TOPIC PAPER #1

COAL IMPACT

On July 18, 2007, The National Petroleum Council (NPC) in approving its report, *Facing the Hard Truths about Energy,* also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the Task Groups and their Subgroups. These Topic Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached Topic Paper is one of 38 such working document used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix E of the final NPC report provides a complete list of the 38 Topic Papers and an abstract for each. The printed final report volume contains a CD that includes pdf files of all papers. These papers also can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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Executive Summary

World Coal Trade

Historically, international coal trade was in hard (i.e., bituminous and anthracite) coal for power generation and coke making. Coal for steel making has typically required more exacting quality standards than that for power generation, for steel making requires a specific combination or blend of characteristics. Since the characteristics are rarer, coking coal, and particularly high grade coking coal, is not found in such abundance. Therefore, it was the first coal to be systematically traded, with the development of the Australia-Japan coal trade in the late 1960s and early 1970s. Today, most quality coking coal is still found largely in Australia, the USA and Canada.

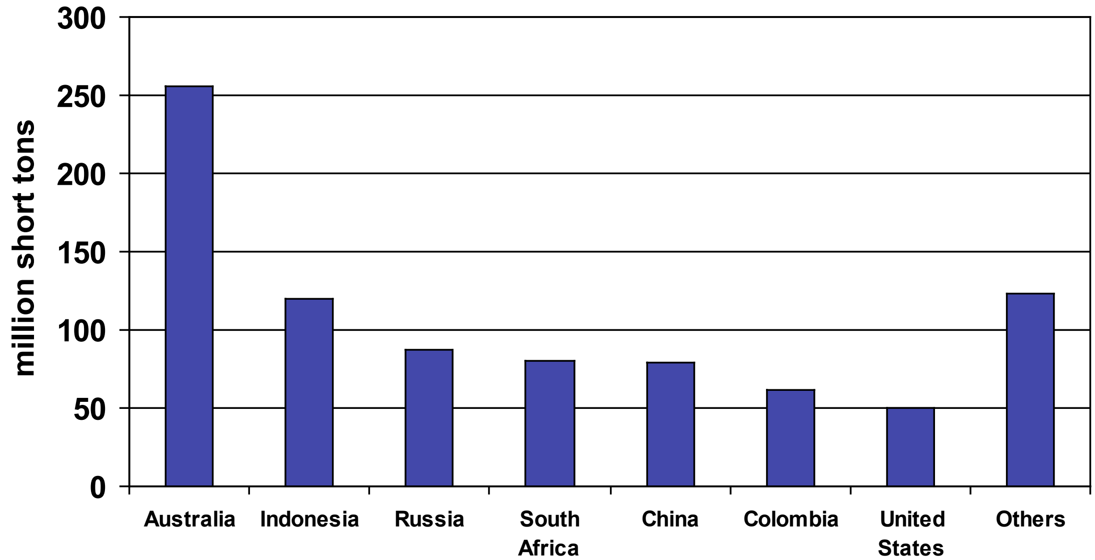
Thermal coal, on the other hand, does not require such a specific mix of characteristics. International trade in this case also began with Australia and Japan, although there was significant intra-regional trade in Europe before that. The limit on coals that were internationally traded for power generation was largely set by efficiency, as coals with lower heat value and higher moisture were more costly to transport. This remains largely the case today, although there has been steady penetration of Indonesian sub-bituminous coals into the Asian market.

Coal trade patterns have shown a steady evolution since the early days of the international coal industry. As long ago as the early 1980s, Australia was still a minor coal exporter. Indonesia, now the world's largest thermal coal exporter, did not emerge as a force in the international market until the 1990s. A similar pattern exists on the demand side. In the 1970s, there was regional trade in Europe with supply coming from Germany and Poland. The 1980s were dominated by Japan on the demand side while the 1990s saw Korea and Taiwan as significant markets. The early years of this decade have seen rapid increases in demand from smaller countries in Asia as well as the emergence of China as both a significant coal exporter and a major import market.

Trade patterns are hard to project as some countries have dedicated export facilities as well as mines that are intended for purely domestic purposes. Exports and imports are not simply differences between two large numbers. A large proportion of coal is consumed relatively close to where it is mined and export coal requires dedicated infrastructure so often import and export coal production is intended to address different markets.

The current major exporters of coal are Indonesia, Australia, China, South Africa, Russia and Colombia, as shown in Figure 1. All of these countries, except Indonesia and China, have reserve production ratios in excess of 100 years.

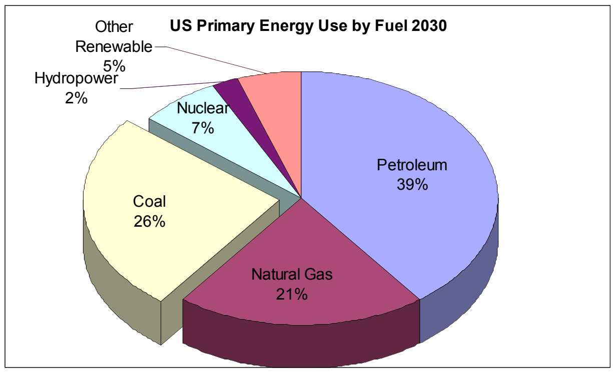
Figure 1: Major Hard Coal Exporters - 2005



United States Coal Market

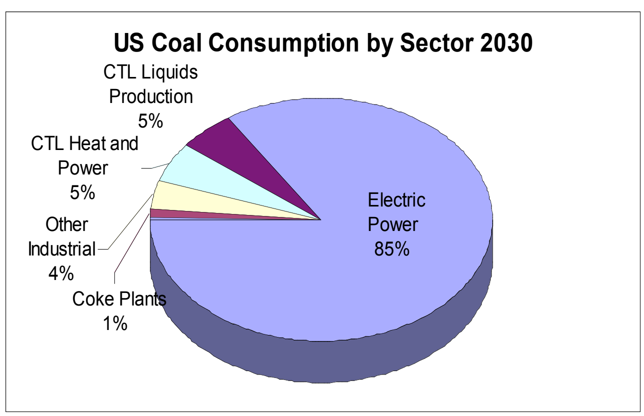
The United States is endowed with the largest coal reserves in the world, with recoverable reserves of approximately 270 billion tons, representing 27% of the world total of 1 trillion tons[1]. The second largest reserve holder is Russia, with 17%, followed by China with 13%.

Figure 2: US Energy Use by Fuel



Coal currently provides 23% of the approximately 100 quadrillion Btus of energy used in the US in 2005, according to the Department of Energy's (DOE) Energy Information Administration' s (EIA) Annual Energy Outlook (AEO) 2006. It is projected to provide 26% of the total by 2030.

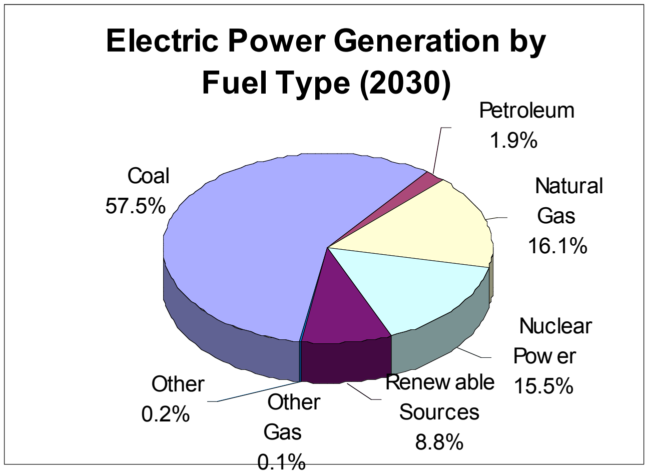
Figure 3: Coal Consumption - 2030



[1] EIA,"Annual Coal Report 2005", Table 15

The primary consumer of coal in the US is the Power Industry, consuming 92% of the 1.125 billion tons used in 2005[2]. Approximately 49.7% of power generated in 2005 was from coal. EIA projects power generation will be only 85% of consumption by 2030[3], with the growth of new technologies, such as coal-to-liquids (CTL) and coal-to-gas (CTG).

Figure 4: Generation by Fuel Type

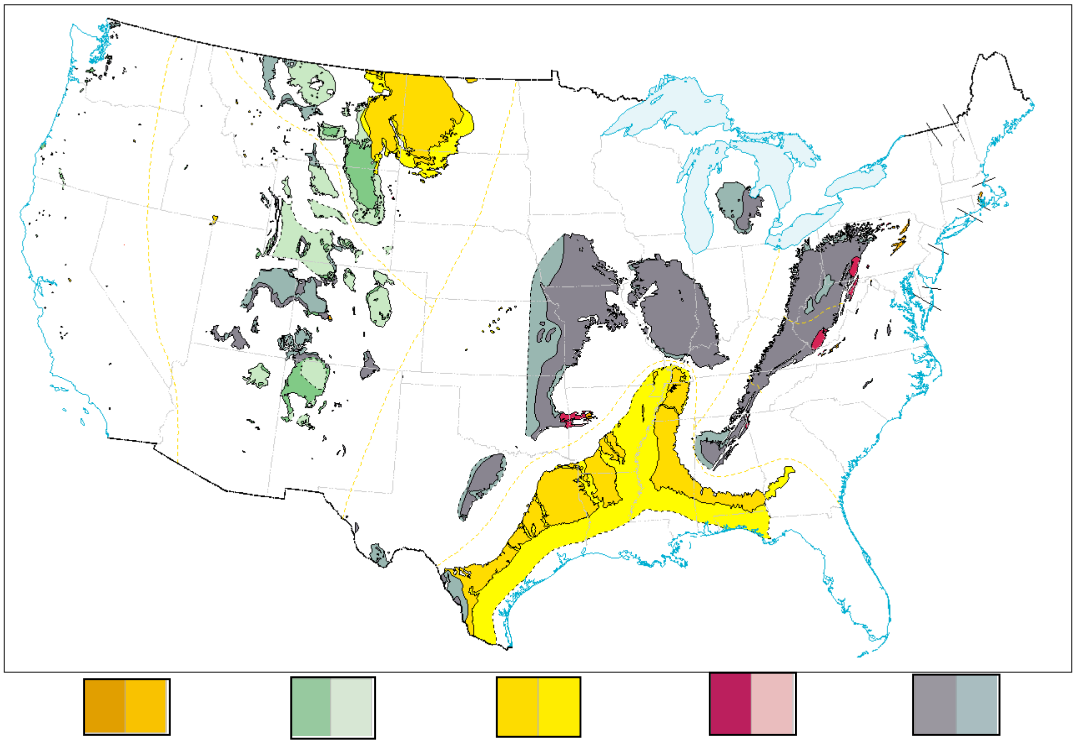


EIA projects coal demand from CTL of 94 million tons annually in 2030 (5.3% of coal market of 1.8 billion tons). Studies by the US National Coal Council (NCC) and the Southern States Energy Board (SSEB) project coal demand from new technologies to be from 1.3 to1.5 billion tons (48% of coal market of ~3 billion tons[4]).

Figure 5 shows the location and rank of coal resources in the contiguous United States (excludes Alaska and Hawaii). Most bituminous coals are located in the east, while most subbituminous coals are located in the west. While lignite occurs in both the Northern Plains and the Gulf Coast, nearly 68% of lignite reserves are located in the Dakotas and Montana. A detailed description of each coal rank is included in the "Types of Coal" section of "Appendix 1 - Definitions".

[2] EIA," Annual Coal Report, 2005", Table 26
[3] EIA,"Annual Energy Outlook, 2006", Table 15
4 Assuming the CTL demand is incremental to EIA's projected demand of 1.69 billion tons (1.784bn, less 0.94bn projected CTL demand)

Figure 5: US Coal Resources5



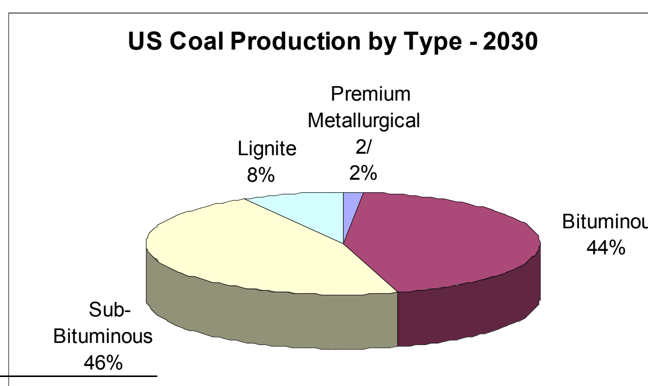
Anthracite | Subbituminous | Lignite | Low volatile Bituminous | Medium & High Volatile Bituminous

Deep color represents areas known to contain coal beds that are of commercial value at the present time or may be of value in the future. In general, the minimum thicknesses included are 14" for anthracite and bituminous coal and 30" for subbituminous coal and lignite.

Light color represents areas of doubtful value for coal. these may be divided into three classes - (1) areas containing thin or irregular beds, which generally have little or no value, but which locally may be thick enough to mine; (2) areas in which the coal is poor in quality; and (3) areas where information on the thickness and quality of coal beds is meager or lacking.

Figure 6: US Coal Production - 2030

In 2005, 44% of the coal produced in the US was bituminous and 43% was subbituminous. Nine percent of the tons

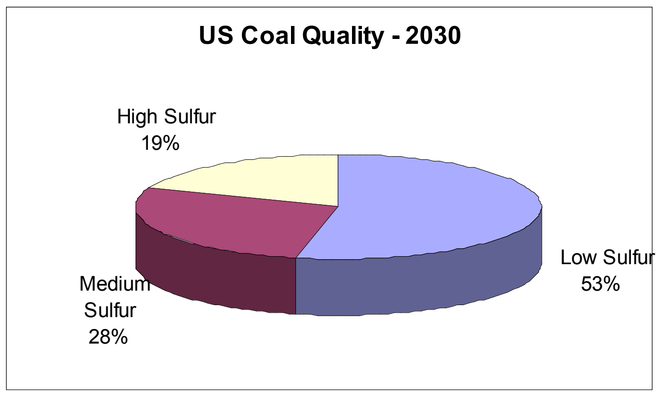


5 USGS - http://pubs.usgs.gov/of/1996/of96-092/map.htm

produced were lignite and only 4% was metallurgical coal. By 2030, EIA projects 46% of the coal produced will be subbituminous coal. Bituminous coal will retain its share of the market, however lignite will drop slightly, to 8%, and metallurgical coal will represent only 2% of production.

EIA classifies Coal as being low- sulfur at concentrations of between 0 and 0.60 pounds of sulfur per million British thermal units (mmBtu), medium sulfur between 0.61 and 1.67 pounds per mmBtu, and high-sulfur at concentrations greater than 1.67 pounds per mmBtu. Forty-nine percent of US coal produced in 2005 was low sulfur; nearly 80% of it was subbituminous coal. By 2030, 53% of production is expected to be low sulfur coal, with just over 80% being subbituminous.

Figure 7: US Coal Quality



Medium sulfur coal represented 36% of total production in 2005, 75% of which was bituminous coal. Approximately 42% of the medium sulfur coal was Central Appalachian bituminous, 20% was Northern Appalachian bituminous, and 10% was bituminous coal from the Eastern Interior (Illinois Basin). Medium sulfur coal will only make up 28% of the coal produced in 2030. While Central Appalachia will produce the largest percentage (27%), its production is down significantly from 2005. Northern Appalachia will produce 22% of US medium sulfur coal in 2030, while the Eastern Interior will increase their contribution to 14%.

High sulfur coal, which represented 15% of 2005 production, was produced primarily in Northern Appalachia (45%) and the Eastern Interior (37%), with the remainder being lignite. By 2030, 19% of coal production will be high sulfur coal, nearly half (48%) will be from the Eastern Interior. Northern Appalachia produces 42% and lignite production represents the remaining high sulfur coal production.

In 2004, 66% of domestic coal reached its final destination by rail, followed by truck at 12%, and barge at 10%. The remaining 12% was delivered by conveyor, slurry, or tram. It should be noted that the only operating coal slurry in the US was shut down in 2005, due to water concerns.

Supply Growth

Range of Outlooks

United States Outlooks

Due to the fact that there are large reserves of coal available for use into the future (see discussion on coal reserves), of the several reports that were reviewed for this study there was only one report that contained a detailed forecast of U.S. coal supply. That forecast was done by the Energy Information Administration (EIA) of the U.S. Department of Energy. The other reports reviewed concentrated on demand side forecasts and issues.

EIA does an annual forecast of the entire energy sector of United States. The following discussion is based on the coal forecast section of the report titled "Annual Energy Outlook 2006 with Projections to 2030" as posted on the EIA website at www.eia.doe.gov/oiaf/aeo/index.html. EIA uses the "National Energy Modeling System (NEMS) to project energy supply and demand for the U.S. The NEMS is made up of several modules that represent the various fuels, the consuming sectors, as well as one for macroeconomic activity. NEMS also contains a module that integrates all the other modules into one that represents the energy picture of the U.S.

The AEO 2006 reference case incorporates provisions of the Clean Air Act Amendments of 1990, as well as the finalized versions of the Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). Also, labor productivity is assumed to increase on average 0.4 percent per year through 2030, while wage rates and mine equipment costs remain constant in 2004 dollars. Assumptions that affect coal transportation are 1) railroad productivity will increase at an average rate of 1.4 percent in the east and 1.5 percent in the west; and 2) railroad equipment costs will decline on average by 0.4 percent per year from 2004.

The AEO 2006 delineates the coal supply forecast into three primary geographic coal-producing regions: Appalachia, Interior, and Western. It also provides coal supply forecasts by east and west of the Mississippi, and a breakout of the geographically smaller sub-regions for every year through 2030. Four of the sub-regions are of primary interest: the northern Appalachian (Maryland, Ohio, Pennsylvania, and northern West Virginia), the central Appalachian (eastern Kentucky, Virginia, and southern West Virginia), the eastern Interior (Illinois, Indiana, western Kentucky, and Mississippi), and the Wyoming portion of the Powder River Basin (PRB). This discussion will focus on the coal supply forecasts for the years of 2010, 2020, and 2030.

As a reference point for discussion, the following table also contains the 2004 and 2005 EIA final coal production totals (including waste coal) in million short tons and the AEO 2006 coal supply reference case forecast.

Table 1: EIA Regional Coal Production and AEO 2006 Projections (MM Tons)

	2004	2005	2010	2020	2030
Appalachia	403	409	426	379	412
Interior	146	149	190	219	281
Western	575	585	645	758	1,010
Total U.S.	1,125	1,144	1,261	1,355	1,703

Total U.S. coal production is forecast to increase by an average of 1.6 percent per year from 2004 through 2030 in response to increasing demand for use of coal to generate electricity as new coal-fired generating capacity is added and several coal-to-liquids (CTL) plants are brought online. The AEO 2006 forecast shows a combination of slow improvements in mine productivity and a continuing proportional shift of coal production from the eastern portion of the country to the western, especially to the relative low-cost coal from the PRB. The annual average increase in Appalachian coal supply is forecast at a level of only 0.1 percent, the smallest increase for any region. The Interior region, which has the lowest production level, is forecast to increase at the highest annual average percentage over the time period, 2.5 percent. The Western region is forecast to increase by an average annual level of 2.2 percent through 2030.

When the forecast is examined in relation to the shares of total U.S. coal supply, the Appalachian region is forecast to shrink as a share of the total U.S. coal supply from 35 percent in 2005 down to 24 percent in 2030. The Interior region is forecast to increase somewhat in its share of the coal supply, from 13 percent in 2005 to over 16 percent in 2030. The Western region is forecast to increase from 52 percent in 2005 to almost 60 percent in 2030.

Sub-Regional details

The AEO 2006 forecast provides a more detailed picture of the coal supply when the sub-region's forecasts are examined. The Northern Appalachian sub-region is actually forecast to increase in its share of total U.S. coal supply from 12 percent in 2005 to 14 percent in 2030. The forecast for Central Appalachian sub-region shows a large decline in its share of the coal supply, dropping from 21 percent in 2005 to 9 percent in 2030. The Eastern Interior sub-region forecast shows a slight increase over the time period, increasing from 8 percent of total U.S. coal supply in 2005 to 13 percent in 2030. The Wyoming portion of the Powder River Basin is forecast to increase by EIA from 34 percent in 2005 to 39 percent in 2030.

Table 2: EIA Sub-regions Coal Production and AEO 2006 Projections (MM Tons)

	2005	2010	2020	2030
Northern Appalachia	140	202	205	241
Central Appalachia	235	202	156	153
Eastern Interior	96	133	163	221
Wyoming - PRB	379	457	515	657

The coal supply forecast from EIA also includes a forecast of coal imports into the U.S., which account for a small portion of the total supply. The amount of coal imports forecast in 2010 is 15 million short tons (1.2 percent of total supply), in 2020 are 55 million short tons (3.9 percent), and in 2030 are 99 million short tons (5.5 percent).

When comparing domestic supplies of all fuels, EIA projects that coal will continue to be the largest single source of energy production in the U.S. in the future. The EIA forecasts that in terms of quads of energy produced in the U.S., coal will continue to dominate the picture. In 2010, coal production is forecast to account for 33.3 percent of all energy quads produced in the country. In 2020, coal's share slips slightly to 32.5 percent, before increasing to a level of 38.2 percent of total energy production in 2030. The second largest source of energy production in EIA's forecast is dry natural gas, accounting for 24.7 percent in 2010, 26.3 percent in 2020, and 24.0 percent in 2030. All of the other energy production sources in the forecast account for smaller portions of the total energy supply. Crude oil production is forecast to decline as a share of total domestic supply, declining from 16.1 percent in 2010 to 10.8 percent in 2030. Nuclear power production remains fairly constant throughout the forecast at 10 to 11 percent of total supply. The other U.S. energy production sources, natural gas liquids, renewables, and other sources, are each forecast to account for 10 percent or less to the U.S. total in 2010, 2020, and 2030.

Although there were other reports that were reviewed, none provided a detailed coal supply forecast. However, the National Coal Council published a report in March 2006 entitled "Coal: America's Energy Future" that contained challenges and opportunities for using U.S. coal for future energy needs. The report did not contain a specific forecast of coal supply, but there was a statement in the summary of the report that stated that coal production can be 2.4 billion tons by 2030.

Underlying Resources

World Coal Resources

The European Union projects that European solid fuel production will fall from 212 Mtoe (467 million short tons) in 2005 to 147 Mtoe (324 million short tons) in 2030. Given that consumption is projected to rise from 345 Mtoe (761 million short tons) to 353 Mtoe (778 million short tons) then this would suggest an increase in net imports from 133 Mtoe (293 million short tons) to 206 Mtoe(454 million short tons). Thus European dependence on coal imports is set to rise,

China and India represent the overwhelming majority of incremental projected coal demand to the horizon of 2030. Clearly then, the indigenous resources of these countries will represent a key aspect of meeting world energy supply as well as stimulating a shift in coal trade patterns.

The 2006 BP Review of World Energy identifies world proved coal reserves as about 1000 billion short tons. In terms of volume this is evenly split between anthracite/bituminous coal and lignite/sub-bituminous coal. Five countries hold over three quarters of the world's proved coal reserves - the United States holds 27% of these reserves, the Russian Federation 17%, China 12.6%, India 10.2% and Australia 8.6%.

This suggests a reserve-production ratio of about 155 years making coal much more abundant in these terms than oil or gas. A closer examination of the data, though, reveals that India has sufficient coal for 217 years of consumption at 2005 levels but China has coal for only 52 years. Chinese coal production capacity in 2010 is planned to be 1.9 billion tonnes (2.1 billion short tons) and, in 2020 after some restructuring of township coal mines, is expected to be reduced to 1.5 billion tonnes (1.65 billion short tons). This suggests, compared with IEA consumption forecasts, an increasing reliance upon coal imports. Clearly, with Chinese industrial (i.e., steel making) demand growing significantly, China will require not only coal but the right sort of coal and any restructuring plans will need to be viewed in that light.

The 2006 report from the Australian Bureau of Agriculture and Resource Economics (ABARE) projects that trade in thermal coal will increase from 573 Mt (632 million short tons) in 2005 to 733 Mt (809 million short tons) in 2020 while metallurgical coal is set to increase from 200 Mt (220 million short tons) to 290 Mt (320 million short tons). In 2025, thermal coal imports are projected to be 775 Mt (855 million short tons) and metallurgical coal imports 315 Mt (350 million short tons). Clearly, the majority of coal consumed is likely to remain untraded across national borders.

China and India will be fastest growing markets for coal exporters and it is expected that those regions best placed to serve those markets would experience the greatest growth in exports. Australia is projected to increase exports from 233 Mt (257 million short tons) in 2005 to 394 Mt (435 million short tons) in 2025 while Indonesia is projected to increase exports from 125 Mt (138 million short tons) to 184 Mt (203 million short tons). This suggests that Australia and Indonesia will represent 70% of the increase in coal exports between 2005 and 2025 and from 46% of coal exports in 2005 they will rise to 53% of exports in 2025. Coal trade will depend more and more heavily upon coal from Australia and Indonesia.

In order to meet these projections, infrastructure investment will be required. There is considerable rail investment planned. Potentially, the Hunter Valley export chain (including the Gunnedah and Ulan corridors) could have an export infrastructure of 220 Mt (240 million short tons) by 2022 although that could be limited by track capacity. Port Kembla could be expanded beyond it's current 18 Mt per year within the existing footprint of the port. Potentially, New South Wales could have export infrastructure amounting to almost 240 Mt (265 million short tons) although rail capacity may limit that slightly. In Queensland, there are a number of expansion projects which should raise port capacity out of the Central and North Bowen Basin from 89 Mt (98 million short tons) in 2005 to potentially 213 Mt (235 million short tons) by 2022. Export infrastructure from the South Bowen basin and Surat Basin is likely to be at least 145 Mt (160 million short tons) by 2022 and may yet be even higher with the development of the Wiggins Island Coal Terminal.

Infrastructure is not likely to present a long run constraint on Australian coal exports, although Indonesia may well prove to be more problematic. Although Indonesian coal resources are substantial, a significant proportion is located some distance from the coast and dedicated port terminals. Currently, a significant portion of Indonesian coal exports is transported by barge and later transshipped. Investment in providing the infrastructure to significantly develop interior coal deposits is likely to be significant.

Other countries are also projected to grow namely Colombia (55 Mt to 96 Mt – 61 to 106 million short tons), Russia (73 Mt to 109 Mt – 81 to 120 million short tons) although exports from China remain flat.

Coal Resource Base in the United States

Coal is the most abundant fossil fuel resource in the U.S. Total U.S. coal resources are very large. The total coal in-place resource was 3.97 trillion short tons[6]. Of this total resource, the demonstrated reserve base (DRB) was estimated at 492.9 billions short tons in 2005 (Figure 8). However, a significant portion of the DRB is not recoverable. Only 267.5 billion short tons of coal (about 54% of the DRB) are classified as reserves[7].

To understand the significance of these numbers, it is important to define the difference in the terms "resource" and "reserve". Resources are naturally occurring concentrations or deposits of coal in the Earth's crust, in such forms and amounts that economic extraction is currently or potentially feasible. This includes those resources that are currently economic (reserves), marginally economic, some of those that are currently sub economic, and some of the resources that will be lost-in-mining. For example, the 3.7 trillions tons of total resources in Figure 8 include coal seams as thin as 14 inches and depths to 6000 feet. Since current maximum practical mining depths are limited to about 4000 ft., many deeper resources will not be recoverable in foreseeable future

The term "reserve base" includes those parts of the identified resources that meet specified minimum physical and chemical criteria related to current mining and production practices, including those for quality, depth, thickness, rank, and distance from points of measurement.

Reserves are the fraction of the in-situ coal reserve base which could be economically extracted or produced at a sustainable profit at the time of determination considering environmental, legal, and technologic constraints. The term *reserves* need not signify that extraction facilities are in place or operative

6 EIA, 1999, U.S. Coal Reserves: 1997 Update; Energy Information Administration, www.eia.doe.gov/cneaf/coal/reserves/front-1.html, 65 p
7 EIA, 2005, Annual Coal Report; Energy Information Administration, http://www.eia.doe.gov/cneaf/coal/page/acr/acr_sum.html, 73 p

Demonstrated Reserve Base

The in situ coal resources comprising the DRB were estimated by the Energy Information Administration (EIA) to be 492.9 billion tons in its 2005 Annual Energy Review. There are three mining regions reported by EIA, the Appalachian, Interior, and Western regions. The Western region contains 47% of the reserve base, followed by the Interior, with 32%, and Appalachia, with 21%. The demonstrated coal reserve base, broken down by key state, rank, region and mining method, are shown in Figure 10.

Of the 234.5 billion tons of Western reserves, about 77% are subbituminous coal, 13% are lignite, and the remaining 10% are bituminous coal. This region contains all of the US subbituminous reserves and 68% of US lignite reserves, primarily Montana and North Dakota. The bituminous coal is dispersed among the western States, with the largest reserves in Colorado, Utah, Wyoming, and New Mexico, in descending order.

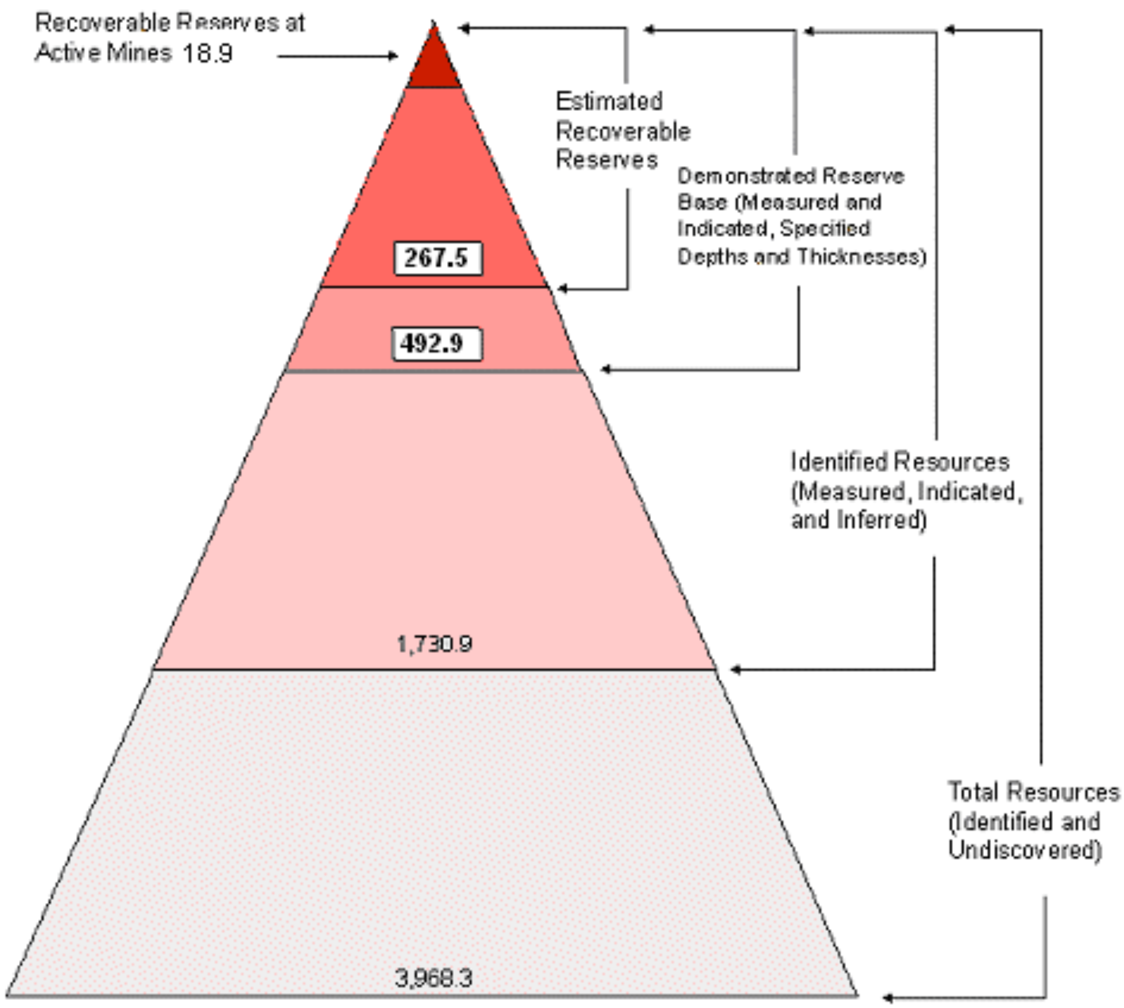
Approximately 92% of the Interior's 158 billion tons of reserves are bituminous coal, while the remainder is lignite. Of those bituminous reserves, approximately 40% are located in Illinois. The lignite reserves are located primarily in Texas, Louisiana, and Mississippi.

In the Appalachian region, 92% of the reserves are bituminous coal and 7% is anthracite. Nearly all of the anthracite is located in Pennsylvania. There is a little over a billion tons of lignite in Alabama.

The Southern States Energy Board Study (SSEB) adjusted the EIA estimates to reflect State estimates, provided in response to SSEB's survey, resulting in an estimated 771 billion tons, an increase of 276 billion tons over EIA's estimate. The largest increase was to Alaska's reserve base, from 3.3 to 170 billion tons, making it the State with the largest reserve base. Under this scenario, 58% of US reserves are located in the West, 28% in the Interior, and 14% in Appalachia. However, there is currently only one working mine in Alaska, the Usibelli mine, and much of Alaska's coal is remote, with no transportation and currently no market. It may be a stretch calling these resources 'reserves'.

Figure 8: Delineation of U.S. Coal Resources8 and Reserves 9

(Billions of short tons))



f[8] Resources include coal beds 14"+ down to 6000 ft deep. Current maximum mining depths are about 4000', so many resources are not recoverable in foreseeable future

[9] Resources and reserves data are in billion short tons. Darker shading in the diagram corresponds to greater relative data reliability. The estimated recoverable reserves depicted near the top of the diagram assume that the 18.9 billion short tons of recoverable reserves at active mines reported by mine operators to EIA are part of the same body of resource data. This diagram, updated with January 1, 2006 Recoverable reserves at Active Mines, ERR, and DRB estimates, portrays the theoretical relationships of data magnitude and reliability among coal resource data. All numbers are subject to revision with changes in knowledge of coal resource data. (http://www.eia.doe.gov/cneaf/coal/reserves/chapter1.html#chapter1b.html)

Recoverable Reserves

It must be stressed that almost half of the DRB is not expected to be recovered[10]. Therefore, the recoverable coal reserves, which are a subset of the DRB, are much more important when addressing future energy needs. These reserves represent the total economically producible coal available after coal resources affected by environmental, legal, and technologic constraints are subtracted from the DRB. An estimated 17% of the DRB is inaccessible to mining, due to primarily environmental and other land restrictions. Approximately 34% of the accessible portion of the DRB are unrecovered or lost during mining, due to technology constraints, thin coal seams, washing, mining method, geology, etc. The net recoverable coal reserves were estimated at 267.5 billion short tons, which is only about 54% of the original DRB (Figure 10).

Three States contain nearly 60% of estimated recoverable reserves, Montana (75 billion tons), Wyoming (42 billion tons), and Illinois (38 billion tons). The top 12 states in terms of total estimated recoverable reserves are shown in Figure 9. If one applies EIA's recovery estimate to the Southern States estimate of Alaska's DRB of 54%, Alaska may have as much as 88 billion tons of recoverable coal. Alaska, Montana, and Wyoming have limited infrastructure to support capacity expansions, or in the case of Alaska, to start capacity.

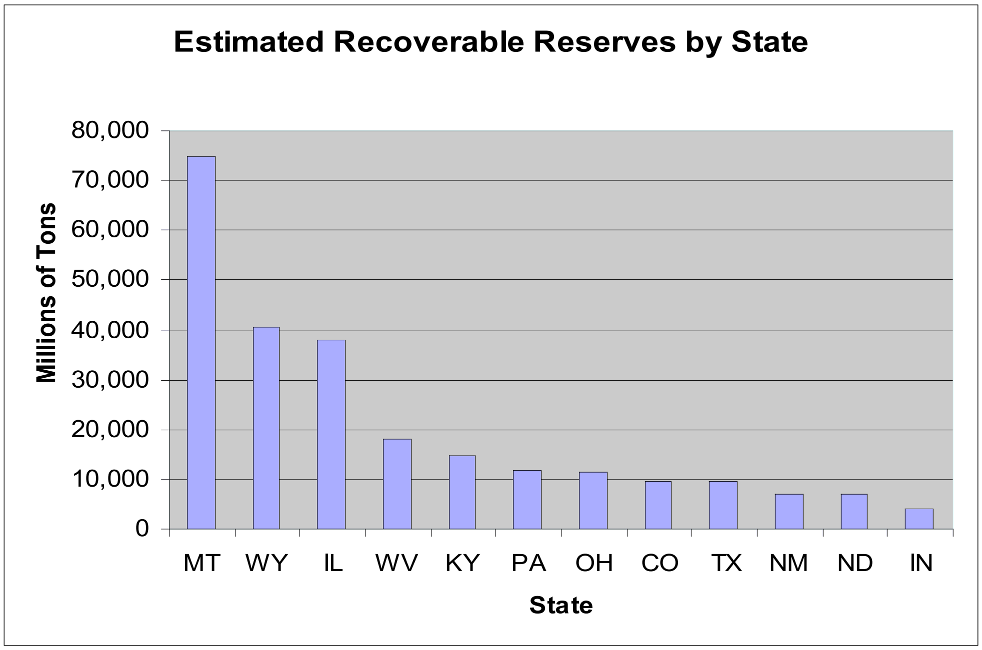
In 2005, the U.S. produced about 493 million tons of coal from East of the Mississippi and about 638 million tons from West of the Mississippi for a total production of around 1.13 billion tons. Based on current annual production, the U.S. has an approximately 240-year coal supply.[11,12] However, this estimate needs to be placed within the context of the projected use of domestic coal in the U.S. and how coal reserves and resources are defined and quantified. The EIA projects a steady rise in annual coal consumption to 1.78 billion short tons by 2030 in its reference economic growth case. Using the projected 2030 production level, the recoverable reserves, based on the EIA estimates, would last nearly 150 years.

A 2006 study by the National Coal Council suggested that the U.S. reserve base requires additional study[13]. They pointed out that the current DRB by EIA is based on a 1974 study[14] utilizing pre-1971 geologic knowledge and mining technology and criteria. Much has changed in the past 35 plus years. For example, the Surface Mining Control and Reclamation Act of 1977 (SMCRA), post dates the 1974 study. SMCRA resulted in more stringent controls regarding inaccessible resources to mining due to environmental and other land constraints. Mining methodology and criteria have also changed. In 1971, the Powder River Basin (PRB) in Wyoming and Montana produced only about 1% of the total production. In 2005, the total PRB

10 EIA, 1999, U.S. Coal Reserves: 1997 Update; Energy Information Administration, www.eia.doe.gov/cneaf/coal/reserves/front-1.html, 65 p
11 EIA AEO 2006 Early Release, Reference Case, Table A15.
12 http://www.nma.org/pdf/c_most_requested.pdf
13 National Coal Council, 2006, Coal: America's Energy Future; National Coal Council, Washington, DC, 132 p
14 U.S. Bureau of Mines, 1974, Demonstrated Coal Reserve Base of the United States on January 1, 1974; U.S. Bureau of Mines Mineral Industry Surveys; June 1974

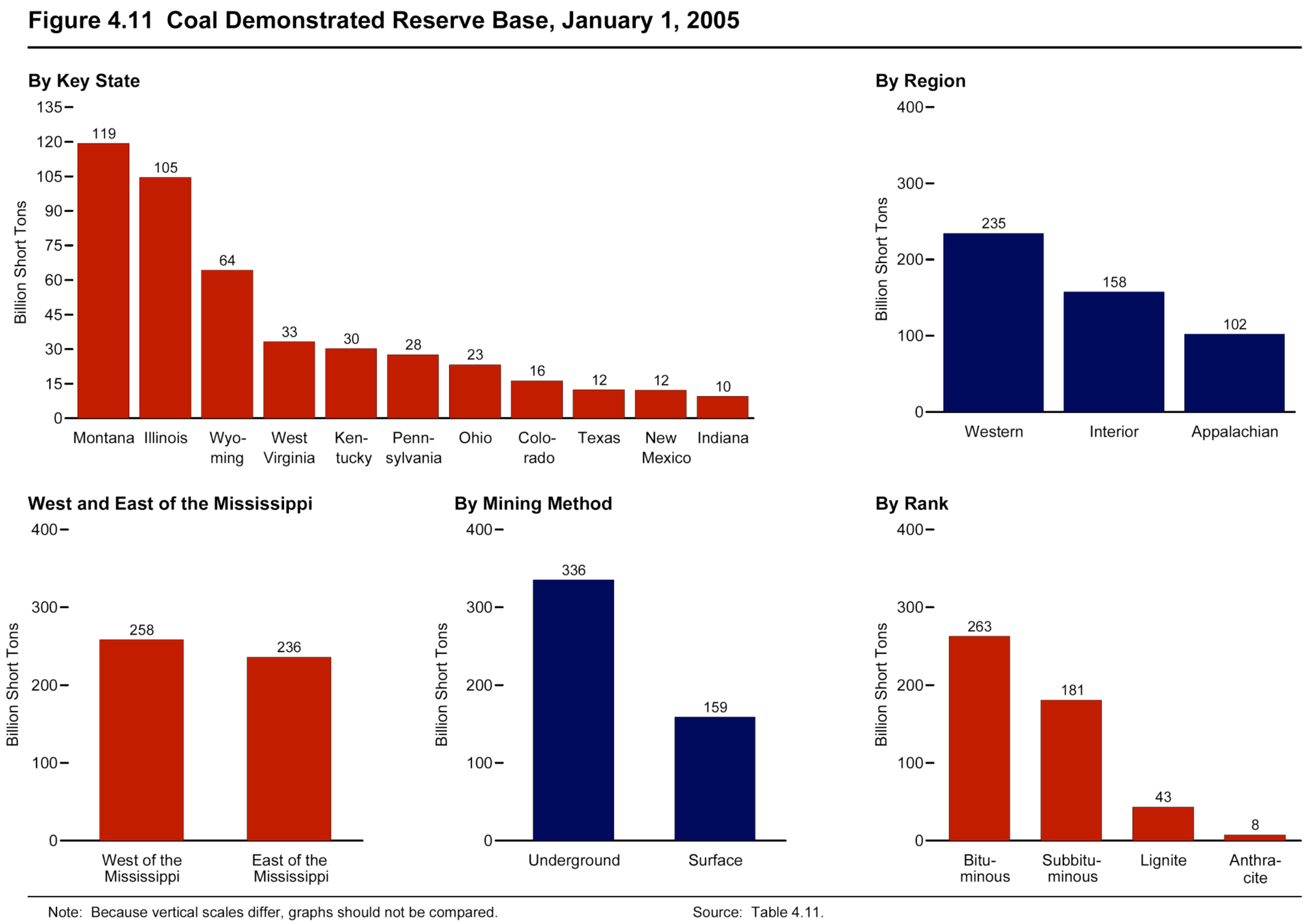
production had climbed to about 38%. The DRB has undergone minor revisions in the past 20 years, but the original 1974 study is still the foundation for the current DRB. As coal mining technology advances, additional geological information becomes available, and the economic environment changes, estimates of reserves will affected accordingly.

Figure 9: The ranking of the estimated recoverable reserves by state[15]



[15] EIA, 2005b, Annual Coal Report; Energy Information Administration, **http://www.eia.doe.gov/aer/**, 435 p

Figure 10: Demonstrated coal reserve base by key state, rank, region and mining method16



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[16] EIA, 2005, Annual Coal Report; Energy Information Administration, http://www.eia.doe.gov/aer/, 435 p

Demand Growth

Range of Outlooks

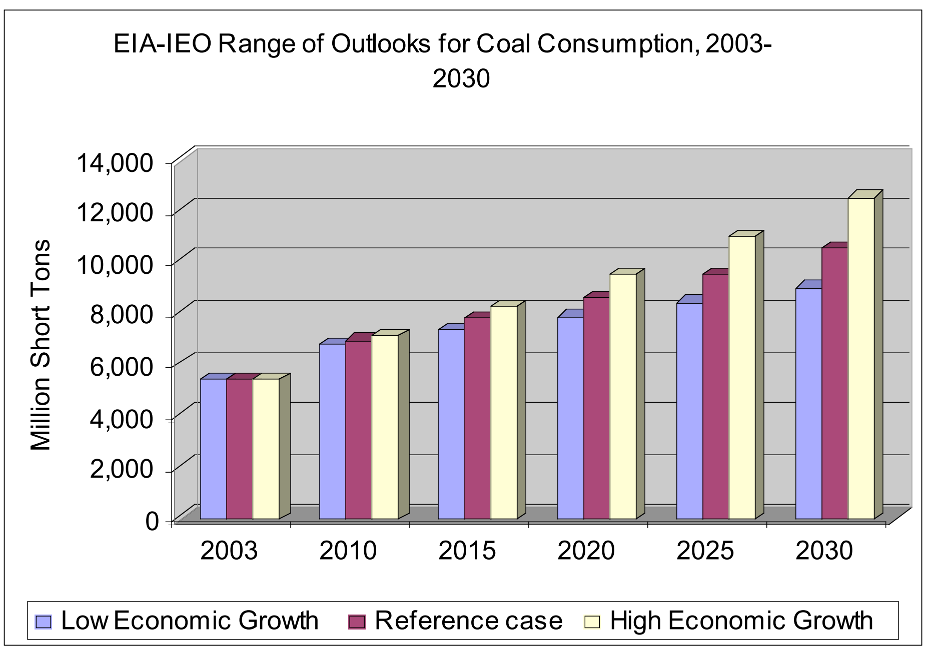
The two most widely recognized projections of demand for energy in general, and demand for coal in particular, are annual publications by (1) the Energy Information Administration (EIA) *, International Energy Outlook (IEO)* and (2) the International Energy Agency (IEA*) ,World Energy Outlook (WEO).*

But while these projections are based upon the best available data and methodologies, they face the obvious difficulty of peering into a murky future of unknown shifts in the social, political, economic, and technological landscape of an ever changing world..

The energy and coal demand data presented in this section are largely based upon the reference cases of the EIA-IEO-2006, the IEA-WEO-2006 and the United States' focused EIA 2006 *Annual Energy Outlook.*

While all of these various projections by different groups , coupled with varying "reference" , "high" and "low" cases, present a broad array of possible energy futures across the globe, there appears to be at least one constant. Specifically, coal has constituted, currently constitutes and increasingly will constitute, a central position in the steadily rising demand for more and more energy—particularly electricity.

Figure 11: Coal Consumption Range of Outlooks



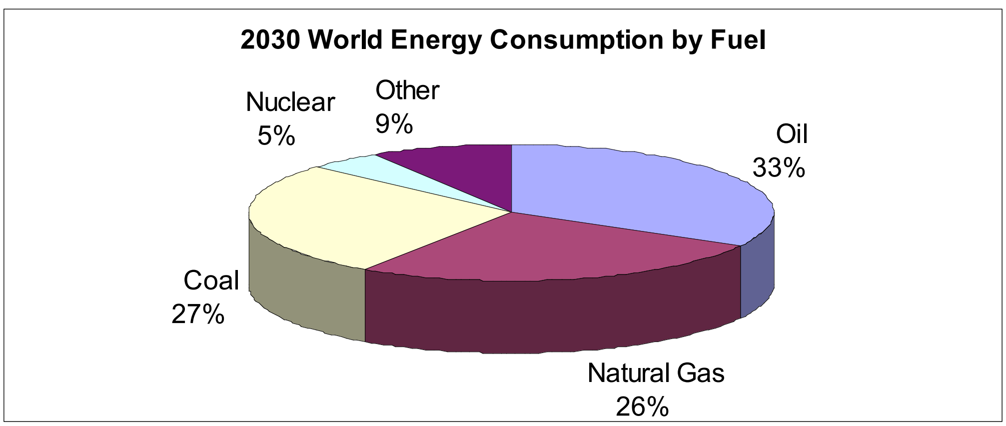
In terms of the three EIA cases projected out to 2030, for instance, while the reference case sees global demand for coal growing by 94%, the high case projects 130% and even the low case predicts 66%. Further, while the EIA reference case sees coal demand growing by 94% by 2030, the IEA reference case is also projecting substantial demand growth at over 61%. In essence, in virtually all scenarios posited by these leading analytical entities, the global demand for coal is strong and will continue to grow significantly for decades to come.

The Escalating Demand for Coal

<u>Basic Premise</u>

Burgeoning demand for energy over the next several decades will lead to significant increases in coal consumption both at the global level (+94%) and in the United States (+57%). The great bulk of this incremental consumption will be driven by the ever increasing demand for electric power in both developed and developing nations. Electricity is the lifeblood of modern society and the *sine qua non* to economic growth. In the continuing reliance on fossil fuels, additional coal is essential to meet the demand for electricity associated with the tidal sweep of <u>billions</u> of people into the modern age. Accordingly, almost 900 GW (33%) of the electric generation installed through 2030 will be coal based, increasing coal's contribution to the energy mix from 24 to 27%, as shown in Figure 12. These new power plants, coupled with the existing fleet, are projected to essentially double the worldwide demand for coal.

Figure 12: Projected Worldwide Energy Mix (2030)



And, while electricity will account for most of this demand, more coal will also be needed to produce liquid fuels (CTL) and natural gas equivalents (CTG). In essence, virtually all societies will be aggressively seeking additional energy supplies to improve quality of life, meet the rising expectations of their populace and to maintain economic growth.

The perspective of a key energy policy maker in China, a nation with 1.3 billion people, is informative of the role coal will play in the future. When asked how his nation would ever meet the massive growing demand for electricity, liquid fuel and natural gas, Du Minghua, Director of the Beijing Research Institute of Coal Chemistry, responded: "Coal is the solution to all three"[17]. Indeed, China is quickly taking the lead in CTL activities –recently announcing a plan to invest **$128 Billion**[18] through 2020 to convert coal to oil and chemicals.

The Global Perspective

Demand for energy is the hallmark of modern society. As more and more societies transition to modernization the demand of energy for electricity, transportation and environmental control is a steady drumbeat. The Energy Information Administration has projected substantial growth in global energy consumption over the next several decades.

Table 3: Global Consumption of Energy (quadrillion Btu)

Year	EIA	IEA
2004	446	445
2010	510	510
2015	563	558
2020	613	
2030	722	678

SOURCE: EIA-AER-2005/EIA-IEO-2006 and WEO-2006[19]

In essence, as seen in Table 3, EIA projects energy demand to increase more than 70% over the next three decades.

Drivers of this demand for ever increasing amounts of energy are a complex set of structural variables over which no individual nation has control:

(1) Developing nations seek electrification and transportation freedom amidst the ever rising expectations of their population. Yet, in 2005, over **1.6 billion people did not have electricity** and nations with a billion people (e.g., India) have fewer cars than the state of California[20].

(2) Developed nations demand electricity, liquid fuels and natural gas to make the lives of their citizens more comfortable and more productive.

(3) Population growth proceeds apace as the cumulative impact of sheer numbers steadily drives energy demand, as seen in Table 4.

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[17] The Energy Development Report of China, 2006
[18] China's National Development and Reform Commission , December 2006
[19] Assumes 1 toe = 39.683 mmBtu
[20] IEA-WEO, pg. 156.

Table 4: Global Population Growth

Year	World Population in Billions
2000	6.3
2010	6.8
2020	7.6
2030	8.2

SOURCE: EIA-IEO-2006

(4) Economic Development, reflected by growth in GDP shown in Table 5, spurs energy demand across the globe.

Table 5: Global Economic Development

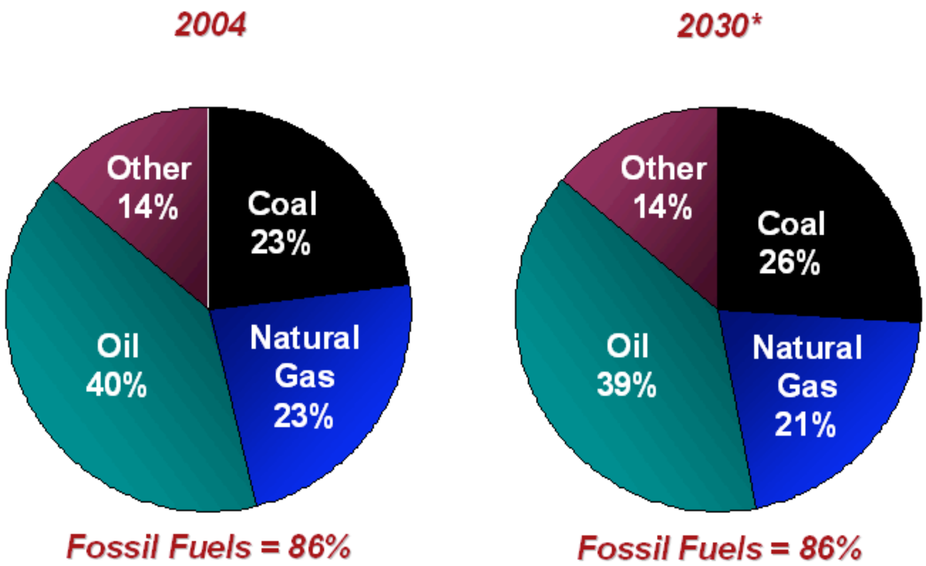
Year	GDP in Billion (2000) dollars
2000	50,786
2010	68,435
2020	98,917
2030	140,331

SOURCE: EIA-IEO-2006

Fossil Fuels form the core of global energy supply and will continue to do so for the foreseeable future[21]:

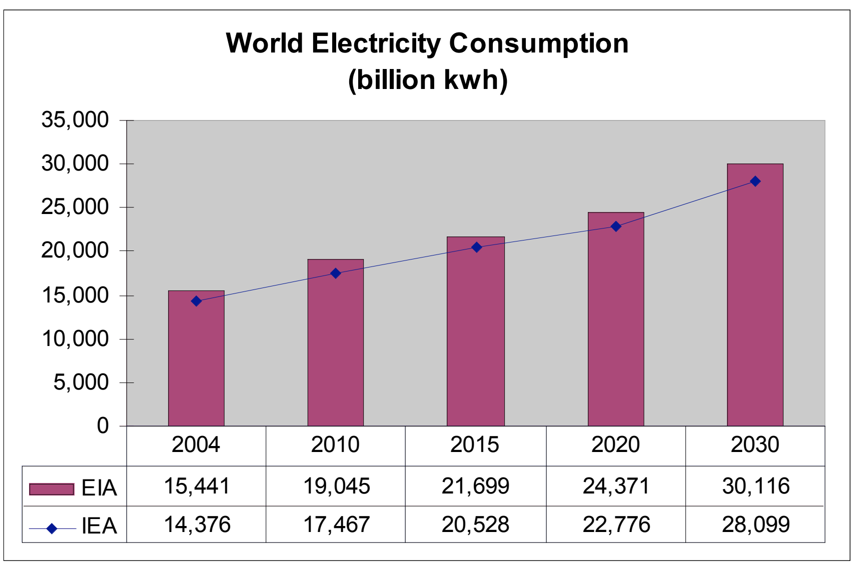
[21] EIA IEO-2006

Figure 13: Continuing Reliance on Fossil Fuels



Electricity is the lifeblood of modern society and profound increases in consumption of electric power can be expected as societies strive to modernize.

Figure 14: World Electricity Consumption



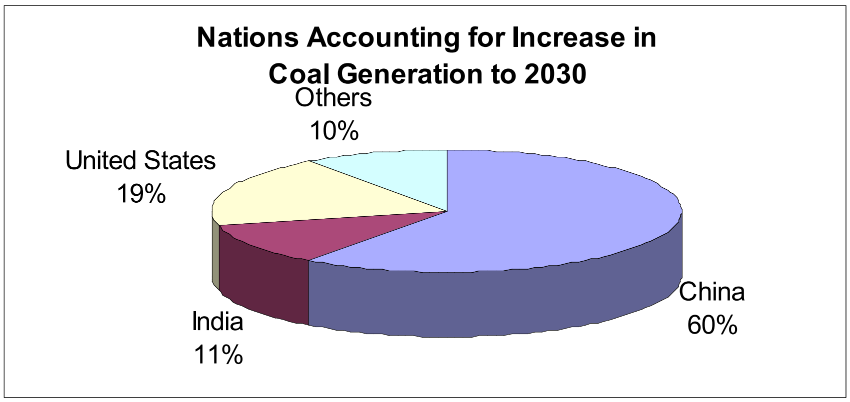
SOURCE: EIA-AER-2005/EIA-IEO-2006 and WEO-2006[22]

[22] Assumes 1 toe = 11,630 kwh

Coal is the continuing foundation of electricity supply. In 2003 coal generated 41% of the world's electricity and by 2030 coal will generate 40%. Production will more than double with coal generating 6,160 billion kwh in 2003 and by 2030 generating 12,592 billion kwh.

Three nations will account for 90% of this global increase in coal based electricity generation, as shown in Figure 15.

Figure 15: Nations Accounting for Increase in Coal Based Generation



SOURCE: EIA-IEO-2006

Non-electricity consumption of coal through 2030 will be centered around four broad areas:

- Manufacturing – especially in China
- Combined Heat and Power (CHP)
- Coal to Liquids (CTL)
- Coal Gasification (CTG)

Coal Consumption at the global level is projected to increase substantially, primarily to meet demand for electricity but also for conversion of coal to liquid fuel and syngas:

Table 6 : Global Consumption of Coal

Year	Global Consumption of Coal (Billion Tons)	
	EIA	IEA
2004	5.7	6.1
2010	6.9	7.4
2015	7.8	8.1
2020	8.6	
2030	10.6	9.8

SOURCE: EIA-AER-2005/EIA-IEO-2006 and WEO-2006

As shown in Table 6, 2004, world coal consumption was from 5.7 billion tons (EIA) to 6.1 billion tons (from IEA 2773 Mtoe, using a conversion factor of 2.205 tons per toe[23]). The growth rates above project this to rise to 8.1 billion tons (3666 Mtoe) in 2015 and 9.8 billion tons (4441 Mtoe) in 2030.

The IEA presents coal as including hard coal, sub-bituminous coal and lignite. It projects that world coal demand between 2004 and 2015 will increase by an average annual rate of 2.6 per cent per annum. If a longer time period, 2004 to 2030, is used then this drops to 1.8 per cent per annum suggesting that the increase in coal demand, along with energy in general, is likely to slow over time.

Total primary energy demand, as defined by the IEA[24], is projected to increase by an annual average rate of 2.1 per cent between 2004 and 2015 and 1.6 per cent between 2004 and 2030. This suggests an increase in the share of coal in meeting the world's energy needs.

In 2004, 68% of world primary coal consumption was used in the generation of power and heat and 18% in industry. These will remain the main drivers going forward, although growth will be mitigated by the higher efficiency of new generating plant. In 2030, coal consumption in power and heat generation is projected to represent 73% of total primary coal consumption and industry 18%. Electricity generation remains the key driver for coal consumption and IEA projects the share of coals in power generation increases from 40% in 2004 to 44% in 2030.

Clearly, demand increases are not evenly spread geographically and this increase in share reflects different consumption growth rates across countries and different national resource endowments. It is, therefore, necessary to look in more detail region by region.

In the OECD Pacific region (Japan, Australia, New Zealand and South Korea), coal demand is projected to rise from 217 Mtoe (478 million short tons) in 2004 to 230 Mtoe (207 million short tons) in 2030. In Japan, the major consumer in the region, demand is set to fall from 116 Mtoe (256 million short tons) in 2004 to 98 Mtoe (216 million short tons) in 2030. Almost all of this will be imported hard coal for power generation.

Coal consumption in OECD Europe is projected to remain flat through the period 2004 to 2030, at around 330 Mtoe (728 million short tons). In this case, gains in power generation are offset by losses in industry. The coal share of power generation is projected to slip from 29% to 27% at the expense of natural gas. The European Union modeling work projects that solid fuel consumption in the EU27 nations will fall between 2005 and 2030 by some 12 Mtoe (26.5 million short tons). Coal inputs to power generation are projected to fall in the period to 2020 and then increase between 2020 and 2030 due to the retirement of nuclear power plants and an assumed improvement in the competitiveness of coal versus natural gas.

[23] IEA-WEO, pg 580, 1 mtoe = 2.0003 metric tons. Since 1 short tons = 1.1023 metric tons, 1 mtoe~2.205 short tons

[24] Represents domestic demand only, including power generation, other transformation, own use and losses, and total final consumption. Except in the case of world primary energy demand, it excludes international marine bunkers.

Coal consumption in the transition economies (i.e., mainly the countries of the former Soviet Union) is projected to rise by an annual average of 1.1% between 2004 and 2015 and then to fall back to the 2004 level by 2030. Coal in industry is projected to increase throughout the period while coal consumption in power generation is projected to fall. Coal-fired power generation capacity is assumed to fall throughout the period as coal-fired plants age and are replaced by gas. The share of coal in power generation is projected to fall significantly from 21 per cent in 2015 to 15 per cent in 2030.

In developing Asia, coal consumption is projected to rise from 1309 Mtoe (2886 million short tons) in 2004 to 2054 Mtoe (4529 million short tons) in 2015 and then to 2750 Mtoe (6064 million short tons) in 2030, a growth rate over the period of 2.7% per annum. The consumption of coals in the region is heavily dominated by China and India. In both countries the power generation sector is coal dominated. In India, coals account for around 70 per cent of electricity generated throughout the forecast period while in China they represent nearly 80 per cent. One area that is noteworthy in the case of China is that, unlike every other region in the IEA's World Energy Outlook, total final consumption of coals is set to rise. This is due to increased coal consumption in industry.

Latin America is a relatively minor consumer of coal. Consumption is projected to increase from 22 Mtoe (48.5 million short tons) in 2004 to 27 Mtoe (59.5 million short tons) in 2015 and then to 37 (82 million short tons) Mtoe in 2030. In this region, the major coal consumer is Brazil which by 2030 will consume 18 Mtoe (40 million short tons).

The Middle East is a minor coal consumer and consumes less coal today than does Brazil at about 9 Mtoe (20 million short tons) but will rise to a similar level as Brazil reaches in 2030.

In 2004, Africa consumed about 100 Mtoe (220 million short tons) of coal and this is projected to increase to about 130 Mtoe (2887 million short tons) by 2030. The main driver behind this increase in consumption is continued electrification in Southern Africa.

The above paragraphs suggest that incremental coal demand is likely to be concentrated in India and China. Annual demand in 2030 is projected to be some 1668 Mtoe (3678 million short tons) greater than in 2004. Of this, China represents 1066 Mtoe (2350 million short tons) and India 254 Mtoe (560 million short tons). Together these two countries account for nearly 80% of annual incremental demand. Both countries have significant domestic coal resources but are likely to become increasingly integrated into the world traded coal market.

THE UNITED STATES

I. Demand for energy is projected to continue its steady growth over the next several decades. Through 2030, EIA projects an annual growth rate per capita of 0.3%. The cumulative impact of this growth in demand will result in a consumption increase of 31 Quads (31%) over 2005-2030:

Table 7: Energy Consumption in the United States

Year	Quadrillion Btu
2005	100
2010	106
2020	118
2030	131

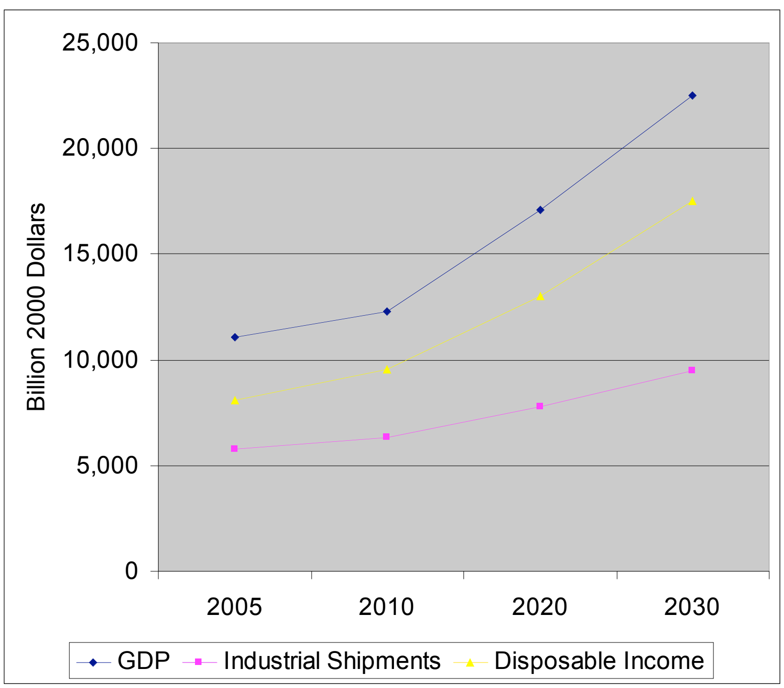
SOURCE: EIA-IEO-2006

II. Drivers of this demand for more and more energy include a range of factors but two are paramount:

Population growth in the United States is projected to increase at an annual rate of .8% through 2030. From a current population of about 300 million, the population of the United States is expected to reach 365 million by 2030.

Economic growth has been shown to stimulate energy demand in general and demand for electricity in particular. Strong economic growth is projected in the U.S. through 2030.

Figure 16: Macroindicators of US Economic Growth



SOURCE: EIA-IEO-2006

III. Fossil Fuels have provided the core energy supply in the United States and will continue to do so for the foreseeable future:

Table 8: Fossil Fuel Reliance

Source of Energy	2005	2030
Coal	23%	26%
Oil	40%	40%
Natural Gas	23%	21%
Total supplied these 3 fuels	86%	87%

SOURCE: EIA-IEO-2006

IV. Electricity consumption is projected to steadily increase in the United States over the next several decades:

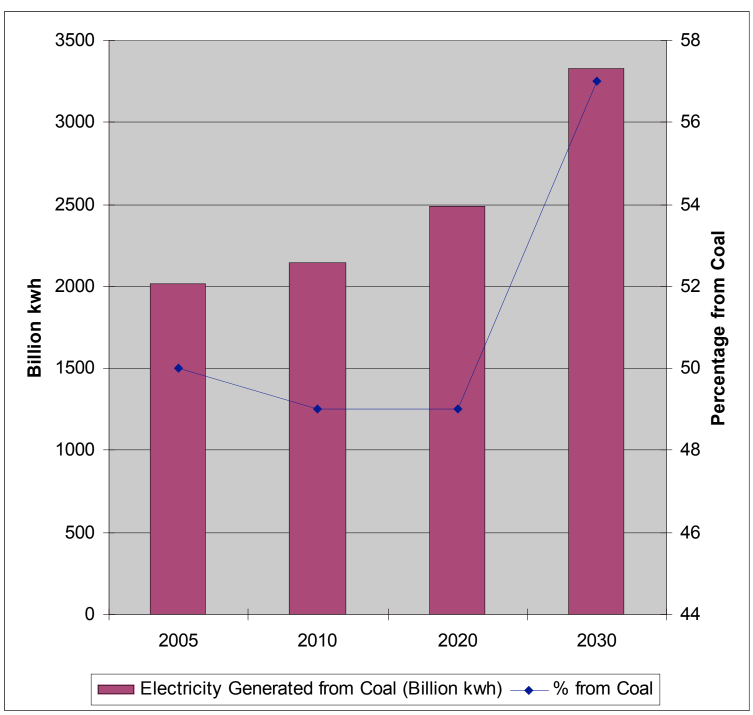
Table 9: Electricity Consumption in the United States

Year	Billion Kwh
2005	4038
2010	4392
2020	5037
2030	5797

SOURCE: EIA-IEO-2006

V. Coal has been the foundation of electricity supply in the United States and this core position is projected to continue into the foreseeable future:

Figure 17: Coal as Core of US Electricity Supply



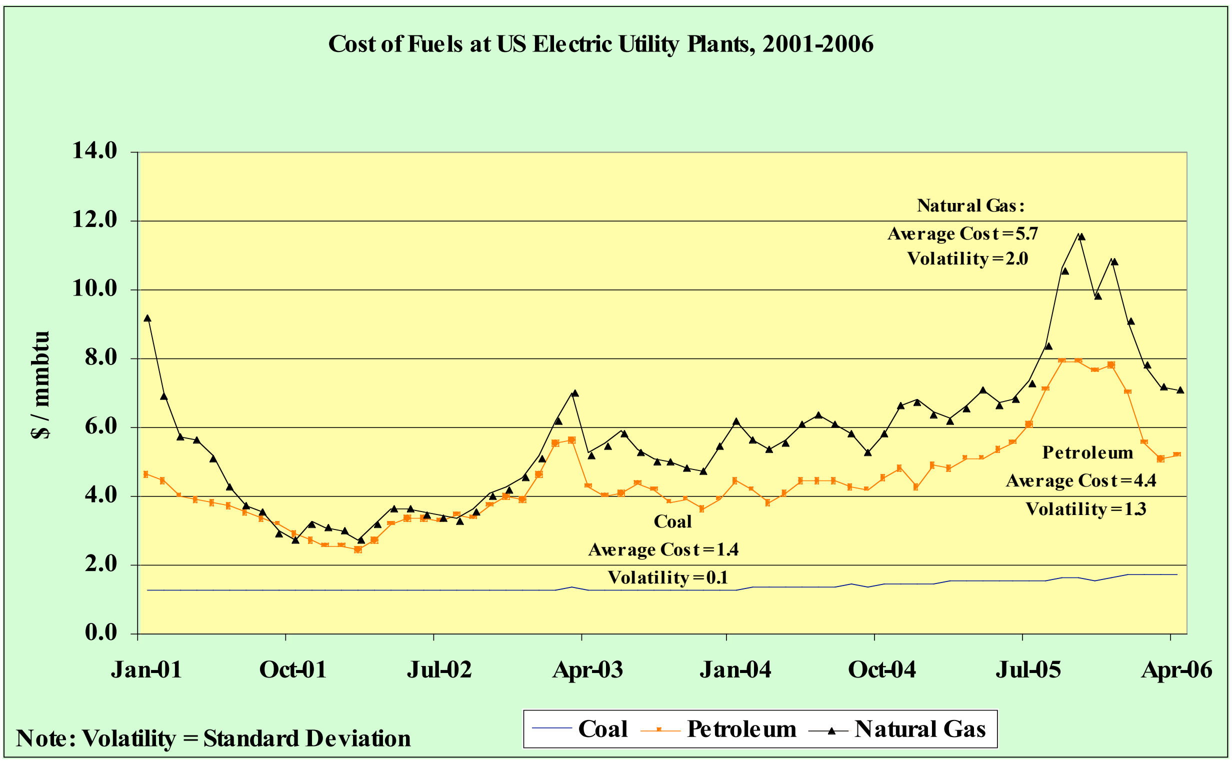
SOURCE: EIA-IEO-2006

The central role of coal in the U.S. electricity supply system is based on two key attributes:

Availability –both oil and natural gas production appear to have peaked in the United States but we have enough economically recoverable coal to last over 100 years. In 2004, the EIA estimated the Demonstrated Reserve Base (DRB) of the United States is almost 500 billion tons distributed across more than two dozen states, although only 54% of those reserves are currently viewed as economically recoverable. Coal is the only domestic fuel that has the flexibility and reserve base to meet ever growing energy demand in the United States.

Price—coal has been, and is projected to be, cheaper and less volatile in price than natural gas:

Figure 18: Coal vs NG -- Cost and Price Volatility



Further, this cost advantage is projected to continue going forward:

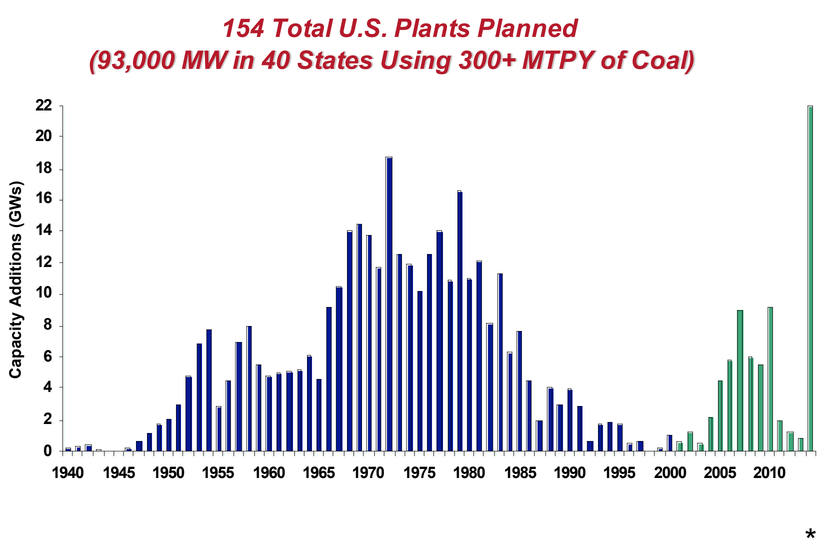
Table 10: Coal vs. NG Going Forward

Year	Projected Price Per Million Btu	
	NG (Henry Hub)	Coal (Delivered)
2005	8.60	1.61
2010	6.28	1.77
2020	5.71	1.62
2030	6.52	1.71

SOURCE: EIA-IEO-2006

VI. A **wave of new coal based power plants** is steadily emerging to take advantage of the availability and economic advantage of coal. Figure 19details planned additions of coal based generation units. It should be noted that a significant portion of these plants do not have a specific schedule. Some of these units, of course, will not be built due to escalating construction costs, changes in system planning requirements or a variety of other drivers of cancellation. On the other hand, other units will be added to this list over time. It should be noted that virtually all reference case forecasts indicate significant increases in demand for electricity. And all of these forecasts indicate coal based electricity will meet a substantial segment of this new demand. Alternative policy scenarios, of course, may present either decreased or increased coal demand for electricity generation.

Figure 19: Planned US Capacity Additions

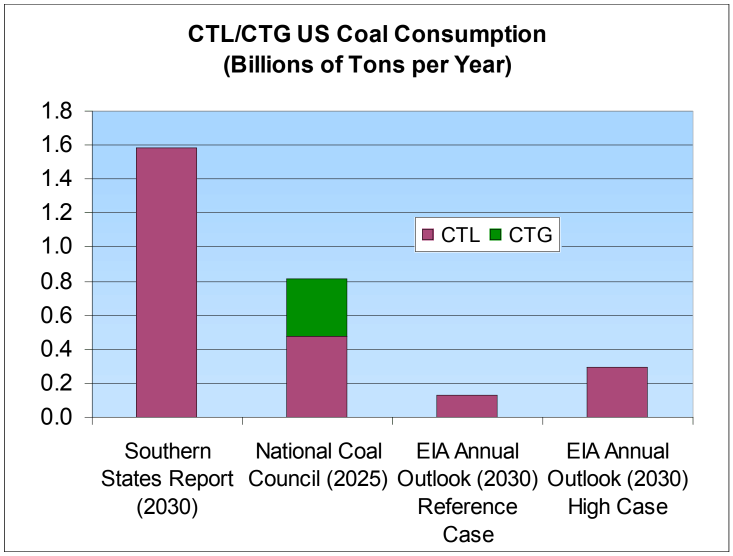


* Timing not yet committed.
Source: U.S. Department of Energy 's National Energy Technology Laboratory, June 21 2006.

VII. **Non-electricity** consumption of coal going forward in the United States will largely be related to coal conversion – primarily to liquid fuels and syngas.

The estimates of coal consumption for CTL range from 94 million tons annually in 2030 (5.3% of coal market of 1.8 billion tons) to 1.58 billion tons (48% of coal market of ~3 billion tons[25]), as shown in Figure 20: Projected Coal Consumption from CTL/CTG. Only the NCC study forecast CTG consumption, with an expected output of 4 Tcf/yr by 2025.

Figure 20: Projected Coal Consumption from CTL/CTG



Headwaters Energy Services estimates from 500 million to 1 billion tons of low-cost reserves will be required for CTL plants of 30,000 to 80,000 barrels per day[26]. Headwaters does not define "low-cost reserves", but the implication is the cost of the feedstock is expected to remain low relative to the price of the product produced.

Alternative Policy Scenario

World Outlook

The above projections by the IEA take into account those government policies that had been enacted or adopted by mid-2006. It represents something of a "business as usual" scenario. This means that the projections of coal demand are not significantly constrained by policies to limit carbon emissions. The IEA does, though, present an "Alternative Policy Scenario" where countries adopt climate change and energy security policies that are currently under consideration. The decision to include these policies only reflects that they are under discussion and does not indicate cost-effectiveness.

[25] Assuming the CTL demand is incremental to EIA's projected demand of 1.69 billion tons (1.784bn, less 0.94bn projected CTL demand)
[26] American Coal Council 2006 Buyers Guide, pg 52

Under these assumptions, world coal demand is projected to increase to 3512 Mtoe (7744 million short tons) by 2030, an average annual growth rate of 0.9 per cent. By 2030, coal demand is projected to be about 20% or over 900 Mtoe (1984 million short tons) lower than in the reference case. Under this set of assumptions coal consumption in the United States is projected to rise by only 24 Mtoe (53 million short tons) between 2004 and 2030.

In the OECD as a whole, coal demand in 2030 is projected to be over 24% or about 300 Mtoe (661.5 million short tons) lower than the reference case. In OECD Europe, the decline in coal consumption in the reference case is even more pronounced. Coal consumption is projected to fall to 215 Mtoe (474 million short tons) from 330 Mtoe (728 million short tons). Obviously, then, non-OECD countries, principally China and India, are assumed to adopt policies that reduce coal consumption by about 600 Mtoe (1323 million short tons).

China is projected to consume 1702 Mtoe (3752 million short tons) of coal under the alternative policy scenario which is some 360 Mtoe (794 million short tons) below that of the reference case. The principal drivers here are an increase in nuclear power (50 GW by 2030 compared with 31 GW in the reference case), greater use of renewables (reaching 6% of electricity generation compared with 3% in the reference case) and greater end use efficiencies.

India is projected to make greater improvements with consumption nearly 390 Mtoe (860 million short tons) below the reference. Again nuclear power (50GW in 2030 compared with 19GW), renewables (4% of electricity generation to 6% by 2030) and end-use efficiencies account for this.

The results of this analysis suggest that, although world coal demand will continue to rise, it is sensitive to policies designed to limit carbon dioxide emissions through energy efficiency measures and fuel switching. A key aspect of this is the willingness of countries such as China and India to develop nuclear power generation at the expense of coal.

United States Outlook

In the United States various climate change policies are being discussed and debated. The outcome of these policies is uncertain and their implementation could eventually reduce or increase coal consumption. On the one hand, electric power generation could become even more dependent on natural gas and nuclear. On the other hand, if certain assumptions made by these proposed policies (e.g. low natural gas prices) prove incorrect, the dependence on , and consumption of, coal would increase.

As stated earlier, at the present time a significant number of electric utilities are turning to coal for future generation units needed to meet burgeoning demand for electricity. These new plants have been proposed because: (1) coal has clear advantages of reliability, security and cost ;and (2) the U.S. has made significant progress in providing society with reliable and affordable electricity in the context of increasingly lower carbon emissions per unit of production.

In terms of the most developed nations, for example, the U.S. leads in carbon intensity improvements, reducing it on average 2 percent per year from 1994 to 2004. Further, The Energy Policy Act of 2005 includes a range of technology-related provisions that, with robust budget support and implementation, could facilitate wider adoption of carbon management initiatives. In essence, continuous improvement in carbon intensity is on the horizon as emerging clean coal technologies come on line.

At the present time, there are too many unknowns to project the impact of currently debated climate change proposals on future coal consumption. But we do know: (1) demand for electricity is steadily increasing, (2) coal has been, and is projected to remain, the primary source of electric power in the U.S. and (3) to the extent there are shortfalls in other sources--nuclear, natural gas or hydroelectric--coal will be expected to meet the void.

Sources of New Demand

As shown above, the two primary sources of new demand for coal will revolve around two processes:

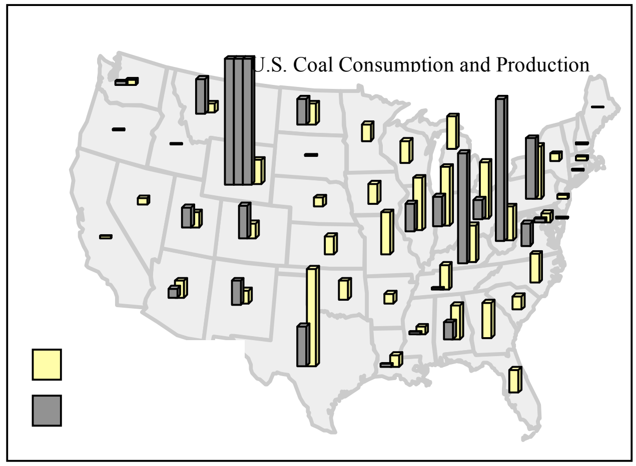
The steady expansion of electric generation across the world. At least 1.5 billion people do not have electricity and societies where electricity is available demand more and more.

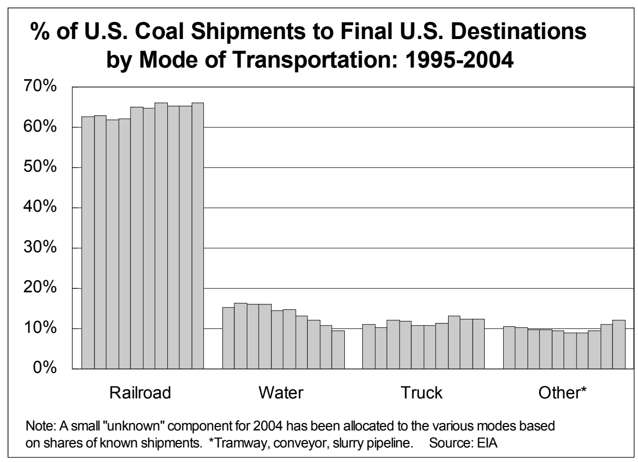
The conversion of coal to liquid fuels (CTL) and to the equivalent of natural gas (CTG). While a number of countries are moving in this direction (e.g. U.S and South Africa) it is clear China is taking the lead. In December of 2006, China announced a $128 billion program to build CTL plants to convert coal to liquids.

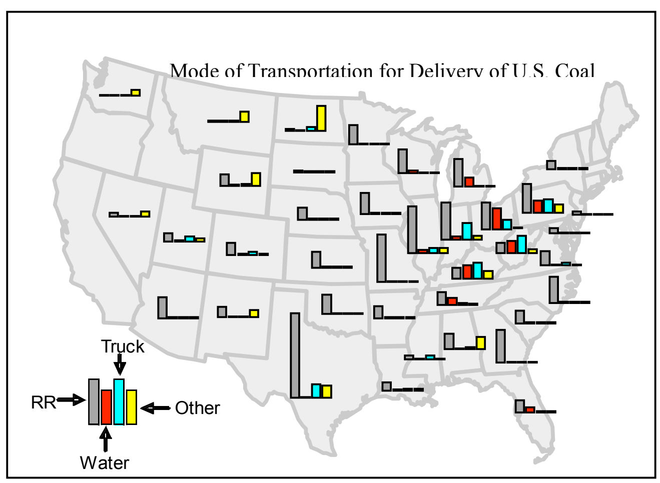
U.S. Coal Transportation Infrastructure: Issues and Prospects

Introduction

Coal is consumed in large quantities all over the United States, while most production is focused in a relatively small number of states, meaning that huge amounts of coal must be transported long distances. To that end, U.S. coal consumers and producers have access to the world's most comprehensive and efficient coal transportation system.







All major surface transportation modes carry large amounts of coal. According to the U.S. Department of Energy's Energy Information Administration (EIA) reported in 2004, approximately 66 percent of U.S. coal shipments were delivered to their final domestic destinations by rail in 2004 (the most recent year available), followed by truck (12 percent), the aggregate of conveyor belts, slurry pipelines, and tramways (12 percent), and water (9 percent, of which 8 percentage points were inland waterways and the remainder tidewater or the Great Lakes).

Over the past 15 years, the rail share has trended upward, largely reflecting the growth of western coal that moves long distances by rail. The truck share has fluctuated, but it too has trended upward since 1990, while the waterborne share has fallen.

Cleary, the extent to which coal is able to help meet our future energy challenges will depend heavily on the performance of coal transporters. Some issues — e.g., the need to have the quality and quantity of assets in place that is adequate to handle coal transportation demand, the need for supportive regulatory and legislative policies, and the need to incorporate technological advances to improve operations and improve efficiency — are common to all coal transporters. If the past is a reliable guide, the various modes will be able to handle increased coal transportation demand, albeit perhaps with occasional "hiccups" along the way.

Water Transport

Approximately 98.2 million tons of U.S. coal were delivered to their final U.S. destination by water, including river (83.1 million tons, or 85 percent of the water total), the Great Lakes (11.1 million tons, 11 percent), and tidewater piers (3.9 million tons, 4 percent)[27].

Coal Traffic on U.S. Waterways
(Millions of Tons)

Waterway Name	1995	2000	2004
Ohio River	129.5	118.9	123.1
Mississippi River	52.9	47.7	41.3
Monongahela River	30.6	33.3	22.7
Big Sandy River	18.4	19.7	21.4
Tennessee River	18.7	19.2	20.6
Kanawha River	17.3	17.8	14.9
Black Warrior & Tombigbee River	12.0	12.2	13.0
Cumberland River	8.8	10.1	11.0
Gulf Intracoastal Waterway	8.0	5.9	6.4
Illinois Waterway	8.2	2.5	4.2
Allegheny River	1.1	1.2	1.4
Tennessee-Tombigbee River	1.9	1.5	0.7

Source: U.S. Army Corps of Engineers

Coal is among the most important commodities carried on the 25,000-mile U.S. inland waterway system, accounting for more than 25 percent of total waterway tonnage. The vast majority of this coal moves on barges on waterways in the Ohio River Basin, including the Ohio River and several of its major tributaries, including the Monongahela River, the Big Sandy River, the Tennessee River, and the Kanawha River. Dozens of power plants, many of which are coal-powered, are located on these rivers. The Mississippi River also carries significant amounts of coal.

Final delivery by water is an option only for power plants located near a navigable water source, which include navigable rivers (in the east or Pacific Northwest), the Great Lakes, or coastal areas. Some coal is barged for part of its journey from a mine, then transloaded to rail or truck for final delivery to a power plant.

In addition to geographic limitations, barging can also have other obstacles associated with it. For example, because of the transit time and because of regular problems with the waterways (*e.g.*, low water, high water, freezing, and congestion), electric utilities often need to maintain larger inventories at barge-served plants than at rail-served plants. For barge coal users on the Upper Mississippi and Great Lakes, the river is not navigable from up to five months due to winter freeze.

Trucks

More coal is delivered to its final U.S. destination by truck than by any other mode except rail — approximately 132 million tons in 2004[28]. Truck movements to final destinations

[27] EIA-2004
[28] EIA-2004

are generally feasible when the distance between the coal pickup and point of consumption is relatively short (*e.g.*, 50 or fewer miles), and for these relatively short distances it is not surprising that rail or barge might not be competitive. In some areas, mostly in Appalachia, trucks are the only economical way to transport coal because of terrain and other factors.

Kentucky, West Virginia, Indiana, and Pennsylvania — all important coal producing states — are typically the top four states receiving coal by truck.

<u>Tramways, Conveyors, and Pipelines</u>

In several states, large amounts of coal — 128 million tons in 2004[29] — are delivered to their final destinations by means of conveyor belts, tramways, or pipelines. Most of this tonnage travels short distances from a mine to an adjacent or nearby minemouth power plant.

Most minemouth plants operating today were built in the 1960s and 1970s to minimize coal transportation costs and achieve greater coal supply security. High-capacity transmission lines transmit the electricity generated at the plants to population centers.

By the mid-1990s, however, many minemouth plants began to obtain increasing amounts of coal from other sources. In many cases, coal reserves originally slated to supply the minemouth plant were depleted, or operating costs at the mine became too high. In other cases, changes in environmental regulations made the original coal unsuitable. In still other cases, plant operators wanted to diversify supply options while still relying on the original source for most of the plants' needs.[30] In all these cases, the new coal supply might be nearby or it might be hundreds of miles away.

North Dakota and Texas, which have several large minemouth lignite plants, lead the nation in coal delivered by tramway or conveyors. Until recently, there was also a 273-mile coal slurry pipeline that transported several million tons of coal each year from a mine in northeastern Arizona to a power plant in southern Nevada.

<u>Railroads</u>

U.S. freight railroads, the vast majority of which are privately owned, operate over an interconnected network of more than 140,000 route-miles across the country. Almost all of these miles are owned and/or managed by railroads themselves.

Coal is the most important single commodity carried by rail. In 2005, coal accounted for 42 percent of tonnage (far more than any other commodity), 23 percent of carloads, and 20 percent of gross revenue for Class I railroads[31]. Only intermodal (the movement of trailers and containers on railroad flat cars) among all other commodity categories accounts for more railroad revenue than coal. Rail coal traffic has trended upward for years. Coal ton-mile growth has

[29] EIA-2004
[30] Kathryn Heidrich, "Mine-Mouth Power Plants: Convenient Coal Not Always a Simple Solution," *Coal Age*, June 1, 2003.
[31] Class I railroads are defined as those with operating revenue of at least $319 million in 2005. There are currently seven Class I railroads.

been especially pronounced due to the growth of Powder River Basin (PRB) coal that moves long distances by rail.

In 2005 the average coal car carried 111.7 tons, up 7 percent from the 104.5 tons in 1996 and doubles the capacity of coal cars in the 1930s. Due in part to the growing use of PRB coal by utilities in other parts of the country, the average haul for coal rose from 539 miles in 1990 to 754 miles in 2005.

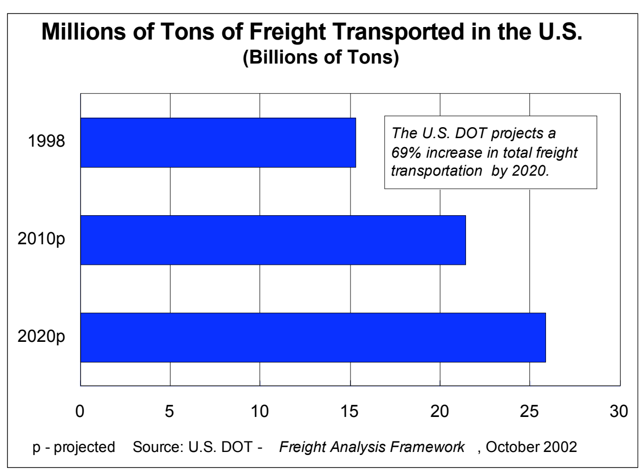
Around 95 percent of coal transported by railroads moves in unit trains, which often operate around the clock, use dedicated equipment, generally follow direct shipping routes, and have lower costs per unit shipped than non-unit trains.

Transportation and Future Coal Demand

Handling the huge volumes of coal now being produced and consumed is already a tremendous challenge for coal transporters, and this challenge will likely intensify if, as expected, U.S. coal production and consumption continue to grow. In its *Annual Energy Outlook 2007,* released in December 2006, the EIA projects U.S. coal production in 2015 will total 1.27 billion tons, a 140-million ton increase (12 percent) over the 1.13 billion produced in 2005. U.S. coal consumption is projected to increase from 1.13 billion tons in 2005 to 1.28 billion tons in 2015, a 147-million ton increase. A September 2006 analysis by the Department of Energy's National Energy Technology Laboratory reports that 154 new coal-fired generating plants representing 93 gigawatts of new coal-fired generating capacity are at some stage of development.[32] If ultimately built, this new generation would increase annual U.S. coal requirements by more than 300 million tons.

Coal's future is not assured, however, mainly because it faces major environmental challenges. Among many, coal is perceived to be a dirty fuel whose emissions (of carbon dioxide, particulates, sulfur dioxide, nitrogen oxides, and mercury) pollute the environment and harm public health. Although coal's environmental performance will continue to improve with advancements in "clean-coal" technologies (*e.g.*, integrated coal gasification combined cycle systems), these environmental challenges are significant. Depending on how they are resolved, coal use and transportation will obviously be affected.

Coal, of course, is just one among countless commodities that are transported, and coal must compete with these other commodities for transport capacity. And



[32] See NETL, "Tracking New Coal–Fired Power Plants," at http://www.netl.doe.gov/coal/refshelf/ncp.pdf.

while there is a tremendous amount of strength and flexibility in our nation's transportation systems, it is clear that all freight modes in the United States are facing serious capacity challenges today. These challenges could intensify if overall freight transportation demand grows as quickly as many expect.

For instance, the U.S. Department of Transportation (DOT) has projected that overall demand for freight rail service (measured in tons) will increase 55 percent (1.3 billion tons) by 2020 from 1998 levels, equal to 2.0 percent per year. The DOT projects a 69 percent increase (10.6 billion tons) in total freight transportation demand.[33] In a 2006 forecast, economic consultants Global Insight predicted that rail carload and intermodal tonnage will increase by 32 percent (716 million tons) from 2005 to 2017, or 2.3 percent per year. Global Insight expects total freight transportation demand to rise 30 percent by 2017.[34]

Water

Barges face substantial infrastructure and equipment challenges that must be resolved if they are to be able to efficiently handle major increases in coal movements over the next decade.

For example, more than half of the 275 lock chambers on the 25,000 miles of U.S. waterways are more than 50 years old (generally considered to be their useful life); around 10 percent are more than 80 years old. This includes locks on the Ohio River which, as noted earlier, sees far more coal traffic than any other inland waterway. Scheduled and unscheduled closures are reportedly becoming more frequent and concerns about reliability are growing.[35]

Equipment supply is another major challenge for waterways operators in meeting the needs of coal shippers over the next decade. Reportedly, some 15 percent of the inland barge fleet has been retired over the past seven years.[36] Over the next five years, approximately 40 percent of the nation's barges on inland waterways could come out service, and new barges are not being built fast enough to replace them — in part because high steel prices have slowed barge construction and in part because barge companies are more hesitant to purchase barges because of past oversupply. At the same time, some older barges are being retired, perhaps prematurely, to take advantage of high steel scrap prices. Still, "beyond 2006, we see equilibrium between supply and demand returning as we, and others in the industry, have increased orders for new barges to replace retired barges."[37]

Finally, Section 29 of the Internal Revenue Code of 1986 offers a tax credit for the production of synthetic fuel from coal. At their peak, dozens of Section 29 plants (also know as synfuel plants) were in operation. Most of these plants are located in the eastern United States, and many of them are located on river docks where coal moves through the synfuel plants prior to being loaded into barges. The credit is so substantial — in 2003, it was $1.104 per MMBtu, or

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[33] U.S. Department of Transportation- *Freight Analysis Framework*, October 2002. [Update reportedly will be available soon.]
[34] *U.S. Freight Transportation Forecast to 2017*, produced for the American Trucking Associations.
[35] Pamela Glass, "Inland industry fights off woes on way toward banner year," *Workboat*, June 2006.
[36] Pamela Glass, "Inland industry fights off woes on way toward banner year," *Workboat*, June 2006.
[37] Craig Philip, President and CEO-Ingram Barge Co., quoted in Pamela Glass, "Inland industry fights off woes on way toward banner year," *Workboat*, June 2006.

$27 per ton for a 12,000 Btu/lb coal — that it is sometimes more lucrative to route shipments through these river terminals in order to obtain the tax credit than to move the coal by other modes. Consequently, if the credit is not renewed when it expires in 2007, less barging is a strong possibility.

The U.S. Army Corps of Engineers is responsible for waterways upkeep and maintenance.[38] For years, waterways operators and their allies have been seeking substantially higher Corps funding for lock and dam upgrades, increased dredging, and other waterway infrastructure issues.. To upgrade the entire system would cost tens of billions of dollars, and it has been a perpetual struggle for waterways interests to persuade Congress to appropriate what they consider to be adequate funding. If this does not change, more congestion and less reliability can be expected on the waterways system. At this writing, however, Congress is moving toward final passage of the $10 billion Water Resources Development Act (WRDA). If passed and ultimately funded, this legislation would, among many other things, double the size of a number of locks on the upper Mississippi River and the Illinois River.

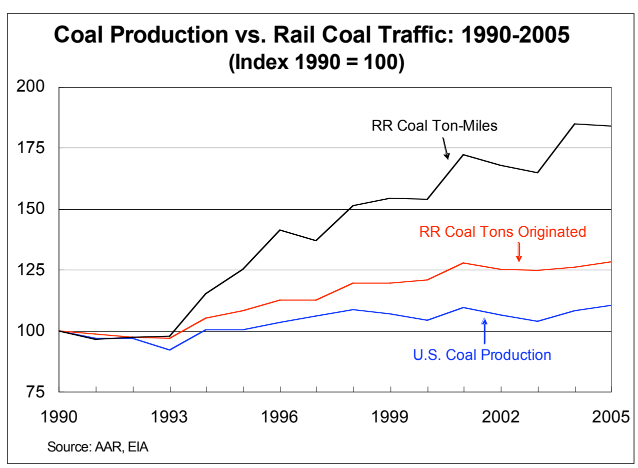
In 2006 the cost to ship international dry freight, including coal and iron ore, nearly doubled, primarily due to demand from China. Since freight can account for a third or more of the price of delivered coal, ocean freight is now traded like a commodity, primarily in London, although not currently on a formal futures exchange. In the longer term, the barriers to entry in the ocean freight market are limited and the vessel fleet is increasing. Once port constraints are alleviated it is expected that freight rates will come down as all vessels in the fleet will become fully productive.

Trucks

Over the next decade trucks will continue to serve primarily eastern markets. They are limited by weight restrictions, have a seemingly perpetual problem finding and retaining enough drivers, and, more so than inland barges and railroads, are negatively affected by high fuel costs. Still, the capital requirements of trucking are low and it is an extremely flexible mode.

Railroads

With coal demand expected to continue to rise for the next decade and beyond, railroads, like other modes, will likely be called upon to move much more coal than they do today. If the past is any indication, railroads will be able to handle this increase in demand, but it will require huge new investments in rail capacity



[38] A fuel tax paid by waterways users covers a small portion of the expenses associated with the waterways system. The remainder comes from general appropriations.

expansion and supportive regulatory and legislative policies.

From 1990 to 2005, U.S. coal production rose 10 percent. During this same period, rail coal tons originated rose 28 percent and, due largely to the growth of long-distance PRB coal movements, rail coal ton-miles rose 84 percent — both far higher than the growth in coal production. This market response by railroads can continue as long as railroads' ability to make the necessary investments in their networks is not constrained

U.S. railroads today are hauling more freight than ever before. These traffic increases have resulted in capacity constraints and related service issues at certain locations and corridors within the rail network. In fact, excess capacity has disappeared from some critical segments of the national rail system, including some used to carry coal.

This means that as traffic grows, railroads will have to concentrate increasingly on replacing and building new capacity in addition to maintaining their existing capacity.

Railroads, like other transportation modes, are taking a number of steps to improve their ability to move all types of traffic, including coal, more efficiently. Over the past couple of years railroads have hired and trained thousands of new workers, purchased thousands of new locomotives, instituted new operating plans, forged new alliances with other carriers and with their customers, and looked to new technology applications — all with the eye toward increasing capacity and service capability.

To help specifically ensure that adequate coal-carrying capacity is available to meet future coal transportation needs, railroads are taking a variety of actions. For example, they are emphasizing the need for coordinated, timely planning with customers and suppliers. To this end, railroads meet regularly with coal companies and electricity producers to determine how to best conform rail transportation offerings to their needs. These joint efforts include such objectives as meeting peak period demand and performing track maintenance as efficiently and unobtrusively as possible

Railroads have not been immune to coal delivery issues. For example, in May 2005, two coal trains derailed on a critical rail line in the Powder River Basin region of Wyoming due to accumulated coal dust and heavy rain and snow. The PRB today is the source of around 40 percent of U.S. coal production, and PRB-produced coal is used to generate electricity consumed in dozens of states. The derailments and a subsequent comprehensive repair program disrupted coal trains for much of the rest of the year. Floods in Kansas and hurricanes in the Gulf restricted rail operations, as well. Railroads moved more coal in 2005 than ever before, but because of the problems railroads faced, not every coal consumer could obtain all the coal it wanted as quickly as desired. The delivery problems coincided with a substantial and rapid increase in the demand for coal due, in part, to sharply higher natural gas prices.

In addition to trying to better balance earnings with investment needs, railroads are taking other steps to position future capital investment to support coal utilization. For example, they support a legislative effort to provide tax incentives to be made available to railroads, shippers, coal consumers, and others for projects that expand existing rail capacity. Like other modes, railroads also continue to aggressively seek productivity and technological enhancements to improve their operations.

The freight rail industry is at or near the top among all U.S. industries in terms of capital intensity. Including capital and maintenance spending, from 1980 through 2006, Class I railroads invested more than $370 billion (and short lines spent additional billions) to maintain and improve their infrastructure and equipment — with most of this spending directly or indirectly benefiting coal. (`Looking ahead, billions of dollars of rail investments will be directed specifically at coal, including new locomotives and train sets; double-, triple-, and even quadruple-tracking heavily-used coal routes; bypasses, sidings, and terminals; and thousands of new employees. These investments will enhance coal-carrying capacity and the fluidity of rail operations.

Conclusion

Railroads, barges, and trucks are all critical coal transportation providers. Each mode faces challenges, some of which are unique to it and some of which are common to each of the modes. For each mode, having capacity that is adequate to meet growing demand is perhaps the most pressing need.

Available truck capacity will be determined by factors such as the amount of public spending on highways, how well the industry resolves the driver retention issue, and fuel costs.

Waterways, like trucks, depend on publicly-owned and maintained infrastructure. Waterway infrastructure is, in general, in need of significant maintenance and improvement. The availability of public funds to provide these improvements will feature prominently in how well waterways can handle future coal transportation needs.

Railroads, on the other hand, rely overwhelmingly on privately-owned, maintained, and operated infrastructure. However, railroads do not have unlimited funds to invest in capacity expansion. Nor can they afford to keep spare capacity on hand "just in case." Thus, before they enhance capacity, railroads, as private-sector companies, must be confident that traffic and revenue will remain high enough in the long term to justify the investments.

Railroads will continue to spend huge amounts of private capital to help ensure that adequate capacity exists, but they can do so only if regulatory or legislative restraints do not hinder rail earnings. Some groups, for example, are calling for the re-regulation of railroads.

Under re-regulation, rail managers could not commit, and rail stockholders would not supply, investment capital needed to improve service and expand capacity, because the railroads considering such investments would not have a reasonable opportunity to capture the benefits of those investments. Disaster might not occur overnight, but there would be little or no capacity expansion — something that certainly would have a near-term and significant adverse effect on coal shipments.

Other Factors Impacting Supply/Demand Growth

Siting of Mines and Facilities

Coal surface mines range significantly in size. A recently permitted mine in West Virginia includes 18 million tons of reserves on about 4,000 acres. A pending lease application with the US Bureau of Land Management (BLM) for the right to mine PRB coal includes 588 million tons of reserves on about 4590 acres. In addition to the area being mined, surface facilities are required for staging and loading the coal, as well as storing the overburden for future reclamation. Environmental groups and surface land owners are becoming louder in their objections to new surface mines, delaying the permitting process and increasing costs through litigation.

Underground mining requires surface facilities for staging, loading and storage, exposing them to litigation and delay, as well. They also face issues with subsidence and both ground and surface water, which can restrict where mining can occur.

There are also land use rules and regulations, such as the federal 'Roadless Area Conservation Rule', which restricts mining access to some public lands. There are also local, State, and Federal regulations that place land use restrictions on private lands, such as populated areas, which also limit mining access.

Labor

EIA projects approximately 27,000 additional mine employees will be required to meet the reference case coal production increase of 690 million tons in 2030, a 34% increase over 2005 mine employment of 78,656. This number does not reflect new employees required to replace retiring employees (average age of mine workers in 2005 is 45-55), or additional employees required in supporting roles outside the mine, such as rail employees, truck drivers, plant employees, etc.

EIA projects coal demand from the Eastern Interior Region, which includes Illinois, Indiana, and Western Kentucky to grow by 116%, to 220 million tons/year, compared to a projected population increase of approximately 7%. Coal miners currently comprise about 0.1% of the population of that region.

Table 11 reflects the number of new miners required in the Eastern Interior coal producing region, assuming productivity remains flat. The figures include EIA's labor projections for its base forecast, as well as projections required to meet the National Coal Council's projection of 475 million additional tons per year from Illinois Basin and the Southern States Energy Board's projection of 1580 million additional tons per year.

Table 11: Projected New Miners in US Eastern Interior

Producing Region	Projected Population Increase	Miners Needed EIA	NCC
Eastern Interior	1,862,399	20,954	137,942

*Eastern Interior: Illinois, Indiana, Mississippi, Western Kentucky. However, since population estimates are only reported by State, all of Kentucky's population was included.

Table 12 contrasts regional population growth estimates in the Western subbituminous producing States, with miners needed to support projected production growth.

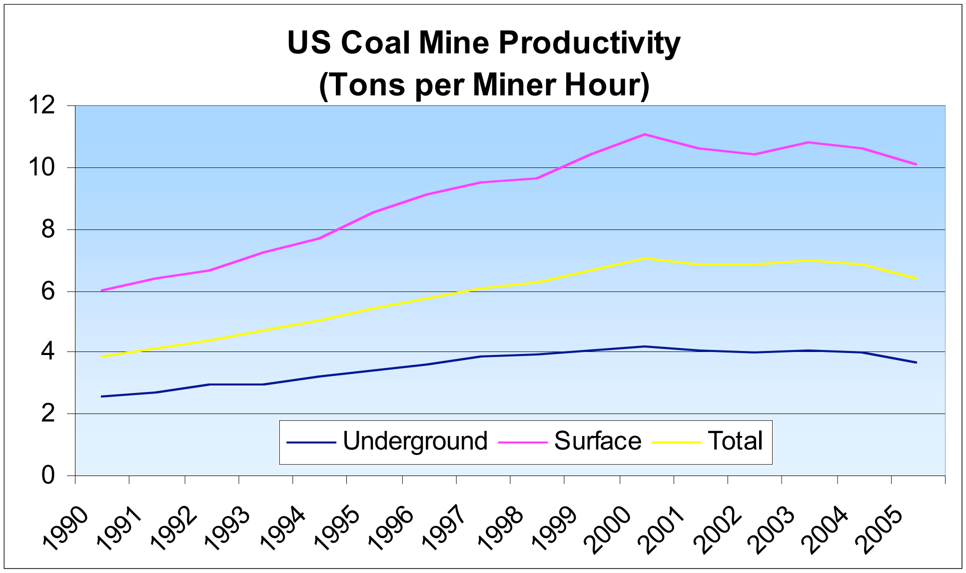
Table 12: Projected New Miners in Subbituminous Producing

Producing State	Projected Population Increase	Miners Needed EIA	SSEB*
Montana	111,893	752	3,218
Wyoming	15,711	3,041	7,509

*Assumes 70% of production from Wyoming

EIA assumes productivity will remain flat over the forecast period, with productivity increases from an increased percentage of tons from western surface mines and more efficient longwall operations in underground mines offset by regulatory issues and more difficult mining conditions. Figure 21 shows productivity trends from 1990-2005, by mining method.

Figure 21: Historical US Mine Productivity



To produce the tonnage required for the SSEB and NCC projections, the increased demand, thus increased number of miners, will likely lead to higher labor cost.

Safety

2006 saw an increased emphasis on mine safety. International scrutiny of the numbers of mining related deaths in China resulted in significant changes to the industry, including consolidation of smaller mining operations into a limited number of large, better managed and equipped organizations and more stringent regulation of illegal mining. This resulted in the closure of a large number of small, locally operated mines.

There were 24 mining related deaths in the US in 2006, which lead to passage of the 'Mine Improvement and New Emergency Response Act of 2006'. The increased emphasis on safety adds both equipment and labor to the cost of coal production, as well as increasing penalties for non-compliance.

Equipment

Competing demand for mining equipment comes from domestic mining of other commodities, international mining activities, and international construction activities. The industry has had to deal with significant queues for delivery of new equipment for several years.

Mining equipment manufacturers use backlog values as a tool for sales forecasting and production planning. A company supplying equipment to international markets reported an increase of over 26% in their backlog between December 31, 2005 and September 30, 2006, primarily due to new machine orders[39]. They are currently implementing a three-phase expansion program, expected to be completed in early 2008.

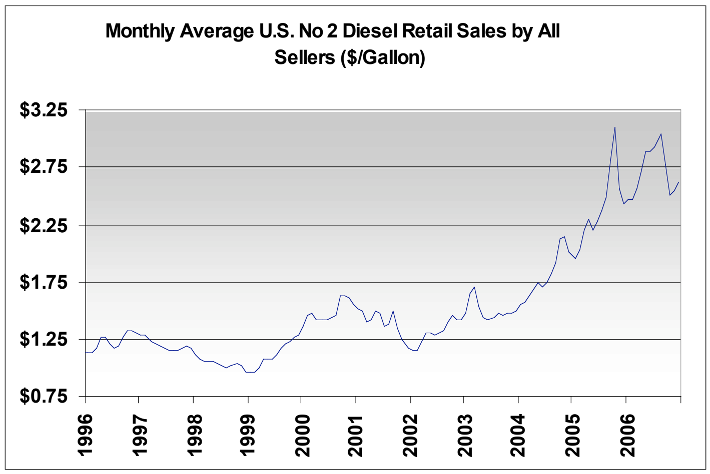
A shortage of new tires for large mining and construction equipment emerged in 2004 that is expected to persist through 2007 into 2008, when capacity expansion currently under construction comes on line.

Based on this experience, addition of new equipment manufacturing capacity can be expected to lag future demand increases by 3 to 4 years.

Figure 22: Monthly Average Diesel Price

Diesel

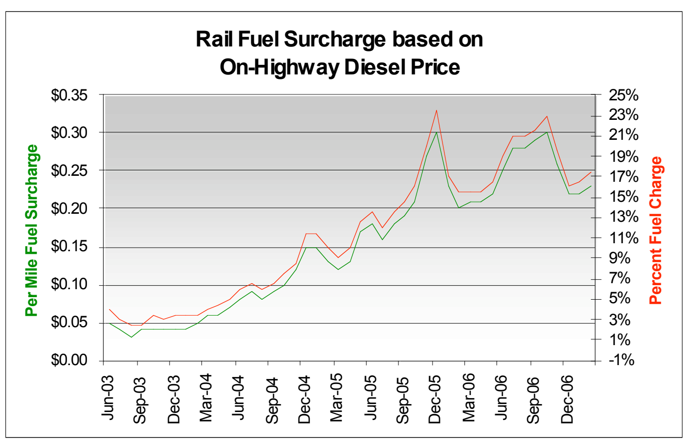
The coal market is very sensitive to the price of diesel fuel. Next to labor, it is one of the largest contributors to the cost of surface mining. As shown in Figure 22, diesel prices have shown a great deal of volatility in the past 10 years, significantly so in the past 3 years.



It is also one of the main contributors to the cost of transporting coal. The major modes for transporting coal, truck, rail, and barge are all diesel powered.

Figure 23: Rail Fuel Surcharge

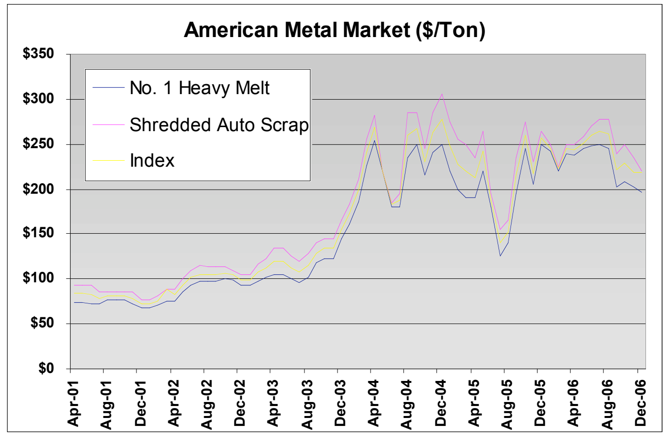
As noted above, to recover their costs, railways and barge operators now include a fuel surcharge in the cost of transportation, either as an adder or a percentage of the underlying contract price. Figure 23 shows the rail fuel surcharge charged by a Class I railroad, based on the On-Highway Diesel Fuel published weekly by EIA.



[39] Bucyrus International, Inc. Form 10-Q, September 30, 2006

Steel

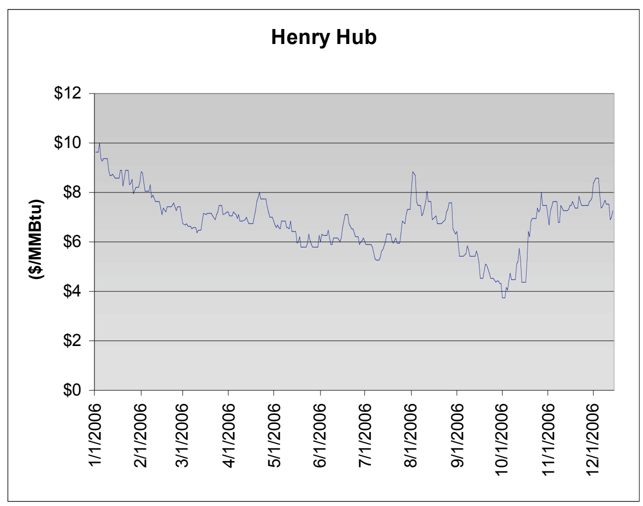
Figure 24: Steel Prices



Steel also contributes significantly to the cost of mining. It is a large component of the cost of mining equipment, both underground and surface. Both longwall and continuous underground miners are made of steel components. Roof supports and roof bolts are steel. Surface mine equipment, including haul trucks, shovels and loaders are made of steel.

Coal transportation cost is affected by steel costs, as well. Rail cars, engines, and track are all made of steel. River barges are also made of steel. Equipment used to load and unload coal is made of steel.

Figure 25: Natural Gas Price



As Figure 24 shows, steel has exhibited significant price volatility over the last 3 years.

Explosives

Explosives used in mining contain ammonium nitrate and/or fuel oil derivatives. Natural gas is the primary feedstock used in ammonia production, introducing additional price volatility into the cost of coal production.

Figure 25 shows how the price of natural gas has changed over the course of 2006, from a maximum per MMBtu price of $10.01, to a minimum of $3.76, back to $7.24 in mid-December.

Conclusions

Construction, labor, equipment, and supply costs have escalated significantly in recent years and are more volatile than in the past, contributing to higher, less predictable production costs. Permitting a new facility takes longer, costs more, and is subject to more scrutiny than in the past.

Appendix 1 - Definitions

Types of Coal

Coal is classified into four main types, or ranks (lignite, subbituminous, bituminous, anthracite), depending on the amounts and types of carbon it contains and on the amount of heat energy it can produce. The rank of a deposit of coal depends on the pressure and heat acting on the plant debris as it sank deeper and deeper over millions of years. For the most part, the higher ranks of coal contain more heat-producing energy.

Lignite is the lowest rank of coal with the lowest energy content. Lignites tend to be relatively young coal deposits that were not subjected to extreme heat or pressure. Lignite is brownish-black, crumbly and has a high inherent moisture content, sometimes as high as 45 percent. About eight percent of the coal produced in the United States is lignite, and most of it comes from Texas and North Dakota. Lignite is mainly burned at power plants to generate electricity.

Lignite is often referred to as brown coal, used almost exclusively as fuel for steam-electric power generation. The heat content of lignite ranges from 9 to 17 million Btu per ton (4,500 to 8,500 Btu/lb) on a moist, mineral-matter-free basis. The heat content of lignite consumed in the United States averages 13 million Btu per ton (6.500 Btu/lb), on the as-received basis (i.e., containing both inherent moisture and mineral matter).

Subbituminous coal has a higher heating value than lignite. Subbituminous coal typically contains 35-45 percent carbon, compared to 25-35 percent for lignite. Most subbituminous coal in the U.S. is at least 100 million years old. Over 40 percent of the coal produced in the United States is subbituminous.

Subbituminous coal may be dull, dark brown to black, soft and crumbly, at the lower end of the range, to bright, jet black, hard, and relatively strong, at the upper end. It contains 20 to 30 percent inherent moisture by weight. The heat content of subbituminous coal ranges from 17 to 24 million Btu per ton on a moist (8,500 to 12,000 Btu/lb), mineral-matter-free basis. The heat content of subbituminous coal consumed in the United States averages 17 to 18 million Btu per ton (8,500 to 9,000 Btu/lb), on the as-received basis (i.e., containing both inherent moisture and mineral matter).

Bituminous coal contains 45-86 percent carbon, and has two to three times the heating value of lignite. Bituminous coal was formed under high heat and pressure. Bituminous coal in the United States is between 100 and 300 million years old. It is the most abundant coal in active U.S. mining regions, accounting for about half of U.S. coal production. Bituminous coal is used primarily as fuel in steam-electric power generation, with substantial quantities also used for heat and power applications in manufacturing and to make coke for the steel and iron industries.

Bituminous coal is a dense coal, usually black, sometimes dark brown, often with well-defined bands of bright and dull material. Its moisture content usually is less than 20 percent. The heat content of bituminous coal ranges from 21 to 30 million Btu per ton (10,500 to 15,000

Btu/lb) on a moist, mineral-matter-free basis. The heat content of bituminous coal consumed in the United States averages 24 million Btu per ton (12,000 Btu/lb), on the as-received basis (i.e., containing both inherent moisture and mineral matter).

Anthracite contains 86-97 percent carbon and its heating value is slightly lower than bituminous coal. Anthracite is very rare in the United States. The only anthracite mines in the United States are located in northeastern Pennsylvania.

Anthracite, the highest rank of coal; is used primarily for residential and commercial space heating. It is a hard, brittle, and black lustrous coal, often referred to as hard coal, containing a high percentage of fixed carbon and a low percentage of volatile matter. The moisture content of fresh-mined anthracite generally is less than 15 percent. The heat content of anthracite ranges from 22 to 28 million Btu per ton (11,000 to 14,000 Btu/lb) on a moist, mineral-matter-free basis. The heat content of anthracite coal consumed in the United States averages 25 million Btu per ton (12,500 Btu/lb), on the as-received basis (i.e., containing both inherent moisture and mineral matter). Note: Since the 1980's, anthracite refuse or mine waste has been used for steam electric power generation. This fuel typically has a heat content of 15 million Btu per ton (7,500 Btu/lb) or less.

Coal Reserve/Resource Terminology [40]

Recoverable Reserves at Producing (Active) Mines: The amount of in situ coal that can be recovered by mining existing reserves at mines reporting on Form EIA-7A. This reserve category is not especially meaningful.

Estimated Recoverable Reserves: This category is calculated from the Demonstrated Reserve Base (the DRB as defined below). A recovery factor is applied to the DRB to estimate recoverable reserves. The recovery factor is derived from actual mining practices in the active mining district. Estimated recoverable reserves include the coal in the "in-place" demonstrated reserve base that is considered to be accessible to the mining industry, technologically mineable, and can be recovered by the prevailing mining methods for a region. Accessibility factors relate to limitations to mining due to regulatory and land use constraints. Technological limitations may be regulatory (required mine buffers) or other physical barriers to mining. Recovery percentages are estimated according to mining method. Surface mining regions have higher recovery rates, longwall mines have intermediate rates, and conventional and continuous underground mining areas have the lowest recovery rates.

The ERR recovery rate averages 54 percent of the DRB for the nation, with a range between 36 and 77 percent for individual states. Table 3, presented later in this chapter, sets forth DOE's estimated average recovery rates for each state.

[40] SSEB Appendices, pgs 16-17

Demonstrated Reserve Base: Represents that portion of identified coal resources from which reserves are calculated. A collective term for the sum of coal in both measured and indicated resource categories of reliability which represents 100 percent of the coal in these categories in place as of a certain date. Includes beds of bituminous coal and anthracite 28 inches or more thick and beds of subbituminous coal 60 inches or more thick that occur at depths to 1,000 feet. This includes beds of lignite 60 inches or more thick that can be surface mined. Includes also thinner and/or deeper beds that presently are being mined or for which there is evidence that they could be mined commercially at this time.

The demonstrated reserve base includes publicly available data on coal mapped to measured and indicated degrees of certainty and found at depths and in coalbed thickness considered technologically minable at the time of determination. In most cases, the DRB begins with Identified Resources and then excludes coal in certain resource categories. For example, the DRB includes only bituminous coal greater than 28 in thick (subbituminous and lignite greater than 5 feet that is surface mineable). DRB coal must be less than 1000 ft in depth for bituminous and subbituminous coals, or 500 ft for lignite. Only coal within ¾ mile of a thickness measurement is included in the DRB. It is also periodically reduced to account for historical mining production or increased as a result of additions of new data or mining activity in areas outside the DRB. In cases where state estimates used different classifications than Circular 891 or lack certain categories (e.g., not all estimates include overburden data), the EIA devised methods for estimating these categories. The current DRB is about 15% of total Identified Resources.

Identified Resources: Specific bodies of coal whose location, rank, quality, and quantity are known from geologic evidence supported by engineering measurements. Included are beds of bituminous coal and anthracite 14 inches or more thick and beds of subbituminous coal and lignite 30 inches or more thick that occur at depths to 6,000 feet and whose existence and quantity have been delineated within specified degrees of geologic assurance as measured, indicated, and inferred (see definitions below).

USGS Circular 891 specifies the criteria for subdividing coal resources on the basis of coal rank, total coal thickness, overburden thickness, and confidence of the estimate. Confidence of the estimate is based on proximity to coal thickness measurements (from outcrops, drill holes, logged wells and mine measurements), and is determined by scribing circles of increasing diameter around thickness locations used for preparing the estimate. This categorization is especially significant, because recoverable coal in the Identified Resources classification may be excluded from the DRB estimate due to wide spacing of measurement data (see Figure 5). This is perhaps one of the biggest shortcomings of the EIA classification system.

Undiscovered Resources: Unspecified bodies of coal surmised to exist on the basis of broad geologic knowledge and theory but not specifically drilled or measured in the field. Undiscovered resources include beds of bituminous coal and anthracite 14 inches or more thick and beds of subbituminous coal and lignite 30 inches or more thick that are presumed to occur in unmapped and unexplored areas to depths of 6,000 feet. The speculative and hypothetical resource categories (defined below) comprise undiscovered resources. In remote areas in the U.S. such as Alaska huge amounts of coal in this category are known to exist.

Hypothetical Resources: Undiscovered coal resources in beds that may reasonably be expected to exist in known mining districts under known geologic conditions. In general, hypothetical resources are in broad areas of coalfields where points of observation are absent and evidence is from distant outcrops, drill holes, or wells. Exploration that confirms their existence and better defines their quantity and quality would permit their reclassification as identified or demonstrated resources. Quantitative estimates are based on a broad knowledge of the geologic character of a coal bed or region. Measurements of coal thickness are more than 6 miles apart. The assumption of continuity of coal bed is supported by geologic models not direct measurements.

Speculative Resources: Undiscovered coal in beds that may occur either in known types of deposits in a favorable geologic setting where no discoveries have been made, or in deposits that remain to be recognized. Exploration that confirms their existence and better defines their quantity and quality would permit their reclassification as identified resources.