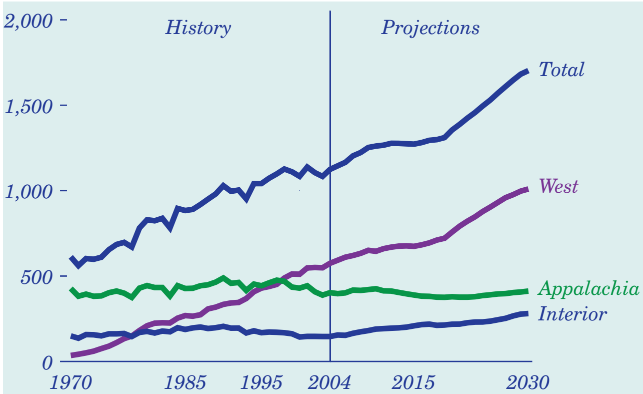
Market Share of Western Coal Continues To Increase

Figure 97. Coal production by region, 1970-2030 (million short tons)



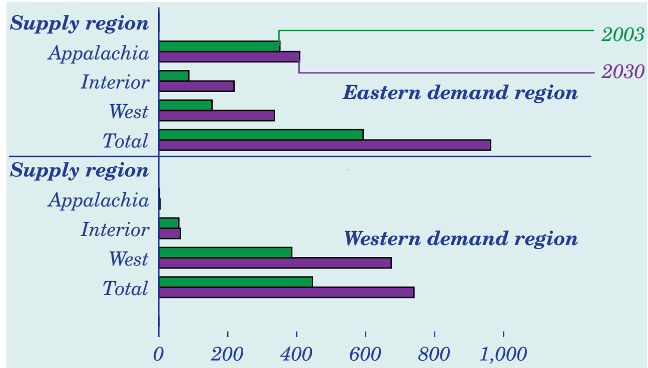
U.S. coal production has remained near 1,100 million tons annually since 1996. In the *AEO2006* reference case, increasing coal use for electricity generation at existing plants and construction of a few new coal-fired plants lead to annual production increases that average 1.1 percent per year from 2004 to 2015, when total production is 1,272 million tons. The growth in coal production is even stronger thereafter, averaging 2.0 percent per year from 2015 to 2030, as substantial amounts of new coal-fired generating capacity are added, and several CTL plants are brought on line.

Western coal production, which has grown steadily since 1970, continues to increase through 2030 (Figure 97), especially in the Powder River Basin, where vast reserves are contained in thick seams accessible to surface mining. Easing of rail transportation bottlenecks will be needed for producers in the West to exploit the market opportunities presented by slow growth in Appalachian coal production and by demand for coal at new power plants built to serve electricity markets in the Southwest and California.

Appalachian coal production remains nearly flat in the reference case. Although producers in Central Appalachia are well situated geographically to supply coal to new generating capacity in the Southeast, the Appalachian basin has been mined extensively, and production costs have been increasing more rapidly than in other regions. The Eastern Interior coal basin (Illinois, Indiana, and western Kentucky), with extensive reserves of mid- and high-sulfur bituminous coals, does benefit from the new builds of coal-fired generating capacity in the Southeast.

More Eastern Power Plants Are Expected To Use Western Coal

Figure 98. Distribution of domestic coal by demand and supply region, 2003 and 2030 (million short tons)

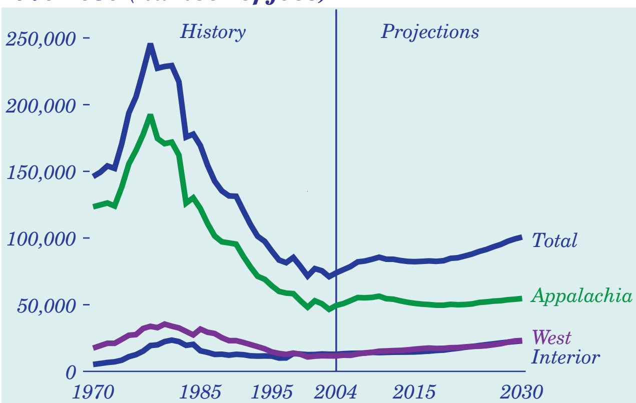


In the reference case, low-cost Western coal continues to gain market share east of the Mississippi River and remains the dominant supplier in markets west of the Mississippi River (Figure 98). Use of low-sulfur Western coal continues to increase through 2030, even though 141 gigawatts of existing coal-fired capacity is retrofitted with flue gas desulfurization equipment and another 174 gigawatts of new environmentally compliant coal-fired capacity is built. Even in the absence of sulfur compliance costs, Western coal is the lowest cost fuel option for electricity generation in many areas of the country. As a result, each year typically sees more coal-fired plants switching to Western coal, particularly from the Powder River Basin. In 2004, approximately 20 plants, many located east of the Mississippi River, used Powder River Basin coal for the first time.

Although two new pieces of environmental legislation enacted in 2005, CAIR and CAMR, will increase the cost of coal-fired generation, they have only minor impacts on overall coal use in the electric power sector or regional coal production patterns. As a result of the stricter caps on SO_2 emissions in CAIR, allowance prices increase substantially, virtually eliminating by 2030 the use of medium- and high-sulfur coals (containing more than 0.6 pounds sulfur per million Btu) at power plants not equipped with scrubbers. In 2004, medium- and high-sulfur coals accounted for about 40 percent of the 638 million tons of coal consumed at generating units without scrubbers [*93*]. In 2030, coal-fired power plants without scrubbers consume only 233 million tons.

Coal Mine Employment Increases As Production Expands

Figure 99. U.S. coal mine employment by region, 1970-2030 (number of jobs)



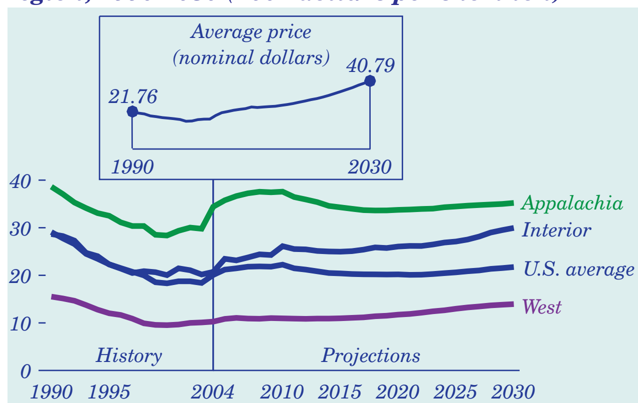
Most jobs in the U.S. coal industry remain east of the Mississippi River, mainly in the Appalachian region (67 percent in 2004). Most coal production, however, occurs west of the Mississippi River (56 percent in 2004), with the major share from the Powder River Basin. As coal demand increases, pressure to keep prices low will shift more production to mines with higher labor productivity. Large surface mines in the Powder River Basin take advantage of economies of scale, using large earth-moving equipment and combining adjacent mines to increase operating flexibility. Underground mines in the Northern Appalachia and Rocky Mountain supply regions use highly productive and increasingly automated longwall equipment to maximize production while reducing the number of miners required.

In the reference case, labor productivity remains near current levels in most coal supply regions, reflecting the trend of the past 5 years. Higher stripping ratios and the additional labor needed to maintain more extensive underground mines offset productivity gains achieved from improved equipment, automation, and technology. Productivity in some areas of the East declines as operations move to marginal reserve areas. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that can be achieved by Appalachian producers from economies of scale.

Some 27,000 additional mining jobs are created between 2004 and 2030 (Figure 99). In the East, job losses in Central Appalachia are more than offset by additional jobs at more productive mines in Northern Appalachia.

Average Minemouth Coal Prices Increase Slowly

Figure 100. Average minemouth price of coal by region, 1990-2030 (2004 dollars per short ton)

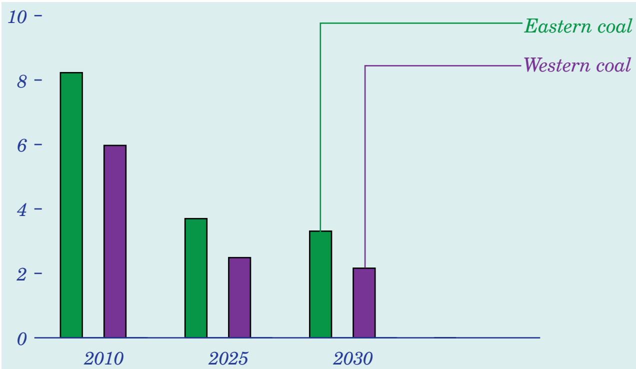


From 1990 to 1999, the average minemouth price of coal declined by 4.9 percent per year, from $29.09 per ton (2004 dollars) to $18.54 per ton (Figure 100). Increases in U.S. coal mining productivity of 6.3 percent per year during the period helped to reduce mining costs and contributed to the decline in prices. Since 1999, growth in U.S. coal mining productivity has slowed to 0.6 percent per year, and the average minemouth coal price has increased by 1.6 percent per year, to $20.07 per ton in 2004.

In the reference case, the average minemouth coal price drops slightly from 2010 to 2020, as mine capacity utilization declines and production shifts away from higher cost Central Appalachian mines. After 2020, rising natural gas prices and the need for baseload generating capacity result in the construction of 126 gigawatts of new coal-fired generating plants (72 percent of all coal builds from 2004 to 2030 in the reference case), and production in most of the major coal supply basins increases. The substantial investment in new mining capacity required to meet increasing demand during the period, combined with low productivity growth and rising utilization of mining capacity, leads to an increase in the average minemouth price, from $20.20 per ton in 2020 to $21.73 per ton in 2030. Strong growth in production in the Interior and Western supply regions, combined with limited improvement in coal mining productivity, results in minemouth price increases of 1.4 and 1.2 percent per year, respectively, in those regions from 2004 through 2030. With little increase in production, average minemouth prices in Appalachia increase by only 0.1 percent per year over the same period.

Rising Regional Coal Transportation Rates Depart from Historical Trend

Figure 101. Changes in regional coal transportation rates, 2010, 2025, and 2030 (percent increase from 2004 rates)



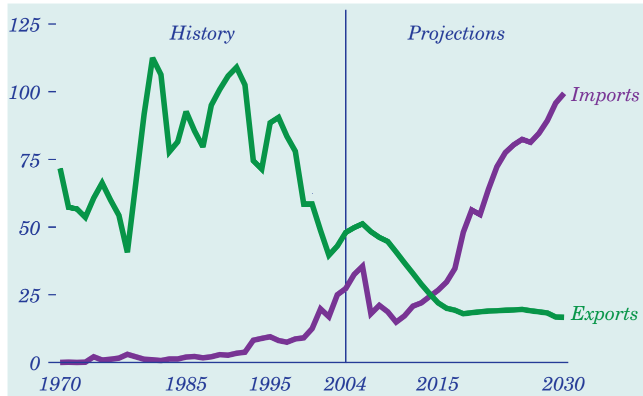
Coal transportation rates (in constant 2004 dollars), rise in the reference case, ending the decreasing trend of the past 20 years. Historically, infrastructure investments and subsequent overcapacity, as well as the efficiency gains associated with consolidation of the railroad industry, have steadily reduced coal transportation rates. Productivity improvements continue in the forecast, but they are dampened by larger demands on rail infrastructure and an expectation that investments will be made incrementally, as needed, rather than in anticipation of higher demand.

Periodic bottlenecks are likely as railroads adapt to increasing traffic flows from western mines and changing coal distribution patterns in the East. In constant dollars, coal transportation costs peak in 2010, then fall to 2.2 percent and 3.3 percent above 2004 levels in 2030 for coal originating in the West and East, respectively (Figure 101). In general, western suppliers are at a greater disadvantage than eastern suppliers when transportation rates rise, because western coal typically travels over longer distances.

Despite the increases in transportation rates, the national average continues to decline, because 76 percent of the increase in demand from 2004 to 2030 is from CTL plants and new electric power plants, many of which are expected to be built near sources of coal supply. In 2030, the average coal transportation rate for new electric power capacity is $7.14 per short ton (2004 dollars), compared with $8.63 for existing capacity.

Demand for Imported Coal Increases in the East and Southeast

Figure 102. U.S. coal exports and imports, 1970-2030 (million short tons)



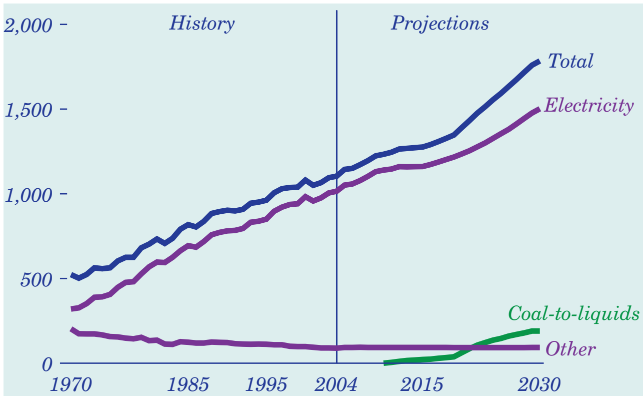
U.S. imports of low-sulfur coal rise from 27 million tons in 2004 to 99 million tons in 2030 (Figure 102). In addition to further displacement of more expensive Central and Southern Appalachian coal at existing power plants, imports fuel some of the new coal-fired generating capacity expected to be built in the U.S. East and Southeast. Much of the additional import tonnage originates from mines in Colombia, Venezuela, and Indonesia.

U.S. coal exports have been in steady decline from their 1996 level of 90 million tons, falling to 40 million tons in 2002, despite a substantial increase in world coal trade (from 503 million tons to 656 million tons). Low-cost supplies of coal from China, Colombia, Indonesia, Russia, and Australia satisfied much of the growth in international demand for steam coal during the period, and low-cost supplies of coking coal from Australia supplanted substantial amounts of U.S. coking coal in world markets. Since 2002, however, U.S. exports have rebounded, including increases in steam coal exports to Canada in 2003 and coking coal to overseas customers in 2004.

Although U.S. exports remain near their 2004 level for the next several years, their share of total world coal trade ultimately falls from 6 percent in 2004 to 1 percent in 2030, as international competition intensifies and imports of coal to Europe and the Americas (excluding the United States) grow more slowly or decline. With the planned decommissioning of Ontario's five coal-fired generating plants, U.S. coal exports to Canada decline from 19 million tons in 2004 to 7 million tons in 2030.

Coal-Fired Generators Can Comply With CAIR and CAMR

Figure 103. Electricity and other coal consumption, 1970-2030 (million short tons)

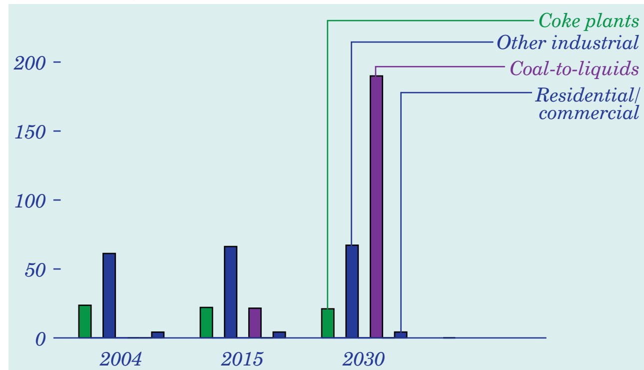


EPA's CAIR and CAMR regulations tighten restrictions on emissions of SO_2 and NO_x and, for the first time, address mercury emissions from electric power plants. Even with the new regulations, however, the average capacity utilization of coal-fired power plants rises from 72 percent in 2004 to 80 percent in 2012. Coal-fired power plants fitted with emissions control equipment remain competitive with natural-gas-fired generators because of their lower fuel costs. Coal consumption in the electric power sector rises to 1.5 billion tons in 2030 (Figure 103). To comply with CAIR and CAMR, selective catalytic reduction equipment is added to 118 gigawatts of coal-fired capacity between 2004 and 2030 in the reference case, flue gas desulfurization equipment is added to 141 gigawatts, and supplemental fabric filters are added to 126 gigawatts between 2004 and 2030. Activated carbon, a sorbent added to post-combustion flue gases to remove mercury, is also used in some plants.

In the projections, a mix of advanced IGCC and conventional coal-fired capacity is built in the electric power sector; 55 percent of the 154 gigawatts of new coal capacity is IGCC, which has low emissions of both SO_2 and mercury. A typical IGCC plant may remove 99 percent of the sulfur and 95 percent of the mercury present in bituminous coal. In addition, sustained high world oil prices combined with competitive coal prices stimulate investment in 19 gigawatts of CTL capacity, requiring 190 million tons of coal per year, by 2030. SO_2 and mercury emissions from CTL plants are comparable with those from IGCC plants.

Emerging Coal-to-Liquids Industry Increases Industrial Coal Use

Figure 104. Coal consumption in the industrial and buildings sectors and at coal-to-liquids plants, 2004, 2015, and 2030 (million short tons)



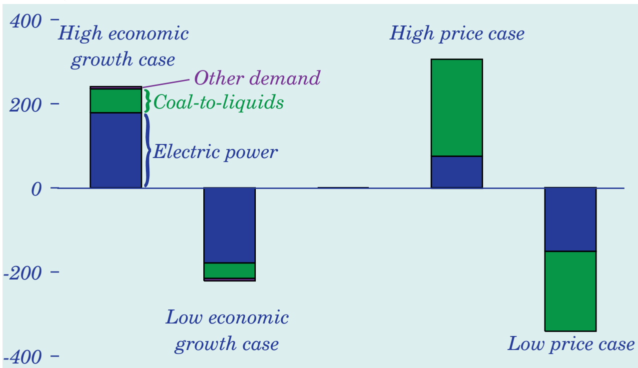
Although the electric power sector accounts for the bulk of U.S. coal consumption, 89 million tons of coal currently is consumed in the industrial and buildings (residential and commercial) sectors (Figure 104). In the industrial sector, steam coal is used to manufacture or produce cement, paper, chemicals, food, primary metals, and synthetic fuels; as a boiler fuel to produce process steam and electricity; as a direct source of heat; and as a feedstock. Coal consumption in the other industrial sector (excluding production of coal-based synthetic liquids) increases slightly in the *AEO2006* reference case.

Coal is also used to produce coke, which in turn is used as a source of energy and as a raw material input at blast furnaces to produce iron. A continuing shift from coke-based production at integrated steel mills to electric arc furnaces, combined with a relatively flat outlook for U.S. steel production, leads to a slight decline in consumption of coal at coke plants.

Outside the electric power sector, most of the increase in coal demand in the reference case is for production of coal-based synthetic liquids. High world oil prices spur investment in the CTL industry, leading to the construction of new plants in the West and Midwest that produce just under 0.8 million barrels of liquids per day in 2030. In *AEO2006*, CTL technology is represented as an IGCC coal plant equipped with a Fischer-Tropsch reactor to convert the synthesis gas to liquids. Of the total amount of coal consumed at each plant, 49 percent of the energy input is retained in the product, 20 percent is used for conversion, and 31 percent is used for grid-connected electricity generation.

High Economic Growth, High Oil and Gas Prices Increase Coal Demand

Figure 105. Projected variation from the reference case projection of U.S. total coal demand in four cases, 2030 (million short tons)



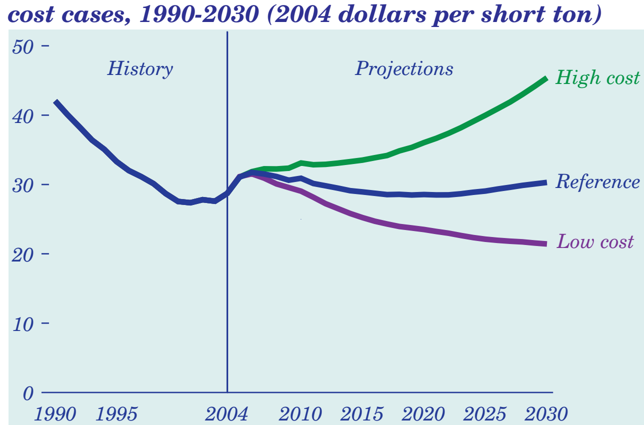
In comparison with the reference case, electricity demand is higher in the high economic growth case and lower in the low growth case. Accordingly, coal consumption also rises and falls in the high and low growth cases, respectively (Figure 105). As in the reference and high growth cases, the first CTL plant comes on line in 2011 in the low economic growth case; but total CTL capacity in 2030 in the low growth case is only 62 percent of that in the high growth case.

In the high price case, higher natural gas prices discourage natural-gas-fired generation and boost coal-fired generation. Delivered natural gas prices to the electric power sector in 2030 are $1.63 per million Btu higher in the high price case than in the reference case, whereas coal prices are only 10 cents per million Btu higher than in the reference case. In the reference case, coal fuels 57 percent of total electricity generation in 2030 in the reference case, as compared with 64 percent in the high price case and 46 percent in the low price case.

Higher world oil prices in the high price case favor increased investment in CTL, and the demand for coal at CTL facilities increases to 20 percent of total coal consumption in 2030. In the low price case, no CTL plants are operating in 2030. Because electricity generation at CTL plants displaces some generation in the electric power sector in the high price case, coal demand in the electric power sector is only 75 million tons higher than in the reference case. In the low price case there is more natural-gas-fired electricity generation, and as a result coal demand in the electric power sector is 151 million tons lower than in the reference case.

Higher Mining and Transportation Costs Reduce Demand for Coal

Figure 106. Average delivered coal prices in three cost cases, 1990-2030 (2004 dollars per short ton)



Alternative assumptions about future coal mining and transportation costs affect coal prices and, consequently, demand. The two alternative coal cost cases developed for *AEO2006* examine the impacts on U.S. coal markets of alternative assumptions about mining productivity, labor costs and mine equipment costs on the production side, and railroad productivity and rail equipment costs on the transportation side. Adjustments of about 2.5 percent from the reference case assumptions are based on variations in historical growth rates for the coal mining and rail transportation industries since 1980.

In the high cost case, the average delivered coal price in 2030, in constant 2004 dollars, is $45.39 per ton—50 percent higher than in the reference case (Figure 106). As a result, U.S. coal consumption is 284 million tons (16 percent) lower than in the reference case in 2030, reflecting both a switch from coal to natural gas, nuclear, and renewables in the electricity sector and reduced production of coal-based synthetic liquids. In the electric power sector, 111 gigawatts of new coal-fired generating capacity is built by 2030 in the high cost case—63 gigawatts less than in the reference case. CTL production in 2030 in the high cost case totals only 0.2 million barrels per day, or 77 percent less than in the reference case.

In the low cost case, the average delivered coal price in 2030 is $21.42 per ton—29 percent lower than in the reference case—and total coal consumption is 160 million tons (9 percent) higher than in the reference case.