4. Generating Resources

Existing, planned-committed, and potential are the three types of generating units modeled in EPA 2023 Reference Case. Electric generating units currently in operation are termed existing units. Units that are anticipated to be in operation in the near future, for having broken ground or secured financing, are planned-committed. Potential units refer to new generating options that IPM builds to meet industry capacity expansion projections. Existing and planned-committed units enter IPM as exogenous inputs, whereas potential units are endogenous to IPM in that the model determines the location and size of the potential units to build.

This chapter is organized as follows.

i) Section 4.1 provides background information on the National Electric Energy Data System (NEEDS), the database that serves as the repository for information on existing and planned-committed electric generating units modeled,

ii) Section 4.2 provides detailed information on existing non-nuclear generating units,

iii) Section 4.3 provides detailed information on planned-committed units,

iv) Section 4.4 provides detailed information on potential units, and

v) Section 4.6 describes assumptions pertaining to existing and potential nuclear units.

4.1 National Electric Energy Data System (NEEDS)

EPA 2023 Reference Case uses the NEEDS database as its source for data on all existing and planned-committed units. Section 4.2 discusses the sources used in developing data on existing units. The population of existing units in the NEEDS represents electric generating units that were in operation through the end of 2023. Section 4.3 discusses the sources used in developing data on planned-committed units. The population of planned-committed includes units online or scheduled to come online from 2024 through June 30, 2028.

4.2 Existing Units

The sections below describe the procedures for determining the population of existing units in NEEDS, as well as the capacity, location, and configuration information of each unit in the population.

4.2.1 Population of Existing Units

The capacity data for existing units in NEEDS was obtained from the sources reported in Table 4-1. The January 2023 EIA Form 860M is the primary data source on existing units. Table 4-2 specifies the screening rules applied to the data source to ensure data consistency and adaptability for use in EPA 2023 Reference Case.

Table 4-1 Data Sources for NEEDS

Data Source[1]	Data Source Documentation
EIA's Form EIA-860	EIA's Form EIA-860 is both a monthly and annual survey of utility and non-utility power plants at the generator level. It contains data such as summer, winter and nameplate capacity, location (state and county), operating status, prime mover, energy sources and in-service date of existing and proposed generators. NEEDS uses EIA Form 860 (January and August 2023 monthly versions, and 2021 annual release) data as primary generator data inputs. EIA's Form EIA-860 also collects data of steam boilers such as energy sources, boiler identification, location, operating status, and design information; and associated environmental equipment such as NO_x combustion and post-combustion control, FGD scrubber, mercury control and particulate collector device information. Note that boilers in plants with less than 10 MW do not report all data elements. The association between boilers and generators is also provided. Note that boilers and generators are not necessarily in a one-to-one correspondence. NEEDS uses EIA Form 860 (2021 annual release) data as one of the primary boiler data inputs.
EIA's Annual Energy Outlook (AEO)	The Energy Information Administration (EIA) Annual Energy Outlook presents annually updated projections of energy supply, demand and prices covering a 20-25 year time horizon. The projections are based on results from EIA's National Energy Modeling System (NEMS). Information from AEO 2023 Reference Case such as capacity for nuclear units was used in NEEDS.
EPA's Emission Tracking System	The Emission Tracking System (ETS) database is updated quarterly. It contains boiler-level information such as primary fuel, heat input, SO_2, NO_x, Mercury, and HCL controls, and SO_2 and NO_x emissions. NEEDS uses annual and seasonal ETS (2019) data as one of the primary data inputs for NO_x rate development and ETS (2022) data for environmental equipment assignment.
Utility and Regional EPA Office Comments	Comments from utilities and regional EPA offices, and EPA research regarding the population in NEEDS as of Summer 2023 (e.g., retirements and new units) as well as unit characteristics were incorporated in NEEDS.

Note:

[1] Shown in Table 4-1 are the primary issue dates of the indicated data sources used. Other vintages of these data sources were also used in instances where data were not available for the indicated issued date, or where there were methodological reasons for using other vintages of the data.

Table 4-2 Rules Used in Populating NEEDS

Scope	Rule
Capacity	Excluded units that had reported summer capacity, winter capacity, and nameplate capacity of zero or blank.
Status	Excluded units that were out of service for three consecutive years (i.e., generators or boilers with status codes "OS[36]" or "OA[37]" in the latest three reporting years) and units that were no longer in service and not expected to be returned to service (i.e., generators or boilers with status codes of "RE[38]"). Status of boiler(s) and associated generator(s) were considered for determining operation status.
Planned or Committed Units	For plant types other than wind, solar and energy storage, included planned units that had broken ground and were expected to be online by June 30, 2028.

[36] OS - Out of service and was not used for some or all of the reporting period and is NOT expected to be returned to service in the next calendar year.

[37] OA - Out of service and was not used for some or all of the reporting period but is expected to be returned to service in the next calendar year.

[38] RE - Retired and no longer in service and not expected to be returned to service.

Scope	Rule
	For wind, solar and energy storage units, included planned units that had broken ground, had received, had pending regulatory approvals or had planned for installation and were expected to be online by June 30, 2028[39].
Firm/Non-firm Electric Sales	Excluded non-utility onsite generators that did not produce electricity for sale to the grid on a net basis.

The NEEDS includes steam units at the boiler level and non-steam units at the generator level (nuclear units are also at the generator level). A unit in NEEDS, therefore, refers to a boiler in the case of a steam unit and a generator in the case of a non-steam unit.

Table 4-3 provides a summary of the population and capacity of the existing units included in NEEDS through 2023. The final population of existing units is supplemented based on information from other sources. These include comments from utilities, submissions to EPA's Emission Tracking System, Annual Energy Outlook, and other research.

EPA 2023 Reference Case removes units from the NEEDS inventory based on public announcements of future closures. The removal of such units pre-empts IPM from making any further decisions regarding the operational status or configuration of the units. These units are removed from the NEEDS inventory only if a high degree of certainty could be assigned to future implementation of the announced action and are identified from reviewing several data sources, including:

i) Reviewing unit retirement list from EIA Electric Generator Capacity data (EIA Form 860M), January 2023

ii) PJM Future Deactivation Requests and PJM Generator Deactivations, May 2023 (updated frequently)

iii) Units that have committed specifically to retire before June 30, 2028, under federal or state enforcement actions or regulatory requirements

iv) Research by EPA and ICF staff as of Summer 2023

Research includes:

- Reviewing utility company Integrated Resource Plan (IRP), Sustainably, Climate and ESG Reports, along with company news releases, to capture retirement or repowering data on the owned fleet.
- Reviewing investor news released by the company that outlines the closure or repowering of owned fleet
- Referencing EIA Electric Power Monthly Report Table 6.6 Planned U.S. Electric Generation Unit Retirements.
- Reviewing outside news articles that capture closure or repowering of individual Electricity Generating Units (EGU), or reports released from utility companies.

Units required to retire pursuant to enforcement actions or state rules on July 1, 2028, or later are retained in NEEDS. Such July 1, 2028- or later retirements are captured as constraints on those units in IPM modeling, and the units are retired in future year projections per the terms of the related requirements.

[39] Also included one solar PV unit at Alira plant with a capacity of 222.8 megawatt that has pending regulatory approval and is scheduled to come online in 2030, one solar PV unit at Aiya Solar Project plant with a capacity of 100 megawatt that has planned for installation and is scheduled to come online in 2029, as well as one offshore wind unit at Ocean Wind II plant with a capacity of 1,148 megawatt that is planned for installation and is scheduled to come online in 2029.

The “Capacity Dropped” and the “Retired Through 2028” worksheets in NEEDS list all units that are removed from the NEEDS inventory.

Table 4-3 Summary Population (through 2023) of Existing Units in NEEDS

Plant Type	Number of Units	Capacity (MW)
Biomass	144	3,123
Coal Steam	360	154,170
Combined Cycle	1,889	288,182
Combustion Turbine	6,285	148,865
Energy Storage	646	19,656
Fossil Waste	54	1,071
Fuel Cell	207	354
Geothermal	164	2,609
Hydro	3,766	79,541
IGCC	5	815
Landfill Gas	1,425	1,659
Municipal Solid Waste	147	1,913
Non-Fossil Waste	197	2,094
Nuclear	91	93,570
O/G Steam	393	63,581
Offshore Wind	3	171
Onshore Wind	1,510	149,351
Pumped Storage	151	22,907
Solar PV	6,267	102,177
Solar Thermal	12	1,480
Tires	1	26
US Total	23,717	1,137,316

4.2.2 Capacity

The unit capacity data implemented in NEEDS reflects net summer dependable capacity.[40] Table 4-4 summarizes the hierarchy of data sources used in compiling capacity data. In other words, capacity values are taken from a particular source only if the sources listed above it do not provide adequate data for the unit in question.

Table 4-4 Hierarchy of Data Sources for Capacity in NEEDS

Sources Presented in Hierarchy
Net Summer Capacity from Comments / ICF Research
AEO 2023 Nuclear Capacity in 2028
January 2023 EIA Form 860 monthly Net Summer Capacity
2021 EIA Form 860 Net Summer Capacity

Notes:
Presented in a hierarchical order that applies.
If the capacity of a unit is zero MW, the unit is excluded from the NEEDS population.

As noted earlier, NEEDS includes boiler-level data for steam units and generator-level data for non-steam units. Capacity data in EIA Form 860 are generator-specific, not boiler-specific. Therefore, it was necessary to develop an algorithm for parsing generator-level capacity to the boiler level for steam-producing units.

The capacity-parsing algorithm used for steam units in NEEDS considered boiler-generator mapping. Fossil steam electric units have boilers attached to generators that produce electricity. There are

[40] As used here, net summer dependable capacity is the net capability of a generating unit in megawatts (MW) for daily planning and operation purposes during the summer peak season, after accounting for station or auxiliary services.

generally four types of links between boilers and generators: one boiler to one generator, one boiler to many generators, many boilers to one generator, and many boilers to many generators.

The capacity-parsing algorithm used for steam units in NEEDS utilizes steam flow data with the boiler-generator mapping. Under EIA Form 860, steam units report the maximum steam flow from the boiler to the generator. There is, however, no further data on the steam flow of each boiler-generator link. Instead, EIA Form 860 contains only the maximum steam flow for each boiler. Table 4-5 summarizes the algorithm used for parsing capacity with data on maximum steam flow and boiler-generator mapping. In Table 4-5, MF_{Bi} refers to the maximum steam flow of boiler *i* and MW_{Gj} refers to the capacity of generator *j*. The algorithm uses the available data to derive the capacity of a boiler, referred to as MW_{Bj} in Table 4-5.

Table 4-5 Capacity-Parsing Algorithm for Steam Units in NEEDS

	Type of Boiler-Generator Links			
For Boiler B1 to BN linked to Generators G1 to GN	One-to-One	One-to-Many	Many-to-One	Many-to-Many
	$MW_{Bi} = MW_{Gj}$	$MW_{Bi} = \Sigma jMW_{Gj}$	$MW_{Bi} = (MF_{Bi} / \Sigma iMF_{Bi}) * MW_{Gj}$	$MW_{Bi} = (MF_{Bi} / \Sigma iMF_{Bi}) * \Sigma jMW_{Gj}$

Notes:
MF_{Bi} = maximum steam flow of boiler *i*
MW_{Gj} = electric generation capacity of generator *j*

Since EPA 2023 Reference Case uses net energy for load as demand, NEEDS includes only generators that sell most of their power to the electric grid. The approach is intended to be broadly consistent with the generating capacity used in the AEO projections where demand is net energy for load. The generators that should be in NEEDS by this qualification are determined from the 2021 EIA Form 923 non-utility source and disposition data set.

4.2.3 Plant Location

The physical location of each unit in NEEDS is represented by the unit's model region, state, and county data.

State and County

NEEDS uses the state and county data from the January 2023 EIA Form 860M.

Model Region

For each unit, the associated model region was derived based on NERC assessment regions reported in EIA Form 860 and ISO/RTO reports. For units with no NERC assessment region data, state, and county data were used to derive associated model regions. Table 3-1 in Chapter 3 provides a summary of the mapping between NERC assessment regions and EPA 2023 Reference Case model regions.

4.2.4 Online Year

EPA 2023 Reference Case uses online year to capture when a unit entered service. NEEDS includes online years for all units in the population. Online years for boilers were from the 2021 EIA Form 860, and online years for generators were derived primarily from reported in-service dates in the January 2023 EIA Form 860M.

EPA 2023 Reference Case includes constraints to set the retirement year for generating units that are firmly committed to retiring after June 30, 2028, based on state or federal regulations, enforcement actions, and announcements.

Economic retirement options are also provided to allow the model the option to retire a unit if it finds it economical to do so. In IPM, a retired unit ceases to incur fixed O&M and variable O&M costs. The unit, however, continues to make annualized capital cost payments on any previously incurred capital cost for model-installed retrofits projected before retirement.

4.2.5 Unit Configuration

Unit configuration refers to the physical specification of a unit's design. Unit configuration in EPA 2023 Reference Case drives model plant aggregation and modeling of pollution control options and mercury emission modification factors. NEEDS contains for each unit, data on the firing and bottom type, as well as existing and committed emission controls the unit has. Table 4-6 shows the hierarchy of data sources used in determining a unit configuration. The sources listed below are also supplemented by recent ICF and EPA research to ensure the unit configuration data in NEEDS is the most comprehensive and up-to-date possible.

Table 4-6 Data Sources for Unit Configuration in NEEDS

Unit Component	Primary Data Source	Secondary Data Source	Tertiary Data Source	Other Sources	Default
Firing Type	EPA's Emission Tracking System (ETS) – 2022	2021 EIA 860	--	--	--
Bottom Type	EPA's Emission Tracking System (ETS) – 2022	2021 EIA 860	--	--	Dry
SO_2 Pollution Control	EPA's Emission Tracking System (ETS) – 2022	2018 EIA 860	NSR Settlement or Comments	--	No Control
NO_x Pollution Control	EPA's Emission Tracking System (ETS) – 2022	2018 EIA 860	NSR Settlement or Comments	--	No Control
Particulate Matter Control	EPA's Emission Tracking System (ETS) – 2022	2021 EIA 860	NSR Settlement or Comments	--	--
Mercury Control	EPA's Emission Tracking System (ETS) – 2022	2018 EIA 860	NSR Settlement or Comments	--	--
HCL Control	EPA's Emission Tracking System (ETS) – 2022	2018 EIA 860	NSR Settlement or Comments	--	--

4.2.6 Model Plant Aggregation

While EPA 2023 Reference Case using IPM is comprehensive in representing all the units contained in NEEDS, an aggregation scheme is used to combine existing units with similar characteristics into model plants. The aggregation scheme serves to reduce the size of the model, making the model manageable while capturing the essential characteristics of the generating units. The aggregation scheme is designed so that each model plant represents only generating units from a single model region and state. The design makes it possible to obtain state-level results directly from IPM outputs. In addition, the aggregation scheme supports the modeling of plant-level emission limits on fossil generation.

The aggregation scheme encompasses different categories including location, size, technology, heat rate, fuel choices, unit configuration, SO_2 emission rates, and environmental regulations among others. Units are aggregated together only if they match on all the different categories specified for the aggregation. The 11 major categories used for the aggregation scheme in EPA 2023 Reference Case are the following.

i) Facility (ORIS) for all fossil units except combustion turbine units smaller than or equal to 25 MW in the United States
ii) Model Region
iii) State

iv) Unit Technology Type
v) Unit Configuration
vi) Cogen
vii) Fuel Category
viii) Fuel Demand Region
ix) Applicable Environmental Regulations
x) Heat Rates for coal steam and Oil/Gas steam units
xi) Size

Table 4-7 shows the number of actual units by generation technology type and the related number of aggregated model plants in the EPA 2023 Reference Case. For each plant type, the table shows the number of generating units and the number of model plants representing the generating units.[41]

Table 4-7 Aggregation Profile of Model Plants as Provided at Set up of the EPA 2023 Reference Case

Existing and Planned/Committed Units		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
Biomass	296	108
Coal Steam	375	290
Combined Cycle	2,013	866
Combustion Turbine	6,589	1,193
Distributed Solar PV	130	130
Energy Storage	667	70
Fossil Waste	60	25
Fuel Cell	207	23
Geothermal	164	13
Hydro	5,461	213
IGCC	5	2
IMPORT	1	1
Landfill Gas	1,449	92
Municipal Solid Waste	148	52
Non-Fossil Waste	228	86
Nuclear	104	104
O/G Steam	481	296
Offshore Wind	16	7
Onshore Wind	1,950	87
Pumped Storage	158	28
Solar PV	6,798	110
Solar Thermal	13	6
Tires	1	1
Total	**27,314**	**3,803**
New Units		

[41] (1) The “Number of IPM Model Plants” shown for many of the “Plant Types” in the “Retrofits” block in Table 4-7 exceeds the “Number of IPM Model Plants” shown for “Plant Type” “Coal Steam” in the block labeled “Existing and Planned - Committed Units”, because a particular retrofit “Plant Type” can include multiple technology options and multiple timing options (e.g., Technology A in Stage 1 + Technology B in Stage 2 + Technology C in Stage 3, the reverse timing, or multiple technologies simultaneously in Stage 1).

(2) Since only a subset of coal plants is eligible for certain retrofits, many of the “Plant Types” in the “Retrofits” block that represent only a single retrofit technology (e.g., “Retrofit Coal with SNCR”) have a “Number of IPM Model Plants” that is a smaller than the “Number of IPM Model Plants” shown for “Plant Type” “Coal Steam”.

(3) The total number of model plants representing different types of new units often exceeds the 67 U.S. model regions and varies from technology to technology for several reasons. First, some technologies have multiple vintages (i.e., different cost and/or performance parameters depending on which run year in which the unit is created), which must be represented by separate model plants in each IPM region. Second, some technologies are not available in particular regions (e.g., geothermal is geographically restricted to certain regions).

Plant Type	Number of Units	Number of IPM Model Plants
New Battery Storage	--	524
New Biomass	--	134
New Combined Cycle	--	82
New Combined Cycle with CCS	--	128
New Combined Cycle with CCS Retrofit	--	142
New Combined Cycle with CF Limit	--	71
New Combined Cycle with HRI Retrofit	--	71
New Combined Cycle with Hydrogen Retrofit	--	71
New Combined Cycle with Hydrogen Retrofit Undone	--	71
New Combustion Turbine	--	94
New Combustion Turbine with HRI Retrofit	--	83
New Combustion Turbine with Hydrogen Retrofit	--	166
New Combustion Turbine with Hydrogen Retrofit Undone	--	166
New Fuel Cell	--	75
New Geothermal	--	61
New Hydro	--	153
New Landfill Gas	--	379
New Nuclear	--	66
New Offshore Wind	--	388
New Onshore Wind	--	2,058
New Small Modular Reactor	--	66
New Solar PV	--	2,110
New Solar Thermal	--	248
New Ultrasupercritical Coal with 30% CCS	--	128
New Ultrasupercritical Coal with 90% CCS	--	128
New Ultrasupercritical Coal without CCS	--	5
Total	--	**7,668**
Retrofits		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
Retrofit Coal with ACI	--	98
Retrofit Coal with ACI + C2G	--	69
Retrofit Coal with ACI + C2G + SCR	--	16
Retrofit Coal with ACI + CCS	--	74
Retrofit Coal with ACI + DRET	--	98
Retrofit Coal with ACI + DSI	--	2
Retrofit Coal with ACI + DSI + C2G	--	2
Retrofit Coal with ACI + DSI + C2G + SCR	--	2
Retrofit Coal with ACI + DSI + DRET	--	2
Retrofit Coal with ACI + DSI + GPM	--	2
Retrofit Coal with ACI + DSI + GPM + C2G	--	2
Retrofit Coal with ACI + DSI + GPM + C2G + SCR	--	2
Retrofit Coal with ACI + DSI + GPM + DRET	--	2
Retrofit Coal with ACI + DSI + GPM + NGC	--	2
Retrofit Coal with ACI + DSI + GPM + SCR	--	2
Retrofit Coal with ACI + DSI + GPM + SCR + DRET	--	2
Retrofit Coal with ACI + DSI + GPM + SCR + NGC	--	2
Retrofit Coal with ACI + DSI + GPM + Scrubber + SCR + CCS	--	4
Retrofit Coal with ACI + DSI + GPM + SNCR	--	2
Retrofit Coal with ACI + DSI + GPM + SNCR + DRET	--	2
Retrofit Coal with ACI + DSI + GPM + SNCR + NGC	--	2
Retrofit Coal with ACI + DSI + NGC	--	2
Retrofit Coal with ACI + DSI + SCR	--	2
Retrofit Coal with ACI + DSI + SCR + DRET	--	2
Retrofit Coal with ACI + DSI + SCR + NGC	--	2
Retrofit Coal with ACI + DSI + Scrubber + SCR + CCS	--	4
Retrofit Coal with ACI + DSI + SNCR	--	2
Retrofit Coal with ACI + DSI + SNCR + DRET	--	2
Retrofit Coal with ACI + DSI + SNCR + NGC	--	2

Retrofit Coal with ACI + GPM	--	81
Retrofit Coal with ACI + GPM + C2G	--	54
Retrofit Coal with ACI + GPM + C2G + SCR	--	14
Retrofit Coal with ACI + GPM + CCS	--	61
Retrofit Coal with ACI + GPM + DRET	--	81
Retrofit Coal with ACI + GPM + NGC	--	81
Retrofit Coal with ACI + GPM + SCR	--	14
Retrofit Coal with ACI + GPM + SCR + CCS	--	6
Retrofit Coal with ACI + GPM + SCR + DRET	--	14
Retrofit Coal with ACI + GPM + SCR + NGC	--	14
Retrofit Coal with ACI + GPM + Scrubber + SCR + CCS	--	4
Retrofit Coal with ACI + GPM + SNCR	--	21
Retrofit Coal with ACI + GPM + SNCR + DRET	--	21
Retrofit Coal with ACI + GPM + SNCR + NGC	--	21
Retrofit Coal with ACI + NGC	--	98
Retrofit Coal with ACI + SCR	--	16
Retrofit Coal with ACI + SCR + CCS	--	8
Retrofit Coal with ACI + SCR + DRET	--	16
Retrofit Coal with ACI + SCR + NGC	--	16
Retrofit Coal with ACI + Scrubber + SCR + CCS	--	4
Retrofit Coal with ACI + SNCR	--	22
Retrofit Coal with ACI + SNCR + DRET	--	22
Retrofit Coal with ACI + SNCR + NGC	--	22
Retrofit Coal with C2G	--	239
Retrofit Coal with C2G + SCR	--	98
Retrofit Coal with CCS	--	190
Retrofit Coal with DCCS	--	163
Retrofit Coal with DCCS + CCS	--	95
Retrofit Coal with DCCS + SCR + CCS	--	41
Retrofit Coal with DCCS + Scrubber + CCS	--	8
Retrofit Coal with DCCS + Scrubber + SCR + CCS	--	19
Retrofit Coal with DCCS + SNCR + CCS	--	2
Retrofit Coal with DRET	--	278
Retrofit Coal with DSI	--	34
Retrofit Coal with DSI + C2G	--	33
Retrofit Coal with DSI + C2G + SCR	--	24
Retrofit Coal with DSI + DRET	--	33
Retrofit Coal with DSI + GPM	--	9
Retrofit Coal with DSI + GPM + C2G	--	9
Retrofit Coal with DSI + GPM + C2G + SCR	--	6
Retrofit Coal with DSI + GPM + DRET	--	9
Retrofit Coal with DSI + GPM + NGC	--	9
Retrofit Coal with DSI + GPM + SCR	--	6
Retrofit Coal with DSI + GPM + SCR + DRET	--	6
Retrofit Coal with DSI + GPM + SCR + NGC	--	6
Retrofit Coal with DSI + GPM + Scrubber + CCS	--	6
Retrofit Coal with DSI + GPM + Scrubber + SCR + CCS	--	11
Retrofit Coal with DSI + GPM + SNCR	--	6
Retrofit Coal with DSI + GPM + SNCR + DRET	--	6
Retrofit Coal with DSI + GPM + SNCR + NGC	--	6
Retrofit Coal with DSI + NGC	--	33
Retrofit Coal with DSI + SCR	--	24
Retrofit Coal with DSI + SCR + DRET	--	24
Retrofit Coal with DSI + SCR + NGC	--	24
Retrofit Coal with DSI + Scrubber + CCS	--	12
Retrofit Coal with DSI + Scrubber + SCR + CCS	--	40
Retrofit Coal with DSI + SNCR	--	26
Retrofit Coal with DSI + SNCR + DRET	--	26
Retrofit Coal with DSI + SNCR + NGC	--	26
Retrofit Coal with GPM	--	278
Retrofit Coal with GPM + C2G	--	238
Retrofit Coal with GPM + C2G + SCR	--	97

Retrofit Coal with GPM + CCS	--	186
Retrofit Coal with GPM + DRET	--	277
Retrofit Coal with GPM + NGC	--	277
Retrofit Coal with GPM + SCR	--	97
Retrofit Coal with GPM + SCR + CCS	--	80
Retrofit Coal with GPM + SCR + DRET	--	97
Retrofit Coal with GPM + SCR + NGC	--	97
Retrofit Coal with GPM + Scrubber + CCS	--	16
Retrofit Coal with GPM + Scrubber + SCR + CCS	--	52
Retrofit Coal with GPM + SNCR	--	92
Retrofit Coal with GPM + SNCR + CCS	--	6
Retrofit Coal with GPM + SNCR + DRET	--	92
Retrofit Coal with GPM + SNCR + NGC	--	92
Retrofit Coal with NGC	--	278
Retrofit Coal with SCR	--	98
Retrofit Coal with SCR + C2G	--	98
Retrofit Coal with SCR + CCS	--	80
Retrofit Coal with SCR + DRET	--	98
Retrofit Coal with SCR + NGC	--	98
Retrofit Coal with SCR + Scrubber + CCS	--	52
Retrofit Coal with Scrubber + CCS	--	16
Retrofit Coal with SNCR	--	93
Retrofit Coal with SNCR + C2G	--	79
Retrofit Coal with SNCR + CCS	--	6
Retrofit Coal with SNCR + DRET	--	93
Retrofit Coal with SNCR + NGC	--	93
Retrofit Combined Cycle with CCS	--	1476
Retrofit Combined Cycle with CF Limit	--	741
Retrofit Combined Cycle with HRI	--	672
Retrofit Combined Cycle with Hydrogen	--	741
Retrofit Combined Cycle with Hydrogen Retrofit Undone	--	741
Retrofit Combustion Turbine with HRI	--	769
Total	--	**11,101**
Retirements		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
Biomass Retirement	--	108
Coal Steam Retirement	--	5,006
Existing Combined Cycle Retirement	--	5,237
Existing Combustion Turbine Retirement	--	1,962
Fossil Other Retirement	--	25
Fuel Cell Retirement	--	23
Geothermal Retirement	--	13
Hydro Retirement	--	105
IGCC Retirement	--	2
Landfill Gas Retirement	--	92
New Combined Cycle Retirement	--	426
New Combustion Turbine Retirement	--	332
Non Fossil Other Retirement	--	139
Nuclear Retirement	--	104
Oil/Gas Steam Retirement	--	1,378
Total	--	**14,952**
Grand Total (Existing and Planned/Committed + New + Retrofits + Early Retirements): 37,524		

4.2.7 Cost and Performance Characteristics of Existing Units[42]

In EPA 2023 Reference Case, the cost and performance characteristics of an existing unit are determined by the unit's heat rates, emission rates, variable operation, and maintenance cost (VOM), and fixed operation and maintenance costs (FOM). For existing units, only the cost of maintaining (FOM) and running (VOM) the unit are modeled because capital costs and all related carrying capital charges are sunk, and hence, economically irrelevant for projecting least-cost investment and operational decisions going forward. The section below discusses the cost and performance assumptions for existing units used in the EPA 2023 Reference Case.

Variable Operating and Maintenance Cost (VOM)

VOM represents the non-fuel variable cost associated with producing electricity. If the generating unit contains pollution control equipment, VOM includes the cost of operating the control equipment. Table 4-8 below summarizes VOM assumptions used in EPA 2023 Reference Case. The following further discusses the components of VOM costs and the VOM modeling methodology.

Variable O&M Approach: EPA 2023 Reference Case uses a modeling construct termed as Segmental VOM for combined cycle units to capture the variability in operation and maintenance costs that are treated as a function of the unit's dispatch pattern. All other technologies are assigned static VOM assumptions.

The VOM for combustion turbines are differentiated by the turbine technology. The VOM for combined cycles and combustion turbine units includes the costs of both major maintenance and consumables while for coal steam and oil/gas steam units includes only the cost of consumables. The VOM cost of various emission control technologies is also incorporated.

Major maintenance: Major maintenance costs are those required to maintain a unit at its delivered performance specifications and whose terms are usually dictated through its long-term service agreement (LTSA). The three main areas of maintenance for gas turbines include combustion inspection, hot gas path inspection, and major inspections. All these costs are driven by the hours of operation and the number of starts that are incurred within that time period of operation. In a cycling or mid-merit type mode of operation, there are many starts, accelerating the approach of an inspection. As more starts are incurred compared to the generation produced, the cost per generation increases. For base load operation there are fewer starts spread over more generations, lowering the cost per generation. While this nomenclature is for gas-turbine based systems, steam turbine-based systems have a parallel construct.

Consumables: The model captures consumable costs, as purely a function of output and does not vary across the segmented time period. In other words, the consumables cost component is held constant over both peak and off-peak segments. Consumables include chemicals, lube oils, make-up water, wastewater disposal, reagents, and purchased electricity.

Data Sources for Gas-Turbine Based Prime Movers:

ICF has engaged its deep expertise in operation & maintenance costs for these types of prime movers to develop generic variable O&M costs as a function of technology. As mentioned above, the variable O&M for gas-turbine based systems tracks LTSA costs, start-up, and consumables.

[42] All units excluding nuclear units.

Data Sources for Stand-Alone Steam Turbine Based Prime Movers:

The value levels of non-fuel variable O&M data for stand-alone steam turbine plants are based on ICF expertise. The VOM cost adders of various emission control technologies are based on cost functions described in Chapter 5.

Table 4-8 VOM Assumptions in the EPA 2023 Reference Case

Capacity Type	SO_2 Control	NO_x Control	Hg Control	Variable O&M (2022$/mills/kWh)
Biomass	--	--	--	8.05
Coal Steam	No SO_2 Control	No NO_x Control	No Hg Control	1.72
			ACI	1.93 - 2.17
		SCR	ACI	2.94 - 3.85
		SNCR	ACI	2.68
	Dry FGD	No NO_x Control	No Hg Control	6.02
			ACI	2.84 - 6.93
		SCR	No Hg Control	4.21
			ACI	3.63 - 9.28
		SNCR	No Hg Control	6.56 - 8.04
			ACI	3.84 - 6.51
	Wet FGD	No NO_x Control	No Hg Control	2.90 - 6.86
			ACI	2.88 - 4.68
		SCR	No Hg Control	3.83 - 9.47
			ACI	3.71 - 9.48
		SNCR	No Hg Control	3.10 - 8.79
			ACI	3.63 - 14.75
	DSI	No NO_x Control	No Hg Control	6.39 - 6.43
			ACI	6.20 - 10.16
		SCR	ACI	8.09 - 12.51
		SNCR	ACI	6.92 - 11.65
Combined Cycle	No SO_2 Control	No NO_x Control	No Hg Control	4.55
		SCR		4.62 - 5.28
Combustion Turbine	No SO_2 Control	No NO_x Control	No Hg Control	5.22 - 7.38
		SCR		5.34 - 7.51
		SNCR		5.34 - 7.51
Fuel Cell	--	--	--	0.67
Geothermal	--	--	--	1.58
Hydro	--	--	--	1.89
IGCC	--	--	--	4.87
Landfill Gas / Municipal Solid Waste	--	--	--	6.97
Oil/gas Steam	No SO_2 Control	No NO_x Control	No Hg Control	1.00
		SCR	No Hg Control	1.12 - 1.68
		SNCR	No Hg Control	1 - 1.76
Pumped Storage	--	--	--	0.01
Solar	--	--	--	0.00
Wind	--	--	--	0.00

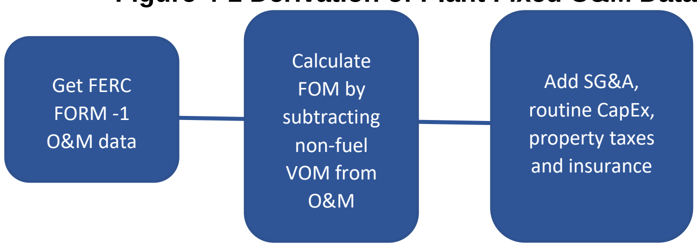
Fixed Operation and Maintenance Cost (FOM)

FOM represents the annual fixed cost of maintaining a unit. FOM costs are incurred independent of generation levels and signify the fixed cost of operating and maintaining the unit's availability to provide generation. Table 4-9 summarizes the FOM assumptions.[43] Note that FOM varies by the age of the unit, and the total FOM cost incurred by a unit depends on its capacity size. The values appearing in the table include the cost of maintaining any associated pollution control equipment. The values in Table 4-9 are based on FERC (Federal Energy Regulatory Commission) Form 1 data maintained by SNL and ICF research. The following further discusses the procedure for developing the FOM costs.

Stand Alone – Steam Turbines Based Prime Movers

O&M cost data for existing coal and oil/gas steam units were developed starting with FERC Form 1 data sets from the years 2011 to 2016. The FERC Form-1 database does not explicitly report separate fixed and variable O&M expenses. In deriving Fixed O&M costs, generic variable O&M costs are assigned to each individual power plant. Next, the assumed variable O&M cost is subtracted from the total O&M reported by FERC Form-1 to calculate a starting point for fixed O&M. Thereafter, other cost items which are not reported by FERC Form-1 are added to the raw FOM starting point. These unreported cost items are selling, general, and administrative expenses (SG&A), property taxes, insurance, and routine capital expenditures. A detailed description of the fixed O&M derivation methodology is provided below.

Figure 4-1 Derivation of Plant Fixed O&M Data



i) Assign generic VOM cost to each unit in FERC Form 1 based on the control configuration. Subtract this VOM from the total O&M cost from FERC Form 1 to calculate raw FOM cost. The FOM cost of operating the existing controls is estimated based on cost functions in Chapter 5. and deducted from the raw FOM cost. Aggregate this unit level raw FOM cost data into age-based categories. The weighted average raw FOM costs for uncontrolled units by age group is the output of this step and is used as the starting point for subsequent steps.

ii) An owner/operator fee for SG&A services in the range of 20-30% is added to raw fixed O&M figures in step 1.

iii) Property tax and insurance cost estimates in $/kW-year are also added. These figures vary by plant type.

iv) A generic percentage value to cover routine capex is added to raw fixed O&M figures in step 1. The percentage varies by prime mover and is based on a review of FERC Form 1 data

v) Finally, generic FOM cost adders for various emission control technologies are estimated using cost functions described in Chapter 5. Based on the emission control configuration of each unit in NEEDS, the appropriate emission control cost adder is added to the FOM cost of an uncontrolled unit from step iv.

[43] Cogen units whose primary purpose is to provide process heat are called as bottoming cycle units and are identified based on Form EIA 860. Such units are provided a FOM of zero in EPA 2023 Reference Case. This is to acknowledge the fact that the economics of such a unit cannot be comprehensively modeled in a power sector focused model.

The fixed O&M derivation approach relies on top-down calculation of fixed costs based on FERC Form-1 data and ICF's own non-fuel variable O&M, SG&A, routine capital expenditures, property tax, and insurance.

Gas-Turbine Based Prime Movers

Similar to the stand-alone steam turbine based prime movers, the fixed O&M for gas-turbine based systems tracks labor, routine maintenance, property taxes, insurance, owner/operator SG&A, and routine capital expenditures. These generic fixed O&M costs as a function of technology are based on ICF's expertise in fixed O&M costs for these types of prime movers.

Table 4-9 FOM Assumptions in the EPA 2023 Reference Case

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2022$ /kW-Yr)
Biomass	--	--	--	All Years	169.3
Coal Steam	No SO_2 Control	No NO_x Control	No Hg Control	0 to 40 Years	34.1
				40 to 50 Years	39.0
				Greater than 50 Years	50.1
			ACI	0 to 40 Years	36.1
				40 to 50 Years	39.1 - 39.5
				Greater than 50 Years	50.2 - 51.4
		SCR	ACI	40 to 50 Years	40.0 - 40.1
				Greater than 50 Years	51.2 - 52.5
		SNCR	ACI	40 to 50 Years	39.3
	Dry FGD	No NO_x Control	No Hg Control	0 to 40 Years	46.2
			ACI	0 to 40 Years	44.0 - 57.6
				40 to 50 Years	45.8 - 62.1
				Greater than 50 Years	70.7
		SCR	No Hg Control	Greater than 50 Years	67.5
			ACI	0 to 40 Years	41.5 - 60.5
				40 to 50 Years	47.2 - 48.8
				Greater than 50 Years	59.5 - 65.7
		SNCR	No Hg Control	0 to 40 Years	46.1 - 56.7
			ACI	0 to 40 Years	45.6 - 56.9
				40 to 50 Years	46.6 - 48.4
				Greater than 50 Years	59.0
	Wet FGD	No NO_x Control	No Hg Control	0 to 40 Years	46.0
				40 to 50 Years	49.7 - 50.1
				Greater than 50 Years	61.1 - 70.1
			ACI	0 to 40 Years	45.0 - 45.7
				40 to 50 Years	48.4 - 66.7
				Greater than 50 Years	59.6 - 81.7
		SCR	No Hg Control	0 to 40 Years	43.9 - 46.6
				40 to 50 Years	47.5 - 56.5
				Greater than 50 Years	58.5 - 82.1
			ACI	0 to 40 Years	43.3 - 56.9
				40 to 50 Years	48.8 - 52.4
				Greater than 50 Years	60.0 - 67.1
		SNCR	No Hg Control	0 to 40 Years	45.7 - 45.8
				40 to 50 Years	68.3
				Greater than 50 Years	63.2 - 82.0
			ACI	40 to 50 Years	47.9 - 60.3
				Greater than 50 Years	60.6 - 69.0
	DSI	No NO_x Control	No Hg Control	Greater than 50 Years	52.7
			ACI	40 to 50 Years	39.7 - 40.3
				Greater than 50 Years	55.9 - 65.0

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2022$ /kW-Yr)
		SCR	ACI	0 to 40 Years	35.3
				40 to 50 Years	40.2 - 41.3
				Greater than 50 Years	53.0
		SNCR	ACI	40 to 50 Years	40.2
				Greater than 50 Years	51.5 - 58.9
Combined Cycle	No SO_2 Control	No NO_x Control	No Hg Control	-	34.2
		SCR	No Hg Control	-	34.4 - 37.6
Combustion Turbine	No SO_2 Control	No NO_x Control	No Hg Control	-	22.3
		SCR	No Hg Control	-	22.8 - 27.2
		SNCR	No Hg Control	-	22.3
Fuel Cell	--	--	--	All Years	34.8
Geothermal	--	--	--	All Years	112.5
Hydro	--	--	--	All Years	18.2
Integrated Gasification Combined Cycle	No SO_2 Control	No NO_x Control	--	All Years	123.1
Landfill Gas / Municipal Solid Waste	--	--	--	All Years	211.6
Oil/gas Steam	No SO_2 Control	No NO_x Control	No Hg Control	0 to 40 Years	20.4
				40 to 50 Years	31.0
				Greater than 50 Years	40.3
		SCR	No Hg Control	0 to 40 Years	21.3 - 24.3
				40 to 50 Years	34.7 - 34.7
				Greater than 50 Years	40.7 - 43.2
		SNCR	No Hg Control	0 to 40 Years	20.4 - 22.3
				40 to 50 Years	31.1
				Greater than 50 Years	40.5 - 41.4
Pumped Storage	--	--	--	All Years	20.7
Solar Photovoltaics	--	--	--	All Years	18.7
Solar Thermal	--	--	--	All Years	91.9
Wind	--	--	--	All Years	30.0

Heat Rates

Heat Rates describe the efficiency of the unit expressed as BTUs per kWh. The treatment of heat rates is discussed in Section 3.9.

Lifetimes

Unit lifetime assumptions are detailed in Sections 3.8 and 4.2.8.

SO_2 Rates

Section 3.10.1 contains a detailed discussion of SO_2 rates for existing units.

<u>NO_x Rates</u>

Section 3.10.3 contains a detailed discussion of NO_x rates for existing units.

<u>Mercury Emission Modification Factors (EMF)</u>

Mercury EMF refers to the ratio of mercury emissions (mercury outlet) to the mercury content of the fuel (mercury inlet). Section 5.7.2 contains a detailed discussion of the EMF assumptions in EPA 2023 Reference Case.

<u>Cogeneration Units</u>

For cogeneration units, the dispatch decisions in IPM are only based on the benefits obtained from the electric portion of a cogeneration unit. In IPM, a cogeneration unit uses a net heat rate, which is calculated by dividing the heat content of fuel consumed for power generation by electricity generated from this fuel. To capture the total emissions from the cogeneration unit, a multiplier is applied to the power-only emissions. The multiplier is calculated as a ratio between the total heat rate and the net heat rate, where the total heat rate is calculated by dividing the heat content of fuel consumed for power and steam generation by electricity generated from this fuel.

<u>Coal Switching</u>

Recognizing that boiler modifications and fuel handling enhancements may be required for unrestricted switching from bituminous to subbituminous coal, and vice versa, the following procedure applies in EPA 2023 Reference Case to coal units that have the option to burn both bituminous and subbituminous coals.

(i) An examination of the EIA Form 923 coal delivery data for the period 2010-2019 is conducted for each unit to determine the unit's historical maximum share of bituminous coal and that of subbituminous coal. For example, if in at least one year during the period 2010-2019 a unit burned 90% or less subbituminous coal, its historical maximum share of subbituminous coal is set at 90%.

(ii) The following rules then apply.

<u>Blending Subbituminous Coal:</u>

If a unit's historical maximum share of subbituminous coal is greater than 90%, the unit incurs no fuel switching cost adder to increase its subbituminous coal burn. The unit is assumed to have already made the fuel handling and boiler investments needed to burn up to 100% subbituminous coal. It would therefore face no additional cost. In addition, the unit's heat rate is assumed to reflect the impact of burning the corresponding proportion of subbituminous coal.

If a unit's historical maximum share of subbituminous coal is less than 90%, the unit incurs a heat rate penalty of 5% and a fuel switching cost adder. The heat rate penalty reflects the impact of the higher moisture content subbituminous coal on the unit's heat rate. The cost adder is designed to cover boiler modifications, or alternative power purchases in lieu of capacity deratings that would otherwise be associated with burning subbituminous coal with its lower heating value relative to bituminous coal. The cost adder is determined as follows:

- If the unit's historical maximum share of subbituminous coal is less than 20%, the unit can burn up to 20% subbituminous coal at no cost adder. Burning beyond 20% subbituminous coal, the unit incurs a cost adder of 324 (2022$ per kW).

- If the unit's historical maximum share of subbituminous coal is greater than 20% but less than 90%, the unit can burn up to its historical maximum share of subbituminous coal at no cost adder. Burning beyond its historical maximum share of subbituminous coal, the unit incurs a cost adder calculated by the following equation:

$$\text{Fuel Switching Cost Adder (2022\$ per kW)} =$$

$$324 \times \left\{\frac{(100 - \text{Historical Maximum Share of Subbituminous})}{(100 - 20)}\right\}$$

Blending Bituminous Coal:

If a unit's historical maximum share of bituminous coal is greater than 90%, the unit incurs no fuel switching cost adder.

If a unit's historical maximum share of bituminous coal is less than 90%, the unit incurs a fuel switching cost adder determined as follows:

- If the unit's historical maximum share of bituminous coal is less than 20%, the unit can burn up to 20% bituminous coal at no cost adder. Burning beyond 20% bituminous coal, the unit incurs a cost adder of 65 (2022$ per kW).
- If the unit's historical maximum share of bituminous coal is greater than 20% but less than 90%, the unit can burn up to its historical maximum share of bituminous coal at no cost adder. Burning beyond its historical maximum share of bituminous coal, the unit incurs a cost adder calculated by the following equation:

$$\text{Fuel Switching Cost Adder (2022\$ per kW)} =$$

$$65 \times \left\{\frac{(100 - \text{Historical Maximum Share of Bituminous})}{(100 - 20)}\right\}$$

4.2.8 Life Extension Costs for Existing Units

The modeling time horizon in EPA 2023 Reference Case extends to 2059 and covers almost 30 years. This time horizon requires consideration of investments, beyond routine maintenance, necessary to extend the life of existing units. The life extension costs for different unit types are summarized in Table 4-10 below. Each unit has the option to retire or incorporate the life extension costs. These costs were based on a review of 2007-2016 FERC Form 1 data maintained by SNL regarding reported annual capital expenditures made by older units. The life extension costs were added once the unit reached its assumed lifespan. Life extension costs for nuclear units are discussed in Section 4.6.1.

Table 4-10 Life Extension Cost Assumptions Used in the EPA 2023 Reference Case

Plant Type	Lifespan without Life Extension Expenditures	Life Extension Cost (2022$/kW)	Capital Cost of New Unit (2022$/kW)	Life Extension Cost as Proportion of New Unit Capital Cost (%)
Biomass	40	276	4,201	6.6
Coal Steam	40	221	3,789	5.84
Combined Cycle	30	90	989	9.06
Combustion Turbine	30	260	717	36.3
IC Engine	30	252	1,914	13.2
Oil/Gas Steam	40	190	3,450	5.5
IGCC	40	281	3,789	7.4

Notes:
Life extension expenditures double the lifespan of the unit.

4.3 Planned-Committed Units

EPA 2023 Reference Case includes all planned-committed units that are likely to come online because ground has been broken, financing obtained, or other demonstrable factors indicate a high probability that the unit will be built before June 30, 2028.

In addition, wind, solar, and energy storage units that had received, had pending regulatory approvals, or were flagged as planned for installation per the August 2023 version of EIA Form 860 monthly and were expected to be online by June 30, 2028, were also included.

4.3.1 Population and Model Plant Aggregation

Table 4-11 summarizes the extent of the inventory of planned-committed units represented by unit types and generating capacity. Table 4-34 gives a breakdown of planned-committed units by IPM region, plant type, and capacity.

Table 4-11 Summary of Planned-Committed Units in NEEDS

Type	Capacity (MW)	Year Range Described
Renewables/Non-conventional		
Biomass	20	2025 - 2025
Energy Storage	23,778	2024 - 2028
Hydro	13	2024 - 2024
Non-Fossil Waste	42	2024 - 2024
Offshore Wind	6,014	2024 - 2029
Onshore Wind	18,550	2024 - 2028
Solar PV	67,109	2024 - 2030
Subtotal	115,527	
Fossil/Conventional		
Combined Cycle	6,287	2024 - 2026
Combustion Turbine	2,722	2024 - 2027
Subtotal	9,009	
Grand Total	124,535	

Note:
Any unit in NEEDS that has an online year of 2024 or later was considered a Planned/Committed Unit.

4.3.2 Capacity

The capacity data of planned-committed units in NEEDS was obtained from the August 2023 version of EIA Form 860 monthly.

4.3.3 State and Model Region

State location data for the planned-committed units in NEEDS came from the August 2023 version of EIA Form 860 monthly. The state-county information was then used to assign planned-committed units to their respective model regions.

4.3.4 Online and Retirement Year

As noted above, planned-committed units included in NEEDS are only those likely to come online before June 30, 2028, as 2028 is the first analysis year in the EPA 2023 Reference Case. All planned-committed units were assigned an online year and given a default retirement year of 9999.

4.4 Potential Units

The EPA 2023 Reference Case includes options for developing a variety of potential units that may be built at a future date in response to electricity demand and the constraints represented in the model. Defined by region, technology, and the year available, potential units with an initial capacity of zero MW are inputs into IPM. When the model is run, the capacity of certain potential units is raised from zero to meet demand and other system and operating constraints. This results in the model's projection of new capacity.

In Table 4-7, the block labeled "New Units" provides the type and number of potential units available in EPA 2023 Reference Case. The following sections describe the cost and performance assumptions for the potential units represented in the EPA 2023 Reference Case.

4.4.1 Methodology for Deriving the Cost and Performance Characteristics of Conventional Potential Units

The cost and performance characteristics of conventional potential units in EPA 2023 Reference Case are derived primarily from assumptions used in the Annual Energy Outlook (AEO) 2023 published by the U.S. Department of Energy's Energy Information Administration.

4.4.2 Cost and Performance for Potential Conventional Units

Table 4-12 shows the cost and performance assumptions for potential conventional units. The cost and performance assumptions are based on the size (i.e., net electrical generating capacity in MW) indicated in the table. However, the total new capacity that is added in each model run for these technologies is not restricted to these capacity levels.

The table includes several components of cost. The total installed cost of developing and building a new unit is captured through capital cost. It includes expenditures on pollution control equipment that new units are assumed to be installed to satisfy air regulatory requirements. The capital costs shown are typically referred to as overnight capital costs. They include engineering, procurement, construction, startup, and owner's costs (for such items as land, cooling infrastructure, administration and associated buildings, site works, switchyards, project management, and licenses). The capital costs of new units are increased to account for the cost of maintaining and expanding the transmission network. This cost based on AEO 2023 is equal to 116 2022$/kW outside of WECC and NY regions and 174 2022$/kW within these regions. The capital costs do not include interest during construction (IDC). IDC is added to the capital costs during the set-up of an IPM run. The calculation of IDC is based on the construction profile of the build option and the discount rate. Details on the discount rate used in the EPA 2023 Reference Case are provided in Chapter 10 of this documentation.

Table 4-12 also shows fixed operating and maintenance (FOM) and variable operating and maintenance (VOM) components of cost. FOM is the annual cost of maintaining a generating unit. It represents expenses incurred regardless of the extent that the unit is run. It is expressed in units of $ per kW per year. VOM represents the non-fuel variable costs incurred in running an electric generating unit. It is proportional to the electrical energy produced and is expressed in units of $ per MWh.

In addition to the three components of cost, Table 4-12 indicates the first run year available, lead time, vintage periods, heat rate, and availability for each type of unit. Lead time represents the construction time needed for a unit to come online. Vintage periods are used to capture the cost and performance improvements resulting from technological advancement and learning-by-doing. Mature technologies and technologies whose first year available are not at the start of the modeling time horizon may have only one vintage period, whereas newer technologies may have several vintage periods. Heat rate indicates the efficiency of the unit and is expressed in units of energy consumed (Btus) per unit of electricity generated (kWh). Availability indicates the percentage of time that a generating unit is available to provide electricity to the grid once it is online. Availability considers estimates of the time consumed by planned maintenance and forced outages. The emission characteristics of the potential units can be found in Table 3-24.

4.4.3 Short-Term Capital Cost Adder

In addition to the capital costs shown in Table 4-12 and Table 4-15, EPA 2023 Reference Case includes a short-term capital cost adder that takes effect if the new capacity deployed in a specific model run year exceeds certain upper bounds. This adder reflects the added cost incurred due to short-term competition for scarce labor and materials. Table 4-13 shows the cost adders for each type of potential unit for model run years through 2035. The adder is not imposed after 2035, assuming markets for labor and materials have sufficient time to respond to changes in demand.

The column labeled “Step 1” in Table 4-13 indicates the total capacity of a particular plant type that can be built in a given model run year without incurring a cost adder. However, if the Step 1 upper bound is exceeded, then either the Step 2 or Step 3 cost adder is incurred by the entire capacity deployed, where the level of the cost adder depends upon the total new capacity added in that run year. For example, the Step 1 upper bound in 2030 for landfill gas potential units is 355 MW. If no more than this total new landfill gas capacity is built in 2030, only the capital cost shown in Table 4-15 is incurred. If the model builds between 355 and 617 MW, the Step 2 cost adder of $745/kW applies to the entire capacity deployed. If the total new landfill gas capacity exceeds the Step 2 upper bound of 617 MW, the Step 3 capacity adder of $2,367/kW is incurred by the entire capacity deployed in that run year. The short-term capital cost adders shown in Table 4-13 were based on AEO assumptions. The short-term capital cost adder step widths for renewable technologies are increased by 21%, 29%, and 50% in 2028, 2030, and 2035 run years respectively to reflect the impact of IRA’s Advanced Manufacturing Production Tax Credit (45X). The scalars are linearly interpolated in between 2023 (no increase) and 2035 (50% increase).

4.4.4 Regional Cost Adjustment

The capital costs reported in Table 4-12 are generic. Before implemented, the capital cost values are converted to region-specific costs by applying regional cost adjustment factors that capture regional differences in labor, material, and construction costs and ambient conditions. These factors are calculated by multiplying the regional cost and ambient condition multipliers. The regional cost multipliers are based on county level estimates developed by the Energy Institute at the University of Texas at Austin.[44] The ambient condition multipliers are from AEO 2017. Table 4-14 summarizes the regional cost adjustment factors at the IPM region and technology level. The factors are applied to both conventional technologies shown in Table 4-12 and renewable and nonconventional technologies shown in Table 4-15. However, they are not applied to hydro and geothermal technologies as site-specific costs are used for these two technologies.

[44] New U.S. Power Costs: by County, with Environmental Externalities, University of Texas at Austin, Energy Institute. July 2016

Table 4-12 Performance and Unit Cost Assumptions for Potential (New) Capacity from Conventional Technologies in the EPA 2023 Reference Case

	Combined Cycle - Single Shaft	Combined Cycle - Multi Shaft	Combined Cycle with 90% CCS	Combustion Turbine - Industrial Frame	Combustion Turbine - Aeroderivative	Advanced Nuclear	Small Modular Reactor	Ultra-supercritical Coal without CCS
Size (MW)	418	1083	377	237	105	2156	600	650
First Year Available	2028	2028	2030	2028	2028	2030	2030	2028
Lead Time (Years)	3	3	3	2	2	6	6	4
Availability	87%	87%	87%	92%	92%	90%	95%	85%
Vintage #1 (2028)								
Heat Rate (Btu/kWh)	6,431	6,370	7,124	9,905	9,124	10,447	10,447	8,638
Capital (2022$/kW)	1,118	989	2,605	717	1,182	6,426	7,019	3,789
Fixed O&M (2022$/kW/yr)	15.87	13.73	31.06	7.88	18.35	136.91	106.92	45.68
Variable O&M (2022$/MWh)	2.87	2.10	6.57	5.06	5.29	2.67	3.38	5.06
Vintage #2 (2030)								
Heat Rate (Btu/kWh)	6,431	6,370	7,124	9,905	9,124	10,447	10,447	8,638
Capital (2022$/kW)	1,096	969	2,539	697	1,148	6,304	6,886	3,717
Fixed O&M (2022$/kW/yr)	15.87	13.73	31.06	7.88	18.35	136.91	106.92	45.68
Variable O&M (2022$/MWh)	2.87	2.10	6.57	5.06	5.29	2.67	3.38	5.06
Vintage #3 (2035)								
Heat Rate (Btu/kWh)	6,431	6,370	7,124	9,905	9,124	10,447	10,447	8,638
Capital (2022$/kW)	1,054	932	2,396	665	1,096	5,999	6,554	3,538
Fixed O&M (2022$/kW/yr)	15.87	13.73	31.06	7.88	18.35	136.91	106.92	45.68
Variable O&M (2022$/MWh)	2.87	2.10	6.57	5.06	5.29	2.67	3.38	5.06
Vintage #4 (2040)								
Heat Rate (Btu/kWh)	6,431	6,370	7,124	9,905	9,124	10,447	10,447	8,638
Capital (2022$/kW)	1,012	895	2,252	635	1,047	5,683	6,210	3,353
Fixed O&M (2022$/kW/yr)	15.87	13.73	31.06	7.88	18.35	136.91	106.92	45.68
Variable O&M (2022$/MWh)	2.87	2.10	6.57	5.06	5.29	2.67	3.38	5.06
Vintage #5 (2045)								
Heat Rate (Btu/kWh)	6,431	6,370	7,124	9,905	9,124	10,447	10,447	8,638
Capital (2022$/kW)	968	856	2,105	604	995	5,356	5,853	3,160
Fixed O&M (2022$/kW/yr)	15.87	13.73	31.06	7.88	18.35	136.91	106.92	45.68
Variable O&M (2022$/MWh)	2.87	2.10	6.57	5.06	5.29	2.67	3.38	5.06
Vintage #6 (2050 - 2055)								
Heat Rate (Btu/kWh)	6,431	6,370	7,124	9,905	9,124	10,447	10,447	8,638
Capital (2022$/kW)	922	816	1,958	572	942	5,026	5,494	2,966
Fixed O&M (2022$/kW/yr)	15.87	13.73	31.06	7.88	18.35	136.91	106.92	45.68
Variable O&M (2022$/MWh)	2.87	2.10	6.57	5.06	5.29	2.67	3.38	5.06

Notes:

[a] Capital cost represents overnight capital cost.

[b] IPM regions in urban areas (NENGREST, NY_Z_J, NY_Z_K, PJM_SMAC, PJM_COMD, WEC_LADW, WEC_SDGE, and WEC_BANC) are assigned "Combined Cycle - Single Shaft" and "Combustion Turbine - Aeroderivative" technologies. All other regions are assigned "Combined Cycle - Multi Shaft" and "Combustion Turbine - Industrial Frame" technologies.

[c] The ultra-supercritical coal plant without CCS is not compliant with 80 FR 64510.

Table 4-13 Short-Term Capital Cost Adders for New Power Plants in the EPA 2023 Reference Case (2022$)

Plant Type		2028			2030			2035		
		Step 1	Step 2	Step 3	Step 1	Step 2	Step 3	Step 1	Step 2	Step 3
Biomass	Upper Bound (MW)	3,220	5,614	No limit	1,296	2,254	No limit	3,240	5,634	No limit
	Adder ($/kW)	-	1,347	4,277	-	1,887	5,994	-	1,796	5,704
Coal Steam - UPC + UPC36 + UPC90	Upper Bound (MW)	8,784	15,276	No limit	3,513	6,110	No limit	8,784	15,276	No limit
	Adder ($/kW)	-	2,793	8,872	-	2,732	8,679	-	2,581	8,199
Combined Cycle + Combustion Turbine	Upper Bound (MW)	109,085	190,861	No limit	44,255	76,965	No limit	110,637	192,413	No limit
	Adder ($/kW)	-	318	1,011	-	306	971	-	292	926
Fuel Cell	Upper Bound (MW)	2,875	5,000	No limit	1,150	2,000	No limit	2,875	5,000	No limit
	Adder ($/kW)	-	2,503	7,952	-	2,402	7,631	-	2,152	6,837
Geothermal	Upper Bound (MW)	643	1,119	No limit	287	498	No limit	833	1,449	No limit
	Adder ($/kW)	-	3,148	10,000	-	3,113	9,887	-	3,113	9,887
Landfill Gas	Upper Bound (MW)	887	1,542	No limit	355	617	No limit	887	1,542	No limit
	Adder ($/kW)	-	448	1,424	-	745	2,367	-	694	2,204
Nuclear	Upper Bound (MW)	7,471	12,993	No limit	3,329	5,790	No limit	9,677	16,830	No limit
	Adder ($/kW)	-	2,309	6,716	-	2,266	6,589	-	2,156	6,270
Solar Thermal	Upper Bound (MW)	5,416	9,419	No limit	2,413	4,197	No limit	7,016	12,201	No limit
	Adder ($/kW)	-	1,657	5,264	-	1,454	4,617	-	1,402	4,452
Solar PV	Upper Bound (MW)	41,328	107,753	No limit	40,045	69,644	No limit	116,411	202,454	No limit
	Adder ($/kW)	-	299	949	-	258	819	-	179	567
Onshore Wind	Upper Bound (MW)	83,292	154,447	No limit	42,897	74,604	No limit	124,701	216,872	No limit
	Adder ($/kW)	-	306	973	-	244	775	-	210	667
Hydro	Upper Bound (MW)	1,695	3,770	No limit	1,251	2,176	No limit	3,637	6,326	No limit
	Adder ($/kW)	-	669	2,126	-	669	2,126	-	669	2,126

Table 4-14 Regional Cost Adjustment Factors for Conventional and Renewable Generating Technologies in the EPA 2023 Reference Case

Model Region	Regional Multiplier															
	Combined Cycle	Combined Cycle with 90% CCS	Combustion Turbine	Hydro	Nuclear	Biomass	Geothermal	Landfill Gas	Offshore Wind	Onshore Wind	Solar PV/Battery Storage	Solar Thermal	Fuel Cell	Ultra-supercritical Coal without CCS	Ultra-supercritical Coal with 36% CCS	Ultra-supercritical Coal with 90% CCS
ERC_PHDL	1.006	1.006	1.042	1.000	0.979	0.922	1.000	0.920	1.002	1.002	0.961	0.916	0.937	1.005	1.005	0.992
ERC_REST	0.977	0.977	1.027	1.000	0.969	0.922	1.000	0.920	0.968	0.968	0.935	0.889	0.937	0.981	0.981	0.969
ERC_WEST	0.999	0.999	1.038	1.000	0.976	0.922	1.000	0.920	0.989	0.989	0.952	0.909	0.937	0.997	0.997	0.985
FRCC	0.983	0.983	1.033	1.000	0.976	0.948	1.000	0.949	0.961	0.961	0.936	0.899	0.960	1.001	1.001	0.991
MIS_AMSO	0.955	0.955	1.015	1.000	0.963	0.930	1.000	0.933	0.949	0.949	0.917	0.865	0.946	0.958	0.958	0.947
MIS_AR	0.977	0.977	1.022	1.000	0.977	0.930	1.000	0.933	0.977	0.977	0.950	0.914	0.946	0.995	0.995	0.987
MIS_MS	0.958	0.958	1.013	1.000	0.968	0.930	1.000	0.933	0.958	0.958	0.929	0.884	0.946	0.972	0.972	0.962
MIS_IA	1.001	1.001	1.017	1.000	0.999	0.968	1.000	0.968	1.041	1.041	1.011	0.993	0.975	1.013	1.013	1.008
MIS_IL	1.000	1.000	1.016	1.000	0.999	1.017	1.000	1.019	1.014	1.014	0.999	0.990	1.017	1.021	1.021	1.020
MIS_INKY	0.987	0.987	1.007	1.000	0.998	1.010	1.000	0.994	1.003	1.003	0.987	0.972	0.997	1.009	1.009	1.008
MIS_LA	0.958	0.958	1.013	1.000	0.967	0.930	1.000	0.933	0.957	0.957	0.926	0.879	0.946	0.968	0.968	0.956
MIS_LMI	1.009	1.009	1.015	1.000	1.016	0.995	1.000	0.997	1.024	1.024	1.007	1.002	0.999	1.025	1.025	1.022
MIS_MAPP	0.970	0.970	1.003	1.000	0.986	0.968	1.000	0.968	1.035	1.035	0.985	0.945	0.975	0.976	0.976	0.967
MIS_MIDA	0.996	0.996	1.015	1.000	0.997	0.968	1.000	0.968	1.040	1.040	1.007	0.984	0.975	1.007	1.007	1.000
MIS_MNWI	1.006	1.006	1.020	1.000	1.000	0.968	1.000	0.968	1.050	1.050	1.021	1.008	0.975	1.015	1.015	1.010
MIS_MO	0.995	0.995	1.015	1.000	0.995	1.017	1.000	1.019	1.016	1.016	0.996	0.981	1.017	1.013	1.013	1.009

Model Region	Regional Multiplier															
	Combined Cycle	Combined Cycle with 90% CCS	Combustion Turbine	Hydro	Nuclear	Biomass	Geothermal	Landfill Gas	Offshore Wind	Onshore Wind	Solar PV/Battery Storage	Solar Thermal	Fuel Cell	Ultra-supercritical Coal without CCS	Ultra-supercritical Coal with 36% CCS	Ultra-supercritical Coal with 90% CCS
MIS_WOTA	0.956	0.956	1.010	1.000	0.966	0.930	1.000	0.933	0.956	0.956	0.923	0.875	0.946	0.964	0.964	0.952
MIS_WUMS	1.028	1.028	1.032	1.000	1.013	1.010	1.000	0.994	1.045	1.045	1.029	1.029	0.997	1.046	1.046	1.044
NENG_CT	1.181	1.181	1.146	1.000	1.068	1.030	1.000	1.009	1.081	1.081	1.076	1.103	1.009	1.112	1.112	1.116
NENG_ME	1.064	1.064	1.074	1.000	1.042	1.030	1.000	1.009	1.065	1.065	1.017	0.993	1.009	1.048	1.048	1.047
NENGREST	1.115	1.115	1.105	1.000	1.053	1.030	1.000	1.009	1.068	1.068	1.038	1.034	1.009	1.075	1.075	1.075
NY_Z_A	1.061	1.061	1.072	1.000	1.039	1.034	1.000	0.999	1.021	1.021	1.000	0.988	0.995	1.050	1.050	1.046
NY_Z_B	1.076	1.076	1.081	1.000	1.043	1.034	1.000	0.999	1.027	1.027	1.004	0.992	0.995	1.058	1.058	1.054
NY_Z_C&E	1.110	1.110	1.111	1.000	1.056	1.034	1.000	0.999	1.038	1.038	1.015	1.005	0.995	1.080	1.080	1.078
NY_Z_D	1.076	1.076	1.092	1.000	1.045	1.034	1.000	0.999	1.043	1.043	1.008	0.986	0.995	1.056	1.056	1.053
NY_Z_F	1.129	1.129	1.122	1.000	1.055	1.034	1.000	0.999	1.060	1.060	1.039	1.040	0.995	1.085	1.085	1.085
NY_Z_G-I	1.195	1.195	1.161	1.000	1.068	1.034	1.000	0.999	1.079	1.079	1.085	1.130	0.995	1.119	1.119	1.122
NY_Z_J	1.257	1.257	1.205	1.000	1.074	1.227	1.000	1.260	1.093	1.093	1.123	1.216	1.212	1.157	1.157	1.162
NY_Z_K	1.241	1.241	1.196	1.000	1.073	1.227	1.000	1.260	1.092	1.092	1.104	1.163	1.212	1.153	1.153	1.158
PJM_AP	1.073	1.073	1.088	1.000	1.034	1.010	1.000	0.994	1.008	1.008	0.982	0.961	0.997	1.072	1.072	1.069
PJM_ATSI	1.031	1.031	1.046	1.000	1.018	1.010	1.000	0.994	1.007	1.007	0.988	0.974	0.997	1.043	1.043	1.039
PJM_COMD	1.022	1.022	1.026	1.000	1.009	1.010	1.000	0.994	1.040	1.040	1.033	1.042	0.997	1.039	1.039	1.039
PJM_Dom	1.144	1.144	1.153	1.000	1.046	0.913	1.000	0.911	1.018	1.018	0.988	0.964	0.932	1.130	1.130	1.127
PJM_EMAC	1.209	1.209	1.179	1.000	1.073	1.065	1.000	1.033	1.066	1.066	1.063	1.090	1.027	1.144	1.144	1.148
PJM_PENE	1.097	1.097	1.105	1.000	1.047	1.065	1.000	1.033	1.024	1.024	1.002	0.988	1.027	1.083	1.083	1.081
PJM_SMAC	1.155	1.155	1.144	1.000	1.063	1.065	1.000	1.033	1.036	1.036	1.008	0.990	1.027	1.118	1.118	1.118
PJM_West	0.991	0.991	1.019	1.000	1.004	1.010	1.000	0.994	0.989	0.989	0.965	0.939	0.997	1.012	1.012	1.008
PJM_WMAC	1.151	1.151	1.144	1.000	1.060	1.065	1.000	1.033	1.043	1.043	1.024	1.018	1.027	1.113	1.113	1.113
S_C_KY	0.981	0.981	1.015	1.000	0.990	0.934	1.000	0.933	0.979	0.979	0.953	0.919	0.948	1.006	1.006	1.004
S_C_TVA	0.957	0.957	1.003	1.000	0.979	0.934	1.000	0.933	0.968	0.968	0.939	0.899	0.948	0.981	0.981	0.975
S_D_AECI	0.989	0.989	1.014	1.000	0.992	1.017	1.000	1.019	1.013	1.013	0.990	0.971	1.017	1.005	1.005	0.999
S_SOU	0.963	0.963	1.020	1.000	0.969	0.925	1.000	0.925	0.953	0.953	0.922	0.873	0.942	0.982	0.982	0.972
S_VACA	1.015	1.015	1.059	1.000	1.003	0.913	1.000	0.911	0.975	0.975	0.940	0.896	0.932	1.033	1.033	1.025
SPP_N	1.000	1.000	1.032	1.000	0.986	0.973	1.000	0.975	1.016	1.016	0.980	0.948	0.979	1.009	1.009	0.998
SPP_NEBR	0.976	0.976	1.009	1.000	0.988	0.968	1.000	0.968	1.029	1.029	0.984	0.945	0.975	0.982	0.982	0.971
SPP_SPS	0.992	0.992	1.028	1.000	0.980	0.956	1.000	0.952	1.005	1.005	0.963	0.920	0.962	0.991	0.991	0.979
SPP_WAUE	0.974	0.974	1.006	1.000	0.987	0.968	1.000	0.968	1.034	1.034	0.986	0.947	0.975	0.979	0.979	0.970
SPP_WEST	0.978	0.978	1.020	1.000	0.978	0.956	1.000	0.952	0.991	0.991	0.957	0.918	0.962	0.989	0.989	0.978
WEC_BANC	1.232	1.232	1.173	1.000	1.072	1.076	1.000	1.055	1.124	1.124	1.098	1.112	1.045	1.208	1.208	1.203
WEC_CALN	1.230	1.230	1.172	1.000	1.071	1.076	1.000	1.055	1.123	1.123	1.096	1.109	1.045	1.207	1.207	1.201
WEC_LADW	1.183	1.183	1.141	1.000	1.055	1.076	1.000	1.055	1.104	1.104	1.074	1.076	1.045	1.167	1.167	1.151
WEC_SDGE	1.154	1.154	1.120	1.000	1.046	1.076	1.000	1.055	1.084	1.084	1.054	1.049	1.045	1.141	1.141	1.123
WECC_AZ	1.187	1.187	1.190	1.000	1.011	1.000	1.000	0.982	1.035	1.035	0.998	0.970	0.986	1.181	1.181	1.166
WECC_CO	1.157	1.157	1.194	1.000	0.988	0.936	1.000	0.947	1.027	1.027	0.976	0.932	0.958	1.156	1.156	1.142
WECC_ID	1.045	1.045	1.070	1.000	1.004	1.002	1.000	0.982	1.048	1.048	1.000	0.965	0.989	1.066	1.066	1.058
WECC_IID	1.262	1.262	1.236	1.000	1.036	1.000	1.000	0.982	1.069	1.069	1.038	1.028	0.986	1.252	1.252	1.233
WECC_MT	1.021	1.021	1.054	1.000	0.992	1.002	1.000	0.982	1.039	1.039	0.990	0.953	0.989	1.037	1.037	1.030
WECC_NM	1.131	1.131	1.161	1.000	0.990	1.000	1.000	0.982	1.018	1.018	0.977	0.938	0.986	1.129	1.129	1.115
WECC_NNV	1.157	1.157	1.137	1.000	1.040	1.002	1.000	0.982	1.087	1.087	1.053	1.045	0.989	1.157	1.157	1.147
WECC_PNW	1.123	1.123	1.109	1.000	1.035	1.002	1.000	0.982	1.074	1.074	1.042	1.032	0.989	1.145	1.145	1.144
WECC_SCE	1.180	1.180	1.139	1.000	1.054	1.076	1.000	1.055	1.100	1.100	1.070	1.071	1.045	1.163	1.163	1.144
WECC_SNV	1.230	1.230	1.220	1.000	1.030	1.000	1.000	0.982	1.071	1.071	1.044	1.042	0.986	1.237	1.237	1.219
WECC_UT	1.050	1.050	1.075	1.000	1.002	1.002	1.000	0.982	1.043	1.043	0.997	0.962	0.989	1.063	1.063	1.051
WECC_WY	1.016	1.016	1.055	1.000	0.987	1.002	1.000	0.982	1.031	1.031	0.976	0.927	0.989	1.024	1.024	1.012

Table 4-15 Performance and Unit Cost Assumptions for Potential (New) Renewable and Non-Conventional Technologies in the EPA 2023 Reference Case

	Geothermal	Biomass	Landfill Gas LGHI	Fuel Cells	Solar Photovoltaic	Solar Thermal	Onshore Wind	Offshore Wind	Battery Storage (4 Hours)	Battery Storage (10 hours)
Size (MW)	50	50	36	10	100	115	200	1000	60	60
First Year Available	2028	2028	2028	2028	2028	2028	2028	2028	2028	2028
Lead Time (Years)	4	4	3	3	1	3	3	3	1	1
Availability	80% - 90%	83%	90%	87%	90%	90%	95%	95%	96.4%	96.4%
Generation Capability	Economic Dispatch	Economic Dispatch	Economic Dispatch	Economic Dispatch	Generation Profile	Economic Dispatch	Generation Profile	Generation Profile	Economic Dispatch	Economic Dispatch
	Vintage #1 (2028-2055)	**Vintage #1 (2028)**								
Heat Rate (Btu/kWh)	30,000	13,500	8,513	6,469	0	0	0	0	0	0
Capital (2022$/kW)	3,662 - 48,811	4,201	1,707	5,571	1,065	5,594	1,206	1,979	960	2,077
Fixed O&M (2022$/kW/yr)	114 - 1,208	141.50	21.82	34.65	19.08	59.54	29.66	96.04	34.59	74.82
Variable O&M (2022$/MWh)	0.00	5.44	6.73	0.66	0.00	3.37	0.00	0.00	0.00	0.00
Vintage #2 (2030)										
Heat Rate (Btu/kWh)		13,500	8,513	6,469	0	0	0	0	0	0
Capital (2022$/kW)		4,121	1,659	5,346	1,005	5,107	1,159	1,923	891	1,902
Fixed O&M (2022$/kW/yr)		141.50	21.82	34.65	18.37	55.43	28.88	92.95	32.11	68.52
Variable O&M (2022$/MWh)		5.44	6.73	0.66	0.00	3.21	0.00	0.00	0.00	0.00
Vintage #3 (2035)										
Heat Rate (Btu/kWh)		13,500	8,513	6,469	0	0	0	0	0	0
Capital (2022$/kW)		3,921	1,544	4,790	856	4,925	1,102	1,818	823	1,741
Fixed O&M (2022$/kW/yr)		141.50	21.82	34.65	16.60	55.43	27.89	86.93	29.64	62.74
Variable O&M (2022$/MWh)		5.44	6.73	0.66	0.00	3.21	0.00	0.00	0.00	0.00
Vintage #4 (2040)										
Heat Rate (Btu/kWh)		13,500	8,513	6,469	0	0	0	0	0	0
Capital (2022$/kW)		3,715	1,449	4,236	788	4,743	1,044	1,742	754	1,581
Fixed O&M (2022$/kW/yr)		141.50	21.82	34.65	15.88	55.43	26.90	82.40	27.16	56.97
Variable O&M (2022$/MWh)		5.44	6.73	0.66	0.00	3.21	0.00	0.00	0.00	0.00
Vintage #5 (2045)										
Heat Rate (Btu/kWh)		13,500	8,513	6,469	0	0	0	0	0	0
Capital (2022$/kW)		3,500	1,361	3,686	721	4,560	987	1,683	685	1,422
Fixed O&M (2022$/kW/yr)		141.50	21.82	34.65	15.16	55.43	25.91	78.76	24.68	51.23
Variable O&M (2022$/MWh)		5.44	6.73	0.66	0.00	3.21	0.00	0.00	0.00	0.00
Vintage #6 (2050-2055)										
Heat Rate (Btu/kWh)		13,500	8,513	6,469	0	0	0	0	0	0
Capital (2022$/kW)		3,284	1,268	3,150	653	4,378	930	1,634	617	1,263
Fixed O&M (2022$/kW/yr)		141.50	21.82	34.65	14.44	55.43	24.92	75.72	22.21	45.51
Variable O&M (2022$/MWh)		5.44	6.73	0.66	0.00	3.21	0.00	0.00	0.00	0.00

Note: The capital costs for the landfill gas units at low, and very low methane producing sites are assumed to be 26% and 94% higher than the capital costs for the landfill gas units at high methane producing sites.
The capital costs for solar PV units in 2028 are from the ATB 2023 advanced case, and the capital costs starting in 2035 are from the ATB 2023 moderate case. The capital costs in 2030 are linearly interpolated.
The capital costs and FOM of energy storage units are based on the AEO 2023 estimate for 2023 and are adjusted in future years based on the trend underlying the ATB 2023 moderate case assumptions

4.4.5 Cost and Performance for Potential Renewable Generating and Non-Conventional Technologies

Table 4-15 summarizes the cost and performance assumptions in EPA 2023 Reference Case for potential renewable and non-conventional technology generating units. The parameters shown in the table are based on AEO 2023 for biomass, landfill gas, and fuel cells. For battery storage, onshore wind, offshore wind, solar PV, and solar thermal technologies, the parameters shown are based on the National Renewable Energy Laboratory's (NREL's) 2023 Annual Technology Baseline (ATB) moderate case. The geothermal assumptions are based on ATB 2019. The size (MW) shown in Table 4-15 represents the capacity on which unit cost estimates were developed and does not indicate the total potential capacity that the model can build for a given technology. Due to the distinctive nature of generation from renewable resources, some of the values shown are averages or ranges that are discussed in further detail in the following subsections. The short-term capital cost adder in Table 4-13 and the regional cost adjustment factors in Table 4-14 apply equally to the renewable and non-conventional generation technologies as to the conventional generation technologies.

<u>Wind Generation</u>

EPA 2023 Reference Case includes onshore wind, offshore-fixed, and offshore-floating wind generation technologies. The following sections describe key aspects of the representation of wind generation: wind quality and resource potential, distance to transmission, generation profiles, reserve margin contribution, and capital cost calculation.

<u>Wind Quality and Resource Potential</u>: The NREL resource base for onshore wind is represented by ten wind speed class categories (Class 1 - Class 10). EPA 2023 Reference Case only models the categories Class 1 - Class 9. The NREL resource base for offshore wind is represented by fixed (Class 1 - Class 7), and floating (Class 8 - Class 14) categories. EPA 2023 Reference Case models the categories Class 1 - - Class 6 and Class 8 - Class 12. Table 4-36, Table 4-16, and Table 4-17 present the onshore, offshore fixed, and offshore floating wind resource assumptions. The resource class field in the tables further subdivides the wind speed class categories based on wind speed.

Table 4-16 Offshore Fixed Regional Potential Wind Capacity (MW) by Wind Class, Resource Class, and Cost Class in the EPA 2023 Reference Case

IPM Region	State	Wind Class	Resource Class	Cost Class					
				1	2	3	4	5	6
ERC_REST	TX	Class 5	6	2,976	693				
		Class 6	5	2,622	3,245	3,035	3,052	3,004	4,243
FRCC	FL	Class 6	5	2,900	3,091	2,636	3,362	2,810	9,172
MIS_AMSO	LA	Class 6	5	885	909	858	900	920	12,957
MIS_LA	LA	Class 6	5	31					
MIS_LMI	MI	Class 2	7	154					
MIS_WOTA	LA	Class 6	5	871	922	903	903	875	36,861
	TX	Class 6	5	519	1,038	1,038	781	1,049	15,042
MIS_WUMS	MI	Class 3	7	237					
	WI	Class 4	6	0					
NENG_ME	ME	Class 1	8	12					
NENGREST	MA	Class 1	8	1,418	2,118	4,236	2,118	2,118	8,708
	RI	Class 1	8	14					
NY_Z_K	NY	Class 1	8	165					
		Class 2	7	685	212				
PJM_ATSI	OH	Class 3	7	1,560	1,606	1,491			
PJM_Dom	NC	Class 2	7	2,597	2,545	841			
	VA	Class 2	7	2,390	1,022				
		Class 4	6	2					
PJM_EMAC	DE	Class 1	8	2,894					
		Class 2	7	2,987	274				

IPM Region	State	Wind Class	Resource Class	Cost Class					
				1	2	3	4	5	6
	MD	Class 2	7	2,423					
	NJ	Class 1	8	2,945	3,010	3,004	2,922		
		Class 2	7	2,968	2,475				
	VA	Class 2	7	2,983	3,014	14			
S_SOU	AL	Class 6	5	2,950	3,040	983			
	FL	Class 6	5	29					
	GA	Class 6	5	2,980	3,020	357			
	MS	Class 6	5	2,435					
S_VACA	NC	Class 3	7	2,971	2,393				
		Class 5	6	2,767	2,645	3,586	2,307		
	SC	Class 5	6	2,647	2,885	3,299	2,978	3,162	20,234
		Class 6	5	2,957	2,996				

Note: Resource potential depleted to account for the NEEDS capacity built in 2021 - 2028 by IPM Region & State.

Table 4-17 Offshore Floating Regional Potential Wind Capacity (MW) by Wind Class, Resource Class, and Cost Class in the EPA 2023 Reference Case

IPM Region	State	Wind Class	Resource Class	Cost Class					
				1	2	3	4	5	6
MIS_LMI	MI	Class 12	7	2,154					
MIS_WUMS	MI	Class 12	7	113					
NENG_ME	ME	Class 8	8		330	330	330	330	85,755
		Class 11	7		397	397	397		6,940
NENGREST	MA	Class 8	8	2,176	2,888	1,444	3,882	2,528	370,283
		Class 11	7	1,450					
	RI	Class 8	8	376					
NY_Z_J	NY	Class 11	7						8,509
NY_Z_K	NY	Class 9	8	608	696	796	694	663	74,310
		Class 11	7	397	794	794	789	588	
PJM_Dom	NC	Class 12	7	2,509	2,681	2,595	1,782	2,515	4,918
	VA	Class 12	7	1,986					
PJM_EMAC	DE	Class 10	8	2,978	992				
		Class 11	7	496					
	MD	Class 10	8	397					
		Class 11	7	2,846	2,846	2,846	2,846	2,846	27,846
	NJ	Class 10	8	2,717	3,194	2,577	3,376	3,022	33,803
		Class 11	7	2,942	3,031	1,539	3,839	1,919	34,612
	VA	Class 12	7	2,978	2,796	3,200	2,600		
S_VACA	NC	Class 12	7	397	3,176	3,176	3,176	3,176	321,572
WEC_CALN	CA	Class 8	8	2,222	3,640		3,640	3,640	360,347
		Class 12	7	2,984	2,800	3,210	2,762	3,177	513,613
WECC_PNW	CA	Class 8	8	2,780	3,197	2,774	1,646		
	OR	Class 8	8	2,754	3,175	3,064	2,908	2,383	43,714
		Class 12	7						345,408
	WA	Class 12	7	2,646	2,646	2,646	2,646	2,646	74,215
WECC_SCE	CA	Class 12	7	1,312	3,772	3,772		3,772	72,915

Note: Resource potential depleted to account for the NEEDS capacity built in 2021 - 2028 by IPM Region & State.

Generation Profiles: Unlike other generation technologies, which dispatch on an economic basis subject to their availability constraint, wind, and solar technologies dispatch only when the wind blows and the sun shines. To represent intermittent renewable generating sources such as wind and solar, EPA 2023 Reference Case uses hourly generation profiles. All wind and solar photovoltaic units are provided with hourly generation profiles. The profiles are customized for each resource class within an IPM region and state combination.

The generation profile indicates the amount of generation (kWh) per MW of available capacity. The wind generation profiles were prepared with data from NREL. Table 4-37 shows the generation profiles for onshore and offshore wind units in all model region, state, and class combinations for vintage 2028. Improvements in onshore wind capacity factors over time are modeled through two vintages (2028 and 2030) of potential wind units.

To obtain the seasonal generation for the units in a particular resource class in a specific region, the installed capacity is multiplied by the number of hours in the season and the seasonal capacity factor. Capacity factor is the average "kWh of generation per MW" from the applicable generation profile. The annual capacity factors for wind generation that are used in EPA 2023 Reference Case were obtained from NREL and are shown in Table 4-35, Table 4-18, and Table 4-19.

Table 4-18 Offshore Fixed Average Capacity Factor by Wind Class and Resource Class in the EPA 2023 Reference Case

IPM Region	State	Wind Class	Resource Class	Capacity Factor (%) Vintage #1 (2028-2059)
ERC_REST	TX	Class 5	6	50%
		Class 6	5	45%
FRCC	FL	Class 6	5	40%
MIS_AMSO	LA	Class 6	5	39%
MIS_LA	LA	Class 6	5	41%
MIS_LMI	MI	Class 2	7	53%
MIS_WOTA	LA	Class 6	5	42%
	TX	Class 6	5	44%
MIS_WUMS	MI	Class 3	7	54%
	WI	Class 4	6	53%
NENG_ME	ME	Class 1	8	55%
NENGREST	MA	Class 1	8	54%
	RI	Class 1	8	51%
NY_Z_K	NY	Class 1	8	51%
		Class 2	7	53%
PJM_ATSI	OH	Class 3	7	52%
PJM_Dom	NC	Class 2	7	50%
	VA	Class 2	7	50%
		Class 4	6	51%
PJM_EMAC	DE	Class 1	8	50%
		Class 2	7	53%
	MD	Class 2	7	52%
	NJ	Class 1	8	51%
		Class 2	7	53%
	VA	Class 2	7	50%
S_SOU	AL	Class 6	5	39%
	FL	Class 6	5	38%
	GA	Class 6	5	45%
	MS	Class 6	5	39%
S_VACA	NC	Class 3	7	51%
		Class 5	6	50%
	SC	Class 5	6	48%
		Class 6	5	45%

Table 4-19 Offshore Floating Average Capacity Factor by Wind Class and Resource Class in the EPA 2023 Reference Case

IPM Region	State	Wind Class	Resource Class	Capacity Factor (%) Vintage #1 (2028-2059)
MIS_LMI	MI	Class 12	7	52%
MIS_WUMS	MI	Class 12	7	50%
NENG_ME	ME	Class 8	8	57%
		Class 11	7	53%
NENGREST	MA	Class 8	8	55%
		Class 11	7	55%
	RI	Class 8	8	56%
NY_Z_J	NY	Class 11	7	55%
NY_Z_K	NY	Class 9	8	56%
		Class 11	7	55%
PJM_Dom	NC	Class 12	7	50%
	VA	Class 12	7	49%
PJM_EMAC	DE	Class 10	8	54%
		Class 11	7	55%
	MD	Class 10	8	54%
		Class 11	7	54%
	NJ	Class 10	8	55%
		Class 11	7	55%
	VA	Class 12	7	50%
S_VACA	NC	Class 12	7	50%
WEC_CALN	CA	Class 8	8	60%
		Class 12	7	54%
WECC_PNW	CA	Class 8	8	51%
	OR	Class 8	8	55%
		Class 12	7	50%
	WA	Class 12	7	48%
WECC_SCE	CA	Class 12	7	53%

Reserve Margin Contribution (also referred to as capacity credit): EPA 2023 Reference Case uses reserve margins, discussed in detail in Section 3.6, to model reliability. Each region has a reserve margin requirement which is used to determine the total capacity needed to reliably meet peak demand. The ability of a unit to assist a region in meeting its reliability requirements is modeled through the unit's contribution to the reserve margin. If the unit has a 100 percent contribution towards the reserve margin, then the entire capacity of the unit is counted towards meeting the region's reserve margin requirement. However, if any unit has less than a 100 percent contribution towards the reserve margin, then only the designated share of the unit's capacity counts towards the reserve margin requirement.

All units except those that depend on intermittent resources have 100% contributions toward the reserve margin. Intermittent resources such as wind and solar have limited (less than 100 percent) contributions toward reserve margin requirements.

Capacity credit assumptions for onshore wind, offshore wind, and solar PV units are estimated as the function of penetration of solar and wind. A two-step approach is developed to estimate the capacity credit at a unit level. In the first step, the method estimates the sequence of solar and wind units to be built in each ISO/NERC assessment region. Table 3-11 provides the mapping between the ISO/NERC assessment region and the IPM region. To do so, each solar and wind unit in an ISO/NERC assessment region is sorted from cheapest to most expensive in terms of cost and potential revenue generation. Unit-level capital costs, FOM costs, capital charge rate, and average energy price in each IPM region are used. In the second step, capacity credit is estimated for each unit in the sequence as the ratio between the MW of peak reduced and the capacity of the unit. Unit-level hourly generation profiles and ISO/NERC assessment region-level hourly load curves are used. The approach allows the EPA 2023 Reference

Case to endogenously account for the decline of capacity credit for intermittent resources with their rising penetration.

Table 4-20, Table 4-21, and Table 4-22 present the reserve margin contributions apportioned to new wind units in the EPA 2023 Reference Case.

Table 4-20 Onshore Reserve Margin Contribution by Wind Class in the EPA 2023 Reference Case

Wind Class	Vintage #1 (2028)	Vintage #2 (2030-2059)
Class 1	0% - 70%	0% - 75%
Class 2	15%	16%
Class 3	0% - 82%	0% - 88%
Class 4	0% - 78%	0% - 84%
Class 5	0% - 55%	0% - 59%
Class 6	0% - 83%	0% - 90%
Class 7	0% - 83%	0% - 90%
Class 8	0% - 62%	0% - 67%
Class 9	0% - 93%	0% - 100%

Table 4-21 Offshore Fixed Reserve Margin Contribution by Wind Class in the EPA 2023 Reference Case

Wind Class	Vintage #1 (2028-2059)
Class 1	0.3% - 89%
Class 2	0.1% - 94%
Class 3	0% - 20%
Class 4	7.4% - 21%
Class 5	1.5% - 40%
Class 6	0% - 70%

Table 4-22 Offshore Floating Reserve Margin Contribution by Wind Class in the EPA 2023 Reference Case

Wind Class	Vintage #1 (2028-2059)
Class 8	0% - 93.8%
Class 9	1.9% - 78.5%
Class 10	1.6% - 3.1%
Class 11	0% - 34.4%
Class 12	0% - 36.1%

Capital cost calculation: Capital costs for wind units include spur-line transmission costs. The resources for wind and solar are highly sensitive to location. These spur-line costs represent the cost of needed spur lines and are based on an estimated distance to transmission infrastructure. NREL develops these supply curves based on a geographic-information-system analysis, which estimates the resource accessibility costs in terms of supply curves based on the expected cost of linking renewable resource sites to the high-voltage, long-distance transmission network. For IPM modeling purposes, the NREL spur line cost curves are aggregated into a piecewise step curve for each resource class within each model region and state combination. The sizes of the initial steps are based on the model region load, while the last step holds the residual resource. The wind class and resource class level spur line cost curves for each model region and state combination are aggregated into a six-step cost curve for onshore wind and offshore wind units. To obtain the capital cost for a particular new wind model plant, the capital cost adder applicable to the new plant by resource and cost class shown in Table 4-23, Table 4-24, and Table 4-38, is added to the base capital cost shown in Table 4-15.

Table 4-23 Capital Cost Adder (2022$/kW) for New Offshore Fixed Wind Plants in the EPA 2023 Reference Case

IPM Region	State	Wind Class	Resource Class	Cost Class 1	2	3	4	5	6
ERC_REST	TX	Class 5	6	140	1,040				
		Class 6	5	31	31	35	46	54	110
FRCC	FL	Class 6	5	22	23	30	35	54	149
MIS_AMSO	LA	Class 6	5	47	56	133	199	207	406
MIS_LA	LA	Class 6	5	5,143					
MIS_LMI	MI	Class 2	7	5,431					
MIS_WOTA	LA	Class 6	5	70	95	114	120	127	354
	TX	Class 6	5	28	28	28	29	31	108
MIS_WUMS	MI	Class 3	7	11,000					
	WI	Class 4	6	133,304					
NENG_ME	ME	Class 1	8	6,139					
NENGREST	MA	Class 1	8	15	178	178	178	178	476
	RI	Class 1	8	14,035					
NY_Z_K	NY	Class 1	8	278					
		Class 2	7	4	207				
PJM_ATSI	OH	Class 3	7	296	458	1,683			
PJM_Dom	NC	Class 2	7	44	148	420			
	VA	Class 2	7	67	400				
		Class 4	6	17,645					
PJM_EMAC	DE	Class 1	8	71					
		Class 2	7	49	438				
	MD	Class 2	7	204					
	NJ	Class 1	8	35	89	124	211		
		Class 2	7	4	225				
	VA	Class 2	7	325	244,697	4,032,984			
S_SOU	AL	Class 6	5	117	246	720			
	FL	Class 6	5	1,241					
	GA	Class 6	5	58	135	691			
	MS	Class 6	5	235					
S_VACA	NC	Class 3	7	76	528				
		Class 5	6	9	67	74	232		
	SC	Class 5	6	6	12	17	20	22	103
		Class 6	5	21	148				

Table 4-24 Capital Cost Adder (2022$/kW) for New Offshore Floating Wind Plants in the EPA 2023 Reference Case

IPM Region	State	Wind Class	Resource Class	Cost Class 1	2	3	4	5	6
MIS_LMI	MI	Class 12	7	873					
MIS_WUMS	MI	Class 12	7	5,044					
NENG_ME	ME	Class 8	8		67	67	67	67	669
		Class 11	7		67	67	67		251
NENGREST	MA	Class 8	8	9	11	11	12	66	383
		Class 11	7	133					
	RI	Class 8	8	1,264					
NY_Z_J	NY	Class 11	7						133
NY_Z_K	NY	Class 9	8	3	3	6	13	49	251
		Class 11	7	104	104	104	105	105	
PJM_Dom	NC	Class 12	7	51	73	111	233	266	320
	VA	Class 12	7	101					
PJM_EMAC	DE	Class 10	8	55	104				
		Class 11	7	189					

IPM Region	State	Wind Class	Resource Class	Cost Class					
				1	**2**	**3**	**4**	**5**	**6**
	MD	Class 10	8	58					
		Class 11	7	78	78	78	78	78	198
	NJ	Class 10	8	21	45	77	80	85	142
		Class 11	7	57	61	73	78	78	122
	VA	Class 12	7	78	253	526	174,958		
S_VACA	NC	Class 12	7	67	70	70	70	70	245
WEC_CALN	CA	Class 8	8	9	79		79	79	429
		Class 12	7	4	30	42	59	76	361
WECC_PNW	CA	Class 8	8	287	311	724	1,389		
	OR	Class 8	8	38	41	47	72	74	173
		Class 12	7						68
	WA	Class 12	7	51	51	51	51	51	271
WECC_SCE	CA	Class 12	7	63	92	92		92	596

As an illustrative example, Table 4-25 shows the calculations that would be performed to derive the potential electric generation, reserve margin contribution, and cost of potential (new) onshore capacity in wind class 7, resource class 5, and cost class 1 in the WECC_CO model region in run year 2028.

Table 4-25 Example Calculations of Wind Generation, Reserve Margin Contribution, and Capital Cost for Onshore Wind in WECC_CO for Wind Class 7, Resource Class 5, and Cost Class 1.

Required Data

Table 4-36	Potential wind capacity (C) =	1,876 MW
Table 4-37	Winter average generation (G_W) per available MW =	277 kWh/MW
Table 4-37	Spring average generation (G_{SP}) per available MW =	397 kWh/MW
Table 4-37	Summer average generation (G_{SM}) per available MW =	363 kWh/MW
Table 4-37	Fall average generation (G_F) per available MW =	262 kWh/MW
	Hours in Winter (H_W) season (December - February) =	2,160 hours
	Hours in Spring (H_{SP}) season (March - April) =	1,464 hours
	Hours in Summer (H_{SM}) season (May - September) =	3,672 hours
	Hours in Summer (H_F) season (October - November) =	1,464 hours
Table 4-20	Reserve Margin Contribution (RM) WECC_CO, Wind Class 7, Resource Class 5 =	3.64 percent
Table 4-15	Capital Cost (Cap_{2028}) in vintage range for year 2028 =	$1,206/kW
Table 4-38	Capital Cost Adder ($CCA_{ON,C1}$) for onshore cost class 1 =	$37/kW
Table 4-14	Regional Factor (RF)	1.027

Calculations

$$
\begin{aligned}
\text{Generation Potential} &= \mathrm{C} \times \mathrm{G_W} \times \mathrm{H_W} + \mathrm{C} \times \mathrm{G_{SP}} \times \mathrm{H_{SP}} + \mathrm{C} \times \mathrm{G_{SM}} \times \mathrm{H_{SM}} + \mathrm{C} \times \mathrm{G_F} \times \mathrm{H_F} \\
&= 1{,}876\ \text{MW} \times 277\text{kWh/MW} \times 2{,}160\ \text{hours} \ + \\
&\quad 1{,}876\ \text{MW} \times 397\text{kWh/MW} \times 1{,}464\ \text{hours} \ + \\
&\quad 1{,}876\ \text{MW} \times 363\text{kWh/MW} \times 3{,}672\ \text{hours} \ + \\
&\quad 1{,}876\ \text{MW} \times 262\text{kWh/MW} \times 1{,}464\ \text{hours} \\
&= 5{,}431\ \text{GWh}
\end{aligned}
$$

$$
\begin{aligned}
\text{Reserve Margin Contribution} &= \mathrm{RM} \times \mathrm{C} \\
&= 3.64\% \ \times 1{,}876\ \text{MW} \\
&= 68\ \text{MW}
\end{aligned}
$$

$$
\begin{aligned}
\text{Capital Cost} &= (\mathrm{Cap_{2028}} \times \mathrm{RF} + \mathrm{CCA_{ON,C1}}) \times \mathrm{C} \\
&= (\$1{,}207/\text{kW} \times 1.027 + \$33/\text{kW}) \times 1{,}876\text{MW} \\
&= \$2{,}394{,}152
\end{aligned}
$$

Solar Generation

EPA 2023 Reference Case includes solar photovoltaics and solar thermal generation technologies. The following sections describe four key aspects of the representation of solar generation: solar resource potential, generation profiles, reserve margin contribution, and capital cost calculation.

Solar Resource Potential: The resource potential estimates for solar photovoltaics and solar thermal technologies were developed by NREL by model region, state, and resource class. The NREL resource base for solar photovoltaics is represented by ten resource classes. In EPA 2023 Reference Case, the top ten resource classes are primarily modeled for solar photovoltaics. The NREL resource base for solar thermal is represented by twelve resource classes. In EPA 2023 Reference Case, the top eight resource classes are modeled for solar thermal. The solar thermal technology has a ten-hour thermal energy storage (TES) and is considered a dispatchable resource for modeling purposes. These are summarized in Table 4-39 and Table 4-40.

Generation Profiles: Table 4-41 shows the generation profiles for solar photovoltaics units in all model region, state, and resource combinations. The capacity factors for solar generation that are used in EPA 2023 Reference Case were obtained from NREL and are shown in Table 4-44 and Table 4-45.

Reserve margin contribution (also referred to as capacity credit): The reserve margin contribution section for wind units summarizes the approach followed for calculating the reserve margin contribution for solar photovoltaics units. Table 4-26 presents the reserve margin contributions apportioned to new solar photovoltaics units in the EPA 2023 Reference Case. The solar thermal units are assumed to have 10-hour TES and are assigned 100% reserve margin contribution.

Table 4-26 Solar Photovoltaic Reserve Margin Contribution by PV Class in the EPA 2023 Reference Case

PV Class	Vintage #1 (2028-2059)
Class 1	0%
Class 2	0% - 100%
Class 3	0% - 65%
Class 4	0% - 100%
Class 5	0% - 64%
Class 6	0% - 49%
Class 7	0% - 61%
Class 8	0% - 100%
Class 9	0% - 3%
Class 10	0% - 37%

Capital Costs: Similar to wind units, capital costs for solar units include transmission spur line cost adders. The resource class level spur line cost curves for each model region and state combination are aggregated into a seven-step cost curve. Table 4-42 and Table 4-43 illustrate the capital cost adder by resource and cost class for new solar units.

Geothermal Generation

Geothermal Resource Potential: Twelve model regions in EPA 2023 Reference Case have geothermal potential. The potential resource in each of these regions is shown in Table 4-27 and is based on NREL ATB 2019. GEO-Hydro Flash[45], GEO-Hydro Binary, GEO-NF EGS Flash, and GEO-NF EGS Binary are the included technologies.

[45] In dual flash systems, high temperature water (above 400□F) is sprayed into a tank held at a much lower pressure than the fluid. This causes some of the fluid to “flash,” i.e., rapidly vaporize to steam. The steam is used to drive a turbine, which, in turn, drives a generator. In the binary cycle technology, moderate temperature water (less than

Table 4-27 Regional Assumptions on Potential Geothermal Capacity in the EPA 2023 Reference Case

IPM Model Region	Capacity (MW)
WEC_CALN	498
WECC_AZ	26
WECC_CO	21
WECC_ID	237
WECC_IID	2,832
WECC_MT	29
WECC_NM	22
WECC_NNV	1,421
WECC_PNW	633
WECC_SCE	496
WECC_UT	208
WECC_WY	39
Grand Total	**6,461**

Cost Calculation: EPA 2023 Reference Case does not contain a single capital cost, but multiple geographically dependent capital costs for geothermal generation. The assumptions for geothermal were developed using NREL 2019 ATB cost and performance estimates for 152 sites. Both dual flash and binary cycle technologies were represented. The 152 sites were aggregated into 61 different options based on geographic location and cost and performance characteristics of geothermal sites in each of the 12 eligible IPM regions where geothermal generation opportunities exist. Table 4-28 shows the potential geothermal capacity and cost characteristics for applicable model regions.

Table 4-28 Potential Geothermal Capacity and Cost Characteristics by Model Region in the EPA 2023 Reference Case

Region	Net Capacity (MW)	Capital Cost (2022$/kW)	FOM (2022$/kW-yr)
WEC_CALN	6	17,886	556
	8	24,471	674
	11	15,277	436
	29	4,823	139
	29	6,978	225
	82	28,516	695
	333	12,724	242
WECC_AZ	26	23,588	654
WECC_CO	8	24,495	675
	12	17,206	486
WECC_ID	10	20,301	567
	14	25,697	694
	28	22,479	628
	28	48,811	1,208
	44	14,444	408
	112	10,836	301
WECC_IID	74	3,766	129
	85	30,678	744
	91	6,572	214
	137	5,210	166
	257	12,856	236
	2,188	4,764	114
WECC_MT	7	24,912	683

400□F) vaporizes a secondary, working fluid, which drives a turbine and generator. Due to its use of more plentiful, lower temperature geothermal fluids, these systems tend to be most cost effective and are expected to be the most prevalent future geothermal technology.

Region	Net Capacity (MW)	Capital Cost (2022$/kW)	FOM (2022$/kW-yr)
	22	20,139	563
WECC_NM	9	24,399	672
	13	16,944	437
WECC_NNV	45	17,932	491
	50	7,107	215
	66	8,541	248
	67	22,005	607
	77	15,293	444
	92	30,716	769
	93	4,342	145
	103	3,662	116
	138	10,601	318
	148	4,631	155
	264	26,571	667
	279	5,240	172
WECC_PNW	6	22,875	658
	12	9,042	285
	15	18,915	555
	15	24,695	678
	17	21,053	606
	19	18,230	505
	23	14,863	419
	23	19,139	537
	41	6,092	199
	48	11,107	331
	57	13,981	390
	101	7,565	232
	124	3,704	123
	132	8,610	261
WECC_SCE	25	27,424	712
	27	18,382	517
	155	12,468	226
	289	3,662	114
WECC_UT	1	35,564	589
	2	25,456	606
	86	3,662	126
	120	21,854	532
WECC_WY	39	15,974	450

Landfill Gas Electricity Generation

Landfill Gas Resource Potential: Estimates of potential electric capacity from landfill gas are based on the AEO 2019 inventory. EPA 2023 Reference Case represents the “high”, “low”, and “very low” categories of potential landfill gas units. The categories refer to the amount and rate of methane production from the existing landfill site. Table 4-46 summarizes the potential electric capacity of landfill gas.

There are several things to note about Table 4-46. The AEO 2019 NEMS region-level estimates of the potential electric capacity from new landfill gas units are disaggregated to IPM regions based on electricity demand. The limits listed in Table 4-46 apply to the IPM regions indicated in column 1. In EPA 2023 Reference Case, the new landfill gas electric capacity in the corresponding IPM regions shown in column 1 cannot exceed the limits shown in columns 3-5. As noted, the capacity limits for three categories of potential landfill gas units are distinguished in the table based on the rate of methane production at three categories of landfill sites: LGHI = high rate of landfill gas production, LGLo = low rate of landfill gas production, and LGLVo = very low rate of landfill gas production. The values shown in Table 4-46 represent an upper bound on the amount of new landfill capacity that can be added in each of the indicated model regions and states for each of the three landfill categories. The cost and performance assumptions for adding new capacity in each of the three landfill categories are presented in Table 4-15.

Small Hydro

EPA 2023 Reference Case models resource potential from non-powered dams (NPDs) and new stream development (NSDs) categories of new small hydro. While NPDs are existing dams that do not currently have hydropower, NSDs are greenfield hydropower developments along previously undeveloped waterways. Table 4-29 and Table 4-30 summarize the assumptions for NPDs and NSDs.

Table 4-29 Potential Non-Powered Dam in the EPA 2023 Reference Case

IPM Region	State	Capacity (MW)	Capacity Factor (%) - Winter	Capacity Factor (%) - Spring	Capacity Factor (%) - Summer	Capacity Factor (%) - Fall	Capital Cost (2022$/kW)	FOM (2022$/kW)
ERC_REST	TX	338	55.1%	68.4%	48.7%	46.6%	2,485	17.35
ERC_WEST	TX	27	45.0%	64.8%	49.4%	41.3%	2,480	54.51
FRCC	FL	126	56.6%	53.0%	66.6%	67.8%	2,645	27.19
MIS_AMSO	LA	158	66.8%	76.3%	43.5%	45.9%	1,863	24.53
MIS_AR	AR	786	61.3%	81.2%	53.9%	46.1%	1,845	11.84
MIS_IA	IA	383	49.4%	90.3%	75.5%	52.4%	1,988	16.40
MIS_IL	IL	630	55.1%	90.5%	72.7%	53.2%	1,752	13.09
MIS_INKY	IN	65	68.4%	79.6%	52.2%	51.5%	3,174	36.66
	KY	536	75.2%	85.0%	46.1%	52.2%	1,481	14.09
MIS_LA	LA	643	66.7%	76.2%	43.3%	45.7%	1,823	12.97
MIS_LMI	MI	24	75.4%	90.5%	60.8%	62.4%	4,402	57.37
MIS_MAPP	MT	17	42.5%	76.4%	80.2%	46.7%	2,515	62.88
	ND	15	32.2%	81.0%	67.1%	38.7%	2,968	71.83
MIS_MIDA	IA	150	49.4%	90.3%	75.5%	52.3%	1,994	25.05
MIS_MNWI	MI	0.02	68.6%	90.8%	72.0%	65.0%	5,822	145.56
	MN	123	54.0%	86.7%	74.8%	56.8%	2,594	27.46
	WI	94	52.1%	92.0%	76.7%	57.0%	2,175	30.94
MIS_MO	IA	4	49.1%	90.1%	75.3%	51.7%	2,106	52.65
	MO	159	52.7%	90.0%	74.8%	52.7%	1,648	24.47
MIS_MS	MS	102	73.4%	72.1%	45.1%	54.1%	2,271	29.86
MIS_WOTA	LA	23	66.8%	76.3%	43.5%	45.9%	2,011	50.28
	TX	123	60.4%	73.7%	46.1%	44.7%	1,699	27.43
MIS_WUMS	MI	4	71.1%	90.7%	67.8%	64.0%	4,998	124.96
	WI	111	53.7%	92.8%	77.2%	58.0%	2,102	28.71
NENG_CT	CT	59	74.3%	89.9%	54.7%	60.1%	3,418	38.41
NENG_ME	ME	15	66.7%	87.4%	61.6%	60.1%	5,706	70.84
NENGREST	MA	53	74.2%	89.3%	51.1%	57.7%	5,278	40.13
	NH	56	70.2%	91.1%	58.3%	59.9%	3,548	39.34
	RI	11	76.3%	87.9%	48.7%	56.7%	5,153	81.81
	VT	13	69.5%	91.8%	56.3%	57.5%	3,655	76.09
NY_Z_A	NY	12	74.2%	87.4%	50.6%	58.0%	2,684	67.11
NY_Z_B	NY	8	74.2%	87.4%	50.6%	58.0%	2,759	68.97
NY_Z_C&E	NY	66	74.2%	87.4%	50.6%	58.0%	2,867	36.37
NY_Z_D	NY	49	74.2%	87.4%	50.6%	58.0%	2,839	41.66
NY_Z_F	NY	78	74.2%	87.4%	50.6%	58.0%	2,887	33.67
NY_Z_G-I	NY	28	74.2%	87.4%	50.6%	58.0%	2,650	53.51
PJM_AP	MD	13	70.2%	85.5%	49.5%	51.4%	3,132	76.36
	PA	236	78.3%	86.3%	47.7%	56.5%	2,311	20.42
	VA	3	68.9%	83.7%	50.1%	54.0%	4,048	101.21
	WV	138	73.7%	84.7%	48.1%	51.5%	2,244	26.03
PJM_ATSI	OH	64	70.2%	83.9%	52.0%	50.7%	3,162	36.86

IPM Region	State	Capacity (MW)	Capacity Factor (%) - Winter	Capacity Factor (%) - Spring	Capacity Factor (%) - Summer	Capacity Factor (%) - Fall	Capital Cost (2022$/kW)	FOM (2022$/kW)
	PA	43	77.9%	85.9%	48.2%	56.9%	2,146	44.25
PJM_COMD	IL	198	57.5%	90.0%	71.9%	55.2%	2,115	22.14
PJM_Dom	NC	2	68.6%	74.3%	49.4%	57.1%	2,416	60.41
	VA	13	68.9%	83.8%	50.1%	53.9%	3,424	75.64
PJM_EMAC	DE	1	71.3%	85.4%	56.7%	57.9%	5,422	135.56
	MD	13	72.8%	85.0%	58.5%	60.7%	2,781	69.52
	NJ	17	75.7%	84.5%	56.3%	62.8%	4,998	66.71
	PA	9	74.9%	83.7%	50.7%	58.9%	2,884	72.11
PJM_PENE	PA	316	77.7%	85.9%	48.2%	56.9%	2,360	17.91
PJM_SMAC	DC	1	72.8%	85.0%	58.5%	60.7%	3,458	86.46
	MD	15	72.5%	85.0%	57.9%	60.2%	3,602	71.46
PJM_West	IN	8	69.6%	77.6%	53.4%	54.0%	2,960	74.00
	KY	375	74.8%	84.6%	46.5%	52.0%	1,690	16.57
	OH	170	70.2%	85.0%	51.1%	49.1%	2,959	23.70
	VA	8	69.2%	84.6%	49.4%	51.8%	2,881	72.01
	WV	37	70.5%	85.7%	46.1%	48.3%	2,524	47.47
PJM_WMAC	PA	49	74.9%	84.2%	50.1%	58.3%	3,085	41.83
S_C_KY	KY	134	70.4%	80.6%	40.0%	46.4%	2,550	26.38
S_C_TVA	AL	118	74.5%	75.5%	41.3%	50.0%	1,896	27.94
	GA	30	75.8%	78.3%	61.9%	64.3%	2,055	51.38
	KY	1,022	76.6%	85.7%	48.3%	53.8%	1,351	10.52
	MS	94	75.3%	76.5%	43.4%	51.5%	2,273	31.06
	NC	2	72.7%	79.0%	57.4%	61.0%	4,247	106.18
	TN	12	75.4%	77.1%	48.4%	55.2%	2,705	67.63
	VA	1	69.2%	84.6%	49.3%	51.7%	2,875	71.88
S_D_AECI	MO	92	53.5%	90.9%	73.1%	52.8%	1,853	31.35
S_SOU	AL	723	74.5%	76.1%	43.8%	51.3%	1,542	12.30
	FL	11	72.5%	78.4%	64.4%	62.9%	2,688	67.19
	GA	51	75.8%	78.3%	61.9%	64.3%	2,226	40.90
	MS	12	74.1%	73.6%	44.5%	53.3%	2,298	57.45
S_VACA	GA	0.09	75.8%	78.3%	61.9%	64.3%	2,537	63.43
	NC	91	68.9%	74.6%	50.0%	57.3%	2,735	31.47
	SC	43	75.5%	77.8%	62.4%	65.9%	3,463	44.06
SPP_N	KS	36	40.3%	67.6%	58.5%	38.1%	2,603	47.96
	MO	10	63.9%	80.8%	50.5%	47.0%	2,888	72.21
SPP_NEBR	KS	3	40.3%	67.6%	58.5%	38.1%	2,803	70.08
SPP_SPS	NM	26	40.6%	71.0%	75.7%	52.9%	2,766	55.29
SPP_WEST	AR	343	61.3%	81.2%	53.8%	46.1%	1,774	17.24
	LA	24	66.8%	76.3%	43.5%	45.9%	1,881	47.02
	MO	0.40	53.5%	74.7%	48.4%	39.9%	3,272	81.80
	OK	312	48.5%	75.7%	54.6%	39.9%	2,116	17.99
	TX	20	59.7%	64.1%	35.0%	38.9%	2,533	62.86
WEC_BANC	CA	0.09	62.6%	84.4%	61.6%	53.6%	4,020	100.50
WEC_CALN	CA	111	62.7%	84.4%	61.6%	53.7%	2,985	28.77
WEC_LADW	CA	27	55.6%	85.9%	77.5%	58.5%	2,322	54.15
WECC_AZ	AZ	58	67.3%	81.6%	72.8%	65.9%	2,529	38.59
WECC_CO	CO	146	47.5%	76.7%	80.4%	54.3%	2,167	25.38
WECC_ID	ID	6	65.8%	81.8%	72.1%	66.3%	4,126	103.15
WECC_IID	CA	0.38	55.6%	85.9%	77.5%	58.5%	1,990	49.74
WECC_MT	MT	54	52.8%	76.1%	79.5%	56.7%	3,299	39.83
WECC_NM	NM	63	37.8%	84.7%	82.1%	49.8%	2,735	37.29
	TX	15	36.6%	86.2%	83.0%	48.1%	2,846	70.24
WECC_NNV	NV	12	50.0%	82.5%	69.2%	48.7%	4,673	79.40
WECC_PNW	CA	4	74.8%	88.5%	68.5%	65.2%	3,779	94.47
	ID	1	47.5%	80.1%	74.2%	48.5%	3,477	86.93
	OR	87	79.1%	82.8%	56.1%	61.5%	2,979	32.16
	WA	70	83.9%	83.6%	61.4%	61.7%	2,871	35.39

IPM Region	State	Capacity (MW)	Capacity Factor (%) - Winter	Capacity Factor (%) - Spring	Capacity Factor (%) - Summer	Capacity Factor (%) - Fall	Capital Cost (2022$/kW)	FOM (2022$/kW)
WECC_SCE	CA	34	55.6%	85.9%	77.4%	58.4%	2,226	49.37
WECC_SNV	NV	2	88.1%	83.2%	81.7%	86.2%	4,086	102.15
WECC_UT	UT	29	55.5%	79.1%	78.4%	59.3%	2,697	53.14
WECC_WY	WY	36	43.8%	83.6%	76.2%	45.9%	2,447	47.90

Table 4-30 Potential New Stream Development in the EPA 2023 Reference Case

IPM Region	State	Capacity (MW)	Capacity Factor (%) - Winter	Capacity Factor (%) - Spring	Capacity Factor (%) - Summer	Capacity Factor (%) - Fall	Capital Cost (2022$/kW)	FOM (2022$/kW)
MIS_MO	MO	639	51.7%	86.9%	75.2%	51.1%	4,039	13.02
NENG_ME	ME	406	65.4%	86.6%	62.7%	59.9%	6,698	15.97
NENGREST	MA	13	75.3%	89.9%	53.6%	59.6%	6,343	76.43
	NH	117	71.1%	91.4%	59.9%	61.0%	5,636	28.05
	VT	58	69.9%	91.4%	57.4%	58.5%	6,608	38.59
PJM_AP	PA	7	74.6%	85.8%	48.3%	56.4%	5,224	97.89
PJM_EMAC	NJ	27	75.7%	85.3%	56.6%	63.0%	5,631	54.24
	PA	30	74.8%	85.8%	48.3%	56.5%	5,224	52.20
PJM_PENE	PA	239	74.8%	85.8%	48.3%	56.5%	4,731	20.32
PJM_SMAC	MD	79	69.8%	85.6%	50.6%	53.9%	5,664	33.56
PJM_WMAC	PA	622	74.8%	85.9%	48.2%	56.4%	4,599	13.17
S_VACA	SC	51	76.0%	78.7%	61.5%	65.8%	6,372	40.85
SPP_N	MO	350	49.7%	86.9%	79.6%	53.0%	3,993	17.09
WECC_NNV	NV	13	47.5%	83.8%	71.7%	47.8%	7,620	74.87
WECC_PNW	OR	48	51.3%	87.4%	86.5%	57.2%	5,190	42.18
	WA	394	64.8%	88.0%	72.3%	54.1%	4,512	16.21

Energy Storage

Energy storage is the capture of energy produced at one time for use at a later time. Presently, the most common energy storage technologies are pumped storage and lithium-ion battery storage. EPA 2023 Reference Case includes both existing and new battery storage by IPM region and state. While EPA 2023 Reference Case models existing pumped storage, it does not model new pumped storage options.

The cost and performance assumptions for new 4-hour and 10-hour battery storage units in EPA 2023 Reference Case are based on NREL ATB 2023 and are summarized in Table 4-15. Energy storage options in EPA 2023 Reference Case are assigned capacity credits that are a function of penetration. Using a heuristic approach, a capacity credit curve is independently calculated for both 4-hour and 10-hour battery storage options at an IPM model region level. It estimates how much storage is needed to reduce net peak demand at different levels of storage penetration. For each model region, 300 storage power capacities (sized from 0 to 30% of the annual peak in 0.1% increments) are simulated. The amount of stored energy required to reduce the episodic peak demand by the storage power capacity is determined for each storage power capacity. The capacity credit is calculated as the ratio between the storage duration (4/10 hours) and the episode length with the most storage requirement. Hourly load curves adjusted for hourly generation from existing solar and wind units are used for the analysis. Four steps of storage options are provided in each IPM region. The first step is assigned 100% capacity credit for 4-hour storage options, and the second step 100% capacity credit for 10-hour storage options. The sum of step widths for the first and second steps equals the step width of the 100% capacity credit step of 10-hour energy storage options. The other two steps are assigned lower than 100% capacity credits based on the capacity credit curve for 10-hour storage options. Table 4-31 summarizes these assumptions.

Table 4-31 Bounds and Reserve Margin Contribution for Potential (New) Battery Storage in the EPA 2023 Reference Case

IPM Region	Bound (MW)				Reserve Margin Contribution (%)			
	Step 1	Step 2	Step 3	Step 4	Step 1	Step 2	Step 3	Step 4
ERC_PHDL	0	1,748	418	NA	100%	100%	0%	0%
ERC_REST	0	17,643	2,826	NA	100%	100%	0%	0%
ERC_WEST	0	1,748	418	NA	100%	100%	0%	0%
FRCC	9,139	14,190	1,483	NA	100%	100%	0%	0%
MIS_AMSO	301	572	768	NA	100%	100%	0%	0%
MIS_AR	482	727	1,870	NA	100%	100%	21%	0%
MIS_IA	419	789	270	NA	100%	100%	0%	0%
MIS_IL	1,775	2,130	87	NA	100%	100%	0%	0%
MIS_INKY	1,449	3,190	193	NA	100%	100%	0%	0%
MIS_LA	698	721	1,601	NA	100%	100%	0%	0%
MIS_LMI	2,778	3,188	2,755	NA	100%	100%	0%	0%
MIS_MAPP	229	337	102	NA	100%	100%	0%	0%
MIS_MIDA	961	562	513	NA	100%	100%	0%	0%
MIS_MNWI	3,544	3,107	378	NA	100%	100%	0%	0%
MIS_MO	658	1,860	254	NA	100%	100%	0%	0%
MIS_MS	494	638	781	NA	100%	100%	0%	0%
MIS_WOTA	383	443	815	NA	100%	100%	0%	0%
MIS_WUMS	1,331	1,546	1,532	NA	100%	100%	0%	0%
NENG_CT	1,661	1,595	1,557	NA	100%	100%	0%	0%
NENG_ME	330	568	145	NA	100%	100%	0%	0%
NENGREST	4,475	2,826	512	NA	100%	100%	0%	0%
NY_Z_A	711	655	52	NA	100%	100%	0%	0%
NY_Z_B	798	308	188	NA	100%	100%	0%	0%
NY_Z_C&E	1,197	1,295	0	NA	100%	100%	0%	0%
NY_Z_D	37	116	28	NA	100%	100%	0%	0%
NY_Z_F	723	425	178	NA	100%	100%	0%	0%
NY_Z_G-I	393	624	817	NA	100%	100%	0%	0%
NY_Z_J	72	2,503	1,229	NA	100%	100%	0%	0%
NY_Z_K	907	750	211	NA	100%	100%	0%	0%
PJM_AP	735	1,013	438	NA	100%	100%	0%	0%
PJM_ATSI	1,729	2,137	1,519	NA	100%	100%	0%	0%
PJM_COMD	2,168	4,290	2,214	NA	100%	100%	0%	0%
PJM_Dom	668	1,086	3,531	NA	100%	100%	37%	0%
PJM_EMAC	5,176	4,780	3,714	NA	100%	100%	0%	0%
PJM_PENE	380	525	214	NA	100%	100%	0%	0%
PJM_SMAC	1,347	2,013	1,038	NA	100%	100%	0%	0%
PJM_West	4,185	746	3,192	NA	100%	100%	0%	0%
PJM_WMAC	738	1,541	229	NA	100%	100%	0%	0%
S_C_KY	513	1,444	609	NA	100%	100%	0%	0%
S_C_TVA	1,646	1,308	3,780	NA	100%	100%	17%	0%
S_D_AECI	623	385	189	NA	100%	100%	0%	0%
S_SOU	5,430	3,196	8,523	NA	100%	100%	9%	0%
S_VACA	5,503	3,259	4,997	NA	100%	100%	0%	0%
SPP_N	870	4,316	783	NA	100%	100%	0%	0%
SPP_NEBR	456	1,569	263	NA	100%	100%	0%	0%
SPP_SPS	100	1,350	465	NA	100%	100%	0%	0%
SPP_WAUE	378	251	180	NA	100%	100%	0%	0%
SPP_WEST	508	5,762	952	NA	100%	100%	0%	0%
WEC_BANC	968	519	152	NA	100%	100%	0%	0%
WEC_CALN	10,263	3,993	5,216	NA	100%	100%	0%	0%
WEC_LADW	2,768	3,126	418	NA	100%	100%	0%	0%
WEC_SDGE	1,052	1,144	198	NA	100%	100%	0%	0%
WECC_AZ	5,784	3,206	1,109	NA	100%	100%	0%	0%
WECC_CO	2,236	3,750	577	NA	100%	100%	0%	0%
WECC_ID	1,224	794	171	NA	100%	100%	0%	0%
WECC_IID	0	593	0	NA	100%	100%	0%	0%
WECC_MT	324	251	279	NA	100%	100%	0%	0%

IPM Region	Bound (MW)				Reserve Margin Contribution (%)			
	Step 1	Step 2	Step 3	Step 4	Step 1	Step 2	Step 3	Step 4
WECC_NM	1,301	1,553	1,106	NA	100%	100%	0%	0%
WECC_NNV	706	1,056	269	NA	100%	100%	0%	0%
WECC_PNW	3,393	4,613	1,411	NA	100%	100%	0%	0%
WECC_SCE	7,759	5,768	2,725	NA	100%	100%	0%	0%
WECC_SNV	119	1,416	2,022	NA	100%	100%	0%	0%
WECC_UT	2,145	847	517	NA	100%	100%	0%	0%
WECC_WY	1,186	367	189	NA	100%	100%	0%	0%
CN_AB	964	964	1,151	NA	100%	100%	0%	0%
CN_BC	952	1,073	2,040	NA	100%	100%	11%	0%
CN_MB	341	218	494	NA	100%	100%	7%	0%
CN_NB	182	90	145	NA	100%	100%	0%	0%
CN_NF	81	88	96	NA	100%	100%	0%	0%
CN_NL	184	137	173	NA	100%	100%	0%	0%
CN_NS	227	339	36	NA	100%	100%	0%	0%
CN_ON	1,266	4,558	2,880	NA	100%	100%	0%	0%
CN_PE	58	71	21	NA	100%	100%	0%	0%
CN_PQ	5,687	776	2,585	NA	100%	100%	0%	0%
CN_SK	224	178	238	NA	100%	100%	0%	0%

Multiple U.S. states have instituted standalone targets and mandates for energy storage procurement. Table 4-33 summarizes the state-specific energy storage mandates in EPA 2023 Reference Case. Under Assembly Bill No. 2514 and Assembly Bill No. 2868, the California Public Utilities Commission (CPUC) established energy storage targets for the state's three investor-owned utilities (IOUs), namely, Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric. The California state mandates are therefore modeled at the utility level.

4.5 Inflation Reduction Act Impacts on New Units

The tax credits for new renewable technology investments provided under the Inflation Reduction Act of 2022 are implemented in EPA 2023 Reference Case as a reduction to capital costs. A production tax credit (PTC) of 1.5 cents/kWh in 1992 dollars or an investment tax credit (ITC) of 30 percent are applied to renewable technologies, The 1.5 cents PTC and 30 percent ITC is the rate for units that meet the wage and apprenticeship requirements. While a 10% energy community tax credit is provided to all new energy storage technologies, the 10% energy community tax credit is prorated based on the share of the total IPM regional land area that qualifies as an energy community for solar and wind units. Table 4-32 summarizes the PTC/ITC Energy Community Tax Credit increment allocated to each IPM region.

The tax credits are applied to investments made in the run years during the 2028-2055 period when the power sector CO_2 emissions do not reduce by 75% below the 2022 level of 1,539 million metric tonnes.

Table 4-32 Energy Community Tax Credit Increment for Solar and Wind Units

IPM Region	PTC/ITC increment (%)	IPM Region	PTC/ITC increment (%)
ERC_PHDL	10	PJM_Dom	2.5
ERC_REST	5	PJM_EMAC	2.5
ERC_WEST	10	PJM_PENE	10
FRCC	2.5	PJM_SMAC	2.5
MIS_AMSO	7.5	PJM_West	5
MIS_AR	0	PJM_WMAC	7.5
MIS_D_MS	0	S_C_KY	5
MIS_IA	2.5	S_C_TVA	2.5
MIS_IL	7.5	S_D_AECI	2.5
MIS_INKY	5	S_SOU	2.5
MIS_LA	5	S_VACA	2.5
MIS_LMI	2.5	SPP_N	2.5
MIS_MAPP	2.5	SPP_NEBR	0
MIS_MIDA	2.5	SPP_SPS	10
MIS_MNWI	2.5	SPP_WAUE	2.5
MIS_MO	2.5	SPP_WEST	2.5
MIS_WOTA	7.5	WEC_BANC	0
MIS_WUMS	2.5	WEC_CALN	0
NENG_CT	0	WEC_LADW	0
NENG_ME	0	WEC_SDGE	0
NENGREST	0	WECC_AZ	5
NY_Z_A	2.5	WECC_CO	7.5
NY_Z_B	2.5	WECC_ID	0
NY_Z_C&E	2.5	WECC_IID	0
NY_Z_D	0	WECC_MT	2.5
NY_Z_F	0	WECC_NM	7.5
NY_Z_G-I	0	WECC_NNV	2.5
NY_Z_J	0	WECC_PNW	2.5
NY_Z_K	2.5	WECC_SCE	5
PJM_AP	7.5	WECC_SNV	7.5
PJM_ATSI	5	WECC_UT	5
PJM_COMD	2.5	WECC_WY	5

Table 4-33 Energy Storage Mandates in the EPA 2023 Reference Case

State/Region	Bill	Mandate Type	Mandate Specifications	Implementation Status
California	Assembly Bill No. 2514	Target in MW	Energy storage target of 1,325 megawatts for Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric by 2020, with installations required no later than the end of 2024.	2025
			LADWP adopted a resolution setting its 2021 energy storage target at 178 MW.	
Maryland	House Bill 910.	Target in MW	3,000 MW energy storage target for 2033, with interim targets of 750 MW in 2027 and 1500 MW in 2030.	2033
New York	New York State Energy Storage Target	Target in MW	1,500 Megawatts by 2025 and up to 3,000 megawatts by 2030.	2025
New Jersey	Assembly Bill No. 3723	Target in MW	600 megawatts of energy storage by 2021 and 2,000 megawatts of energy storage by 2030.	2021
Oregon	House Bill 2193	Target in MWh per electric company	An electric company shall procure one or more qualifying energy storage systems that have the capacity to store at least five megawatt hours of energy on or before January 1, 2020.	2020
Massachusetts	Chapter 188	Target in MWh	200 Megawatt hour (MWh) energy storage target for electric distribution companies to procure viable and cost-effective energy storage systems to be achieved by January 1, 2020.	2020
	House Bill 4857	Target in MWh	Goal of 1,000 MWh of energy storage by the end of 2025.	2025
Virginia	Virginia Clean Economy Act	Target in MW	Requires, by 2035, American Electric Power and Dominion Energy Virginia to construct or acquire 400 and 2,700 megawatts of energy storage capacity, respectively	2035
Connecticut		Target in MW	300 MW by 2025, 650 MW by 2028, and 1,000 MW by 2031	2025
Minnesota		Target in MW	400 MW by 2030	2030
Nevada	Order No. 44671	Target in MW	1,000 MW by 2030	2030

4.6 Nuclear Units

4.6.1 Existing Nuclear Units

Population, Plant Location, and Unit Configuration: To provide maximum granularity in forecasting the behavior of existing nuclear units, all 91 nuclear units in EPA 2023 Reference Case are represented by separate model plants. All units are listed in Table 4-47. The population characteristics, plant location, and unit configuration data in the NEEDS were obtained primarily from EIA Form 860 and AEO 2023.

Capacity: Nuclear units are baseload power plants with high fixed (capital and fixed O&M) costs and relatively low variable (fuel and variable O&M) costs. Due to their low variable costs, nuclear units are typically projected to dispatch up to their assumed availability (the maximum extent possible). Consequently, a nuclear unit's capacity factor is equivalent to its availability. Thus, EPA 2023 Reference Case uses capacity factor assumptions to define the upper bound on generation from nuclear units. Nuclear capacity factor assumptions in EPA 2023 Reference Case are based on an Annual Energy Outlook projection algorithm. The nuclear capacity factor projection algorithm is described below:

- For each reactor, the capacity factor over time depends on the reactor's age.
- Capacity factors increase initially due to learning and decrease in the later years due to aging.
- For individual reactors, vintage classifications (older and newer) are used.
- For the older vintage (starting before 1982) nuclear power plants, the performance peaks at 25 years:
  - Before 25 years: Performance increases by 0.5 percentage points per year;
  - 25- years: Performance remains flat; and
- For the newer vintage (starting in or after 1982) nuclear power plants, the performance peaks at 30 years:
  - Before 30 years: Performance increases by 0.7 percentage points per year;
  - 30- years: Performance remains flat; and
- A maximum capacity factor of 90 percent is assumed unless a capacity factor above 90 percent was observed for the unit.

Cost and Performance: Unlike non-nuclear existing conventional units discussed in Section 4.2.7, emission rates are not needed for nuclear units since there are no SO_2, NO_x, CO_2, or mercury emissions from nuclear units.

As with other generating resources, EPA 2023 Reference Case uses heat rate, variable O&M costs, and fixed O&M costs from AEO 2023 to characterize the cost of operating existing nuclear units. The data are shown in Table 4-47.

As nuclear units have aged, some units have been retired from service or are planning to retire over the modeled time horizon. For a list of operational nuclear units, see the NEEDS database In EPA 2023 Reference Case.

Zero Emission Credit (ZEC) Programs: New York and Illinois passed legislation in 2017 to provide support to selected existing nuclear units that could be at risk of early closure due to declining profitability.

The New York Clean Energy Standard for a 12-year period creates ZECs that are currently applicable for Fitzpatrick, Ginna, and Nine Mile Point nuclear power plants. The New York load-serving entities (LSEs) are responsible for purchasing ZECs equal to their share of the statewide load, providing an additional revenue stream to the nuclear power plants holding the ZECs. Similar to the New York program, the

Illinois Future Energy Jobs Bill creates a ZEC program covering a 10-year term for Clinton and Quad Cities nuclear power plants.

EPA 2023 Reference Case implicitly models the effect of ZECs by disabling the retirement options for Fitzpatrick, Ginna, Nine Mile Point nuclear power plants in the 2028 run years.

New Jersey has established a ZEC program. As a result, Salem Harbor 1 & 2 and Hope Creek nuclear units are eligible to receive payments during the year of implementation plus the three following years and may be considered for additional three-year renewal periods thereafter.

Ohio passed House Bill 6 which includes 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. Due to the ongoing uncertainty of this provision, the EPA 2023 Reference Case does not model the impact of this provision on the Perry and Davis Besse nuclear plants.

Nuclear Retirement Limits: In EPA 2023 Reference Case, endogenous retirements of nuclear units are not allowed. Nuclear units are retired per a predetermined retirement schedule. Single-unit plants owned by regulated and nonregulated entities and multiple-unit plants owned by nonregulated entities are assumed to have a lifetime of 60 years. In addition, multiple-unit plants owned by regulated entities are assumed to have a lifetime of 80 years.

Life-Extension Costs: EPA 2023 Reference Case imposes lifetime extension costs for nuclear units. Attachment 4-1 summarizes the approach to estimating unit-level life extension costs for existing nuclear units. Unlike other plant types, life-extension costs for nuclear units are calculated as a function of age and are applied starting in the 2028 run year. The life-extension costs are calculated as 17 + 1.25 multiplied by the age of the unit before 50 years of age. After the age of 50 years, the life-extension costs are assumed to be 70 $/kW-yr.

To reflect the improvements made through the life extension investments, the FOM costs are reduced by 25 $/kW-yr starting age of 51 years.

4.6.2 Potential Nuclear Units

The cost and performance assumptions for nuclear potential units that the model has the option to build are shown in Table 4-12. The cost assumptions are from AEO 2023.

List of tables that are uploaded directly to the web:

Table 4-34 Planned-Committed Units by Model Region in NEEDS for EPA 2023 Reference Case

Table 4-35 Onshore Average Capacity Factor by Wind Class, Resource Class, and Vintage in EPA 2023 Reference Case

Table 4-36 Onshore Regional Potential Wind Capacity (MW) by Wind Class, Resource Class, and Cost Class in EPA 2023 Reference Case

Table 4-37 Wind Generation Profiles in EPA 2023 Reference Case (kWh of Generation per MW of Capacity)

Table 4-38 Capital Cost Adder (2022$/kW) for New Onshore Wind Plants by Resource and Cost Class in EPA 2023 Reference Case

Table 4-39 Solar Photovoltaic Regional Potential Capacity (MW) by Resource and Cost Class in EPA 2023 Reference Case