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Mr. Chairman and Members of the Committee:

I appreciate the opportunity to appear before you today. As requested in your invitation, my testimony focuses on the current and future reliability of coal-based generation and the major forces impacting the coal supply chain.

The Energy Information Administration (EIA) is the independent 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 Congress, the Administration, and the public. Because we have an element of statutory independence with respect to this work, our views are strictly those of EIA and should not be construed as representing those of the Department of Energy or the Administration.

For the past 50 years, coal has fueled roughly half of the Nation's electricity generation. The national average delivered cost of coal to the electric power sector has increased from about $1.36 per million British thermal units (Btu) in 2004 to about $1.65 per million Btu as of January 2006. Rail shipments in 2005 accounted for 72 percent of all coal delivered to electric power plants. National average rail transportation costs, which now represent about 40 percent of delivered cost, increased from $0.51 per million Btu in 2004 to about $0.63 per million Btu by February 2006, with the cost of contract rail transportation representing a much larger share of the average total cost of rail-delivered coal for western subbituminous coal than for eastern bituminous coal (60 percent and 25 percent, respectively).[1]

The national averages for delivered coal costs encompass a wide range of factors affecting individual electric generators, such as their specific circumstances and the types of coal and rail transportation they require. The average also reflects the fact that electric generators buy both coal and rail transportation under pre-existing and newly negotiated contracts as well as in spot market transactions. So it is undoubtedly the case that some generators have recently experienced much larger changes in their delivered coal costs, while others have experienced smaller changes. Nonetheless, despite recent increases in the delivered cost of coal, coal-fired

[1] Data on rail transportation costs from the COALdat database, a product of Platts/McGraw-Hill.

generation generally remains very cost-effective compared to generation using natural gas, whose price has increased to a much greater extent in recent years.

When discussing the reliability of coal-fired generation for electricity, it is useful to make a distinction between Western subbituminous coal, primarily produced in the Powder River Basin (PRB), whose share of the overall coal market has been growing over time, and bituminous coal generally produced in the East and Midwest. In 2005, subbituminous and bituminous coal each accounted for about 46 percent of total coal consumed for power generation, with lignite coal and a small amount of waste coal accounting for the rest.

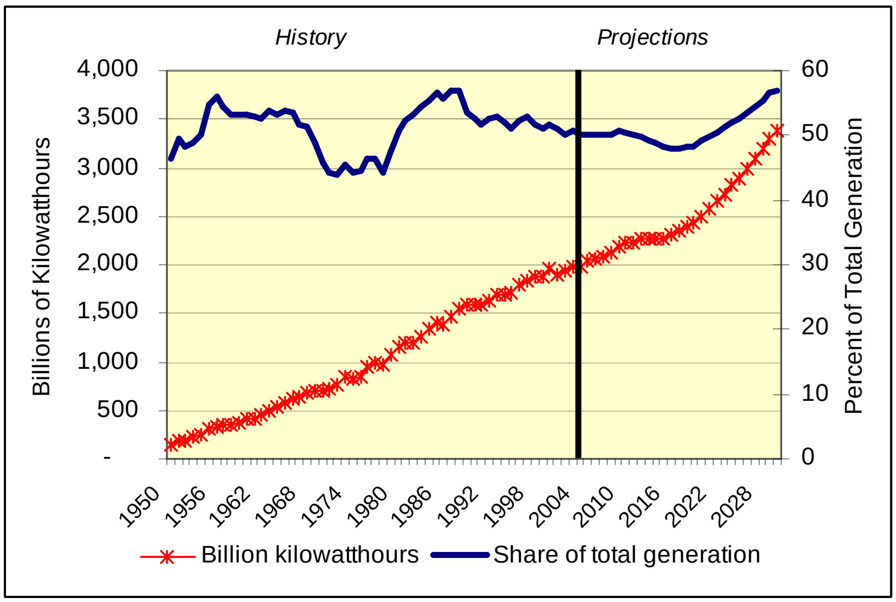
Although annual shipments of PRB coal have grown steadily and reached a new record high in 2005, actual shipments in 2005 fell short of demand. For example, in June 2005 at the beginning of the peak summer demand season, the Union Pacific Railroad (one of the two railroads serving the PRB) incurred an average daily shortfall in PRB coal shipments of four trains per day, or about 12 percent less than it achieved prior to operational problems that began in mid-May. At the beginning of July, the Union Pacific informed its customers that it would be unable to meet all its obligations for coal and recommended that customers take steps to conserve coal. In September 2005, the Union Pacific and the Burlington Northern Santa Fe Railway, the second PRB carrier, together moved about 14 percent fewer trains of coal than targeted from jointly served mines (an average of 60.5 trains per day compared to a target of 70.7 trains). In October the shortfall in average daily trains moved from jointly served mines was 15 percent.

PRB coal shipments were short of expectations primarily due to disruptions in the PRB rail transportation infrastructure and the corrective actions being taken to address them. The shortfall in PRB shipments is reflected in a drawdown of subbituminous coal inventories at power plants over the past year and has also led to some reduction in utilization rates at some coal-fired plants. Although overall inventories of bituminous coal have grown over the past year, rail congestion in the East has also periodically disrupted deliveries to electricity generators. Looking ahead, while significant projects to address bottlenecks in the PRB are now being implemented and others are planned, EIA expects reliance on all types of coal to increase over time, suggesting a requirement for increased capacity in the Nation's rail transportation system.

Coal Usage by Electric Generators

Coal-fired generation is the single largest source of electric power generation for the United States, accounting for between approximately 45 and 55 percent of total generation in each of the last 50 years. (See **Figure 1**).

Figure 1. Coal Share of Generation (percentage) and Coal Generation (billion kilowatthours)



Source: **History**: Annual Energy Review; **Projections**: Annual Energy Outlook 2006

In 2005, coal accounted for 50 percent of total net generation, while the next largest sources, natural gas and nuclear power, accounted for 19 percent each. Hydroelectric power accounted for 7 percent of the total, and a variety of other energy sources, including petroleum, other fossil fuels, and other renewables such as biomass and wind power, accounted for the balance.

Between 1989 and 2005, net generation from coal increased by 27 percent, from 1,584 billion kilowatthours to 2,014 billion kilowatthours (See **Figure 1**). This increased output primarily reflected improved utilization of existing coal-fired plants, as total coal-fired generating capacity increased only 3 percent, from 303.1 gigawatts of net summer capacity to 313.5 gigawatts over the same period. In 1989, the average capacity factor of coal-fired plants (a measure of actual generation compared to the hypothetical maximum output from power plants) was 60 percent. In 2005 the average capacity factor for coal plants was 72 percent.

Although coal-fired generation has grown by 27 percent since 1989, the coal consumption measured in tons increased by 34 percent (from 782 million tons to 1,051 million tons). Consumption of coal outpaced the growth in generation because of increasing use of subbituminous coal produced in the PRB. This subbituminous western coal has less energy content per ton than eastern and midwestern bituminous coal, so more tons are needed to produce an equivalent amount of electricity. Western subbituminous coal is generally lower in sulfur and less expensive to produce than bituminous coal, which often makes subbituminous coal a preferred option for environmental and economic reasons despite its lower energy content.

Coal Production, Consumption, and Trade

Coal production set a record in 2005 as the industry mined a total of 1,133 million short tons of coal, an increase of 1.9 percent over 2004. However, the regional coal production levels have followed different patterns over the last 5 years. Coal production in northern and central Appalachia decreased in 2002 and 2003 and then increased in both 2004 and 2005. This irregular pattern in eastern production was due to changes in demand and operational and permitting issues that affected production. Most recently, coal production in northern Appalachia was 140 million short tons in 2005, an increase of 3.5 percent over 2004. Central Appalachian coal production was 236 million short tons in 2005, an increase of 1.1 percent. Illustrative of the shift to subbituminous coal, production in the PRB has increased every year since 2000 and now accounts for the largest share of total U.S. coal production.

Total coal consumption increased in 2005 by 1.9 percent, slightly higher than the 1.1 percent increase experienced in 2004, but less than the 2.7 percent experienced in 2003. These trends are driven by developments in the electric power sector, which accounts for 92 percent of all domestic coal use. Coal consumption in the other sectors has varied only slightly over the last 5 years.

The United States also imports and exports coal, although the volumes are small in relation to domestic production and consumption. Total coal exports were 49.9 million short tons in 2005, including metallurgical coal exports of 28.7 million short tons. Most exported coal is mined in the East and transported from eastern or southern ports. Coal imports, also received predominantly through eastern and southern ports, were 30.5 million short tons in 2005, an increase of 12 percent over 2004. Most of these coal imports are consumed in the electric power sector.

Trends in Electric Power Sector Coal Stockpiles

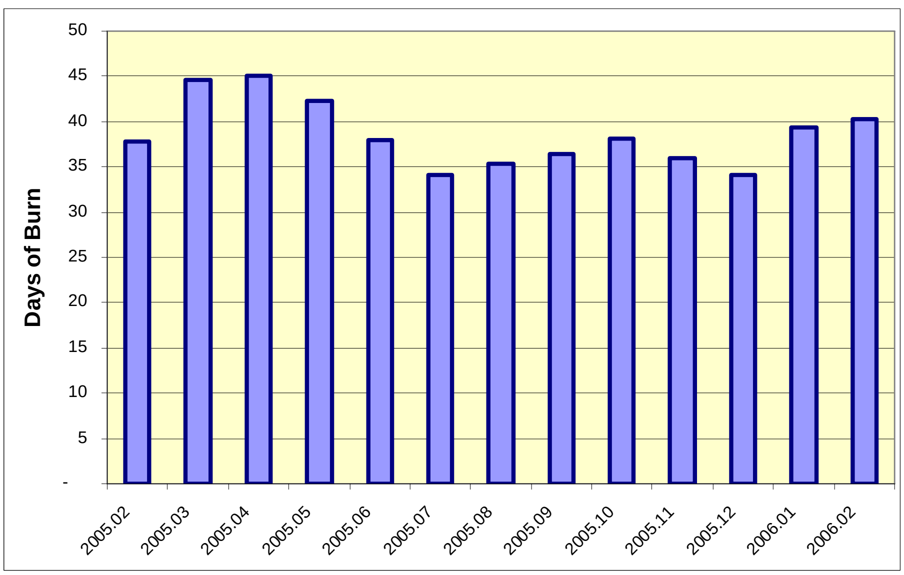
Power plant stockpiles, or inventories, of coal are used to protect against both routine and unusual disruptions in supply. Most plants receive coal by rail, truck, or water delivery. However, 72 percent of coal shipments are delivered to these power plants by rail. All of these transportation modes are subject to minor delays in shipments. Coal transportation and supply can also suffer major disruptions due to a variety of factors, including shortfalls in transportation, coal handling and mining capacity, infrastructure and equipment failure, and the weather.

A plant's stockpile of coal provides a buffer against these interruptions. If deliveries of coal are severely reduced, the operator of a coal-fired plant may be forced to reduce its utilization rate. In this case the reduced generation is replaced with power from other plants, such as natural-gas-fired units, which is often more costly.

Although there has been significant year-to-year variation, coal stockpiles at electric power plants have generally been declining for years. For example, end-of-year stocks declined from 135.9 million tons in 1989 to 101.2 million tons in 2005, down 26 percent, although coal-fired generation and coal consumption both increased during this period. The long-term trend represents, in part, efforts by power plant operators to minimize their coal inventory holding costs. Over the past several years, however, operators at times have found it difficult to maintain stockpiles because of intermittent disruptions in coal production and transportation. Concerns over coal deliveries and reduced stockpiles have grown over the past year due to problems with shipments of coal from the PRB, as discussed below.

At the end of February 2005, coal-fired electric power plants had 98.3 million tons of coal in inventory. By the end of February 2006, inventories had increased to 105 million tons. Coal stockpiles are often expressed in terms of "days of burn," which is a measure of the number of days a plant, or group of plants, can operate using only on-site inventories for supply. EIA has estimated the days of burn at larger coal plants (net summer generating capacity of 250 megawatts or greater) by comparing each month's ending inventory with the historical average demand for the next month. At the national level, days of burn at large coal plants have increased from 38 to 40 days comparing February of 2005 and 2006 (see **Figure 2**).

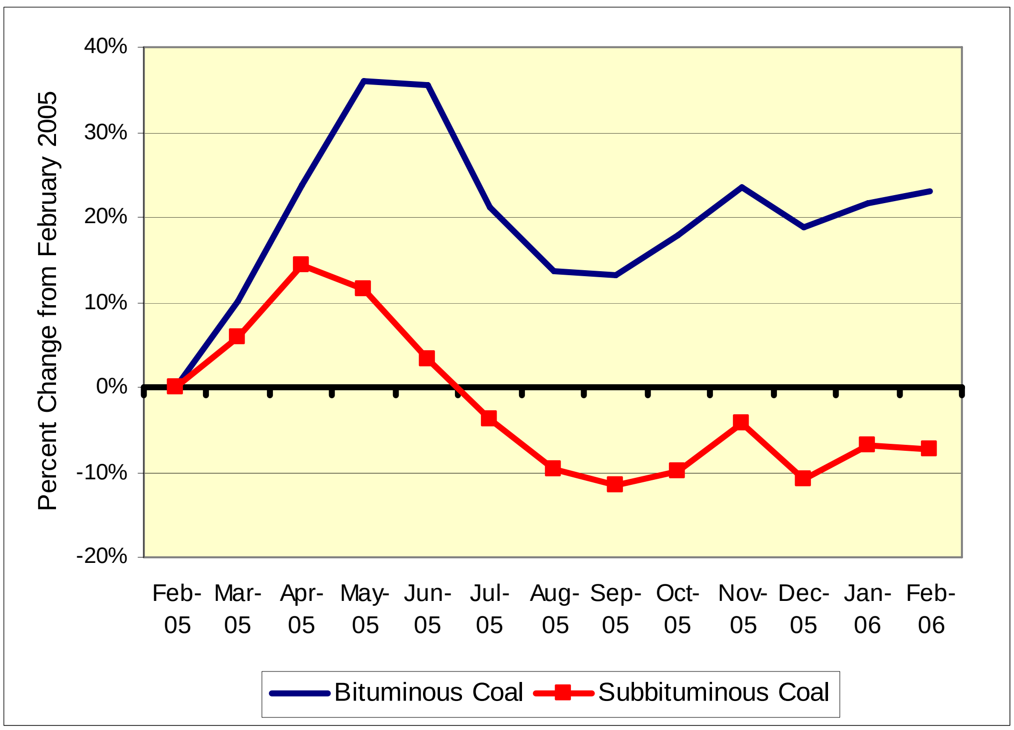
Figure 2. Days of Burn at Large Coal Plants, February 2005 to February 2006



Source: Data from Forms EIA-906 "Power Plant Report" and EIA-920 "Combined Heat and Power Plant Report"; EIA calculations.

However, the increase in coal inventories over the past year has not been uniform. During this period, stocks of bituminous coal, which is primarily mined in the East and Midwest, increased 23 percent from 44.6 to 54.8 million tons (see **Figure 3**). But inventories of subbituminous coal, the vast majority of which is shipped from the PRB, dropped 7 percent from 49.8 to 46.1 million tons. This decline in subbituminous stockpiles is indicative of the transportation problems for shipments of PRB coal. It is also consistent with press reports that over the past year some generators relying on subbituminous coal decided to reduce coal burn in order to conserve coal supplies; i.e., the 7-percent decline in subbituminous stockpiles would have been greater if those generators had not reduced the output at their plants.

**Figure 3. Electric Power Sector Coal Stocks by Coal Rank
February 2005 to February 2006**



Source: EIA, Electric Power Monthly, April 2005; EIA calculations

Railroad Transportation Issues

In the PRB, a number of disruptions occurred in planned coal shipments during 2005. Structural failures in the rail roadbeds caused two major train derailments on the weekend of May 14. The roadbed failures were triggered by unusually wet weather for the region. Accumulated coal dust infiltrated the road foundations (stone ballast) and created drainage problems which led to the derailments. This affected all three mainlines in the Joint Line shared by the Burlington Northern Santa Fe Railway (BNSF) and Union Pacific Railroad (UP) used to move coal unit trains in and out of the PRB. Normally, the Joint Line operates 365 days a year, 24 hours per day and moves three loaded coal trains per hour out of the basin. After the derailments, BNSF and UP replaced more than 100 miles of roadbed, including new concrete railroad ties and new tracks to facilitate trains passing. Rebuilding continued, as scheduled, through November 2005 and was restarted with the spring thaw in 2006. During this entire period, rail traffic in and out of the PRB has been disrupted at times, but it is now moving more fluidly, even though the reconstruction project is not yet quite complete.

BNSF and UP have invested heavily over the past 20 years in rail infrastructure and equipment to serve the PRB coal market. Both railroads continue to make additional capital improvements throughout their respective rail systems: adding parallel tracks, upgrading classification yards, alleviating bottlenecks, and generally improving capacity for all types of rail traffic. On May 8, 2006, the UP and BNSF announced that they would spend $100 million over the next 2 years to construct more than 40 miles of third and fourth main line tracks on the PRB Joint Line. This follows the addition of 14 miles of third line track in 2005 and 19 miles currently under construction in 2006. The railroads believe the completion of these projects will raise Joint Line capacity to at least 400 million short tons per year, compared with the record 325 million short tons hauled in 2005.

The Dakota, Minnesota & Eastern (DM&E) Railroad has spent the past 8 years in the permitting, reviewing and financing processes surrounding its plans to open a new route into the PRB from the East. The DM&E would upgrade existing routes to connect the PRB more directly to the Chicago area to the East and to power plants in South Dakota, Minnesota, Wisconsin, Iowa, Illinois, and possibly points east of Chicago. If built, the railroad could potentially haul 100 million short tons of coal per year out of the southern PRB directly eastward. This could alleviate congestion on the Joint Line.

EIA is not directly involved in the DM&E project. However, in 2005, at the request of the Surface Transportation Board (STB), we provided an analysis of the impact of changes in coal transportation rates on the projected use of coal in electric power generation using a set STB-specified transportation rate sensitivity cases. Our analysis found that the projected level of coal use in electric power generation in the United States did not change appreciably across the cases, but that the projected use of PRB coal varied to some degree across the sensitivity cases. For example, an assumed 7 percent reduction in rates to Ohio, Illinois, Indiana, Michigan, Wisconsin, Minnesota, Iowa, North Dakota, South Dakota, Nebraska, Missouri, and Kansas, together with a smaller reduction in rates to Kentucky and Tennessee, was estimated to increase the projected use of PRB coal by roughly 3 percent.

As a result of the disruptions of 2005, shipments of PRB coal fell short of demand. Some affected power plants had sufficient inventories of coal to continue normal operations, but others reduced generation as a part of their strategy to mitigate the disruptions in the supply chain. To compensate, they bought power from other generators, or relied more heavily on other, generally natural-gas-fired, generating plants within their systems. The capacity of natural-gas-fired power plants (including oil-burning plants that can also use natural gas) more than doubled, from 165.9 to 409.2 gigawatts between 1989 and 2005. Most of this capacity is not fully utilized, but using it in lieu of coal-fired power can be an expensive option. At the average cost of delivered natural gas to the electric power sector in January 2006, a new, efficient natural-gas-fired combined-cycle plant can produce electricity at a fuel cost of roughly 6.4 cents per kilowatthour. The comparable cost for a conventional coal-fired plant at the January 2006 national average delivered price was less than a third as much, about 1.5 cents per kilowatthour.[2]

Because of the complex and (currently) capacity-constrained PRB operations and delivery schedules, it will take some time to rebuild subbituminous stocks. With the supply chain for PRB coal as fully committed and finely tuned as it is, any future weather, equipment or infrastructure failure has the potential to reverberate through the entire system. Hardly a month goes by that delivery of PRB coal somewhere in the supply chain is not interrupted by a derailment, freezing, flooding, or other natural occurrence. In most cases, the events are small compared with the amount of PRB coal delivered each year, and the rail system and inventories

[2] This does not include the higher capital costs or the higher operations and maintenance costs of coal-fired plants.

are capable of absorbing them, unless the events are particularly severe or occur simultaneously.

The situation in the East is somewhat different. The primary eastern railroads, Norfolk Southern Railway (NS) and CSX Transportation (CSXT), divided and absorbed Conrail's assets in 1998. Both railroads experienced a number of customer complaints related to slow deliveries in the years following the Conrail acquisition. The impact of population density and geography mean the eastern railroads must contend with more traffic per mile of track, more congested routes and delivery areas, steeper grades and narrower, winding right-of-ways and routes than the western railroads. Recent increases in the export coal market have further congested rail lines in the East. Therefore, deliveries of bituminous coal to eastern power plants may also have been disrupted, to some degree, by hauls to export docks.

It is important to note that railroad capacity constraints nationwide entail more than just the infrastructure improvements at important coal origins and destinations. Other parts of the rail system are also increasingly constrained in their capacity to handle **all** rail traffic, not just coal. Nationwide rail capacity is constrained in part because of growth in demand in other freight sectors, including agricultural products, consumer goods, and especially, intermodal shipments (trailers or containers on flat cars). Use of these has been growing as an alternative to long-haul trucking which has been impacted by a shortage of drivers and higher diesel fuel costs. Future economic growth and the possibility that railroads will reacquire market share for shipments previously lost to truck and barge will continue to challenge the railroads to provide sufficient capacity.

Coal Prices and Transportation Rates

Delivered costs of coal reflect two components: the costs of mined coal, and the transportation costs. For western subbituminous coal, the cost of contract rail transportation represented approximately 60 percent of the average cost of rail-delivered coal in February 2006. For the same period, the cost of contract rail transportation of eastern bituminous coal represented only about 25 percent of the average cost of rail-delivered coal. Therefore, the impact of transportation costs on the total delivered cost of coal is significantly higher for electric generators who rely on western rather than eastern coal.

Until recently, real (inflation-adjusted) delivered coal prices had fallen steadily for the past two decades as coal output grew by increasing man-hours, improving efficiency, and opening new operations, while railroad rates declined due to significant productivity improvements. The balance has now shifted, rather dramatically, to a more supply-constrained market. At the beginning of 2005, all four major railroads began offering coal shippers much higher rates when old contracts expired. The magnitude of the rate increases varies with specific circumstances, but significant rate increases have been reported in the trade press.

In 2005 and 2006, coal buyers reported rapid escalation in coal supply costs, both in rail transportation contracts and minemouth coal prices. Between February 2004 and February 2006, average minemouth prices for subbituminous coal increased by about 44 percent while average minemouth prices for Central Appalachian bituminous coal increased by 50 percent. During the same period, average contract rail transportation costs for subbituminous coal increased by about 19 percent while average contract rail transportation costs for bituminous coal increased by 13 percent.[3]

These data reflect average contract prices paid by electric generators for rail-delivered coal. As such, the data reflect pre-existing as well as recently renegotiated contracts for coal and transportation. Therefore, the price paid by specific generators may vary from these averages.

The Future Outlook for Coal

Over the next 25 years, EIA expects significant growth in the use of coal for the generation of electricity and the rail transportation system will need to be expanded to accommodate it. Over the same time period, coal use in the industrial sector is expected to grow as coal is used to produce liquid fuels together with electricity. While there are uncertainties, particularly with

[3] Data on minemouth prices and rail costs from COALdat database, a product of Platts/McGraw-Hill

respect to the potential impact of future environmental regulations on coal use, the wide-spread availability and relatively low cost of coal make it very economical for electricity generation. As a result, in the reference case in EIA's *Annual Energy Outlook 2006* (*AEO2006*), total coal consumption is projected to increase from 1.1 billion short tons in 2004 to 1.3 billion short tons in 2015 and 1.8 billion short tons in 2030.

The increase in coal use over the next 5 to 10 years is driven primarily by greater use of existing coal plants, while in the longer term, a large number of new plants are expected to be added. The current average utilization rate of approximately 72 percent is projected to increase to 80 percent by 2013. In addition, over the 2004 to 2030 time period, 174 gigawatts of new coal-fired electricity generation capacity, including 19 gigawatts of coal-to-liquids capacity, are projected to be added. Most of the projected new coal plants, 126 gigawatts, are expected to be added after 2020, and a little over half of them are expected to be integrated gasification combined-cycle (IGCC) plants. By 2030, coal-fired generation is projected to account for 57 percent of total generation in the *AEO2006* reference case, up from 50 percent in 2004 (See **Figure 1**).

To meet the growing demand for coal, most coal supply regions, particularly those in the West, are projected to increase their annual production volumes. The exceptions to this are the Central and Southern Appalachia regions where mining difficulties and reserve depletion are projected to contribute to lower production levels in 2030 compared to 2004. In contrast, the PRB has large, productive surface mines that are able to produce coal at a comparatively low cost. In 2030, the PRB is projected to produce 719 million short tons, 298 million tons higher than in 2004, accounting for 52 percent of the total increase in annual coal production between 2004 and 2030.

After declining for most of the past 25 years, the average real delivered price of coal to the electricity power sector has risen sharply recently. Over the next 25 years, EIA projects that coal prices in inflation-adjusted dollars will moderate somewhat from their current level and then increase slowly. Even so, the price of coal still remains well below competing fuels such as natural gas. At the regional level, minemouth coal prices are projected to rise significantly in several of the major coal supply areas. For example, they increase by 38 percent in the Eastern Interior Region and 40 percent in the PRB. However, the average national minemouth price is projected to increase only 8 percent because a large portion of the growth in coal consumption comes from the relatively low cost subbituminous coal deposits in the PRB.

The increase in coal use is not expected to lead to increased power sector emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), or mercury, but carbon dioxide (CO_2) emissions grow. In fact, because of recently enacted regulations, SO_2, NO_x and mercury emissions are all expected to fall as control equipment is added to existing plants. Between 2004 and 2030, power sector SO_2, NO_x and mercury emissions are projected to fall by 66, 42, and 71 percent, respectively, while CO_2 emissions grow by 44 percent.

As with all long-term projections, there are significant uncertainties. With respect to coal markets, key areas of uncertainty include future economic growth, long-term productivity improvements that influence coal prices, competing natural gas prices, the development of competing technologies such as nuclear, and the possibility of new policies to curb the growth in CO_2 emissions. In addition to the reference case, the *AEO2006* includes numerous sensitivity cases that address some of these uncertainties. For instance, in the high coal cost case, higher coal production and transportation costs lead to delivered prices to the electricity sector that are 48 percent higher in 2030 than the reference case (on a Btu basis). In the high coal cost case, coal's share of generation remains at 50 percent in 2030 rather than rising to 57 percent with only 111 gigawatts of new coal capacity is added rather than the 174 gigawatts that are added in the reference case. In addition, coal production in the PRB grows to only 493 million tons in 2030, 226 million tons below the level projected in the reference case. Overall, total coal production in the high coal cost case is 283 million tons lower than in the reference case. Conversely, in the low coal cost case, delivered prices to the electricity sector are 29 percent lower in 2030 than in the reference case. As a result, 200 gigawatts of new coal capacity are added. Without exception, coal production and consumption increases in all of the sensitivity cases included in the *AEO2006*. However, EIA analyses of proposals to control greenhouse gas emissions have sometimes shown significant reductions in coal use.

In sum, coal-based generation has been, and will continue to be, the dominant source of the Nation's electricity supply. Recent structural changes in the Nation's rail industry have led, at times, to some disruptions in deliveries of PRB coal to power plants. While these have generally been compensated for by alternate coal supplies, reduction of inventories, or switching to natural gas, they have also had some impact on electricity prices borne by consumers. The railroad industry appears to be investing in and/or planning measures to increase capacity and reliability at key coal origin and destination locations. EIA's long-term outlook for electricity assumes that transportation will not constrain the growth of coal-fired generation.

This concludes my testimony, Mr. Chairman and members of the Committee. I will be happy to answer any questions you may have.