Electricity Market Module

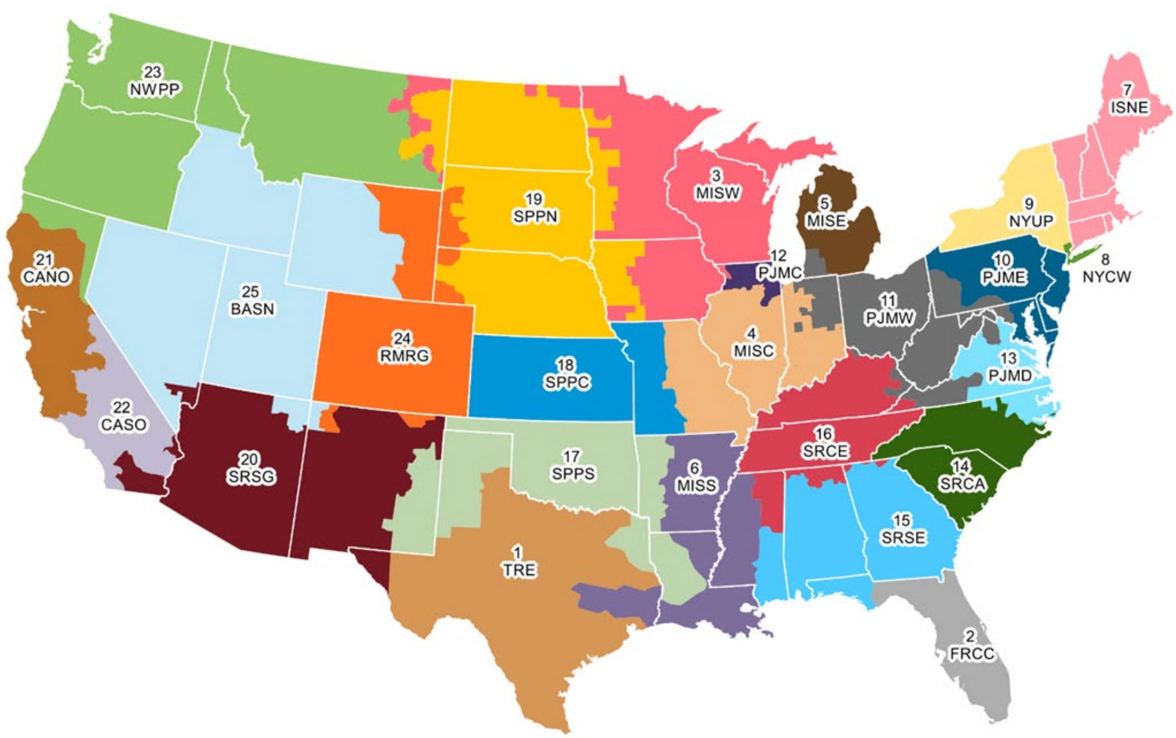
The Electricity Market Module (EMM) in the U.S. Energy Information Administration's (EIA) National Energy Modeling System (NEMS) is composed of four submodules: electricity load and demand, electricity capacity planning, electricity fuel dispatching, and electricity finance and pricing. The EMM also includes nonutility capacity and generation as well as electricity transmission and trade. The EIA publication, *The Electricity Market Module of the National Energy Modeling System: Model Documentation 2020, DOE/EIA-M068* (*2020*), describes the EMM.

Based on fuel prices and electricity demands provided by the other modules of NEMS, the EMM determines the most economical way to supply electricity within environmental and operational constraints. Each EMM submodule includes assumptions about the operations of the electricity sector and the costs of various options. This section describes the model parameters and assumptions used in the EMM and discusses legislation and regulations that EIA incorporates in the EMM.

EMM regions

EIA last updated the supply regions used in the EMM for its *Annual Energy Outlook 2020* (AEO2020) to account for changes in Independent System Operator (ISO) and Regional Transmission Organization (RTO) composition and to better represent U.S. power markets. The regions follow North American Electric Reliability Corporation (NERC) assessment region boundaries and ISO region boundaries (as of early 2019), and subregions are based on regional pricing zones, as shown in Figure 1 and described in Table 1.

Figure 1. Electricity Market Module regions



Source: U.S. Energy Information Administration

Table 1. National Energy Modeling System Electricity Market Module regions

Number	Abbreviation	NERC/ISO[1] subregion name	Geographic name[2]
1	TRE	Texas Reliability Entity	Texas
2	FRCC	Florida Reliability Coordinating Council	Florida
3	MISW	Midcontinent ISO/West	Upper Mississippi Valley
4	MISC	Midcontinent ISO/Central	Middle Mississippi Valley
5	MISE	Midcontinent ISO/East	Michigan
6	MISS	Midcontinent ISO/South	Mississippi Delta
7	ISNE	Northeast Power Coordinating Council/ New England	New England
8	NYCW	Northeast Power Coordinating Council/ New York City & Long Island	Metropolitan New York
9	NYUP	Northeast Power Coordinating Council/Upstate New York	Upstate New York
10	PJME	PJM/East	Mid-Atlantic
11	PJMW	PJM/West	Ohio Valley
12	PJMC	PJM/Commonwealth Edison	Metropolitan Chicago
13	PJMD	PJM/Dominion	Virginia
14	SRCA	SERC Reliability Corporation/East	Carolinas
15	SRSE	SERC Reliability Corporation/Southeast	Southeast
16	SRCE	SERC Reliability Corporation/Central	Tennessee Valley
17	SPPS	Southwest Power Pool/South	Southern Great Plains
18	SPPC	Southwest Power Pool/Central	Central Great Plains
19	SPPN	Southwest Power Pool/North	Northern Great Plains
20	SRSG	Western Electricity Coordinating Council/Southwest	Southwest
21	CANO	Western Electricity Coordinating Council/California North	Northern California
22	CASO	Western Electricity Coordinating Council/California South	Southern California
23	NWPP	Western Electricity Coordinating Council/ Northwest Power Pool	Northwest
24	RMRG	Western Electricity Coordinating Council/Rockies	Rockies
25	BASN	Western Electricity Coordinating Council/Basin	Great Basin

[1] NERC=North American Electric Reliability Corporation, ISO=Independent System Operator.
[2] Names are intended to describe approximate locations. Exact regional boundaries do not necessarily correspond to state borders or to other regional naming conventions.
Source: U.S. Energy Information Administration

Model parameters and assumptions

Generating capacity types

Table 2 shows the capacity types represented in the EMM.

Table 2. Generating capacity types represented in the Electricity Market Module

Capacity type
Existing coal steam plants[1]
Ultra-supercritical coal (USC)
USC with 30% carbon capture and sequestration (CCS)
USC with 90% CCS
Oil/natural gas steam—oil/natural gas steam turbine
Combined-cycle (CC)—single shaft (1x1x1)[2] configuration
Combined-cycle—multi shaft (2x2x1)[3] configuration
Combined-cycle with CCS—single shaft configuration with 90% CCS
Internal combustion engine
Combustion turbine (CT)—aeroderivative
CT—industrial frame
Fuel cell—solid oxide
Conventional nuclear
Advanced nuclear—advanced light water reactor
Advanced nuclear – small modular reactor
Generic distributed generation—base load
Generic distributed generation—peak load
Conventional hydropower—hydraulic turbine
Pumped storage—hydraulic turbine reversible
Battery storage—four-hour lithium-ion battery
Geothermal
Municipal solid waste (MSW)—landfill gas-fired internal combustion engine
Biomass—fluidized bed
Solar thermal—central tower
Solar photovoltaic (PV) with single-axis tracking
Solar PV with battery storage[4]
Wind
Wind offshore

[1] The Electricity Market Module represents 32 types of existing coal steam plants, based on the different possible configurations of nitrogen oxide (NOx), particulate and sulfur dioxide (SO2) emission control devices, and options for controlling mercury and carbon (see Table 9).
[2] Single-shaft (1x1x1) configuration with one H-class combustion turbine, one heat recovery steam generator, and one steam turbine generator.
[3] Multi-shaft (2x2x1) configuration with two H-class combustion turbines, two heat recovery steam generators, and one steam turbine generator.
[4] Includes 150 megawatts (MW) of PV and 50 MW of four-hour battery storage coupled through a direct current bus and connected to the grid through a 150 MW inverter.
Source: U.S. Energy Information Administration

New generating plant characteristics

Inputs to the electricity capacity planning submodule are the cost and performance characteristics of new generating technologies (Table 3). In addition to these characteristics, EIA uses fuel prices from the NEMS fuel supply modules and foresight on fuel prices to compare options when new capacity is needed. Heat rates for new fossil-fueled technologies are assumed to remain constant throughout the projection period.

For AEO2021, initial cost inputs remain as in AEO2020, but Table 3 reflects learning cost adjustments for any capacity added in 2019. For AEO2020, an EIA consultant updated the current cost estimates for most utility-scale electric generating plants.[1] This report used a consistent estimation methodology across all technologies to develop cost and performance characteristics for technologies that EIA specified for consideration in the EMM. EIA did not use the costs the consultant developed for geothermal and hydro plants because it continues to use previously developed site-specific costs. EIA also did not update costs for distributed generation plants in the power sector for this report, and input assumptions remain as in previous AEOs.

AEO2021 incorporates two additional technologies that were part of the AEO2020 cost report but not originally included in the EMM. A second advanced nuclear technology is now modeled representing a small modular reactor (SMR). The technology is modeled as a 12x50 megawatt (MW) representative SMR plant and not a specific design. AEO2021 also includes a solar photovoltaic (PV) plus battery storage hybrid plant. The modeled hybrid system includes 150 MW of PV and 50 MW of four-hour battery storage coupled with each other through a direct current bus and connected to the grid through a 150 MW inverter.

Except as noted below, the overnight costs shown in Table 3 represent the estimated cost of building a plant before adjusting for regional cost factors. Overnight costs exclude interest expenses during plant construction and development. Although not broken out as in previous AEOs, the base overnight costs include project contingency to account for undefined project scope, pricing uncertainty, and owners' cost components. Technologies with limited commercial experience may include a technological optimism factor to account for the tendency during technology research and development to underestimate the full engineering and development costs for new technologies. A cost-adjustment factor, based on the producer price index for metals and metal products, allows the overnight capital costs in the future to drop if this index decreases or to rise if it increases.

All technologies demonstrate some degree of variability in cost, based on project size, location, and access to key infrastructure (such as grid interconnections, fuel supply, and transportation). For onshore wind and solar PV, in particular, the cost favorability of the lowest-cost regions compounds the underlying variability in regional cost and creates a significant differential between the unadjusted costs and the capacity-weighted average national costs as observed from recent market experience. To account for this difference, Table 3 shows a weighted-average cost for both onshore wind and solar PV based on the regional cost factors assumed for these technologies in AEO2021 and the actual regional distribution of wind and solar builds that occurred in 2019.

Table 4 lists the overnight capital costs for each technology and EMM region (Figure 1) for the resources or technologies that are available to be built in each region. The regional costs reflect the impact of locality adjustments, including one to address ambient air conditions for technologies that include a combustion turbine and one to adjust for additional costs associated with accessing remote wind resources. Temperature, humidity, and air pressure can affect the available capacity of a combustion turbine, and EIA's modeling addresses this possibility through an additional cost multiplier by region. Unlike most other generation technologies where fuel can be transported to the plant, wind generators must be located in areas with the best wind resources. Sites that are located near existing transmission with access to a road network or are otherwise located on lower-development-cost lands are generally built up first, after which additional costs may be incurred to access sites with less favorable characteristics. EIA represents this trend through a multiplier applied to the wind plant capital costs that increases as the best sites in a given region are developed.

Table 3. Cost and performance characteristics of new central station electricity generating technologies

Technology	First available year[1]	Size (MW)	Lead time (years)	Base overnight cost[2] (2020 $/kW)	Techno-logical optimism factor[3]	Total overnight cost[4,5] (2020 $/kW)	Variable O&M[6] (2020 $/MWh)	Fixed O&M (2020$/ kW-yr)	Heat rate[7] (Btu/kWh)
Ultra-supercritical coal (USC)	2024	650	4	3,672	1.00	3,672	4.52	40.79	8,638
USC with 30% carbon capture and sequestration (CCS)	2024	650	4	4,550	1.01	4,595	7.11	54.57	9,751
USC with 90% CCS	2024	650	4	5,861	1.02	5,978	11.03	59.85	12,507
Combined-cycle—single shaft	2023	418	3	1,082	1.00	1,082	2.56	14.17	6,431
Combined-cycle—multi shaft	2023	1,083	3	957	1.00	957	1.88	12.26	6,370
Combined-cycle with 90% CCS	2023	377	3	2,471	1.04	2,570	5.87	27.74	7,124
Internal combustion engine	2022	21	2	1,813	1.00	1,813	5.72	35.34	8,295
Combustion turbine—aeroderivative[8]	2022	105	2	1,169	1.00	1,169	4.72	16.38	9,124
Combustion turbine—industrial frame	2022	237	2	709	1.00	709	4.52	7.04	9,905
Fuel cells	2023	10	3	6,277	1.09	6,866	0.59	30.94	6,469
Nuclear—light water reactor	2026	2,156	6	6,034	1.05	6,336	2.38	122.26	10,455
Nuclear—small modular reactor	2028	600	6	6,183	1.10	6,802	3.02	95.48	10,455
Distributed generation—base	2023	2	3	1,560	1.00	1,560	8.65	19.46	8,935
Distributed generation—peak	2022	1	2	1,874	1.00	1,874	8.65	19.46	9,921
Battery storage	2021	50	1	1,165	1.00	1,165	0.00	24.93	NA
Biomass	2024	50	4	4,077	1.00	4,078	4.85	126.36	13,500
Geothermal[9, 10]	2024	50	4	2,772	1.00	2,772	1.17	137.50	8,946
Municipal solid waste—landfill gas	2023	36	3	1,566	1.00	1,566	6.23	20.20	8,513
Conventional hydropower[10]	2024	100	4	2,769	1.00	2,769	1.40	42.01	NA
Wind[5]	2023	200	3	1,846	1.00	1,846	0.00	26.47	NA
Wind offshore[9]	2024	400	4	4,362	1.25	5,453	0.00	110.56	NA
Solar thermal[9]	2023	115	3	7,116	1.00	7,116	0.00	85.82	NA
Solar photovoltaic (PV) with tracking[5, 9, 11]	2022	150	2	1,248	1.00	1,248	0.00	15.33	NA
Solar PV with storage[9, 11]	2022	150	2	1,612	1.00	1,612	0.00	32.33	NA

[1] Represents the first year that a new unit could become operational.
[2] Base cost includes project contingency costs.
[3] The technological optimism factor is applied to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.
[4] Overnight capital cost includes contingency factors and excludes regional multipliers (except as noted for wind and solar PV) and learning effects. Interest charges are also excluded. The capital costs represent current costs for plants that would come online in 2021.
[5] Total overnight cost for wind and solar PV technologies in the table are the average input value across all 25 electricity market regions, as weighted by the respective capacity of that type installed during 2019 in each region to account for the substantial regional variation in wind and solar costs (as shown in Table 4). The input value used for onshore wind in AEO2021 was $1,268 per kilowatt (kW) and for solar PV with tracking it was $1,232/kW, which represents the cost of building a plant excluding regional factors. Region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions, accessibility of resources, and variation in labor and other construction costs throughout the country.
[6] O&M = Operations and maintenance.
[7] The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860, *Annual Electric Generator Report*. No heat rate is reported for battery storage because it is not a primary conversion technology; conversion losses are accounted for when the electricity is first generated; electricity-to-storage losses are accounted for through the additional demand for electricity required to meet load. For hydropower, wind, solar, and geothermal technologies, no heat rate is reported because the power is generated without fuel combustion and no set British thermal unit conversion factors exist. The model calculates the average heat rate for fossil-fuel generation in each year to report primary energy consumption displaced for these resources.
[8] Combustion turbine aeroderivative units can be built by the model before 2022, if necessary, to meet a region's reserve margin.
[9] Capital costs are shown before investment tax credits are applied.
[10] Because geothermal and hydropower cost and performance characteristics are specific for each site, the table entries show the cost of the least expensive plant that could be built in the Northwest region for hydro and Great Basin region for geothermal, where most of the proposed sites are located.
[11] Costs and capacities are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.
Sources: Input costs are primarily based on a report provided by external consultants: Sargent & Lundy, December 2019. Hydropower site costs for non-powered dams were most recently updated for AEO2018 using data from Oak Ridge National Lab

Table 4. Total overnight capital costs of new electricity generating technologies by region

2020 dollars per kilowatt

Technology	1 TRE	2 FRCC	3 MISW	4 MISC	5 MISE	6 MISS	7 ISNE	8 NYCW	9 NYUP	10 PJME	11 PJMW	12 PJMC	13 PJMD
Ultra-supercritical coal (USC)	3,412	3,512	3,838	3,939	3,985	3,531	4,255	NA	4,159	4,293	3,662	4,614	3,952
USC with 30% CCS	4,308	4,422	4,774	4,903	4,942	4,450	5,272	NA	5,167	5,306	4,594	5,640	4,939
USC with 90% CCS	5,642	5,786	6,173	6,381	6,387	5,841	6,764	NA	6,590	6,775	5,956	7,214	6,331
CC—single shaft	977	997	1,112	1,122	1,151	1,006	1,298	1,722	1,301	1,300	1,078	1,302	1,241
CC—multi shaft	851	872	989	1,006	1,032	882	1,134	1,554	1,115	1,140	934	1,196	1,054
CC with 90% CCS	2,410	2,432	2,599	2,605	2,645	2,455	2,729	3,091	2,667	2,707	2,489	2,822	2,593
Internal combustion engine	1,705	1,743	1,862	1,936	1,915	1,766	1,984	2,487	1,909	1,985	1,778	2,164	1,847
CT—aeroderivative	1,034	1,056	1,223	1,226	1,263	1,077	1,315	1,684	1,269	1,308	1,122	1,437	1,190
CT—industrial frame	626	639	742	746	768	653	801	1,033	771	797	680	877	723
Fuel cells	6,589	6,691	6,997	7,299	7,160	6,804	7,428	8,745	7,126	7,364	6,784	7,851	6,993
Nuclear—light water reactor	5,981	6,110	6,450	7,036	6,786	6,309	7,177	NA	6,696	7,013	6,199	7,711	6,451
Nuclear—small modular reactor	6,338	6,486	7,066	7,369	7,366	6,567	7,608	NA	7,246	7,623	6,648	8,506	6,904
Distributed generation—base	1,408	1,437	1,603	1,618	1,659	1,450	1,871	2,482	1,876	1,874	1,554	1,877	1,788
Distributed generation—peak	1,657	1,692	1,959	1,965	2,024	1,727	2,108	2,698	2,034	2,096	1,798	2,303	1,907
Battery storage	1,165	1,168	1,151	1,207	1,168	1,192	1,201	1,196	1,169	1,173	1,162	1,177	1,173
Biomass	3,784	3,887	4,208	4,348	4,358	3,919	4,842	6,572	4,857	4,942	4,156	4,951	4,736
Geothermal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
MSW—landfill gas	1,476	1,508	1,606	1,673	1,652	1,530	1,713	2,133	1,647	1,711	1,538	1,861	1,596
Conventional hydropower	4,040	4,935	1,963	1,305	2,657	3,932	1,819	NA	3,722	3,866	3,370	NA	3,420
Wind	2,477	NA	1,395	1,268	1,518	1,268	1,680	NA	2,049	1,680	1,268	1,846	1,750
Wind offshore	5,325	6,390	6,304	NA	6,529	NA	6,360	5,486	6,652	6,097	4,985	7,219	5,679
Solar thermal	6,865	6,969	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Solar PV with tracking	1,214	1,191	1,232	1,278	1,264	1,202	1,276	1,501	1,264	1,301	1,229	1,341	1,226
Solar PV with storage	1,561	1,577	1,624	1,677	1,653	1,593	1,687	1,917	1,656	1,690	1,588	1,757	1,643

Technology	14 SRCA	15 SRSE	16 SRCE	17 SPPS	18 SPPC	19 SPPN	20 SRSG	21 CANO	22 CASO	23 NWPP	24 RMRG	25 BASN
Ultra-supercritical coal (USC)	3,533	3,586	3,634	3,557	3,779	3,597	3,748	NA	NA	3,971	3,712	3,873
USC with 30% CCS	4,454	4,496	4,563	4,466	4,713	4,508	4,703	NA	NA	4,942	4,653	4,828
USC with 90% CCS	5,852	5,904	5,974	5,821	6,117	5,863	6,098	NA	NA	6,398	6,008	6,287
CC—single shaft	993	1,005	1,036	1,004	1,066	995	978	1,432	1,399	1,138	922	996
CC—multi shaft	872	883	915	882	947	874	842	1,259	1,225	987	793	889
CC with 90% CCS	2,424	2,437	2,492	2,428	2,509	2,391	2,212	2,774	2,743	2,559	2,080	2,336
Internal combustion engine	1,776	1,781	1,812	1,763	1,858	1,781	1,798	2,155	2,116	1,916	1,775	1,900
CT—aeroderivative	1,071	1,081	1,121	1,079	1,155	1,087	981	1,381	1,347	1,211	949	1,082
CT— industrial frame	649	655	680	654	701	658	594	844	822	737	575	657
Fuel cells	6,853	6,848	6,942	6,728	7,010	6,789	6,884	7,887	7,796	7,209	6,751	7,191
Nuclear—light water reactor	6,390	6,340	6,546	6,135	6,487	6,133	6,361	NA	NA	6,885	6,162	6,893
Nuclear—small modular reactor	6,600	6,651	6,802	6,584	6,993	6,640	6,728	NA	NA	7,285	6,656	7,235
Distributed generation—base	1,432	1,449	1,493	1,448	1,536	1,434	1,409	2,064	2,017	1,641	1,328	1,436
Distributed generation—peak	1,717	1,732	1,797	1,729	1,852	1,741	1,572	2,213	2,158	1,941	1,521	1,734
Battery storage	1,203	1,186	1,201	1,159	1,167	1,153	1,180	1,213	1,216	1,193	1,155	1,201
Biomass	3,934	3,963	4,016	3,937	4,183	4,020	4,305	5,515	5,390	4,451	4,265	4,265
Geothermal	NA	NA	NA	NA	NA	NA	2,825	2,802	2,269	2,742	NA	2,772
MSW—landfill gas	1,539	1,541	1,568	1,525	1,605	1,539	1,555	1,857	1,825	1,655	1,534	1,642
Conventional hydropower	1,904	4,130	2,135	4,086	1,722	1,619	3,282	3,473	3,344	2,769	3,306	3,613
Wind	1,512	1,713	1,268	1,395	1,395	1,395	1,395	2,799	2,418	1,848	1,395	1,395
Wind offshore	4,907	NA	NA	NA	NA	NA	NA	8,224	8,628	6,170	NA	NA
Solar thermal	NA	NA	NA	6,934	7,203	6,864	7,193	8,473	8,367	7,656	6,912	7,671
Solar PV with tracking	1,251	1,188	1,228	1,190	1,237	1,199	1,211	1,348	1,341	1,241	1,225	1,236

Solar PV with storage	1,604	1,588	1,607	1,577	1,628	1,594	1,602	1,756	1,751	1,656	1,595	1,653

NA = not available; plant type cannot be built in the region because of a lack of resources, sites, or specific state legislation.

USC = ultra-supercritical, CCS = carbon capture and sequestration, CC = combined cycle, CT = combustion turbine, PV = photovoltaic, MSW = municipal solid waste

Electricity Market Module region map

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis

Notes: Costs include contingency factors and regional cost and ambient conditions multipliers. Interest charges are excluded. The costs are shown before investment tax credits are applied.

New construction financing

The capacity planning module of the EMM assumes that new power plants are built in a competitive environment and that different generating technologies generally have the same financing assumptions. A few exceptions are described below. Projects are assumed to be financed by both debt and equity, and the after-tax weighted average cost of capital is used as the discount rate when calculating the discounted cash flow analysis for building and operating new plants.

AEO2021 continues to include the impacts of the Tax Cuts and Jobs Act of 2017. In the EMM, these factors are reflected by setting the corporate tax rate to 21% and immediately expensing all new construction through a one-year depreciation schedule. The change to depreciation schedules is phased out by 2027. This phase out affects both retail price calculations and costs of financing new generation, transmission, and distribution builds.

In the EMM, the assumed debt fraction for new builds is 60%, with a corresponding 40% equity fraction. Because plants that receive a tax credit—either production tax credit (PTC) or investment tax credit (ITC)—typically require a tax equity partner to take advantage of the credits, they will have a larger share of equity. Therefore, the EMM assumes that the debt fraction is lowered to 50% for technologies receiving a tax credit, but this fraction reverts to 60% as the tax credits are phased out. If tax credits were extended, the difference in the debt fraction would remain (as in the No PTC/ITC Sunset case run for an AEO2018 *Issues in Focus* article).

The cost of debt is based on the Industrial Baa bond rate, passed to the EMM as an annual projection from the Macroeconomic Module. The cost of debt in AEO2021 averages 4.5% for capacity builds from 2020 through 2050. The cost of equity is calculated using the Capital Asset Pricing Model (CAPM), which assumes the return is equal to a risk-free rate plus a risk premium specific to the industry (described in more detail in the EMM documentation). The average cost of equity in AEO2021 is 9.7%, and the resulting discount rate with a 60/40 debt/equity split is 5.9% from 2020 through 2050.

The AEO2021 Reference case includes a three-percentage-point adder to the cost of capital (both equity and debt) when evaluating investments in new coal-fired power plants and new coal-to-liquids (CTL) plants without full carbon capture and sequestration (CCS). AEO2021 also assumes pollution control retrofits to reflect financial risks associated with major investments in long-lived power plants with a relatively higher rate of carbon dioxide (CO2) emissions. The coal technology that captures 30% of CO2 emissions is still considered a high emitter relative to other new sources and may continue to face potential financial risk if carbon emission controls are further strengthened. Only the technology designed to capture 90% of CO2 emissions does not receive the three-percentage-point increase in cost of capital.

Technological optimism and learning

EIA calculates overnight costs for each technology as a function of regional construction parameters, project contingency, and the technological optimism and learning factors.

The technological optimism factor represents the demonstrated tendency to underestimate actual costs for a first-of-a-kind, unproven technology. As experience is gained, the technological optimism factor is gradually reduced to 1.0.

The learning function in NEMS is determined at a component level. Each new technology is broken into its major components, and each component is identified as revolutionary, evolutionary, or mature. Different learning rates are assumed for each component, based on the level of experience with the design component (Table 5). Where technologies use similar components, these components learn at the same rate that these units are built. For example, the underlying turbine generator for a combustion turbine, combined-cycle, and integrated coal-gasification combined-cycle unit is assumed to be basically the same. Therefore, construction of any of these technologies would contribute to learning reductions for the turbine component.

Table 5. Learning parameters for new generating technology components

Technology component	Period 1 learning rate (LR1)	Period 2 learning rate (LR2)	Period 3 learning rate (LR3)	Period 1 doublings	Period 2 doublings	Minimum total learning by 2035
Pulverized coal	—	10%	1%	—	5	10%
Internal combustion engine	—	—	1%	—	—	5%
Combustion turbine – natural gas	—	10%	1%	—	5	10%
Heat recovery steam generator (HRST)	—	—	1%	—	—	5%
Gasifier	—	10%	1%	—	5	10%
Carbon capture/sequestration	20%	10%	1%	3	5	20%
Balance of plant—turbine	—	—	1%	—	—	5%
Balance of plant—combined cycle	—	—	1%	—	—	5%
Fuel cell	20%	10%	1%	3	5	20%
Advanced nuclear	5%	3%	1%	3	5	10%
Biomass	—	10%	1%	—	5	10%
Distributed generation—base	—	5%	1%	—	5	10%
Distributed generation—peak	—	5%	1%	—	5	10%
Geothermal	—	8%	1%	—	5	10%
Municipal solid waste	—	—	1%	—	—	5%
Hydropower	—	—	1%	—	—	5%
Battery storage	20%	10%	1%	1	5	20%
Wind	—	—	1%	—	—	5%
Wind offshore	20%	10%	1%	3	5	20%
Solar thermal	20%	10%	1%	3	5	10%
Solar photovoltaic (PV)—module	20%	10%	1%	1	5	10%
Balance of plant—solar PV	20%	10%	1%	1	5	10%

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis

Note: The learning assumptions text describes the methodology for learning in the Electricity Market Module. Where no value is shown for a column, that learning period has already passed for the technology.

The learning function, OC, has the following nonlinear form:

$$OC(C) = a*C^{-b},$$

where C is the cumulative capacity for the technology component.

The progress ratio (pr) is defined by speed of learning (that is, how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (learning rate, or LR) is an exogenous parameter input for each component (Table 5). The progress ratio and LR are related by the following:

$$pr = 2^{-b} = (1 - LR).$$

The parameter b is calculated from the second equality above (that is, $b = -(\ln(1\text{-}LR)/\ln(2))$). The parameter *a* is computed from the following initial conditions:

$a = OC(C_0)/C_0^{-b}$,

where

C_0=the initial cumulative capacity.

Once the LR and the cumulative capacity (C_0) are known for each interval, the parameters (a and b) can be computed. EIA developed three learning steps to reflect different stages of learning as a new design is introduced into the market. New designs with significant untested technology will see high rates of learning initially, while more conventional designs will not have as much learning potential. Costs of all design components are adjusted to reflect minimal learning, even if new capacity additions are not projected. This methodology represents cost reductions as a result of future international development or increased research and development.

Once the learning rates by component are calculated, EIA calculates a weighted-average learning factor for each technology. The weights are based on the share of the initial cost estimate that is attributable to each component (Table 6). For technologies that do not share components, this weighted-average learning rate is calculated exogenously and is input as a single component.

Table 6. Component cost weights for new technologies

Technology	Pulverized coal	Combustion turbine	HRSG	Carbon capture/ sequestration	Balance of plant—turbine	Balance of plant—combined cycle
Ultra-supercritical coal (USC)	100%	0%	0%	0%	0%	0%
USC with 30% CCS	80%	0%	0%	20%	0%	0%
USC with 90% CCS	90%	0%	0%	10%	0%	0%
Combined-cycle—single shaft	0%	25%	10%	0%	0%	65%
Combined-cycle—multi shaft	0%	25%	10%	0%	0%	65%
Combined-cycle with 90% CCS	0%	15%	5%	40%	0%	40%
Combustion turbine—aeroderivative	0%	50%	0%	0%	50%	0%
Combustion turbine—industrial frame	0%	50%	0%	0%	50%	0%

HRSG = heat recovery steam generator, CCS = carbon capture and sequestration.
Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis

These technologies may still have a mix of revolutionary components and more mature components, but this detail is not necessary to include in the model unless capacity from multiple technologies would contribute to component learning. In the case of the solar PV technology, the module component is assumed to account for 30% of the cost, and the balance of system components is assumed to account for the remaining 70%. Because the amount of end-use PV capacity (existing and projected) is significant relative to total solar PV capacity and the technology of the module component is common across the end-use and electric power sectors, the calculation of the learning factor for the PV module component also takes into account capacity built in the residential and commercial sectors. The PV with battery

storage cost is split between the battery component (20%), the PV module (20%), and the PV balance of system (60%).

Table 7 shows the capacity credit toward component learning for the various technologies. For all combined-cycle technologies, the turbine unit was assumed to contribute two-thirds of the capacity, while the heat recovery steam generator (HRSG) contributed the remaining one-third. Therefore, building one gigawatt (GW) of natural gas/oil combined-cycle capacity would contribute 0.67 GW toward turbine learning and 0.33 GW toward HRSG learning. Components that do not contribute to the capacity of the plant, such as the balance of plant category, receive 100% capacity credit for any capacity built with that component. For example, when calculating capacity for the balance of plant component for the combined-cycle technology, all combined-cycle capacity would be counted as 100%, both single-shaft and multi-shaft.

Table 7. Component capacity weights for new technologies

Technology	Pulverized coal	Combustion turbine	HRSG	Carbon capture/ sequestration	Balance of plant—turbine	Balance of plant—combined cycle
Ultra-supercritical coal (USC)	100%	0%	0%	0%	0%	0%
USC with 30% CCS	100%	0%	0%	100%	0%	0%
USC with 90% CCS	100%	0%	0%	100%	0%	0%
Combined-cycle—single shaft	0%	67%	33%	0%	0%	100%
Combined-cycle—multi shaft	0%	67%	33%	0%	0%	100%
Combined-cycle with 90% CCS	0%	67%	33%	100%	0%	100%
Combustion turbine—aeroderivative	0%	100%	0%	0%	100%	0%
Combustion turbine—industrial frame	0%	100%	0%	0%	100%	0%

HRSG = heat recovery steam generator, CCS = carbon capture and sequestration
Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis

International learning

In AEO2021, the learning algorithm incorporates international capacity for onshore wind and solar PV technologies because of significant overlap in the market for major plant components. Existing international capacity that is consistent with technology characteristics used in U.S. markets is counted toward the base capacity amount, and assumed future additions are added to EMM projections of new U.S. capacity additions, which contributes to future doublings of capacity and associated learning cost reduction. The international projections for onshore wind and solar PV capacity are from the *International Energy Outlook 2019* projections for countries outside of the United States. EIA applies a weighting factor to reduce the international capacity projections to reflect components of the project cost that may not be applicable to U.S. markets, such as country-specific labor or installation costs.

Distributed generation

Distributed generation is modeled in the end-use sectors (as described in the appropriate AEO2021 Assumptions sections) and in the EMM. This section describes the representation of distributed generation in the EMM only. Two generic distributed technologies are modeled. The first technology represents peaking capacity (capacity that has relatively high operating costs and is operated when demand levels are at their highest). The second generic technology for distributed generation represents

base-load capacity (capacity that is operated on a continuous basis under a variety of demand levels). See Table 3 for costs and performance characteristics. EIA assumes these plants reduce the costs of transmission upgrades that would otherwise be needed.

Demand storage

Although not currently modeled in AEO2021, the EMM includes a demand storage technology that could simulate load shifting through programs such as smart meters. The demand storage technology would be modeled as a new technology capacity addition but with operating characteristics similar to pumped storage. The technology can decrease the load during peak periods, but it must generate electricity to replace that demand at other times. An input factor is used to identify the replacement generation needed, where a factor of less than 1.0 can be used to represent peak shaving rather than purely shifting the load to other times. The AEO2021 cases no longer project builds of this technology type because EIA added a more detailed modeling of battery storage, and it is described in the demand section below. This storage technology is also a method of reducing and shifting peak demand use.

Coal-to-gas conversion

Since AEO2015, the EMM includes existing coal plants that were converted to burn natural gas. In recent years, a number of companies have retrofitted their coal plants to operate as single-cycle steam plants to reduce emissions from the plant or to take advantage of low natural gas prices.[2] The EMM reflects the current configuration and primary fuel use of the plants as reported to EIA. The EMM includes the option to convert additional coal plants to natural gas-fired steam plants, if economical.

The modeling structure for coal-to-gas conversions is based on the U.S. Environmental Protection Agency's (EPA) modeling for the Base Case v.5.13.[3] For this modeling, coal-to-gas conversion is when an existing boiler is modified to burn natural gas. Coal-to-gas conversion, in this instance, is not the same as adding a natural gas turbine, replacing a coal boiler with a new natural gas combined-cycle plant, or gasifying coal for a combustion turbine. The cost for the retrofit option has two components: boiler modification costs and the cost of extending natural gas lateral pipeline spurs from the boiler to a natural gas main pipeline.

Allowing natural gas firing in a coal boiler typically means installing new natural gas burners, modifying the boiler, and potentially modifying the environmental equipment. EPA's engineers developed the estimates based on discussions with industry engineers. These estimates were designed to apply across the existing coal fleet. In the EMM, costs were estimated for eligible coal plants that EPA identified, which excluded units of less than 25 MW and units with fluidized-bed combustion or stoker boilers. The EMM does not include any capacity penalty for converting to natural gas, but a 5% heat rate penalty is assumed to reflect reduced efficiency as a result of lower stack temperature and the corresponding higher moisture loss when natural gas is combusted instead of coal. Fixed operations and maintenance (O&M) costs are assumed to be reduced by 33% for the converted plant because these plants need fewer operators, maintenance materials, and maintenance staff. Variable O&M costs are reduced by 25% because of lower waste disposal and other costs. The incremental capital cost (in 2011 dollars per kilowatt) is described by these functions:

For pulverized-coal-fired boilers:

$$\text{Cost per kW} = 267 * (75 / CAP)^{0.35};$$

For cyclone boilers:

$$\text{Cost per kW} = 374 * (75 / CAP)^{0.35};$$

where

CAP=the capacity of the unit in MW.

To get unit-specific costs, EIA used EPA's assumptions for natural gas pipeline requirements, which were based on a detailed assessment of every coal boiler in the United States, to determine natural gas volumes needed, distance to the closest pipeline, and size of the lateral pipeline required. The resulting cost per kilowatt (kW) of boiler capacity varies widely; an average cost is $200/kW (in 2020 dollars).

Representing electricity demand

The annual electricity demand projections from the NEMS demand modules are converted into load-duration curves for each of the EMM regions using historical hourly load data. The load-duration curve in the EMM has nine time periods. First, the load data are split into three seasons: winter (December through March), summer (June through September), and fall/spring (October through November and April through May, respectively). Within each season, the load data are sorted from high to low, and three load segments are created: a peak segment representing the top 1% of the load and then two off-peak segments representing the next 49% and 50%, respectively. The seasons were defined to account for seasonal variation in supply availability.

In AEO2021, EIA revised the residential and commercial models so that the end-use consumption provided to the EMM includes both demand from the grid and onsite generation. This revision builds on an earlier enhancement developed for AEO2017 to account for behind-the-meter PV generation (in other words, rooftop PV generation) more explicitly in the EMM. Because the end-use models only provide an annual demand, they cannot accurately reflect when the PV generation occurs. Instead, EIA models the generation from these systems by estimating reductions in load for several specific end-use applications. The EMM now receives the total end-use demands without removing onsite generation, including rooftop PV generation. The EMM dispatches both power sector and end-use PV capacity using detailed solar resource profiles. For non-PV onsite generation, the EMM assumes the onsite end-use generation has a uniform capacity factor throughout the year. Although the total generation requirement from the power sector capacity is the same as before, this enhancement more accurately reflects the demand and resource availability by time period for PV. In the residential and commercial reporting, the end-use consumption more accurately reflects the total electricity consumed by end use, whether provided from generation onsite or purchased from the grid.

Intermittent/storage modeling

For AEO2019, EIA introduced a new submodel, the ReStore model, within the EMM to provide the granularity needed to represent renewable availability at a greater level of detail than the nine time periods described in the previous section. It also introduced the new submodel to adequately model the value of the four-hour battery storage technology, which can be used to balance renewable generation in periods of high intermittent output but low demand. The ReStore submodel solves a set of linear

programming sub-problems within the EMM to provide the capacity planning and dispatch submodules information regarding the value of battery storage and the level of variable renewable energy curtailments. The sub-problems solve a set of 576 representative hours for the year, and the results are aggregated back to the nine time periods the EMM uses. The ReStore model better represents hydroelectric dispatch, determines wind and solar generation and any required curtailments, and determines the optimal use of any battery storage capacity. Because it includes hourly level dispatch, the ReStore model represents the costs or constraints to ramping conventional technologies up and down to respond to fluctuations in intermittent generation. It also provides the planning model information on the value of storage to determine future builds. Additional details on the ReStore model are available in the Renewables section of the AEO2021 Assumptions.

Capacity and operating reserves

Reserve margins (the percentage of capacity in excess of peak demand required to adequately maintain reliability during unforeseeable outages) are established for each region by its governing body: public utility commission, NERC region, or ISO/RTO. The reserve margin values from the AEO2021 Reference case are based on these regional reference margins reported to NERC, ranging from 12% to 20%.[4]

In addition to the planning reserve margin requirement, system operators typically require a specific level of operating reserves (in other words, generators available within a short amount of time to meet demand in case a generator goes down or another supply disruption occurs). These reserves can be provided through plants that are already operating but not at full capacity (spinning reserves) as well as through capacity not currently operating but that can be brought online quickly (non-spinning reserves). This assumption is particularly important as more intermittent generators are added to the grid because technologies such as wind and solar have uncertain availability that can be difficult to predict. Since AEO2014, the capacity and dispatch submodules of the EMM have been updated to include explicit constraints requiring spinning reserves in each load time period. The amount of spinning reserves required is computed as a percentage of the load height of the time period plus a percentage of the distance between the load of the time period and the seasonal peak. An additional calculated requirement is a percentage of the intermittent capacity available in that period to reflect the greater uncertainty associated with the availability of intermittent resources. All technologies except storage, intermittent plant types, and distributed generation can be used to meet spinning reserves. Different operating modes are developed for each technology type to allow the model to choose between operating a plant to maximize generation versus contributing to spinning reserves, or a combination of the two. Minimum levels of generation are required if a plant is contributing to spinning reserves, and these minimums vary by plant type. Plant types typically associated with baseload operation have higher minimums than those that can operate more flexibly to meet intermediate or peak demand.

Variable heat rates for coal-fired power plants

Low natural gas prices and rising shares of intermittent generation have led to a shift in coal plant operations from baseload to greater cycling. The efficiency of coal plants can vary based on their output levels, and plants can experience reduced efficiency when they run in a cycling mode or are providing operating reserves. The AEO2017 code introduced variable heat rates for coal plants based on the operating mode chosen by the EMM to better reflect actual fuel consumption and costs.

A relationship between operating levels and efficiencies was constructed from data available for 2013 through 2015 in the EPA continuous emission monitoring system (CEMS) and other EMM plant data. A statistical analysis was used to estimate piecewise linear equations that reflect the efficiency as a function of the generating unit's output. The equations were estimated by coal plant type, taking into account the configuration of existing environmental controls, and by the geographic coal demand region for the plant, based on plant-level data. Equations were developed for up to 10 coal plant configurations across the 16 coal regions used in the EMM. The form of the piecewise linear equations for each plant type and region combination can vary and has between 3 and 11 steps.

Within the EMM, these equations are used to calculate heat-rate adjustment factors to normalize the average heat rate in the input plant database (which is based on historical data and is associated with a historical output level) and to adjust the heat rate under different operating modes. The EMM currently allows six different modes within each season for coal plants. These modes are based on combinations of maximizing generation, maximizing spinning reserves, or load following, and they can be invoked for the full season (all three time periods) or for about half the season (only peak and intermediate time periods). Each of these modes is associated with different output levels, and the heat-rate adjustment factor is calculated based on the capacity factor implied by the operating mode.

Fossil fuel-fired and nuclear steam plant retirement

Fossil fuel-fired steam plant retirements and nuclear retirements are determined endogenously within the model. EIA assumes generating units retire when continuing to run them is no longer economical. Each year, the model determines whether the market price of electricity is sufficient to support the continued operation of existing plant generators. EIA projects that a generating unit will retire if the expected revenues from the generator are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building replacement capacity. The going-forward costs include fuel, O&M costs, and annual capital expenditures (CAPEX), which are unit-specific and based on historical data. The average annual capital additions for existing plants are $11 per kW for oil and natural gas steam plants and $27 per kW for nuclear plants (in 2019 dollars). These costs are added to the estimated costs at existing plants regardless of their ages. Beyond 30 years old, the retirement decision includes an additional $37 per kW capital charge for nuclear plants to reflect further investment to address the impacts of aging. Age-related cost increases are attributed to capital expenditures for major repairs or retrofits, decreases in plant performance, and increases in maintenance costs to reduce the effects of aging.

For the AEO2019 modeling cycle, EIA commissioned Sargent and Lundy (S&L) to analyze historical fossil fuel O&M costs and CAPEX and to recommend updates to the EMM.[5] The study focused particularly on whether age is a factor in the level of costs over time. They found that for most technologies, age is not a significant variable influencing annual costs, and in particular, capital expenditures seem to be incurred steadily over time rather than in the form of a particular step increase at a certain age. Therefore, EIA does not model step-wise increases in O&M costs for fossil fuel technologies. For coal plants, the report developed a regression equation for capital expenditures for coal plants based on age and whether the plant had installed a flue gas desulfurization (FGD) unit. The equation below has been incorporated in NEMS to assign capital expenditures for coal plants over time:

CAPEX (2017 \$/KW-yr) = 16.53 + (0.126 × age in years) + (5.68 × FGD)

where

FGD = 1 if a plant has an FGD; zero otherwise.

For the remaining fossil fuel technologies, the model assumes no aging function. Instead, both O&M and CAPEX remain constant over time. The O&M and CAPEX inputs for existing fossil fuel plants were updated using the data set analyzed by S&L and are described in more detail in S&L's report. Costs were assigned for the EMM based on plant type and size category (three to four tiers per type), and plants within a size category were split into three cost groups to provide additional granularity for the model. Plants that were not in the data sample, primarily those not reporting to the Federal Energy Regulatory Commission (FERC), were assigned an input cost based on their sizes and the cost group that was most prevalent for their regional locations.

The report found that most CAPEX spending for combined-cycle and combustion-turbine plants is associated with vendor-specified major maintenance events generally based on factors such as the number of starts or total operating hours. S&L recommended that CAPEX for these plants be recovered as a variable cost, so EIA assumes no separate CAPEX costs for combined-cycle or combustion-turbine plants and incorporates the CAPEX data into the variable O&M input cost.

EIA assumes that all retirements reported as planned during the next 10 years on the Form EIA-860, *Annual Electric Generator Report*, will occur in addition to some others that have been announced but not yet reported to EIA. This assumption includes 8.7 GW of nuclear capacity retirements and 55.6 GW of coal capacity retirements after 2020.

For AEO2018, EIA updated the nuclear unit operating costs using inputs from an Idaho National Laboratory (INL) Report,[6] which was based on a review of public and proprietary cost data for three plant types:

- Small single-unit nuclear plants (less than 900 MW)
- Large single-unit nuclear plants (greater than or equal to 900 MW)
- Multiple-unit nuclear plants

EIA compared the INL data with the average unit cost data previously used in the EMM for these plant types and found that for multiple-unit plants, EIA data were close to the reported INL costs. However, for the single-unit plants, the costs were substantially lower than the INL estimates, particularly for small single-unit nuclear plants. EIA updated the input nuclear O&M cost assumptions to be consistent with the INL costs.

Biomass co-firing

EIA assumes coal-fired power plants co-fire with biomass fuel if doing so is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure is assumed to be \$570 per kW of biomass capacity. A coal-fired unit modified to allow co-firing can generate up to 15% of the total output using biomass fuel, assuming sufficient residue supplies are available.

Nuclear uprates

The AEO2021 nuclear power projection assumes capacity increases at existing units. Nuclear plant operators can increase the rated capacity at plants through power uprates, which are license amendments that the U.S. Nuclear Regulatory Commission must approve. Uprates can vary from small (less than 2%) increases in capacity, which require very little capital investment, or extended uprates of 15% to 20%, which require significant plant modifications. EIA assumes that uprates reported as planned modifications on the Form EIA-860 will take place in the Reference case; however, none were reported to occur after 2020. EIA also analyzed the remaining uprate potential by reactor, based on the reactor design, previously implemented uprates, and developed regional estimates for projected uprates. As a result, EIA assumes 2.1 GW of increased nuclear capacity through uprates to occur in 2022 through 2050.

Interregional electricity trade

Both firm and economy electricity transactions among utilities in different regions are represented in the EMM. In general, firm power transactions involve trading capacity and energy to help another region satisfy its reserve margin requirement, and economy transactions involve energy transactions motivated by the marginal generation costs of different regions. The flow of power from region to region is constrained by the existing and planned capacity limits. The interregional capacity limits are primarily derived from transmission capacity input files to the National Renewable Energy Laboratory ReEDS (Regional Energy Deployment System) model. Additional sources include Western Electricity Coordinating Council (WECC) seasonal reliability assessments and New York Independent System Operator Reliability Needs Assessments. International capacity limits are derived from Northeast Power Coordinating Council (NPCC) and WECC seasonal assessments, Electricity Reliability Council of Texas DC Tie Operations Documents and Canadian Provincial Electricity websites. Known firm power contracts are compiled from the FERC Form 1, *Annual Report of Major Electricity Utility*, and information obtained from utility Integrated Resource Plan documents, individual Independent System Operator reports, and Canadian Provincial Electricity websites. The EMM includes an option to add interregional transmission capacity. In some cases, building generating capacity in a neighboring region may be more economical, but expanding the transmission grid may incur additional costs. Explicitly expanding the interregional transmission capacity may also make the transmission line available for additional economy trade.

Economy transactions are determined in the dispatching submodule by comparing the marginal generating costs of adjacent regions in each time period. If one region has less expensive generating resources available in a given time period (adjusting for transmission losses and transmission capacity limits) than another region, the regions are assumed to exchange power.

International electricity trade

Two components of international firm power trade are represented in the EMM: existing and planned transactions and unplanned transactions. Data on existing and planned transactions are compiled from the FERC Form 1 and provincial reliability assessments. International electricity trade on an economic basis is determined endogenously based on surplus energy expected to be available from Canada by region in each time slice. Canadian surplus energy was determined using a mini-dispatch model that uses Canadian provincial plant data, load curves, demand forecasts, and fuel prices to determine the excess electricity supply by year, load slice, supply step, step cost, and Canadian province.

Electricity pricing

Electricity pricing is projected for the 25 electricity market regions for fully competitive, partially competitive, and fully regulated supply regions. The price of electricity to the consumer consists of the price of generation, transmission, and distribution, including applicable taxes.

In the AEO2021, transmission and distribution remain regulated. This assumption means that the price of transmission and distribution is based on the average cost to build, operate, and maintain these systems using a cost-of-service regulation model. Continued capital investment in the transmission and distribution system is projected as a function of changes in peak demand, based on historical trends. Additional transmission capital investment is added with each new generating build to account for the costs to connect to the grid. Regression equations have been developed to project transmission and distribution operating and maintenance costs as a function of peak demand and overall customer sales. The total price of electricity in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class.

In competitive regions, the generation price includes the marginal energy cost, taxes, and a capacity payment. The marginal energy cost is defined as the cost of the last (or most expensive) unit dispatched, reflecting fuel and variable costs only. EIA calculates the capacity payment as a weighted average of the levelized costs for combustion turbines and the marginal value of capacity calculated within the EMM, which reflects the cost of maintaining the assumed reserve margin. EIA calculates the capacity payment for all competitive regions, and these payments should be viewed as a proxy for additional capital recovery that must be procured from customers rather than as representing a specific market. The capacity payment also includes the costs associated with meeting the spinning reserves requirement discussed earlier in this report. The total cost for both reserve margin and spinning reserve requirements in a given region is calculated within the EMM and allocated to the sectors based on their contributions to overall peak demand.

The total price of electricity in regions with a competitive generation market is the competitive cost of generation summed with the average costs of transmission and distribution. The price for mixed regions reflects a load-weighted average of the competitive price and the regulated price, based on the percentage of electricity load in the region subject to deregulation.

The AEO2021 Reference case assumes full competitive pricing in the two New York regions and in the mid-Atlantic and Metropolitan Chicago regions, and it assumes 95% competitive pricing in New England (Vermont being the only fully regulated state in that region). Twelve regions fully regulate their electricity supply: the Florida, Virginia, Carolinas, Southeast, Tennessee Valley, Southern, Central and Northern Great Plains, Upper Mississippi Valley, Mississippi Delta, Southwest, and Rockies regions. The Texas region, which in the past was considered fully competitive by 2010, is now only 88% competitive because many cooperatives have declined to become competitive or allow competitive energy to be sold to their customers. In California, 33% of the Northern California region is competitively supplied, and 7% of the Southern California region is competitively supplied. All other regions also reflect a mix of both competitive and regulated prices.

Pricing structures for ratepayers in competitive states have experienced ongoing changes since the inception of retail competition. The AEO2021 has incorporated these changes as they have been

incorporated into utility tariffs. For example, as a result of volatile fuel markets, state regulators have sometimes had difficulty enticing retail suppliers to offer competitive supply to residential and smaller commercial and industrial customers. Subsequent state legislation has led to generation service supplied by a regulator or utility-run auction or a competitive bid for the market energy price plus an administration fee.

Typical charges that all customers must pay on the distribution portion of their bills (depending on where they reside) include transition charges (including persistent stranded costs), public benefits charges (usually for efficiency and renewable energy programs), administrative costs of energy procurement, and nuclear decommissioning costs. Costs added to the transmission portion of the bills include the Federally Mandated Congestion Charges (FMCC), a bill pass-through associated with the FERC passage of Standard Market Design (SMD) to enhance reliability of the transmission grid and control congestion. Additional costs not included in historical data sets have been added in adjustment factors to the transmission and distribution capital and O&M costs, which affect the cost of both competitive and regulated electricity supply. Because many of these costs are temporary in nature, EIA gradually phases them out during the projection period.

Fuel price expectations

Capacity planning decisions in the EMM are based on a life-cycle cost analysis during a 30-year period, which requires foresight assumptions for fuel prices. Expected prices for coal, natural gas, and oil are derived using rational expectations, or perfect foresight. In this approach, expectations for future years are defined by the realized solution values for these years in a previous model run. The expectations for the world crude oil price and natural gas wellhead price are set using the resulting prices from a previous model run. EIA calculates the markups to the delivered fuel prices based on the markups from the previous year within a NEMS run. Coal prices are determined using the same coal supply curves developed in the NEMS Coal Market Module. The supply curves produce prices at different levels of coal production, as a function of labor productivity, and mine costs and utilization. The EMM develops expectations for each supply curve based on the actual demand changes from the previous run throughout the projection period, resulting in updated mining utilization and different supply curves.

The perfect foresight approach generates an internally consistent scenario from which EIA can form expectations consistent with the projections realized in the model. The NEMS model involves iterative cycling of runs until the expected values and realized values for variables converge between cycles.

Nuclear fuel prices

Nuclear fuel prices are calculated through an offline analysis that determines the delivered price to generators in dollars per megawatthour (MWh). To produce reactor-grade uranium, the uranium (U3O8) must first be mined and then sent through a conversion process to prepare for enrichment. The enrichment process takes the fuel to the purity of uranium-235, typically 3% to 5% for commercial reactors in the United States. Finally, the fabrication process prepares the enriched uranium for a specific type of reactor core. The price of each of the processes is determined, and the prices are summed to get the final price of the delivered fuel. The analysis uses forecasts from Energy Resources International for the underlying uranium prices.

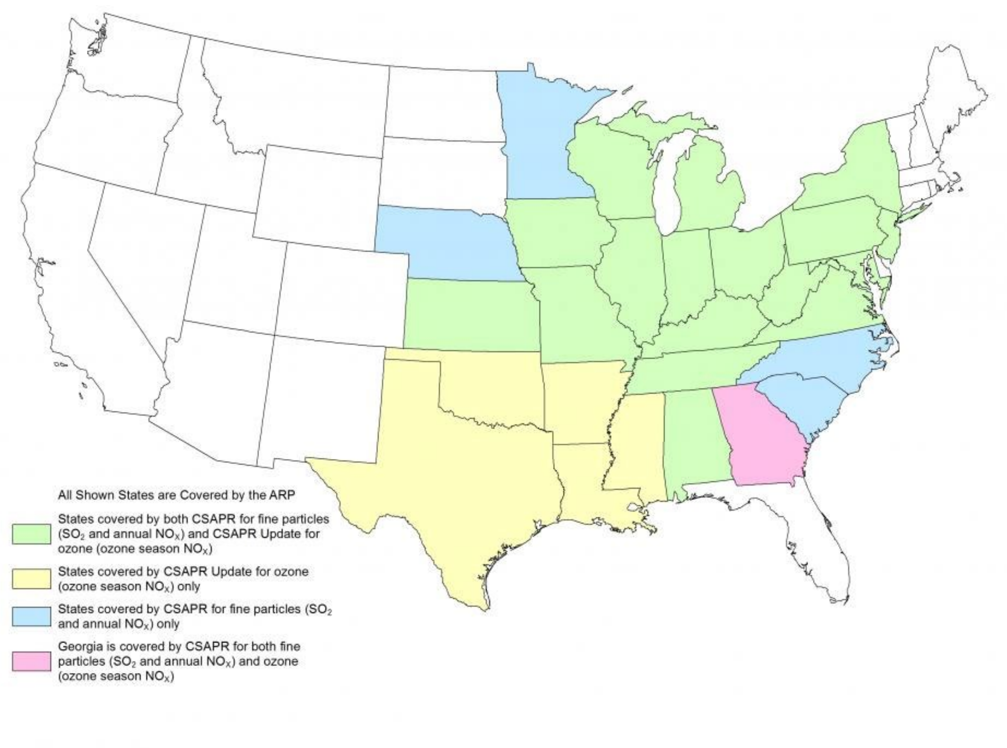
Legislation and regulations

Cross-State Air Pollution Rule and Clean Air Act Amendments of 1990

AEO2021 continues to include the Cross-State Air Pollution Rule (CSAPR), which addresses the interstate transport of air emissions from power plants. After a series of court rulings over the years, the Supreme Court in October 2014 lifted its stay and upheld CSAPR as a replacement for the Clean Air Interstate Rule. On September 7, 2016, EPA finalized an update to the CSAPR ozone season program, which is reflected in EIA's assumed emission budgets and target dates.

Under CSAPR, 27 states must restrict emissions of sulfur dioxide (SO2) and nitrogen oxide (NOx), which are precursors to the formation of fine particulate matter (PM2.5) and ozone. CSAPR establishes four allowance trading programs for SO2 and NOx composed of different member states based on the contribution of each state to downwind nonattainment of National Ambient Air Quality Standards (Figure 2). In addition, CSAPR splits the allowance trading program into two regions for SO2, Group 1 and Group 2, and trading is permitted only between states within a group (estimated in NEMS by trade between coal demand regions) but not between groups.

Figure 2. Cross-State Air Pollution Rule



Source: U.S. Environmental Protection Agency, Clean Air Markets

In addition to interstate transport, the Clean Air Act Amendments of 1990 (CAAA1990) required existing major stationary sources of NOx located in nonattainment areas to install and operate NOx controls that meet Reasonably Available Control Technology (RACT) standards. To implement this requirement, EPA developed a two-phase NOx program. The first set of RACT standards for existing coal plants took effect in 1996 and the second set in 2000. Coal plant operators were required to significantly reduce NOx

emissions from dry bottom wall-fired and tangential-fired boilers, the most common boiler types (Group 1 Boilers), beginning in 1996 and again in 2000. Relative to their uncontrolled emission rates, which range from about 0.6 to 1.0 pounds per million British thermal units (Btu), EPA requires that these boilers emit 25% to 50% fewer NOx emissions to meet the Phase I limits. Further reductions are required to meet the Phase II limits. EPA did not impose limits on existing oil and natural gas plants, but some states have instituted additional NOx regulations. All new fossil-fuel units are required to meet current standards. These limits are 0.11 pounds/million Btu for conventional coal, 0.02 pounds/million Btu for advanced coal, 0.02 pounds/million Btu for combined cycle, and 0.08 pounds/million Btu for combustion turbines. The EMM incorporates these RACT NOx limits.

Table 8 shows the average capital costs for environmental control equipment used in NEMS for existing coal plants as retrofit options to remove SO2, NOx, mercury (Hg), and hydrogen chloride (HCl). In the EMM, plant-specific costs are calculated based on the size of the unit and other operating characteristics, and these numbers reflect the capacity-weighted averages of all plants falling into each size category. EIA assumes FGD units remove 95% of the SO2 and selective catalytic reduction (SCR) units remove 90% of the NOx.

Table 8. Coal plant retrofit costs

2020 dollars per kilowatt

Coal plant size (megawatts)	FGD capital costs	FF capital costs	SCR capital costs
<100	1027	294	471
100–299	693	211	295
300–499	563	182	262
500–699	495	166	232
>=700	447	151	215

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis
Notes: FGD = flue gas desulfurization unit, FF = fabric filter, SCR = selective catalytic reduction unit.

Affordable Clean Energy Rule (ACE)

Following the Presidential Executive Order on Energy Independence and Economic Growth, signed March 28, 2017, EPA issued a Notice of Proposed Rulemaking (NOPR) to repeal the Clean Power Plan (CPP) on October 12, 2017, based on the finding that it was inconsistent with the CAA.[7, 8] Under the authority of CAA Section 111(d), EPA proposed the Affordable Clean Energy (ACE) rule in August 2018 to replace the CPP, which defines the best system of emission reduction (BSER) for existing power plants as onsite, heat rate efficiency improvements.[9] On June 19, 2019, EPA issued the final ACE rule,[10] establishing guidelines for states to use when developing plans to limit CO2 at existing coal-fired electric generating units. The rule provides a list of candidate heat rate improvement technologies for state plans, but it does not set specific technology-based emissions standards. The AEO2021 Reference and side cases include the implementation of ACE by requiring all coal-fired power plants with heat rate improvement options available to undertake these projects or retire by 2025. The year 2025 is an

estimate taken from EPA's ACE rule Regulatory Impact Analysis for when the standards of performance under the final rule might be implemented, given the flexibility that states have to submit plans and for EPA review. Potential heat rate improvement options are based on a 2015 analysis discussed in the next section. A side case assuming ACE is not implemented was also developed for AEO2020, but it was not updated for AEO2021[11].

EPA also finalized carbon pollution standards for new, modified, and reconstructed power plants under CAA Section 111(b) in October 2015.[12] On December 6, 2018, EPA proposed a revision to the 2015 standards, which were based on the determination that partial CCS was the BSER for new plants. The new proposal increases the proposed emissions rate for newly constructed steam units from 1,400 pounds of CO2/MWh to 1,900–2,000 pounds of CO2/MWh, depending on plant size, based on the determination that the BSER for new plants is the most efficient demonstrated steam cycle (supercritical) in combination with best operating practices.[13] By withdrawing the 2015 ruling, EPA has affirmed its intention that new coal plants without CCS can be built and the AEO2021 allows a new coal technology (ultra-supercritical technology) to be built if economical. The new natural gas combined-cycle plants modeled in the EMM have lower emission rates than both the original and revised standards, and no change was necessary to the natural gas technology assumptions. The NEMS electricity model does not explicitly represent modified or reconstructed power plants, which are also covered by the rule.

Heat rate improvement retrofits

Since AEO2015, the EMM can evaluate heat rate improvements at existing coal-fired generators. A generator with a lower heat rate can generate the same quantity of electricity while consuming less fuel, which reduces corresponding emissions of SO2, NOx, mercury, and CO2. Improving heat rates at power plants can lower fuel costs and help achieve compliance with environmental regulations. Heat rate improvement is a planning activity because it considers the tradeoff between the investment expenditures and the savings in fuel and environmental compliance costs. The amount of potential increase in efficiency can vary depending on the type of equipment installed at a unit and the beginning configuration of the plant. The EMM represents 32 configurations of existing coal-fired plants based on different combinations of particulate, SO2, NOx, mercury, and carbon emissions controls (Table 9). These categories form the basis for evaluating the potential for heat rate improvements.

EIA entered into a contract with Leidos, Inc., to develop a methodology to evaluate the potential for heat rate improvement at existing coal-fired generating plants.[14] Leidos performed a statistical analysis of the heat rate characteristics of coal-fired generating units modeled by EIA in the EMM. Specifically, Leidos developed a predictive model for coal-fired electric generating unit heat rates as a function of various unit characteristics, and Leidos employed statistical modeling techniques to create the predictive models.

For the EMM plant types, Leidos categorized the coal-fired generating units into four equal groups, or quartiles, based on observed versus predicted heat rates. Units in the first quartile (Q1), which operated more efficiently than predicted, were generally associated with the least potential for heat rate improvement. Units in the fourth quartile (Q4), representing the least efficient units relative to predicted values, were generally associated with the highest potential for heat rate improvement.

Leidos developed a matrix of heat rate improvement options and associated costs, based on a literature review and engineering judgment.

Little or no coal-fired capacity exists for the EMM plant types with mercury and carbon-control configurations; therefore, Leidos did not develop estimates for those plant types. These plant types were ultimately assigned the characteristics of the plants with the same combinations of particulate, SO2, and NOx controls. Plant types with relatively few observations were combined with other plant types that had similar improvement profiles. As a result, Leidos developed nine unique plant type combinations for the quartile analysis, and for each of these combinations, Leidos created a maximum potential for heat rate improvement along with the associated costs to achieve those improved efficiencies.

Leidos used the minimum and maximum characteristics as a basis for developing estimates of mid-range cost and heat rate improvement potential. The EMM used the mid-range estimates as its default values (Table 10).

Table 9. Existing pulverized-coal plant types in the National Energy Modeling System Electricity Market Module

Plant type	Particulate controls	SO2 controls	NOx controls	Mercury controls	Carbon controls
B1	BH	None	Any	None	None
B2	BH	None	Any	None	CCS
B3	BH	Wet	None	None	None
B4	BH	Wet	None	None	CCS
B5	BH	Wet	SCR	None	None
B6	BH	Wet	SCR	None	CCS
B7	BH	Dry	Any	None	None
B8	BH	Dry	Any	None	CCS
C1	CSE	None	Any	None	None
C2	CSE	None	Any	FF	None
C3	CSE	None	Any	FF	CCS
C4	CSE	Wet	None	None	None
C5	CSE	Wet	None	FF	None
C6	CSE	Wet	None	FF	CCS
C7	CSE	Wet	SCR	None	None
C8	CSE	Wet	SCR	FF	None
C9	CSE	Wet	SCR	FF	CCS
CX	CSE	Dry	Any	None	None
CY	CSE	Dry	Any	FF	None
CZ	CSE	Dry	SCR	FF	CCS
H1	HSE/Oth	None	Any	None	None
H2	HSE/Oth	None	Any	FF	None
H3	HSE/Oth	None	Any	FF	CCS
H4	HSE/Oth	Wet	None	None	None
H5	HSE/Oth	Wet	None	FF	None
H6	HSE/Oth	Wet	None	FF	CCS
H7	HSE/Oth	Wet	SCR	None	None
H8	HSE/Oth	Wet	SCR	FF	None
H9	HSE/Oth	Wet	SCR	FF	CCS
HA	HSE/Oth	Dry	Any	None	None
HB	HSE/Oth	Dry	Any	FF	None
HC	HSE/Oth	Dry	Any	FF	CCS

Source: U.S. Energy Information Administration
Notes: Particulate controls: BH = baghouse, CSE = cold-side electrostatic precipitator, HSE/Oth = hot-side electrostatic precipitator/other/none.
SO_2 = sulfur dioxide, NO_x = nitrogen oxide.
SO2 controls: Wet = wet scrubber, Dry = dry scrubber. NOx controls: SCR = selective catalytic reduction. Mercury controls: FF = fabric filter.
Carbon controls: CCS = carbon capture and sequestration.

Table 10. Heat rate improvement (HRI) potential and cost (capital, fixed operations and maintenance) by plant type and quartile as used for input into the National Energy Modeling System

Plant type and quartile combination	Count of total units	Percentage HRI potential	Capital cost (million 2014 dollars per megawatt)	Average fixed operations and maintenance cost (2014 dollars per megawatt per year)
B1-Q1	32	(s)	0.01	200
B1-Q2	15	1%	0.10	2,000
B1-Q3	18	4%	0.20	4,000
B1-Q4	20	6%	0.90	20,000
B3-Q1	13	(s)	0.01	300
B3-Q2	24	1%	0.05	1,000
B3-Q3	16	6%	0.20	3,000
B3-Q4	15	9%	0.60	10,000
B5C7-Q1	16	(s)	(s)	80
B5C7-Q2	42	1%	0.03	700
B5C7H7-Q3	84	7%	0.10	2,000
B5C7H7-Q4	59	10%	0.20	4,000
B7-Q1	27	(s)	(s)	70
B7-Q2	25	1%	0.04	800
B7-Q3Q4	30	7%	0.30	5,000
C1H1-Q1	148	(s)	0.01	200
C1H1-Q2	117	1%	0.10	2,000
C1H1-Q3	72	4%	0.40	8,000
C1H1-Q4	110	7%	1.00	30,000
C4-Q1	15	(s)	(s)	80
C4-Q2	27	1%	0.04	900
C4-Q3	32	6%	0.20	2,000
C4-Q4	39	10%	0.30	5,000
CX-Q1Q2Q3Q4	15	7%	0.20	4,000
H4-Q1Q2Q3	13	3%	0.20	3,000
IG-Q1	3	(s)	(s)	60
Total set	**1,027**	**4%**	**0.30**	**6,000**

Source: U.S. Energy Information Administration, based on data from Leidos, Inc.
(s) = less than 0.05% for HRI potential or less than 0.005 million dollars per megawatt for capital cost.
Note: Leidos selected the plant type and quartile groupings so that each grouping contained at least 10 generating units, except for the integrated gasification combined-cycle (IG) type, which has essentially no heat rate improvement potential.

Mercury regulation

The Mercury and Air Toxics Standards (MATS) were finalized in December 2011 to fulfill EPA’s requirement to regulate mercury emissions from power plants. MATS also regulate other hazardous air pollutants (HAPS) such as hydrochloric acid (HCl) and fine particulate matter (PM2.5). MATS applies to coal- and oil-fired power plants with a nameplate capacity greater than 25 MW, and it requires that all

qualifying units achieve the maximum achievable control technology (MACT) for each of the three covered pollutants by 2016. For AEO2021, EIA assumes that all coal-fired generating units affected by the rule meet HCl and PM2.5 standards, which the EMM does not explicitly model.

All power plants are required to reduce their mercury emissions to 90% less than their uncontrolled emissions levels. When plants alter their configuration by adding equipment, such as an SCR to remove NOx or an SO2 scrubber, mercury removal is often a resulting co-benefit. The EMM considers all combinations of controls and may choose to add NOx or SO2 controls purely to lower mercury if it is economical to do so. Plants can also add activated carbon-injection systems specifically designed to remove mercury. Activated carbon can be injected in front of existing particulate-control devices, or a supplemental fabric filter can be added with activated carbon injection capability.

EIA assumes the equipment to inject activated carbon in front of an existing particulate control device costs about $7 (2020 dollars) per kW of capacity.[15] EIA calculates the costs of a supplemental fabric filter with activated carbon injection (often referred as a COPAC unit) by unit, and the average costs are shown in Table 8. The amount of activated carbon required to meet a given percentage removal target is given by the following equations:[16]

For a unit with a cold-side electrostatic precipitator (CSE) that uses subbituminous coal and simple activated carbon injection, the following equation is used:

ACI = activated carbon injection rate in pounds per million actual cubic feet of flue gas

- Hg Removal (%) = 65 - (65.286 / (ACI + 1.026))

For a unit with a CSE that uses bituminous coal and simple activated carbon injection, the following equation is used:

- Hg Removal (%) = 100 - (469.379 / (ACI + 7.169))

For a unit with a CSE and a supplemental fabric filter with activated carbon injection, the following equation is used:

- Hg Removal (%) = 100 - (28.049 / (ACI + 0.428))

For a unit with a hot-side electrostatic precipitator (HSE) or other particulate control and a supplemental fabric filter with activated carbon injection, the following equation is used:

- Hg Removal (%) = 100 - (43.068 / (ACI + 0.421))

Power plant mercury emissions assumptions

The EMM represents 36 coal plant configurations and assigns a mercury emissions modification factor (EMF) to each configuration. Each configuration represents different combinations of boiler types, particulate control devices, SO2 control devices, NOx control devices, and mercury control devices. An EMF represents the amount of mercury that was in the fuel that remains after passing through all the plant’s systems. For example, an EMF of 0.60 means that 40% of the mercury in the fuel is removed by various parts of the plant. Table 11 provides the assumed EMFs for existing coal plant configurations without mercury-specific controls.

Table 11. Mercury emission modification factors

	Configuration		EIA EMFs			EPA EMFs		
SO2 control	particulate control	NOX control	Bit coal	Sub coal	Lignite coal	Bit coal	Sub coal	Lignite coal
None	BH	—	0.11	0.27	0.27	0.11	0.26	1.00
Wet	BH	None	0.05	0.27	0.27	0.03	0.27	1.00
Wet	BH	SCR	0.10	0.27	0.27	0.10	0.15	0.56
Dry	BH	—	0.05	0.75	0.75	0.50	0.75	1.00
None	CSE	—	0.64	0.97	0.97	0.64	0.97	1.00
Wet	CSE	None	0.34	0.73	0.73	0.34	0.84	0.56
Wet	CSE	SCR	0.10	0.73	0.73	0.10	0.34	0.56
Dry	CSE	—	0.64	0.65	0.65	0.64	0.65	1.00
None	HSE/Oth	—	0.90	0.94	0.94	0.90	0.94	1.00
Wet	HSE/Oth	None	0.58	0.80	0.80	0.58	0.80	1.00
Wet	HSE/Oth	SCR	0.42	0.76	0.76	0.10	0.75	1.00
Dry	HSE/Oth	—	0.60	0.85	0.85	0.60	0.85	1.00

Sources: U.S. Environmental Protection Agency emission modification factors (EPA EMFs).
EIA EMFs not from EPA: Lignite EMFs, Mercury Control Technologies for Coal-Fired Power Plants, presented by the Office of Fossil Energy on July 8, 2003
Bituminous coal mercury removal for a Wet/HSE/Oth/SCR configured plant, Table EMF1, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology, U.S. Department of Energy, January 2003, Washington, DC
Notes: Under SO2 control: SO2 = sulfur dioxide, Wet = wet scrubber, and Dry = dry scrubber; Under Particulate control: BH = fabric filter/baghouse, CSE = cold-side electrostatic precipitator, HSE/Oth = hot-side electrostatic precipitator/other/none; Under NOx control: NOx = nitrogen oxide and SCR = selective catalytic reduction.
— = not applicable, Bit = bituminous coal, Sub = subbituminous coal. The NOx control system is not assumed to enhance mercury removal unless a wet scrubber is present, so it is left blank (—) in such configurations.

Tax Credit for Carbon Dioxide Sequestration

The section 45Q sequestration tax credit was amended and expanded as part of the Bipartisan Budget Act of 2018.[17] The AEO2021 reflects this update in both the EMM and the Oil and Gas submodule. The 45Q credits are available to both power and industrial sources that capture and permanently sequester CO2 in geologic storage and use CO2 in enhanced oil recovery (EOR). Credits are available to plants that start construction, or begin a retrofit, before January 1, 2024, and are assumed to be applied for the first 12 years of operation. The credit values vary depending on whether the CO2 is used for EOR or is permanently sequestered.

Carbon capture and sequestration retrofits

The EMM includes the option of retrofitting existing coal plants for CCS. The modeling structure for CCS retrofits within the EMM was developed by the National Energy Technology Laboratory[18] and uses a generic model of retrofit costs as a function of basic plant characteristics (such as heat rate). The costs have been adjusted to be consistent with costs of new CCS technologies. EIA assumes the CCS retrofits remove 90% of the carbon input. The addition of the CCS equipment results in a capacity derate of about 30% and a reduced efficiency of 43% at the existing coal plant. The costs depend on the size and efficiency of the plant; capital costs average $1,819 per kW and range from $1,326 per kW to $2,557 per

kW. This analysis assumes that only plants greater than 500 MW and with heat rates lower than 12,000 Btu per kilowatthour (kWh) would be considered for CCS retrofits.

Beginning in AEO2018, the EMM includes the option to retrofit existing natural gas-fired combined-cycle plants with CCS technology, also based on the modeling structure developed by NETL.

State air emissions regulations

AEO2021 continues to model the Northeast Regional Greenhouse Gas Initiative (RGGI), which applies to fossil-fuel powered plants larger than 25 MW in the northeastern and certain mid-Atlantic states. After withdrawing in 2011, New Jersey adopted rules to rejoin the program in 2019.[19] In July 2020, Virginia also passed legislation to join the program and will be included beginning in 2021;[20] at this point, 11 states will be in the accord. The rule caps CO2 emissions from covered electricity generating facilities and requires that they account for each ton of CO2 emitted with an allowance purchased at auction. The original cap was revised downward in 2014, and the new cap has been reflected in NEMS since AEO2014. The participating states reviewed the program, which led to an Updated Model Rule in December 2017.[21] EMM incorporates the updates to the original rule, which includes a specified cap through 2030, modifications to the Cost Containment Reserves (available if defined allowance-price triggers are exceeded), and an Emissions Containment Reserve (to be used if prices fall lower than established trigger prices). The cap was adjusted for AEO2021 to reflect the additional budget allocated for Virginia in 2021 and beyond.

The California Senate Bill 32 (SB32), passed in October 2016, revises and extends the greenhouse gas (GHG) emission reductions that were previously in place to comply with Assembly Bill 32 (AB32), the Global Warming Solutions Act of 2006. AB32 implements a cap-and-trade program in which the electric power sector as well as industrial facilities and fuel providers need to meet emission targets by 2020. SB32 requires the California Air Resources Board (CARB) to enact regulations to ensure the maximum technologically feasible and cost-effective GHG emission reductions occur, and it sets a new state emission target of 40% lower than 1990 emission levels by 2030. A companion law, Assembly Bill 197 (AB197), directs the CARB to consider social costs for any new programs to reduce emissions and to make direct emission reductions from stationary, mobile, and other sources a priority. The California Assembly Bill 398 (AB398), passed in July 2017, clarifies more clearly how the new targets will be achieved. AEO2021 continues to assume that a cap-and-trade program remains in place, and it sets annual targets through 2030 that remain constant afterward. The emissions constraint is in the EMM but accounts for the emissions determined by other sectors. Within the power sector, emissions from plants owned by California utilities but located outside of the state, as well as emissions from electricity imports into California, count toward the emission cap, and estimates of these emissions are included in the EMM constraint. EIA calculated and added an allowance price to fuel prices for the affected sectors. EIA modeled a limited number of banking and borrowing of allowances as well as an allowance reserve and offsets, as specified in the bills. These provisions provide some compliance flexibility and cost containment. Changes in other modules to address SB32 and AB197, such as assumed policy changes that affect vehicle travel and increases in energy efficiency, are described in the appropriate chapters of this report.

State revenue support for existing nuclear power plants

Four states have passed legislation in recent years to provide price support for existing nuclear units that could be at risk of early closure because of declining profitability. The New York Clean Energy Standard,[22] established in 2016, creates zero emission credits (ZEC) that apply to certain nuclear units. The New York load-serving entities are responsible for purchasing ZECs equal to their share of the statewide load, which provides an additional revenue source to the nuclear units holding the ZECs. The program is set to cover a 12-year term, and the annual value of the ZEC is determined by the state, taking into account the state-determined value of clean energy, which states will reevaluate over time.

The Illinois Future Energy Jobs Act,[23] passed in 2017, also creates a ZEC program covering a 10-year term. Nuclear power plants serving at least 100,000 customers in Illinois are eligible for ZECs. The Illinois Power Agency must procure ZECs in each year of the program to cover 16% of 2014 utility sales. The value of the ZEC is capped at a state-determined value of clean energy and will increase over time, subject to an annual cap of $250 million.

In 2018, the New Jersey Senate passed bill S. 2313,[24] which established a ZEC program that is funded by a $0.004 per kWh annual charge to create a fund of about $300 million per year. Three nuclear reactors are eligible to receive payments from the fund during the year of their implementation plus the three following years, and they may be considered for additional three-year renewal periods thereafter.

In July 2019, Ohio passed House Bill 6,[25] which included a provision to collect $150 million per year through 2027 into a Nuclear Generation Fund to be distributed to qualifying nuclear generating units located in Ohio at a rate of $9 per MWh credit.

This legislation is modeled in AEO2021 by explicitly requiring nuclear units located in Illinois, upstate New York, New Jersey, and Ohio to continue to operate through the specific program's period (the model cannot choose to endogenously retire the plant). The cost of each program is determined by comparing the affected plants' costs with the corresponding revenues based on the modeled marginal energy prices to evaluate plant profitability. If plant costs exceed revenues, a subsidy payment is applied. The cost of the subsidy payment is recovered through retail prices as an adder to the electric distribution price component to represent the purchase of ZECs by load-serving entities.

The Ohio legislation also supports the coal-fired power plants owned and operated by the Ohio Valley Electric Corporation, which includes the 1,300-MW Clifty Creek Generating Station on the Ohio River in Jefferson County, Indiana, and the 1,086-MW Kyger Creek Generating Station on the Ohio River in Gallia County, Ohio. These plants were designated as must-run plants in the EMM until 2030 and are not candidates for economic retirement during that time.

Connecticut passed Senate Bill No. 1501[26] in June 2017 that permits nuclear power to compete in zero-emissions state energy auctions. In December 2018, Connecticut's Department of Energy and Environmental Protection selected a 10-year proposal from Millstone for about half of its 2.1 GW output. Between 2022 and 2029, Millstone will receive higher prices based on environmental, economic, and grid benefits. It also selected Seabrook NPP in New Hampshire, and the plant's contract will begin in 2022. EIA does not explicitly model this program in the EMM through the ZEC structure because it does

not provide specific support to existing nuclear generating plants; however, in the AEO2021 cases the nuclear plants in New England tend to be economical and are not projected to retire through 2030.

Energy Policy Acts of 1992 (EPACT1992) and 2005 (EPACT2005)

The provisions of EPACT1992 include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs). EPACT1992 also implemented a permanent 10% ITC for geothermal and solar facilities and introduced a PTC for eligible renewable technologies (subsequently extended and expanded). EPACT2005 provides a 20% ITC for integrated coal-gasification combined-cycle capacity and a 15% ITC for other advanced coal technologies. These credits are limited to 3 GW in both cases. These credits have been fully allocated and are not assumed to be available for new, unplanned capacity built within the EMM. EPACT2005 also contains a PTC of 1.8 cents (nominal) per kWh for new nuclear capacity beginning operation by 2020. This PTC is specified for the first eight years of operation and is limited to $125 million annually and to 6 GW of new capacity. EPACT2005 extended the PTC for qualifying renewable facilities by two years (through December 31, 2007) and also repealed the Public Utility Holding Company Act (PUHCA).

The investment and energy PTCs initiated in EPACT1992 and amended in EPACT2005 have been further amended through a series of acts that were incorporated in previous AEOs. A history of these tax credits is described in AEO2016 Legislation and Regulations LR3—Impact of a Renewable Energy Tax Credit extension and phaseout.[27] AEO2021 continues to reflect the most recent changes implemented through the 2016 Consolidated Appropriation Act passed in December 2015. Based on guidance from the Internal Revenue Service that allows four years from construction start to online date, the 30% ITC is assumed for all solar plants online by 2023. The ITC drops to 10% for plants coming online after 2023. For nuclear plants, the Bipartisan Budget Act of 2018 revised the PTC eligibility to include plants online after 2020, while retaining the 6 GW limit.

The PTC is a per-kWh tax credit available for qualified wind, geothermal, closed-loop and open-loop biomass, landfill gas, municipal solid waste, hydroelectric, and marine and hydrokinetic facilities. The value of the credit, originally 1.5 cents/kWh, is adjusted for inflation annually and is available for 10 years after the facility has been placed in service. For AEO2021, wind, poultry litter, geothermal, and closed-loop biomass resources receive a tax credit of 2.4 cents/kWh; all other renewable resources receive a 1.2 cent/kWh tax credit (that is, one-half the value of the credit for other resources). EIA assumes that biomass facilities obtaining the PTC will use open-loop fuels because closed-loop fuels are assumed to be unavailable or too expensive for widespread use during the period that the tax credit is available. The 2016 Consolidated Appropriation Act passed in December 2015 extended the PTC for projects under construction through 2016. The PTC was scheduled to phase down in value for wind projects under that act, but that plan has since been revised.

The Taxpayer Certainty and Disaster Tax Relief Act of 2019 that passed in December 2019 included a one-year extension to the wind PTC. The legislation extended the PTC through 2020 and restored the PTC to 60% (from 40%) of its full value for facilities that either enter service or secure 5% safe harbor through the 2020 calendar year. AEO2021 reflects this change by allowing the PTC for all wind plants online by 2024.

The ITCs and PTCs are exclusive of one another and both cannot be claimed for the same facility. EIA assumes that the PTC is chosen for new geothermal plants when it is available (through December 2016)

and that the 10% ITC is chosen for geothermal plants developed after 2016. Both onshore and offshore wind projects are eligible to claim the ITC instead of the PTC. Although onshore wind projects are expected to choose the PTC, EIA assumes offshore wind farms will claim the ITC because of the high capital costs for offshore wind.

American Recovery and Reinvestment Act (ARRA)

Smart grid expenditures

The ARRA provides $4.5 billion for smart grid demonstration projects. Although somewhat difficult to define, smart grid technologies generally include a wide array of measurement, communications, and control equipment employed throughout the transmission and distribution system that enable real-time monitoring of the production, flow, and use of power from the generator to the consumer. Among other things, these smart grid technologies are expected to enable more efficient use of the transmission and distribution grid, lower line losses, and increase use of renewables. Smart grid technologies also provide information to utilities and their customers that may contribute to greater investment in energy efficiency and reduced peak load demands. The funds provided will not support a widespread implementation of smart grid technologies, but the investments could stimulate more rapid development than would otherwise occur.

EIA made several changes throughout NEMS to represent the impacts of the smart grid funding provided in ARRA. In the electricity module, line losses are assumed to fall slightly, peak loads are assumed to fall as customers shift their usage patterns, and customers are assumed to be more responsive to pricing signals. Historically, line losses, expressed as the percentage of electricity lost, have been falling for many years as utilities have invested in replacing aging or failing equipment.

FERC Orders 888 and 889

FERC issued two related rules (Orders 888 and 889) designed to bring low-cost power to consumers through competition, ensure continued reliability in the industry, and provide for open and equitable transmission services by owners of these facilities.

Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable as a result of consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and an Open Access Same-Time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. As a result, utilities have functionally or physically unbundled their marketing functions from their transmission functions.

The EMM represents these orders by assuming that all generators in a given region can satisfy load requirements anywhere within the region. Similarly, the EMM assumes that transactions between regions will occur if the cost differentials between them make those transactions economical.

Notes and sources

[1] Cost and Performance Estimates for New Utility-Scale Electric Power Generating Technologies, Sargent & Lundy, December 2019.

[2] Numerous press announcements regarding coal to gas conversions, for example, "NRG Energy completes four coal to gas projects," December 20, 2016; and "IPL burns coal for the last time at Harding Street Station," February 25, 2016.

[3] Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model, November 2013.

[4] North American Electric Reliability Corporation, Summer Reliability Assessment (June 2019).

[5] Generating Unit Annual Capital and Life Extension Costs Analysis, Sargent & Lundy Consulting, May 2018.

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