Chapter 12. 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 2014, DOE/EIA-M060 (2014) (Washington, DC, 2014).

Key assumptions

Coal production

The CMM generates a different set of supply curves for each year of the projection. Combinations of 14 supply regions, 9 coal types (unique groupings of thermal grade and sulfur content), and 2 mine types (underground and surface), result in 41 separate supply curves. Supply curves are constructed using an econometric formulation that relates the mine mouth 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 follows:

- As capacity utilization increases, higher mine mouth prices for a given supply curve are projected. The opportunity to add production capacity is allowed within the modeling framework if capacity utilization rises to a pre-determined level, typically in the 80% 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 supply region, the capacity utilization level, 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.
- In the CMM, different rates of labor productivity improvement or decline are assumed for each of the 41 coal supply curves used to represent U.S. coal supply. AEO2017 Reference case projections for regional coal mining productivity are provided in Table 12.1. Overall U.S. coal mining labor productivity declines at a rate of 0.1% per year between 2014 and 2040 in the Reference case. Higher stripping ratios at surface mines and the added labor needed to maintain more extensive underground mines offset productivity gains achieved from improved equipment, automation, and technology in most coal supply regions. Historical data on labor productivity are provided on a quarterly and annual basis by individual coal mines and preparation plants on the U.S. Department of Labor, Mine Safety and Health Administration's Form 7000-2, "Quarterly Mine Employment and Coal Production Report," and EIA's Form EIA-7A, "Annual Survey of Coal Production and Preparation."

- Between 1980 and 2000, U.S. coal mining labor productivity increased at an average rate of 6.6% per year, from 1.93 to 6.99 short tons per miner per hour. The major factors underlying these gains were inter-fuel price competition, structural change in the industry, and technological improvements in coal mining [12.1]. Between 2000 and 2014, growth in overall U.S. coal mining productivity has been negative, declining at a rate of 1.5% per year to 5.64 short tons per miner-hour in 2014. In all regions but one (Alaska/Washington), productivity in coal producing basins represented in the CMM has declined from the productivity level in 2000.
- Productivity in some areas of the coalfields in the eastern United States is projected to decline as operations move from mature coal fields to marginal reserve areas. In the Central Appalachian coal basin, which has been mined extensively, productivity declined by almost 50% between 2000 and 2014, corresponding to an average decline of 4.5% per year. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that can be achieved by Appalachian producers from economies of scale.
- While productivity declines have been more moderate at the more highly-productive mines in Wyoming's Powder River Basin (PRB), coal mining productivity in this region still fell by almost 30% between 2000 and 2014, corresponding to an average rate of decline of 2.4% per year. For AEO2017 onward, productivity figures for the PRB production areas were modified based on an assessment of recent private sector analyses [12.2], with productivity in the southern PRB declining at a greater average rate of 1.5% per year from 2014 to 2040, compared with 1.1% in the AEO2016 Reference case. The 1.1% average rate per year of productivity decline projected for the northern PRB is the same as in AEO2016 reference case.
- The Rocky Mountain production region relies on less efficient underground operations. Accordingly, productivity in the Rocky Mountain region declines at 2.3%, the fastest rate per year of any coal supply region in the AEO Reference case.
- Of the top coal producing regions showing declines, the Eastern Interior has shown the best overall performance, with coal mining productivity declining by only 1.8% between 2000 and 2014, or 0.1% per year. The Eastern Interior region, which has a substantial amount of thick, underground-minable coal reserves, is currently experiencing a resurgence in coal mining activity, with several coal companies operating highly-productive longwall mines. Productivity is expected to increase modestly at a rate of 0.7% per year from 2014 to 2040.

• In the AEO2017 Reference case, the wage rate for U.S. coal miners increases by 0.8% per year and mine equipment costs are assumed to remain constant in 2013 dollars (i.e., increase at the general rate of inflation) over the projection period.

Table 12.1. Coal mining productivity by region

short tons per miner hour

Supply Region	2014	2020	2025	2030	2035	2040	Average Annual Growth 2014-2040
Northern Appalachia	3.43	3.26	3.06	2.82	2.72	2.59	-1.1%
Central Appalachia	2.20	1.77	1.62	1.38	1.26	1.29	-2.0%
Southern Appalachia	1.88	1.61	1.46	1.33	1.24	1.17	-1.8%
Eastern Interior	4.64	4.98	5.11	5.26	5.40	5.54	0.7%
Western Interior	2.73	2.38	2.24	2.11	2.04	1.99	-1.2%
Gulf Lignite	6.94	6.40	6.09	5.79	5.57	5.38	-1.0%
Dakota Lignite	11.53	11.53	10.96	10.42	10.03	9.69	-0.7%
Western Montana	16.58	14.76	16.39	15.85	14.69	13.55	-0.8%
Wyoming, Northern Powder River Basin	29.35	28.20	26.85	26.65	24.27	22.23	-1.1%
Wyoming, Southern Powder River Basin	34.32	26.87	24.78	23.73	23.31	22.99	-1.5%
Western Wyoming	6.36	7.37	7.01	6.67	6.44	6.25	-0.1%
Rocky Mountain	6.12	5.01	4.42	3.89	3.56	3.32	-2.3%
Arizona/New Mexico	8.01	7.57	7.24	6.90	6.67	6.47	-0.8%
Alaska/Washington	5.42	5.84	5.96	6.08	6.15	6.22	0.5%
U.S. Average	5.64	6.22	6.22	6.16	5.55	5.45	-0.1%

Source: U.S. Energy Information Administration, AEO2017 National Energy Modeling System run REF2017.D120816A.

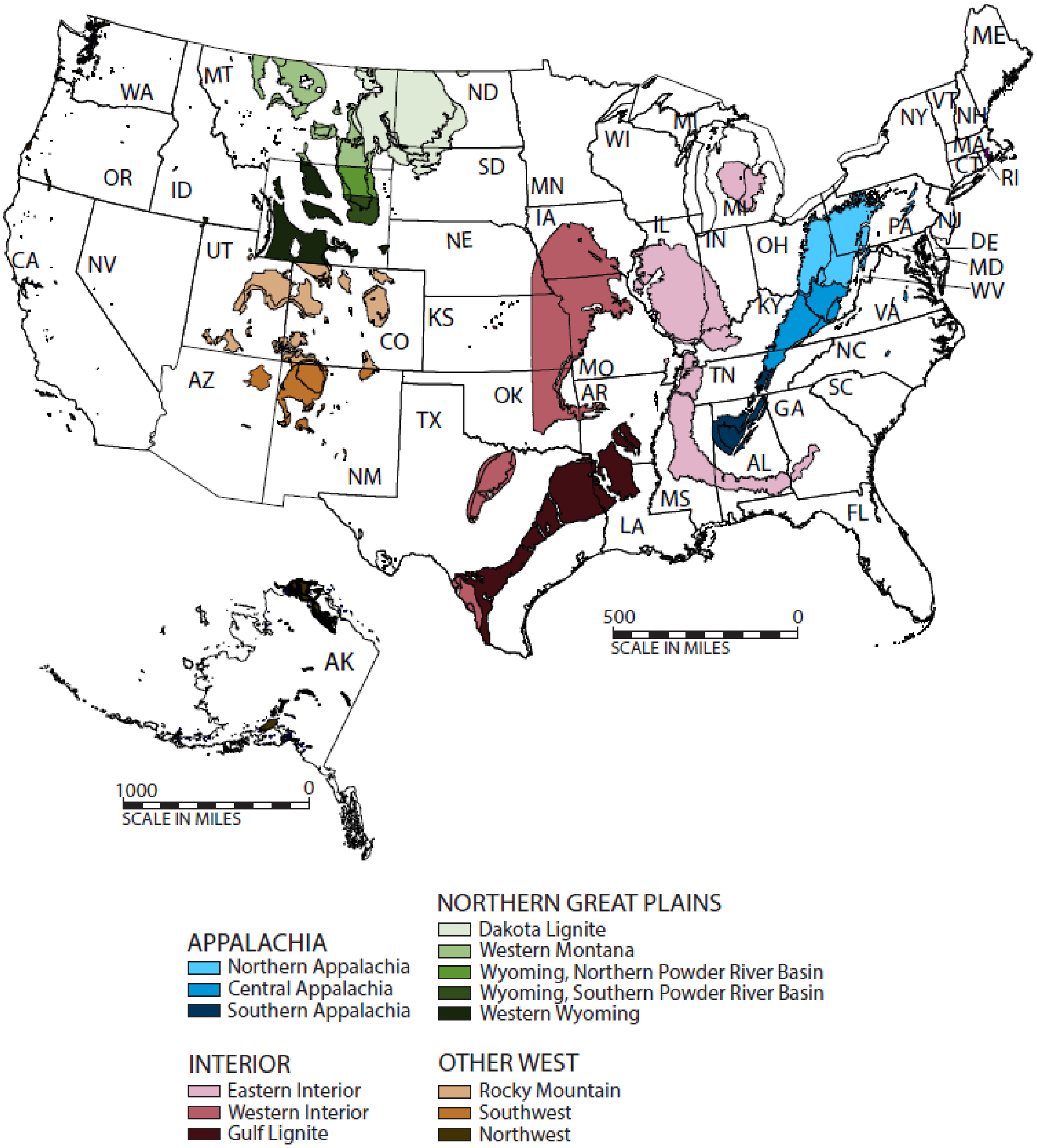
Coal distribution

The coal distribution submodule of the CMM determines the least-cost (mine mouth 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 12.1) and 16 demand regions (Figure 12.2) for 49 demand subsectors.

The projected levels of coal-to-liquids, industrial steam, coking, and commercial/institutional coal demand are provided by the liquid fuel market, industrial, and commercial demand modules, respectively. Electricity coal demands are projected by the Electricity Market Module (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 (non-U.S.) coal import demands (non-U.S.).

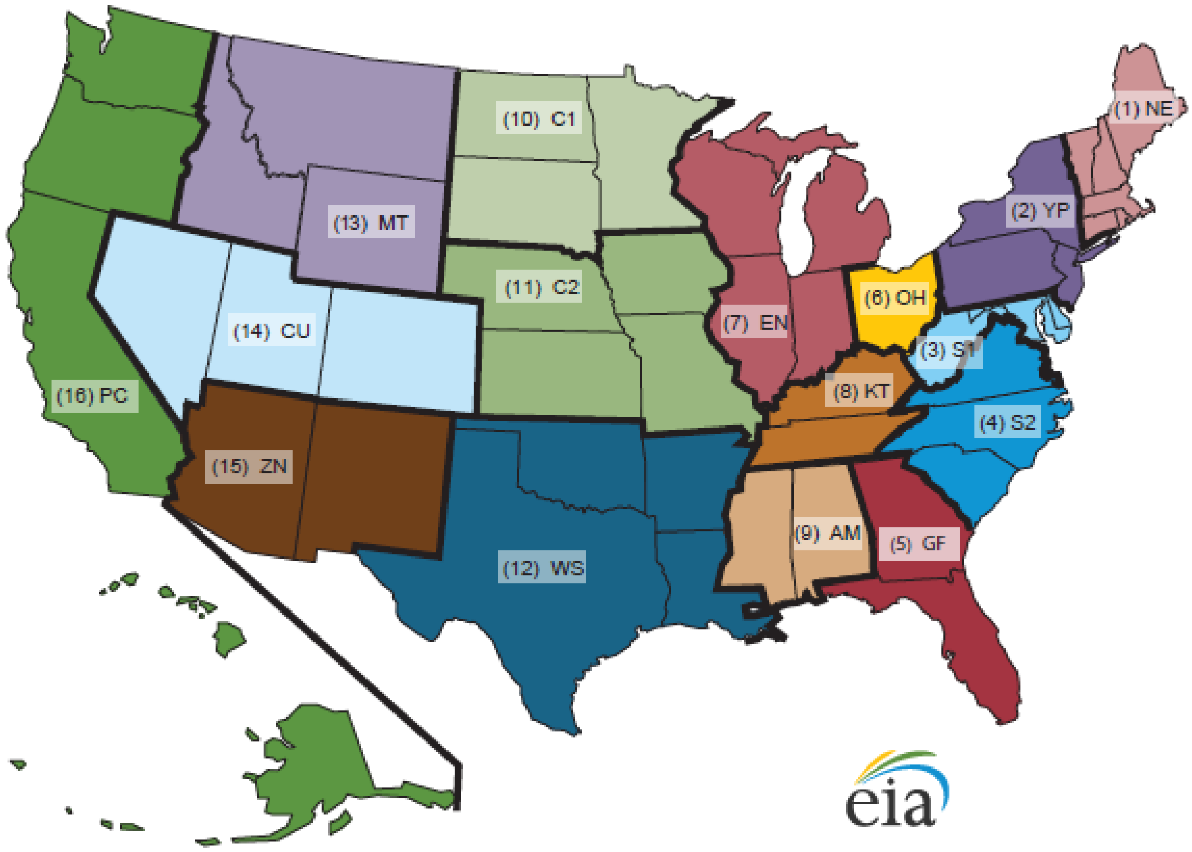
Transportation rates between coal supply and demand regions are determined by applying annual, projected regional transportation price indices to a two-tier rate structure. The first tier is representative of the historical average transportation rate which is estimated for a base year using recent EIA survey data. The second tier captures costs associated with changing patterns of coal demand for electricity generation. Regional fuel surcharges are then added to the indexed transportation rates to reflect the impact of higher diesel fuel costs.

Figure 12.1. Coal Supply Regions



Source: U.S. Energy Information Administration

Figure 12.2. Coal Demand Regions



Region	Code	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	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

The key assumptions underlying the coal distribution modeling are as follows:

Base-year (2014) 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 mine mouth price for a supply curve. Delivered price data are from 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-923, "Power Plant Operations Report", and the U.S. Bureau of the Census, "Monthly Report EM-545". Mine mouth 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 changing patterns of coal demand, 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 British Thermal Units (Btu) (2000 dollars) [12.3].

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, which occurs between successive years for coal shipments. An east index is used for coal originating from coal supply regions located east of the Mississippi River, while a west index is used for coal originating from coal supply regions located west of the Mississippi River. The indices are universally applied to all domestic coal transportation movements within the CMM. In the AEO2017 Reference case, both eastern and western coal transportation rates are projected to remain near their 2014 levels. The transportation rate indices for six AEO2017 cases are shown in Table 12.2 where the index value equals 1.00 for 2014.

- The east index is negatively correlated with improvements in railroad productivity, and it is positively correlated with the user cost of capital for railroad equipment and the 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 and depreciation occurring as a result of use of the equipment (assumed at 10%), 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 a national level program to regulate greenhouse gas emissions may be implemented in the future. An increase in national ton-miles (total tons of coal shipped multiplied by the average distance) increases PPI and, consequently, the user cost of capital. Diesel fuel is removed from the equation for the east in the projection period in order to avoid double-counting the influence of diesel fuel costs with the impact of the fuel surcharge program.

The west index is negatively correlated with improvements in railroad productivity, and positively correlated with increases in investment and the western share of national coal consumption. The investment variable is analogous to the user cost of capital of railroad equipment variable applied in the east and similarly increases with an increase in national ton-miles (total tons of coal shipped multiplied by the average distance).

- 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 this reason, transportation productivity is held flat for the projection period for both regions.

Table 12.2. Transportation rate multipliers

constant dollar index, 2014=1.000

Scenario	Region:	2014	2020	2025	2030	2035	2040
Reference	East	1.0000	1.0833	1.0613	1.0464	1.0379	1.0345
	West	1.0000	1.0149	1.0185	1.0199	1.0135	1.0136
Low Oil Price	East	1.0000	1.0785	1.0582	1.0434	1.0361	1.0325
	West	1.0000	1.0149	1.0185	1.0199	1.0136	1.0136
High Oil Price	East	1.0000	1.0897	1.0650	1.0489	1.0399	1.0380
	West	1.0000	1.0147	1.0185	1.0199	1.0136	1.0136
Low Economic Growth	East	1.0000	1.0938	1.0675	1.0480	1.0357	1.0283
	West	1.0000	1.0149	1.0185	1.0199	1.0136	1.0136
High Economic Growth	East	1.0000	1.0833	1.0626	1.0483	1.0405	1.0374
	West	1.0000	1.0149	1.0185	1.0199	1.0135	1.0135
High Resource	East	1.0000	1.0827	1.0617	1.0462	1.0378	1.0341
	West	1.0000	1.0147	1.0184	1.0197	1.0133	1.0131

Source: Projections: U.S. Energy Information Administration, National Energy Modeling System runs REF2017.D120816A, LOWPRICE. D120816A, HIGHPRICE. D120816A, LOWMACRO. D120816A, HIGHMACRO. D120816A, and HIGHRESOURCE. D120816A Based on methodology described in Coal Market Module of the National Energy Modeling System 2014, DOE/EIA-M060 (2014) (Washington, DC, 2014).

- 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 AEO2017, 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, 100% of all coal shipments are assumed to be 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 (2014) coal contracts between coal producers and electricity generators are estimated on the basis of receipts data reported by generators on the Form 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.
- 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 832 megawatts (MW) (295 MW for the grid and 537 MW to support the conversion process) and the capability of producing 48,000 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 Fischer-Tropsch process. Of the total amount of coal consumed at each plant, 40% 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. For AEO2017, coal-biomass-to-liquids (CBTL) are not modeled. CTL facilities produce distillate fuel oil (about 72%) and paraffinic naphtha used in plastics production and blend-able naphtha used in motor gasoline (together about 28% of the total by volume). CTL facilities are not economic in the AEO2017 Reference case in any forecast year.

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 CMM projects steam and metallurgical coal trade flows from 17 coal-exporting regions of the world to 20 import regions for 2 coal types (steam and metallurgical), including 5 U.S. export regions and 4 U.S. import regions. The linear program determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting U.S. import demand and a pre-specified set of regional coal import demands, subject to constraints on export capacity and trade flows.

The key assumptions underlying coal export modeling are as follows:

- 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.

Table 12.3. World steam coal import demand by import region[1]

million metric tons of coal equivalent

	2013	2015	2020	2025	2030	2035	2040
The Americas	**33.7**	**34.5**	**29.6**	**25.9**	**23.6**	**22.6**	**22.2**
United States[2]	7.2	8.7	4.5	2.2	0.9	0.2	0.1
Canada	4.5	3.1	2.7	1.6	0.9	0.9	0.9
Mexico	3.4	3.4	3.3	3.3	3.2	3.2	3.1
South America	18.6	19.3	19.1	18.8	18.6	18.3	18.1
Europe	**161.4**	**169.8**	**163.7**	**161.8**	**157.5**	**149.6**	**140.5**
Scandinavia	6.3	6.8	6.6	5.9	5.0	4.6	4.1
U.K./Ireland	39.8	25.5	17.1	14.4	12.6	10.8	8.0
Germany/Austria/Poland	39.3	39.1	38.8	37.8	36.8	32.4	26.9
Other NW Europe	17.0	20.6	18.9	17.8	16.5	15.3	14.5
Iberia	13.4	18.1	15.3	13.2	11.4	10.5	9.1
Italy	12.9	15.0	14.6	14.4	14.1	12.2	10.4
Med/E Europe	32.7	44.7	52.4	58.3	61.1	63.8	67.5
Asia	**610.5**	**575.6**	**513.0**	**527.4**	**542.1**	**562**	**580.5**
Japan	98.0	100.7	96.5	93.5	90.3	88.9	86.6
East Asia	124.9	140.9	152.4	151.0	152.2	157.9	165.0
China/Hong Kong	210.5	119.9	117.4	114.8	112.3	107.2	100.5
ASEAN	49.3	56.1	60.0	79.3	94.9	113.0	131.2
Indian Sub	127.8	158.0	86.7	88.8	92.4	95.0	97.2
TOTAL	**805.6**	**779.9**	**706.3**	**715.1**	**723.2**	**734.2**	**743.2**

[1]Tables 12.3 and 12.4: Import Regions: United States: East Coast, Gulf Coast, Northern Interior, Non-Contiguous; Canada: Eastern, Interior; 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, Vietnam; Indian Sub: Bangladesh, India, Iran, Pakistan, Sri Lanka.
[2]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[3]Malaysia, Philippines, Thailand, and Vietnam 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.

The data inputs for coal trade modeling are as follows:

- World steam and metallurgical coal import demands for the AEO2017 cases (Tables 12.3 and 12.4).
  - U.S. coal exports are determined, in part, by these estimates of world coal import demand. The assumed demands for AEO2016 are based on the projections made in IEO2016.

- 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.

Table 12.4. World metallurgical coal import demand by import region[1]

million metric tons of coal equivalent

	2013	2015	2020	2025	2030	2035	2040
The Americas	**22.9**	**19.2**	**19.2**	**21.6**	**23.1**	**26.1**	**28.1**
United States[2]	0.9	1.6	1.0	1.0	1.0	1.0	1.0
Canada	3.3	3.1	3.1	3.0	2.9	2.8	2.7
Mexico	3.7	1.2	1.2	1.7	2.2	2.8	3.3
South America	15.0	13.4	13.9	15.9	17.0	19.5	21.1
Europe	**56.9**	**51.6**	**54.9**	**54.9**	**53.9**	**53.8**	**53.9**
Scandinavia	3.2	2.4	2.7	2.7	2.7	2.7	2.7
U.K./Ireland	7.2	6.0	7.0	7.0	7.0	7.0	7.0
Germany/Austria/Poland	11.6	12.3	13.2	12.2	11.2	11.2	11.2
Other NW Europe	13.4	12.3	12.1	11.9	11.7	11.4	11.3
Iberia	3.2	1.7	1.7	1.7	1.7	1.7	1.7
Italy	5.3	3.5	4.0	5.0	5.0	5.0	5.0
Med/E Europe	13.0	13.4	14.2	14.4	14.6	14.8	15.0
Asia	**227.2**	**215.8**	**230.8**	**249.5**	**253.1**	**257.0**	**266.8**
Japan	75.4	78.2	76.9	76.5	74.8	71.3	66.0
East Asia	39.0	40.6	44.1	50.4	55.6	60.1	64.5
China/Hong Kong	72.0	47.4	51.2	53.3	41.7	30.1	27.2
ASEAN[3]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Indian Sub	40.8	49.6	58.6	69.3	81.0	95.5	109.1
TOTAL	**307.0**	**286.6**	**304.9**	**326.0**	**330.1**	**336.9**	**348.8**

[1]Tables 12.3 and 12.4: Import Regions: United States: East Coast, Gulf Coast, Northern Interior, Non-Contiguous; Canada: Eastern, Interior; 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, Vietnam; Indian Sub: Bangladesh, India, Iran, Pakistan, Sri Lanka.
[2]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[3]Malaysia, Philippines, Thailand, and Vietnam 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.

Coal quality

Each year, the values of base year coal production–heat, sulfur, and mercury content–and carbon dioxide (CO2) emission factors 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, the Form EIA-3, which records the origin, cost, and quality of coal delivered to U.S. manufacturers, transformation and processing plants, and commercial and institutional users, and the Form EIA-5, which records the origin, cost, and quality of coal delivered to domestic coke plants. Estimates of coal quality for the export sector are based on coal quality data collected on EIA surveys for domestic shipments. Mercury content data for coal by supply region and coal type, in units of pounds of mercury per trillion Btu, shown in Table 12.5, were derived from shipment-level data reported by electricity generators to the U.S. Environmental Protection Agency (EPA) in its 1999 Information Collection Request. CO2 emission factors for each coal type, based on data published by the EPA, are shown in Table 12.5 in units of pounds of CO2 emitted per million Btu [12.4].

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	2014 Production (million short tons)	2014 Heat Content (million Btu per short ton)	2014 Sulfur Content (pounds per million Btu)	Mercury Content (pounds per trillion Btu)	CO2 (pounds per million Btu)
Northern Appalachia	PA, OH, MD, WV (North)	Metallurgical	Underground	15.4	28.62	1.10	N/A	204.7
		Mid-Sulfur Bituminous	All	16.3	24.94	1.40	11.17	204.7
		High-Sulfur Bituminous	All	93.2	24.85	2.68	11.67	204.7
		Waste Coal (Gob and Culm)	Surface	3.9	10.70	4.11	63.90	204.7
Central Appalachia	KY (East), WV (South), VA, TN (North)	Metallurgical	Underground	49.2	28.71	0.68	N/A	206.4
		Low-Sulfur Bituminous	All	8.4	24.90	0.51	5.61	206.4
		Mid-Sulfur Bituminous	All	53.2	23.64	1.15	7.58	206.4
Southern Appalachia	AL, TN (South)	Metallurgical	Underground	13.6	28.66	0.49	N/A	204.7
		Low-Sulfur Bituminous	All	0.3	24.81	0.52	3.87	204.7
		Mid-Sulfur Bituminous	All	5.1	24.52	1.26	10.15	204.7
East Interior	IL, IN, KY(West), MS	Mid-Sulfur Bituminous	All	6.7	22.70	1.25	5.60	203.1
		High-Sulfur Bituminous	All	113.1	22.76	2.79	6.35	203.1
		Mid-Sulfur Lignite	Surface	2.6	10.59	0.93	14.11	216.5
West Interior	IA, MO, KS, AR, OK, TX (Bit)	High-Sulfur Bituminous	Surface	0.8	23.50	1.82	21.55	202.8
Gulf Lignite	TX (Lig), LA	Mid-Sulfur Lignite	Surface	31.6	13.60	1.23	14.11	212.6
		High-Sulfur Lignite	Surface	8.5	12.63	1.92	15.28	212.6
Dakota Lignite	ND, MT (Lig)	Mid-Sulfur Lignite	Surface	29.4	13.29	1.28	8.38	219.3
Western Montana	MT (Bit & Sub)	Low-Sulfur Bituminous	Underground	0.4	20.59	0.38	5.06	215.5
		Low-Sulfur Subbituminous	Surface	16.8	18.40	0.38	5.06	215.5
		Mid-Sulfur Subbituminous	Surface	13.3	17.00	0.81	5.47	215.5

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	2014 Production (million short tons)	2014 Heat Content (million Btu per short ton)	Sulfur Content (pounds per million Btu)	Mercury Content (pounds per trillion Btu)	CO2 (pounds per million Btu)
Wyoming, Northern PRB	WY (Northern Powder River Basin	Low-Sulfur Subbituminous	Surface	129.6	16.84	0.37	7.08	214.3
		Mid-Sulfur Subbituminous	Surface	2.3	16.36	0.77	7.55	214.3
Wyoming, Southern PRB	WY (Southern Powder River Basin)	Low-Sulfur Subbituminous	Surface	247.3	17.62	0.28	5.22	214.3
Wyoming	WY (Non-Powder River Basin)	Low-Sulfur Bituminous	Underground	2.9	18.19	0.65	2.9	214.3
		Low-Sulfur Bituminous	Surface	5.1	19.06	0.49	4.06	214.3
		Mid-Sulfur Subbituminous	Surface	5.0	19.29	0.75	4.35	214.3
Rocky Mountain	CO, UT	Metallurgical	Surface	0.0[1]	28.71[1]	0.48[1]	N/A	209.6
		Low-Sulfur Bituminous	Underground	29.2	22.71	0.51	3.82	209.6
		Low-Sulfur Subbituminous	Surface	5.0	20.19	0.50	2.04	212.8
Southwest	AZ, NM	Low-Sulfur Bituminous	Surface	8.2	21.53	0.55	4.66	207.1
		Mid-Sulfur Subbituminous	Surface	13.0	17.76	0.93	7.18	209.2
		Mid-Sulfur Bituminous	Underground	6.2	18.23	0.90	7.18	207.1
Northwest	WA, AK	Low-Sulfur Subbituminous	Surface	0.6	23.44	0.57	6.99	216.1

N/A = not available.
[1] No production in 2014, displayed values from 2013.

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, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008, ANNEX 2 Methodology and Data for Estimating CO2 Emissions from Fossil Fuel Combustion, EPA 430-R-10-006 (Washington, DC, April 2010), Table A-37, https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2008.

Legislation and regulations

The AEO2017 is based on current laws and regulations in effect as of the end of February 2016. The AEO2017 Legislation and Regulations chapter discusses in detail many rulings and environmental regulations that indirectly affect coal use, including the EPA's Clean Power Plan (CPP), which requires states to reduce CO2 emissions from existing power plants. The implementation of this program could significantly impact coal use, but will occur through electricity markets and therefore the modeling and assumptions related to the CPP are discussed in the Electricity chapter of this report. The CMM is capable of modeling compliance with emissions limits established by the Clean Air Act Amendments of 1990 (CAAA90). Specifically, two EPA rules currently impacting coal markets represented in the CMM are the Mercury Air Toxics Standard (MATS) and the Cross-State Air Pollution Rule (CSAPR).

MATS, which was finalized in December 2011, sets emissions limits for mercury, other heavy metals, and acid gases from coal and oil power plants that are 25 MW or greater. Since generators are expected to request one-year extensions for compliance, MATS is assumed to be fully in place by 2016 rather than 2015 as stated in the regulation. Retrofit decisions in the Electric Market Model (EMM) are the primary means of compliance for MATS, but the CMM also includes transportation cost adders for removing mercury using activated carbon injection.

The CSAPR [12.5] rule replaced the prior Clean Air Interstate Rule (CAIR) [12.6] cap-and-trade program at the start of 2015. CSAPR requires fossil fuel-fired electric generating units in 27 states to restrict emissions of sulfur dioxide (SO2) and nitrogen oxide, which are precursors to the formation of fine particulate matter (PM2.5) and ozone. The CMM sets regional limits (constraints) throughout the projection for SO2 based on annual allowance set by EPA under CSAPR. The sulfur content for U.S. coal produced in 2014 is displayed in Table 12.5 along with heat content, mercury content, and average CO2 emissions.

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), contain provisions affecting the cost of mining coal and coal-related research and development. 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 CO2. Subtitle B of EIEA, which extends the payment of current coal excise taxes for the Black Lung Disability Trust Fund program of $1.10 per ton on underground-mined coal and $0.55 per ton on surface-mined coal from 2013 to 2018, is also represented in the AEO2017. Prior to the enactment of EIEA, contribution rates for the Black Lung Disability Trust Fund were to be reduced in 2014 to $0.50 per ton on underground-mined coal and to $0.25 per ton on surface-mined coal. Lignite production is not subject to the Black Lung Disability Trust Fund program's coal excise taxes.

Title IV under ARRA provides $3.4 billion for additional research and development on fossil energy technologies. This funding includes about $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 CO2 for enhanced oil recovery (EOR). The Hydrogen Energy California (HECA) project in Kern County, California and the Texas Clean Energy Project (TCEP) in Penwell, Texas include efforts to use captured carbon dioxide for EOR.

Title XVII of the Energy Policy Act of 2005 (EPACT2005) authorized loan guarantees for projects that avoid, reduce, or sequester greenhouse gasses. EPACT2005 also provided a 20% investment tax credit for Integrated Coal-Gasification Combined Cycle (IGCC) capacity and a 15% investment tax credit for other advanced coal technologies. EIEA allocated an additional $1.25 billion in investment tax credits for IGCC and other advanced, coal-based generation technologies. For the AEO2017, all of the EPACT 2005 and EIEA investment tax credits are assumed to have been fully allocated and, therefore, not available for new, unplanned capacity builds in the NEMS Electricity Market Module.

Beginning in 2009, electricity generating units of 25 MW or greater were required to hold an allowance for each ton of CO2 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 AEO2017 as an emissions reduction program for the Central Atlantic region.

The AEO2017 continues to include a representation of the State of California GHG emissions reduction targets based on the California Assembly Bill (AB32) California Global Warming Solutions Act of 2006 and Senate Bill 32, (SB32) which updated the regulation in 2016 [12.7]. The SB32 bill authorized the California Air Resources Board (CARB) to set the state overall GHG emissions target to 40% below the 1990 level by 2030. The cap-and-trade program features an enforceable cap on GHG emissions that will decline over time. An allowance price, representing the incremental cost of complying with SB32 cap-and-trade, is modeled in the NEMS Electricity Market Module via a region-specific emissions constraint. This allowance price increases the effective delivered price of coal, reducing its ability to compete with other generating sources such as natural gas, which emits less CO2 per unit of electricity produced.

In accordance with California Senate Bill 1368 (SB 1368), which established a greenhouse gas emission performance standard for electricity generation, the AEO2017 prohibits builds of new coal-fired generating capacity without carbon capture and storage (CCS) for satisfying electricity demand in California. SB 1368 limits the generating emissions rate for all power plants that California utilities build, invest in, or sign a long-term contract with to be no more than 1,100 pounds of CO2 per megawatt-hour, which is the approximate emissions rate for a new natural gas combined-cycle power plant [12.8]. The methodology to represent SB 1368 includes the modeling of the expiration of contracts for imported coal-fired generation from the Four Corners, Navajo, Reid Gardner, San Juan, and Boardman plants and the retirement of the Intermountain plant in 2025.

Notes and sources

[12.1] Flynn, Edward J., “Impact of Technological Change and Productivity on The Coal Market,” U.S. Energy Information Administration (Washington, DC, October 2000), http://www.eia.gov/oiaf/analysispaper/pdf/coal.pdf; and U.S. Energy Information Administration, The U.S. Coal Industry, 1970-1990: Two Decades of Change, DOE/EIA-0559 (Washington, DC, November 1992).

[12.2] Powder River Basin Coal Resource and Cost Study. Report. No. 3155.001. John T. Boyd Company, (Denver Colorado, September 2011). https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PSCo-ERP-2011/8-Roberts-Exhibit-No-MWR-1.pdf .

[12.3] 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 Schwartz, Seth, 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).

[12.4] U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2008, Annex 2 Methodology and Data for Estimating CO2 Emissions from Fossil Fuel Combustion, EPA 430-R-10-006 (Washington, DC, April 2010), Table A-37, https://www3.epa.gov/climatechange/Downloads/ghgemissions/508_Complete_GHG_1990_2008.pdf {*EPA web link inactive as of February 2017*}.

[12.5] U .S. Environmental Protection Agency, “Cross-State Air Pollution Rule (CSAPR)” (Washington, DC: September 7, 2016), https://www.epa.gov/csapr/cross-state-air-pollution-rule-csapr-basics

[12.6] U .S. Environmental Protection Agency, “Clean Air Interstate Rule (CAIR)” (Washington, DC: February 21, 2016), https://archive.epa.gov/airmarkets/programs/cair/web/html/index.html

[12.7] SB-32 California Global Warming Solutions Act of 2006: emissions limit. (State of California, September 08, 2016). https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB32

[12.8] California Energy Commission, SB 1368 Emission Performance Standards, http://www.energy.ca.gov/emission_standards/index.html.