
COAL: The Primary Fuel of the Electric Utility Industry

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COAL: THE PRIMARY FUEL OF THE UTILITY INDUSTRY

The United States electricity industry has long relied on coal as its major fuel source for generating electric power in the United States. Coal's domestic abundance and low cost have made it the logical choice for most baseload generation. In the 1990s it appeared that natural gas threatened to upset coal's dominant position, but due to a confluence of factors, principally the increasing and volatile costs of oil and natural gas, as well as the slow development of alternative fuels, coal looks to maintain its position as the dominant fuel of the electric industry.

Background: Over-investment in Natural Gas

Throughout the 1990s natural-gas fired plants were built at a very rapid rate. Investors were encouraged by natural gas's relatively low cost and greater environmental friendliness. In addition, natural gas plants tend to have low capital costs and take less time to build, factors which attracted many merchant generators to them. These merchant generators were also driven by anticipated ample supplies of natural gas at low prices and a booming economy, as well as the expectation that the implementation of Federal Energy Regulatory Commission (FERC) Order Nos. 888, 889, and 2000 would help open the national electric grid to more third-party competition.¹

Many also expected that technological and environmental developments would spur greater investment in the natural gas industry. In an August 1999 report, Moody's Investors Service predicted that combined cycle combustion turbine technology and increased investment of gas supplies would lead to a significant increase in natural gas-fired generation.² The Energy Information Administration (EIA), in its *Annual Energy Outlook* for 1996, predicted that more natural gas pipeline capacity would be built in all regions of the country by 2010.³

The restructuring of electric wholesale markets was also predicted to result in a greater role for natural gas. In December 1995 Douglas Olesen – CEO of Battelle, a major technology company – predicted that increased competition would lead to more technological development in the utility industry. Much of the new technology would be

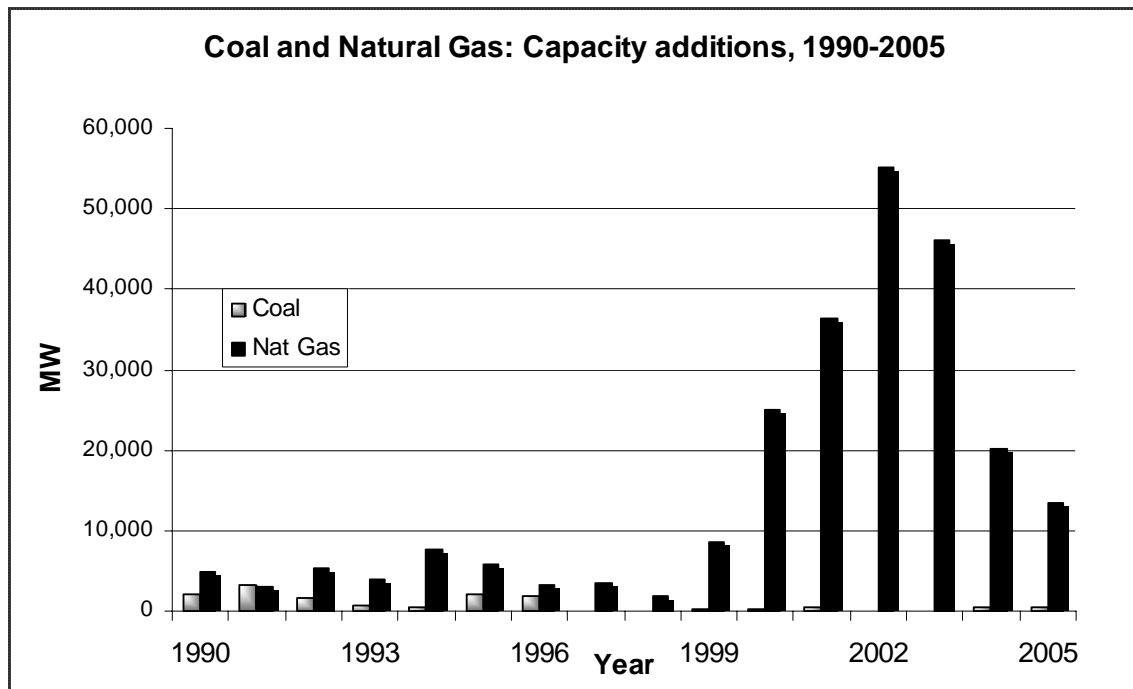
¹ Gary L. Hunt and Fereidoon P. Sioshansi, "Is There a Capacity Glut, and How Long Will it Last?" *Electricity Journal*, August/September 2002, pp. 64-65.

² Moody's Investors Service, "Credit Outlook Stable for City-Owned Electric Utilities, but Credit Risks Will Increase When Customer Choice of Electricity Supplier Begins," August 1999, p. 8.

³ Energy Information Administration, *Annual Energy Outlook 1996*, January 1996, p. 46.

clean-fired electricity, with natural gas being one of the principal components of this new clean electricity.⁴

But the natural gas boom petered out soon after it began. Merchant generators over-invested in capacity and then had difficulty recovering their costs because of low power prices. Numerous proposed plants were cancelled. The following chart shows how much natural gas capacity was added compared with new coal-fired capacity over the past fifteen years:



Source: EIA-860 data for years through 2004, and *Electric Power Annual* for 2005 capacity.

A second major reason for the end of the natural gas boom has been the fuel's price volatility. As recently as January 2002, natural gas spot prices were below \$2 per million Btu. Prices have risen precipitously over the past four years, exacerbated by the severe hurricanes of 2005, when prices reached \$15.27 per million Btu at the Henry Hub in September 2005.⁵ Prices have since fallen back to the \$6 to \$7 range, but remain volatile.

Forecasts taken from EIA's *Annual Energy Outlook* 2000 and 2006 demonstrate how expectations of natural gas's place in the electric industry have fallen. In the 2000 edition, EIA forecasted that natural gas would account for 31 percent of all electricity generation by 2020. EIA also predicted that dry gas production in 2020 would be 26.4 trillion cubic

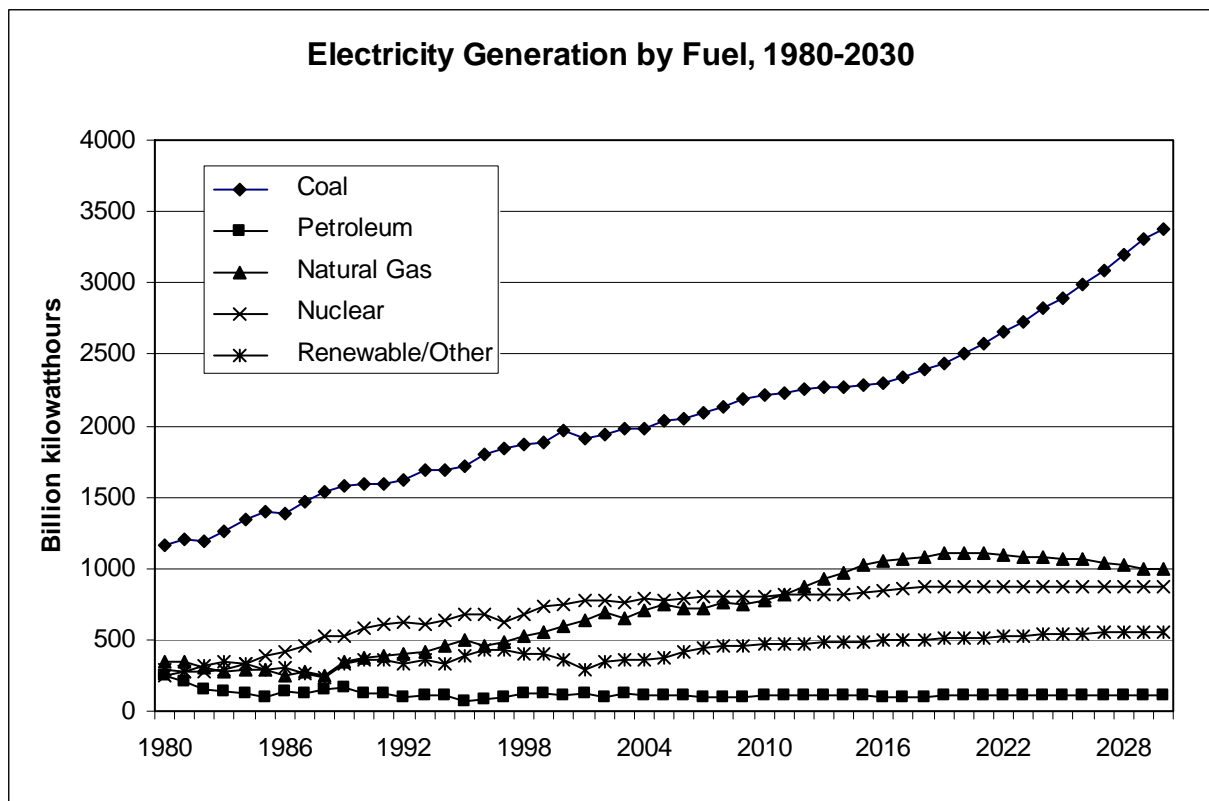
⁴ Douglas E. Olesen, "Unprecedented Competition, Fabulous Technologies: A Whole New Ballgame for the Energy Industry," *Electricity Journal*, December 1995, pp. 57-58.

⁵ Source: Energy Information Administration, NGI's (Natural Gas Intelligence) Daily Gas Price Index (<http://intelligencepress.com>), as published in EIA's *Natural Gas Weekly Update*.

feet, with 9.26 trillion cubic feet being used for electric generation.⁶ In the 2006 outlook, however, EIA forecasts that natural gas will only account for 22 percent of electric generation in 2020, with 21.44 trillion cubic feet of dry gas production, and 7.46 trillion cubic feet for electric production.⁷

In contrast, EIA's recent coal forecasts reveal an upward trend for coal. Coal currently represents roughly half of all electricity generation in the United States. Though EIA's 2006 forecast for coal's portion of electric generation in 2020 remains largely unchanged from its 2000 forecast (49 percent in the former, 50 percent in the latter), EIA's 2006 forecast shows coal's share of the electricity market climbing to 57% by 2030. EIA also foresees the construction of 174 gigawatts (GW) of coal-fired generating capacity by 2030.⁸

The following chart shows EIA's long-term generation forecast:



Source: EIA *Annual Energy Outlook*, 2006

Increasing costs of other fuel types – primarily oil and natural gas – will spur this increased coal consumption. EIA forecasts dramatic price increases for oil and natural gas, with both fuels predicted to rise in cost by over a dollar per million Btu (in 2004 dollars) over

⁶ Energy Information Administration, *Annual Energy Outlook 2000*, December 1999, p. 5; 135. Dry gas production is defined as marketed production (wet) minus extraction losses.

⁷ Energy Information Administration, *Annual Energy Outlook 2006*, February 2006, p. 7; 155.

⁸ *Annual Energy Outlook 2006*, p. 7.

the next 25 years. EIA predicts natural gas prices of \$6.26 and petroleum prices of \$7.61 (in 2004 dollars) per million Btu in 2030. Coal prices, meanwhile, are predicted to remain relatively flat – fluctuating between \$1.40 and \$1.50 per million Btu (in 2004 dollars) throughout the forecast period.⁹ In addition to the comparatively high prices for natural gas, there are supply issues. Offshore drilling for oil and natural gas is relatively constrained, although Congress is considering legislation that would expand drilling rights. Furthermore, the existing supply was hampered by Hurricanes Rita and Katrina, and other oil and gas assets remain vulnerable to future catastrophic storms. Faster depletion of domestic natural gas reserves and the increasing production in more costly recovery areas will keep upward pressure on gas prices.

The comparative costs of other fuels will have a significant impact on coal consumption. According to EIA alternate case forecasts, if gas and oil prices do not increase as much as predicted, then coal's share of the market could fall to 46%, but if the other prices go up even more than the base forecast, then coal could account for as much as 64% of the electricity generated in 2030.¹⁰ Higher oil and natural gas prices could also spur more investment in coal-to-liquid (CTL) plants.

Coal's Comeback

These EIA projections reflect new thinking about coal as a fuel for electric generation. Natural gas has lost its place as the “fuel of the future,” with coal rebounding to a place of prominence. This development is all the more surprising in light of the fact that much debate took place in the late 1990's over stranded cost recovery. Older coal plants were expected to retire in light of the construction of new natural gas-fired plants. As a result, regulators granted coal and nuclear plants stranded cost recovery because they were not expected to be able to compete with the new gas-fired capacity.

Not only has natural gas not made a significant dent in coal's share of electric utility generation, but many of these older coal plants have remained in operation. About half of the coal plants built in 1950 or earlier that were still on line in 2001 have since been retired, but less than ten percent of capacity built between 1951 and 1970 that was in operation in 2001 has gone off-line.¹¹

All in all, the outlook for the coal industry as regards electricity is very bright. One analyst summarizes the positive outlook for coal as follows:

Coal demand, production, and prices are high. Competitive fuel prices are higher on a Btu equivalent basis. Utility inventories remain at record low levels, while the economy improves and demand for electricity grows. In addition to basic supply

⁹ Ibid., p. 82.

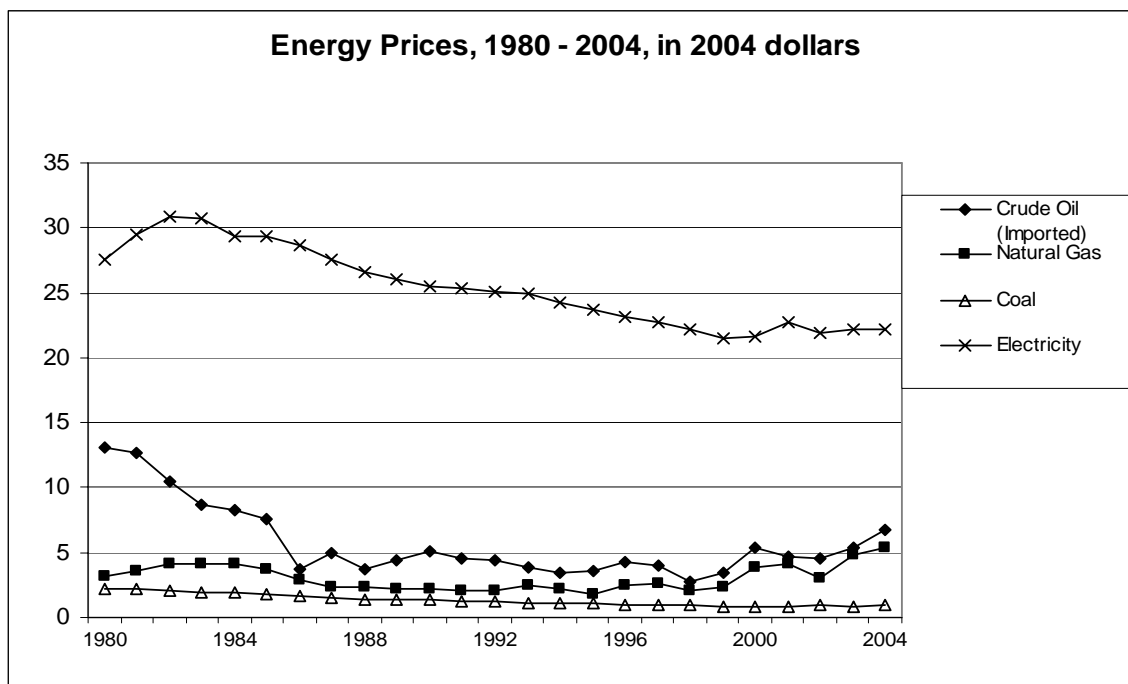
¹⁰ *Annual Energy Outlook, 2006*, p. 102.

¹¹ Source: Energy Velocity Database as of June 2006, and Form EIA-860 data as of 2001.

and demand principles, the Energy Policy Act of 2005 was signed into law this summer, creating several potential alternative use scenarios for coal.¹²

All of these conditions taken together are boosting confidence in and within the coal industry. There are some mitigating factors – particularly continuing problems with railroad transportation and supply shortages – that impair production performance. But, overall, coal is expected to maintain its prominent position regarding electric generation.

The financial industry also has a positive attitude about coal. Moody's Investors Service has given nine of the ten rated coal companies a stable credit outlook and one (Peabody Energy) a positive outlook.¹³ Standard and Poor's believes that the combination of high natural gas and oil prices, decreased coal production in Central Appalachia, global economic expansion – particularly in Asia, and the construction of new coal-fired plants all will cause coal prices to rise in the short-term. The rating agency does not think that oil or natural gas will be able to make a dent in coal's market share. "Over the longer term, alternative energy sources might become a factor but will not materially supplant King Coal's dominant position as the primary source of electric power in the U.S."¹⁴ Environmental regulations are a concern, but Standard and Poor's does not think they will severely impact the coal industry. As the chart below demonstrates, coal prices remain consistently below those of other fuels:



Source: EIA Annual Energy Outlook, 2006

¹² Steve Fiscor, "Coal Market Momentum Converts Skeptics," *Coal Age*, January 2006, p. 26.

¹³ Moody's Investors Service, "North American Coal Industry Outlook, 2006," December 2005, pp. 1-2.

¹⁴ Standard & Poor's, "Why High Prices Are Not Energizing Outlooks On U.S. Coal Producers," October 11, 2005, pp. 5-6.

Nuclear energy is coal's main competitor for baseload generation; however, Standard & Poor's maintains that the risks related to nuclear power plants – for example, high capital costs and safety concerns – mean that Wall Street investors will be more likely to invest in coal-fired power plants. The Energy Policy Act of 2005 (EPACT) established financial incentives for nuclear power investment, but those incentives may not be adequate to spur investment.¹⁵

Though it was assumed electric competition would prompt greater merchant investment while regulated utilities stepped back from investing in new generation, both regulated utilities and merchant investors will be key players in the construction of new-coal fired power plants. In many cases, regulated utilities are hoping to protect themselves from volatile wholesale markets, while merchant generators hope to benefit from the “dark spread.”¹⁶ One independent power producer that has been especially aggressive in its plans to build new coal-fired plants is NRG Energy. In June 2006 it announced its plans to build 10,500 MW of new generating capacity over the next decade – with a mix of both new nuclear and coal-fired plants. NRG's plans contribute to the overall total of 93 GW of coal-fired plants being proposed as of June 2006.¹⁷

This spate of development has caused some analysts to worry about a potential glut of new coal-fired and nuclear generation, particularly if natural gas prices do not remain high.¹⁸ NRG claims its slated projects have technological advantages over other projects and says that it will not begin projects unless it has committed 70% of all potential electric generation through long-term contracts.¹⁹ These long-term contracts ease the worries of investors, and help to shore up the independent power producer's credit rating.²⁰ In addition to independent power producers and utilities signing long-term power purchasing agreements, another method of ensuring a market for the plant's power is to share with customers in the development of new generating facilities. For example, the Plum Point Energy plant – a 665-MW coal-fired plant in Arkansas – is being financed by LS Power Associates, with a nearly 40% stake owned by municipals and co-ops.²¹

¹⁵ “Wall Street leery of nuclear plants, likely to favor coal,” in *Electric Power Daily*, March 28, 2006.

¹⁶ The dark spread refers to markets where natural gas – which has a high variable price – sets the market price and lower cost nuclear and coal-fired plants are able to receive higher revenues than their variable costs. For example, in the New England and ERCOT region natural gas usually sets the price. Steep increases in the price of natural gas have resulted in significant margins for coal and nuclear plants. See for example Craig K. Shere and Lance Ettus, “The Power of the Dark Spread,” Calyon Securities, October 6, 2005.

¹⁷ National Energy Technology Laboratory, “Tracking New Coal-Fired Power Plants: Coal's Resurgence in Electric Power Generation,” June 21, 2006.

¹⁸ “NRG Unveils Bold Generation Plan,” *The Energy Daily*, June 22, 2006.

¹⁹ “NRG Announces Comprehensive Repowering Initiative,” NRG Energy Press Release, June 21, 2006.

²⁰ Standard & Poor's, “Will High-Yield or High-Grade Financing Fuel New U.S. Coal Power Plants?” January 18, 2006, p. 34.

²¹ “Private equity, not just utilities, to build next round of plants, financiers say at conference,” *Electric Utility Week*, April 10, 2006.

Environmental Concerns

Though the outlook for coal is generally positive, and there are new methodologies for burning coal more cleanly, environmental concerns may hamper infrastructural investment and development. In addition to proposals on the federal level, such as legislation containing carbon dioxide (CO₂) caps, states are also proposing more stringent environmental regulations. For example, Illinois Governor Rod Blagojevich has proposed a plan that calls for coal plants to cut mercury emissions by 90% by July 2009.²² The California legislature recently passed AB 32, which limits greenhouse gas emissions from industrial sources.²³ Also, North Carolina filed suit against the Tennessee Valley Authority, alleging that emissions from the Authority's coal-fired plants "constitute a public nuisance in the state."²⁴

Despite these issues, and despite the wide-spread belief that tighter environmental regulations are on the horizon, most analysts maintain that coal will continue to be the dominant fuel for generation. In fact, EIA forecasts that if more stringent emission regulations are put in place, the average capacity utilization of coal-fired plants will increase from the current 72% to 80% in 2012 as newer, more efficient plants fitted with emission control equipment come on line and older plants are retired. EIA also states that coal plants fitted with emissions controls should remain competitive with natural gas-fired plants because of the low cost of coal. Moreover, EIA forecasts that 55% of the new coal capacity developed over the next 25 years or so will be Integrated Gasification Combined Cycle (IGCC) plants.²⁵

IGCC plants have the promise of environmental benefits, especially their ability to remove "criteria pollutants" such as sulfur dioxide, nitrous oxide, and other particulate matter.²⁶ However, questions remain about the feasibility of CO₂ capture, transportation and storage. For example, there is no demonstrated technology on a commercial basis for IGCC plants to separate and store CO₂ at a utility plant.²⁷

Capital costs for IGCC plants are considerably higher than for conventional coal plants. The Electric Power Research Institute (EPRI) puts the additional capital cost – in terms of dollars per kW of generating capacity – for IGCC compared to conventional pulverized coal at 14 percent, without considering additional costs for CO₂ capture and

²² "Illinois governor's plan sharply cuts mercury emissions," *Electric Power Daily*, January 6, 2006.

²³ "Schwarzenegger strikes deal on GHG bill," *Electric Power Daily*, August 31, 2006. Bill details can be accessed at [http://www.leginfo.ca.gov/pub/bill/asm/ab_0001-0050/ab_32_bill_20060831_enrolled.html](http://www.leginfo.ca.gov/pub/bill/asm/ab_0001-0050/ab_0001-0050/ab_32_bill_20060831_enrolled.html).

²⁴ "North Carolina sues TVA over emissions from 11 coal plants," *Electric Power Daily*, January 31, 2006.

²⁵ *Annual Energy Outlook 2006*, p. 101.

²⁶ American Public Power Association, "The Challenge of Carbon Sequestration for the Utility Sector," comments submitted to the National Commission on Energy Policy, November 22, 2005. The report can be accessed at <http://www.appanet.org/utility/index.cfm?ItemNumber=15144> (APPA members only.)

²⁷ "The Challenge of Carbon Sequestration." Also, see Taylor Moore, "Coal-Based Generation at the Crossroads," *EPRI Journal*, Summer 2005, p. 10.

sequestration.²⁸ The EPRI report also notes that reliability concerns associated with gasifier operations are an issue as well. Utilities may opt to install two gasifiers in order to improve reliability, but that would increase capital costs even further. These and other questions have dissuaded some utilities from investing in IGCC plants. Other utilities, such as Duke Energy and NRG Energy, are investigating the feasibility of building IGCC plants.²⁹

Utilities might be more apt to build these plants if the government provides financial incentives. Some incentives are provided in the Energy Policy Act of 2005.³⁰ Also, the Western Governors' Association has put together a Clean and Diversified Energy Advisory Committee to study ways in which western states can promote environmentally friendly power plant development, in particular by building 30,000 MW of clean energy by 2015. The committee encourages a broad portfolio of such energy including geothermal, solar, and clean coal. Specifically regarding clean coal, the committee recommends incentives to invest in commercially non-viable technologies, for example through tax breaks and loan guarantees. The committee also recommends that states grant full cost recovery for projects related to clean coal.³¹

Some members of the federal government have also called for greater national encouragement of investments in clean coal. Representative Joe Barton (R-TX) – Chairman of the House Energy and Commerce Committee – has sought funding for a program that would retrofit old coal plants with new pollution control equipment.³² Barton has clashed with the DOE on this issue because the agency has instead called for more funding of projects related to nuclear energy and spent fuel. The retrofit program was authorized under the Energy Policy Act of 2005.³³

The federal government has also announced the creation of the FutureGen project, which is a cost-sharing program between the DOE and eight coal and utility companies to construct a power plant that utilizes coal gasification and carbon sequestration.³⁴ Although the federal government has committed financial resources to the FutureGen

²⁸ Electric Power Research Institute, *Financial Incentives for Deployment of IGCC: A CoalFleet Working Paper*, prepared for the Senate Committee on Energy & Natural Resources Bipartisan Coal Conference, March 10, 2005.

²⁹ “Air quality rules make IGCC attractive to some,” *Electric Power Daily*, May 11, 2006; see also “David: NRG plans several coal-fired plants in Northeast,” *Electric Power Daily*, December 21, 2005. Also see NRG’s Press Release, June 21, 2006, for a more detailed breakdown of its planned capacity development. <http://www.snl.com/irweblinkx/file.aspx?IID=4057436&FID=2499948>

³⁰ Energy Policy Act 2005, Title IV, Sections 402 and 412. The act authorizes DOE to provide loans for projects producing energy from a plant using IGCC technology.

³¹ “Governors’ advisory panel details Western energy goals,” *Electric Power Daily*, January 11, 2006.

³² “Barton to seek clean coal program funding, blasts DOE,” *Electric Power Daily*, March 10, 2006.

³³ Energy Policy Act 2005, Title IV, Sections 3103 and 3105.

³⁴ “DOE, Industry Group Launch \$950 Million Clean Coal Project,” *The Energy Daily*, December 7, 2005 Two sites each in Illinois and Texas are the finalists for the project, “Illinois, Texas sites compete for FutureGen coal plant,” *Electric Power Daily*, July 26, 2006.

project, DOE's proposed Fiscal Year 2007 budget contains cuts amounting to 90% from previous levels for other clean coal projects.³⁵

Rail Issues

Though environmental issues will pose potential problems for coal-related projects, nothing currently plagues the industry as much as troubles with rail deliveries of coal. Standard & Poor's puts the problem into focus:

With fewer rail companies in existence than a generation ago, existing railroads cutting back on staff and infrastructure improvements – especially the laying of new track and the purchase of locomotives – and increasing demand for coal, we are witnessing a perfect storm that has created a vortex of upward pressure on transportation costs.³⁶

The consolidation of the railroad industry has deeply impacted the coal and utility industries. Since rail industry deregulation took place in 1980, the number of railroads has shrunk from 40 to four major railroads that are responsible for over 90% of rail traffic.³⁷ As a result many utilities are served by only one railroad, subjecting them to “captive” rail rates. Consumers United for Rail Equity (C.U.R.E.) documents the marked difference in rail transportation costs where competition exists and where railroads have captive customers, as captive rates are often double those of competitive rates.³⁸ Furthermore, Glenn English, CEO of the National Rural Electric Cooperative Association, says that railroads are making six to eight percent profits in competitive markets, while making 300-400% profits in captive markets.³⁹

Robert Sahr, Chairman of the South Dakota Public Utilities Commission, in testimony before the U.S. Senate, highlighted some other major problems with rail shipments of coal. The most serious development has been dwindling stockpiles. While the average utility stockpile is over 30 days of supply, some utilities face critical shortages. For example, the Big Stone Power Plant's stockpile fell to ten days in March, 2006, and Laramie River Station in Wyoming has also faced severe shortages. Coal shortages have forced power plants to purchase electric power on the open market. Big Stone had to purchase power that was \$20 a megawatt higher than the power the plant can produce.

³⁵ “Flat DOE Budget Boosts Renewables, Nuclear,” *The Energy Daily*, February 7, 2006.

³⁶ Standard & Poor's, “Coal And Public Power: Credit Issues With Obtaining It,” April 24, 2006, p. 4.

³⁷ Testimony of the Honorable Robert K. Sahr, Chairman, South Dakota Public Utilities Commission on Behalf of the National Association of Regulatory Utility Commissioners, before the Committee on Energy and Natural Resources, U.S. Senate, May 25, 2006, (“Sahr Testimony”), p.4.

³⁸ Consumers United for Rail Equity, “How Do Captive Rail Rates Compare to Competitive Rail Rates,” August 2004. APPA is a member of C.U.R.E.

³⁹ “Captive rail customers urge Congress to act,” *Electric Power Daily*, March 10, 2006.

These costs are then transferred to rate payers. Sahr said that rising Powder River Basin (PRB) rail rates may cost South Dakota utility customers \$7.7 million.⁴⁰

In addition to hampering utilities' ability to get needed coal for existing plants, problems with rail shipments might dissuade some from investing in new coal-fired facilities. Robert McLennan of Tri-State Generation and Transmission Association – a rural electric wholesale power supply cooperative – states that Tri-State is currently considering its future resource planning, and it would prefer to use coal for new generation because of its relatively low cost and domestic availability. But even though Tri-State is located near the PRB, it must be assured that it can receive timely deliveries of coal to go ahead with construction of new coal-fired generation. In his testimony before the Senate McLennan said:

If there are continued constraints on rail lines moving out of the Powder River Basin to other parts of the nation, there will be a significant negative impact on Tri-State's ability to meet its service obligations in the future. If the major rail carriers are permitted to continue their monopolistic, anti-competitive practices, the cost of providing electricity using America's vast reserves of coal may force generators to rely on other fuels and even to foreign suppliers.⁴¹

This last point was hammered home by MEAG Power's Steven Jackson. Jackson testified at this same hearing that unreliable shipments have forced MEAG to look offshore for coal supply. Ultimately, MEAG began importing coal from Indonesia in January 2006. These deliveries will continue until the end of the year, and perhaps longer if MEAG continues to have difficulty with domestic shipments.⁴² Considering that the United States has been called the "Saudi Arabia of coal" because of the nation's estimated 250 years of coal reserves,⁴³ foreign imports of such an abundant domestic product come as a surprise.

High transportation costs also affect EIA's otherwise positive forecasts for coal use. EIA compiled an alternative model for future coal production based on high rail transport cost. According to this alternate forecast, coal consumption would decrease 16 percent by 2030 from EIA's reference case. Additionally, EIA predicts that 63 gigawatts less coal-fired generating capacity would be built if transportation costs for coal increase by 50% from the reference case.⁴⁴

⁴⁰ Sahr Testimony at p. 10.

⁴¹ Testimony of Robert "Mac" McLennan, Vice President, External Affairs, On Behalf of Tri-State Generation and Transmission Association, Inc. before the Committee on Energy and Natural Resources, U.S. Senate, May 25, 2006.

⁴² Testimony of Steven Jackson, Municipal Electric Authority of Georgia (MEAG Power), before the Committee on Energy and Natural Resources, U.S. Senate, May 25, 2006.

⁴³ Testimony of Glenn English, C.E.O., National Rural Electric Cooperative Association, before the House Committee on Transportation & Infrastructure, Subcommittee on Railroads, April 26, 2006.

⁴⁴ Annual Energy Outlook, p. 102.

Beginning in 2000, Congress permitted railroads to include fuel surcharges to make up for the rising fuel costs of transporting coal. Utilities do not have a problem with the concept of a surcharge, but they complain that these surcharges have become excessive. Where these surcharges used to account for about two percent of the total freight charge, they have climbed to 18.5 percent for coal transported from the Powder River Basin. The utilities also claim that the fuel surcharges go to pad the railroads' profit margins rather than covering the increasing fuel costs.⁴⁵

The acrimony between railroads and utilities has been growing. Entergy Arkansas filed suit recently against Union Pacific (UP) for failure to maintain its rail lines, a failure which has impaired Entergy's ability to receive coal deliveries. Union Pacific has claimed *force majeure* for its inability to make its promised coal deliveries in 2005, but Entergy asserts that the railroad should be cited for negligence.⁴⁶ Wisconsin Electric Power, operator of We Energies, has also joined in a suit against UP for failing to meet its delivery contracts from 2003 to 2005 and for overcharging on the coal it did deliver.⁴⁷

There has been some improvement in rail deliveries in the first half of 2006. Rail carriers Burlington Northern Santa Fe (BNSF) and UP have expanded their capacity and will make further additions over the next few years to allow for the transportation of an additional 400 million short tons per year. Despite these capacity additions, space limitations at plant sites mean that utilities will be unable to stockpile enough coal to alleviate the risk of long disruptions.⁴⁸

Because of these continued problems, utilities are lobbying Capitol Hill to require railroads to charge more competitive rates and improve deliveries. As of May 2006 there were bills in both the House and Senate that attempt to ensure reasonable rates. H.R. 3318 would strike down antitrust exemptions for the railroad industry, and S 919 would require the Surface Transportation Board (STB) to institute new procedures to hear customer complaints. S 919 also calls for the implementation of cost-based rates for rail transportation.⁴⁹

⁴⁵ "Railroads abuse fuel surcharges, utilities tell STB; they want board to set standards," *Electric Utility Week*, May 15, 2006.

⁴⁶ "Entergy sues Union Pacific over limited PRB coal deliveries," *Electric Power Daily*, April 13, 2006.

⁴⁷ "Wisconsin utilities, regulators pressure rail companies on coal delivery costs, shortfalls," *Electric Utility Week*, May 1, 2006.

⁴⁸ Trygve Gaalaas, "Update on PRB Coal Transportation: Still a Hot Issue," *Coal Age*, June 2006, pp. 32-34.

⁴⁹ Chris Holly, "Utilities Rip Railroads On Coal Deliveries; Demand Hill Action," *The Energy Daily*, May 26, 2006. For a text of the House bill, see <http://thomas.loc.gov/cgi-bin/query/D?c109:1:/temp/~c109yg6RR0>:: For the Senate bill, see <http://thomas.loc.gov/cgi-bin/query/F?c109:1:/temp/~c10996hgCv:e0>

Conclusion

Despite the problems related to rail delivery of coal and environmental regulations, coal still has numerous advantages over other generation choices. It is cheaper, more abundant, and exhibits less price volatility than other standard fuel options. Development of technologies to improve coal's environmental performance and investment in rail transportation infrastructure are both needed to ensure that the U.S. can take full advantage of its most abundant energy source.