, when utilities solicit bids for new capacity, they receive 11 MW offered for every 1 MW needed.[12]
- Exempt wholesale generators (that is, exempt from state regulations) may file for recognition by FERC. To date, 238 have filed, 185 have been approved, 18 have been denied, and 20 have been withdrawn. (Many of these are subsidiaries of traditional utility companies, including some from overseas.)[13]
- Marketers of electricity (that is, brokers between wholesalers) may file for recognition under FERC; 111 have applied, 87 have been approved. In the first quarter of 1995, the volume of such marketer transactions amounted to 2.4 million MWH purchased and 2.7 million MWH sold. (For purposes of comparison, total U.S. electricity generated in the first quarter was 728 million MWH. Therefore, the marketers' share was on the order of 0.4 percent.[14])
- Twenty utilities have filed voluntary open access tariffs; 19 cases were ordered to file (for example, as a condition of merger approval), of which 11 have had orders issued, and one case was withdrawn.[15]

Because oversight of local service is vested in the state commissions, Congress in EPAct specifically relegated to the states the responsibility for affecting retail wheeling. Retail wheeling would mandate access to the transmission system by individual customers, thereby giving these customers the right to buy from any generator they desire. Most states have considered the matter, but few have taken action to date.

In the first half of 1995, bills addressing retail wheeling or related issues have been introduced in 13 state legislatures. While no state has passed a bill requiring retail wheeling, a number have passed bills requiring study of the subject or establishing or clarifying the authority of the state commission on such matters. Regulators in 23 states have initiated or completed processes addressing retail

[12] Edison Electric Institute, *Current Competition*, Vol. 5, No. 8.
[13] EEI Regulatory Research Service, private communication.
[14] Monthly Energy Review, August 95.
[15] EEI Regulatory Research Service, private communication.

wheeling or related issues. All but a dozen states have had or are having some form of activity related to retail wheeling.

It is important to note that, as of mid-1995, no state has put retail wheeling requirements into effect. Closest are Michigan, which has ordered each of the two largest utilities in the state to provide a retail wheeling experiment, and Massachusetts, which has ordered its utilities to file retail wheeling plans in the near future. The Michigan administrative law judge set rates, terms, and conditions on February 21, 1995, and a Public Service Commission (PSC) decision is expected soon. An appeal by Detroit Edison to the U.S. District Court was dismissed without prejudice to allow the complaint to be refiled at a later date.

Regulators in California have progressed to the stage of a proposal to form a wholesale pool (or POOLCO) to begin January 1, 1997. This would be a transitional structure leading, if certain conditions are met, to retail wheeling after January 1999. Retail wheeling would be allowed at first only to the very largest customers, but it would be expanded over time to include all customers.

In response to these implemented or impending changes, many utilities have gone through critical re-examinations of their structures and operations with an eye toward improving their long-term viability. As a result, there have been a number of mergers among small to medium-sized utilities. A number of utilities have changed their structural form, for example, separating generation and/or transmission from the distribution function. Even more prevalent are attempts to streamline, increase efficiency, and reduce costs by re-engineering, downsizing, spinning-off, or out-sourcing, or through operations redesign.

The number of mergers and acquisitions among substantial electric utilities is particularly indicative of the trend to restructure to be better able to meet the future. In the decades of the 1960s and 1970s, only a very few utility mergers or acquisitions took place. In the last ten years, 36 such events have been announced. Of these 36, 19 have been consummated, 8 are pending, and 9 were not completed. Fourteen of the 36 were hostile offers, three of which were consummated in whole or in part, and one remains pending as to outcome (Table 2). Some utilities are changing from their traditional organizational design. Utilicorp and Pacificorp, for example, have acquired non-contiguous utilities, one basing its decision on the synergies to be gained through diversity of territories, the other on a transmission tie and diversity of demand. The recently announced merger of Public Service of Colorado and Southwestern Public Service involves non-contiguous territories and crosses NERC reliability regions, as does the announced Northern States Power and Wisconsin Electric merger. The Puget Sound P&L and Washington Energy merger is unusual because it is one of the rare mergers of an electric utility with a gas utility to form a combination utility. There have been a number of mergers in which a combination utility merged with an all-electric or all-gas or another combination utility, but the formation of a new combination utility is unique.

Table 2: Electric Utility Mergers and Acquisitions Since 1985

	Companies				
Announced	A	B	Resulting	Hostile?	Status
6/85	Cleveland El. Il.	Toledo Ed.	Centerior	-	Complete
8/87	PacifiCorp.	Utah P&L	PacifiCorp.	Yes	Complete
11/87	Southern Co.	Savannah E&P	Southern Co.	-	Complete
6/88	San Diego G&E	Tucson EP	-	Yes	Terminate
7/88	So. Ca. Ed.	San Diego G&E	-	Yes	Terminate
3/89	WP&L	Madison G&E	WP&L	Yes	Terminate
3/89	UNITIL	Fitchburg G&E	UNITIL	-	Complete
4/89	E. Ut. Assoc.	UNITIL	East Ut. A	Yes	Terminate
4/89	E. Ut. Assoc.	Fitchburg G&E	East Ut. A	Yes	Terminate
6/89	E. Ut. Assoc.	Newport Elect.	East Ut. A	Yes	Complete
?/89	PacifiCorp	Pinnacle West		Yes	Sold Assets
1/90	NEU	PSNH	NEU	Yes	Complete
2/90	NEES	PSNH	NEES	Yes	Terminate
3/90	Midwest Energy	Ia. Resources	Midwest Res	-	Complete
4/90	Union Elect	Ark. P&L (Mo Prop.)	Union Elect	-	Complete
7/90	KC P&L	K G&E	KCP&L	Yes	Terminate
10/90	K P&L	KG&E	KP&L	white knight	Complete
12/90	UtiliCorp	Centel (Elect)	UtiliCorp	-	Complete
2/91	IE Ind	IS Ind	IES Ind	-	Complete
1/92	IES Ind	Union Elect (IA Prop)	IES Ind	-	Complete
1/92	CIPS Co.	Union Elect. (IL Prop)	CIPS Co.	-	Complete
6/92	Entergy	Gulf States	Entergy	-	Complete
12/92	PSI	CG&E	CINergy	-	Complete
3/93	IPALCo	PSI	IPALCo	Yes	Terminate
≈ 93?	NEES	Nantucket	NEES	?	?
5/93	C&SW	El Paso	C&SW	Yes	Terminate
5/94	Delmarva	Conowingo	Delmarva	-	Complete
6/94	Wash. Water P	Sierra Pacific	Resources W.	-	Pending
7/94	Mid Res	IIG&E	MidAmerican	-	Complete
5/95	NSP	WE	Primergy	-	Pending
8/95	UE	CIPS Co.	TBD	-	Pending
8/95	PE Co	PP&L	PE Co	Yes	Pending

Table 2: Electric Utility Mergers and Acquisitions Since 1985 (Continued)

	Companies				
Announced	**A**	**B**	**Resulting**	**Hostile?**	**Status**
8/95	PS Co of CO	SW PS Co	TBD	-	Pending
9/95	Baltimore G&E	Potomac EP	Chesapeake Power	-	Pending
10/95	Puget Snd P&L	Washington Energy	TBD	-	Pending
11/95	IES Ind. | WP&L | Interstate Power		Interstate Energy Corp.	-	Pending
8/95	PS Co of CO	SW PS Co	TBD	-	Pending
9/95	Baltimore G&E	Potomac EP	Chesapeake Power	-	Pending
10/95	Puget Snd P&L	Washington Energy	TBD	-	Pending
11/95	IES Ind. | WP&L | Interstate Power		Interstate Energy Corp.	-	Pending

Finally, a number of utilities have reached outside the U.S. market to achieve a measure of balance against domestic uncertainties and to capture some of the perceived opportunities from the overseas privatization of utilities. Many U.S. utilities have been active in acquiring utility properties in such countries as Argentina, Chile, Peru, Australia, New Zealand, Great Britain, and the Eastern European states.

The Drive to Deregulate Continues

The drive to deregulate has produced profound changes in the natural gas, shipping, telecommunications, and airline industries. Many comfortable assumptions have dissolved because deregulation has challenged companies to re-invent themselves. Previously healthy companies have been forced to struggle for survival in competition with new entrants. For some previously regulated companies, reorganization through bankruptcy was necessary; for others, going out of business was the outcome; for still others, growth and success resulted. New players have grown to challenge the previously undisputed market dominance of companies accustomed to operating under the protection afforded by rate-of-return regulation.

Many major industrial customers of electric utilities are leading the charge to deregulate the electric utility business. These customers have experienced major cost savings from virtually every deregulated industry with which they do business. They also remember each of those industries' initial insistence that deregulation would wreak economic havoc by destroying the efficiencies they enjoyed from the scale and vertical integration of their businesses. They believe firmly that the rigors of competition will drive down electric energy costs and more than offset any of the risks forecast by cautious electric utilities.

Many factors relating to changes in the business world are reinforcing the drive to deregulate. Some of these factors are:

- General change in business focus from mass production to choice;
- Breakdown of vertically integrated business structures into networked, horizontally integrated businesses;
- Expanding international competition and the need for the U.S. to compete for industries with countries undergoing utility deregulation;
- Increasing acceptance of the idea that free-market competition acts in society's general best interests; and
- A turning away from government regulation.

To some observers, the fact that deregulation in other sectors, such as natural gas, airlines, and telecommunications, fits so well into current business trends makes it obvious that similar deregulation is inevitable for the electricity sector. Conversely, the management of some utilities has been characterized as limited by their own depth of understanding of the current complex regulated monopoly structure; hence, they are unable to imagine the large-scale changes ahead. Certainly, there are difficult issues to resolve, such as recovery of stranded assets, protection of customers with no options, and assuring that market dominance does not lead to abuses. There is general consensus, however, that may make it possible for us to draw some conclusions regarding possible effects of deregulation on coal markets.

The one point upon which there is general agreement is that generation is the segment where deregulation has begun and is expected to proceed most rapidly. Because generation most directly affects coal producers, coal markets will experience changes related to changes in these structures. An understanding of these changes can be posited from an examination of utilities' structural evolution and generalizations drawn from recent restructurings in deregulated industries. Coal producers' basic question can be framed as: "How will deregulation affect how utilities do business?" Utilities will change the manner in which they make business decisions.

The nature and importance of a utility's relationship with its fuel suppliers and transporters may change. The consolidation that has occurred in the rail sector has driven producer and utility concerns that railroads' increased market power may force transportation costs upward. However, as the mutual value of the utility's success in competitive markets and the interdependence of the supplier-user relationships become apparent, it may well be that strategic alliances and partnerships will lead to greater success for all three participants.

PART 3
Implications for Utilities

Choosing the Structure

To assess the implications that re-structuring of the industry will have on coal markets, a prospective view of the electric utility industry is needed. With a re-focused cost perspective and an increasing awareness of the importance of the customer, the individual utility must decide between two basic strategic directions: the traditional utility structure or the de-integration of the utility into a distributor and generator of power. In the de-integration strategy, the distributor would remain regulated to some degree and would maintain operation of the transmission and distribution assets. Any power requirements would be purchased from the bulk power market. The generation portion of the utility would "spin" off into a separate generation division. The generator would then compete in the bulk power market with other generators. If a utility chooses to remain fully integrated, it will be necessary to heighten its focus on costs (for in a competitive environment, utilities that choose this strategy will survive only if their cost structure remains competitive). Both general strategies, however, must account for the characteristics of various market mechanisms, such as open access to the transmission system.

Establishing the strategic direction of the utility defines the philosophical boundaries for the utility, but it does not answer how the strategy ought to be implemented. In the de-integrated structure, the interrelationships among the three market segments (that is, generation, transmission, and distribution) must be clearly understood and defined in order for this particular structure to be operational.

In the de-integrated structure, the generation market will consist of generation companies, or what have been referred to as GENCOs. These GENCOs will provide generation services at the wholesale level into the transmission grid on an open-access basis. The transmission services that are supported by the transmission grid will be controlled by TRANSCOs. (The term TRANSCO is sometimes used to denote the entity providing the transmission function, but it usually includes the pool operation services defined separately in this report as POOLCO. See below.) The TRANSCOs will then provide power to the distribution-based utilities, or what have been referred to as DISCOs. These DISCOs will then provide power, or energy services, to the customer. It is unclear whether DISCOs would be regulated. One alternative supplier of these functions could be energy services companies, sometimes referred to as ESCOs.

The POOLCO enters into the market by coordinating the sellers of power (or the GENCOs) with the buyers of power (or the DISCOs) by utilizing the transmission services of the TRANSCOs. The POOLCO essentially will determine the demand needed to meet the requirements of its customers and compare that demand to the available generation power. The generation resources will be dispatched in the least-cost manner. The price signal sent to the customer will be driven by the interrelationship between the demand for power and its cost of production. The POOLCO operates as a stock market or clearinghouse for electric power, with the added responsibility of ensuring that transactions are viable from a system reliability perspective.

Alternative structures can vary from the example discussed above. For example, a utility could consist of a GENCO and a DISCO/TRANSCO, where bilateral contracts and an open-access transmission system would replace the services of a POOLCO. Because there can be any number of alternative structures, there will be an equal number of unique planning processes and financial structures as integrated utilities divide operations among the various market segments.

The National Coal Council envisions an electricity sector in which generation facility owners will compete actively for supply contracts with all other marketers of electricity. Some owners will be former traditional utilities; others, today's IPPs; still others, new marketers of capacity and energy. In the longer term, facilities which can compete successfully in this type of market will be built. They will be owned and their output marketed by those seeing opportunity for profitable return on investments in this new unregulated, competitive environment.

Short-Term Implications for the Electric Industry

While there can be a variety of structures which will vary by utility, there does appear to be a clear indication that restructuring of the electric utility industry will generally break into generators, transmitters, and distributors. There are those who believe that the unbundling of these functions may not be necessary and would not be desirable. Nevertheless, there will be a need to provide access to transmission systems on a non-discriminatory basis, facilitating competitive opportunities for non-utility generators. Given that restructuring is "on its way," the question remains: "Will this restructuring impact the demand for coal in the short term?"

The lowest marginal cost electric generating facilities are likely to be dispatched at their highest capability. Existing plants with low marginal costs are already base loaded and, therefore, are likely to have limited additional generating capability. Many coal plants are in this first group of low-cost plants. The next tier of plants, however, also have many coal-fired units. These remaining coal plants, which operate at modest or low-capacity factors, have the greatest potential for increased coal-fired generation. However, these are plants with higher costs because of lower efficiency (high heat rates), high O&M costs, or high cost fuel contracts. Only by reducing these costs are we likely to see these plants utilized more intensively. Some high-cost coal plants may now have high utilization because of contractual take-or-pay provisions on their fuel supply. These plants will be a problem for their owners in the new environment unless the costs of production can be made competitive.

Most of these higher-cost plants are older, but as Figure 8 shows, 50 percent of the steam boiler capacity is less than 25 years old, and almost none predates the 1950s. Under this new competitive operating regime, strategies are likely to evolve by owners of non-competitive facilities to minimize losses that otherwise would occur. For example, all owners of generating facilities would like to cover all variable and fixed costs, or what can be termed total costs. If the output of a unit would not be priced competitively at total cost, then reducing the price to cover all variable costs plus some of the fixed costs is a better strategy than selling none of the output. It may be that a number of players using fuels other than coal will be willing to sell closer to their marginal costs than coal plant operators. If so, coal could lose some market share. On the other hand, were coal operators better able to use this strategy because coal costs less than other fuels, coal producers could gain market share against other fuels.

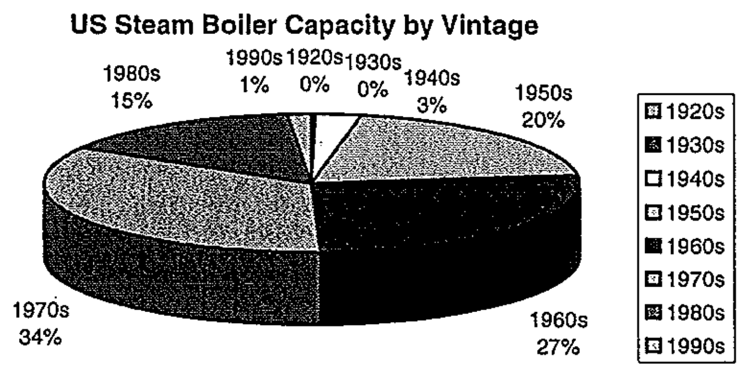


Figure 8: U.S. Steam Boiler Electrical Capacity by Vintage

Figure 9, with the data summarized in Table 3, shows the average variable costs for the average of utility units fueled by coal, nuclear, oil-gas, or other. This can be viewed as the minimum price for electricity at which all of the variable but none of the fixed costs would be covered. As with any statistic, care must be taken in interpreting the results. The average is more weighted by high-capacity factor units because they generate more KWHs in the equation. Moreover, there tends to be a good deal of dispersion around the mean, particularly on the side of higher-cost units. Nevertheless, the data in Figure 9 show that coal plants are low cost on average and, therefore, are likely to benefit in competition for market share of electricity output.

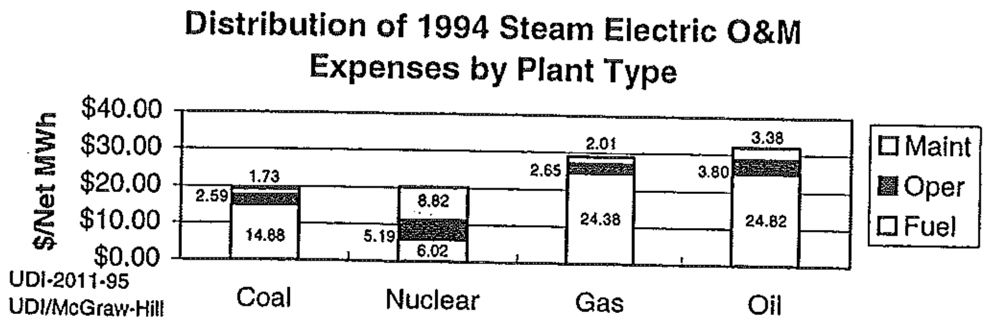


Figure 9: Distribution of 1994 Steam Electric O&M Expenses by Plant Type

Table 3: Average Variable Production Costs (Including Fuel) for U.S. Steam Electric Plants

FUEL	1993 ($/MWH)
Coal	$19.67
Gas	$34.02
Nuclear	$21.52
Oil	$34.08
Other	$29.13

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Another possible effect is derived from the probable reduction in cost of electricity. From what has been written above, it is likely that the generation of electricity will be less costly than from a fully regulated industry, whether because of more efficient operation or because of write-offs of non-competitive assets. Lower prices should result in higher consumption of electricity and, therefore, possible increases in use of all fuels.

Because there are varying amounts of reserve margin overhanging the market in different regions, (Table 4), the change from what would have been under previous structures is dependent upon transmission costs and available capacity. However, it should be noted that capacity utilization for coal plants now averages only 62 percent (Table 5). Capacity factors for coal plants certainly have room to increase. To increase, however, there will have to be either an increase in peak loads or a change in dispatch resulting from competitive pressures. It is not clear whether other units, especially those currently dispatched independent of economic dispatch priority, can be cycled to accommodate this change. Many nuclear plants and cogeneration facilities currently fall into this category.

Table 4: Reserve Margins by NERC Region

NERC Region	Summer Reserve Margin (MW)	% of Total Cap.	Winter Reserve Margin (MW)	% of Total Cap.
ECAR	15,285	13%	23,949	20%
ERCOT	8,457	16%	16,879	32%
MAIN	7,882	16%	16,588	32%
MACC	5,508	11%	13,512	25%
MAPP	3,872	13%	8,780	28%
NPCC	5,047	10%	10,236	19%
SERC	15,549	10%	19,465	13%
SPP	12,085	18%	25,865	38%
WSCC	22,374	16%	36,168	26%

RDI per 1994 FERC Form 411 IRP filings for 1995.

Table 5: Current Coal-Fired and Nuclear Plant Capacity Factors

Current Average Nuclear Capacity Factor

$$\frac{610{,}300 \text{ million kWh Generated per year}}{(99.1 \text{ million kW})(8{,}760 \text{ hrs per year})} = 70.3\%$$

Source: EIA/AER 1993

Current Average Capacity Factor for Plants Using Coal as a Primary Fuel

$$\frac{1{,}639 \text{ million kWh Generated per year}}{(301.9 \text{ million kW})(8{,}760 \text{ hrs per year})} = 61.9\%$$

Source: RDI

Note: Capacity shown is demonstrated summer capacity. If unavailable, nameplate rating was used. Data exclude petroleum coke.

Mid to Long-Term Implications for the Electric Industry

For all of the predicted changes in utility structures under deregulation, there is one common characteristic: In the re-structured industry, power plants require fuel, regardless of whether the plants are owned by a fully integrated utility or by a separate GENCO. Thus, the general effects on coal producers and marketers will be driven by coal's ability to compete against natural gas as the fuel of choice.

Figure 10 illustrates the effect of deregulation on the entire electric utility industry where existing capacity and the capacity from new resources can be owned by a variety of owners ranging from utilities to IPPs. It shows that demand for electricity is likely to grow over time. DSM will reduce the amount of generation needed to meet this "gross demand" growth. The residual total "net demand" will be met in part by cogeneration or other types of customer-dedicated facilities. Nevertheless, there is likely to be a need for new generation facilities because of growth in demand and retirement of existing facilities because of their age or high costs. This need is shown in Figure 10 as "New Generation." It is likely to be large if the lives of nuclear plants are not extended, the amount of good cogeneration opportunities is limited, or the development of dispersed technologies is not rapid.

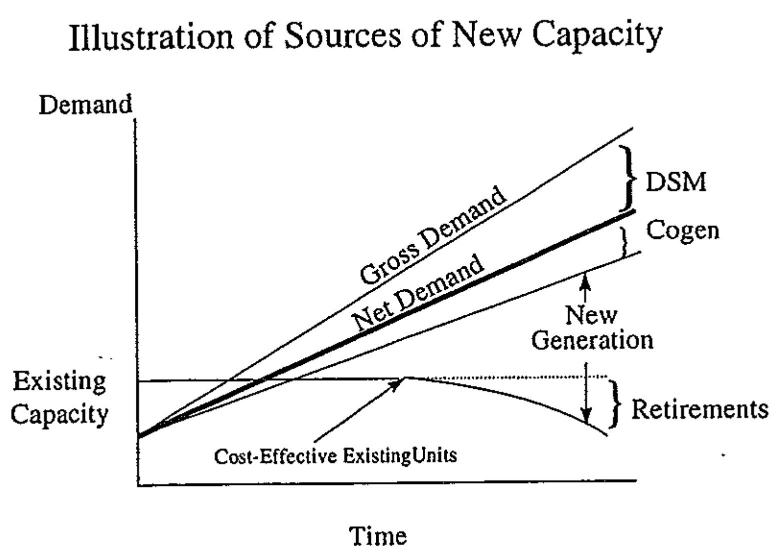

Figure 10: New Capacity Sources

Whether new coal-fired plants can meet this need depends upon a number of factors:

- The penetration of cogeneration (mostly natural gas-fired self-generation);
- The use of targeted resources that are designed to reduce demand and to provide generation for specific areas primarily for distribution purposes;
- The penetration of natural gas-fired generation options (such as CC/CT technologies) which will be driven by the ability of coal-fired technologies to compete against natural gas-fired technologies;
- The cost-effectiveness of renewable options;
- The ability of existing coal plants to compete in the re-structured environment;
- The ability of new and existing coal-fired facilities to compete in the bulk power market; and
- The ability of coal producers, marketers, and coal consumers to be more flexible than they have been in the past in order to reduce the resulting cost of coal.

Because coal markets are intimately tied to power generators, other segments of the electric utility business are largely incidental to the discussion. Their relevance is in the indirect effects they have on generation economics. The major change of focus for system planners and power dispatchers will be their turning away from generation assets within their service territory to consider the myriad of options produced from open access to wholesale energy. Moreover, regulators may be more insistent that transmission and distribution systems facilitate system interconnections to increase generation competition, or market forces may push the issue in the same direction.

Under this scenario, power plants with high-cost fuel contracts may be "orphaned." Without a fuel pass-through, utilities will be forced to choose between contract buy-outs or a longer-term drain directly affecting the bottom line. If collection of some transition costs of coal contract re-negotiations is allowed, there will be a strong incentive to attempt buy-outs of high-cost contracts. Even without such regulatory assurance, there may be a mutual interest in a plant's continuing operations. In some cases, high-priced fuel contracts may be traded for equity interests in power plants. With rate of return regulation removed, coal producers could meet their corporate investment criteria by participating in creating more competitive generating stations.

Although high-value cost-plus fuel contracts may have protected high-cost coal mining operations in the past, tremendous pressure to be cost-competitive will result from deregulation. Coal companies will fight to supply fuel to aging power plants. Each coal company's growth will come from increasing underutilized power plants' capacity factors, finding low-margin spot coal opportunities, and transferring market share from their less efficient competitors.

Coal companies should have highly motivated partners in fighting for these more competitive markets: the railroads and barge companies. Transporters will have to be sensitive to competitive sources of fuel for generation, such as new gas-fired generation or opportunities to switch existing facilities to other fuels.

Currently, very little new generation is forecast to be coal-fired. The inherent uncertainty in a market undergoing the sort of sea change described will discourage long-term capital investment in coal-fired plants and favor lower capital cost gas-fired combustion turbines in combined cycle and non-condensing cogeneration configurations. The only brake on this trend would come from rapidly escalating gas prices or the perception of future price escalation. Considering recent history and the current competitive pressures within the natural gas industry, a rapid run up in gas prices is by no means certain.

Because CC/CT technologies are 40 percent less than the installed per unit capital costs and generation efficiencies (measured by heat rates), at least 30 percent higher than pulverized coal (PC) units, new coal units[16] have a lot to overcome to become competitive with gas. However, more current data indicate that PC capital costs may be declining in response to this competition. Anecdotal information implies that the costs of both technologies have declined substantially and that CC/CT technologies now cost 60 percent less than the historical cost of PC units. There are claims that heat rates of new designs of CC/CT units will be more than 40 percent better than conventional PC heat rates.

Atmospheric fluidized beds (AFB) are currently competitive with PC units with sulfur removal equipment, although recent initiatives involving scrubbed supercritical PC units may raise the bar for AFB boiler manufacturers. Pressurized fluidized bed (PFB) boilers may offer some hope of improved economics, assuming their hot gas clean-up cycles are proven. Integrated gasification combined cycle (IGCC) technology also has some promise, but it carries high capital and O&M overhead to convert coal feed to a lower heat-value form of the fuel supplied directly by the interstate gas pipelines. Some estimates have shown this complex technology may have capital costs competitive with new pulverized coal on a dollar-per-kilowatt-of-capacity basis. Because of the efficiency advantages of combined cycle technology, integrated gasification could prove to be the most competitive coal using technology for generation of electricity. One view of the future of coal technologies is summarized in an article from *Coal Trans International*.[17] Another view believes that a coal-biomass mix for gasification could be advantageous.[18] Additional R&D could lower the costs of such coal using technologies, but the time needed to convert ideas through R&D to commercial technologies is long.

[16] EPRI, Technical Assessment Guide (EPRI/TAG), June 1993, pp. 8-7, 8-8.
[17] "Coal with CGT: in Front on Cost and Cleanliness," *Coal Trans International*, September/October 1995, pp. 62-67. This article concludes that CC/CT technology fueled with natural gas is now the low-cost alternative for generating electricity. A developing technology using an air-blown gasifier could compete were gas prices to increase by 15 percent; PFBC technology could compete with gas prices 40 percent higher; and IGCC and AFB with gas prices 50 percent higher. Gas prices would have to increase by 70 percent before PCs would be competitive.
[18] Alex Green *et al.*, "Cogasification of Domestic Fuels," *FACT ASME 1995*, forthcoming.

Key Long-Term Uncertainties

There are five uncertainties that represent a major risk to coal users. The first uncertainty is new environmental legislation or additional regulations based on present legislation. For example, a carbon tax, increasingly stringent air toxic legislation, or environmentally based restrictions on mine operations could lessen coal's ability to compete with alternative fuels. Of special importance to the outlook for coal use is the Phase II implementation of the 1990 Clean Air Act Amendments, which is due in the year 2000. Also, low NOx emission limits promulgated either under ozone transport regulations or as a part of FERC's resolution of Giga-NOPR issues could force the use of Selective Catalytic Reduction (SCR) technology. Some believe that such limits, if not extremely low, could be met by improved combustion technology. Because these factors directly affect the cost of coal-fired generation, producers' sensitivity would be heightened under competitive deregulation of generation.

The second uncertainty is related to the emergence of new and increasingly cost-effective technologies, not only for coal using technologies, but also for others, such as gas and renewable fuels-related technologies. This trend has already exerted a profound influence on the industry. In fact, it can be argued that the biggest boost to the competitiveness of IPPs came not from the enactment of PURPA, but from the declining costs and rising efficiencies of CC/CTs. The big question is whether this trend will continue, particularly whether improvements in coal using technologies will be faster or slower than improvements in other technologies.

A third uncertainty concerns the opportunity for coal producers related to the closing of the nation's nuclear power plants. Depending on their treatment by regulators, nuclear plants subjected to competitive market pressures may face shutdown or conversion. A large shift away from nuclear power, with or without significant new growth in electric demand, may strain electricity supplies to an unprecedented degree. This could drive up gas pricing and make new coal-fired generation the least-cost alternative. This issue becomes especially critical after 2010 when most existing nuclear plant licenses expire.

A fourth uncertainty is the price of the primary competitive fuel, natural gas. While the supply currently is perceived as sufficient to fuel much of the increased generation need in the short term, external forces may affect the gas role in the long run. A legislative restriction has happened before. Unfavorable results in exploratory drilling against a backdrop of rising use could cause the price to escalate. In the longer term, increased demand for gas, displacing oil demand, may drive gas prices upward. Oil production has peaked in the U.S. and is expected to peak worldwide in five or ten years. If this happens, gas prices are likely to be driven toward parity with oil pricing. Similarly, successful deployment of a gas or electric low emissions vehicle could put upward pressure on gas prices. Finally, some regions of the country have limited excess gas transmission capacity. Additional demand will require additional investment in pipelines and infrastructure, driving up gas transportation costs.

A fifth uncertainty is the amount of transmission capacity that will be available to wheel electricity from areas of low-cost generation to regions with high-cost generation. Also, there is uncertainty as to whether additional transmission capacity can be built if there is a need. In the last two decades, many transmissions projects have suffered from public opposition or have had difficulties meeting environmental requirements. If transmission becomes a constraint, it will limit opportunities for low-cost coal plants to increase production.

PART 4
Implications for Coal Markets

Basis for Comparison

In June 1990, the National Coal Council published *The Long Range Role of Coal in the Future Energy Strategy of the United States.* The analysis for this report used three scenarios to band the projection of coal use over the next 60 years. All of these scenarios concluded that coal production would grow throughout the period (Figure 11). These base levels reflected a number of prospective changes in the world in which coal is to be used. These changes included tightening environmental regulations, slowing economic activity, availability of new coal use technologies, and projected worldwide political stability. The projections did not envision the possible significant institutional change discussed in the prior section of this report.

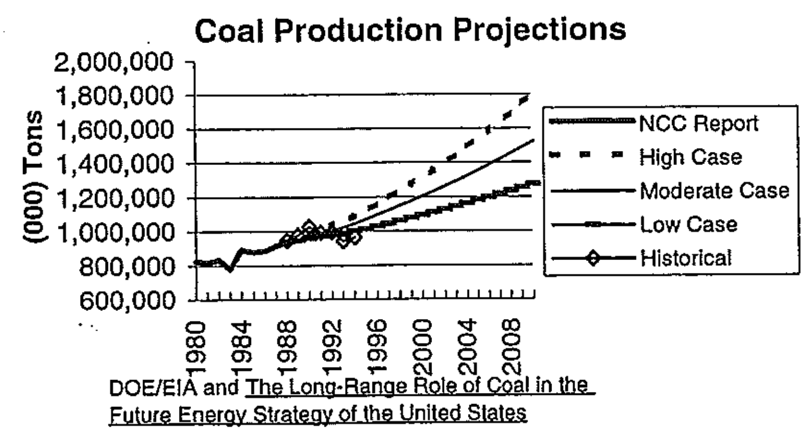

Figure 11: Coal Production Projections from Previous NCC Report

Rather than attempt to forecast specific levels of coal production, this report is the National Coal Council's consensus on the direction of change from prior projections such as those detailed in the report cited above. This report will limit its horizon to impacts over a short time period. The primary focus will be the next five years, with a secondary focus extending to ten years. In the first period, the primary effects result from shifts in utilization of existing resources and the use of resources already under construction. The second period will begin to reflect new capital investments responding to changes taking place in the institutional structure of the electric industry.

Primary Implications of Deregulation and Restructuring

The Council identified the following six primary implications from the forces affecting the electric industry:

1. *Increased competition* among existing suppliers of electricity and new entrants will be greatest at the generation or wholesale market level but could extend to some or all of the retail sales level of electricity.
2. *More customer choice* will be available in the purchase of electricity. Whether or not the retail supplier remains the same, customers will be able to choose indirectly from other suppliers and certainly will have more options for conditions of delivery of their electricity. Technology and institutional change will make it more feasible for customers to convert energy resources into electricity.
3. Utilities will have *less protection by regulatory oversight* from the outcomes of their decisions. Whether such decisions are mandated by legislation or regulation, or selected by utility management, non-competitive costs will be increasingly difficult to recoup from electricity users. It is likely to be completely true for future decisions and may be for some or all past decisions.
4. The functions of *generation, transmission, and distribution* are likely to be *unbundled.* It is almost certain that generation will no longer be integrated with transmission and distribution.
5. The relative *cost of alternate technologies* is likely to *decrease.* If retail wheeling is allowed, the cost of stand-by service for customers who generate their own electricity is likely to decrease. This will reduce the effective cost of using CTs or diesels on customer premises and may enhance smaller applications of such technologies as photo-voltaic cells. Distributed technologies (those technologies used for generating electricity at the customer's premise) may then benefit even more by reducing the load on distribution and transmission facilities.
6. *Partnering* of coal suppliers, transportation providers, equipment suppliers, coal conversion entities, and others may streamline the process,

creating significant economies and reducing financial risks of this part of the business. Such partnering is likely as each group seeks to enhance its share of the changing market for fuel, fuel transportation, and generation services.

Impact on Coal Use

Taking each of the implications listed above, this section summarizes the views of the Council concerning likely impacts on coal use. It should be noted that the six implications previously listed do not lead to independent effects. For example, increased competition and less regulatory protection will likely reduce risk-taking by utilities. This would lead utilities to build fewer coal plants than otherwise would have been the case. Another behavior resulting from competition is increased sensitivity to fuel price and, therefore, greater reliance on low-priced fuels and efficient utilization of existing assets. Current knowledge precludes easy quantification of these effects or the amplification or suppression of their individual influences in their combined effects. The Council believes that an impression of the general direction and magnitude of these effects is as much as can currently be accomplished. These directional changes are taken against a base of current or recent experiences that reflect the influences of the early 1990s, but do not include the institutional changes contemplated here.

Increased Competition

A large fraction of existing coal-fired generating units now produce electricity at the lowest overall marginal cost (fuel plus incremental O&M). In many cases, the marginal cost is very little more than fuel itself. Moreover, nationally, coal plants operated at a 62 percent capacity factor in 1993. In theory, they should be able to approach a 90 percent capacity factor, but the 70 percent capacity factor[19] (Table 5) now achieved by nuclear units is a more feasible maximum. A 70 percent capacity factor would mean substantially increased use of coal: over 100 million tons per year (Table 6).

Table 6: Coal Consumption Increase Calculation for Capacity Factor Increase to 70%

$$\left[\left(\frac{70\%}{62\%}\right)-1\right] \text{X } 814 \text{ million tons} = 105 \text{ million tons}$$

Some costs in the coal cycle can be reduced by better coordination between the coal supplier, coal transporter, and coal user. For example, were it possible to reduce the inventory at the mine, in the coal cars, or at the station by smoothing the supply cycle, coal costs would be lower. One idea that has been proposed is to have the coal producer own the coal until it enters the boiler. Then a single

[19] EIA/AER, 1993, p. 257.

entity might be able to optimize better than the current three players. The Council believes the three players, as a matter of self-interest, will enter into such arrangements to enhance the competitive position of coal. This, too, will work to increase use or, at least, maintain coal's market share of electricity generation. This competition may also be reflected in competition among coal suppliers.

Competition among fuels may accelerate the technical development and deployment of improved coal mining equipment, and possibly new technologies for coal mining. For example, surface mines have been upgrading to ever larger equipment, which helps reduce costs. Another example is the possible development of unmanned, remote continuous mining equipment along with continuous haulage equipment for application in underground long-wall mining. Such equipment would reduce labor costs and other costs, such as mine roof bolting. To the extent that such developments reduce the cost of coal, they would enhance the use of coal.

Competition's effect on electric utility decision making may affect development and deployment of clean coal technologies. A strong focus on reducing costs and managing business rather than regulatory risks will reduce utilities' willingness to invest in new technologies. Without a regulated utility's guarantee of a return on prudent investments in new technologies, funding and partners to participate in such investments may be in short supply. If this occurs, clean coal technology implementation may languish, reducing both opportunities for coal to fuel new generation growth and potential improvements in the environment.

On the other hand, CC/CTs currently fueled by gas provide the lowest marginal cost new generation in many areas of the country, and they can be constructed more quickly than coal plants. The latter reduces risk to the entrepreneur undertaking such new plants. One alternative, which could be lower cost and lower risk, is the refurbishment of some older coal plants which otherwise would have been shut down. Such decisions are site and equipment specific and are unlikely to be a major factor in coal use trends over the next decade.

For these reasons, the National Coal Council sees the probability that much of the new capacity in the near-term future will be non-coal-based. This will remain true until the price of gas escalates substantially over present levels. It should be noted that, were the price of gas to escalate sufficiently, gasified coal could be used to replace natural gas. The technology for gasifying coal to make fuel for many such turbines was demonstrated at the Coolwater facility over a decade ago and now is being developed at several additional facilities.[20] But the Council considers it uncertain that such a price rise in gas will occur over the horizon being discussed (that is, over the next ten years).

With assured transmission access, some generators may be encouraged to build coal-fired mine mouth plants in five to ten years. This could provide a significantly increased market for coal to produce electricity for customers within economic reach of the transmission system.

[20] EPRI/TAG, June 1993, pp. 8-44,8-48/

Were there to be a breakthrough in development of coal using technology which reduced equipment cost and construction cycle time, it could increase demand for coal during the latter part of this period. Such a breakthrough does not seem apparent at this time.

Overall, the Council sees coal consumption increasing in the short term, then leveling or declining until there is the opportunity to build coal-fired units based on new technologies in about ten years. These statements are relative to the prior consensus forecast of continued smooth growth in coal use throughout the next ten years. The reason for the short-term increased demand for coal is the potential for using current coal capacity more intensely because it will be lower cost than other alternatives. In the mid-term, coal's growth relative to prior forecast will be lower because CC/CT plants are the lowest cost added capacity. Currently, in some regions, even if coal was free, CC/CT technology still would be the lowest cost alternative. However, depending on what occurs with coal technology development and with future natural gas prices, coal could fuel the lower cost additional units in about ten years.

More Customer Choice

Related to increased competition is the increased customer choice envisioned in this new environment. This implies that customers who found it difficult in the old regulated system to obtain grid reliability while using their own generation may find it easier in the future. The Council believes that such customer-owned generators are likely to be gas-fueled, reducing coal's share of new opportunities and possibly replacing electricity from existing coal-fired units. Over the longer term, some of these customer-owned units for the largest installations could be coal-fired, particularly if gas prices begin to rise significantly or are perceived as likely to rise in the future.

On the other hand, were retail wheeling made available to customers, it might enhance the increased utilization of the low-cost coal plants discussed in the prior section. The Council envisions the possibility of large users of electricity contracting for high load factor, low-cost electricity to be wheeled from the most efficient plant or plants in the region. This would enhance coal's short-term growth more quickly through higher utilization of existing plants. Longer term, it might enhance the possibility of new coal-fired merchant plants contracting their output prior to construction and thereby reducing the risks of the higher capital, longer lead time plants.

Overall, then, customer choice should help enhance coal's growth in the short term and could be a positive force in helping coal capture some of the new electricity market in the longer term. But during the middle part of this period, it is likely that consumer choice will enhance the position of other fuels.

Less Protection by Regulatory Oversight

As discussed in reviewing the history of the utility industry, regulation provided the assurance to utilities that prudent expenditures taken to fulfill their service obligations could be recouped over time in electric rates. Such an assurance made it much less risky for utilities to undertake long lead time, high-capital investments with long expected lives. Generating stations, particularly nuclear but also coal, represent relatively high-risk ventures where benefits accrue over lives of 30 to 40 years or longer.

One major implication of the institutional change we are contemplating is a significant increase in risk for functions in the electricity sector, because only the market will determine whether a venture is profitable. (In fact, one of the major barriers to the transition is the "stranded cost" of prior utility decisions.) This implication clearly means that there will be fewer coal plants built than there otherwise would have been. A number of coal-based utility systems whose planning extends to the year 2010 include no new coal plants in their projections. Growth in projected demand in such utilities is forecast to be met with CC/CT units.

In the short term, risk avoidance may imply a reduction in all plant construction. The reduction in all new plant construction would enhance the utilization of existing plants. Hence, this would lead to increased use of coal, but only for the very short term. During most of the period under question, coal consumption will be less than it otherwise would have been.

On the other hand, the same risk aversion may enhance coal's prospects toward the end of the period as nuclear units come to the end of their licensed lives. The decision to extend a nuclear plant's license will be less likely because of the greater financial risk exposure, given a utility's decreased assurance in recovery of expenditures through the rate-making process. This means that there will be an opportunity for coal to replace a larger fraction of the 111 GW of nuclear capacity that will be coming to the end of its licensing period by 2030. Over 40 GW of this licensed capacity will expire by 2010.[21] Some nuclear plants have been shut down during the last few years because the cost of shutting them down was less than the projected cost of their continued operation. A continuation of this trend could improve the prospects for increased coal usage.

Generation/Transmission/Distribution Unbundling

As discussed earlier, it is almost certain that generation assets will be separated from transmission and distribution facilities. This means that the owners of presently integrated systems will not be able to run the generation system as a unit with a system average cost. It is much more likely that each generating unit will be run as a separate competitor in the marginal cost race.

The Council believes that, while some older, higher-cost coal units might continue to find a role in a cycling or even peaking regime, many such units will not be able to compete. The consequence will be that the unit will have to be refurbished (usually expensive, except for base load service), converted or replaced (such as the boiler used as a heat recovery steam generator when coupled with a gas turbine), or retired. The Council believes that retirement is the likely fate of a substantial

[21] "Moving Forward," *EEI Issues and Trends* No. 70, May 1994, p. 8.

fraction of such older units with poor boiler efficiencies caused by design limitations combined with high operation and maintenance costs. These units are likely to be operating presently at low capacity factors. This implies a permanent, relatively near-term slight decline in coal use.

Decreased Cost of Alternative Technologies

Over the last two decades, significant investments have been made in developing alternative technologies. One technology which has been developed successfully is the CC/CTs. But, for the most part, the technology has been applied at a utility scale rather than one for individual large customers. Part of the reason that this technology has not penetrated further at the level of individual customer sites is that the institutional system now allows utilities to charge stand-by costs which represent the full cost of keeping capacity available to provide for such customers' emergency needs. This results in such customers having to build duplicate facilities or pay a relatively high stand-by charge.

One major change implied in utility restructuring is the opening of the transmission system. For customers needing back-up service, the cost under this new regime could be substantially lower. If so, this would provide an impetus for such technologies. With greater opportunity to use such technologies, it is likely there would be a further reduction in cost from their volume production. The same effect on CC/CTs may be true for advanced small diesel engines. Less developed are small-scale technologies, such as wind turbines, geothermal energy, and fuel cells. While stand-by charges have been less of a factor on these small-scale technologies, their use may be enhanced by the possible institutional changes. The exit costs or other limitations or costs regulators impose on such stand-by rates could affect the outcome.

Because these technologies can be distributed throughout the system more easily than can larger coal plants, they can help meet transmission and distribution system requirements by reducing loads, thereby reducing the cost of "wire." To the extent that such technologies become more attractive in response to the institutional changes and benefit from mass production, they will reduce centralized facilities' share of the electricity market. The effect, albeit small, will be a reduction in coal demand.

However, deregulation provides a countervailing force. In many regulatory jurisdictions, alternate technologies have received a boost from the consideration of "externalities." This refers to the economic concept of costs imposed on society at large, such as ecological damage and the use of air resources, which are not compensated for and which are not reflected in the price of the good or service produced. By using such "externalities" to determine the most desirable resource use, regulatory commissions have been able to force utilities to use more expensive technologies and charge their customers for this extra cost. For example, some states have mandated utilities to buy electricity at much above the market rate from producers using renewable fuels.

With deregulation, it is unlikely that the market can sustain such expensive alternate providers. In fact, many utilities are buying down these expensive contracts to get ready for the new competitive environment. To the extent that such "externalities" are no longer used to mandate alternative fuels, coal will get a boost in demand.

Partnering

For suppliers of coal, associated services, and equipment, a decline in coal markets means either a reduction in their business or a reduction in expected growth. To a small degree, we have seen the response of equipment manufacturers and architect-engineers who have seen their expected business in new power stations fall off over the last ten years. A number of these have partnered, some with a utility, others without, to construct deregulated or "merchant" plants as IPPs. It should be noted that many states currently require hearings to demonstrate the "need for additional capacity" before new plants will be licensed for construction. Such processes may retard the initiation of new "merchant" and other plants.

The Council believes that coal suppliers, transportation companies, equipment companies, architect-engineers, financial institutions, GENCOs, and others may find it attractive to partner in building new "merchant" coal plants in the unregulated environment. If delivered coal can be made the lowest cost delivered fuel by an adequate margin, and if the capital costs of new plants can be brought close to the level of new CC/CT plants, then such a combination of players could go a long way to offset the risks discussed under "Less Protection by Regulatory Oversight," above. Moreover, such plants could then enter the competitive market as the lowest total (including new capital) marginal cost player and earn a premium return.

In the short term, alliances between coal producers, transporters, and users might be able to lower coal costs by minimizing storage and delivery times and increasing efficient use of coal-related capital investments. For example, reducing coal inventories through better coordination among the parties would reduce the overall cost of burning coal.

The Council believes such consortia of coal producers, transporters, and users are likely. The entry of others, such as oil companies with proprietary gasification technology, may be a second step in the process. The first effort will be to lower the coal chain cost; the second and later effort will be to compete in the merchant plant business. To the extent such arrangements become a reality, demand for coal will be increased. This force could be the boost for coal demand during the middle of the time frame considered when most of the other factors will be leading to a sagging coal demand. In addition, it could portend a strong coal demand in the longer run because it is an appropriate response to the requirements of the new institutional order. One concern is that such partnering may raise anti-trust issues.

Summary of Short-Term, Mid-Term, and Long-Term Implications

Because the National Coal Council has not quantified the effect of each implication, it is difficult to summarize the whole. Directions seem fairly clear, as shown in Table 1 and graphically displayed in

Figure 12. In the short run, it appears to the Council that it is likely there will be a modest increase in domestic coal demand. This will come from better utilization of existing facilities offset by the closing of older, non-competitive facilities. The major portion of increasing demand over the later part of the next five years is likely to be met by other fuels, decreasing prospects for coal as compared to earlier forecasts.

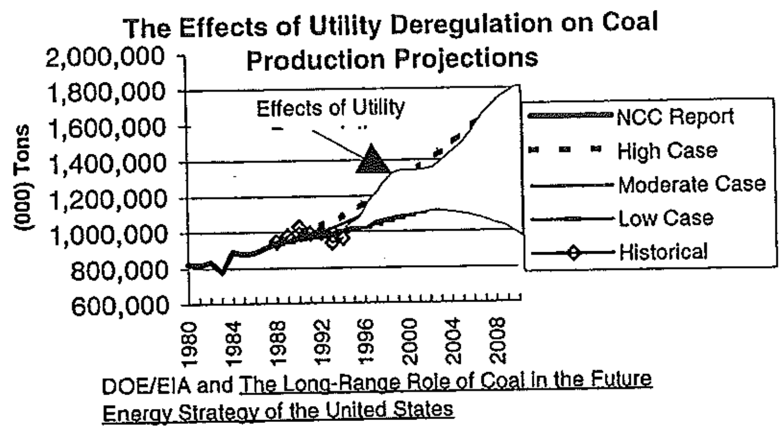

Figure 12: Effects of Utility Deregulation on Coal Production Projections

In the mid to long term, there is a potential for domestic coal use to grow again. One force which could lead to this growth is an increase in the price of natural gas sufficient to make coal the preferred fuel in new facilities, although the Council believes that counting on gas price increases is a risky strategy. Another force might be new organizational arrangements to reduce the cost of coal and to share the risk of building new coal-fired generating capacity. A third force is the potential for new coal technologies to be sufficiently improved so that the cost of new generating capacity and the time to build such capacity will become more competitive with other alternatives.

It should be noted that these changes in domestic utility industry structures will not have significant impact on international coal markets. International coal markets, particularly in Asia, are projected to grow in parallel with overall economic development in these countries. Limited growth in domestic markets is likely to fuel increased competition among domestic coal producers.

The National Coal Council believes that the parties who have a vital interest in the use of coal will work diligently to overcome the barriers to its use so that coal increasingly becomes the fuel of choice. The Council also believes that there is a national interest in using coal and that legislators, regulators, and others therefore will find the means to assure that coal is used intensively as a fuel source within the next ten years.

APPENDIX A

Description of the National Coal Council

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Description of the National Coal Council

Recognizing the valuable contribution of the industry advice provided over the years to the Executive Branch by the National Petroleum Council and the extremely critical importance of the role of coal to America and the world's energy mix for the future, the idea of a similar advisory group for the coal industry was put forward in 1984 by the White House Conference on Coal. The opportunity for the coal industry to have an objective window into the Executive Branch drew overwhelming support.

In the fall of 1984, The National Coal Council was chartered; and in April 1985, the Council became fully operational. This action was based on the conviction that such an industry advisory council could make a vital contribution to America's energy security by providing information that could help shape policies relative to the use of coal in an environmentally sound manner which, in turn, could lead to decreased dependence on other, less abundant, more costly, and less secure sources of energy.

The National Coal Council is chartered by the Secretary of Energy under the Federal Advisory Committee Act. The purpose of the Council is solely to advise, inform, and make recommendations to the Secretary of Energy with respect to any matter relating to coal or the coal industry about which the Secretary may request its expertise.

Members of the National Coal Council are appointed by the Secretary of Energy and represent all segments of coal interests and geographical regions. The National Coal Council is headed by a Chairman and a Vice-Chairman who are elected by the Council.

The Council is supported entirely by voluntary contributions from its members. It receives no funds whatsoever from the Federal Government. In reality, by conducting studies at no cost which might otherwise have to be conducted by the Department, it saves money for the government.

The National Coal Council does not engage in any of the usual trade association activities. It specifically does not engage in lobbying efforts. The Council does not represent any one segment of the coal or coal-related industry or the views of any one particular part of the country. It is, instead, to be a broad, objective advisory group whose approach is national in scope.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the requested study. The first major studies undertaken by the National Coal Council at the request of the Secretary of Energy were presented to the Secretary in the summer of 1986, barely one year after the startup of the Council.

Reports of the National Coal Council completed through November 1995:

June 1986	*Coal Conversion*
June 1986	*Clean Coal Technologies*
June 1986	*Interstate Transmission of Electricity*
June 1986	*Report on Industrial Boiler New Source Performance Standards*
June 1987	*Reserve Data Base: Report of The National Coal Council*
June 1987	*Improving International Competitiveness of U.S. Coal and Coal Technologies*
November 1988	*Innovative Clean Coal Technology Deployment*
December 1988	*The Use of Coal in the Industrial, Commercial,Residential and Transportation Sectors*
June 1990	*Industrial Use of Coal and Clean Coal Technology --Addendum Report*
June 1990	*The Long Range Role of Coal in the Future Energy Strategy of the United States*
January 1992	*The Near Term Role for Coal in the Future Energy Strategy of the United States*
January 1992	*Improving Coal's Image: A National Energy Strategy Imperative*
May 1992	*Special Report on Externalities*
February 1993	*The Role of U.S. Coal in Energy, the Economy, and the Environment -- Special Report*
February 1993	*A Synopsis of the Reports (1986-1992)*
November 1993	*The Export of U.S. Coal and Coal Technology*
February 1994	*Clean Coal Technology for Sustainable Development*
May 1995	*A Critical Review of Efficient and Environmentally Sound Coal Utilization Technology*

November 1995	*The Implications for Coal Markets of Utility Deregulation and Restructuring*

Members of the National Coal Council who have served as Chairmen:

June 1985 - June 1986	The Late Honorable John N. Dalton Former Governor of Virginia
	B. R. Brown President, Consolidated Coal Company
June 1986 - June 1987	James W. McGlothlin Chairman, The United Companies
June 1987 - June 1989	James G. Randolph Former President, Kerr-McGee Coal Company Former Assistant Secretary for Fossil Energy, United States Department of Energy
June 1989 - May 1991	William Carr President, Jim Walter Resources, Inc.
May 1991 - May 1992	W. Carter Grinstead, Jr. Former Vice President, Exxon Coal and Minerals Company
May 1992 - May 1994	William R. Wahl Vice President, AMAX, Inc.
May 1994 - Present	Joseph W. Craft III President, MAPCO COAL Inc.

APPENDIX B

The National Coal Council Membership Roster

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JAMES R. ALDRICH
State Director
The Nature Conservancy
Kentucky Chapter

DR. SY ALI
Manager, Industrial Engine Technology
Allison Engine Company

BARBARA F. ALTIZER
Executive Director
Virginia Coal Council

JOHN Q. ANDERSON
Executive Vice President
Coal Business Group
Burlington Northern Railroad

CHARLES J. BAIRD
Baird, Baird, Baird & Jones, P.S.C.

WILLIAM B. BALES
Vice President, Coal Marketing
Norfolk Southern Corporation

THE HON. GERALD BALILES
Hunton & Williams

C. A. BAYENS
President
Shell Synthetic Fuels Inc.

DR. JANOS M. BEER
Director, Combustion Research Facility
Massachusetts Institute of Technology

FRANK J. BENNER
President and Chief Operating Officer
Cogentrix, Inc.

JACQUELINE F. BIRD
Director, Ohio Coal Development Office
Ohio Department of Development

DR. SANDY BLACKSTONE
Natural Resources Attorney/Consultant

GENERAL WALTER E. BOOMER
President, Power Generation Group
Babcock & Wilcox

WILLIAM H. BOWKER
Executive Director
Kentucky Coal Marketing and Export Council

GREGORY BOYCE
President
Kennecott Energy Company

L. G. BRACKEEN
Vice President, Fuel and Energy Management
Houston Lighting and Power Company

JULIAN J. BRIX
General Manager
Cooperative Power Association

TERRI L. BRONOCCO
Director of Public Relations
The Nature Conservancy of Texas

B. R. BROWN
Chairman, President, and CEO
CONSOL Inc.

DONALD P. BROWN
Chief Executive Officer
International Executive Services

DR. LOUIS E. BUCK, JR.
Vice President and Chief Accounting Officer
Entergy Corporation

DR. DONALD CARLTON
President
Dow Radian Corporation

WILLIAM CARR
President and Chief Operating Officer
Jim Walter Resources, Inc.

ROBERT J. CASEY
Long Law Firm

FRED CLAYTON
Chairman and CEO
Shand Mining, Inc.

WILFRED CONNELL
Vice President
Illinois Power Company

ROBERT P. COOPER
Executive Vice President
Farrell-Cooper Mining Company, Inc.

MARYANN R. CORRENTI
Partner
Arthur Andersen & Company

JOSEPH W. CRAFT III
President
MAPCO COAL Inc.

JAMES B. CRAWFORD
Chairman and CEO
James River Coal

DAVID C. CRIKELAIR
Vice President
Texaco Inc.

DR. H. DOUGLAS DAHL

DR. E. LINN DRAPER, JR.
Chairman, President, and CEO
American Electric Power Company

JOHN DWYER
President
Lignite Energy Council

IRL F. ENGELHARDT
Chairman and CEO
Peabody Holding Company, Inc.

DR. ROBERT H. ESSENHIGH
Professor of Mechanical Engineering
The Ohio State University

MYRLEEN B. FAIRCHILD
Chairwoman/Chief Executive Officer
Fairchild International, Inc.

JOHN C. FAY, JR.
President
Empire Coal Sales, Inc.

JOSEPH A. FRANK
President
Centralia Coal Sales Company

KENT FRIZZELL

THE HON. GEORGE FUMICH, JR.
George Fumich Associates, Inc.

PETER M. GARSON
President
PMG Advisory Group

SONDRA J. GILLICE
President
RusSon, Inc.

BARBARA GRANNELL
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Western States Public Lands Coalition

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Charles River Associates

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Mission Energy Americas

DR. WILLIAM B. HARRISON

J. BRETT HARVEY
President and CEO
Interwest Mining Company

H. RICHARD HORNER
Allan F. Dow & Associates, Inc

HENRY McC. INGRAM
Partner
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JOHN JANAK
Group Vice President
T U Electric

GEORGIA L. JOHNSON
Founder, Editor, and President
Acquire's Coal Today

JOSEPH P. KEARNEY
President and Chief Executive Officer
U.S. Generating Company

WILLIAM M. KELCE
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STEVEN F. LEER
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Arch Mineral Corporation

A. DAVID LESTER
Executive Director
Council on Energy Resource Tribes

PETER B. LILLY
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Peabody Holding Company, Inc.

DR. ROBERT E. LUMPKIN
Amoco Corporation

RENÉ H. MALÈS
President
Strategic Decision, Inc.

WILLIAM B. MARX
President
Council of Industrial Boiler Owners

E. MORGAN MASSEY
Chairman
A. T. Massey Coal Company, Inc.

DR. CHRISTOPHER C. MATHEWSON
Director, Center for Engineering Geosciences
Texas A&M University

BARRY G. McGRATH
President and Chairman
The Pittsburg & Midway Coal Mining Company

ROBERT L. McPHAIL
General Manager
Basin Electric Power Cooperative

EMMANUEL R. MERLE
President
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APPENDIX C

The National Coal Council Coal Policy Committee

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The National Coal Council Coal Policy Committee

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APPENDIX D

The National Coal Council Coal Production and Utilization Subcommittee

APPENDIX D
The National Coal Council
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APPENDIX E

The National Coal Council Working Group for the Report *The Implications for Coal Markets of Utility Deregulation and Restructuring*

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The National Coal Council Working Group for the Report *The Implications for Coal Markets of Utility Deregulation and Restructuring*

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APPENDIX F

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APPENDIX F
Acknowledgements

The members of the Working Group wish to acknowledge, with sincere thanks, the special assistance received from the following persons in connection with various phases of the development of this report:

- Barbara F. Altizer, Virginia Coal Council
- Gary Hart, The Southern Company
- Suzanne Langevin, National Coal Council
- James F. McAvoy, National Coal Council
- David M. Ratcliffe, The Southern Company

Editorial Consultant
William T. Poole

APPENDIX G

Comments and Responses on the Report *The Implications for Coal Markets of Utility Deregulation and Restructuring*

APPENDIX G
Comments and Responses on the Report *The Implications for Coal Markets of Utility Deregulation and Restructuring*

The following tabulation lists comments gathered during reviews of the report by members of the National Coal Council. Comments were gathered during several meetings of the National Coal Council's Production and Utilization Working Group, as well as during the Main Meeting of the National Coal Council held November 15 and 16, 1995. The name of the commenting party, the specific comments offered, and the response developed for the comment are shown in each case.

Tabulation of Comments and Responses

Source	Comment	Response
James F. McAvoy National Coal Council	1. Clarify competition's effect on CCTs	Added paragraph in conclusion, added to discussion in Section 4
Alex E. S. Green University of Florida	2. Clarify conclusions re: alternate technologies	Short reference in conclusion
	3. and emergence of CC-CTs	Added paragraph to conclusion
	4. Expand cogeneration applications of CC-CTs in Section 4.3	Addition to clarify intent
	5. Application of small CC-CTs	Cited in 4.2.5 and 4.3.5
	6. Further improvements in CTs	Cited in 3.3
	7. Need to clarify footnote 17	Added clarification (Note: it is article that makes claim re: air blown gasifier)
	8. Reference to Green paper	Footnote added
	9. Extend partnering to oil and gas sector, etc.	Added clarifying sentence
	10. Cite specific partnering example	Already broad enough to include
Robert E. Nickell TEK-KOL Partnership	11. Remove "Possible" from title	Agree
	12. Move partnering recommendation to top	Do not agree, other recommendations address sponsor of report
	13. Discuss rail deregulation	Add to 2.7
	14. Section 4 needs to be more quantitative	Cannot meaningfully be done
	15. Note "lack of independence" of six implications	Add to intro of Section 4.3

Tabulation of Comments and Responses (Continued)

Source	Comment	Response
Robert E. Nickell TEK-KOL Partnership (continued)	16. Choose "dominant" effect	Does not appear to add to understanding. Effects are already evaluated as to importance.
Steve Pike Kennecott Energy	17. Recommend that participation be with a purpose	Add "with an objective" Sec 1.3
	18. More than utilities initially embraced nuclear power	Add ", the government, and the nation:" to Sec 2.3
	19. Make clear of responsibility of more than FERC on stranded costs	Add sentence to Sec 2.4
	20. Clarify that FERC may impose "exit fee" on new municipal utilities	Add sentence to Sec 2.4
	21. IPP financing advantage over utilities may not continue in future	Add word "historically" to Sec 2.5
	22. Make clear that "energy services companies" may be created to compete with DISCO's for retail service	Add sentence to Sec 3.1
	23. Need to identify limits to increased coal plant capacity factors	Add sentence to Sec 3.2
	24. Collection of coal contract "buy-outs" not necessary to achieve goal of operating high coal cost plants	Add clarification to Sec 3.3
	25. Clarify relationship of CC-CTs and PCs	Edit sentence in Sec 3.3
	26. Add concept of price elasticity as major uncertainty to Sec. 3.4	Agree price elasticity is important, but <u>not</u> major uncertainty
	27. Clarify that exit costs could be imposed on prior stand-by rate constraint cases	Add sentence to 4.3.5
	28. "Merchant" plants too limiting; any unregulated plant is a possibility	Add "deregulated or" to 4.3.6
	29. Based on text "Five to Ten Years" total assessment in Table 1 reflects possible negative impact of factors such as environmental constraints. Similarly, Figure 12 should show potential for zero or negative growth post 2000	Added downward arrow with footnote and flat arrow to Table 1 Modified Figure 12 to show possible decline.
John Kitto, Jr. Babcock & Wilcox	30. the Executive Summary would be enhanced by relocating Table 6 nearer the front of the report	Agreed. Table 6-> Table 1 and other tables and references were renumbered
	31. Recommendation 1 is very general. Should a more specific recommendation be made?	The recommendation is in keeping with the NCCs role as a policy advisor, rather than a lobbying organization.
	32. Is the report too long?	Considering the breadth of the subject and time constraints a major revision abbreviating the report is not addressed.

Tabulation of Comments and Responses (Continued)

Source	Comment	Response
János M. Beér MIT	33. DOE Combustion 2000 Low Emission Boiler System (LEBS) Program will make PC units more competitive and place a difficult benchmark for AFB units to attain.	Added language to first sentence of last paragraph of Sec 3.3
Roger Gale Wash. Inter. Energy Group	34. Clarify report focuses on domestic coal consumption; There will be growth in international coal consumption, particularly in Asia.	Clarified "domestic" in Sections 1.1, 1.2, and 4.4
Ray Harry Southern Company Services	35. Inadequate attention to environmental issues	FERC's EIS cited in Section 4.2; Environmental issues key uncertainty in Section 3.4; Institutional changes independent of environmental regulation.
	36. Give examples of strategic alliances	Paragraph added to Section 4.3.6.
	37. Need more discussion regarding price of gas	Council position clarified in Section 4.4.
	38. Appears to be inconsistent with regard to coal plant retirements and short term increase in coal use.	Clarified in Section 4.3.4 that high cost coal plants likely to be low capacity factor plants.
George Preston EPRI	39. Should be whole coal chain involved	Covered in the report
	40. Results in coal-to-coal producer competition.	Added sentence to 4.3.1 and 4.4.
	41. Too much on gas * Growth in coal generation likely * Gas projects based on high dispatch levels risky * Editing	Disagree, gas is the major competitor now and throughout the period With regard to new generation, coal projects are riskier due to higher unit capital costs Modified sentence in Section 3.3
	42. Clarify nuclear license expiration issues	Add language in Section 3.4
	43. Sum of implications too pessimistic; highlight potential to expand existing coal plants and partnering opportunities	Assessment conveys the analysis in the preceding sections.
Joseph C. Bilardello AEP	44. Edit in Section 1.2	Okay.
Gerry Andersen TECO	45. Increased use of electricity due to increased efficiency of electro-technologies	Added sentence to Section 2.2
	46. Restructuring (particularly unbundling) of electric utilities not necessary outcome and may not be desirable	Added clarification in Section 3.2
	47. There are states where "need for capacity" processes now operate and will affect merchant plants	Added sentence clarifying "need" issue in Section 4.3.6
	48. Some regions have limited available additional gas transmission capability	Added sentence to Section 3.4

Tabulation of Comments and Responses (Continued)

Source	Comment	Response
Elliott Doane Kerr-McGee	49. In face of declining US oil production and peaking of world oil production around 2000, isn't gas price likely to rise?	Clarify risk in Section 3.4
Lawrence C. Grundmann, Jr. Mission Energy	50. Development of natural gas or electric vehicles will put pressure on gas prices	Added sentence to Section 3.4.1
David F. Surber Izaak Walton League	51. Partnering may create anti-trust issues	Added sentence to Section 4.3.6
Dwain F. Spencer SIMTECHE	52. Use consistent terminology short-term 0-5 yrs, mid-term 5-10 years, long-term >10yrs.	Changed terminology
	53. Coal unlikely to increase capacity factors due to need to run other units	Added cautionary terms in Section 3.2
	54. IPPs, after covering fixed cost, may be willing to sell at marginal cost replacing coal-fired capacity	Issue discussed in Section 3.2
Jacqueline F. Bird Ohio Department of Development	55. If no NO_x standards promulgated under ozone transport regulations or as part of restrictions associated with FERC's Giga-NOPR, coal plants will have to add SCR increasing costs	Added issue to Section 3.4
Peter B. Lilly Peabody Holding Company	56. Some nuclear units have already been shut down, therefore others may not go to their licensed life	Added discussion to Section 4.3.3

AST Applied Science & Technology

November 8, 1995

to: Mr. James F. McAvoy, Executive Director
The National Coal Council, Inc.
P. O. Box 17370
Arlington, VA 22216

REN
from: Dr. Robert E. Nickell, Consultant
The TEK-KOL Partnership
16630 Sagewood Lane
Poway, California 92064-1408

subject: Draft Report, "The Implications on Coal Markets of Possible Utility Deregulation and Restructuring"

The subject draft report is an excellent read. The Secretary will find the information and recommendations useful. However, an equally interested audience could be the coal producers, who might integrate the information into their corporate planning process if it is possible to quantify the findings in Section 4 further. The comments provided below are intended to be helpful in that regard.

1. Remove the word "Possible" from the title. Electric utilities *are* being deregulated and *are* being restructured. The issue is not whether, but how much.
2. Move Recommendation 4 in Section 1.3 up on the list, at least to the third position, even though this is a report to the DOE. The economic imbalance between producer, transporter, and end user is best resolved through partnering. This would seem to be the most important implication for producers.
3. Even though the subject of the report is deregulation and restructuring of electric utilities, the impact of deregulation and restructuring of transporters is almost as important. The report had several opportunities to integrate the effects of both into the discussion (p. 18, last paragraph; p. 25, last bullet; p. 30, first paragraph), but failed to do so. The most important elements to discuss are the effects on delivered coal price of continued efficiency gains by producers, and the positive (or negative) effects of increasing (decreasing) railroad competition.

ROBERT E. NICKELL, PH.D. • 16630 SAGEWOOD LANE • POWAY, CALIFORNIA 92064

4. Section 4 needs to be more quantitative. The first step is to acknowledge the lack of independence of the six implications, and to suggest a means of separating effects. Consider the following introduction to Section 4.3:

   "The six implications listed above are not independent. For example, increased competition is affected by reduced regulatory oversight, partnering is affected by the cost of alternate technologies, and so forth. Therefore, in order to isolate and attempt to quantify the effects of each of the six implications, a dominant near-term embodiment for each implication was identified. Then, this section summarizes and quantifies the impact on coal use through an analysis of each of these dominant near-term embodiments."

   The second step is to identify the dominant near-term embodiment of each implication within the appropriate subsection. In my judgment, for Increased Competition, the dominant near-term embodiment was selected in the report to be Increased Capacity Factor. The quantitative analysis was deterministic, based on expected values, the effect was positive, and the treatment was excellent. For Increased Consumer Choice, no dominant near-term embodiment was identified, but Increased Distributed Generation would seem to be a good choice. This would also seem to be rather easily quantified on an expected value basis, and would appear to have a purely negative effect. For Decreased Regulatory Protection, no dominant near-term embodiment was identified, but Decreased Capital Investment Timeline would seem to be a good choice. This would also lend itself to quantification, and would appear to have a purely negative effect. For Unbundling, no dominant near-term embodiment was identified, but Increased Baseload Participation would seem to be choice. The current discussion is deficient on this point, and should be revised. Under wholesale power wheeling, the most efficient plants will be driven toward baseload operation. The effect can be quantified, and the effect will be purely positive. For Decreased Alternative Costs, no dominant near-term embodiment was identified, but either Increased Distributed Generation or Decreased Coal-Fired Baseload Capacity would work. The effect could be quantified and would be purely negative in either case. Finally, for Increased Partnering, two dominant near-term embodiments, Increased Capacity Factor and Increased Repowering, and one dominant long-term embodiment, Increased Coal-Fired (Merchant) Baseload Capacity, would seem to be appropriate. The effects can be quantified and they are purely positive.

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November 9, 1995

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Executive Director
The National Coal Council, Inc.
Post Office Box 17370
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By Fax: (703) 527-1195
Re: *"The Implications on Coal Markets of Possible Utility Deregulation & Restructuring"*

Dear Jim,

Thank you for the draft report, which I have read with great interest. I generally agree with the discussion and conclusion of the report. I think, however, that the discussion on the coal technology alternatives to the use of natural gas based on an EPRI Technical Assessment Guide of June 1993 is somewhat out of date. (Page 25 last paragraph and Page 26 first paragraph.)

⇒ In the DOE Combustion 2000 Low Emission Boiler System (LEBS) Program three major American boilermakers: ABB, B&W, and Riley Stokes, are competing to produce very low, < 1 lb/10^6 Btu, NO_x and SO_x emission P.C. fired supercritical pressure steam boiler systems with 42% cycle efficiency and a projected cost of $1250/kw installed capacity. The boilers are to be commercial by the year 2000.

⇒ Atmospheric Fluidized Beds (AFB) are not likely to be competitive with these PC boilers because of their lower sulfur capture, and their high N_2O (nitrous oxides) emission.

⇒ Pressurized Fluidized Bed (2nd Generation) with mild coal gasification and topping combustion offers 45% cycle efficiency, elimination of N_2O emission, and competitive economics. Pilot scale studies with hot gas cleanup and the topping combustor show promise for this technology to be commercial by the end of this decade.

⇒ The IGCC technology will be competitive when it produces low calorific value gas and will not need an oxygen blown gasifier. This, however, requires hot gas cleanup and puts IGCC in the same category with the 2nd Generation PFBC.

I therefore differ somewhat in my assessment from those in reference 17 in the report.

Looking forward to seeing you soon,

Sincerely,

János

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November 10, 1995

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Mr. J. McAvoy
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Subject: NCC Draft Report, "The Implications on Coal Markets of Possible Utility Deregulation and Restructuring"

Dear Mr. McAvoy:

Thank you for the opportunity to review the subject report. It provides a good overview of the restructuring just getting underway in the U.S. electric power industry, and I believe that it is generally consistent with what we are seeing. I have no major revisions to suggest. The following minor items are offered for consideration:

1. The Executive Summary would be enhanced by moving the summary table on page 34 forward. This table is one of the critical outputs from the study, and it is somewhat lost at the end of the report.

2. Recommendation 1 in the report is very general. Should the NCC be suggesting something more specific to the Secretary and industry in this area?

3. The report contains a wealth of good background material but length may become somewhat of an issue depending upon who the broader audience is for this work. It took me some time to reach the very important material in Section 4.

4. As implied in the report, we are beginning to see some interest in upgrades and enhancements to reduce the variable operating costs of existing pulverized coal-fired boilers.

I am looking forward to the NNC meeting next week.

Very truly yours,

THE BABCOCK & WILCOX COMPANY
Research & Development Division

J. B. Kitto, Jr. /dss

John B. Kitto, Jr.
Technology & Planning

dss

cc: W. E. Boomer

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2 Total Pages

13 Nov. '95

November 13, 1995

TO: The National Coal Council, Inc.
Jim McAvoy
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FROM: George Preston
Vice President, Generation
Telephone: 415 855 2461

SUBJECT: **Draft Report, Implications on Coal Markets ...**

Jim, recognizing that I am not a member of the Coal Policy Committee, we've nonetheless reviewed the draft you sent out, and I have a few comments to offer.

Where Is the Impact Felt? The Conclusions and Recommendations seem to deal primarily with impacts on coal demand. However, I suggest that impacts of electric utilities' heightened cost-consciousness on the whole coal supply chain (not just producers) are equally or more significant. They also are more predictable than impacts on coal demand. For example, "coal vs. coal" competition is bound to increase - i.e., deregulation and restructuring impacts on utilities will lead to greater differentiation among coal suppliers.

Coal vs. Gas. As a long-time coal supporter, I think the draft focuses excessively on coal vs. gas competition; this could inhibit rather than enhance understanding of the important impacts on the coal industry.

- Gas will dominate new *capacity* additions, but considerable growth in coal *generation* is likely throughout the report's forecast period. Paraphrasing a bumper sticker, "Capacity doesn't burn fuel, generation does."

- New gas-based power projects that rely for viability on the prospect of achieving high dispatch levels are actually pretty risky, considering the prospects for someone else wheeling in cheap coal-fired power after a gas project's major capital investments have been sunk. Transmission infrastructure and transaction-system changes now being discussed make these prospects quite realistic.

- At the bottom of p.23, I suggest a more realistic perspective would be, "The effects on coal producers and marketers will be driven by coal's ability to enhance or maintain coal plant utilization in an increasingly open power market that will set hurdle prices for coal production at lower and lower levels." Competition from gas will be (only) part of this competitive mix.

Climate for Nuclear Power. The uncertainty about nuclear power (p.26) is described in words that could be attacked as wishful thinking, and they raise the coal vs. gas issue yet again. A more credible perspective, to replace the last two sentences, would be: "A large shift away from nuclear power, with or without significant new electric growth, could strain electricity supplies of all types to an unprecedented extent. This issue accelerates after 2010 when many existing nuclear plant licenses will have expired."

Sum of Implications. In an era of rapid change, caution about projecting market size and growth potential is no doubt appropriate, but the tone on pp.33-34 comes through as resigned pessimism. Some mention could be made of opportunities to expand generation at existing coal-fired plants. The opportunities presented by "new organizational arrangements" could be brought out more explicitly as a path to reducing costs and expanding markets.

Jim, I hope these comments are not too late to be useful to you and the Committee in the November 15-16 meetings. Best regards.

Comments on Draft Report, *The Implications on Coal Markets of Possible Utility Deregulation and Restructuring*

1. There appears to be inadequate attention to environmental issues and their impact on competition, especially the FERC Environmental Impact Statement on their Mega-NOPR. While there is mention of direct regulatory issues, such as air toxics, etc., there are some issues, mostly air quality related, that are arising in the competitive debate especially between high cost and lower cost generators. These should be discussed more thoroughly.

2. Several references are made to possible "strategic alliances" between the coal industry and its partners to enhance the competitiveness of coal. Examples of such alliances would be helpful.

3. The future price of natural gas is a key determinant in the marketability of coal in a more competitive environment. This seems to be inadequately addressed in the report. A short paragraph on page 26 of the report implies that gas prices could be expected to escalate while a section of text on page 30 states that "... the Council considers it uncertain that such a price rise in gas will occur over the horizon being discussed, i.e., over the next ten years." The future supply and price of gas should be more thoroughly examined in the report.

4. While the conclusions of the report support a possible near term increase in the use of coal and a longer term decline, the underlying report seems weak in supporting this presumption. Section 4.3.4 on page 32 states that retirement of older higher cost coal units "implies a permanent, relatively near term slight decline in coal use." , the summary in Section 4.4 on page 33 states that "In the short run, it appears to the Council that it is likely to see a modest increase in coal demand." Perhaps a 5 year planning horizon is too short for making projections based on an uncertain future and impacts of competition.

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Governmental Affairs

APPENDIX H

Correspondence Between National Coal Council and U.S. Department of Energy

The Secretary of Energy
Washington, DC 20585

September 28, 1995

Mr. Joseph W. Craft III
Chairman
National Coal Council
P.O. Box 17370
Arlington, Virginia 22216

29 Sept. '95

Dear Mr. Craft:

I am writing to ask the Council to prepare two reports that would further address issues raised in the Council's May 1995 report, "A Critical Review of Efficient and Environmentally Sound Coal Utilization Technology." The report analyzed the status of the development of a wide variety of clean coal technologies and identified generally obstacles that could impede the commercialization of those technologies. In view of the importance of deploying clean coal technologies to national economic stability and sustainable development throughout the world, a brief update of a previous National Coal Council report examining the role of U.S. coal in energy, the economy, and the environment would be a timely and valuable source document for the Department of Energy. Also, recent developments in electric utility deregulation and restructuring have made evident the need for a focused study on the implications on coal and coal utilizations markets of these developments.

Therefore, I again seek the advice of the Council and request that the Council prepare two studies described as follows:

- <u>Consumption Issues Affecting the Role of Coal in the U.S. Energy Strategy</u> - This study should outline the major obstacles to the full use of coal as an energy source for the U.S., and highlight the issues related to recent developments in international markets for coal utilization technologies. This study should serve as an update of the prior National Coal Council report, <u>The Role of U.S. Coal in Energy, the Economy, and the Environment</u>.

- <u>Implications on Coal Markets of Possible Utility Deregulation and Restructuring</u> - This study should be designed on a simple, limited effort basis and (1) be based on existing literature regarding utility change; (2) include the development of simple models as appropriate; and (3) evaluate the direction of the impact on coal markets of possible utility deregulation using these simple models.

Thank you for considering this request.

Sincerely,

Hazel R. O'Leary

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