Coal Market Module

The NEMS Coal Market Module (CMM) provides projections of U.S. coal production, consumption, exports, imports, distribution, and prices. The CMM comprises three functional areas: coal production, coal distribution, and coal exports. A detailed description of the CMM is provided in the EIA publication, Coal Market Module of the National Energy Modeling System 2012, DOE/EIA-M060(2012) (Washington, DC, 2012).

Key assumptions

Coal production

The coal production submodule of the CMM generates a different set of supply curves for the CMM for each year of the projection. Forty-one separate supply curves are developed for each of 14 supply regions, nine coal types (unique combinations of thermal grade and sulfur content), and two mine types (underground and surface). Supply curves are constructed using an econometric formulation that relates the minemouth prices of coal for the supply regions and coal types to a set of independent variables. The independent variables include: capacity utilization of mines, mining capacity, labor productivity, the user cost of capital of mining equipment, the cost of factor inputs (labor and fuel), and other mine supply costs.

The key assumptions underlying the coal production modeling are:

- As capacity utilization increases, higher minemouth prices for a given supply curve are projected. The opportunity to add capacity is allowed within the modeling framework if capacity utilization rises to a pre-determined level, typically in the 80 percent range. Likewise, if capacity utilization falls, mining capacity may be retired. The amount of capacity that can be added or retired in a given year depends on the level of capacity utilization, the supply region, and the mining process (underground or surface). The volume of capacity expansion permitted in a projection year is based upon historical patterns of capacity additions.
- Between 1980 and 2000, U.S. coal mining productivity increased at an average rate of 6.6 percent per year, from 1.93 to 6.99 short tons per miner per hour. The major factors underlying these gains were interfuel price competition, structural change in the industry, and technological improvements in coal mining. Since 2000, however, growth in overall U.S. coal mining productivity has been negative, declining at a rate of 2.3 percent per year to 5.55 short tons per miner hour in 2010. By region, productivity in most of the coal producing basins represented in the NEMS Coal Market Module has declined some during the past decade. In the Central Appalachian coal basin, which has been mined extensively, productivity declined by 45 percent between 2000 and 2010, corresponding to an average decline of 5.9 percent per year. While productivity declines have been more moderate at the highly productive mines in Wyoming's Powder River Basin, overall coal mining productivity still fell by 24 percent between 2000 and 2010, corresponding to an average rate of decline of 2.7 percent per year.
- Over the projection period, labor productivity is expected to decline in a number of coal supply regions, reflecting the trend of the previous ten years. Higher stripping ratios and the added labor needed to maintain more extensive underground mines offset productivity gains achieved from improved equipment, automation, and technology. Productivity in some areas of the East is projected to decline as operations move from mature coalfields to marginal reserve areas. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that can be achieved by Appalachian producers from economies of scale.
- In the CMM, different rates of productivity improvement are assumed for each of the 41 coal supply curves used to represent U.S. coal supply. These estimates are based on recent historical data and expectations regarding the penetration and impact of new coal mining technologies [2]. Data on labor productivity are provided on a quarterly and annual basis by individual coal mines and preparation plants on the U.S. Mine Safety and Health Administration's Form 7000-2, "Quarterly Mine Employment and Coal Production Report" and the U.S. Energy Information Administration's Form EIA-7A, "Coal Production and Preparation Report". In the Reference case, overall U.S. coal mining labor productivity declines at rate of 1.4 percent per year between 2010 and 2035. Reference case projections of coal mining productivity by region are provided in Table 12.1.
- In the *AEO2012* Reference case, the wage rate for U.S. coal miners increases by 1.0 percent per year and mine equipment costs are assumed to remain constant in 2010 dollars (i.e., increase at the general rate of inflation) over the projection period.

Coal distribution

The coal distribution submodule of the CMM determines the least-cost (minemouth price plus transportation cost) supplies of coal by supply region for a given set of coal demands in each demand sector using a linear programming algorithm. Production and distribution are computed for 14 supply (Figure 11) and 16 demand regions (Figure 12) for 49 demand subsectors.

The projected levels of coal-to-liquids, industrial steam, coking, and residential/commercial coal demand are provided by the petroleum market, industrial, commercial, and residential demand modules, respectively; electricity coal demands are projected by the EMM; coal imports and coal exports are projected by the CMM based on non-U.S. supply availability, endogenously determined U.S. import demand, and exogenously determined world coal import demands (non-U.S.).

Table 12.1. Coal mining productivity by region
short tons per miner hour

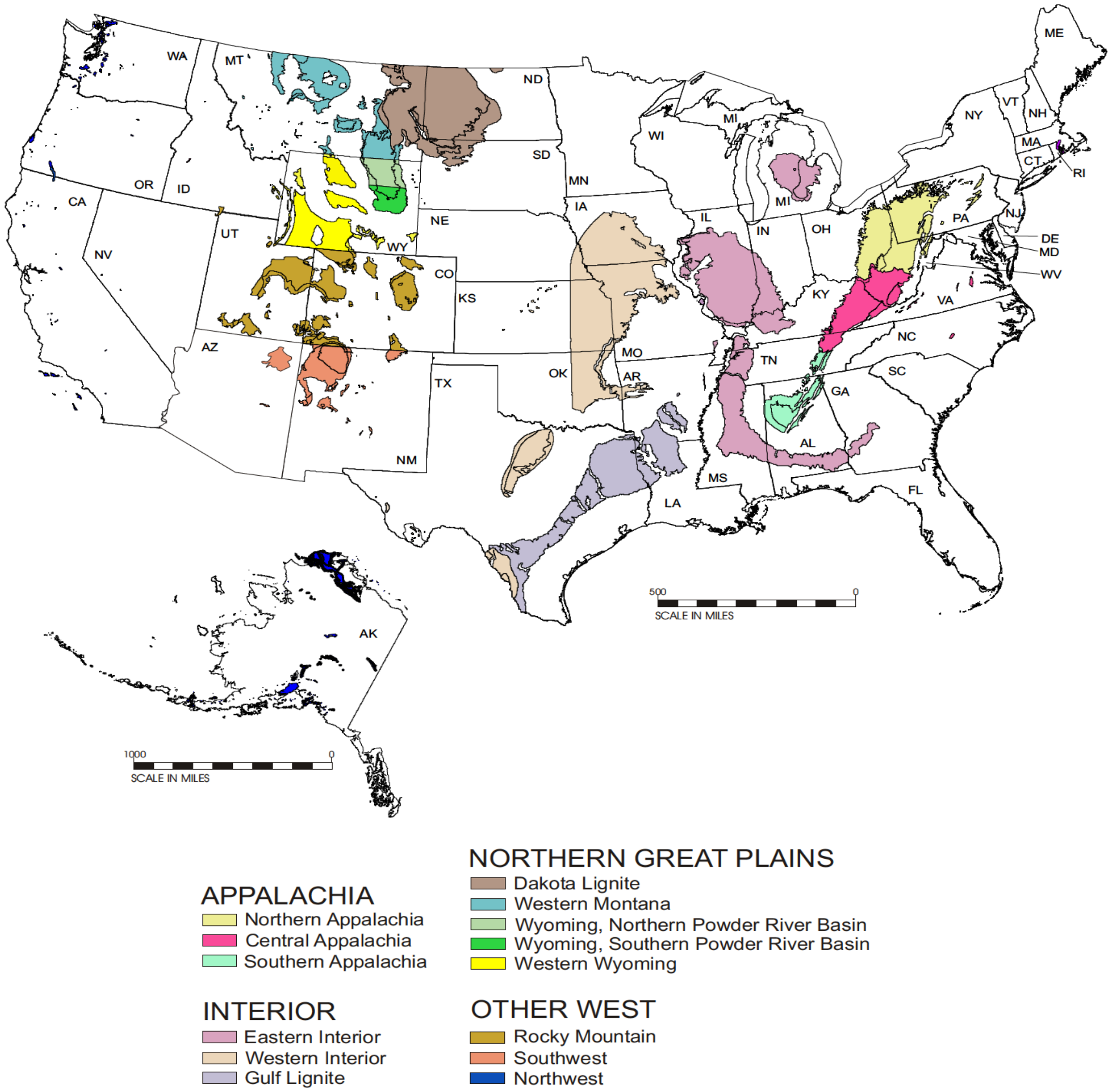
Supply Region	2010	2015	2020	2025	2030	2035	Average Annual Growth 10-35
Northern Appalachia	3.42	3.02	2.89	2.72	2.57	2.47	-1.3%
Central Appalachia	2.27	1.57	1.28	1.08	0.94	0.84	-3.9%
Southern Appalachia	1.97	1.51	1.35	1.20	1.05	0.97	-2.8%
Eastern Interior	4.11	3.99	3.85	3.68	3.54	3.46	-0.7%
Western Interior	2.43	1.96	1.77	1.59	1.43	1.33	-2.4%
Gulf Lignite	6.84	5.41	4.81	4.28	3.81	3.54	-2.6%
Dakota Lignite	13.43	12.20	11.66	11.15	10.65	10.34	-1.0%
Western Montana	17.15	13.95	13.86	13.38	12.42	12.31	-1.3%
Wyoming, Northern Powder River Basin	32.10	27.14	24.91	22.87	20.99	19.86	-1.9%
Wyoming, Southern Powder River Basin	36.27	30.67	28.15	25.84	23.71	22.44	-1.9%
Western Wyoming	7.26	6.46	6.10	5.79	5.52	5.34	-1.2%
Rocky Mountain	5.34	4.44	4.07	3.73	3.42	3.22	-2.0%
Arizona/New Mexico	8.35	7.19	7.16	6.44	6.00	5.71	-1.5%
Alaska/Washington	6.96	5.97	5.54	5.14	4.76	4.53	-1.7%
U.S. Average	5.55	4.64	4.92	4.65	4.15	3.88	-1.4%

Source: U.S. Energy Information Administration, *AEO2012* National Energy Modeling System run REF2012.D020112C.

The key assumptions underlying the coal distribution modeling are:

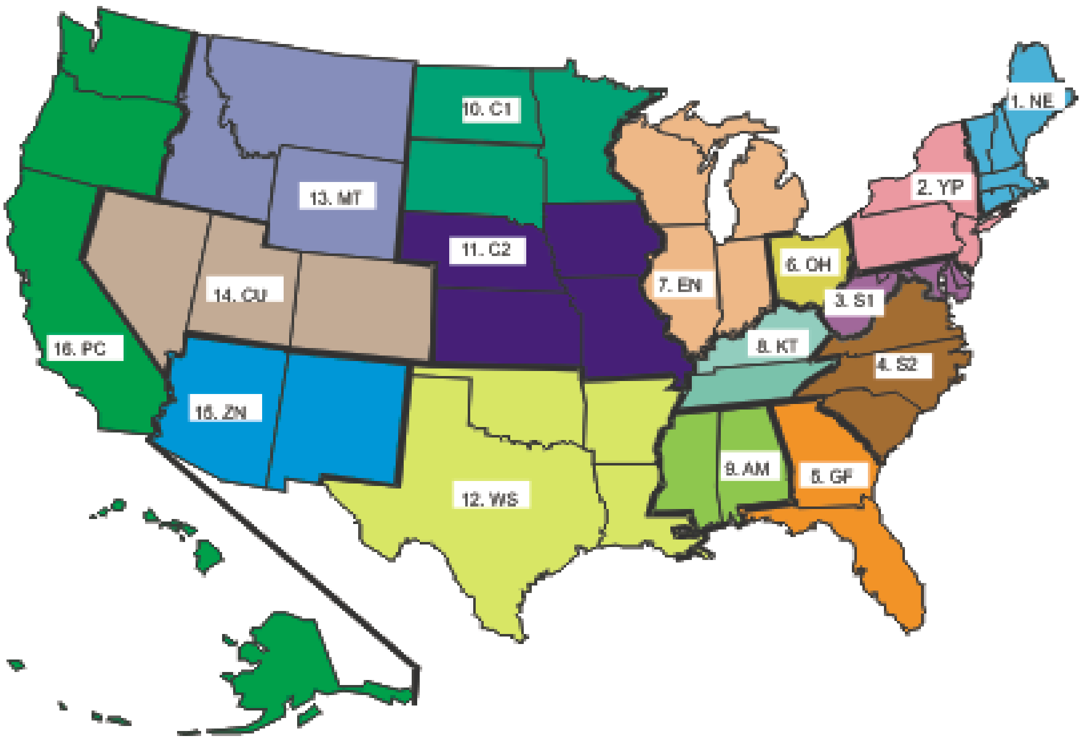
- Base-year (2010) transportation costs are estimates of average transportation costs for each origin-destination pair without differentiation by transportation mode (rail, truck, barge, and conveyor). These costs are computed as the difference between the average delivered price for a demand region (by sector and for export) and the average minemouth price for a supply curve. Delivered price data are from Form EIA-3, "Quarterly Coal Consumption Report-Manufacturing Plants", Form EIA-5, Quarterly Coke Consumption and Quality Report, Coke Plants", Form EIA-923, "Power Plant Operations Report", and the U.S. Bureau of the Census' "Monthly Report EM-545". Minemouth price data are from Form EIA-7A, "Coal Production and Preparation Report".
- For the electricity sector only, a two-tier transportation rate structure is used for those regions which, in response to rising demands or changes in demands, may expand their market share beyond historical levels. The first-tier rate is representative of the historical average transportation rate. The second-tier transportation rate is used to capture the higher cost of expanded shipping distances in large demand regions. The second tier is also used to capture costs associated with the use of subbituminous coal at units that were not originally designed for its use. This cost is estimated at $0.10 per million Btu (2000 dollars) [3].
- Coal transportation costs, both first- and second-tier rates, are modified over time by two regional (east and west) transportation indices. The indices, calculated econometrically, are measures of the change in average transportation rates for coal shipments on a tonnage basis, that occurs between successive years for coal shipments. An east index is used for coal originating from eastern supply regions while a west index is used for coal originating from western supply regions. The east index is a function of railroad productivity, the user cost of capital for railroad equipment, and national average diesel fuel price. The user cost of capital for railroad equipment is calculated from the producer price index (PPI) for railroad equipment, and accounts for the opportunity cost of money used to purchase equipment, depreciation occurring as a result of use of the equipment (assumed at 10 percent), less any capital gain associated with the worth of the equipment. In calculating the user cost of capital, three percentage points are added to the cost of borrowing in order to account for the possibility that greenhouse gas emissions may be regulated in the future. The west index is a function of railroad productivity, investment, and the western share of national coal consumption. The indices are universally applied to all domestic coal transportation movements within the CMM. In the *AEO2012* Reference case, eastern coal transportation rates are projected to be 4 percent higher in 2035 and western rates in 2035 are projected to be the same as in 2010.

Figure 11. Coal Supply Regions



Source: U.S. Energy Information Administration, Office of Energy Analysis

Figure 12. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. S1	WV,MD,DC,DE
4. S2	VA,NC,SC
5. GF	GA,FL
6. OH	OH
7. EN	IN,IL,MI,WI
8. KT	KY,TN

Region Code	Region Content
9. AM	AL,MS
10. C1	MN,ND,SD
11. C2	IA,NE,MO,KS
12. WS	TX,LA,OK,AR
13. MT	MT,WY,ID
14. CU	CO,UT,NV
15. ZN	AZ,NM
16. PC	AK,HI,WA,OR,CA

Source: U.S. Energy Information Administration, Office of Energy Analysis

- For the projection period, the explanatory variables are assumed to have varying impacts on the calculation of the indices. For the west, investment is the analogous variable to the user cost of capital of railroad equipment. The investment value and the PPI for rail equipment, which is used to derive the user cost of capital increase with an increase in national ton-miles (total tons of coal shipped multiplied by the average distance). Increases in investment (west) or the user cost of capital for railroad equipment (east) cause projected transportation rates to increase. For both the east and the west, any related financial savings due to productivity improvements are assumed to be retained by the railroads and are not passed on to shippers in the form of lower transportation rates. For that reason, productivity is held flat for the projection period for both regions. For the east for the projection period, diesel fuel is removed from the equation in order to avoid double-counting the influence of diesel fuel costs with the impact of the fuel surcharge program. The transportation rate indices for seven *AEO2012* cases are shown in Table 12.2.

Table 12.2. Transportation rate multipliers
constant dollar index, 2010=1.000

Scenario	Region:	2010	2015	2020	2025	2030	2035
Reference Case	East	1.000	1.0317	1.0672	1.0405	1.0333	1.0435
	West	1.000	0.9488	0.9625	0.9930	0.9923	0.9991
High Oil Price	East	1.000	1.0204	1.0645	1.0339	1.0422	1.0404
	West	1.000	0.9343	0.9483	0.9935	1.0118	1.0408
Low Oil Price	East	1.000	1.0277	1.0567	1.0356	1.0222	1.0299
	West	1.000	0.9591	0.9750	1.0086	1.0107	1.0105
High Economic Growth	East	1.000	1.0299	1.0581	1.0245	1.0338	1.0289
	West	1.000	0.9566	0.9752	1.0047	1.0125	1.0157
Low Economic Growth	East	1.000	1.0298	1.0999	1.0759	1.0721	1.0829
	West	1.000	0.9419	0.9429	0.9680	0.9692	0.9700
High Coal Cost	East	1.000	1.0700	1.1700	1.2000	1.2400	1.3000
	West	1.000	0.9900	1.0500	1.1300	1.1900	1.2500
Low Coal Cost	East	1.000	0.9900	0.9700	0.9000	0.8300	0.7800
	West	1.000	0.9100	0.8700	0.8500	0.8000	0.7500

Source: Projections: U.S. Energy Information Administration, National Energy Modeling System runs REF2012.D020112C, HP2012.D022112A, LP2012.D022112A, HM2012.D022412A, LM2012.D022412A, HCCST12.D031312A, LCCST12.D031312A. Based on methodology described in Coal Market Module of the National Energy Modeling System 2012, DOE/EIA-M066(2012) (Washington, DC, 2012).

- Major coal rail carriers have implemented fuel surcharge programs in which higher transportation fuel costs have been passed on to shippers. While the programs vary in their design, the Surface Transportation Board (STB), the regulatory body with limited authority to oversee rate disputes, recommended that the railroads agree to develop some consistencies among their disparate programs and likewise recommended closely linking the charges to actual fuel use. The STB cited the use of a mileage-based program as one means to more closely estimate actual fuel expenses.
- For *AEO2012*, representation of a fuel surcharge program is included in the coal transportation costs. For the west, the methodology is based on BNSF Railway Company's mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $1.25 per gallon. For every $0.06 per gallon increase above $1.25, a $0.01 per carload mile is charged. For the east, the methodology is based on CSX Transportation's mileage-based program. The surcharge becomes effective when the projected nominal distillate price to the transportation sector exceeds $2.00 per gallon. For every $0.04 per gallon increase above $2.00, a $0.01 per carload mile is charged. The number of tons per carload and the number of miles vary with each supply and demand region combination and are a pre-determined model input. The final calculated surcharge (in constant dollars per ton) is added to the escalator-adjusted transportation rate. For every projection year, it is assumed that 100 percent of all coal shipments are subject to the surcharge program.
- Coal contracts in the CMM represent a minimum quantity of a specific electricity coal demand that must be met by a unique coal supply source prior to consideration of any alternative sources of supply. Base-year (2010) coal contracts between coal producers and electricity generators are estimated on the basis of receipts data reported by generators on the EIA-923, "Power Plant Operations Report". Coal contracts are specified by CMM supply region, coal type, demand region, and whether or not a unit has flue gas desulfurization equipment. Coal contract quantities are reduced over time on the basis of contract duration data from information reported on the Form EIA-923, "Power Plant Operations Report", historical patterns of coal use, and information obtained from various coal and electric power industry publications and reports.
- Electric generation demand received by the CMM is subdivided into "coal groups" representing demands for different sulfur and thermal heat content categories. This process allows the CMM to determine the economically optimal blend of different coals to minimize delivered cost, while meeting emissions requirements. Similarly, nongeneration demands are subdivided into subsectors with their own coal groups to ensure that, for example, lignite is not used to meet a coking coal demand.

- Coal-to-liquids (CTL) facilities are assumed to be economic when low-sulfur distillate prices reach high enough levels. These plants are assumed to be co-production facilities with generation capacity of 845 MW(300 MW for the grid and 545 MW to support the conversion process) and the capability of producing 50,000 barrels of liquid fuels per day. The technology assumed is similar to an integrated gasification combined cycle, first converting the coal feedstock to gas, and then subsequently converting the syngas to liquid hydrocarbons using the Fisher-Tropsch process. Of the total amount of coal consumed at each plant, 46 percent of the energy input is retained in the product with the remaining energy used for conversion and for the production of power sold to the grid. Beginning with *AEO2010*, coal-biomass-to-liquids (CBTL) capability was incorporated into the NEMS structure. For *AEO2012*, these facilities are assumed to have a generating capacity of 602MW (150 MW for the grid and 452 MW to support the conversion process) and the capability of producing 30,000 barrels of liquid fuels per day. Eighty percent of the energy input is derived from coal with the remaining 20 percent derived from biomass. CTL and CBTL facilities produce paraffinic naptha used in plastics production and blendable naptha used in motor gasoliine (together about 43 percent of the total by volume) and distillate fuel oil (about 57 percent).

Coal imports and exports

Coal imports and exports are modeled as part of the CMM's linear program that provides annual projections of U.S. steam and metallurgical coal exports, in the context of world coal trade. The linear program determines the pattern of world coal trade flows that minimize the production and transportation costs of meeting U.S. import demand and a pre-specified set of regional world coal import demands. It does this subject to constraints on export capacity and trade flows.

The key assumptions underlying coal export modeling are:

- Coal buyers (importing regions) tend to spread their purchases among several suppliers in order to reduce the impact of potential supply disruptions, even though this may add to their purchase costs. Similarly, producers choose not to rely on any one buyer and instead endeavor to diversify their sales.
- Coking coal is treated as homogeneous. The model does not address quality parameters that define coking coals. The values of these quality parameters are defined within small ranges and affect world coking coal flows very little.

Data inputs for coal trade modeling:

- World steam and metallurgical coal import demands for the *AEO2012* cases are shown in Tables 12.3 and 12.4. U.S. coal exports are determined, in part, by these estimates of world coal import demand.
- Step-function coal export supply curves for all non-U.S. supply regions. The curves provide estimates of export prices per metric ton, inclusive of minemouth and inland freight costs, as well as the capacities for each of the supply steps.
- Ocean transportation rates (in dollars per metric ton) for feasible coal shipments between international supply regions and international demand regions. The rates take into account typical vessel sizes and route distances in thousands of nautical miles between supply and demand regions.

Coal quality

Each year the values of base year coal production, heat, sulfur and mercury content and carbon dioxide emissions for each coal source in CMM are calibrated to survey data. Surveys used for this purpose are the Form EIA-923, a survey of the origin, cost and quality of fossil fuels delivered to generating facilities, and the Form EIA-5, which records the origin, cost and quality of coal delivered to domestic industrial consumers. Estimates of coal quality for the export and residential/commercial sectors are made using the survey data for coal delivered to coking coal and industrial steam coal consumers. Mercury content data for coal by supply region and coal type, in units of pounds of Mercury per trillion Btu, shown in Table 71, were derived from shipment-level data reported by electricity generators to the Environmental Protection Agency in its 1999 Information Collection Request. Carbon dioxide emission factors for each coal type are shown in Table 12.5 in pounds of carbon dioxide emitted per million Btu [4].

The CMM projects steam and metallurgical coal trade flows from 17 coal-exporting regions of the world to 20 import regions for three coal types (coking, bituminous steam, and subbituminous). It includes five U.S. export regions and four U.S. import regions.

Table 12.3. World steam coal import demand by import region

million metric tons of coal equivalent

	2010	2015	2020	2025	2030	2035
The Americas	37.8	33.7	45.1	60.6	55.1	64.4
United States[3]	13.9	11.2	22.1	35.6	26.6	28.3
Canada	7.9	3.1	2.8	2.9	2.9	2.9
Mexico	4.0	4.7	4.8	5.3	5.9	8.3
South America	12.0	14.8	15.4	16.8	19.7	24.9
Europe	122.4	173.1	177.3	175.9	174.5	174.4
Scandinavia	7.8	7.4	6.5	5.8	5.0	4.5
U.K./Ireland	16.8	29.9	29.0	29.0	30.3	31.7
Germany/Austria	28.9	38.8	38.5	37.5	36.6	35.6
Other NW Europe	20.5	22.8	22.1	20.8	20.0	19.2
Iberia	8.5	17.1	18.0	17.9	17.6	16.3
Italy	12.4	20.3	25.3	27.1	27.1	27.1
Med/E Europe	27.5	36.8	37.9	37.8	37.9	40.0
Asia	437.6	474.7	500.6	542.6	596.8	644.1
Japan	89.8	88.8	83.1	79.7	79.6	76.7
East Asia	126.5	128.2	129.6	131.8	140.3	150.1
China/Hong Kong	114.5	134.2	144.5	168.0	189.8	203.9
ASEAN	40.0	44.5	52.4	61.5	69.1	77.2
Indian Sub	66.8	79.0	91.0	101.6	118.0	136.2
TOTAL	597.8	681.5	723.0	779.1	826.4	882.9

[1]Import Regions: South America: Argentina, Brazil, Chile, Puerto Rico; Scandinavia: Denmark, Finland, Norway, Sweden; Other NW Europe: Belgium, France, Luxembourg, Netherlands; Iberia: Portugal, Spain; Med/E Europe: Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; East Asia: North Korea, South Korea, Taiwan; ASEAN: Malaysia, Philippines, Thailand; Indian Sub: Bangladesh, India, Iran, Pakistan, Sri Lanka.
[2]The base year of the world trade projection for coal is 2010.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
Notes: One "metric ton of coal equivalent" equals 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Table 12.4. World metallurgical coal import demand by import region
million metric tons of coal equivalent

	2010	2015	2020	2025	2030	2035
The Americas	20.0	30.3	35.4	43.5	54.0	67.3
United States	1.3	1.3	1.3	1.3	1.3	1.3
Canada	3.2	3.2	3.2	3.1	3.0	2.9
Mexico	1.0	1.1	1.1	1.1	1.1	1.1
South America	14.5	24.6	29.8	38.0	48.6	62.0
Europe	59.4	61.3	61.7	61.5	61.5	61.4
Scandinavia	3.2	2.4	2.7	2.7	2.7	2.7
U.K./Ireland	6.7	7.3	7.3	7.3	7.3	7.3
Germany/Austria	12.2	11.4	11.4	11.3	11.3	11.3
Other NW Europe	13.7	14.9	14.7	14.5	14.4	14.3
Iberia	3.5	4.0	3.9	3.9	3.8	3.6
Italy	6.8	7.4	7.4	7.3	7.3	7.3
Med/E Europe	13.3	13.9	14.3	14.5	14.7	14.9
Asia	186.2	201.2	214.6	228.3	232.4	239.7
Japan	79.3	77.4	74.5	70.6	63.8	60.9
East Asia	34.9	36.0	37.1	38.3	39.5	40.6
China/Hong Kong	36.7	42.7	44.1	46.6	48.6	50.9
ASEAN[4]	0.0	0.0	0.0	0.0	0.0	0.0
Indian Sub	35.3	45.1	58.9	72.8	80.5	87.3
TOTAL	265.6	292.8	311.7	333.3	347.9	368.4

[1] Import Regions: South America: Argentina, Brazil, Chile, Puerto Rico; Scandinavia: Denmark, Finland, Norway, Sweden; Other NW Europe: Belgium, France, Luxembourg, Netherlands; Iberia: Portugal, Spain; Med/E Europe: Algeria, Bulgaria, Croatia, Egypt, Greece, Israel, Malta, Morocco, Romania, Tunisia, Turkey; East Asia: North Korea, South Korea, Taiwan; ASEAN: Malaysia, Philippines, Thailand; Indian Sub: Bangladesh, India, Iran, Pakistan, Sri Lanka.
[2] The base year of the world trade projection for coal is 2010.
[3] Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4] Malaysia, Phillipines, and Thailand are not expected to import significant amounts of metallurgical coal in the projection.
Notes: One "metric ton of coal equivalent" equals 27.78 million Btu. Totals may not equal sum of components due to independent rounding.

Legislation and regulations

The *AEO2012* is based on current laws and regulations in effect before October 31, 2011 with two important exceptions. Because of their significance to electricity and coal markets, the Mercury Air Toxics Standard (MATS), finalized in December 2011, is included in the final release of the *AEO2012* Reference case, and the Cross State Air Pollution Rule (CSAPR) (though stayed by the courts in December 2011) is also included.

MATS sets emissions limits for mercury, other heavy metals, and acid gases from coal and oil power plants that are 25 MW or greater. CSASPR was finalized in July 2011 and sets more stringent emission limits for 28 States for sulfur dioxide and nitrogen oxides. CSASPR and MATS are fully in place by 2014 and 2015, respectively.

Table 12.5. Production, heat content, sulfur, mercury and carbon dioxide emission factors by coal type and region

Coal Supply Region	States	Coal Rank and Sulfur Level	Mine Type	2010 Production (Million short Tons	Heat Content (Million Btu per Short Ton)	Sulfur Content (Pounds Per Million Btu)	Mercury Content (Pounds per Trillion Btu)	CO_2 (Pounds Per Million Btu)
Northern Appalachia	PA, OH, MD, WV (North)	Metallurgical	Underground	14.5	26.30	0.76	N/A	204.7
		Mid-Sulfur Bituminous	All	40.2	25.15	1.32	11.17	204.7
		High-Sulfur Bituminous	All	74.9	24.70	2.67	11.67	204.7
		Waste Coal (Gob and Culm)	Surface	13.9	11.76	3.79	63.9	204.7
Central Appalachia	KY (East), WV (South), VA, TN (North)	Metallurgical	Underground	50.8	26.30	0.68	N/A	206.4
		Low-Sulfur Bituminous	All	17.2	24.76	0.54	5.61	206.4
		Mid-Sulfur Bituminous	All	118.4	24.77	0.91	7.58	206.4
Southern Appalachia	AL, TN (South)	Metallurgical	Underground	10.7	26.30	0.57	N/A	204.7
		Low-Sulfur Bituminous	All	0.4	25.21	0.49	3.87	204.7
		Mid-Sulfur Bituminous	All	9.3	24.28	1.25	10.15	204.7
East Interior	IL, IN, KY(West), MS	Mid-Sulfur Bituminous	All	11.8	22.65	1.17	5.6	203.1
		High-Sulfur Bituminous	All	94.0	22.89	2.57	6.35	203.1
		Mid-Sulfur Lignite	Surface	4.0	10.39	0.92	14.11	216.5
West Interior	IA, MO, KS, AR, OK, TX (Bit)	High-Sulfur Bituminous	Surface	1.6	21.56	1.89	21.55	202.8
Gulf Lignite	TX (Lig), LA	Mid-Sulfur Lignite	Surface	31.2	13.47	1.18	14.11	212.6
		High-Sulfur Lignite	Surface	13.8	12.24	2.59	15.28	212.6
Dakota Lignite	ND, MT (Lig)	Mid-Sulfur Lignite	Surface	29.3	13.23	1.17	8.38	219.3
Western Montana	MT (Sub)	Low-Sulfur Subbituminous	Underground	4.4	20.19	0.44	5.06	215.5
		Low-Sulfur Subbituminous	Surface	22.7	18.36	0.38	5.06	215.5
		Mid-Sulfur Subbituminous	Surface	17.3	17.06	0.79	5.47	215.5
Northern Wyoming	WY (Northern Powder River Basin)	Low-Sulfur Subbituminous	Surface	167.6	16.82	0.37	7.08	214.3
		Mid-Sulfur Subbituminous	Surface	2.9	16.17	0.75	7.55	214.3
Southern Wyoming	WY (Southern Powder River Basin	Low-Sulfur Subbituminous	Surface	257.9	17.60	0.30	5.22	214.3

Table 12.5. Production, heat content, sulfur, mercury and carbon dioxide emission factors by coal type and region (cont)

Coal Supply Region	States	Coal Rank and Sulfur Level	Mine Type	2010 Production (Million short Tons	Heat Content (Million Btu per Short Ton)	Sulfur Content (Pounds Per Million Btu)	Mercury Content (Pounds per Trillion Btu)	CO_2 (Pounds Per Million Btu)
Western Wyoming	WY (Other basins, excluding Powder River Basin	Low-Sulfur Subbituminous	Underground	3.8	18.64	0.64	2.19	214.3
		Low-Sulfur Subbituminous	Surface	4.1	19.04	0.62	4.06	214.3
		Mid-Sulfur Subbituminous	Surface	6.2	19.34	0.89	4.35	214.3
Rocky Mountain	CO, UT	Metallurgical	Underground	--	26.30	0.52	N/A	209.6
		Low-Sulfur Bituminous	Underground	39.4	22.85	0.48	3.82	209.6
		Low-Sulfur Subbituminous	Surface	5.1	19.94	0.43	2.04	212.8
Southwest	AZ, NM	Low-Sulfur Bituminous	Surface	7.8	21.64	0.58	4.66	207.1
		Mid-Sulfur Subbituminous	Surface	16.1	17.80	1.01	7.18	209.2
		Mid-Sulfur Bituminous	Underground	4.9	19.16	0.70	7.18	207.1
Northwest	WA, AK	Low-Sulfur Subbituminous	Surface	2.2	16.12	0.31	6.99	216.1

--indicates zero production in 2010.
N/A = not available.
Source: U.S. Energy Information Administration, Form EIA-3, "Quarterly Coal Consumption and Quality Report Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-7A, "Coal Production and Preparation Report", and Form EIA-923, "Power Plant Operations Report". U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM-545." U.S. Environmental Protection Agency, Emission Standards Division, Information Collection Request for Electric Utility Steam Generating Unit, Mercury Emissions Information Collection Effort (Research Triangle Park, NC, 1999). U.S. Environmental Protection Agency, "ANNEX 2 Methodology and Data for Estimating CO_2 Emissions from Fossil Fuel Combustion", Table A-38, web site http://epa.gov/climatechange/emissions/downloads11/US-GHG-Inventory-2011-Annex-2.pdf.

The Energy Improvement and Extension Act of 2008 (EIEA) and Title IV, under Energy and Water Development, of the American Recovery and Revitalization Act of 2009 (ARRA), together, are assumed to result in 1 gigawatt of advanced coal-fired capacity with carbon capture and sequestration by 2017.

EIEA was passed in October 2008 as part of the Emergency Economic Stabilization Act of 2008. Subtitle B provides investment tax credits for various projects sequestering CO_2. Subtitle B, which extends the phaseout of payments by coal producers to the Black Lung Disability Trust Fund from 2013 to 2018, is also modeled in the *AEO2012*.

Title IV under ARRA provides $3.4 billion for additional research and development on fossil energy technologies. This includes $800 million to fund projects under the Clean Coal Power Initiative (CCPI) program, focusing on projects that capture and sequester greenhouse gases or use captured carbon dioxide for enhanced oil recovery (EOR). The Hydrogen Energy California Project and a new plant to be built by Summit Texas Clean Energy in Texas both include efforts to use captured carbon dioxide for EOR.

Title XVII of the Energy Policy Act of 2005 authorizes loan guarantees for projects that avoid, reduce, or sequester greenhouse gasses. For *AEO2012*, the 1 gigawatt of advanced coal-fired capacity with carbon capture and sequestration assumed for EIEA and ARRA are also assumed to benefit from these loan guarantees.

Beginning in 2008, electricity generating units of 25 megawatts or greater were required to hold an allowance for each ton of CO_2 emitted in nine Northeastern States as part of the Regional Greenhouse Gas Initiative (RGGI). The States currently participating in RGGI include Connecticut, Maine, Maryland, Massachusetts, Rhode Island, Vermont, New York, New Hampshire, and Delaware. RGGI is modeled in *AEO2012* as an emissions reduction for the Central Atlantic region.

California Assembly Bill 32 (AB32), the Global Warming Solution Act of 2006, was incorporated for electricity sector power plants serving California. As modeled, AB32 imposes a limit on power sector CO_2 emissions beginning in 2012 and declining at a uniform annual rate through 2020.

EPA issued final guidelines to its regional offices for monitoring the compliance of surface coal mining operations in Appalachia, The guidelines relate primarily to the ongoing controversy over use of the mountaintop removal method at a number of surface coal mining operations in Central Appalachia, primarily in southern West Virginia and eastern Kentucky. While the guidelines require a more rigorous review for all new surface coal mines in Appalachia, the EPA indicated that the practice of valley fills, primarily associated with the mountaintop removal method, is the aspect of Appalachian coal mining that should be most scrutinized. The impact of the EPA's guidelines for surface coal mining operations in Appalachia is represented by downward adjustments to the coal mining productivity assumptions for Central Appalachian surface mines. The revised productivity levels are based on the assumption that average productivity for surface mining operations in Central Appalachia will decline gradually toward the productivity levels for smaller surface mines in the region as a result of the more restrictive guidelines for overburden management at large mountaintop mining operations.

Coal alternative cases

Coal Cost cases

In the Reference case, coal mine labor productivity is assumed to decline on average by 1.5 percent per year through 2035 ,miner wage rates increase by about 1.0 percent per year, and mine equipment costs remain constant in 2010 dollars. Eastern and Western transportation rates are 4 percent higher and flat, respectively, in 2035 compared to 2010. In two alternative coal cost cases, productivity, average miner wages, equipment cost, and transportation rate assumptions were modified for 2012 through 2035 in order to examine the impacts on U.S. coal supply, demand, distribution and prices.

In the Low Mining Cost case, coal mine labor productivity is assumed to increase at an average rate of 4.7 percent per year through 2035. Coal mining wages at the regional level are assumed to remain constant in 2035 relative to 2010. Mine equipment costs and other mine supply costs are all assumed to be about 21 percent lower by 2035 in real terms in the Low Coal Cost case. Coal transportation rates, excluding the impact of fuel surcharges, are assumed to be 25 percent lower by 2035.

In the High Mining Cost case, coal mine labor productivity is assumed to decline at an average rate of 4.6 percent per year through 2035. Coal mining wages increase by about 1.9 percent per year. Mine equipment costs, and other mine supply costs are assumed to be about 27 percent higher by 2035. Compared to the Reference case, coal transportation rates are assumed to be 25 percent higher by 2035. The low and high coal cost cases represent fully integrated NEMS runs, with feedback from the Macroeconomic Activity, International, supply, conversion, and end-use demand modules.

No Greenhouse Gas Concern case

In the Reference case, to reflect the market reaction to potential future GHG regulation, a 3-percentage-point increase in the cost of capital for investments in new coal-fired power plants without carbon capture and sequestration technology and new coal-to-liquids plants is assumed. These assumptions affect cost evaluations for the construction of new capacity but not the actual operating costs for new existing plants. This adjustment was first implemented for *AEO2009*. For *AEO2012*, a 3-percentage-point increase in the cost of capital for investments in retrofits at existing coal plants is also applied for emission control equipment (excluding CCS).

The No GHG concern case excludes the 3-percentage point increase in the cost of capital.

Notes and sources

[1] Energy Information Administration, The U.S. Coal Industry, 1970-1990: Two Decades of Change, DOE/EIA-0559, (Washington, DC, November 1992).

[2] Stanley C. Suboleski, et.al., Central Appalachia: Coal Mine Productivity and Expansion, Electric Power Research Institute, EPRI IE-7117, (September 1991).

[3] The estimated cost of switching to subbituminous coal, $0.10 per million Btu (2000 dollars), was derived by Energy Ventures Analysis, Inc. and was recommended for use in the CMM as part of an Independent Expert Review of the Annual Energy Outlook 2002's Powder River Basin production and transportation rates. Barbaro, Ralph and Seth Schwartz. Review of the Annual Energy Outlook 2002 Reference Case Forecast for PRB Coal, prepared for the Energy Information Administration (Arlington, VA: Energy Ventures Analysis, Inc., August 2002).

[4] U.S. Environmental Protection Agency, "Climate Change—Regulatory Initiative: Greenhouse Gas Reporting Program", website www.epa.gov/climatechange/emissions/