STATEMENT OF

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HEARING ON COAL

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Summary of Major Points

Coal is today a mainstay of U.S. electricity generation, accounting for 52 percent of all generation by electricity producers and cogenerators in 2000. Some 40 percent of all U.S. generating capacity today is coal-fired. The coal industry employs approximately 80,000 miners, a total that has steadily declined as improved productivity and a shift to less labor-intensive Western surface mining have allowed the industry to produce higher quantities of coal with fewer workers. Due to that increasing productivity, coal minemouth prices–the price of coal at the point of production–have steadily declined for the past two decades, now standing at about $16.50 per short ton, down from nearly $23 per ton (in real 1999 dollars) three decades ago. Over the past six months, however, there have been some increases in “spot”, or non-contract, coal prices in some areas of the country.

Under current laws and regulations, the use of coal to generate electricity is expected to grow over the next 20 years as existing plants are used more intensively and a few new plants are built. However, coal is expected to lose market share to natural gas in electricity generation. Coal is projected to provide 44 percent of the nation’s electricity generation in 2020, a decline in relative terms but still an increase in terms of consumption and production. Prices are expected to continue falling, as improved productivity continues, although at a slower pace than recently, reaching $12.70 per ton in 2020 in real 1999 dollars. As a result of the improving productivity and the shift to less-labor-intensive Western surface mining, employment in coal mining is expected to continue its long-term decline, with about 60,000 coal miners expected in 2020, a decline of about a fourth from today’s levels. National coal production is expected to increase to 1.3 billion tons by 2020, with the largest gains coming from the low-sulfur subbituminous mines of the West, especially Wyoming. The older mining areas in the East and Midwest are projected to show declining production through 2020. Coal exports, which are today almost half of their 1991 peak of 109 million tons, are expected to remain at about 60 million tons annually through 2020.

The coal industry faces significant challenges to attain these projections if environmental laws and regulations become more stringent, especially any effort to reduce carbon dioxide emissions. A policy to reduce carbon dioxide emissions to levels similar to those contained in the Kyoto Protocol could have major impacts on coal consumption and production if the U.S. must meet all or most of its reductions domestically. There are a number of proposals to initiate “multi-pollution” strategies, which call for reductions in emissions of carbon dioxide and other coal-producing pollutants such as sulfur dioxide, nitrogen oxides, and mercury below current levels; these proposals could negatively affect the coal industry, depending upon the levels of reduction required. Coal also faces significant competition from natural gas as a fuel source for generation due to its higher efficiency, lower capital cost, better load-following, and lower construction lead times, which makes it more attractive in competitive electricity markets.

Mr. Chairman and Members of the Committee:

I appreciate the opportunity to appear before you today to discuss current and future coal supply, demand, and prices in the United States.

The Energy Information Administration (EIA) is an autonomous statistical and analytical agency within the Department of Energy. We are charged with providing objective, timely, and relevant data, analysis, and projections for the use of the Department of Energy, other Government agencies, the U.S. Congress, and the public. We do not take positions on policy issues, but we do produce data and analysis reports that are meant to help policy makers determine energy policy. Because we have an element of statutory independence with respect to the analyses that we publish, our views are strictly those of EIA. We do not speak for the Department, nor for any particular point of view with respect to energy policy, and our views should not be construed as representing those of the Department or the Administration. However, EIA's baseline projections on energy trends are widely used by Government agencies, the private sector, and academia for their own energy analyses.

The Committee has requested information about current and future utilization of coal for electricity generation, statutory and regulatory provisions that impact the supply of coal, the prospects for using coal to meet future generation needs, and the role of coal in a comprehensive national energy policy. EIA collects and interprets data on the current energy situation, and produces both short-term and long-term energy projections. The projections in this testimony are from our *Annual Energy Outlook 2001*, released late last year. The *Annual Energy Outlook* provides projections and analysis of domestic energy consumption, supply, and prices through 2020. These projections are not meant to be exact predictions of the future, but represent a likely energy future, given technological and demographic trends, current laws and regulations, and consumer behavior as derived from known data. EIA recognizes that projections of energy markets are highly uncertain and subject to many random events that cannot be foreseen, such as weather, political disruptions, strikes, and technological breakthroughs. In addition, long-term trends in technology development, demographics, economic growth, and energy resources may evolve along a different path than assumed in the *Annual Energy Outlook*. Many of these uncertainties are explored through alternative cases.

EIA also performs special studies at the request of the Department of Energy, the U.S. Congress, and other government agencies. In late 2000, EIA performed an analysis of strategies for reducing multiple emissions at power plants, at the request of then-Representative David M. McIntosh, Chairman, Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs of the Committee on Government Reform. The results of this analysis were published in *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*.[1] This report projects the impact on coal markets of such proposals, and I have included it in my testimony as an illustration of the challenges faced by the coal industry in responding to potential environmental policies. In an upcoming

[1]Energy Information Administration (EIA), *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, SR/OIAF/2000-05/APPS-2 (Washington, DC, December 2000), http://www.eia.doe.gov/oiaf/servicerpt/powerplants/index.html.

report, we will also provide projected impacts of including a cap on mercury emissions and a national Renewable Portfolio Standard to this analysis, both separately and in fully integrated cases with sulfur dioxide, nitrogen oxides, and carbon dioxide.

The Current Situation

Supply, Demand, and Prices

U.S. coal production, continuing a recent trend, declined by 1.2 percent between 1999 and 2000, to 1,087 million short tons. This represented the second straight year of production decreases, following a 1.6 percent drop between 1998 and 1999. While consumption rose slightly to an estimated 1,078 million short tons, about a 3 percent growth from 1999, more coal was supplied from producer and consumer stocks, reducing the need for an increase in production. On a regional basis, most of the decline in 2000 was in the Interior section of the country, made up primarily of the Illinois Basin, Texas lignite production, and other smaller deposits in the Midwest. Illinois Basin coal, mainly high sulfur, declined 15 million short tons, or almost 15 percent, from 1999 levels as electricity producers demanded more low-sulfur coal to meet the sulfur dioxide caps of Phase II of the Clean Air Act Amendments of 1990. Appalachian coal production declined slightly, as its older mines continued their long-term loss of market share, while Western coal–dominated by low-sulfur subbituminous production in Wyoming's Powder River Basin–continued to increase production, although at a lower rate than in recent years.

Some 978 million short tons, more than 90 percent of the total consumption, were used by the electric power sector to produce almost 52 percent of total electric generation from all energy sources. Coal use for electricity generation grew by 3.3 percent in 2000, more than a percentage point higher than the growth in total generation. Coal use in the non-electric power sector grew about 2 percent in 2000, to just over 100 million tons. While consumption of coking coal used in steel production grew slightly, steam coal use for general industry showed the largest 1-year increase in over a decade. With the vigorous economy fueling industrial demand, and rising natural gas prices, a 3-year decline in industrial usage of coal was reversed.

Coal prices through the end of 2000 continued the downward trend that started in the early 1980s. On a delivered basis, the average utility coal price dropped to $1.20 per million Btu in 2000, about a 2 percent decline from 1999, or about 4 percent in real (inflation-adjusted) terms. The minemouth price of coal also is estimated to have declined about 4 percent in 2000. Contributing to the decline in prices over the last two decades has been a persistent growth in labor productivity, attributable both to technology improvements such as longwall mining, and to a long-term shift to Western surface mining, which requires far less labor input than the older underground mines of the East. From 1985 through 1998, coal mining productivity improved at an annual average rate of 6.5 percent. This in turn was accompanied by a reduction in coal mining employment from 169,000 to 81,000 workers nationwide, or a decline of 52 percent.

Although coal is the only fuel for which the U.S. is a net exporter, coal exports have fallen precipitously in recent years. From a high of 109 million tons in 1991, exports fell to 59 million tons in both 1999 and 2000. The 2000 level, however, represented at least a temporary halt in the recent decline, which saw annual exports decrease over 30 million tons from 1996 through 1999. Fierce competition from other coal-exporting nations, especially Australia and South Africa, along with a strong U.S. dollar, has greatly reduced U.S. competitiveness in world coal markets, compared to a decade ago. However, U.S. exports still represent about 5 percent of U.S. production.

Coal is the nation's most abundant fossil fuel resource. The Demonstrated Reserve Base, which is a broad measure of available coal resources, is estimated to be about 500 billion short tons. Of this amount, approximately 275 billion short tons are estimated to be recoverable. As of the end of 1998, about 19.3 billion tons of coal were available for recovery at the nation's active coal mines. The U.S. has the world's largest quantity of ultimately recoverable coal reserves.

Legislative and Regulatory Issues Affecting Coal

While coal is expected to continue to play a major role in meeting increasing U.S. electricity demand, there are a number of challenges the industry must face in light of current and future environmental policy goals. The Clean Air Act Amendments of 1990 and related State regulations have placed increasingly stringent requirements on electricity generators to reduce emissions of sulfur dioxide and nitrogen oxides. These requirements have affected coal-fired generators more than other sources of electricity generation (except for petroleum-based generators) because of the higher levels of these pollutants emitted by coal-fired plants.

The greatest challenge to maintaining or increasing use of this domestic energy resource is regulatory uncertainty regarding future environmental policies, especially those dealing with carbon dioxide. Proposed revisions to address ozone emissions, fine particulates, regional haze, and mercury emissions could necessitate additional control measures for coal electricity generation. Water quality regulations related to cooling water intake structures, and total maximum daily loadings on streams may be expanded. Climate change concerns could affect the future use of coal, given the uncertainty surrounding whether and when the U.S. might require reductions in carbon dioxide emissions. Because coal-based electricity generation emits about 70 percent more carbon dioxide per unit of production than natural gas electricity generation, any effort to control carbon dioxide emissions will almost certainly have an impact on coal power plants, which emit about one-third of U.S. carbon dioxide emissions. Because there are currently no economically viable technologies to eliminate carbon dioxide emissions from coal combustion, power producers may need to turn to alternative sources to meet the nation's increasing need for generating capacity.

One issue currently before the courts regards emissions from a number of existing coal plants. The Department of Justice, on behalf of the U.S. Environmental Protection Agency (EPA), filed lawsuits in November 1999 against seven electric utility companies in the Midwest and South, charging that 17 of the companies' power plants had illegally released significant amounts of pollutants for two decades[2]. At the same time, the EPA issued an administrative order against the Tennessee Valley Authority (TVA), charging the Federal agency with similar violations at

[2]In December 1999 a similar suit was also filed against Duke Power.

another seven power plants. In addition to the lawsuits and administrative order, the EPA issued notices of violation, naming an additional eight plants owned by other utilities as sites of similar violations of the Clean Air Act. The dispute in these lawsuits centers around whether certain modifications or capital improvements performed at the plants named in the action were "major"—specifically, whether the actions were aimed at increasing capacity, regaining lost capacity, or extending the life of the units. Any such major modification, under the provisions of the Act, would trigger the New Source Review permitting process, forcing the plants to adopt technology to meet more stringent SO2 and NOx emission standards. At this time one of the suits has been resolved, and pending settlements have been reached with two other companies accused of similar violations. The remaining cases have yet to be resolved. If the result of these and similar future actions is that a large number of older coal-fired power plants will be required to add state-of-the-art emissions control equipment in the near future, some of them may instead choose to retire or repower as natural gas plants, thus reducing overall demand for coal.

Other regulatory issues facing the industry include the status of mountaintop mining, which is a method of surface mining used primarily in West Virginia. This procedure enables the operator to remove the "overburden" covering a coal seam, making the entire deposit more easily available for extraction. Because the removed material must be deposited into adjacent valleys, there is concern that streams and other natural features could be affected by the material, known as "valley fill." In October 1999, the U.S. District Judge for the Southern District of West Virginia issued a ruling that had the effect of eliminating the issuance of surface coal mining permits for certain projects in West Virginia using mountaintop mining methods. The order has currently been stayed pending appeal. The 4^{th} Circuit Court of Appeals heard the case on December 7, 2000. A decision is expected to be made between three to six months from that date. Future projects in Appalachia could be adversely impacted depending upon the final outcome of the case.

Finally, the Department of Labor has issued regulations which would have the effect of increasing eligibility for medical claims arising from Black Lung Disease, an occupational hazard of coal mining. The new regulations were effective on January 19, 2001. However, in response to a challenge from the National Mining Association (NMA) and others, the U.S. District Court for the District of Columbia issued an injunction on February 9, 2001, suspending many sections of the new rules. Oral arguments on the NMA lawsuit are scheduled for May 21, 2001. If approved, these rules could raise insurance rates for mining companies, as well as the excise tax supporting the Black Lung Disability Trust Fund, currently set at $0.55 per ton of surface-mined coal and $1.10 per ton of underground-mined coal. The industry has stated that the regulations could have a severe impact on profitability, especially for smaller operators, while miners have argued that too small a proportion of medical claims related to the condition are currently being approved.

Although each of these issues is important to the future of the coal industry, they are far less likely to have a major impact than would the possible imposition of carbon dioxide limits on power plants. Because there is no commercially-viable technology for reducing or eliminating carbon dioxide emissions from the production of electricity, the only plausible alternatives are to improve efficiency, switch to lower-emitting sources such as natural gas, nuclear, or renewables, or reduce electricity production. All of these options imply lower coal consumption and, consequently, production.

The Outlook

The *Annual Energy Outlook 2001* (AEO2001) reference case projects U.S. energy supply, demand, and prices through 2020. It assumes a continuation of current laws and regulations, but does not include in its reference case the impacts of proposed policies such as the Kyoto Protocol provision for reduced carbon dioxide emissions or multi-emission reductions from power plants. The following summarizes the reference case outlook for coal markets, then discusses how those results might change under a multi-pollutant strategy.

Annual Energy Outlook 2001

Coal is projected to continue to play a major role in meeting electricity generation requirements through 2020 under the assumptions of the AEO2001 reference case. Total purchased electricity consumption is projected to increase at an annual average rate of 1.8 percent between now and 2020, reaching 4804 billion kilowatt-hours (bkwh) (Figure 1). In order to meet this demand, electricity producers and cogenerators will need to increase total generation to 5294 bkwh by 2020, after accounting for on-site consumption by cogenerators and transmission and distribution losses. Of this total, coal-fired generation is expected to contribute 2350 bkwh, or 44 percent of the total (Figure 2). While this represents continued growth in coal-based generation, it also indicates a decline from the share (52 percent) of generation provided by coal-fired capacity in 2000. The decreased share of generation from coal is expected to be made up mainly by increased use of natural gas, which is expected to increase its share of total generation from 16 percent in 2000 to 36 percent by 2020. Despite the higher fuel cost, natural gas is expected to make inroads in the electricity generation sector due to lower capital costs for new natural gas generating capacity, shorter construction lead times, easier permitting and siting of such plants, higher efficiencies than coal-based plants, and lower sulfur dioxide and nitrogen oxide emissions, helping to meet the requirements of the Clean Air Act Amendments of 1990. While coal-fired capacity is currently at 312 gigawatts, about 40 percent of the nation's generating capacity, only about 22 gigawatts are expected to be added through 2020, with 15 gigawatts of today's capacity retiring by that time. Thus, by 2020 coal-fired capacity is expected to make up just 28 percent of total generating capacity, with natural gas-fired combined cycle and combustion turbine units accounting for most of the needed growth (Figure 3). Figure 4 illustrates the kilowatt-hour cost comparisons between new coal- and natural gas-fired generating capacity in 2005 and 2020, showing the advantage expected for natural gas-fired combined cycle capacity to meet future electricity needs.

In order for coal to meet the increasing demand for electricity, production will need to grow at an average annual rate of 0.9 percent through 2020, with total production reaching 1331 million short tons. All of the growth in production, however, is expected to come from Western mines, which are expected to increase their production from 518 million short tons in 2000 to 787 million short tons by 2020, a 2.1 percent annual growth rate. Production in the older mines of Appalachia is projected to decline from the 2000 level of 422 million short tons to 392 million short tons by 2020, while Interior production will remain about the same (Figure 5). Western coal is dominated by the low-sulfur, surface-mined production of Wyoming's Powder River Basin, which in just a couple of decades has become the leading source of U.S. coal, both because of its low cost and low sulfur content. Production in the Interior region tends toward high-sulfur coal, which is less valuable due to the provisions of the Clean Air Act Amendments of 1990. While Appalachia has both low- and high-sulfur coal deposits, mining costs are higher because most of the mines are underground, and the lowest-cost reserves have already been mined.

As additional quantities of coal are produced, current reserves of coal at active mines will decline. Active mines' coal reserves at the end of 1998 totaled about 19.3 billion tons, roughly 19 years' worth of reserves at today's production levels. By 2020, only about 2 billion tons of today's reserves would remain, necessitating major investment in the industry to expand reserves at existing mines or open new mining capacity (Figure 6). This is particularly true of the East, where virtually all of today's reserves must be replaced in order for the industry to operate at projected levels of production. In the West, mine operators are maintaining a higher reserve-to-production ratio, since a large proportion of overall reserves is closer to the surface and thus cheaper to acquire than the older underground reserves in the East. The Demonstrated Reserve Base for coal–roughly equivalent to the discovered resource base–totals more than 500 billion tons of coal, by far the largest of the fossil fuel resource bases in the U.S., and the largest coal resource base of any country in the world.

The increasing demand for electricity generation is the key driver that affects coal consumption. Consumption by the electricity sector is expected to increase from 964 million short tons in 2000 to 1186 million short tons in 2020, a 1.0 percent annual average growth rate, about half the growth rate of the last decade. Both a lower rate of growth in electricity demand, and a shift to natural gas-fired generation, account for the lower expected growth in coal consumption by electricity producers over the next 20 years. Non-electric consumption is expected to remain about the same, at about 110 million short tons, in 2020, as the long-term decline in metallurgical coal consumption used in the production of steel is offset by slight growth of steam coal for use in general industry (Figure 7).

Minemouth coal prices declined by $6.45 per ton (in 1999 dollars) between 1970 and 2000, and they are projected to decline by 1.2 percent per year, to $12.70 per short ton, by 2020 (Figure 8). Both productivity improvements--which are expected to continue but at a lower rate throughout the forecast horizon (Figure 9)--and the long-term shift to lower-cost Western coal, contribute to the continued decline in minemouth prices. Delivered prices to electricity generators are expected to decline, but at a somewhat lower rate. From an estimated $24.16 per short ton (real 1999 dollars) in 2000, prices are expected to decline to $19.45 a short ton by 2020, an annual average decrease of 1.1 percent. While minemouth prices fall at a faster rate, higher transportation costs associated with long shipments of greater quantities of Powder River Basin coal are expected to partially offset the lower cost of coal at the mines. There has been some recent reversal of this trend in spot coal markets over the past six months, with coal prices delivered to utilities up by as much as a third in some areas; but we believe prices will resume their decline in the longer term, as prices of competing energy sources, especially natural gas, return to their long-run equilibrium levels.

Coal exports, once a growing share of production, have declined over the past decade, and are expected to continue to decline through 2020, although at a lower rate. From a 2000 level of about 59 million short tons, U.S. exports are expected to decline to 56 million short tons by 2020. Continuing competition from Australia and South Africa, new competition from Colombia, Indonesia, and China, and a reduction in coal demand in our traditional European markets, mitigate against growth in coal exports over the next two decades.

Analysis of Multi-Pollution Strategies

In its recent Service Report for the House Government Reform Committee, EIA analyzed the impact of various policies to reduce multiple emissions at power plants, concentrating on emissions of sulfur dioxide (SO2), nitrogen oxides (NOx), and carbon dioxide (CO2). While a number of congressional bills have been introduced with varying levels and timing of emission reductions, EIA was asked to provide analysis of proposals to reduce SO2 and NOx by 75 percent from 1997 levels, and CO2 to either 1990 levels or 7 percent below 1990 levels, similar to the general requirements of the Kyoto protocol, but restricted to emissions by electric generators. It was assumed that a cap-and-trade system similar to that developed for SO2 under the Clean Air Act Amendments of 1990 would be used for each pollutant. The main points of the analysis were as follows:

- When emissions caps are examined for each emission individually, power companies are projected to invest primarily in emission control equipment to comply with the NOx and SO2 caps; however, to comply with the CO2 cap they are expected to shift dramatically away from coal to natural gas and, to a lesser extent, renewables.
- The stringency of the emission targets influences the projected impact on electricity and natural gas prices.
- The impacts of meeting the NOx and SO2 caps are not projected to have a large effect on electricity prices—generally 1 percent or so above the prices expected in the reference case.
- The projected price impacts of meeting the CO2 cap are much larger than those of meeting the NOx and SO2 caps, as much as 42 percent over reference case electricity prices.
- The CO2 allowance prices (expressed in dollars per metric ton carbon equivalent) projected in this analysis are generally lower than those projected in comparable studies of efforts to meet the target from the Kyoto Protocol over the whole economy rather than just in the power sector.
- When emissions caps are examined together, actions taken to meet the CO2 cap are expected to overshadow those taken to reduce NOx and SO2 emissions.
- Using an integrated approach--setting caps on power sector NOx, SO2, and CO2

emissions at the same time--is projected to lead to somewhat lower total costs than addressing each emission one at a time.

- If existing coal plants are required to add emission control equipment, NOx and SO2 emissions would be dramatically reduced.
- There is considerable uncertainty about whether the changes projected in this analysis could be accomplished in the relatively short time periods assumed—particularly to meet 2005 CO2 emission targets. The increased production required from the U.S. natural gas industry could be especially difficult to attain in this time frame.

Conclusion

While coal provides more than half of today's electricity generation in the U.S., that share is expected to shrink over the next two decades as natural gas is expected to greatly increase its proportion of electricity generation. Nevertheless, under current laws and regulations, coal consumption and production would continue to grow about 1 percent per year between now and 2020.

The major challenge to coal is the growing trend toward laws and regulations to reduce or eliminate emissions associated with its use. These include Phase II of the Clean Air Act Amendments of 1990, proposals to reduce carbon dioxide emissions similar to the requirements of the Kyoto Protocol, "multi-pollutant" strategies that further reduce sulfur dioxide and nitrogen oxide emissions and add new restrictions on mercury and carbon dioxide, and emission control technology retrofits that could be required if current lawsuits alleging violations of the Clean Air Act's New Source Review provisions against a number of coal-fired generating plants are successful. Coal also faces significant competition from natural gas as a fuel source for generation due to its higher efficiency, lower capital cost, and lower construction lead times, which makes it more attractive in competitive electricity markets. Of these challenges, by far the greatest is the potential for reductions in carbon dioxide emissions.

Thank you, Mr. Chairman and members of the Subcommittee. I will be happy to answer any questions you may have.

Figure 1. Annual Electricity Sales by Sector, 1970-2020 (billion kilowatthours)

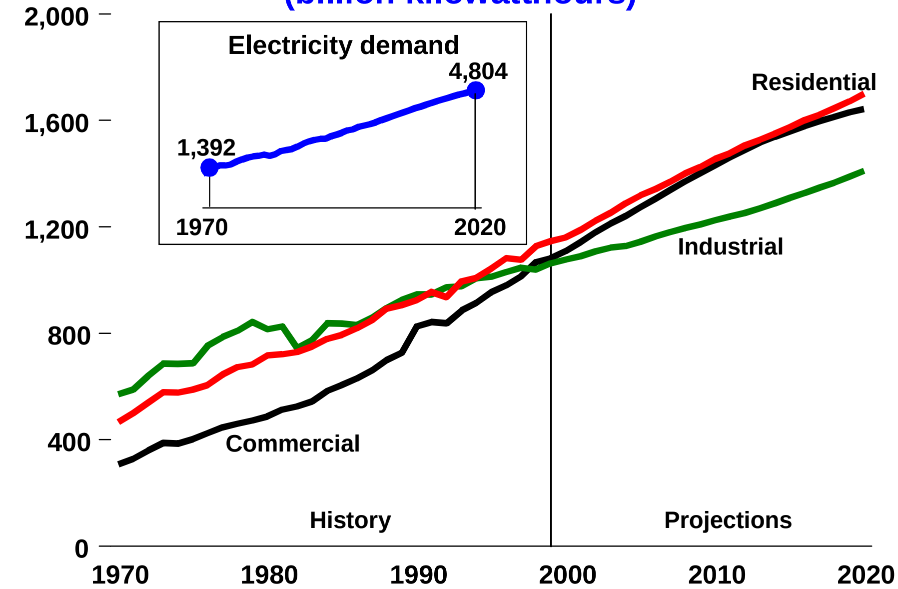

Figure 2. Projected Electricity Generation by Fuel, 1999 and 2020 (billion kilowatthours)

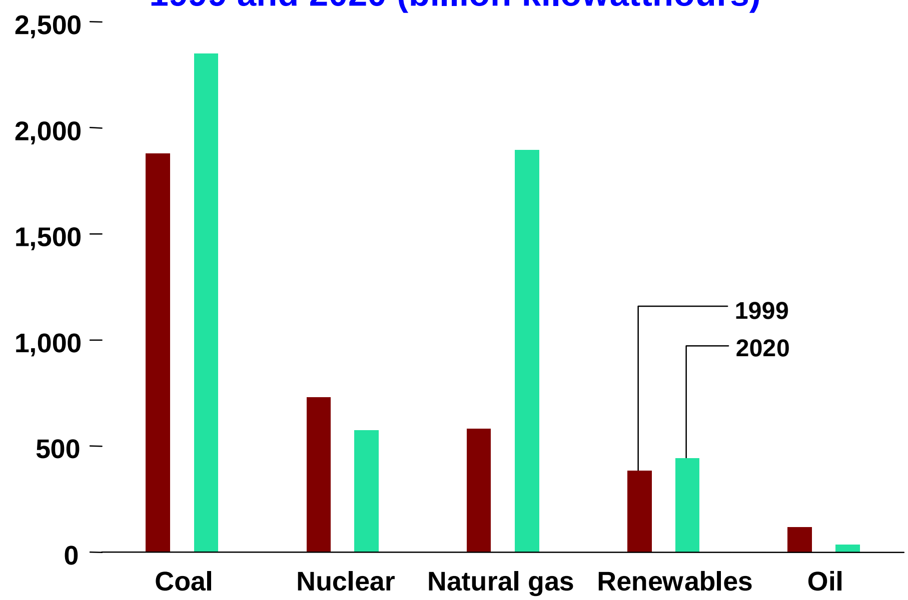

Figure 3. Projected Electricity Generation Capacity Additions by Fuel Type, Including Cogeneration, 2000-2020 (gigawatts)

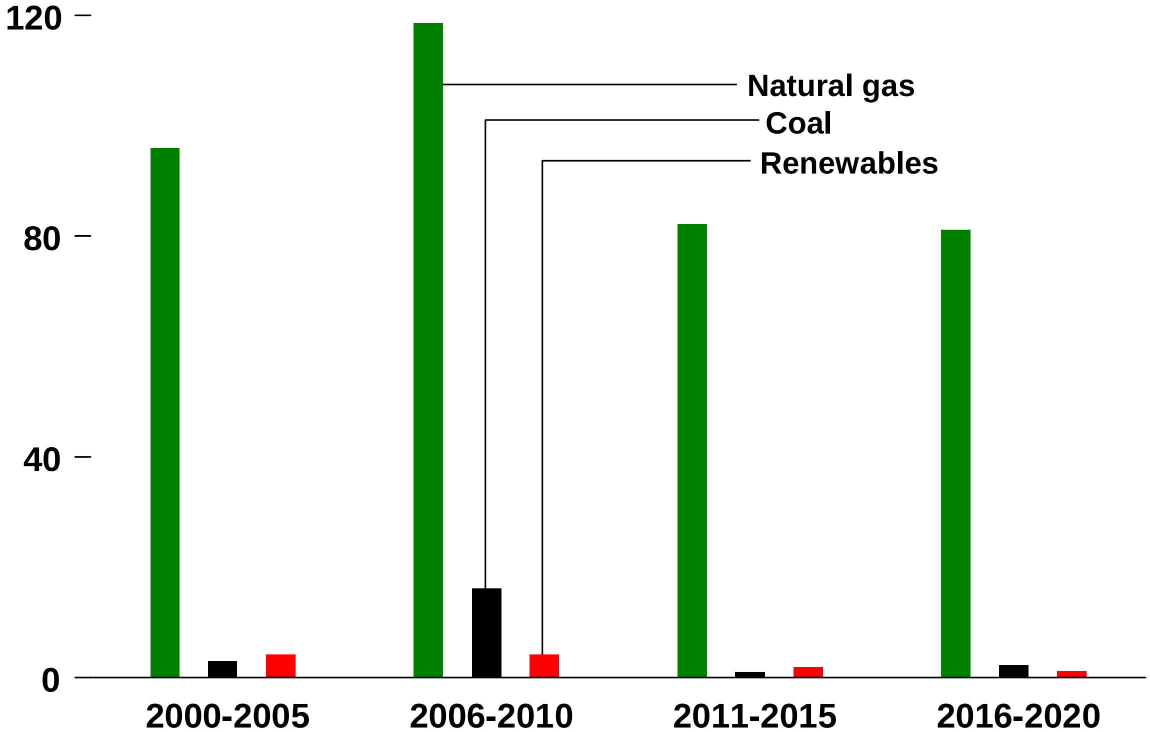

Figure 4. Projected Electricity Generation Costs for New Capacity (1999 mills per kilowatthour)

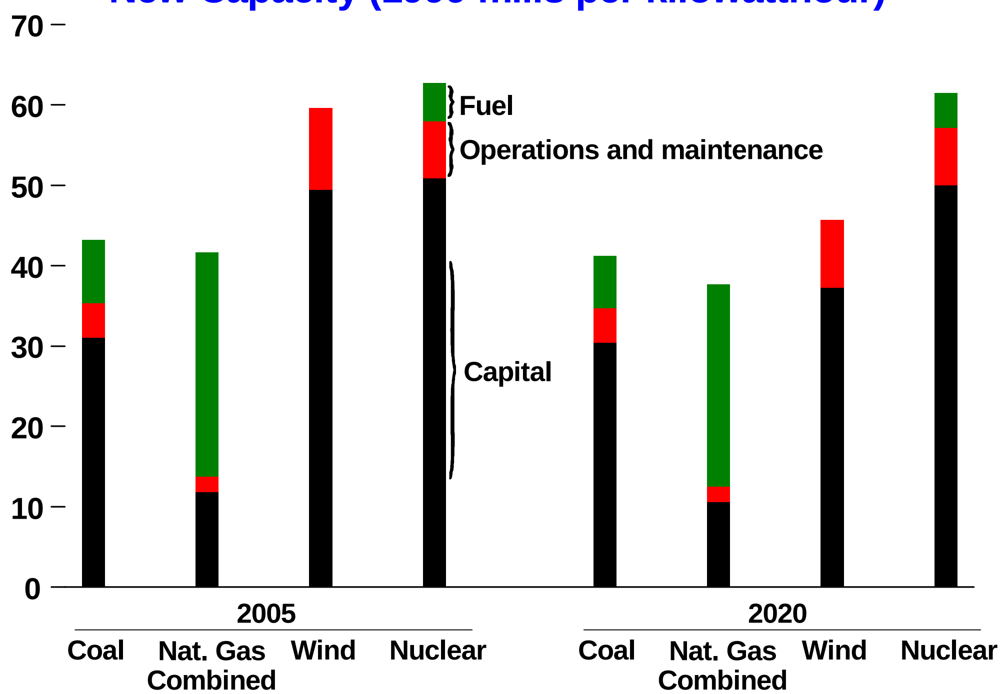

Figure 5. Coal Production by Region, 1970-2020 (million short tons)

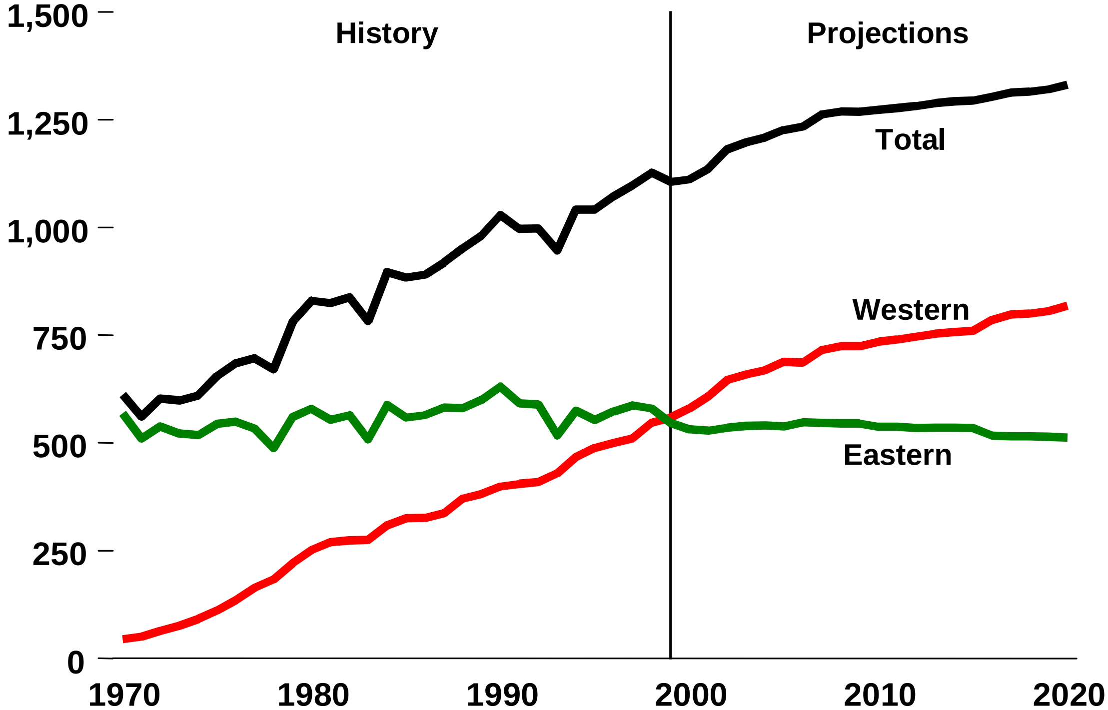

Figure 6. Remaining Coal Reserves at Active Mines, 1997-2020 (million short tons at End of Year)

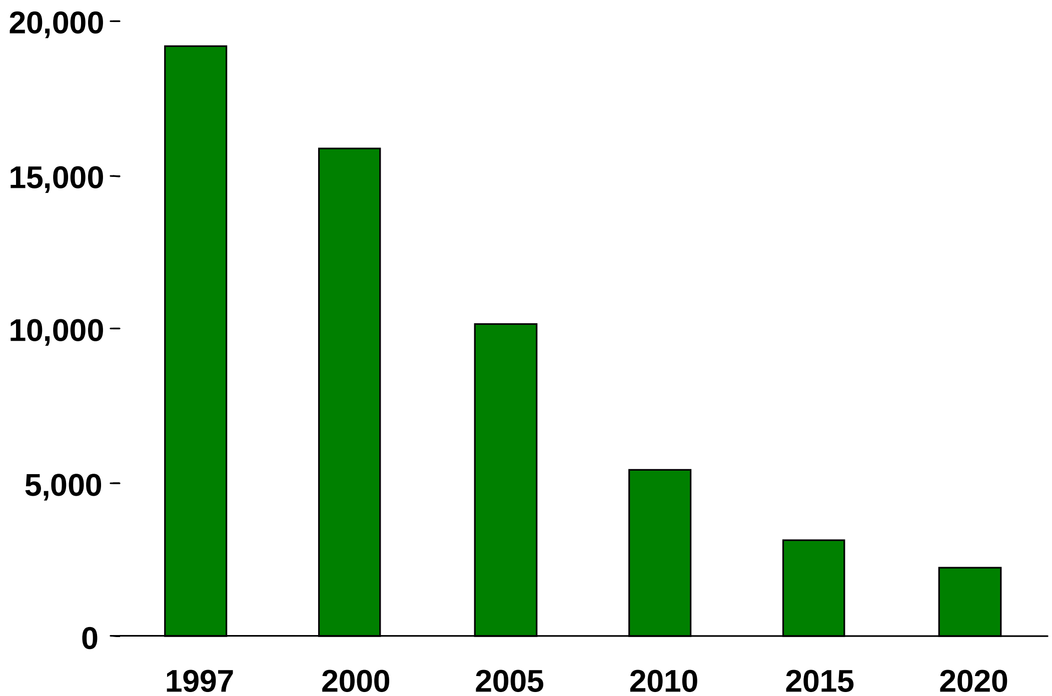

Figure 7. Electricity and Other Coal Consumption, 1970-2020 (million short tons)

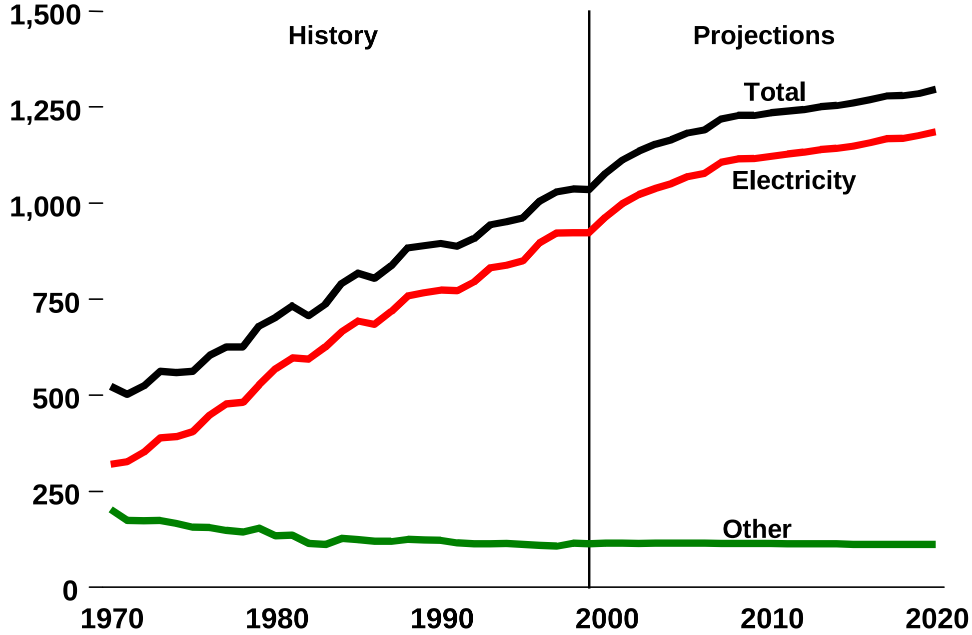

Figure 8. Coal Minemouth Prices, 1970-2020 (1999 dollars per ton)

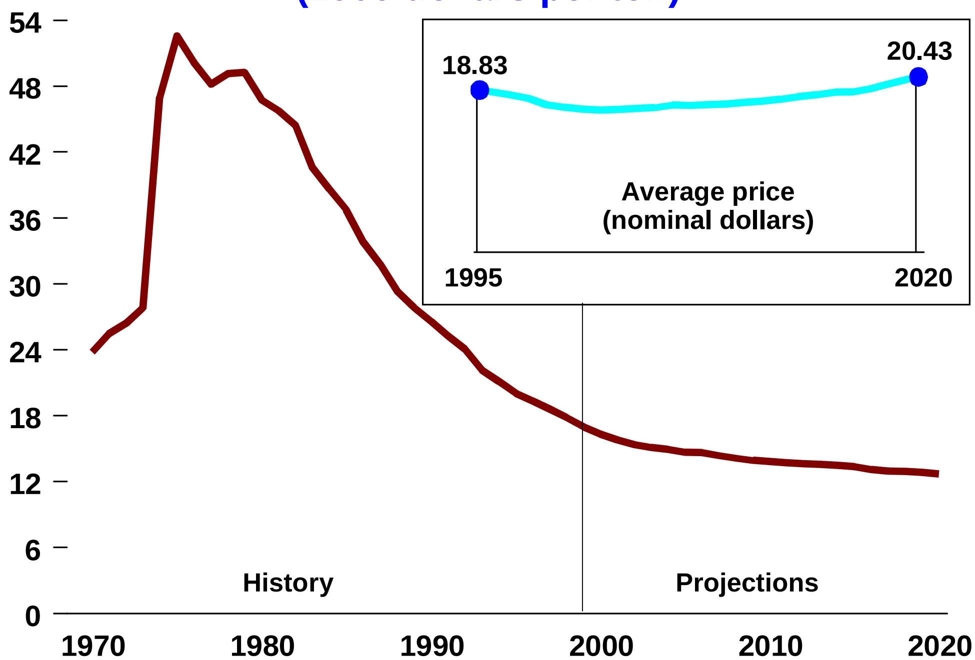

Figure 9. Coal Mining Labor Productivity by Region, 1970-2020 (short tons per miner per hour)