Electricity Market Module

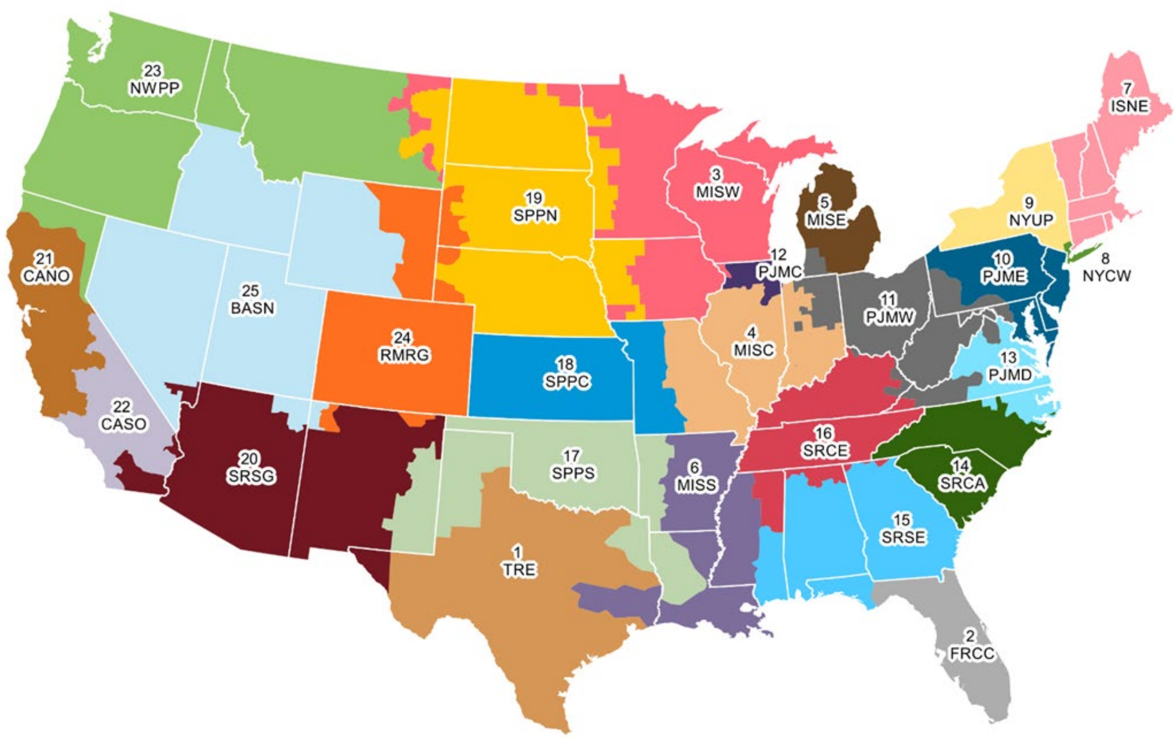
The Electricity Market Module (EMM) in the National Energy Modeling System (NEMS) is composed of four submodules: electricity load and demand, electricity capacity planning, electricity fuel dispatching, and electricity finance and pricing. The EMM also includes nonutility capacity and generation as well as electricity transmission and trade. Our forthcoming publication, *The Electricity Market Module of the National Energy Modeling System: Model Documentation 2022, DOE/EIA-M068* (*2022*), describes the EMM.

Based on fuel prices and electricity demands that other NEMS modules provide, 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 we incorporate in the EMM.

EMM regions

We use 25 electricity supply regions to represent U.S. power markets. The regions follow North American Electric Reliability Corporation (NERC) assessment region boundaries and independent system operator (ISO) and regional transmission organization (RTO) region boundaries (as of early 2019). Subregions are based on regional pricing zones (Figure 1 and Table 1).

Figure 1. Electricity Market Module regions



Source: U.S. Energy Information Administration

Table 1. National Energy Modeling System's Electricity Market Module regions

Number	Abbreviation	NERC/ISO[a] subregion name	Geographic name[b]
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

Source: U.S. Energy Information Administration

[a] NERC=North American Electric Reliability Corporation, ISO=independent system operator

[b] Names are intended to describe approximate locations. Exact regional boundaries do not necessarily correspond to state borders or to other regional naming conventions.

Model parameters and assumptions

Generating capacity types

The EMM considers many capacity types for electricity generation (Table 2).

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

Capacity type
Existing coal steam plants[a]
Ultra-supercritical coal (USC)
USC with 30% carbon capture and sequestration (CCS)
USC with 90% CCS
Oil or natural gas steam—oil or natural gas steam turbine
Combined-cycle (CC)—single-shaft (1x1x1)[b] configuration
Combined-cycle—multi-shaft (2x2x1)[c] 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[d]
Wind
Wind offshore

Source: U.S. Energy Information Administration

[a] The Electricity Market Module represents 32 types of existing coal steam plants based on the different possible configurations of nitrogen oxide (NO_x), particulate and sulfur dioxide (SO_2) emission control devices, and options for controlling mercury and carbon (Table 9).

[b] Single-shaft (1x1x1) configuration with one H-class combustion turbine, one heat recovery steam generator, and one steam turbine generator.

[c] Multi-shaft (2x2x1) configuration with two H-class combustion turbines, two heat recovery steam generators, and one steam turbine generator.

[d] 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.

New generating plant characteristics

The inputs to the Electricity Capacity Planning Submodule are the cost and performance characteristics of new generating technologies (Table 3). In addition to these characteristics, we use fuel prices from the NEMS fuel supply modules and foresight on fuel prices to compare options when new capacity is needed. We assume heat rates for new fossil-fueled technologies remain constant throughout the projection period.

We base initial cost inputs for new technologies on cost estimates developed by a 2019 report prepared by Sargent & Lundy, adjusted for learning cost adjustments for any capacity added since 2019 (Table 3).[1] This report uses a consistent estimation methodology across all technologies to develop cost and performance characteristics for technologies that we considered in the EMM. We did not use the costs that the consultant developed for geothermal and hydro plants, instead we chose to use previously developed site-specific costs. We also did not update costs for distributed generation plants in the electric power sector for this report, and input assumptions remain as in previous *Annual Energy Outlook* (AEO) reports.

Except as noted below, the overnight costs represent the estimated cost of building a plant before adjusting for regional cost factors (Table 3). Overnight costs exclude interest expenses during plant construction and development. The base overnight costs include project contingencies 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. The base year for this commodity cost index is consistent with the base year of the cost estimates, so the initial cost estimate for AEO2022 also reflects changes in the commodity index since 2019.

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 reflect this difference, we report the weighted-average cost for both onshore wind and solar PV based on the regional cost factors assumed for these technologies in AEO2022 and the actual regional distribution of wind and solar builds that occurred in 2020 (Table 3).

Table 4 lists the overnight capital costs for each technology and EMM region for the resources or technologies that are available to be built in each region (Figure 1). 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 our 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. We represent 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[a]	Size (MW)	Lead time (years)	Base overnight cost[2b] (2021$/kW)	Techno-logical optimism factor[c]	Total overnight cost[d,e] (2021$/kW)	Variable O&M[f] (2021 $/MWh)	Fixed O&M (2021$/ kW-y)	Heat rate[g] (Btu/kWh)
Ultra-supercritical coal (USC)	2025	650	4	$4,074	1.00	$4,074	$4.71	$42.49	8,638
USC with 30% carbon capture and sequestration (CCS)	2025	650	4	$5,045	1.01	$5,096	$7.41	$56.84	9,751
USC with 90% CCS	2025	650	4	$6,495	1.02	$6,625	$11.49	$62.34	12,507
Combined-cycle—single-shaft	2024	418	3	$1,201	1.00	$1,201	$2.67	$14.76	6,431
Combined-cycle—multi-shaft	2024	1,083	3	$1,062	1.00	$1,062	$1.96	$12.77	6,370
Combined-cycle with 90% CCS	2024	377	3	$2,736	1.04	$2,845	$6.11	$28.89	7,124
Internal combustion engine	2023	21	2	$2,018	1.00	$2,018	$5.96	$36.81	8,295
Combustion turbine—aeroderivative[h]	2023	105	2	$1,294	1.00	$1,294	$4.92	$17.06	9,124
Combustion turbine—industrial frame	2023	237	2	$785	1.00	$785	$4.71	$7.33	9,905
Fuel cells	2024	10	3	$6,639	1.09	$7,224	$0.62	$32.23	6,469
Nuclear—light water reactor	2027	2,156	6	$6,695	1.05	$7,030	$2.48	$127.35	10,443
Nuclear—small modular reactor	2028	600	6	$6,861	1.10	$7,547	$3.14	$99.46	10,443
Distributed generation—base	2024	2	3	$1,731	1.00	$1,731	$9.01	$20.27	8,923
Distributed generation—peak	2023	1	2	$2,079	1.00	$2,079	$9.01	$20.27	9,907
Battery storage	2022	50	1	$1,316	1.00	$1,316	$0.00	$25.96	NA
Biomass	2025	50	4	$4,524	1.00	$4,525	$5.06	$131.62	13,500
Geothermal[i, j]	2025	50	4	$3,076	1.00	$3,076	$1.21	$143.22	8,813
Conventional hydropower[j]	2025	100	4	$3,083	1.00	$3,083	$1.46	$43.78	NA
Wind[e]	2024	200	3	$1,718	1.00	$1,718	$0.00	$27.57	NA
Wind offshore[i]	2025	400	4	$4,833	1.25	$6,041	$0.00	$115.16	NA
Solar thermal[i]	2024	115	3	$7,895	1.00	$7,895	$0.00	$89.39	NA
Solar photovoltaic (PV) with tracking[e, i, k]	2023	150	2	$1,327	1.00	$1,327	$0.00	$15.97	NA
Solar PV with storage[i, k]	2023	150	2	$1,748	1.00	$1,748	$0.00	$33.67	NA

Source: We primarily base input costs on a report provided by external consultants: Sargent & Lundy, December 2019. We most recently updated hydropower site costs for non-powered dams for AEO2018 using data from Oak Ridge National Lab

Note: MW=megawatt, kW=kilowatt, MWh=megawatthour, kW-y=kilowatt-year, kWh=kilowatthour; Btu=British thermal unit

[a] The first year that a new unit could become operational.

[b] Base cost includes project contingency costs.

[c] We apply the technological optimism factor 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.

[d] 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 2022.

[e] 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 2020 in each region to account for the substantial regional variation in wind and solar costs (Table 4). The input value used for onshore wind in AEO2022 was $1,411 per kilowatt (kW), and for solar PV with tracking, it was $1,323/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.

[f] O&M = Operations and maintenance.

[g] 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 module calculates the average heat rate for fossil-fuel generation in each year to report primary energy consumption displaced for these resources.

[h] Combustion turbine aeroderivative units can be built by the module before 2023, if necessary, to meet a region's reserve margin.

[i] Capital costs are shown before investment tax credits are applied.

[j] 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 the Great Basin region for geothermal, where most of the proposed sites are located.

[k] Costs and capacities are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

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

2021 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)	$3,786	$3,897	$4,259	$4,371	$4,422	$3,918	$4,721	NA	$4,614	$4,763	$4,064	$5,120	$4,385
USC with 30% CCS	$4,777	$4,903	$5,294	$5,437	$5,480	$4,935	$5,846	NA	$5,729	$5,883	$5,094	$6,254	$5,477
USC with 90% CCS	$6,252	$6,411	$6,841	$7,072	$7,078	$6,473	$7,495	NA	$7,303	$7,508	$6,601	$7,994	$7,015
CC—single-shaft	$1,085	$1,107	$1,235	$1,246	$1,277	$1,117	$1,441	$1,912	$1,445	$1,443	$1,197	$1,446	$1,377
CC—multi-shaft	$944	$968	$1,098	$1,117	$1,146	$979	$1,259	$1,725	$1,238	$1,266	$1,037	$1,327	$1,170
CC with 90% CCS	$2,668	$2,693	$2,877	$2,884	$2,928	$2,718	$3,021	$3,422	$2,953	$2,996	$2,756	$3,124	$2,871
Internal combustion engine	$1,898	$1,940	$2,073	$2,155	$2,131	$1,966	$2,209	$2,769	$2,125	$2,209	$1,980	$2,408	$2,056
CT—aeroderivative	$1,145	$1,168	$1,354	$1,357	$1,398	$1,193	$1,456	$1,864	$1,405	$1,448	$1,242	$1,591	$1,317
CT—industrial frame	$692	$707	$822	$826	$851	$723	$886	$1,144	$854	$882	$753	$971	$800
Fuel cells	$6,933	$7,041	$7,362	$7,680	$7,534	$7,159	$7,815	$9,201	$7,498	$7,748	$7,138	$8,261	$7,358
Nuclear—light water reactor	$6,636	$6,779	$7,157	$7,807	$7,530	$7,000	$7,964	NA	$7,430	$7,781	$6,878	$8,556	$7,158
Nuclear—small modular reactor	$7,032	$7,197	$7,841	$8,176	$8,173	$7,287	$8,441	NA	$8,040	$8,459	$7,376	$9,438	$7,660
Distributed generation—base	$1,563	$1,595	$1,779	$1,795	$1,840	$1,609	$2,076	$2,754	$2,081	$2,079	$1,724	$2,083	$1,984
Distributed generation—peak	$1,839	$1,877	$2,174	$2,180	$2,246	$1,916	$2,339	$2,994	$2,257	$2,326	$1,995	$2,555	$2,116
Battery storage	$1,316	$1,320	$1,301	$1,364	$1,319	$1,347	$1,357	$1,351	$1,321	$1,325	$1,313	$1,329	$1,325
Biomass	$4,198	$4,313	$4,669	$4,824	$4,835	$4,348	$5,372	$7,292	$5,389	$5,483	$4,611	$5,493	$5,255
Geothermal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Conventional hydropower	$4,498	$5,495	$2,186	$1,453	$2,959	$4,378	$2,025	NA	$4,144	$4,305	$3,752	NA	$3,808
Wind	$2,757	NA	$1,552	$1,411	$1,690	$1,411	$1,870	NA	$2,281	$1,870	$1,411	$2,055	$1,948
Wind offshore	$5,901	$7,080	$6,984	NA	$7,234	NA	$7,047	$6,079	$7,370	$6,755	$5,524	$7,999	$6,293
Solar thermal	$7,616	$7,731	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Solar PV with tracking	$1,304	$1,279	$1,323	$1,372	$1,357	$1,290	$1,370	$1,612	$1,357	$1,397	$1,320	$1,440	$1,317
Solar PV with storage	$1,692	$1,710	$1,761	$1,817	$1,792	$1,727	$1,828	$2,078	$1,796	$1,832	$1,721	$1,905	$1,781

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)	$3,920	$3,979	$4,032	$3,947	$4,193	$3,991	$4,159	NA	NA	$4,406	$4,119	$4,297
USC with 30% CCS	$4,939	$4,985	$5,059	$4,952	$5,226	$4,999	$5,215	NA	NA	$5,480	$5,159	$5,353
USC with 90% CCS	$6,485	$6,542	$6,620	$6,451	$6,778	$6,497	$6,758	NA	NA	$7,090	$6,658	$6,967
CC—single-shaft	$1,103	$1,116	$1,150	$1,115	$1,183	$1,104	$1,085	$1,590	$1,553	$1,264	$1,023	$1,106
CC—multi-shaft	$968	$980	$1,016	$979	$1,051	$971	$934	$1,398	$1,359	$1,096	$880	$987
CC with 90% CCS	$2,684	$2,698	$2,759	$2,688	$2,777	$2,647	$2,448	$3,071	$3,036	$2,833	$2,303	$2,586
Internal combustion engine	$1,977	$1,982	$2,017	$1,962	$2,068	$1,982	$2,001	$2,398	$2,355	$2,133	$1,975	$2,114
CT—aeroderivative	$1,186	$1,196	$1,241	$1,194	$1,279	$1,203	$1,086	$1,529	$1,491	$1,341	$1,051	$1,198
CT— industrial frame	$718	$726	$753	$724	$777	$729	$658	$934	$910	$816	$637	$728
Fuel cells	$7,211	$7,205	$7,304	$7,080	$7,376	$7,143	$7,243	$8,299	$8,203	$7,585	$7,104	$7,567
Nuclear—light water reactor	$7,090	$7,035	$7,263	$6,807	$7,198	$6,805	$7,058	NA	NA	$7,640	$6,837	$7,648
Nuclear—small modular reactor	$7,323	$7,380	$7,547	$7,306	$7,759	$7,368	$7,465	NA	NA	$8,083	$7,386	$8,028
Distributed generation—base	$1,589	$1,608	$1,657	$1,606	$1,705	$1,591	$1,563	$2,290	$2,238	$1,821	$1,474	$1,593
Distributed generation—peak	$1,905	$1,922	$1,994	$1,919	$2,055	$1,932	$1,744	$2,456	$2,394	$2,154	$1,688	$1,924
Battery storage	$1,359	$1,340	$1,357	$1,310	$1,318	$1,302	$1,333	$1,371	$1,373	$1,348	$1,305	$1,357
Biomass	$4,364	$4,397	$4,455	$4,368	$4,641	$4,460	$4,777	$6,119	$5,981	$4,939	$4,732	$4,731
Geothermal	NA	NA	NA	NA	NA	NA	$3,135	$3,109	$2,517	$3,043	NA	$3,076
Conventional hydropower	$2,120	$4,599	$2,377	$4,550	$1,917	$1,802	$3,655	$3,867	$3,723	$3,083	$3,681	$4,023
Wind	$1,683	$1,907	$1,411	$1,411	$1,552	$1,552	$1,411	$3,116	$2,447	$2,057	$1,411	$1,411
Wind offshore	$5,437	NA	NA	NA	NA	NA	NA	$9,112	$9,560	$6,836	NA	NA
Solar thermal	NA	NA	NA	$7,693	$7,991	$7,614	$7,980	$9,400	$9,282	$8,493	$7,668	$8,510
Solar PV with tracking	$1,343	$1,276	$1,318	$1,278	$1,328	$1,287	$1,300	$1,447	$1,440	$1,332	$1,315	$1,327
Solar PV with storage	$1,739	$1,721	$1,742	$1,709	$1,765	$1,727	$1,736	$1,903	$1,898	$1,795	$1,729	$1,791

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

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

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

Electricity Market Module region map

New construction financing

The Electricity Capacity Planning Submodule of the EMM assumes that new power plants are built in a competitive environment and that different generating technologies generally have the same financing options available. A few exceptions are described below. The EMM assumes projects are financed by both debt and equity, and it uses the after-tax weighted average cost of capital as the discount rate when calculating the discounted cash flow analysis for building and operating new plants.

In the EMM, the corporate tax rate is set at 21%, and all new construction is immediately expensed through a one-year depreciation schedule. The EMM phases out this temporary change to depreciation schedules by 2027, based on the Tax Cuts and Jobs Act of 2017. 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.

The EMM bases the cost of debt on the Industrial Baa bond rate, passed to the EMM as an annual projection from the Macroeconomic Module. The cost of debt in AEO2022 averages 4.8% for capacity builds from 2021 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 that is specific to the industry (described in more detail in the EMM documentation). The average cost of equity in AEO2022 is 10.0%, and the resulting discount rate with a 60/40 debt/equity split is 6.2% from 2021 through 2050.

The AEO2022 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). We also apply the adder to pollution control retrofits to reflect financial risks associated with major investments in long-lived power plants with a relatively higher rate of carbon dioxide (CO_2) emissions. Coal technology that captures 30% of CO_2 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 CO_2 emissions does not receive the three-percentage-point increase in cost of capital.

Technological optimism and learning

We calculate overnight costs for each technology as a function of regional construction parameters, project contingencies, 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.

NEMS determines the learning function at a component level. It breaks each new technology into major components identified as revolutionary, evolutionary, or mature. We assume each component has different learning rates, based on the level of experience with the design component (Table 5). If technologies use similar components, these components learn at the same rate that these units are built. For example, we assume the underlying turbine generator for a combustion turbine, combined-cycle, and integrated coal-gasification combined-cycle unit 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 and 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 text describes the methodology for learning in the Electricity Market Module. If a column does not contain a value, the learning period has already passed for that 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, we can compute the parameters (*a* and *b*). We 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, and more conventional designs will not have as much learning potential. We adjust the costs of all design components 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 we calculate the learning rates by component, we calculate a weighted-average learning factor for each technology. We base the weights on the share of the initial cost estimate that is attributable to each component (Table 6). For technologies that do not share components, we calculate this weighted-average learning rate exogenously and input it as a single component.

Table 6. Component cost weights for new technologies

Technology	Pulverized coal	Combustion turbine	HRSG	Carbon capture and 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%

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

These technologies may still have a mix of revolutionary components and more mature components, but this detail is not necessary to include in the module unless capacity from multiple technologies would contribute to component learning. In the case of the solar PV technology, we assume the module component accounts for 30% of the cost, and we assume the balance of system components 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, we assume the turbine unit contributes two-thirds of the capacity, and the heat recovery steam generator (HRSG) contributes the remaining one-third. Therefore, building one gigawatt (GW) of natural gas or 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, we would count all combined-cycle capacity as 100%, both single-shaft and multi-shaft.

Table 7. Component capacity weights for new technologies

Technology	Pulverized coal	Combustion turbine	HRSG	Carbon capture and 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%

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

International learning

In AEO2022, 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 counts toward the base capacity amount. 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 come from the

International Energy Outlook 2021 projections for countries outside of the United States. We apply 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

We model distributed generation in the end-use sectors (as described in the relevant AEO2022 assumptions documents) 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). Costs and performance characteristics are listed in Table 3. We assume these plants reduce the costs of transmission upgrades that would otherwise be needed.

Demand storage

Although not currently modeled in AEO2022, 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 EMM no longer projects builds of this technology type because we added a more detailed modeling of battery storage (as described in the Intermittent and storage modeling section). This storage technology also reduces and shifts peak demand use.

Coal-to-gas conversion

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

We base the modeling structure for coal-to-natural gas conversions on the U.S. Environmental Protection Agency's (EPA) modeling for the Base Case v.5.13.[2] For this modeling, coal-to-natural gas conversion is when an existing boiler is modified to burn natural gas. Coal-to-natural 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 are estimated for eligible coal plants that EPA identified, which excludes 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 it assumes a 5% heat rate penalty 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. The EMM assumes fixed operations and maintenance (O&M) costs are 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 (kW)) 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 megawatts.

To get unit-specific costs, we use EPA's assumptions for natural gas pipeline requirements, which are 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 kW of boiler capacity varies widely; an average cost is $210/kW (in 2021 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 by using historical hourly load data. The load-duration curve in the EMM has nine time periods. First, we split the load data into three seasons: winter (December through March), summer (June through September), and fall/spring (October through November and April through May). 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. We defined these seasons to account for seasonal variation in supply availability.

Our Residential Demand Module and Commercial Demand Module provide end-use consumption to the EMM, including both demand from the grid and onsite generation. The majority of the onsite generation is supplied by behind-the-meter PV generation (in other words, rooftop PV generation) and the end-use modules only provide an annual amount. The EMM dispatches both electric power sector and end-use PV capacity using detailed solar resource profiles to more accurately reflect when the generation occurs. For non-PV onsite generation, the EMM assumes the onsite end-use generation has a uniform capacity factor throughout the year. In the residential and commercial reporting, the end-use consumption reflects the total electricity consumed by end use, whether provided from generation onsite or purchased from the grid. However, the reported electricity sales by sector only reflect the demand from the grid, and the onsite generation is reported as direct use.

Intermittent and storage modeling

The EMM includes the ReStore Submodule to provide the detail needed to represent renewable availability at a greater level than the nine time periods described in the previous section. We developed this submodule to also 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 Submodule solves a set of linear programming sub-problems within the EMM to provide the capacity planning and dispatch submodules with information on 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 Submodule 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 Submodule represents the costs or constraints to ramping conventional technologies up and down to respond to fluctuations in intermittent generation. It also provides the planning module with information on the value of storage to determine future builds. Additional details on the ReStore Submodule are available in the *Renewables Fuel Module* of the AEO2022 assumptions documents.

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, ISO, or RTO. The reserve margin values from the AEO2022 Reference case are based on these regional reference margins reported to NERC, ranging from 12% to 20%.[3] The reserves required are based on the assumed percentage multiplied by peak demand. We calculate the total capacity required as the average of the net peak load hours (net of variable renewable generation) plus reserves. Dispatchable technologies contribute to the reserve margin constraint fully although intermittent and storage technologies have a capacity credit that we calculate based on their availability during the net peak load hours.

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 by plants that are already operating but not at full capacity (spinning reserves) or by 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. The capacity and dispatch submodules of the EMM include explicit constraints requiring spinning reserves in each load time period. We compute the amount of spinning reserves required 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 module 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 EMM models 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. We used a statistical analysis 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. We developed equations 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 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 we calculate the heat-rate adjustment factor based on the capacity factor implied by the operating mode.

Endogenous plant retirement modeling

Fossil fuel-fired steam plant retirements and nuclear and wind retirements are determined endogenously within the model. We assume generating units retire when continuing to run them is no longer economical. Each year, the module determines whether the market price of electricity is sufficient to support the continued operation of existing plant generators. We project 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 $10/kW for oil and natural gas steam plants and $28/kW for nuclear plants (in 2021 dollars). We add these costs to the estimated costs at existing plants regardless of their ages. Beyond 30 years old, the retirement decision includes an additional $39/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 wind plants, an additional aging cost of $4/kW is added beyond 30 years, rising to $8/kW beyond 40 years. These annual cost adders reflect cost recovery of major capital expenditures to replace major component parts to be able to continue operation.

In 2018, we commissioned Sargent and Lundy (S&L) to analyze historical fossil fuel O&M costs and CAPEX and to recommend updates to the EMM.[4] The study focused particularly on whether age is a factor in the level of costs over time. S&L found that for most technologies, age is not a significant variable that influences annual costs, and in particular, capital expenditures seem to be incurred steadily over time rather than as a step increase at a certain age. Therefore, we do not model step 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. We incorporated the following equation 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 module assumes no aging function. Instead, both O&M and CAPEX remain constant over time. We updated the O&M and CAPEX inputs for existing fossil fuel plants using the data set analyzed by S&L, and S&L's report describes them in more detail. We assigned costs for the EMM based on plant type and size category (three to four tiers per type), and we split plants within a size category into three cost groups to provide additional granularity for the model. We assigned plants that were not in the data sample (primarily those not reporting to the Federal Energy Regulatory Commission (FERC)) 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 we assume no separate CAPEX costs for combined-cycle or combustion-turbine plants, and we incorporate the CAPEX data into the variable O&M input cost.

We assume that all retirements reported as planned 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 us. This assumption includes 3.0 GW of nuclear capacity retirements and 66.7 GW of coal capacity retirements after 2021.

Our nuclear unit operating costs are based on inputs from an Idaho National Laboratory (INL) report,[5] 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

We 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, our 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. We updated the input nuclear O&M cost assumptions to be consistent with the INL costs.

Biomass co-firing

We assume 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. We assume this expenditure is $594/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 AEO2022 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 (for example, less than 2%) increases in capacity, which require very little capital investment, to extended uprates of 15% to 20%, which require significant plant modifications. We assume 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 2021. We 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, we assume 2.1 GW of increased nuclear capacity through uprates in 2022 through 2050.

Interregional electricity trade

The EMM represents both firm and economy electricity transactions among utilities in different regions. 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 existing capacity limits constrain the flow of power from region to region. We primarily derive the interregional capacity limits from transmission capacity input files to the National Renewable Energy Laboratory's 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 ISO 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.

We determine economy transactions 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, we assume the regions exchange power.

International electricity trade

The EMM represents two components of international firm power trade: existing and planned transactions as well as unplanned transactions. We compile data on existing and planned transactions from 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 period. We determine Canada's surplus energy using a mini-dispatching submodule 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

We project electricity pricing 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 AEO2022, 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. We project continued capital investment in the transmission and distribution system as a function of changes in peak demand, based on historical trends. We add additional transmission capital investment with each new generating build to account for the costs to connect to the grid. We have developed regression equations 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 the cost of the last (or most expensive) unit dispatched, reflecting fuel and variable costs only. We calculate 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. We calculate 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 AEO2022 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: Florida, Virginia, Carolinas, Southeast, Tennessee Valley, Southern Great Plains, Central Great Plains, Northern Great Plains, Upper Mississippi Valley, Mississippi Delta, Southwest, and Rockies. All other regions reflect a mix of both competitive and regulated prices.

Pricing structures for ratepayers in competitive states have experienced ongoing changes since the start of retail competition. The AEO2022 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, we gradually phase them out during the projection period.

Fuel price expectations

We base capacity planning decisions in the EMM 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, we define expectations for future years 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. We calculate 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, 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 we 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

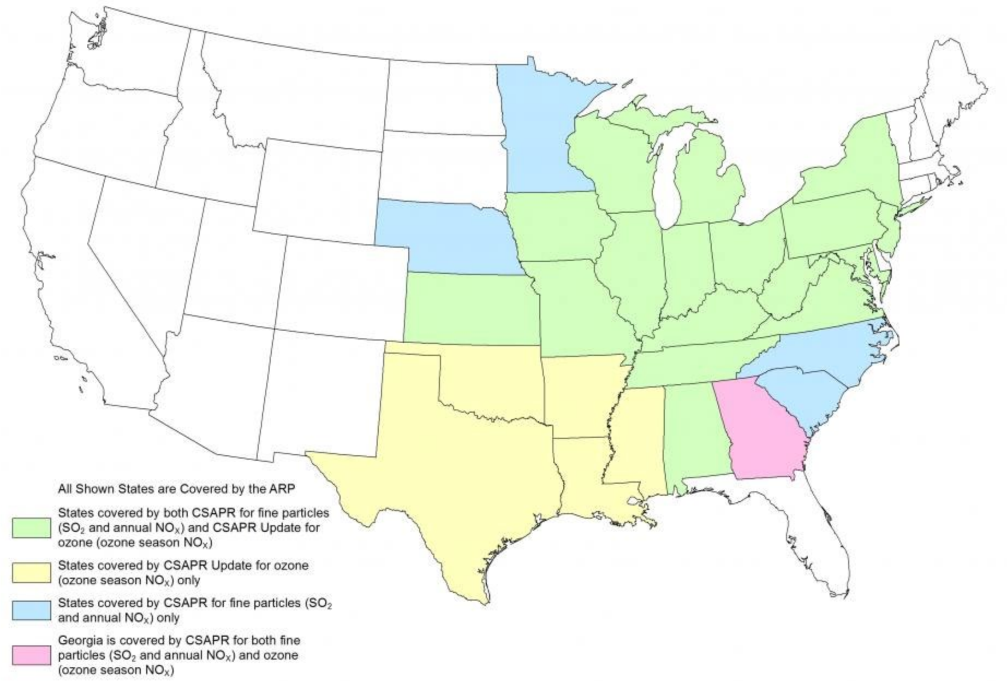
We calculate nuclear fuel prices through an offline analysis that determines the delivered price to generators in dollars per megawatthour (MWh). To produce reactor-grade uranium, the uranium (U_3O_8) must first be mined and then sent through a conversion process to prepare for enrichment. The enrichment 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

AEO2022 continues to include the Cross-State Air Pollution Rule (CSAPR), which addresses the interstate transport of air emissions from power plants. Under CSAPR, 27 states must restrict emissions of sulfur dioxide (SO_2) and nitrogen oxide (NO_x), which are precursors to the formation of fine particulate matter (PM2.5) and ozone. CSAPR establishes four allowance-trading programs for SO_2 and NO_x 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 SO_2, 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. On March 15, 2021, EPA finalized an update to the CSAPR to require additional emissions reductions of nitrogen oxides from power plants in 12 states and revise the budgets for their emissions from 2022 to 2024.

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) require existing major stationary sources of NO_x located in nonattainment areas to install and operate NO_x controls that meet Reasonably Available Control Technology (RACT) standards. To implement this requirement, EPA developed a two-phase NO_x program that took effect for existing coal plants in 1996 and 2000. The EMM assumes all operating plants have made the necessary retrofits to comply with these standards and calculates plant emissions based on the reported environmental controls on each plant. All new fossil fuel units are required to meet current standards. These limits are 0.11 pounds per million British thermal units (MMBtu) for conventional coal, 0.02 pounds/MMBtu for advanced coal, 0.02 pounds/MMBtu for combined cycle, and 0.08 pounds/MMBtu for combustion turbines. The EMM incorporates these RACT NO_x limits.

Table 8 shows the average capital costs for environmental control equipment used in NEMS for existing coal plants as retrofit options to remove SO_2, NO_x, mercury (Hg), and hydrogen chloride (HCl). In the EMM, we calculate plant-specific costs 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. We assume FGD units remove 95% of the SO_2 and selective catalytic reduction (SCR) units remove 90% of the NO_x.

Table 8. Coal plant retrofit costs

2021 dollars per kilowatt

Coal plant size (megawatts)	FGD capital costs	FF capital costs	SCR capital costs
<100	$1,045	$291	$529
100–299	$722	$221	$327
300–499	$584	$188	$289
500–699	$520	$173	$254
>=700	$465	$159	$254

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

In recent years, several rules have been issued, and subsequently repealed, that required states to establish CO_2 standards for existing plants under the CAA Section 111(d). Currently, EPA does not expect states to take any further action to develop and submit plans under Clean Air Act Section 111(d), and the AEO2022 does not incorporate any federal greenhouse gas emission policies for existing power plants.

EPA revised carbon pollution standards for new, modified, and reconstructed power plants under CAA Section 111(b) in December 2018. The emissions rate for newly constructed steam units is 1,900–2,000 pounds of CO_2/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.[6] The EMM allows a new coal technology (ultra-supercritical technology) without carbon capture to be built if economical because it meets this standard. All new natural gas-fired technologies in the module would also comply with this standard. The EMM does not explicitly represent modified or reconstructed power plants, which are also covered by the rule.

Heat rate improvement retrofits

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 SO_2, NO_x, Hg, and CO_2. 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, SO_2, NO_x, Hg, and carbon emissions controls (Table 9). These categories form the basis for evaluating the potential for heat rate improvements.

We contracted with Leidos, Inc., to develop a methodology to evaluate the potential for heat rate improvement at existing coal-fired generating plants.[7] Leidos performed a statistical analysis of the heat rate characteristics of coal-fired generating units that we modeled 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, SO_2, and NO_x 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's Electricity Market Module

Plant type	Particulate controls	SO_2 controls	NO_x 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
Note: *Particulate controls*: BH = baghouse, CSE = cold-side electrostatic precipitator, HSE/Oth = hot-side electrostatic precipitator, other, or none.
SO_2 = sulfur dioxide, NO_x = nitrogen oxide.
SO_2 controls: wet = wet scrubber, dry = dry scrubber. *NO_x 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.
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.
(s) = less than 0.05% for HRI potential or less than 0.005 million dollars per megawatt for capital cost.

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 regulates 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 required that all qualifying units achieve the maximum achievable control technology (MACT) for each of the three covered pollutants by 2016. We assume 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 NO_x or an SO_2 scrubber, mercury removal is often a resulting co-benefit. The EMM considers all combinations of controls and may choose to add NO_x or SO_2 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.

We assume the equipment to inject activated carbon in front of an existing particulate control device costs about $7 (2021 dollars) per kW of capacity.[8] We calculate 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:[9]

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, we use:

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

For a unit with a CSE and a supplemental fabric filter with activated carbon injection, we use:

- 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, we use:

- 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, SO_2 control devices, NO_x control devices, and mercury control devices. An EMF represents the amount of mercury that is 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		
SO_2 control	particulate control	NO_x 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
Note: Under *SO_2 control*: SO_2 = sulfur dioxide, wet = wet scrubber, and dry = dry scrubber; under *particulate control*: BH = fabric filter or baghouse, CSE = cold-side electrostatic precipitator, HSE/Oth = hot-side electrostatic precipitator, other, or none; and under *NO_x control*: NO_x = nitrogen oxide and SCR = selective catalytic reduction.
— = not applicable, Bit = bituminous coal, Sub = subbituminous coal. The NO_x control system is not assumed to enhance mercury removal unless a wet scrubber is present, so we left it blank (—) in such configurations.

Tax credit for carbon dioxide sequestration

The section 45Q sequestration tax credit was extended as part of the Taxpayer Certainty and Disaster Relief Act of 2020.[10] The AEO2022 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 CO_2 in geologic storage or use CO_2 in enhanced oil recovery (EOR). Credits are available to plants that start construction, or begin a retrofit, before January 1, 2026, and are assumed to be applied for the first 12 years of operation. The credit values vary depending on whether the CO_2 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 (NETL)[11] 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. We assume the CCS retrofits remove 90% of the carbon input. The addition of the CCS equipment results in a capacity de-rate 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 $1,901 per kW and range from $1,394 per kW to

$2,712 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.

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

State air emissions regulations

AEO2022 continues to model the Northeast Regional Greenhouse Gas Initiative (RGGI), which applies to fossil-fuel powered plants larger than 25 MW in northeastern and certain mid-Atlantic states. After withdrawing in 2011, New Jersey adopted rules to rejoin the program in 2019.[12] In July 2020, Virginia also passed legislation to join the program and was included beginning in 2021,[13] resulting in 11 states in the accord. The rule caps CO_2 emissions from covered electricity-generating facilities and requires that they account for each ton of CO_2 emitted with an allowance purchased at auction. EMM incorporates all subsequent updates to the original rule, which include amended caps, 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 reflects adjustments to the budget allocation as additional states have joined.

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 set 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 how the new targets will be achieved. AEO2022 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 electric 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. We calculate and add an allowance price to fuel prices for the affected sectors. We model 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 and federal revenue support for existing nuclear power plants

Three states currently have legislation 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,[14] established in 2016, created zero emission credits (ZEC) that apply to certain nuclear units. The Illinois

Future Energy Jobs Act,[15] passed in 2017, also created a ZEC program covering a 10-year term. The Clinton and Quad Cities nuclear plants were selected to receive payments under the original ZEC program. In September 2021, the Illinois Climate and Equitable Jobs Act[16] was passed and includes carbon mitigation credits available to additional nuclear power plants, which led to the reversal of plans to shut down the Byron and Dresden plants. In 2018, the New Jersey Senate passed bill S. 2313,[17] 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.

Although each program has different methods for calculating payments and eligibility, this legislation is modeled more generally in EMM by explicitly requiring nuclear units located in Illinois, upstate New York, and New Jersey 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.

In addition, a federal nuclear credit program was passed as part of the Infrastructure Investment and Jobs Act in August 2021.[18] The program aims to support nuclear power plants that are struggling to remain economically viable in competitive electricity markets and are at risk of shut down. The Secretary of Energy will determine specific unit eligibility and credit level under a $6 billion total budget. The EMM models this program by expanding the same state ZEC logic to all competitive states that are not already receiving state payments, but for these additional states, the costs are not passed through to electricity prices.

In Ohio, House Bill 128[19] repealed provisions of an earlier 2019 bill that provided financial support to nuclear plants. The bill maintained financial support for 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 are designated as must-run plants in the EMM until 2030 and are not candidates for economic retirement during that time.

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. The Bipartisan Budget Act of 2018 revised the PTC eligibility to include plants online after 2020, while retaining the 6 GW limit.

The investment and energy PTCs initiated in EPACT1992 and amended in EPACT2005 have been further amended through a series of acts that have been implemented in NEMS over time. AEO2022 continues to reflect the most recent changes implemented through the Taxpayer Certainty and Disaster Tax Relief Act of 2020. Considering the Continuity Safe Harbor guidance from the Internal Revenue Service, AEO2022 assumes a 26% ITC for all solar plants online by 2025. The ITC drops to 10% for plants coming online after 2025.

The PTC is a per-kWh tax credit originally 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 but is subject to phase out schedules as implemented by more recent amendments. The Taxpayer Certainty and Disaster Tax Relief Act of 2020 extended the PTC phase out by one year, and AEO2022 assumes 60% of the current PTC value is available for all wind plants that began construction by December 31, 2021, and are online through 2025.

The ITCs and PTCs are exclusive of one another, and the same facility cannot claim both. We assume that the 10% ITC is chosen for new geothermal plants. 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, we assume offshore wind farms will claim the ITC because of the high capital costs for offshore wind. The Taxpayer Certainty and Disaster Tax Relief Act of 2020 allows offshore wind projects to claim the full 30% ITC for projects under construction by December 31, 2025, and placed in service no later than December 31, 2035.

Notes and sources

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