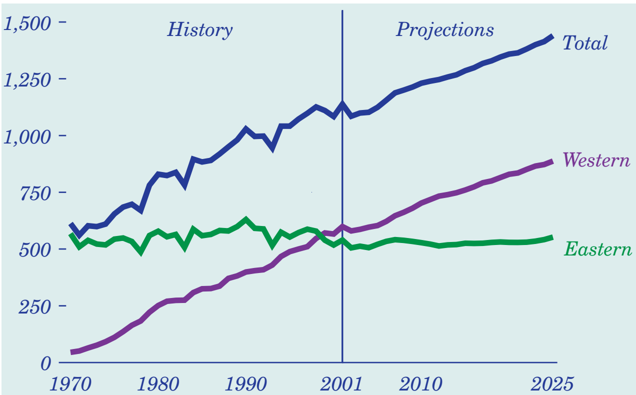
Emissions Caps Lead to More Use of Low-Sulfur Coal From Western Mines

Figure 101. Coal production by region, 1970-2025 (million short tons)



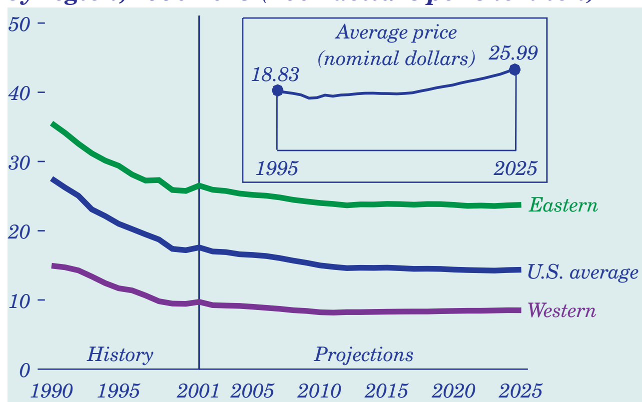
Continued improvements in mine productivity (which have averaged 6.2 percent per year since 1980) are projected to cause falling real minemouth prices throughout the forecast. Higher electricity demand and lower prices, in turn, are projected to yield increasing coal demand, but the demand is subject to an overall sulfur emissions cap from CAAA90, which encourages progressively greater reliance on the lowest sulfur coals (from Wyoming, Montana, Colorado, and Utah).

The use of western coals can result in up to 85 percent lower sulfur dioxide emissions than the use of many types of higher sulfur eastern coal. As coal demand grows in the forecast, new coal-fired generating capacity is required to use the best available control technology: scrubbers or advanced coal technologies that can reduce sulfur emissions by 90 percent or more. Thus, even as the demand for low-sulfur coal is projected to grow, there are still expected to be market opportunities for higher sulfur coal throughout the forecast.

From 2001 to 2025, high- and medium-sulfur coal production is projected to increase from 598 to 607 million tons (0.1 percent per year), and low-sulfur coal production is projected to rise from 540 to 833 million tons (1.8 percent per year). As a result of the competition between low-sulfur coal and post-combustion sulfur removal, western coal production is expected to continue its historical growth, reaching 887 million tons in 2025 (Figure 101), but its annual growth rate is projected to fall from the 8.7 percent achieved between 1970 and 2001 to 1.7 percent in the forecast period.

Rate of Decline in Minemouth Coal Price Is Expected To Slow

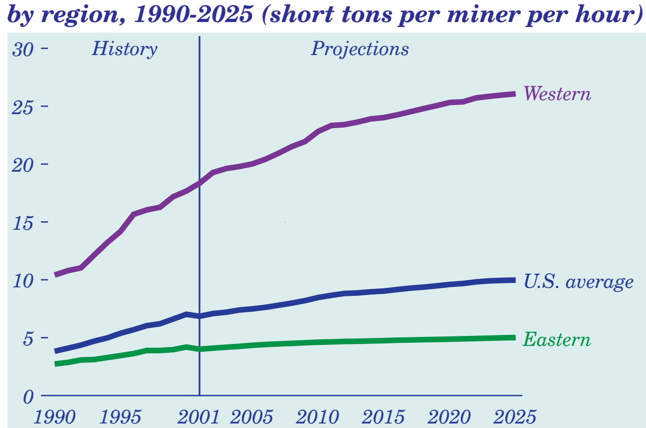
Figure 102. Average minemouth price of coal by region, 1990-2025 (2001 dollars per short ton)



Minemouth coal prices declined by $6.27 per ton (in 2001 dollars) between 1970 and 2001, and they are projected to decline by 0.8 percent per year, or $3.23 per ton, between 2001 and 2025 (Figure 102). The price of coal delivered to electricity generators, which declined by $2.17 per ton between 1970 and 2001, is projected to fall to $22.17 per ton in 2025—a 0.5-percent annual decline.

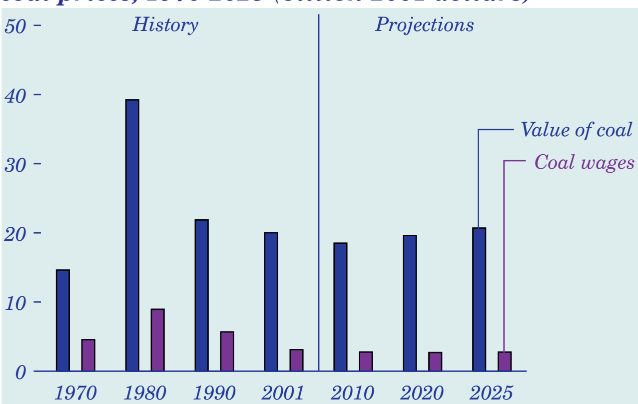
The mines of the Northern Great Plains, with thick seams and low overburden ratios, have had higher labor productivity than other coalfields, and their advantage is expected to be maintained throughout the forecast. Average U.S. labor productivity (Figure 103) is projected to follow the trend for eastern mines most closely, because eastern mining is more labor-intensive than western mining.

Figure 103. Coal mining labor productivity by region, 1990-2025 (short tons per miner per hour)



Labor Costs as Share of Minemouth Coal Revenues Continue to Decline

Figure 104. Labor cost component of minemouth coal prices, 1970-2025 (billion 2001 dollars)



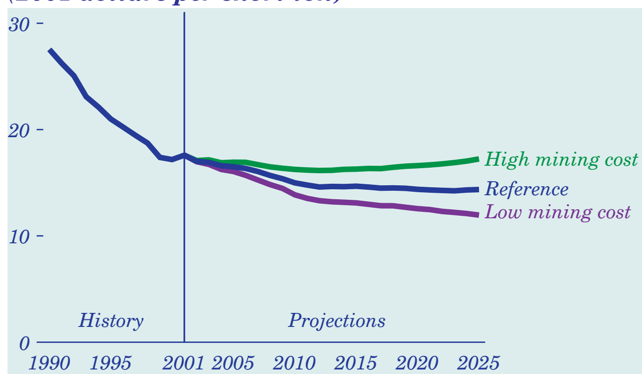
Gains in coal mine labor productivity result from technology improvements, economies of scale, and better mine design. At the national level, however, average labor productivity is also expected to be influenced by changing regional production shares. Competition from low sulfur, low-cost western and imported coals is projected to limit the growth of eastern low-sulfur coal mining. The boiler performance of western low-sulfur coal has been successfully tested by many electricity generators, and its use in eastern markets is projected to increase.

Eastern coalfields contain extensive reserves of higher sulfur coal in moderately thick seams suited to longwall mining. Continued penetration of technologies for extracting and hauling large volumes of coal in both surface and underground mining suggests that further reductions in mining cost are likely. Improvements in labor productivity have been, and are expected to remain, the key to lower coal mining costs.

As labor productivity improved between 1970 and 2001, the average number of miners working daily fell by 2.0 percent per year. With production increases and productivity improvements expected to continue through 2025, a further decline of 0.5 percent per year in the number of miners is projected. The share of wages (excluding irregular bonuses, welfare benefits, and payroll taxes paid by employers) in minemouth coal prices [*47*], which fell from 31 percent to 16 percent between 1970 and 2001, is projected to decline to 13 percent by 2025 (Figure 104).

Lower Mining Cost Assumptions Lead to Higher Production in the East

Figure 105. Average minemouth coal prices in three mining cost cases, 1990-2025 (2001 dollars per short ton)



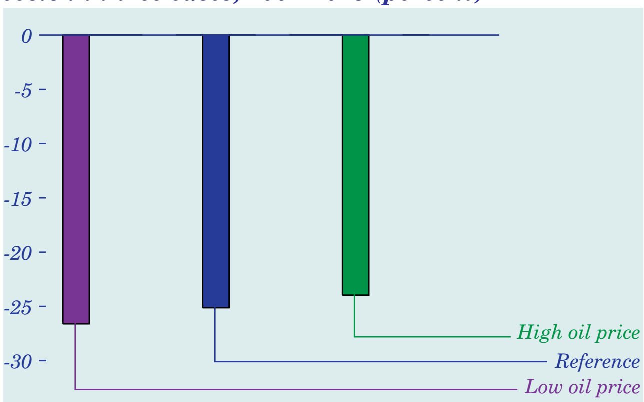
Alternative assumptions about future regional mining costs affect the projections for market shares of eastern and western mines and the national average minemouth price of coal. In two alternative mining cost cases, projected minemouth prices, delivered prices, and the resulting regional coal production levels vary with changes in projected mining costs.

Productivity is assumed to increase by 1.6 percent per year through 2025 in the reference case, while wage rates and equipment costs are constant in 2001 dollars. The national minemouth coal price is projected to decline by 0.8 percent per year to $14.36 per ton in 2025 (Figure 105).

In the low mining cost case, productivity is assumed to increase by 3.1 percent per year, and real wages and equipment costs are assumed to decline by 0.5 percent per year [*48*]. As a result, the average minemouth price is projected to fall by 1.6 percent per year to $11.96 per ton in 2025 (17 percent less than projected in the reference case). Eastern coal production is projected to be 46 million tons higher in the low mining cost case than in the reference case in 2025, reflecting the higher labor intensity of mining in eastern coalfields. In the high mining cost case, productivity is assumed to increase by 0.1 percent per year, and real wages and equipment costs are assumed to increase by 0.5 percent per year. Consequently, the average minemouth price of coal is projected to fall by 0.1 percent per year to $17.24 per ton in 2025 (20 percent higher than in the reference case). Eastern production in 2025 is projected to be 60 million tons lower in the high mining cost case than in the reference case.

Transportation Costs Are a Key Factor for Coal Markets

Figure 106. Projected change in coal transportation costs in three cases, 2001-2025 (percent)



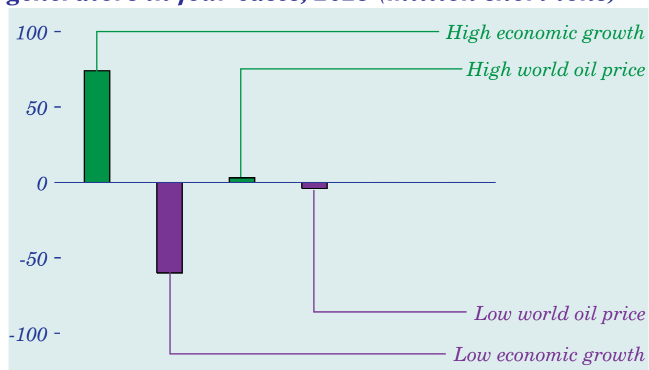
Changes in transportation costs affect the competition between coal and other fuels and among coalfields. In 1997, transportation costs averaged 41 percent of the delivered price of contract coal shipments to electric utilities [*49*]. With the expectation of nationally declining minemouth prices, along with increases in average shipping distances as western coal expands market share, the average percentage is expected to rise. Increases in fuel costs affect transportation costs (Figure 106), but they are also influenced by improvements in transportation fuel efficiency. Overall, in the reference case, average coal transportation costs are projected to decline by 1.2 percent per year between 2001 and 2025.

Historically, the most rapid declines in coal transportation costs have occurred on routes originating in coalfields that have had the greatest declines in real minemouth prices and increases in production. For instance, in the Powder River Basin supply region, the average transportation rate per ton for contract shipments to electric utilities decreased by 35 percent between 1988 and 1997, while shipped tonnage increased by 74 percent [*50*]. For coal from the Powder River Basin, where transportation can make up 60 percent or more of delivered cost, lower transportation costs could further increase its market share.

Also, with Phase 2 of CAAA90, which became effective on January 1, 2000, mines in the Powder River Basin will require expansion of their train-loading capacities to meet the increase in demand for low-sulfur coal. Any coal transportation problems associated with the increased shift to low-sulfur coal are expected to be temporary.

Higher Economic Growth Would Favor Coal for Electricity Generation

Figure 107. Projected variation from reference case projections of coal demand for electricity generators in four cases, 2025 (million short tons)

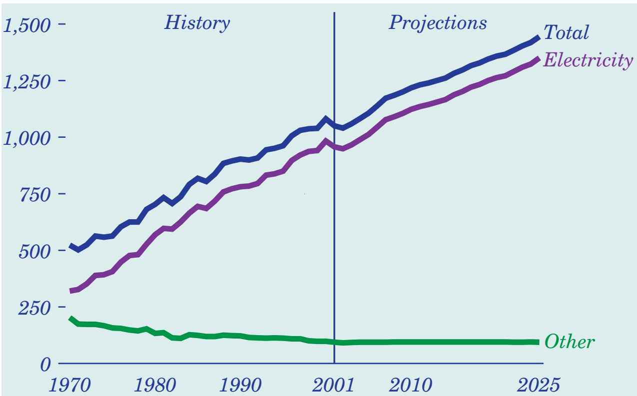


A strong correlation between economic growth and electricity use accounts for the variation in coal demand projections across the economic growth cases (Figure 107), with domestic coal consumption in 2025 projected to range from 1,381 to 1,524 million tons in the low and high economic growth cases, respectively. Of the difference, coal use for electricity generation is projected to make up 133 million tons. The difference in total projected coal production between the two economic growth cases is 144 million tons, of which 54 million tons (37 percent) is projected to be western production. Although western coal must travel up to 2,000 miles to reach some of its markets, it is expected to be competitively priced in all regions except the Northeast.

The world oil price cases show relatively small changes in coal use for electricity generation. The low price case projects only 8 million tons less coal use for electricity generation in 2025 than is projected in the high price case. Low oil prices encourage electricity generation from existing oil-fired units, reducing generation from other fuels, but because oil-fired generation represents a very small proportion of total generation, its impact on coal consumption is minor, even in the high world oil price case. Although changes in oil prices are expected to have little effect on coal-fired generation, high oil prices could stimulate the coal-to-liquids market. In the high world oil price case, 19 million tons of coal is projected to be converted to roughly 35 million barrels of fuel liquids in 2025.

Coal Consumption for Electricity Continues To Rise in the Forecast

Figure 108. Electricity and other coal consumption, 1970-2025 (million short tons)



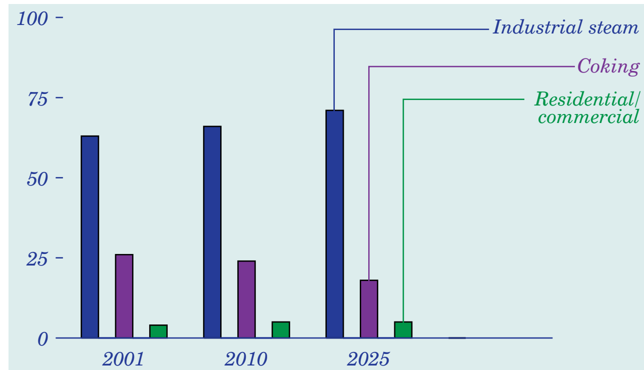
Domestic coal demand is projected to increase by 394 million tons in the reference case forecast, from 1,050 million tons in 2001 to 1,444 million tons in 2025 (Figure 108), because of projected growth in coal use for electricity generation. Total coal demand in other domestic end-use sectors is projected to remain relatively constant.

Coal consumption for electricity generation is projected to increase from 957 million tons in 2001 to 1,350 million tons in 2025 as the utilization of existing coal-fired generation capacity increases and, in later years, new capacity is added. The average utilization rate is projected to increase from 69 percent in 2001 to 83 percent in 2025. Because coal consumption (in tons) per kilowatthour generated is higher for subbituminous and lignite than for bituminous coals, the shift to western coal is projected to increase the tonnage per kilowatthour of generation in the Midwest and Southeast regions. In the East, generators are expected to shift to lower sulfur Appalachian bituminous coals that contain more energy (Btu) per ton.

Although coal is projected to maintain its fuel cost advantage over both oil and natural gas, gas-fired generation is expected to be the most economical choice for construction of new power generation units in most situations, when capital, operating, and fuel costs are considered. Between 2005 and 2025, rising natural gas costs, increasing demand for electricity, and retirements of existing fossil-fired steam capacity are projected to result in increasing demand for coal-fired baseload capacity.

Industrial Steam Coal Use Rises, But Demand for Coking Coal Declines

Figure 109. Projected coal consumption in the industrial and buildings sectors, 2010 and 2025 (million short tons)



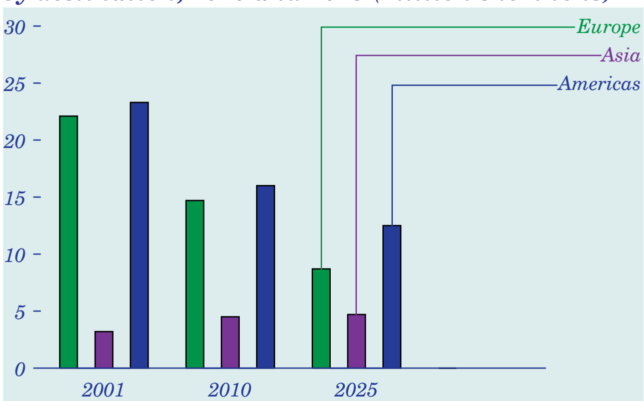
For applications other than electricity generation, a projected increase of 8 million tons in industrial steam coal consumption between 2001 and 2025 (0.5 percent annual growth) is expected to be offset by a decrease of 8 million tons in coking coal consumption (Figure 109). Increasing consumption of industrial steam coal is projected to result primarily from greater use of existing coal-fired boilers in energy-intensive industries.

The projected decline in domestic consumption of coking coal results from the expected displacement of raw steel production from integrated steel mills (which use coal coke for energy and as a material input) by increased production from minimills (which use electric arc furnaces that require no coal coke) and by increased imports of semi-finished steels. The amount of coke required per ton of pig iron produced is also declining, as process efficiency improves and injection of pulverized steam coal is used increasingly in blast furnaces. Domestic consumption of coking coal is projected to fall by 1.5 percent per year through 2025.

Although total energy consumption in the combined residential and commercial sectors is projected to grow by 1.3 percent per year, most of the growth is expected to be captured by electricity and natural gas. Coal consumption in the residential and commercial sectors is projected to remain constant, accounting for less than 1 percent of total U.S. coal demand in the forecast.

U.S. Coal Exports to Europe and the Americas Are Projected To Decline

Figure 110. Projected U.S. coal exports by destination, 2010 and 2025 (million short tons)



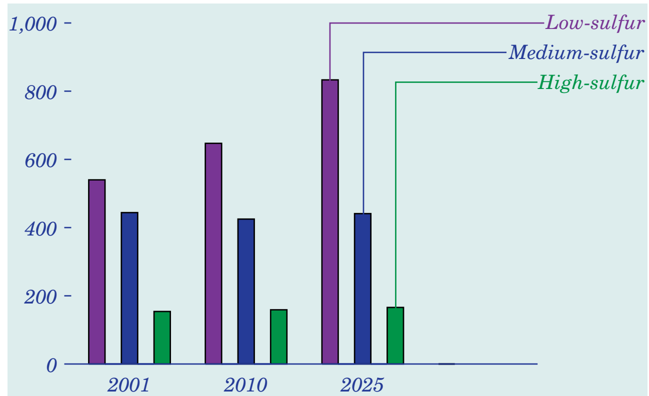
U.S. coal exports declined sharply between 1998 and 2001, from 78 million tons to 49 million tons, and are projected to continue to decline over the forecast horizon, reaching 26 million tons by 2025 (Figure 110). The most recent decline in U.S. coal exports occurred against the backdrop of a world coal market that saw an increase in trade from 546 million tons in 1998 to 650 million tons in 2001. While China and Indonesia satisfied much of the growth in international steam coal demand, low-cost supplies of coking coal from Australia supplanted substantial amounts of U.S. coking coal in the world market.

The U.S. share of total world coal trade is projected to decline from 7 percent in 2001 to 3 percent by 2025 as international competition intensifies and demand for coal imports in Europe and the Americas grows more slowly or declines. From 2001 to 2025, U.S. steam coal exports are projected to decline from 23 million tons to 10 million tons, despite substantial projected growth in world steam coal trade. Steam coal exports from Australia, South Africa, China, and Indonesia are expected to increase in response to growing import demand in Asian countries. Increasing exports from South America (Colombia and Venezuela) are expected to lead to a gradual increase in that region's share of the market for steam coal both in Europe and in the Americas.

U.S. coking coal exports are projected to decline from 25 million tons in 2001 to 16 million tons in 2025. A small increase in the world trade in coking coal is expected, primarily in Asia.

Low-Sulfur Coal Continues To Gain Share in the Generation Market

Figure 111. Projected coal production by sulfur content, 2010 and 2025 (million short tons)



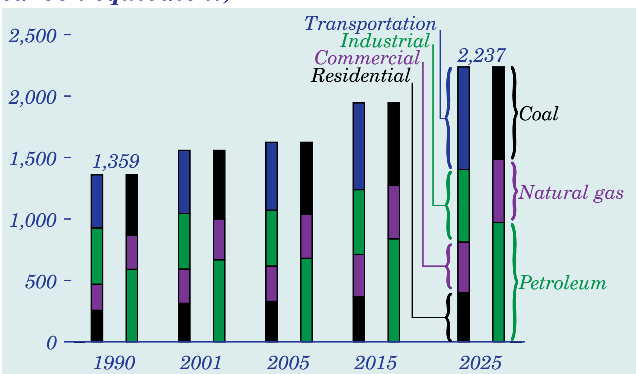
Phase 1 of CAAA90 required 261 coal-fired generating units to reduce sulfur dioxide emissions to about 2.5 pounds per million Btu of fuel. Phase 2, which took effect on January 1, 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also sets restrictions on smaller, cleaner plants fired with coal, oil, and gas [*51*].

During Phase 1, many generators switched either partly or entirely from higher sulfur bituminous coals to low-sulfur subbituminous coal, incurring relatively modest capital investments. Such fuel switching often generated sulfur dioxide allowances beyond those needed for Phase 1 compliance, and the excess allowances generated during Phase 1 were banked for use in Phase 2 or sold to other generators. In the forecast, fuel switching for regulatory compliance and for cost savings is projected to reduce the composite sulfur content of all coal produced (Figure 111). The main sources of low-sulfur coal are the Central Appalachian, Powder River Basin, and Rocky Mountain regions, and coal imported from Colombia.

Coal users are likely to incur additional costs in the future as additional or new restrictions on emissions of nitrogen oxides, particulates, mercury, or carbon dioxide are adopted. An example of a proposal to further reduce emissions from U.S. power plants is the Bush Administration's Clear Skies Initiative. Relative to current law and regulations, the Administration's proposal specifies further restrictions on emissions of nitrogen oxides and sulfur dioxide and would introduce a national cap on mercury emissions.

Higher Energy Consumption Forecast Increases Carbon Dioxide Emissions

Figure 112. Projected carbon dioxide emissions by sector and fuel, 2005-2025 (million metric tons carbon equivalent)



Carbon dioxide emissions from energy use are projected to increase on average by 1.5 percent per year from 2001 to 2025, to 2,237 million metric tons carbon equivalent (Figure 112), and emissions per capita are projected to grow by 0.7 percent per year.

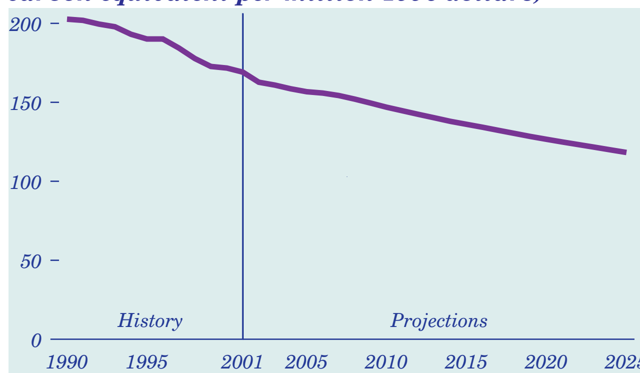
Carbon dioxide emissions in the residential sector, including emissions from the generation of electricity used in the sector, are projected to increase by an average of 1.0 percent per year, reflecting increased electrification and penetration of computers, electronics, and appliances in the sector. Significant growth in office equipment and computers, as well as floorspace, is also projected for the commercial sector. As a result, carbon dioxide emissions from the commercial sector are projected to increase by 1.6 percent per year. Industrial emissions are projected to grow by 1.1 percent per year, as shifts to less energy-intensive industries and efficiency gains help to moderate growth in energy use.

In the transportation sector, carbon dioxide emissions grow at an average annual rate of 2.0 percent. Increases in highway, rail, and air travel are partially offset by efficiency improvements in rail freight and aircraft, but passenger vehicle fuel economy is projected to increase only slightly above 2001 levels.

In all sectors, potential growth in carbon dioxide emissions is expected to be moderated by efficiency standards, voluntary efficiency programs, and improvements in technology. Carbon dioxide mitigation programs, further improvements in technology, or more rapid adoption of voluntary programs could result in lower emissions levels than projected here.

Petroleum Products Lead Carbon Dioxide Emissions From Energy Use

Figure 113. Carbon dioxide emissions per unit of gross domestic product, 1990-2025 (metric tons carbon equivalent per million 1996 dollars)



Petroleum products are the leading source of carbon dioxide emissions from energy use. In 2025, petroleum is projected to account for 971 million metric tons carbon equivalent, a 43-percent share of the projected total. About 84 percent (811 million metric tons carbon equivalent) of the emissions from petroleum use are expected to result from transportation fuel use.

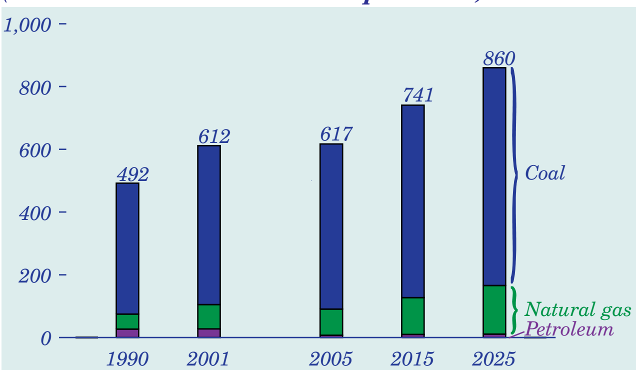
Coal is the second leading source of carbon dioxide emissions, projected to produce 753 million metric tons carbon equivalent in 2025, or 34 percent of the total. The coal share is projected to decline from 36 percent in 2001, because coal consumption is expected to increase at a slower rate through 2025 than consumption of petroleum and natural gas. Most of the increases in emissions from coal use result from electricity generation.

In 2025, natural gas use is projected to produce a 23-percent share of total carbon dioxide emissions, 512 million metric tons carbon equivalent. Of the fossil fuels, natural gas consumption and emissions increase most rapidly through 2025, at an average annual rate of 1.9 percent. Because carbon dioxide emissions from natural gas combustion, per Btu of energy produced, are only 56 percent of those from coal combustion, carbon intensity is reduced as natural gas replaces coal.

As the economy becomes more energy-efficient, its carbon intensity also declines. Between 2001 and 2025, the carbon intensity of the economy is expected to decline at an average rate of 1.5 percent per year (Figure 113).

Electricity Generation Is Also a Major Cause of Carbon Dioxide Emissions

Figure 114. Projected carbon dioxide emissions from the electric power sector by fuel, 2005-2025 (million metric tons carbon equivalent)



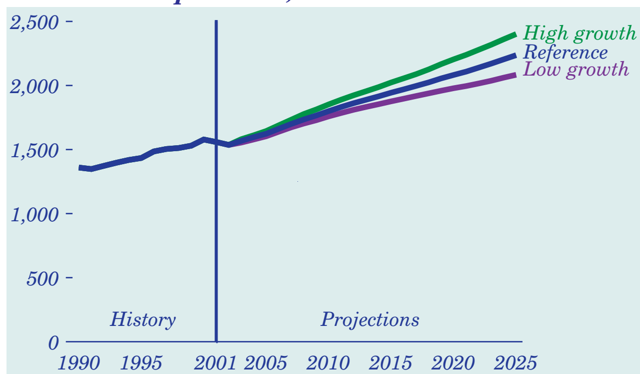
The use of fossil fuels in the electric power industry accounted for 39 percent of total energy-related carbon dioxide emissions in 2001, and the share is projected to be 38 percent in 2025. Coal is projected to account for 50 percent of the power industry's electricity generation in 2025 and to produce 81 percent of electricity-related carbon dioxide emissions (Figure 114). In 2025, natural gas is projected to account for 27 percent of electricity generation but only 18 percent of electricity-related carbon dioxide emissions.

Between 2001 and 2025, the electric power industry is projected to retire 82 gigawatts of generating capacity—about 10 percent of the 2001 level—and to see a 54-percent increase in electricity sales. As a result, the industry is projected to add 414 gigawatts of new fossil-fueled capacity by 2025. Although most of the new plants are expected to be relatively efficient combined-cycle plants fueled by natural gas, the net effect will be to raise the industry's carbon dioxide emissions by 248 million metric tons carbon equivalent, or 41 percent, from 2001 levels.

The electric power industry is projected to increase its reliance on renewable energy, which generally does not contribute to carbon dioxide emissions. Renewable generation is expected to increase by 170 billion kilowatthours, or 65 percent, between 2001 and 2025, helping to offset the projected increase in carbon dioxide emissions from fossil fuels. Average carbon dioxide emissions per kilowatthour of total generation are projected to decline by about 9 percent from 2001 to 2025.

Emissions Projections Change With Economic Growth Assumptions

Figure 115. Carbon dioxide emissions in three economic growth cases, 1990-2025 (million metric tons carbon equivalent)



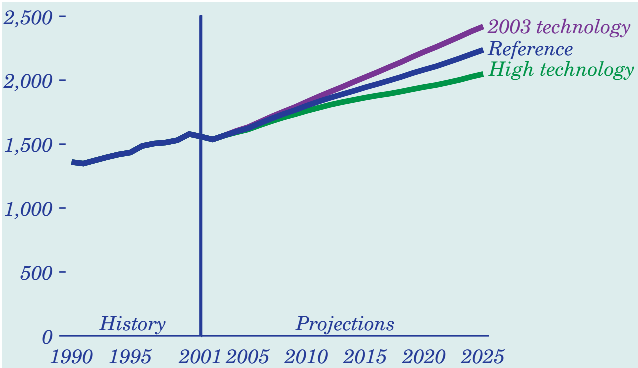
The high economic growth case assumes higher growth in population, labor force, and productivity than in the reference case, leading to higher industrial output, lower inflation, and lower interest rates. GDP growth in the high growth case averages 3.5 percent per year from 2001 to 2025, as compared with 3.0 percent per year in the reference case. In the low economic growth case, which assumes lower growth in population, labor force, and productivity, GDP growth averages 2.5 percent per year.

Higher projections for manufacturing output and income increase the demand for energy services in the high economic growth case, and energy consumption totals 149 quadrillion Btu in 2025, 7 percent higher than in the reference case. As a result, carbon dioxide emissions are projected to reach 2,401 million metric tons carbon equivalent in 2025, also 7 percent higher than in the reference case (Figure 115). Total energy intensity, measured as primary energy consumption per dollar of GDP, declines by 1.7 percent per year in the high growth case, as compared with 1.5 percent in the reference case. With more rapid projected growth in energy consumption, there is expected to be a greater opportunity to turn over the stock of energy-using technologies, adding new equipment and increasing the overall efficiency of the capital stock.

In the low growth case, energy consumption reaches 129 quadrillion Btu in 2025, 7 percent lower than projected in the reference case, and carbon dioxide emissions in 2025 are also 7 percent lower at 2,083 million metric tons carbon equivalent. Energy intensity is projected to decline at a rate of 1.3 percent annually through 2025 in the low growth case.

Technology Advances Could Reduce Carbon Dioxide Emissions

Figure 116. Carbon dioxide emissions in three technology cases, 1990-2025 (million metric tons carbon equivalent)

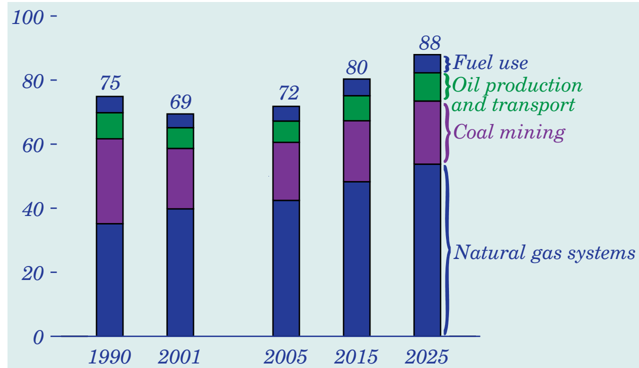


The reference case assumes continuing improvement in energy-consuming and producing technologies, consistent with historic trends, as a result of ongoing research and development. In the high technology case it is assumed that increased spending on research and development will result in earlier introduction, lower costs, and higher efficiencies for end-use technologies than assumed in the reference case. The costs and efficiencies of advanced fossil-fired and new renewable generating technologies are also assumed to improve from reference case values [*52*]. Energy intensity is expected to decline on average by 1.8 percent per year through 2025 in the high technology case, as compared with 1.5 percent in the reference case. As a result, energy consumption is projected to be 6 percent lower than in the reference case in 2025, at 130 quadrillion Btu, and carbon dioxide emissions are projected to be 9 percent lower than in the reference case, at 2,046 million metric tons carbon equivalent (Figure 116).

The 2003 technology case assumes that future equipment choices will be made from the equipment and vehicles available in 2003; that new building shell and plant efficiencies will remain at their 2003 levels; and that advanced generating technologies will not improve over time. Energy efficiency improves in the 2003 technology case as new equipment is chosen to replace older stock and the capital stock expands, and energy intensity declines by 1.3 percent per year through 2025. Energy consumption reaches 147 quadrillion Btu in 2025 in the 2003 technology case, and carbon dioxide emissions in 2025 are projected to be 9 percent higher than in the reference case, at 2,429 million metric tons carbon equivalent.

Moderate Growth in Methane Emissions Is Expected

Figure 117. Projected methane emissions from energy use, 2005-2025 (million metric tons carbon equivalent)



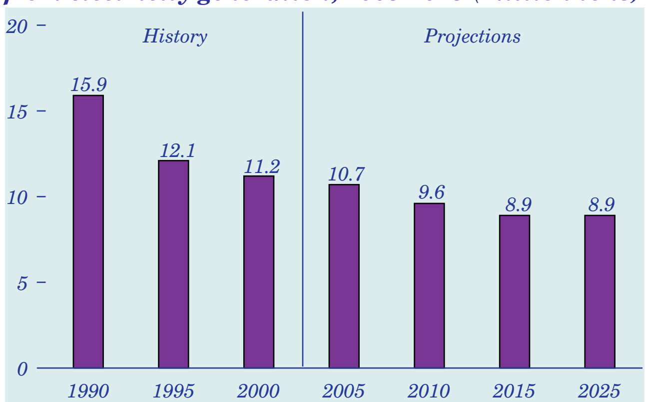
Methane emissions from energy use are projected to increase at an average rate of 1.0 percent per year from 2001 to 2025, somewhat slower than the 1.5-percent projected growth rate for carbon dioxide emissions. Based on global warming potential, methane is the second largest component of U.S. man-made greenhouse gas emissions after carbon dioxide, and it is one of the six gases covered by the Kyoto Protocol. In 2001, methane accounted for 9.5 percent of total U.S. greenhouse gas emissions of 1,887 million metric tons carbon equivalent. About a third of methane emissions are related to energy activities, mostly from energy production and its transportation and to a much smaller extent from incomplete fuel combustion. Other sources of methane emissions include waste management, agriculture, and industrial processes.

Much of the projected increase in energy-related methane emissions is tied to increases in oil and gas use (Figure 117). The fugitive methane emissions that occur during natural gas production, processing, and distribution are expected to increase by 35 percent by 2025, despite declines in the average rate of emissions per unit of production. Emissions related to oil production, refining, and transport are also expected to increase by about the same proportion. Coal-related methane emissions are expected to increase slowly, with little change projected in coal production from methane-intensive underground mining while progress in the recovery of vented gas continues. Methane emissions related to wood and fossil fuel combustion are projected to remain a small share of the total (6 percent) through 2025.

Emissions from Electricity Generation

Sulfur Emissions Are Cut in Response to Tightening Regulations

Figure 118. Projected sulfur dioxide emissions from electricity generation, 2005-2025 (million tons)



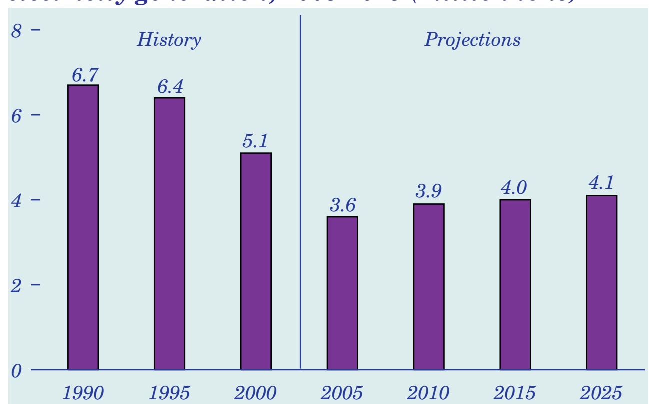
CAAA90 called for annual emissions of sulfur dioxide (SO_2) by electricity generators to be reduced to approximately 12 million tons in 1996, 9.48 million tons between 2000 and 2009, and 8.95 million tons per year thereafter. Because companies can bank allowances for future use, however, the long-term cap of 8.95 million tons per year is not expected to be reached until after 2011. More than 95 percent of the SO_2 produced by generators results from coal combustion and the rest from residual oil.

CAAA90 called for the reductions to occur in two phases, with larger (more than 100 megawatts) and higher emitting (more than 2.5 pounds per million Btu) plants making reductions first. In Phase 1, which began in 1995, 261 generating units at 110 plants were issued tradable emissions allowances permitting SO_2 emissions to reach a fixed amount per year—generally less than the plant's historical emissions. Allowances could also be banked for use in future years. Switching to lower sulfur subbituminous coal was the option chosen by most generators, as only about 12 gigawatts of capacity had been retrofitted with scrubbers by 1995.

In recent years, power companies have announced plans to add scrubbers to 23 gigawatts of capacity to comply with State or Federal initiatives. No additional SO_2 scrubbers are projected to be added beyond those that have been announced. Emissions are projected to decline from 10.6 million tons in 2001 to 8.9 million in 2025 (Figure 118). The price of allowances is projected to vary between about \$100 and \$190 between 2002 and 2020 before declining through 2025.

Nitrogen Oxide Emissions Are Projected To Stay Below 2000 Levels

Figure 119. Projected nitrogen oxide emissions from electricity generation, 2005-2025 (million tons)



Nitrogen oxide (NO_x) emissions from U.S. electricity generation are projected to fall as new regulations take effect (Figure 119). The required reductions are intended to reduce the formation of ground-level ozone, for which NO_x emissions are a major precursor. Together with volatile organic compounds and hot weather, NO_x emissions contribute to unhealthy air quality in many areas during the summer months. CAAA90 NO_x reduction program called for reductions at electric power plants in two phases, the first in 1995 and the second in 2000. The second phase of CAAA90 resulted in NO_x reductions of 0.6 million tons between 1999 and 2000.

For several years the EPA and the States have studied the movement of ozone from State to State. The States in the Northeast have argued that emissions from coal plants in the Midwest make it difficult for them to meet national air quality standards for ground-level ozone, and they have petitioned the EPA to force the coal plant operators to reduce their emissions more than required under current rules.

Interpretations of ozone transport studies have been controversial. In September 1998 the EPA issued a rule, referred to as the Ozone Transport Rule (OTR), to address the problem. The OTR called for capping NO_x emissions in 22 Midwestern and Eastern States during the summer season, and following a court challenge, emissions limits were finalized for 19 States. These limits, which are included in the projections beginning in 2004, are projected to stimulate the addition of emissions control equipment to many existing plants, further lowering NO_x emissions by 0.5 million tons between 2003 and 2004.