# Coal Market Module

The National Energy Modeling System's (NEMS) Coal Market Module (CMM) provides projections of U.S. coal production, consumption, exports, imports, distribution, and prices. The CMM consists of three functional areas: coal production, coal distribution, and coal exports. You can find a detailed description of the CMM in the U.S. Energy Information Administration (EIA) publication, *Coal Market Module of the National Energy Modeling System: Model Documentation 2020*, DOE/EIA-M060 (2020) (Washington, DC).

## Key assumptions

### *Coal production*

The CMM generates different supply curves for each year of the projection period. Combinations of 14 supply regions, nine coal types (unique groupings of thermal grade and sulfur content), and two mine types (underground and surface) result in 41 different supply curves. EIA constructs supply curves by using an econometric formulation that relates the minemouth prices of coal for each supply curve to a set of independent variables. The independent variables include capacity utilization of mines, mining capacity, labor productivity, the capital cost of mining equipment, the cost of factor inputs (labor and fuel), and other mine supply costs.

Key assumptions underlying the coal production modeling:

- As capacity utilization increases, AEO2021 projects higher minemouth prices for a given supply curve. The modeling framework allows opportunity to add production capacity if capacity utilization rises to a predetermined 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 on historical patterns of capacity additions.
- The annual wage for U.S. coal miners averaged $91,836 in 2019.[1] EIA's *Annual Energy Outlook 2021* (AEO2021) assumes miner wages remain flat in real terms (that is, increase at the general rate of inflation) at the 2019 wage level. AEO2021 also assumes mine equipment costs remain constant at the 2019 level during the projection period. The equipment index is built from the U.S. Bureau of Labor Statistics series for *Mining machinery and equipment* for underground mining and *Construction machinery* for surface mining.[2]
- The CMM assumes different rates of labor productivity improvement or decline for each of the 41 coal supply curves used to represent U.S. coal supply. Table 1 shows AEO2021 Reference case projections for regional coal mining productivity. Overall U.S. coal mining labor productivity declines at a rate of 2.0% per year between 2019 and 2050 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. Individual coal mines and preparation plants provide historical data on labor productivity on a quarterly and annual basis on the U.S. Department of Labor, Mine Safety and Health Administration, 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 6.7% per year, from 1.93 short tons per miner-hour to 7.02 short tons per miner-hour. The major factors underlying these gains were inter-fuel price competition, structural change in the industry, and technological improvements in coal mining.[3] Between 2000 and 2019, overall U.S. coal mining productivity year-over-year change has been negative in all CMM supply regions (except Eastern Interior) and has declined nationally at a rate of 0.9% per year to 5.89 short tons per miner-hour in 2019.
- Mine closures can sometimes result in small gains in regional productivity because the least productive mines are often those that suspend operation. On the other hand, highly productive mining operations can appear less productive when existing mine capacity is not fully utilized, as has been the case in recent years. In 2019, 5 out of 14 coal supply regions showed productivity increases from 2018 levels, while the other 9 regions showed declining productivity. Similarly, the 2019 national average coal mining labor productivity rate of 5.89 short tons per miner-hour reflected a 14% increase from the 2012 productivity rate of 5.19 tons per miner-hour, which was the lowest observed rate in more than 20 years.
- Productivity in some areas of the coal fields 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 more than 50% between 2000 and 2019, corresponding to an average decline of 4.3% per year. Regulatory restrictions on surface mines and fragmentation of underground reserves limit the benefits that Appalachian producers can achieve from economies of scale. In 2019, Central Appalachia productivity declined to 1.81 short tons per miner-hour. Furthermore, the Central Appalachia region is projected to have the greatest regional decline in productivity at 2.8% per year from 2019 to 2050.
- Although declines have been more moderate at the highly productive mines in Wyoming's Southern Powder River Basin (PRB), coal mining productivity in this region still fell by 40% between 2000 and 2019, corresponding to an average rate of decline of 2.6% per year. For AEO2017 onward, EIA modified productivity figures for the PRB production areas based on an assessment of recent private-sector analyses.[4] In AEO2021, productivity from 2019 to 2050 in Southern PRB is projected to decline at an average rate of 0.4% per year.
- The Eastern Interior has shown the most productivity growth; coal mining productivity grew by 4% between 2000 and 2019, or 0.2% 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, and several coal companies are operating highly productive longwall mines. Productivity is expected to increase modestly at a rate of 0.3% per year from 2019 to 2050.

**Table 1. Coal mining productivity by region**
short tons per miner-hour

| Supply region | 2019 | 2020 | 2025 | 2030 | 2040 | 2050 | Average annual growth 2019–2050 |
|---|---|---|---|---|---|---|---|
| Northern Appalachia | 4.06 | 3.71 | 3.46 | 3.15 | 2.49 | 2.28 | -1.8% |
| Central Appalachia | 1.81 | 1.66 | 1.42 | 1.21 | 0.94 | 0.75 | -2.8% |
| Southern Appalachia | 1.96 | 1.94 | 1.77 | 1.62 | 1.42 | 1.25 | -1.4% |
| Eastern Interior | 4.89 | 4.90 | 4.96 | 5.06 | 5.22 | 5.32 | 0.3% |
| Western Interior | 2.80 | 2.77 | 2.61 | 2.46 | 2.32 | 2.21 | -0.8% |
| Gulf Lignite | 6.45 | 6.39 | 6.07 | 5.78 | 5.37 | 5.00 | -0.8% |
| Dakota Lignite | 11.16 | 11.05 | 10.51 | 9.99 | 9.29 | 8.66 | -0.8% |
| Western Montana | 13.51 | 12.88 | 12.11 | 11.34 | 10.24 | 9.39 | -1.2% |
| Wyoming, Northern Powder River Basin | 28.10 | 27.94 | 27.11 | 26.30 | 24.77 | 23.32 | -0.6% |
| Wyoming, Southern Powder River Basin | 28.17 | 28.06 | 27.50 | 26.95 | 25.89 | 24.88 | -0.4% |
| Western Wyoming | 6.80 | 6.69 | 6.02 | 5.73 | 5.37 | 5.06 | -0.9% |
| Rocky Mountain | 5.12 | 5.09 | 4.38 | 3.62 | 3.05 | 2.60 | -2.2% |
| Arizona/New Mexico | 7.64 | 7.55 | 7.06 | 6.67 | 5.87 | 5.47 | -1.1% |
| Alaska/Washington | 5.14 | 5.16 | 5.26 | 5.37 | 5.48 | 5.60 | 0.3% |
| U.S. average | 5.89 | 6.11 | 5.14 | 4.88 | 3.83 | 3.19 | -2.0% |

Source: U.S. Energy Information Administration, AEO2021, National Energy Modeling System run REF2021.D113020A

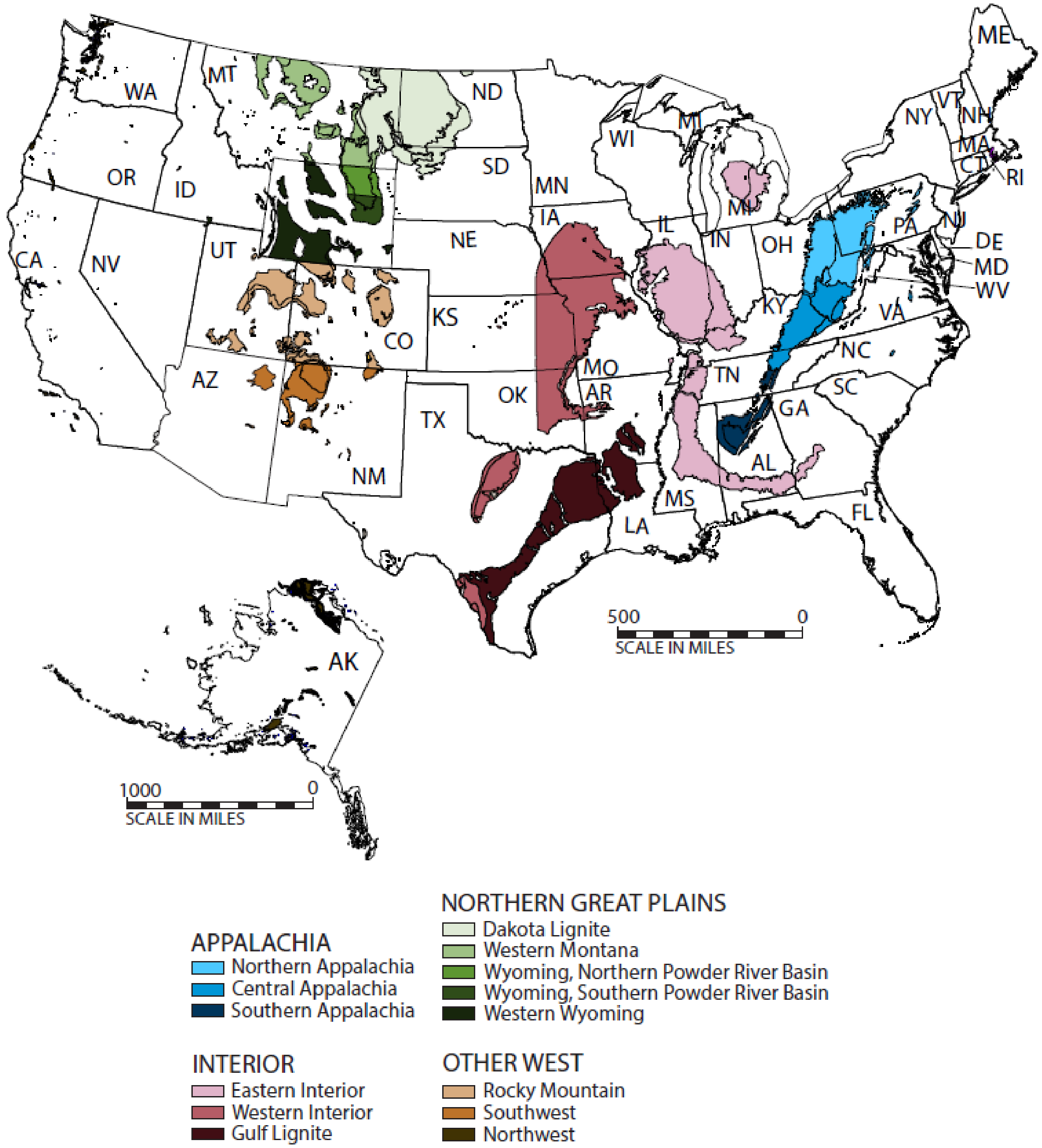
## *Coal distribution*

The domestic coal distribution submodule of the CMM determines the least-cost (minemouth price plus transportation cost) solution for coal transportation by supply region for a given set of coal demands in each demand sector by using a linear programming algorithm. Production and distribution are computed for 14 supply regions (Figure 1) and 16 demand regions (Figure 2) for 49 demand subsectors.

The Liquid Fuels Market Module (LFMM) provides projected levels of coal-to-liquids (CTL), the industrial module provides projected levels of industrial steam and coking, and the commercial demand module provides projected levels of commercial/institutional coal demand. The Electricity Market Module (EMM) projects electricity coal demands. Coal imports and coal exports are projected by the international coal distribution submodule of 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.

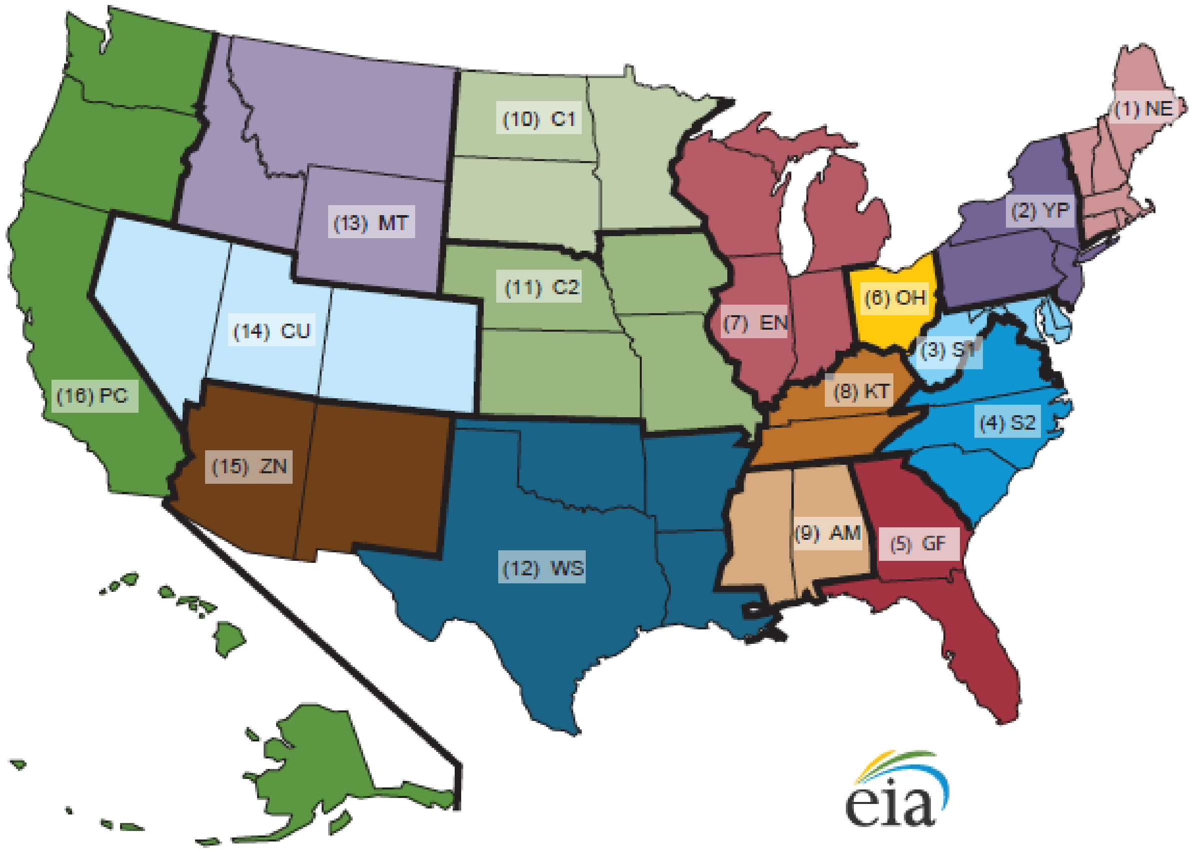
Transportation rates between coal supply and demand regions are determined by applying an annual projected national transportation price index to a two-tier rate structure. The first tier represents the historical average transportation rate that is estimated for a base year using recent EIA survey data. The second tier captures costs associated with changing patterns of coal demand for electricity generation. EIA updated its approach to coal transportation rate escalation for AEO2021 based on its assessment of the current methodology and independent contractor recommendations.[5]

## Figure 1. Coal supply regions




Source: U.S. Energy Information Administration

## Figure 2. Coal demand regions




| Region | Code | Content | Region | Code | Content |
|---|---|---|---|---|---|
| 1 | NE | CT, MA, ME, NH, RI, VT | 9 | AM | AL, MS |
| 2 | YP | NY, PA, NJ | 10 | C1 | MN, ND, SD |
| 3 | S1 | WV, MD, DC, DE | 11 | C2 | IA, NE, MO,KS |
| 4 | S2 | VA, NC, SC | 12 | WS | TX, LA, OK, AR |
| 5 | GF | GA, FL | 13 | MT | MT, WY, ID |
| 6 | OH | OH | 14 | CU | CO, UT, NV |
| 7 | EN | IN, IL, MI, WI | 15 | ZN | AZ, NM |
| 8 | KT | KY, TN | 16 | PC | AK, HI, WA, OR, CA |

Source: U.S. Energy Information Administration

Key assumptions underlying the coal distribution modeling

- EIA calculates base-year domestic coal transportation rates as the average transportation costs for each supply origin-to-demand destination pair without differentiation by transportation mode (rail, truck, barge, and conveyor). These rates are computed (by sector and for export) as the difference between the average delivered price for a coal demand region (Figure 2) and either the reported commodity price or the average minemouth price for each available coal supply curve. These rates are defined by region, coal rank, and mine type (Table 6). EIA derives delivered prices from survey Form EIA-3, *Quarterly Survey of Industrial, Commercial & Institutional Coal Users*; Form EIA-923, *Power Plant Operations Report*; and the U.S. Census Bureau, *Monthly Report EM-545*. EIA derives minemouth prices from survey Form EIA-7A, *Annual Survey of Coal Production and Preparation*. The base-year coal transportation rates in the CMM were updated for AEO2021 based on 2015 to 2018 data for paths that have been active in recent years. As a result of the transportation rate update, some paths used historically are now inactive because either regional coal demand has disappeared, coal mines have shuttered, or coal trade along the path has become uneconomical.
- For the electricity sector, EIA applies a two-tier transportation rate structure to those regions that, in response to changing patterns of coal demand, may expand their market shares beyond historical levels. The first-tier rate represents the historical average transportation rate. The second-tier transportation rate captures the higher cost of expanded shipping distances in large demand regions. The second tier also captures costs associated with using subbituminous coal at units that were not originally designed for that use. This cost is estimated at $0.10 per million British thermal units (Btu) (2000$).[6]

**Table 2. Coal transportation rate multipliers**

constant dollar index, 2019=1.0000

| Case | 2019 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 |
|---|---|---|---|---|---|---|---|---|
| Reference | 1.0000 | 0.9608 | 1.0024 | 0.9668 | 0.9664 | 0.9716 | 0.9739 | 0.9732 |
| Low Oil Price | 1.0000 | 0.9608 | 0.9733 | 0.9268 | 0.9255 | 0.9286 | 0.9268 | 0.9289 |
| High Oil Price | 1.0000 | 0.9608 | 1.0536 | 1.0197 | 1.0243 | 1.0306 | 1.0343 | 1.0394 |
| Low Economic Growth | 1.0000 | 0.9612 | 0.9959 | 0.9661 | 0.9568 | 0.9437 | 0.9226 | 0.8961 |
| High Economic Growth | 1.0000 | 0.9636 | 1.0202 | 0.9849 | 0.9938 | 1.0079 | 1.0254 | 1.0359 |
| Low Oil & Gas Supply | 1.0000 | 0.9608 | 1.0105 | 0.9796 | 0.9859 | 0.9948 | 0.9989 | 0.9983 |
| High Oil & Gas Supply | 1.0000 | 0.9608 | 0.9897 | 0.9469 | 0.9479 | 0.9523 | 0.9562 | 0.9536 |
| Low Renewable Cost | 1.0000 | 0.9608 | 1.0007 | 0.9650 | 0.9649 | 0.9685 | 0.9676 | 0.9589 |
| High Renewable Cost | 1.0000 | 0.9608 | 1.0007 | 0.9674 | 0.9681 | 0.9737 | 0.9789 | 0.9816 |

Source: U.S. Energy Information Administration, AEO2021, National Energy Modeling System runs REF2021.D113020A, LowPrice D113020A, HighPrice D113020A, LowMacro D113020A, HighMacro D113020A, LowOGS D113020A. HighOGS D113020A, LowRenCst D113020A, HighRenCst D113020A

- The CMM adjusts the base-year coal transportation rates, both first and second tier, over time by applying an annual projected national coal transportation rate index. The index measures the change in average transportation rates for coal shipments on a tonnage basis by applying a rail cost adjustment factor (RCAF) approach following the cost breakouts in the Surface Transportation Board's (STB) All-Inclusive Index (STB_A-II), with an additional adjustment for railroad productivity improvements. Table 2 shows the coal transportation rate escalation cumulative multipliers in selected years for each of the AEO2021 side cases.

- The CMM applies relevant price or interest rate indexes available within the NEMS modeling framework to each RCAF cost share included in the STB_A-II. The STB updates the STB_A-II cost component shares annually to reflect data for the latest year for which historical data are available (2019 for AEO2021). The CMM normalizes the NEMS indexes used in the RCAF approach to the year corresponding to the latest shares in the STB_A-II. Under this approach, the CMM applies the 2019 shares to the rate of change from 2019 to 2020 of the corresponding indexes from NEMS to create the weighted-average escalation factor for 2020. The RCAF share weights are then adjusted to reflect their contribution to the escalation factor in 2020 and are used to create the escalation factor for 2021, and so on for each projection year. Table 3 shows the individual cost components, the STB_A-II shares as of 2019, and which NEMS indexes are used to project each cost component. These escalation factors will next be adjusted to account for railroad productivity improvements being shared with coal shippers.

### Table 3. Rail cost adjustment factor (RCAF) shares and escalator basis

| RCAF variable | 2019 share | AAR short term escalator basis | NEMS macroeconomic indexes and prices |
|---|---|---|---|
| Labor | 32.6% | Sector analysis of subcomponents for rail sector | Employment cost index-private wages and salaries adjusted to remove inflation and convert base year (2019=1.00) |
| Fuel | 14.2% | Ultra-Low Sulfur Diesel Fuel referenced, but otherwise, based on a survey of rail purchasers and petroleum experts | Transportation sector diesel fuel price in 1987$/MMBtu indexed to base year (2019=1.00) |
| Materials and supplies | 4.9% | References change in prices for Metal Products and Misc. Products | Index for railroad materials and supplies based on producer price Index of metals and metal products (2019=1.00) |
| Equipment rentals | 5.2% | Price index for Industrial Commodities less Fuel and Related Products and Power (PPI-LF) | Index for equipment rentals based on producer price index of industrial commodities excluding energy (2019=1.00) |
| Depreciation | 15.9% | Producer Price Index for Railroad Equipment (PPI-RE) | Index for depreciation based on railroad equipment from the producer price index of transportation equipment (2019=1.00) |
| Interest | 2.5% | Interest rates for 10- and 30-year U.S. Treasury Bonds are referenced, but the latest historical value based on annual reports from railroads is carried forward | Index for borrowed debt by the railroads based on real AA utility bond rates (2019=1.00) |
| Other | 24.7% | Price index for Industrial Commodities less Fuel and Related Products and Power (PPI-LF) | Index for other costs based on producer price index of industrial commodities excluding energy (1982=1.00) |

Sources: Association of American Railroads (AAR), Rail Cost Indexes, RCAF Quarterly Filings & Decisions, STB RCAF 2020Q4 Decision 9-18-2020, Docket No. EP 290 (Sub-No. 5) (2020-4); U.S. Energy Information Administration, National Energy Modeling System (NEMS)

- EIA assumes that railroad productivity will improve by 1.4% per year, but these improvements will not always be reflected in the rates the railroads charge to shippers. This assumption is based on an independent contractor analysis described in the EIA assessment of its coal transportation rate methodology. If total U.S. annual coal production on a three-year moving average basis is in decline, railroad companies are assumed to share a portion of the rail productivity improvements with shippers to help maintain the competitiveness of coal. If coal production decreases by more than 5% from one year to the next, rail companies are assumed to share half of their productivity improvement, or 0.7%, with rail shippers, which is applied to the computed escalation factor using the RCAF methodology. For example, if the RCAF is projected to increase by 1.0% from one model year to the next, but coal production is set to decline by more than 5%, coal transportation rates would increase by only 0.3% overall. The extent to which shippers share in rail productivity improvements when coal production declines by less than 5% decreases to zero exponentially from 5% as the fall in coal production approaches zero. Railroads are not assumed to share rail productivity improvements if coal production is either flat or increasing from one year to the next.
- 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 before considering any alternative sources of supply. Base-year (2018) coal contracts between coal producers and electricity generators are estimated based on 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 based on contract duration data from information reported on the Form EIA-923, historical patterns of coal use, and information obtained from various coal and electric power industry publications and reports.
- CTL facilities are assumed to be economical when low-sulfur distillate prices reach high enough levels. These plants are assumed to be co-production facilities with a generation capacity of 832 megawatts (MW) (295 MW for the grid and 537 MW to support the conversion process) and to be able to produce 48,000 barrels per day of liquid fuels. The technology assumed is similar to an integrated gasification combined cycle: first, the coal feedstock is converted into synthesis gas and then the syngas is converted into 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, and the remaining energy is used for the conversion and production of power sold to the grid. For AEO2021, coal-biomass-to-liquids are not modeled. CTL facilities produce distillate fuel oil (about 72% of their output) as well as paraffinic naphtha used in plastics production and blendable naphtha used in motor gasoline (together about 28% of the total by volume).

### *Coal imports and exports*

Coal imports and exports are modeled as part of the CMM's linear program that provides an annual projection 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 two 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 predetermined set of regional coal import demands, subject to constraints on export capacity and trade flows.

Key assumptions underlying coal export modeling:

- Coal buyers (importing regions) tend to spread their purchases among several suppliers to reduce the impact of potential supply disruptions, even though this choice may add to their purchase costs. Similarly, producers choose not to rely on any one buyer and instead try 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 only modestly affect world coking coal flows.
    - U.S. coal exports for 2020 to 2021 are benchmarked to match export levels projected in EIA's *Short-Term Energy Outlook .* Exports through 2050 are consistent with international coal trade assumed in EIA's *International Energy Outlook 2020* (IEO2020).

Data inputs for coal trade modeling

- World import demand for steam coal (Table 3) and metallurgical coal (Table 4) for the AEO2021 cases are input from previous analysis or projections. U.S. coal exports are determined, in part, by these estimates of world coal import demand. The assumed levels of international trade demand for AEO2021 are based on the long-term projections made in IEO2020.
- Step-function coal export supply curves for all non-U.S. supply regions are reviewed and updated when preparing the IEO projections. The curves provide estimates of export prices per metric ton, including minemouth and inland freight costs, as well as the capacities for each of the supply steps.
- Ocean transportation rates (in dollars per metric ton) are calculated for feasible coal shipment paths (routes) between international supply regions and international demand regions. An algorithm derives the rates based on input parameters for the following:
    - Transport route distance in nautical miles between each international supply and demand region pair
    - Typical ship capacity (in lading tons) and vessel class (Panamax versus Cape size) for dry bulk transport on each route
    - Annual daily hire rate by vessel class
    - Sailing speed, days in port, port costs, fuel consumption in port, and fuel consumption at sea by vessel class
    - Annual regional fuel prices used in dry bulk transport: bunker fuel/IFO380 (intermediate fuel oil with maximum viscosity of 380 centistokes, composed of about 90% residual oil and 10% distillate oil) and MGO (marine gasoil, a 100% distillate based fuel) on U.S. Gulf Coast fuel prices and price differentials to each supply region.

## Table 4. World steam coal import demand by import region[1]

million metric tons of coal equivalent

| | 2019 | 2020 | 2025 | 2030 | 2035 | 2040 | 2050 |
|---|---|---|---|---|---|---|---|
| **The Americas** | **36.4** | **29.7** | **32.9** | **34.4** | **36.1** | **37.9** | **41.0** |
| United States[2] | 4.2 | 2.4 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 |
| Canada | 2.7 | 1.9 | 2.0 | 2.0 | 1.9 | 1.9 | 1.8 |
| Mexico | 6.9 | 5.6 | 8.0 | 8.0 | 8.0 | 8.0 | 8.3 |
| South America | 22.6 | 19.8 | 22.8 | 24.4 | 26.1 | 27.9 | 30.8 |
| **Europe** | **112.3** | **92.4** | **87.7** | **82.6** | **82.1** | **81.6** | **82.4** |
| Scandinavia | 3.7 | 2.3 | 1.3 | 1.2 | 1.2 | 1.1 | 1.1 |
| United Kingdom/Ireland | 2.6 | 1.6 | 0.9 | 0.9 | 0.8 | 0.8 | 0.8 |
| Germany/Austria/Poland | 23.1 | 17.9 | 14.0 | 13.3 | 12.6 | 12.0 | 11.8 |
| Other northwestern Europe | 16.5 | 12.2 | 10.9 | 10.6 | 10.2 | 9.9 | 9.3 |
| Iberia | 7.8 | 5.1 | 4.5 | 4.4 | 4.3 | 4.2 | 3.9 |
| Italy | 6.3 | 5.6 | 5.3 | 5.0 | 4.8 | 4.5 | 4.5 |
| Mediterranean/eastern Europe | 52.4 | 47.7 | 50.8 | 47.2 | 48.2 | 49.1 | 51.1 |
| **Asia** | **636.4** | **610.1** | **667.0** | **705.4** | **795.8** | **837.7** | **977.8** |
| Japan | 93.4 | 88.1 | 91.0 | 100.0 | 108.5 | 87.8 | 66.9 |
| East Asia | 133.5 | 121.5 | 130.0 | 101.6 | 112.8 | 118.0 | 138.7 |
| China/Hong Kong | 123.7 | 116.9 | 110.0 | 107.8 | 105.6 | 103.5 | 99.4 |
| ASEAN[3] | 117.1 | 131.0 | 150.0 | 163.5 | 178.2 | 194.3 | 230.8 |
| Indian subcontinent | 168.7 | 152.6 | 186.0 | 232.5 | 290.6 | 334.2 | 442.0 |
| **TOTAL** | **785.2** | **732.2** | **787.6** | **822.5** | **914.0** | **957.2** | **1,101.2** |

[1]Import regions: United States: East Coast, Gulf Coast, Northern Interior, Noncontiguous; Canada: Eastern, Interior; South America: Argentina, Brazil, Chile, Puerto Rico; Scandinavia: Denmark, Finland, Norway, Sweden; Other northwestern Europe: Belgium, France, Luxembourg, Netherlands; Iberia: Portugal, Spain; Mediterranean and Eastern 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 subcontinent: Bangladesh, India, Iran, Pakistan, Sri Lanka.

[2]Excludes imports to Puerto Rico and the U.S. Virgin Islands.

[3]ASEAN=Association of Southeast Asian Nations. Malaysia, Philippines, Thailand, and Vietnam are not expected to import significant amounts of metallurgical coal during the projection period.

Source: U.S. Energy Information Administration, National Energy Modeling System run Ref2021.D113020A

Notes: One metric ton of coal equivalent equals 27.78 million British thermal units. Totals may not equal sum of components because of independent rounding.

**Table 5. World metallurgical coal import demand by import region[1]**
million metric tons of coal equivalent

| | 2019 | 2020 | 2025 | 2030 | 2035 | 2040 | 2050 |
|---|---|---|---|---|---|---|---|
| **The Americas** | **18.8** | **16.4** | **22.1** | **23.3** | **24.5** | **25.9** | **28.8** |
| United States[2] | 0.7 | 0.9 | 1.1 | 1.0 | 1.0 | 1.0 | 0.9 |
| Canada | 4.0 | 3.2 | 3.7 | 3.7 | 3.8 | 3.8 | 3.9 |
| Mexico | 0.4 | 0.4 | 1.0 | 1.0 | 1.0 | 1.1 | 1.1 |
| South America | 13.6 | 11.9 | 16.4 | 17.5 | 18.7 | 20.0 | 22.9 |
| **Europe** | **47.1** | **36.5** | **45.5** | **45.0** | **44.5** | **44.1** | **43.2** |
| Scandinavia | 3.0 | 2.2 | 2.3 | 2.2 | 2.2 | 2.1 | 2.0 |
| United Kingdom/Ireland | 2.3 | 1.8 | 2.2 | 2.2 | 2.2 | 2.2 | 2.2 |
| Germany/Austria/Poland | 6.4 | 4.5 | 5.2 | 5.2 | 5.2 | 5.2 | 5.2 |
| Other northwestern Europe | 17.5 | 12.9 | 16.0 | 15.7 | 15.4 | 15.1 | 14.5 |
| Iberia | 0.9 | 0.7 | 1.0 | 1.0 | 1.0 | 0.9 | 0.9 |
| Italy | 2.9 | 2.5 | 2.8 | 2.8 | 2.7 | 2.6 | 2.5 |
| Mediterranean/eastern Europe | 14.1 | 11.8 | 16.0 | 16.0 | 16.0 | 16.0 | 16.0 |
| **Asia** | **238.2** | **222.6** | **263.0** | **280.5** | **296.9** | **314.8** | **362.1** |
| Japan | 68.2 | 63.8 | 69.0 | 70.4 | 67.6 | 64.9 | 59.8 |
| East Asia | 45.3 | 41.0 | 48.0 | 49.0 | 49.9 | 50.9 | 53.0 |
| China/Hong Kong | 52.9 | 52.7 | 51.0 | 50.5 | 50.0 | 49.5 | 48.5 |
| ASEAN[3] | 14.7 | 16.3 | 22.0 | 23.1 | 24.3 | 25.5 | 28.1 |
| Indian subcontinent | 57.1 | 48.9 | 73.0 | 87.6 | 105.1 | 124.0 | 172.7 |
| **TOTAL** | **304.1** | **275.5** | **330.6** | **348.8** | **366.0** | **384.8** | **434.1** |

[1]Import regions: United States: East Coast, Gulf Coast, Northern Interior, Noncontiguous; Canada: Eastern, Interior; South America: Argentina, Brazil, Chile, Puerto Rico; Scandinavia: Denmark, Finland, Norway, Sweden; Other northwestern Europe: Belgium, France, Luxembourg, Netherlands; Iberia: Portugal, Spain; Mediterranean and Eastern 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 subcontinent: Bangladesh, India, Iran, Pakistan, Sri Lanka.
[2]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[3]ASEAN=Association of Southeast Asian Nations. Malaysia, Philippines, Thailand, and Vietnam are not expected to import significant amounts of metallurgical coal during the projection period.

Source: U.S. Energy Information Administration, National Energy Modeling System run Ref2021.D113020A

Notes: One metric ton of coal equivalent equals 27.78 million British thermal units. Totals may not equal sum of components because of independent rounding.

## *Coal quality*

Each AEO cycle, EIA calibrates the base-year coal production for each defined coal source to survey data. In addition, the average values for heat content (million Btu per ton), sulfur content (pounds per million Btu), mercury content (pounds per trillion Btu), and carbon dioxide (CO2) emissions when burned (pounds per million Btu) are calculated to reflect the coal quality of each modeled coal source. Surveys used for this purpose are Form EIA-923, which collects the quantity, origin point, cost, and quality of fossil fuels delivered to generating facilities, and Form EIA-3, which collects the quantity, origin point, cost, and quality of coal delivered to U.S. commercial and institutional users and domestic coke plants.

Coal quality for the export sector is based on data collected on Form EIA-7A for domestic production and is matched to export shipments collected by the U.S. Census Bureau on its *Monthly Report EM-545*. Mercury content data for coal by supply region and coal type, in units of pounds of mercury per trillion Btu, are 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 EPA, are shown in Table 6 in pounds of CO2 emitted per million Btu.[7]

### Table 6. Production, heat content, sulfur, mercury, and carbon dioxide (CO2) emission factors by coal region, rank, and mine type

| Coal supply region | States | Coal rank and sulfur level | Mine type | 2019 production (million short tons) | 2019 heat content (million British thermal units per short ton) | 2019 sulfur content (pounds per million British thermal units) | Mercury content (pounds per trillion British thermal units) | CO2 (pounds per million British thermal units) |
|---|---|---|---|---|---|---|---|---|
| Northern Appalachia | Pennsylvania, Ohio, Maryland, and West Virginia (North) | Metallurgical | Underground | 17.6 | 28.70 | 0.64 | N/A | 204.7 |
| | | Mid-sulfur bituminous | All | 17.2 | 24.42 | 1.33 | 11.47 | 204.7 |
| | | High-sulfur bituminous | All | 69.1 | 25.41 | 2.56 | 12.05 | 204.7 |
| | | Waste coal (gob and culm) | All | 9.3 | 13.51 | 3.50 | 34.16 | 204.7 |
| Central Appalachia | Kentucky (East), West Virginia (South), Virginia, and Tennessee (North) | Metallurgical | Underground | 41.3 | 28.70 | 0.41 | N/A | 206.4 |
| | | Low-sulfur bituminous | All | 12.2 | 25.49 | 0.54 | 5.42 | 206.4 |
| | | Mid-sulfur bituminous | All | 15.8 | 24.46 | 0.94 | 9.46 | 206.4 |
| Southern Appalachia | Alabama and Tennessee (South) | Metallurgical | Underground | 14.0 | 28.69 | 0.49 | N/A | 204.7 |
| | | Low-sulfur bituminous | All | 0.5 | 25.79 | 0.71 | 3.87 | 204.7 |
| | | Mid-sulfur bituminous | All | 1.7 | 23.84 | 1.20 | 10.08 | 204.7 |
| East Interior | Illinois, Indiana, Kentucky (West), and Mississippi | Mid-sulfur bituminous | All | 22.0 | 22.46 | 1.85 | 6.88 | 203.1 |
| | | High-sulfur bituminous | All | 72.2 | 23.04 | 2.51 | 7.54 | 203.1 |
| | | Mid-sulfur lignite | Surface | 2.6 | 10.57 | 0.94 | 25.30 | 216.5 |
| West Interior | Iowa, Missouri, Kansas, Arkansas, Oklahoma, and Texas | High-sulfur bituminous | Surface | 0.5 | 22.74 | 1.23 | 10.64 | 202.8 |
| Gulf Lignite | Texas and Louisiana | Mid-sulfur lignite | Surface | 18.2 | 13.34 | 1.16 | 14.06 | 212.6 |
| | | High-sulfur lignite | Surface | 5.4 | 11.60 | 3.45 | 15.28 | 212.6 |
| Dakota Lignite | North Dakota and Montana | Mid-sulfur lignite | Surface | 27.5 | 13.77 | 1.33 | 7.82 | 219.3 |
| Western Montana | Montana | Low-sulfur bituminous | Underground | 3.8 | 18.30 | 0.44 | 2.43 | 215.5 |

## Table 6. Production, heat content, sulfur, mercury, and carbon dioxide (CO2) emission factors by coal region, rank, and mine type (cont.)

| Coal supply region | States | Coal rank and sulfur level | Mine type | 2019 production (million short tons) | 2019 heat content (million British thermal units per short ton) | 2019 sulfur content (pounds per million British thermal units) | Mercury content (pounds per trillion British thermal units) | CO2 (pounds per million British thermal units) |
|---|---|---|---|---|---|---|---|---|
| Western Montana (cont.) | Montana | Low-sulfur subbituminous | Surface | 14.2 | 18.37 | 0.37 | 6.19 | 215.5 |
| | | Mid-sulfur subbituminous | Surface | 10.9 | 16.85 | 0.80 | 4.04 | 215.5 |
| Wyoming, Northern PRB | Wyoming (Northern Powder River Basin) | Low-sulfur subbituminous | Surface | 86.5 | 16.82 | 0.37 | 7.78 | 214.3 |
| | | Mid-sulfur subbituminous | Surface | 4.9 | 16.25 | 0.65 | 7.42 | 214.3 |
| Wyoming, Southern PRB | Wyoming (Southern Powder River Basin) | Low-sulfur subbituminous | Surface | 174.0 | 17.66 | 0.27 | 6.90 | 214.3 |
| Wyoming | Wyoming (non-Powder River Basin) | Low-sulfur bituminous | Underground | 2.3 | 18.73 | 0.64 | 2.19 | 214.3 |
| | | Low-sulfur bituminous | Surface | 3.9 | 19.29 | 0.52 | 1.90 | 214.3 |
| | | Mid-sulfur subbituminous | Surface | 3.7 | 19.25 | 0.67 | 4.35 | 214.3 |
| Rocky Mountain | Colorado and Utah | Metallurgical | Surface | 0.1 | 28.69 | 0.43 | N/A | 209.6 |
| | | Low-sulfur bituminous | Underground | 20.5 | 22.48 | 0.45 | 2.77 | 209.6 |
| | | Low-sulfur subbituminous | Surface | 4.3 | 20.37 | 0.48 | 2.04 | 212.8 |
| Southwest | Arizona and New Mexico | Low-sulfur bituminous | Surface | 4.0 | 21.40 | 0.48 | 6.00 | 207.1 |
| | | Mid-sulfur subbituminous | Surface | 10.2 | 18.25 | 1.06 | 14.07 | 209.2 |
| | | Mid-sulfur bituminous | Underground | 3.1 | 19.19 | 0.91 | 7.18 | 207.1 |
| Northwest | Washington and Alaska | Low-sulfur subbituminous | Surface | 0.8 | 14.78 | 0.21 | 5.42 | 216.1 |

N/A = not available

[1] No production of this coal type in this region after 2013. Displayed values are from 2013.

Sources: U.S. Energy Information Administration, Form EIA-3, *Quarterly Survey of Industrial, Commercial & Institutional Coal Users*; Form EIA-7A, *Annual Survey of Coal Production and Preparation*; and Form EIA-923, *Power Plant Operations Report*. U.S. Department of Commerce, U.S. Census Bureau, *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: 1990-2009 ANNEX 2 Methodology and Data for Estimating CO2 Emissions from Fossil Fuel Combustion, EPA 430-R-10-006 (Washington, DC, April 2011), Table A-37.

## Legislation and regulations

AEO2021 is based on current laws and regulations in effect as of September 30, 2020. Nearly all of the legislation and regulations that apply to coal-fired electric generating units are implemented in the EMM, although the CMM is used to model certain aspects of the Clean Air Act Amendments of 1990 (CAAA90) emissions limits in certain instances, including the following:

- Mercury and Air Toxics Standards (MATS) finalized in December 2011
- Retrofit decisions in the EMM are the primary means of compliance for MATS, but the CMM also includes transportation cost adders for removing mercury using activated carbon injection.
- Cross-State Air Pollution Rule (CSAPR)[8] finalized in 2015
- The CMM sets regional limits (constraints) throughout the projection period for sulfur dioxide (SO2) based on annual allowance set by EPA under CSAPR. The sulfur content for U.S. coal produced in 2019 is displayed in Table 6 along with heat content, mercury content, and average CO2 emissions.

A full discussion of the legislation and regulations affecting the use of coal generators and the assumptions used to model their effects is provided in the EMM Assumptions document.

## Notes and sources

[1] Quarterly Census of Employment and Wages - Bureau of Labor Statistics, Series: "Private, NAICS 2121 Coal mining, All States and U.S." Supply region and US average weighted by production and labor hours from EIA-7A "Annual Survey of Coal Production and Preparation." https://www.eia.gov/Survey/#eia-7a

[2] Bureau of Labor Statistics, Series: "PCU333131333131 - Mining machinery and equipment mfg" and "PCU333120333120 - Construction machinery mfg"

[3] Flynn, Edward J., "Impact of Technological Change and Productivity on the Coal Market," U.S. Energy Information Administration (Washington, DC, October 2000), and U.S. Energy Information Administration, The U.S. Coal Industry, 1970-1990: Two Decades of Change, DOE/EIA-0559 (Washington, DC, November 1992).

[4] Powder River Basin Coal Resource and Cost Study. Report. No. 3155.001. John T. Boyd Company, (Denver Colorado, September 2011). https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7BEC9AC071-1541-43D3-A57A-418AA72EC7FF%7D&documentTitle=20126-75412-01

[5] U.S. Energy Information Administration, Improving the Method for Coal Transportation Rate Escalation in the NEMS Coal Market Module (Washington, DC: August 2020), https://www.eia.gov/outlooks/documentation/workshops/pdf/coal_transportation_rate_escalation.pdf

[6] 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).

[7] U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009, Annex 2 Methodology and Data for Estimating CO2 Emissions from Fossil Fuel Combustion, EPA 430-R-10-006 (Washington, DC, April 2011), Table A-37, https://www.epa.gov/sites/production/files/2015-12/documents/us-ghg-inventory-2011-complete_report.pdf

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