4. Generating Resources

Existing, planned-committed, and potential are the three types of generating units modeled in EPA Platform v6 2022 Reference Case (EPA Platform v6). Electric generating units currently in operation are termed as existing units. Units that are anticipated to be in operation in the near future, for having broken ground or secured financing, are planned-committed units. 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 4.5 describes assumptions pertaining to existing and potential nuclear units.

4.1 National Electric Energy Data System (NEEDS)

EPA Platform v6 uses the NEEDS v6 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 v6 represents electric generating units that were in operation through the end of 2021. 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 2022 through June 30, 2028.

4.2 Existing Units

The sections below describe the procedures for determining the population of existing units in NEEDS v6, 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 v6 was obtained from the sources reported in Table 4-1. The September 2019 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 Platform v6.

Table 4-1 Data Sources for NEEDS v6

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 v6 uses EIA Form 860 (September 2019 monthly version and 2018 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 v6 uses EIA Form 860 (2018 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 2020 Reference Case such as heat rates and capacity for nuclear units was used in NEEDS v6.
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 v6 uses annual and seasonal ETS (2019) data as one of the primary data inputs for NO_x rate development and 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 Spring 2022 (e.g., retirements and new units) as well as unit characteristics were incorporated in NEEDS v6.

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 v6

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[39]" or "OA[40]" 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[41]"). 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. 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

[39] 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.

[40] 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.

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

Scope	Rule
	be online by June 30, 2028. 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.
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 v6 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 v6, 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 v6 through 2021. 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 Platform v6 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), December 2021

ii) PJM Future Deactivation Requests and PJM Generator Deactivations, March 2022 (updated frequently)

iii) ERCOT Generator Interconnection Status Report, March 2022 (updated frequently)

iv) MISO Generation Interconnection Queue, March 2022 (updated frequently). Units that have been cleared by a regional transmission operator (RTO) or independent system operator (ISO) to retire before June 30, 2028, or whose RTO/ISO clearance to retire is contingent on actions that can be completed before June 30, 2028

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

vi) Research by EPA and ICF staff as of Spring 2022

   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 owned fleet.
   - Reviewing investor news released by company that outlines 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 v6. 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.

The “Capacity Dropped” and the “Retired Through 2028” worksheets in NEEDS lists all units that are removed from the NEEDS v6 inventory.

Table 4-3 Summary Population (through 2021) of Existing Units in NEEDS v6

Plant Type	Number of Units	Capacity (MW)
Biomass	167	3,436
Coal Steam	362	143,653
Combined Cycle	1,883	274,800
Combustion Turbine	5,787	145,510
Energy Storage	376	6,148
Fossil Waste	62	1,382
Fuel Cell	162	268
Geothermal	158	2,472
Hydro	3,817	79,307
IGCC	5	815
Landfill Gas	1,484	1,754
Municipal Solid Waste	150	1,935
Non-Fossil Waste	223	2,299
Nuclear	90	92,345
O/G Steam	395	57,901
Offshore Wind	2	41
Onshore Wind	1,503	137,129
Pumped Storage	152	22,820
Solar PV	5,124	62,459
Solar Thermal	11	1,486
Tires	2	52
US Total	21,915	1,038,011

4.2.2 Capacity

The unit capacity data implemented in NEEDS v6 reflects net summer dependable capacity.[42] 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 v6

Sources Presented in Hierarchy
Net Summer Capacity from Comments / ICF Research
AEO 2020 Nuclear Capacity in 2023
September 2019 EIA Form 860 monthly Net Summer Capacity
2018 EIA Form 860 Net Summer Capacity

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

As noted earlier, NEEDS v6 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.

[42] 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.

The capacity-parsing algorithm used for steam units in NEEDS v6 considered boiler-generator mapping. Fossil steam electric units have boilers attached to generators that produce electricity. There are 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 v6 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 v6

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
	$MW_{Bi} = MW_{Gj}$	$MW_{Bi} = \Sigma j MW_{Gj}$	$MW_{Bi} = (MF_{Bi} / \Sigma i MF_{Bi}) * MW_{Gj}$	$MW_{Bi} = (MF_{Bi} / \Sigma i MF_{Bi}) * \Sigma j MW_{Gj}$

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

Since EPA Platform v6 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 v6 by this qualification are determined from the 2018 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 v6 uses the state and county data from the September 2019 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 Platform v6 model regions.

4.2.4 Online Year

EPA Platform v6 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 2018 EIA Form 860, and online years for generators were derived primarily from reported in-service dates in the September 2019 EIA Form 860M.

EPA Platform v6 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 coal, oil and gas steam, combined cycle, combustion turbines, biomass, and nuclear units to allow the model the option to retire a unit if it finds 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 payment on any previously incurred capital cost for model-installed retrofits projected prior to retirement.

4.2.5 Unit Configuration

Unit configuration refers to the physical specification of a unit's design. Unit configuration in EPA Platform v6 drives model plant aggregation and modeling of pollution control options and mercury emission modification factors. NEEDS v6 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 v6

Unit Component	Primary Data Source	Secondary Data Source	Tertiary Data Source	Other Sources	Default
Firing Type	2018 EIA 860	EPA's Emission Tracking System (ETS) – 2019	--	--	--
Bottom Type	2018 EIA 860	EPA's Emission Tracking System (ETS) – 2019	--	--	Dry
SO_2 Pollution Control	2018 EIA 860	EPA's Emission Tracking System (ETS) – 2019	NSR Settlement or Comments	--	No Control
NO_x Pollution Control	2018 EIA 860	EPA's Emission Tracking System (ETS) – 2019	NSR Settlement or Comments	--	No Control
Particulate Matter Control	2018 EIA 860	EPA's Emission Tracking System (ETS) – 2019	NSR Settlement or Comments	--	--
Mercury Control	2018 EIA 860	EPA's Emission Tracking System (ETS) – 2019	NSR Settlement or Comments	--	--
HCL Control	2018 EIA 860	EPA's Emission Tracking System (ETS) – 2019	NSR Settlement or Comments	--	--

4.2.6 Model Plant Aggregation

While EPA Platform v6 using IPM is comprehensive in representing all the units contained in NEEDS v6, 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 Platform v6 are the following.

i) Facility (ORIS) for all fossil units except combustion turbine units smaller than or equal to 25 MW
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
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 Platform v6. For each plant type, the table shows the number of generating units and the number of model plants representing the generating units.[43]

Table 4-7 Aggregation Profile of Model Plants as Provided at Set up of v6

Existing and Planned/Committed Units		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
Biomass	314	114
Coal Steam	383	291
Combined Cycle	1,994	719
Combustion Turbine	5,820	1,215
Distributed Solar PV	130	130
Energy Storage	162	64
Fossil Waste	68	31
Fuel Cell	99	15
Geothermal	153	10
Hydro	5,502	193
IGCC	5	2
IMPORT	1	1
Landfill Gas	1,482	87
Municipal Solid Waste	151	53
Non-Fossil Waste	250	88
Nuclear	104	104
O/G Steam	477	297
Offshore Wind	1	1
Onshore Wind	1,731	88
Pumped Storage	159	27
Solar PV	4,290	97
Solar Thermal	12	5
Tires	2	1
Total	**23,290**	**3,633**
New Units		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
New Battery Storage	--	504
New Biomass	--	134
New Combined Cycle	--	86
New Combined Cycle with CCS	--	128

[43] (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).

New Combustion Turbine	--	115
New Fuel Cell	--	75
New Geothermal	--	61
New Hydro	--	153
New Landfill Gas	--	379
New Nuclear	--	68
New Offshore Wind	--	582
New Onshore Wind	--	3,087
New Small Modular Reactor	--	64
New Solar PV	--	3,165
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	--	**9,110**
Retrofits		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
Retrofit Coal with ACI	--	2
Retrofit Coal with ACI + DSI	--	4
Retrofit Coal with ACI + DSI + HRI	--	4
Retrofit Coal with ACI + DSI + HRI + SCR	--	3
Retrofit Coal with ACI + DSI + HRI + SCR + Scrubber	--	2
Retrofit Coal with ACI + DSI + HRI + Scrubber	--	4
Retrofit Coal with ACI + DSI + HRI + Scrubber + SNCR	--	2
Retrofit Coal with ACI + DSI + HRI + SNCR	--	3
Retrofit Coal with ACI + DSI + SCR	--	3
Retrofit Coal with ACI + DSI + SCR + Scrubber	--	2
Retrofit Coal with ACI + DSI + Scrubber	--	4
Retrofit Coal with ACI + DSI + Scrubber + SNCR	--	2
Retrofit Coal with ACI + DSI + SNCR	--	3
Retrofit Coal with ACI + HRI	--	2
Retrofit Coal with ACI + HRI + SCR	--	2
Retrofit Coal with ACI + HRI + SCR + Scrubber	--	2
Retrofit Coal with ACI + HRI + Scrubber	--	2
Retrofit Coal with ACI + HRI + Scrubber + SNCR	--	2
Retrofit Coal with ACI + HRI + SNCR	--	2
Retrofit Coal with ACI + SCR	--	2
Retrofit Coal with ACI + SCR + Scrubber	--	2
Retrofit Coal with ACI + Scrubber	--	2
Retrofit Coal with ACI + Scrubber + SNCR	--	2
Retrofit Coal with ACI + SNCR	--	2
Retrofit Coal with C2G	--	231
Retrofit Coal with C2G + SCR	--	231
Retrofit Coal with CCS	--	768
Retrofit Coal with CCS + HRI	--	620
Retrofit Coal with CCS + HRI + SCR	--	184
Retrofit Coal with CCS + HRI + SCR + Scrubber	--	120
Retrofit Coal with CCS + HRI + Scrubber	--	168
Retrofit Coal with CCS + HRI + Scrubber + SNCR	--	120
Retrofit Coal with CCS + HRI + SNCR	--	116
Retrofit Coal with CCS + SCR	--	196
Retrofit Coal with CCS + SCR + Scrubber	--	120
Retrofit Coal with CCS + Scrubber	--	168
Retrofit Coal with CCS + Scrubber + SNCR	--	120
Retrofit Coal with CCS + SNCR	--	128
Retrofit Coal with DSI	--	6
Retrofit Coal with DSI + HRI	--	30
Retrofit Coal with DSI + HRI + SCR	--	24
Retrofit Coal with DSI + HRI + SCR + Scrubber	--	3
Retrofit Coal with DSI + HRI + Scrubber	--	3

Retrofit Coal with DSI + HRI + SNCR	--	24
Retrofit Coal with DSI + SCR	--	39
Retrofit Coal with DSI + SCR + Scrubber	--	9
Retrofit Coal with DSI + Scrubber	--	6
Retrofit Coal with DSI + SNCR	--	39
Retrofit Coal with HRI	--	365
Retrofit Coal with HRI + SCR	--	208
Retrofit Coal with HRI + SCR + Scrubber	--	216
Retrofit Coal with HRI + Scrubber	--	243
Retrofit Coal with HRI + Scrubber + SNCR	--	182
Retrofit Coal with HRI + SNCR	--	160
Retrofit Coal with NGC	--	253
Retrofit Coal with SCR	--	132
Retrofit Coal with SCR + Scrubber	--	270
Retrofit Coal with Scrubber	--	118
Retrofit Coal with Scrubber + SNCR	--	239
Retrofit Coal with SNCR	--	98
Retrofit Combined Cycle with CCS	--	2384
Retrofit Oil/Gas steam with SCR	--	148
Total	--	**8,549**
Retirements		
Plant Type	**Number of Units**	**Number of IPM Model Plants**
Biomass Retirement	--	114
CC Retirement	--	719
Coal Retirement	--	4,761
CT Retirement	--	1,215
Geothermal Retirement	--	10
Hydro Retirement	--	103
IGCC Retirement	--	2
Landfill Gas Retirement	--	87
Nuke Retirement	--	104
Oil/Gas steam Retirement	--	676
Total	--	**7,791**
Grand Total (Existing and Planned/Committed + New + Retrofits + Early Retirements): 29,083		

4.2.7 Cost and Performance Characteristics of Existing Units[44]

In EPA Platform v6, 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 Platform v6.

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 Platform v6. The following further discusses the components of VOM costs and the VOM modeling methodology.

[44] All units excluding nuclear units.

Variable O&M Approach: EPA Platform v6 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, cost per generation increase. For base load operation there are fewer starts spread over more generation, 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.

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 v6

Capacity Type	SO_2 Control	NO_x Control	Hg Control	Variable O&M (2019$/mills/kWh)
Biomass	--	--	--	7.56
Coal Steam	No SO_2 Control	No NO_x Control	No Hg Control	1.52
			ACI	3.08
		SCR	No Hg Control	2.4
			ACI	3.96
		SNCR	No Hg Control	2.3
			ACI	3.86
	Dry FGD	No NO_x Control	No Hg Control	3.55
			ACI	5.11
		SCR	No Hg Control	4.43
			ACI	5.99
		SNCR	No Hg Control	4.33
			ACI	5.89

Capacity Type	SO_2 Control	NO_x Control	Hg Control	Variable O&M (2019$/mills/kWh)
	Wet FGD	No NO_x Control	No Hg Control	4.18
			ACI	5.73
		SCR	No Hg Control	5.06
			ACI	6.62
		SNCR	No Hg Control	4.96
			ACI	6.52
	DSI	No NO_x Control	No Hg Control	7.75
			ACI	9.31
		SCR	No Hg Control	8.63
			ACI	10.19
		SNCR	No Hg Control	8.53
			ACI	10.09
Combined Cycle	No SO_2 Control	No NO_x Control	No Hg Control	2.14 - 4.02
		SCR		2.28 - 4.16
		SNCR		2.81 - 4.69
Combustion Turbine	No SO_2 Control	No NO_x Control	No Hg Control	4.61 - 6.52
		SCR		4.72 - 6.63
		SNCR		4.72 - 6.63
Fuel Cell	--	--	--	45.07
Geothermal	--	--	--	1.16
Hydro	--	--	--	1.39
IGCC	--	--	--	2.42-4.29
Landfill Gas / Municipal Solid Waste	--	--	--	6.94
Oil/gas Steam	No SO_2 Control	No NO_x Control	No Hg Control	0.88
		SCR		1.03
		SNCR		1.55
Pumped Storage	--	--	--	0.02
Solar	--	--	--	0
Wind	--	--	--	0

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.[45] 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.

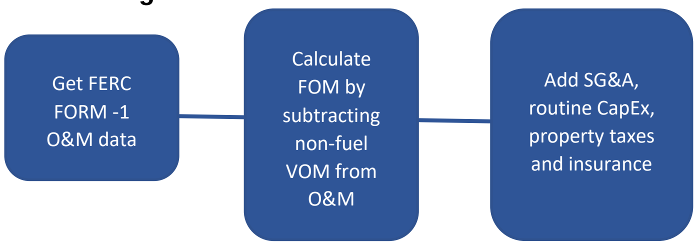
Stand Alone – Steam Turbines Based Prime Movers

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

[45] 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 Platform v6. This is to acknowledge the fact that the economics of such a unit cannot be comprehensively modeled in a power sector focused model.

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.

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.

<u>Gas-Turbine Based Prime Movers</u>

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 v6

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2019$ /kW-Yr)
Biomass	--	--	--	All Years	149.3
Coal Steam	No SO_2 Control	No NO_x Control	No Hg Control	0 to 40 Years	30.1
				40 to 50 Years	34.42
				Greater than 50 Years	44.22
			ACI	0 to 40 Years	30.19

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2019$ /kW-Yr)
				40 to 50 Years	34.51
				Greater than 50 Years	44.31
		SCR	No Hg Control	0 to 40 Years	30.93
				40 to 50 Years	35.25
				Greater than 50 Years	45.05
			ACI	0 to 40 Years	31.01
				40 to 50 Years	35.33
				Greater than 50 Years	45.14
		SNCR	No Hg Control	0 to 40 Years	30.39
				40 to 50 Years	34.71
				Greater than 50 Years	44.52
			ACI	0 to 40 Years	30.48
				40 to 50 Years	34.8
				Greater than 50 Years	44.6
	Dry FGD	No NO_x Control	No Hg Control	0 to 40 Years	39.18
				40 to 50 Years	43.5
				Greater than 50 Years	53.3
			ACI	0 to 40 Years	39.26
				40 to 50 Years	43.58
				Greater than 50 Years	53.39
		SCR	No Hg Control	0 to 40 Years	40
				40 to 50 Years	44.32
				Greater than 50 Years	54.13
			ACI	0 to 40 Years	40.09
				40 to 50 Years	44.41
				Greater than 50 Years	54.21
		SNCR	No Hg Control	0 to 40 Years	39.47
				40 to 50 Years	43.79
				Greater than 50 Years	53.59
			ACI	0 to 40 Years	39.55
				40 to 50 Years	43.87
				Greater than 50 Years	53.68
	Wet FGD	No NO_x Control	No Hg Control	0 to 40 Years	40.95
				40 to 50 Years	45.28
				Greater than 50 Years	55.08
			ACI	0 to 40 Years	41.04
				40 to 50 Years	45.36
				Greater than 50 Years	55.16
		SCR	No Hg Control	0 to 40 Years	41.78
				40 to 50 Years	46.1
				Greater than 50 Years	55.9
			ACI	0 to 40 Years	41.87
				40 to 50 Years	46.19
				Greater than 50 Years	55.99
		SNCR	No Hg Control	0 to 40 Years	41.25
				40 to 50 Years	45.57
				Greater than 50 Years	55.37
			ACI	0 to 40 Years	41.33
				40 to 50 Years	45.65
				Greater than 50 Years	55.46
	DSI	No NO_x Control	No Hg Control	0 to 40 Years	31.44
				40 to 50 Years	35.76

Plant Type	SO_2 Control	NO_x Control	Hg Control	Age of Unit	FOM (2019$ /kW-Yr)
				Greater than 50 Years	45.57
			ACI	0 to 40 Years	31.53
				40 to 50 Years	35.85
				Greater than 50 Years	45.65
		SCR	No Hg Control	0 to 40 Years	32.27
				40 to 50 Years	36.59
				Greater than 50 Years	46.39
			ACI	0 to 40 Years	32.36
				40 to 50 Years	36.68
				Greater than 50 Years	46.48
		SNCR	No Hg Control	0 to 40 Years	31.73
				40 to 50 Years	36.05
				Greater than 50 Years	45.86
			ACI	0 to 40 Years	31.82
				40 to 50 Years	36.14
				Greater than 50 Years	45.95
Combined Cycle	No SO_2 Control	No NO_x Control	No Hg Control	-	30.18
		SCR	No Hg Control	-	31.59
		SNCR	No Hg Control	-	30.92
Combustion Turbine	No SO_2 Control	No NO_x Control	No Hg Control	-	19.73
		SCR	No Hg Control	-	21.84
		SNCR	No Hg Control	-	20.15
Fuel Cell	--	--	--	All Years	0
Geothermal	--	--	--	All Years	100.74
Hydro	--	--	--	All Years	15.81
Integrated Gasification Combined Cycle	No SO_2 Control	No NO_x Control	--	All Years	108.71
Landfill Gas / Municipal Solid Waste	--	--	--	All Years	259.23
Oil/gas Steam	No SO_2 Control	No NO_x Control	No Hg Control	0 to 40 Years	17.99
				40 to 50 Years	27.32
				Greater than 50 Years	35.6
		SCR	No Hg Control	0 to 40 Years	19.34
				40 to 50 Years	28.67
				Greater than 50 Years	36.94
		SNCR	No Hg Control	0 to 40 Years	18.22
				40 to 50 Years	27.55
				Greater than 50 Years	35.83
Pumped Storage	--	--	--	All Years	18.29
Solar Photovoltaics	--	--	--	All Years	31.6
Solar Thermal	--	--	--	All Years	82.65
Wind	--	--	--	All Years	35.26

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.

NO_x Rates

Section 3.10.2 contains a detailed discussion of NO_x rates for existing units.

Mercury Emission Modification Factors (EMF)

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 Platform v6.

Cogeneration Units

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 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.

Coal Switching

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 Platform v6 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.

Blending Subbituminous Coal:

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. And 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 286 (2019$ 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:

$$\text{Fuel Switching Cost Adder (2019\$ per kW)} =$$
$$286 \times \left\{\frac{(100 - \text{Historical Maximum Share of Subbituminous})}{(100 - 20)}\right\}$$

<u>Blending Bituminous Coal:</u>

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 57 (2019$ 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:

$$\text{Fuel Switching Cost Adder (2019\$ per kW)} =$$
$$57 \times \left\{\frac{(100 - \text{Historical Maximum Share of Bituminous})}{(100 - 20)}\right\}$$

4.2.8 Life Extension Costs for Existing Units

The modeling time horizon in EPA Platform v6 extends to 2059 and covers a period of 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 reaches its assumed lifespan. Life extension costs for nuclear units are discussed in Section 4.5.1.

Table 4-10 Life Extension Cost Assumptions Used in v6

Plant Type	Lifespan without Life Extension Expenditures	Life Extension Cost (2019$/kW)	Capital Cost of New Unit (2019$/kW)	Life Extension Cost as Proportion of New Unit Capital Cost (%)
Biomass	40	253	3,853	6.6
Coal Steam	40	203	3,481	5.84

Plant Type	Lifespan without Life Extension Expenditures	Life Extension Cost (2019$/kW)	Capital Cost of New Unit (2019$/kW)	Life Extension Cost as Proportion of New Unit Capital Cost (%)
Combined Cycle	30	82	901	9.06
Combustion Turbine	30	242	667	36.3
IC Engine	30	226	1,713	13.2
Oil/Gas Steam	40	174	3,169	5.5
IGCC	40	258	3,481	7.4
Landfill Gas	20	135	1,480	9.1

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

4.3 Planned-Committed Units

EPA Platform v6 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 December 2021 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 4-33 gives a breakdown of planned-committed units by IPM region, plant type, and capacity.

Table 4-11 Summary of Planned-Committed Units in NEEDS v6

Type	Capacity (MW)	Year Range Described
Renewables/Non-conventional		
Energy Storage	11,339	2022 - 2025
Fuel Cell	16	2022 - 2022
Geothermal	17	2022 - 2022
Hydro	4	2022 - 2022
Landfill Gas	3	2022 - 2022
Offshore Wind	3,285	2024 - 2027
Onshore Wind	16,604	2022 - 2026
Solar PV	47,265	2022 - 2030
Subtotal	78,533	
Fossil/Conventional		
Combined Cycle	11,627	2022 - 2024
Combustion Turbine	1,126	2022 - 2024
Nuclear	1,100	2022 - 2022
Subtotal	13,853	
Grand Total	92,386	

Note:
Any unit in NEEDS v6 that has an online year of 2022 or later was considered a Planned/Committed Unit.

4.3.2 Capacity

The capacity data of planned-committed units in NEEDS v6 was obtained from the December 2021 version of EIA Form 860 monthly.

4.3.3 State and Model Region

State location data for the planned-committed units in NEEDS v6 came from the December 2021 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 v6 are only those likely to come on-line before June 30, 2028, as 2028 is the first analysis year in the EPA Platform v6. All planned-committed units were assigned an online year and given a default retirement year of 9999.

4.4 Potential Units

The EPA Platform v6 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 Platform v6. The following sections describe the cost and performance assumptions for the potential units represented in the EPA Platform v6.

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 Platform v6 are derived primarily from assumptions used in the Annual Energy Outlook (AEO) 2021 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 install 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 2021 is equal to 103 2019$/kW outside of WECC and NY regions and 154 2019$/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. 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 Platform v6 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 3-25.

4.4.3 Short-Term Capital Cost Adder

In addition to the capital costs shown in Table 4-12 and Table 4-15, EPA Platform v6 includes a short-term capital cost adder that kicks in if the new capacity deployed in a specific model run year exceeds certain upper bounds. This adder is meant to reflect 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 amount of 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 amount of capacity deployed, where the level of the cost adder depends upon the total amount of new capacity added in that run year. For example, the Step 1 upper bound in 2030 for landfill gas potential units is 375 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 375 and 652 MW, the Step 2 cost adder of $652/kW applies to the entire capacity deployed. If the total new landfill gas capacity exceeds the Step 2 upper bound of 652 MW, then the Step 3 capacity adder of $2,095/kW is incurred by the entire capacity deployed in that run year. The short-term capital cost adders shown in Table 4-13 were derived from AEO assumptions.

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.[46] 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.

[46] 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 v6

	Combined Cycle - Single Shaft	Combined Cycle - Multi Shaft	Combustion Turbine - Industrial Frame	Combustion Turbine - Aeroderivative	Advanced Nuclear	Small Modular Reactor	Ultra-supercritical Coal without CCS
Size (MW)	418	1083	237	105	2156	600	650
First Year Available	2028	2028	2028	2028	2028	2028	2028
Lead Time (Years)	3	3	2	2	6	6	4
Availability	87%	87%	93%	93%	90%	90%	85%
Vintage #1 (2028)							
Heat Rate (Btu/kWh)	6,431	6,370	9,905	9,124	10,455	10,455	8,638
Capital (2019$/kW)	1,007	891	638	1,051	5,823	6,399	3,454
Fixed O&M (2019$/kW/yr)	13.99	12.10	6.95	16.17	120.69	94.25	40.27
Variable O&M (2019$/MWh)	2.53	1.86	4.46	4.66	2.35	2.98	4.46
Vintage #2 (2030)							
Heat Rate (Btu/kWh)	6,431	6,370	9,905	9,124	10,455	10,455	8,638
Capital (2019$/kW)	977	864	616	1,016	5,620	6,176	3,334
Fixed O&M (2019$/kW/yr)	13.99	12.10	6.95	16.17	120.69	94.25	40.27
Variable O&M (2019$/MWh)	2.53	1.86	4.46	4.66	2.35	2.98	4.46
Vintage #3 (2035)							
Heat Rate (Btu/kWh)	6,431	6,370	9,905	9,124	10,455	10,455	8,638
Capital (2019$/kW)	905	800	568	936	5,140	5,650	3,050
Fixed O&M (2019$/kW/yr)	13.99	12.10	6.95	16.17	120.69	94.25	40.27
Variable O&M (2019$/MWh)	2.53	1.86	4.46	4.66	2.35	2.98	4.46
Vintage #4 (2040)							
Heat Rate (Btu/kWh)	6,431	6,370	9,905	9,124	10,455	10,455	8,638
Capital (2019$/kW)	845	747	527	869	4,733	5,205	2,810
Fixed O&M (2019$/kW/yr)	13.99	12.10	6.95	16.17	120.69	94.25	40.27
Variable O&M (2019$/MWh)	2.53	1.86	4.46	4.66	2.35	2.98	4.46
Vintage #5 (2045)							
Heat Rate (Btu/kWh)	6,431	6,370	9,905	9,124	10,455	10,455	8,638
Capital (2019$/kW)	789	698	490	807	4,355	4,792	2,587
Fixed O&M (2019$/kW/yr)	13.99	12.10	6.95	16.17	120.69	94.25	40.27
Variable O&M (2019$/MWh)	2.53	1.86	4.46	4.66	2.35	2.98	4.46
Vintage #6 (2050-2055)							
Heat Rate (Btu/kWh)	6,431	6,370	9,905	9,124	10,455	10,455	8,638
Capital (2019$/kW)	732	648	452	746	3,973	4,374	2,361
Fixed O&M (2019$/kW/yr)	13.99	12.10	6.95	16.17	120.69	94.25	40.27
Variable O&M (2019$/MWh)	2.53	1.86	4.46	4.66	2.35	2.98	4.46

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.

Table 4-13 Short-Term Capital Cost Adders for New Power Plants in v6 (2019$)

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)	4,471	7,738	No limit	1,263	2,196	No limit	3,157	5,490	No limit
	Adder ($/kW)	-	1,756	5,578	-	1,695	5,384	-	1,551	4,925
Coal Steam - UPC	Upper Bound (MW)	38,189	66,416	No limit	10,911	18,976	No limit	27,278	47,440	No limit
	Adder ($/kW)	-	1,579	5,014	-	1,524	4,840	-	1,394	4,428
Coal Steam - UPC30	Upper Bound (MW)	38,189	66,416	No limit	10,911	18,976	No limit	27,278	47,440	No limit
	Adder ($/kW)	-	1,966	6,246	-	1,895	6,020	-	1,727	5,487
Coal Steam - UPC90	Upper Bound (MW)	38,189	66,416	No limit	10,911	18,976	No limit	27,278	47,440	No limit
	Adder ($/kW)	-	2,546	8,088	-	2,451	7,785	-	2,225	7,069
Combined Cycle	Upper Bound (MW)	317,116	552,171	No limit	90,862	158,020	No limit	227,154	395,050	No limit
	Adder ($/kW)	-	402	1,276	-	389	1,235	-	360	1,142
Combustion Turbine	Upper Bound (MW)	146,018	252,463	No limit	41,147	71,560	No limit	102,868	178,900	No limit
	Adder ($/kW)	-	283	900	-	272	864	-	249	791
Fuel Cell	Upper Bound (MW)	4,056	7,031	No limit	1,150	2,000	No limit	2,875	5,000	No limit
	Adder ($/kW)	-	2,504	7,954	-	2,371	7,530	-	2,057	6,534
Geothermal	Upper Bound (MW)	1,288	2,199	No limit	352	612	No limit	880	1,530	No limit
	Adder ($/kW)	-	4,414	14,019	-	4,404	13,989	-	4,394	13,957
Landfill Gas	Upper Bound (MW)	1,317	2,287	No limit	375	652	No limit	937	1,630	No limit
	Adder ($/kW)	-	680	2,159	-	659	2,095	-	613	1,947
Nuclear	Upper Bound (MW)	9,032	15,708	No limit	2,581	4,488	No limit	6,452	11,220	No limit
	Adder ($/kW)	-	2,737	8,695	-	2,642	8,392	-	2,416	7,674
Solar Thermal	Upper Bound (MW)	6,545	11,382	No limit	1,870	3,252	No limit	4,675	8,130	No limit
	Adder ($/kW)	-	1,854	5,888	-	1,740	5,528	-	1,623	5,156
Solar PV	Upper Bound (MW)	122,494	197,666	No limit	29,058	50,536	No limit	72,646	126,340	No limit
	Adder ($/kW)	-	365	1,159	-	308	978	-	290	922
Onshore Wind	Upper Bound (MW)	159,184	259,817	No limit	38,900	67,652	No limit	97,250	169,130	No limit
	Adder ($/kW)	-	490	1,556	-	445	1,413	-	410	1,302
Offshore Wind	Upper Bound (MW)	4,712	7,687	No limit	7,500	8,350	No limit	14,200	16,325	No limit
	Adder ($/kW)	-	624	1,984	-	817	2,596	-	714	2,268
Hydro	Upper Bound (MW)	4,025	7,000	No limit	1,150	2,000	No limit	2,875	5,000	No limit
	Adder ($/kW)	-	1,104	3,506	-	1,104	3,506	-	1,104	3,506

Table 4-14 Regional Cost Adjustment Factors for Conventional and Renewable Generating Technologies in v6

Model Region	Regional Multiplier															
	Combined Cycle	Combined Cycle with Carbon Capture	Combustion Turbine	Hydro	Nuclear	Biomass	Geothermal	Landfill Gas	Offshore Wind	Onshore Wind	Solar PV	Solar Thermal	Fuel Cell	Ultra super-critical Coal without CCS	Ultra super-critical Coal with 30% CCS	Ultra super-critical 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
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

Model Region	Regional Multiplier															
	Combined Cycle	Combined Cycle with Carbon Capture	Combustion Turbine	Hydro	Nuclear	Biomass	Geothermal	Landfill Gas	Offshore Wind	Onshore Wind	Solar PV	Solar Thermal	Fuel Cell	Ultra super-critical Coal without CCS	Ultra super-critical Coal with 30% CCS	Ultra super-critical Coal with 90% CCS
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 v6

	Geothermal	Biomass	Landfill Gas LGHI	Fuel Cells	Solar Photovoltaic	Solar Thermal	Onshore Wind	Offshore Wind	Battery Storage
Size (MW)	50	50	36	10	100	104	200	1,000	60
First Year Available	2028	2028	2028	2028	2028	2028	2028	2028	2028
Lead Time (Years)	4	4	3	3	1	3	3	3	1
Availability	80% - 90%	83%	90%	87%	90%	90%	95%	95%	96.4%
Generation Capability	Economic Dispatch	Economic Dispatch	Economic Dispatch	Economic Dispatch	Generation Profile	Economic Dispatch	Generation Profile	Generation Profile	Economic Dispatch
	Vintage #1 (2028-2054)				**Vintage #1 (2028)**				
Heat Rate (Btu/kWh)	30,000	13,500	8,513	6,469	0	0	0	0	0
Capital (2019$/kW)	3,233 - 43,097	3,835	1,507	5,573	877	4,628	995	1,666	853
Fixed O&M (2019$/kW/yr)	101 - 1,067	124.74	19.94	30.54	17.98	53.82	39.69	85.77	21.32
Variable O&M (2019$/MWh)	0.00	4.79	6.15	0.58	0.00	2.89	0.00	0.00	0.00
					Vintage #2 (2030)				
Heat Rate (Btu/kWh)		13,500	8,513	6,469	0	0	0	0	0
Capital (2019$/kW)		3,701	1,465	5,275	759	4,409	910	1,559	784
Fixed O&M (2019$/kW/yr)		124.74	19.94	30.54	16.64	50.45	38.95	83.01	19.60
Variable O&M (2019$/MWh)		4.79	6.15	0.58	0.00	2.89	0.00	0.00	0.00
					Vintage #3 (2035)				
Heat Rate (Btu/kWh)		13,500	8,513	6,469	0	0	0	0	0
Capital (2019$/kW)		3,386	1,364	4,578	726	4,119	865	1,439	735
Fixed O&M (2019$/kW/yr)		124.74	19.94	30.54	16.22	50.45	37.49	77.63	18.38
Variable O&M (2019$/MWh)		4.79	6.15	0.58	0.00	2.89	0.00	0.00	0.00
					Vintage #4 (2040)				
Heat Rate (Btu/kWh)		13,500	8,513	6,469	0	0	0	0	0
Capital (2019$/kW)		3,119	1,280	3,971	692	4,067	819	1,348	686
Fixed O&M (2019$/kW/yr)		124.74	19.94	30.54	15.80	50.45	36.03	73.58	17.15
Variable O&M (2019$/MWh)		4.79	6.15	0.58	0.00	2.89	0.00	0.00	0.00
					Vintage #5 (2045)				
Heat Rate (Btu/kWh)		13,500	8,513	6,469	0	0	0	0	0
Capital (2019$/kW)		2,871	1,202	3,414	658	4,055	774	1,275	637
Fixed O&M (2019$/kW/yr)		124.74	19.94	30.54	15.39	50.45	34.57	70.33	15.93
Variable O&M (2019$/MWh)		4.79	6.15	0.58	0.00	2.89	0.00	0.00	0.00
					Vintage #6 (2050-2055)				
Heat Rate (Btu/kWh)		13,500	8,513	6,469	0	0	0	0	0
Capital (2019$/kW)		2,620	1,120	2,878	624	4,043	728	1,214	588
Fixed O&M (2019$/kW/yr)		124.74	19.94	30.54	14.99	50.45	33.11	67.62	14.70
Variable O&M (2019$/MWh)		4.79	6.15	0.58	0.00	2.89	0.00	0.00	0.00

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 Platform v6 for potential renewable and non-conventional technology generating units. The parameters shown in the table are based on AEO 2021 for biomass, landfill gas, and fuel cell. 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) 2021 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 of 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 Platform v6 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 Platform v6 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 Platform v6 models the categories Class 1 - Class 12. Table 4-35, 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 v6

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				

Table 4-17 Offshore Floating Regional Potential Wind Capacity (MW) by Wind Class, Resource Class, and Cost Class in v6

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 12	7	2,984	2,800	3,210	2,762	3,177	513,613
		Class 8	8	2,222	3,640		3,640	3,640	360,347
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

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 Platform v6 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 4-36 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 and offshore wind capacity factors over time are modeled through three vintages (2028, 2030, and 2040) 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 Platform v6 were obtained from NREL and are shown in Table 4-34, Table 4-18, and Table 4-19.

Table 4-18 Offshore Fixed Average Capacity Factor by Wind Class and Resource Class in v6

IPM Region	State	Wind Class	Resource Class	Capacity Factor (%)		
				Vintage #1 (2028-2059)	Vintage #2 (2030-2059)	Vintage #3 (2040-2059)
ERC_REST	TX	Class 5	6	47%	48%	48%
		Class 6	5	42%	43%	43%
FRCC	FL	Class 6	5	37%	38%	38%
MIS_AMSO	LA	Class 6	5	36%	37%	37%
MIS_LA	LA	Class 6	5	38%	39%	39%
MIS_LMI	MI	Class 2	7	47%	48%	49%
MIS_WOTA	LA	Class 6	5	39%	40%	40%
	TX	Class 6	5	41%	42%	42%
MIS_WUMS	MI	Class 3	7	48%	49%	50%
	WI	Class 4	6	48%	49%	50%
NENG_ME	ME	Class 1	8	49%	50%	51%
NENGREST	MA	Class 1	8	49%	50%	50%
	RI	Class 1	8	46%	47%	48%
NY_Z_K	NY	Class 1	8	46%	47%	48%
		Class 2	7	48%	49%	50%
PJM_ATSI	OH	Class 3	7	47%	48%	48%
PJM_Dom	NC	Class 2	7	45%	46%	47%
	VA	Class 2	7	45%	46%	46%
		Class 4	6	46%	47%	48%
PJM_EMAC	DE	Class 1	8	45%	46%	47%
		Class 2	7	48%	49%	49%
	MD	Class 2	7	47%	48%	48%
	NJ	Class 1	8	46%	47%	47%
		Class 2	7	47%	49%	49%
	VA	Class 2	7	45%	46%	47%
S_SOU	AL	Class 6	5	36%	37%	37%
	FL	Class 6	5	36%	36%	37%
	GA	Class 6	5	42%	43%	43%
	MS	Class 6	5	36%	37%	37%
S_VACA	NC	Class 3	7	46%	47%	48%
		Class 5	6	47%	48%	48%
	SC	Class 5	6	45%	46%	46%
		Class 6	5	42%	43%	43%

Table 4-19 Offshore Floating Average Capacity Factor by Wind Class and Resource Class in v6

IPM Region	State	Wind Class	Resource Class	Capacity Factor (%)		
				Vintage #1 (2028-2059)	Vintage #2 (2030-2059)	Vintage #3 (2040-2059)
MIS_LMI	MI	Class 12	7	47%	48%	48%
MIS_WUMS	MI	Class 12	7	46%	46%	47%
NENG_ME	ME	Class 8	8	52%	53%	53%
		Class 11	7	49%	49%	49%
NENGREST	MA	Class 8	8	51%	51%	52%
		Class 11	7	51%	51%	51%
	RI	Class 8	8	52%	52%	52%
NY_Z_J	NY	Class 11	7	50%	51%	51%
NY_Z_K	NY	Class 9	8	51%	52%	52%
		Class 11	7	50%	51%	51%
PJM_Dom	NC	Class 12	7	45%	46%	46%
	VA	Class 12	7	45%	46%	46%
PJM_EMAC	DE	Class 10	8	50%	50%	51%
		Class 11	7	50%	51%	51%
	MD	Class 10	8	50%	50%	50%
		Class 11	7	49%	50%	50%
	NJ	Class 10	8	51%	51%	51%
		Class 11	7	50%	50%	51%
	VA	Class 12	7	45%	46%	46%
S_VACA	NC	Class 12	7	46%	46%	46%
WEC_CALN	CA	Class 8	8	55%	56%	56%
		Class 12	7	49%	49%	50%
WECC_PNW	CA	Class 8	8	47%	47%	47%
	OR	Class 8	8	51%	51%	51%
		Class 12	7	46%	46%	46%
	WA	Class 12	7	44%	44%	45%
WECC_SCE	CA	Class 12	7	48%	49%	49%

Reserve Margin Contribution (also referred to as capacity credit): EPA Platform v6 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 reserve margin. If the unit has 100 percent contribution towards 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 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 reserve margin. Intermittent resources such as wind and solar have limited (less than 100 percent) contributions toward reserve margins 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 build 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 Platform v6 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 Platform v6.

Table 4-20 Onshore Reserve Margin Contribution by Wind Class in v6

Wind Class	Vintage #1 (2028-2059)	Vintage #2 (2030-2059)	Vintage #3 (2040-2059)
Class 1	0% - 77%	0% - 79%	0% - 79%
Class 2	16%	16%	16%
Class 3	0% - 84%	0% - 87%	0% - 88%
Class 4	0% - 82%	0% - 86%	0% - 87%
Class 5	0% - 81%	0% - 84%	0% - 86%
Class 6	0% - 37%	0% - 39%	0% - 40%
Class 7	0% - 83%	0% - 87%	0% - 89%
Class 8	0% - 51%	0% - 53%	0% - 54%
Class 9	0% - 86%	0% - 91%	0% - 93%

Table 4-21 Offshore Fixed Reserve Margin Contribution by Wind Class in v6.21

Wind Class	Vintage #1 (2028-2059)	Vintage #2 (2030-2059)	Vintage #3 (2040-2059)
Class 1	0.3% - 80%	0.3% - 82%	0.3% - 83%
Class 2	0.1% - 85%	0.1% - 87%	0.1% - 88%
Class 3	0% - 30%	0% - 30%	0% - 31%
Class 4	6.6% - 7.6%	6.8% - 7.7%	6.9% - 7.9%
Class 5	1.4% - 36%	1.4% - 37%	1.4% - 37%
Class 6	0% - 63%	0% - 64%	0% - 65%

Table 4-22 Offshore Floating Reserve Margin Contribution by Wind Class in v6.21

Wind Class	Vintage #1 (2028-2059)	Vintage #2 (2030-2059)	Vintage #3 (2040-2059)
Class 8	0% - 86.4%	0% - 87.2%	0% - 87.8%
Class 9	1.9% - 89%	1.9% - 90%	1.9% - 91%
Class 10	1.4% - 2.9%	1.5% - 2.9%	1.5% - 2.9%
Class 11	0% - 32%	0% - 32%	0% - 32%
Class 12	0% - 33%	0% - 33%	0% - 33%

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 4-37, is added to the base capital cost shown in Table 4-15.

The tax credit extensions for new wind units, as prescribed in the Consolidated Appropriations Act of 2021, are implemented through reductions in capital costs. As the credits are based on construction start date, they are assumed available for four years from the start of construction. The capital cost of new offshore wind unit builds in 2028 run year is reduced by 30% to reflect the 30% investment tax credits available for offshore wind units.

Table 4-23 Capital Cost Adder (2019$/kW) for New Offshore Fixed Wind Plants in v6

IPM Region	State	Wind Class	Resource Class	Cost Class					
				1	2	3	4	5	6
ERC_REST	TX	Class 5	6	124	918				
		Class 6	5	27	28	31	41	47	97
FRCC	FL	Class 6	5	19	20	26	31	47	132
MIS_AMSO	LA	Class 6	5	41	50	118	176	183	358
MIS_LA	LA	Class 6	5	4,541					
MIS_LMI	MI	Class 2	7	4,795					
MIS_WOTA	LA	Class 6	5	61	84	101	106	112	312
	TX	Class 6	5	25	25	25	26	27	95
MIS_WUMS	MI	Class 3	7	9,713					
	WI	Class 4	6	117,699					
NENG_ME	ME	Class 1	8	5,420					
NENGREST	MA	Class 1	8	13	157	157	157	157	421
	RI	Class 1	8	12,392					
NY_Z_K	NY	Class 1	8	245					
		Class 2	7	3	183				
PJM_ATSI	OH	Class 3	7	262	404	1,486			
PJM_Dom	NC	Class 2	7	39	130	371			
	VA	Class 2	7	59	353				
		Class 4	6	15,579					
PJM_EMAC	DE	Class 1	8	63					
		Class 2	7	44	387				
	MD	Class 2	7	180					
	NJ	Class 1	8	31	79	109	186		
		Class 2	7	3	198				
	VA	Class 2	7	287	216,051	3,560,858			
S_SOU	AL	Class 6	5	103	217	636			
	FL	Class 6	5	1,096					
	GA	Class 6	5	51	119	610			
	MS	Class 6	5	208					
S_VACA	NC	Class 3	7	67	466				
		Class 5	6	8	59	65	205		
	SC	Class 5	6	5	11	15	18	20	91
		Class 6	5	19	130				

Table 4-24 Capital Cost Adder (2019$/kW) for New Offshore Floating Wind Plants in v6

IPM Region	State	Wind Class	Resource Class	Cost Class					
				1	2	3	4	5	6
MIS_LMI	MI	Class 12	7	771					
MIS_WUMS	MI	Class 12	7	4,453					
NENG_ME	ME	Class 11	7		59	59	59		222
		Class 8	8		59	59	59	59	590
NENGREST	MA	Class 11	7	118					
		Class 8	8	8	10	10	11	59	338
	RI	Class 8	8	1,116					
NY_Z_J	NY	Class 11	7						118
NY_Z_K	NY	Class 11	7	92	92	92	92	93	
		Class 9	8	2	3	6	12	43	222
PJM_Dom	NC	Class 12	7	45	65	98	206	235	282
	VA	Class 12	7	89					
PJM_EMAC	DE	Class 10	8	49	92				
		Class 11	7	167					
	MD	Class 10	8	51					
		Class 11	7	69	69	69	69	69	174

IPM Region	State	Wind Class	Resource Class	Cost Class					
				1	2	3	4	5	6
	NJ	Class 10	8	18	39	68	71	75	125
		Class 11	7	50	54	64	69	69	108
	VA	Class 12	7	69	224	465	154,476		
S_VACA	NC	Class 12	7	59	62	62	62	62	216
WEC_CALN	CA	Class 12	7	4	26	37	52	67	318
		Class 8	8	8	70		70	70	379
WECC_PNW	CA	Class 8	8	254	274	639	1,226		
	OR	Class 12	7						60
		Class 8	8	33	36	41	63	65	153
	WA	Class 12	7	45	45	45	45	45	239
WECC_SCE	CA	Class 12	7	56	81	81		81	526

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 1, resource class 7, and cost class 1 in the WECC_CO model region in run year 2023.

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 4-35	Potential wind capacity (*C*) =	1,876 MW
Table 4-36	Winter average generation (G_W) per available MW =	277 kWh/MW
Table 4-36	Winter Shoulder average generation (G_{WS}) per available MW =	330 kWh/MW
Table 4-36	Summer average generation (G_S) per available MW =	363 kWh/MW
	Hours in Winter (H_W) season (December - February) =	2,160 hours
	Hours in Winter Shoulder (H_{WS}) season (Mar, Apr, Oct. Nov.) =	2,928 hours
	Hours in Summer (H_S) season (May – September) =	3,672 hours
Table 4-20	Reserve Margin Contribution (*RM*) =	3.64 percent
Table 4-15	Capital Cost (Cap_{2028}) in vintage range for year 2028 =	$995/kW
Table 4-37	Capital Cost Adder ($CCA_{ON,C1}$) for onshore cost class 1 =	$33/kW
Table 4-14	Regional Factor (RF)	1.027

Calculations

$$\text{Generation Potential} = \text{C} \times \text{G}_\text{W} \times \text{H}_\text{W} + \text{C} \times \text{G}_\text{WS} \times \text{H}_\text{WS} + \text{C} \times \text{G}_\text{S} \times \text{H}_\text{S}$$

$$= 1{,}876\ \text{MW} \times 277\text{kWh/MW} \times 2{,}160\ \text{hours} + 1{,}876\ \text{MW} \times 330\text{kWh/MW} \times 2{,}928\ \text{hours} + 1{,}876\ \text{MW} \times 363\text{kWh/MW} \times 3{,}672\ \text{hours}$$

$$= 5{,}437\ \text{GWh}$$

$$\text{Reserve Margin Contribution} = \text{RM} \times \text{C}$$

$$= 3.64\% \times 1{,}876\ \text{MW}$$

$$= 68\ \text{MW}$$

$$\text{Capital Cost} = (\text{Cap}_{2028} \times \text{RF} + \text{CCA}_{\text{ON,C1}}) \times \text{C}$$

$$= (\$995/\text{kW} \times 1.027 + \$33/\text{kW}) \times 1{,}876\text{MW}$$

$$= \$1{,}978{,}741$$

Solar Generation

EPA Platform v6 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 Platform v6, the top eight resource classes are primarily modeled for solar photovoltaics. The NREL resource base for solar thermal is represented by twelve resource classes. In EPA Platform v6, 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 4-38 and Table 4-39.

Generation Profiles: Table 4-40 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 Platform v6 were obtained from NREL and are shown in Table 4-43 and Table 4-44.

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 Platform v6. 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 Resource Class in v6

Resource Class	Vintage #1 (2028-2059)	Vintage #2 (2030-2059)	Vintage #3 (2040-2059)
Class 1	0% - 19%	0% - 19%	0% - 20%
Class 2	0% - 94%	0% - 98%	0% - 100%
Class 3	0% - 93%	0% - 98%	0% - 100%
Class 4	0% - 94%	0% - 98%	0% - 100%
Class 5	0% - 49%	0% - 52%	0% - 53%
Class 6	0% - 67%	0% - 70%	0% - 72%
Class 7	0% - 71%	0% - 75%	0% - 77%
Class 8	0% - 91%	0% - 95%	0% - 98%
Class 9	0% - 3%	0% - 3%	0% - 3%
Class 10	0% - 56%	0% - 59%	0% - 61%

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 4-41 and Table 4-42 illustrate the capital cost adder by resource and cost class for new solar units.

Geothermal Generation

Geothermal Resource Potential: Twelve model regions in EPA Platform v6 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[47], GEO-Hydro Binary, GEO-NF EGS Flash, and GEO-NF EGS Binary are the included technologies.

[47] 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 Electric Capacity in v6

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 Platform v6 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 v6

Region	Net Capacity (MW)	Capital Cost (2019$/kW)	FOM (2019$/kW-yr)
WEC_CALN	6	15,793	491
	8	21,606	595
	11	13,488	385
	29	4,259	123
	29	6,161	199
	82	25,178	614
	333	11,235	214
WECC_AZ	26	20,826	577
WECC_CO	8	21,628	596
	12	15,192	429
WECC_ID	10	17,924	501
	14	22,689	612
	28	19,847	555
	28	43,097	1,067
	44	12,753	360
	112	9,567	266
WECC_IID	74	3,325	114
	85	27,086	657
	91	5,803	189
	137	4,600	147
	257	11,351	208
	2,188	4,207	101
WECC_MT	7	21,996	603
	22	17,782	497

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 (2019$/kW)	FOM (2019$/kW-yr)
WECC_NM	9	21,542	594
	13	14,961	386
WECC_NNV	45	15,833	434
	50	6,275	190
	66	7,541	219
	67	19,429	536
	77	13,502	392
	92	27,121	679
	93	3,833	128
	103	3,233	102
	138	9,360	281
	148	4,088	137
	264	23,460	589
	279	4,627	152
WECC_PNW	6	20,197	581
	12	7,984	252
	15	16,701	490
	15	21,804	599
	17	18,588	535
	19	16,096	446
	23	13,123	370
	23	16,899	474
	41	5,379	176
	48	9,807	292
	57	12,345	344
	101	6,679	205
	124	3,270	109
	132	7,602	230
WECC_SCE	25	24,214	628
	27	16,230	457
	155	11,009	200
	289	3,233	101
WECC_UT	1	31,401	520
	2	22,476	535
	86	3,233	111
	120	19,296	470
WECC_WY	39	14,104	398

Landfill Gas Electricity Generation

Landfill Gas Resource Potential: Estimates of potential electric capacity from landfill gas are based on the AEO 2019 inventory. EPA Platform v6 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 4-45 summarizes potential electric capacity from landfill gas.

There are several things to note about Table 4-45. 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 4-45 apply to the IPM regions indicated in column 1. In EPA Platform v6, 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 4-45 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 Platform v6 models resource potential from non-powered dams (NPD) and new stream development (NSD) categories of new small hydro. While NPD are existing dams that do not currently have hydropower, NSD are greenfield hydropower developments along previously undeveloped waterways. Table 4-29 and Table 4-30 summarize the assumptions for NPD and NSD.

Table 4-29 Potential Non-Powered Dam in v6

IPM Region	State	Capacity (MW)	Capacity Factor (%) - Winter	Capacity Factor (%) - Winter Shoulder	Capacity Factor (%) - Summer	Capital Cost (2019 $/kW)	FOM (2019 $/kW)
ERC_REST	TX	338	55.1%	57.5%	48.7%	2,195	16.51
ERC_WEST	TX	27	45.0%	53.0%	49.4%	2,191	51.88
FRCC	FL	126	56.6%	60.4%	66.6%	2,336	25.88
MIS_AMSO	LA	158	66.8%	61.1%	43.5%	1,646	23.34
MIS_AR	AR	786	61.3%	63.7%	53.9%	1,630	11.27
MIS_IA	IA	383	49.4%	71.4%	75.5%	1,756	15.61
MIS_IL	IL	630	55.1%	71.9%	72.7%	1,548	12.46
MIS_INKY	IN	65	68.4%	65.5%	52.2%	2,804	34.89
	KY	536	75.2%	68.6%	46.1%	1,308	13.41
MIS_LA	LA	643	66.7%	61.0%	43.3%	1,610	12.35
MIS_LMI	MI	24	75.4%	76.5%	60.8%	3,889	54.60
MIS_MAPP	MT	17	42.5%	61.6%	80.2%	2,222	55.55
	ND	15	32.2%	59.8%	67.1%	2,622	65.55
MIS_MIDA	IA	150	49.4%	71.3%	75.5%	1,761	23.84
MIS_MNWI	MI	0.02	68.6%	77.9%	72.0%	5,143	128.58
	MN	123	54.0%	71.8%	74.8%	2,292	26.13
	WI	94	52.1%	74.5%	76.7%	1,921	29.45
MIS_MO	IA	4	49.1%	70.9%	75.3%	1,860	46.50
	MO	159	52.7%	71.4%	74.8%	1,456	23.29
MIS_MS	MS	102	73.4%	63.1%	45.1%	2,006	28.42
MIS_WOTA	LA	23	66.8%	61.1%	43.5%	1,777	44.42
	TX	123	60.4%	59.2%	46.1%	1,501	26.10
MIS_WUMS	MI	4	71.1%	77.3%	67.8%	4,415	110.38
	WI	111	53.7%	75.4%	77.2%	1,857	27.32
NENG_CT	CT	59	74.3%	75.0%	54.7%	3,019	36.55
NENG_ME	ME	15	66.7%	73.8%	61.6%	5,040	67.42
NENGREST	MA	53	74.2%	73.5%	51.1%	4,663	38.19
	NH	56	70.2%	75.5%	58.3%	3,134	37.45
	RI	11	76.3%	72.3%	48.7%	4,552	77.86
	VT	13	69.5%	74.7%	56.3%	3,228	72.42
NY_Z_A	NY	12	74.2%	72.7%	50.6%	2,371	59.28
NY_Z_B	NY	8	74.2%	72.7%	50.6%	2,437	60.92
NY_Z_C&E	NY	66	74.2%	72.7%	50.6%	2,532	34.61
NY_Z_D	NY	49	74.2%	72.7%	50.6%	2,508	39.65
NY_Z_F	NY	78	74.2%	72.7%	50.6%	2,550	32.04
NY_Z_G-I	NY	28	74.2%	72.7%	50.6%	2,341	50.93
PJM_AP	MD	13	70.2%	68.5%	49.5%	2,767	69.17
	PA	236	78.3%	71.4%	47.7%	2,042	19.44
	VA	3	68.9%	68.9%	50.1%	3,576	89.40
	WV	138	73.7%	68.1%	48.1%	1,982	24.78
PJM_ATSI	OH	64	70.2%	67.3%	52.0%	2,793	35.08
	PA	43	77.9%	71.4%	48.2%	1,896	42.12
PJM_COMD	IL	198	57.5%	72.6%	71.9%	1,868	21.07
PJM_Dom	NC	2	68.6%	65.7%	49.4%	2,134	53.36

IPM Region	State	Capacity (MW)	Capacity Factor (%) - Winter	Capacity Factor (%) - Winter Shoulder	Capacity Factor (%) - Summer	Capital Cost (2019 $/kW)	FOM (2019 $/kW)
	VA	13	68.9%	68.8%	50.1%	3,025	71.99
PJM_EMAC	DE	1	71.3%	71.7%	56.7%	4,790	119.74
	MD	13	72.8%	72.9%	58.5%	2,456	61.41
	NJ	17	75.7%	73.6%	56.3%	4,415	63.49
	PA	9	74.9%	71.3%	50.7%	2,548	63.69
PJM_PENE	PA	316	77.7%	71.4%	48.2%	2,084	17.05
PJM_SMAC	DC	1	72.8%	72.9%	58.5%	3,055	76.37
	MD	15	72.5%	72.6%	57.9%	3,182	68.01
PJM_West	IN	8	69.6%	65.8%	53.4%	2,615	65.37
	KY	375	74.8%	68.3%	46.5%	1,493	15.77
	OH	170	70.2%	67.1%	51.1%	2,614	22.55
	VA	8	69.2%	68.2%	49.4%	2,544	63.61
	WV	37	70.5%	67.0%	46.1%	2,229	45.18
PJM_WMAC	PA	49	74.9%	71.2%	50.1%	2,725	39.81
S_C_KY	KY	134	70.4%	63.5%	40.0%	2,252	25.11
S_C_TVA	AL	118	74.5%	62.7%	41.3%	1,675	26.59
	GA	30	75.8%	71.3%	61.9%	1,815	45.39
	KY	1,022	76.6%	69.8%	48.3%	1,194	10.01
	MS	94	75.3%	64.0%	43.4%	2,008	29.56
	NC	2	72.7%	70.0%	57.4%	3,752	93.79
	TN	12	75.4%	66.1%	48.4%	2,390	59.74
	VA	1	69.2%	68.2%	49.3%	2,540	63.50
S_D_AECI	MO	92	53.5%	71.8%	73.1%	1,637	29.84
S_SOU	AL	723	74.5%	63.7%	43.8%	1,362	11.71
	FL	11	72.5%	70.7%	64.4%	2,374	59.35
	GA	51	75.8%	71.3%	61.9%	1,966	38.93
	MS	12	74.1%	63.4%	44.5%	2,030	50.75
S_VACA	GA	0.09	75.8%	71.3%	61.9%	2,241	56.03
	NC	91	68.9%	66.0%	50.0%	2,416	29.95
	SC	43	75.5%	71.9%	62.4%	3,059	41.93
SPP_N	KS	36	40.3%	52.9%	58.5%	2,299	45.64
	MO	10	63.9%	63.9%	50.5%	2,551	63.78
SPP_NEBR	KS	3	40.3%	52.9%	58.5%	2,476	61.91
SPP_SPS	NM	26	40.6%	62.0%	75.7%	2,444	52.62
SPP_WEST	AR	343	61.3%	63.6%	53.8%	1,567	16.41
	LA	24	66.8%	61.1%	43.5%	1,661	41.53
	MO	0.40	53.5%	57.3%	48.4%	2,890	72.25
	OK	312	48.5%	57.8%	54.6%	1,869	17.13
	TX	20	59.7%	51.5%	35.0%	2,237	55.94
WEC_BANC	CA	0.09	62.6%	69.0%	61.6%	3,551	88.78
WEC_CALN	CA	111	62.7%	69.0%	61.6%	2,637	27.38
WEC_LADW	CA	27	55.6%	72.2%	77.5%	2,051	51.27
WECC_AZ	AZ	58	67.3%	73.7%	72.8%	2,234	36.72
WECC_CO	CO	146	47.5%	65.5%	80.4%	1,914	24.15
WECC_ID	ID	6	65.8%	74.0%	72.1%	3,644	91.11
WECC_IID	CA	0.38	55.6%	72.2%	77.5%	1,758	43.94
WECC_MT	MT	54	52.8%	66.4%	79.5%	2,914	37.90
WECC_NM	NM	63	37.8%	67.3%	82.1%	2,416	35.49
	TX	15	36.6%	67.1%	83.0%	2,514	62.86
WECC_NNV	NV	12	50.0%	65.6%	69.2%	4,128	75.57
WECC_PNW	CA	4	74.8%	76.9%	68.5%	3,338	83.45
	ID	1	47.5%	64.3%	74.2%	3,071	76.79
	OR	87	79.1%	72.2%	56.1%	2,631	30.60
	WA	70	83.9%	72.6%	61.4%	2,536	33.69
WECC_SCE	CA	34	55.6%	72.2%	77.4%	1,966	46.99
WECC_SNV	NV	2	88.1%	84.7%	81.7%	3,609	90.24
WECC_UT	UT	29	55.5%	69.2%	78.4%	2,382	50.58

IPM Region	State	Capacity (MW)	Capacity Factor (%) - Winter	Capacity Factor (%) - Winter Shoulder	Capacity Factor (%) - Summer	Capital Cost (2019 $/kW)	FOM (2019 $/kW)
WECC_WY	WY	36	43.8%	64.8%	76.2%	2,162	45.59

Table 4-30 Potential New Stream Development in v6

IPM Region	State	Capacity (MW)	Capacity Factor (%) - Winter	Capacity Factor (%) - Winter Shoulder	Capacity Factor (%) - Summer	Capital Cost (2019 $/kW)	FOM (2019 $/kW)
MIS_MO	MO	639	51.7%	69.0%	75.2%	3,567	12.39
NENG_ME	ME	406	65.4%	73.2%	62.7%	5,917	15.20
NENGREST	MA	13	75.3%	74.7%	53.6%	5,603	72.74
	NH	117	71.1%	76.2%	59.9%	4,979	26.69
	VT	58	69.9%	74.9%	57.4%	5,837	36.73
PJM_AP	PA	7	74.6%	71.1%	48.3%	4,614	93.17
PJM_EMAC	NJ	27	75.7%	74.2%	56.6%	4,974	51.62
	PA	30	74.8%	71.2%	48.3%	4,614	49.68
PJM_PENE	PA	239	74.8%	71.2%	48.3%	4,179	19.34
PJM_SMAC	MD	79	69.8%	69.7%	50.6%	5,003	31.94
PJM_WMAC	PA	622	74.8%	71.2%	48.2%	4,062	12.53
S_VACA	SC	51	76.0%	72.3%	61.5%	5,629	38.88
SPP_N	MO	350	49.7%	70.0%	79.6%	3,527	16.27
WECC_NNV	NV	13	47.5%	65.8%	71.7%	6,731	71.25
WECC_PNW	OR	48	51.3%	72.3%	86.5%	4,585	40.14
	WA	394	64.8%	71.0%	72.3%	3,986	15.42

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 Platform v6 includes both existing and new battery storage by IPM region and state. While EPA Platform v6 models existing pumped storage, it does not model new pumped storage options.

The cost and performance assumptions for new battery storage units in EPA platform v6 are based on NREL ATB 2021 and are summarized in Table 4-15. Energy storage options in EPA Platform v6 are assigned capacity credits that are a function of penetration. A capacity credit curve is calculated at an IPM model region level using a heuristic approach and 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. For each storage power capacity, the amount of stored energy required to reduce the episodic peak demand by the storage power capacity is determined. The capacity credit is calculated as the ratio between the storage duration (4 hours) and the length of the episode with the most storage requirement. Hourly load curves adjusted for hourly generation from existing solar and wind units are used for the analysis. Three sets of storage options are provided in each IPM region. The first set is assigned 100% capacity credit while the other two sets are assigned lower than 100% capacity credits based on the capacity credit curve. Table 4-31 summarizes these assumptions.

Table 4-31 Bounds and Reserve Margin Contribution for Potential (New) Battery Storage in v6

IPM Region	Bound (MW)			Reserve Margin Contribution (%)		
	Step1	Step2	Step3	Step1	Step2	Step3
ERC_PHDL	982	223	NA	100%	0.01%	0%
ERC_REST	3,500	5,751	NA	100%	21%	6%

IPM Region	Bound (MW)			Reserve Margin Contribution (%)		
	Step1	Step2	Step3	Step1	Step2	Step3
ERC_WEST	982	223	NA	100%	0.01%	0%
FRCC	5,088	11,432	NA	100%	17%	0%
MIS_AMSO	358	412	NA	100%	9%	0%
MIS_AR	576	668	NA	100%	11%	0%
MIS_IA	313	416	NA	100%	27.92%	0%
MIS_IL	665	2,694	NA	100%	14%	0%
MIS_INKY	995	3,103	NA	100%	10%	0%
MIS_LA	727	453	NA	100%	0%	0%
MIS_LMI	965	3,811	NA	100%	22%	6%
MIS_MAPP	182	82	NA	100%	0%	0%
MIS_MIDA	346	727	NA	100%	24%	19%
MIS_MNWI	1,727	1,040	NA	100%	0%	0%
MIS_MO	456	913	NA	100%	21%	4%
MIS_MS	463	152	NA	100%	0%	0%
MIS_WOTA	470	287	NA	100%	0%	0%
MIS_WUMS	805	2,442	NA	100%	9%	0%
NENG_CT	1,632	357	NA	100%	0.01%	0%
NENG_ME	180	280	NA	100%	36.67%	0%
NENGREST	4,558	48	NA	100%	0.01%	0%
NY_Z_A	451	82	NA	100%	0.01%	0%
NY_Z_B	433	147	NA	100%	0.01%	0%
NY_Z_C&E	725	64	NA	100%	0.01%	0%
NY_Z_D	47	66	NA	100%	16.15%	0%
NY_Z_F	407	36	NA	100%	0.01%	0%
NY_Z_G-I	408	264	NA	100%	0%	0%
NY_Z_J	824	2,663	NA	100%	8%	0%
NY_Z_K	755	61	NA	100%	0%	0%
PJM_AP	778	687	NA	100%	0%	0%
PJM_ATSI	766	2,985	NA	100%	14%	0%
PJM_COMD	1,354	4,860	NA	100%	20%	0%
PJM_Dom	1,301	2,807	NA	100%	0%	0.00%
PJM_EMAC	3,132	5,785	NA	100%	3%	0%
PJM_PENE	291	137	NA	100%	0.01%	0%
PJM_SMAC	1,395	1,170	NA	100%	0%	0%
PJM_West	1,504	2,708	NA	100%	9%	0%
PJM_WMAC	950	1,061	NA	100%	8.90%	0%
S_C_KY	382	702	NA	100%	10%	0%
S_C_TVA	3,396	3,161	NA	100%	0%	0%
S_D_AECI	571	229	NA	100%	0%	0%
S_SOU	5,151	2,083	NA	100%	0%	0%
S_VACA	5,828	3,038	NA	100%	21.37%	0%
SPP_N	739	4,672	NA	100%	26.27%	0%
SPP_NEBR	430	703	NA	100%	5.73%	19%
SPP_SPS	723	1,261	NA	100%	7.15%	0%
SPP_WAUE	377	126	NA	100%	0%	0%
SPP_WEST	850	2,345	NA	100%	30%	14%
WEC_BANC	823	53	NA	100%	0.01%	0%
WEC_CALN	9,589	1,195	NA	100%	0.01%	0%
WEC_LADW	2,499	286	NA	100%	0.01%	0%
WEC_SDGE	1,249	344	NA	100%	0.01%	0%
WECC_AZ	3,827	4,000	NA	100%	0%	0%
WECC_CO	1,394	2,576	NA	100%	26.05%	0%
WECC_ID	1,089	156	NA	100%	0.01%	0%
WECC_IID	442	100	NA	100%	0.01%	0%
WECC_MT	585	260	NA	100%	0.01%	0%
WECC_NM	1,244	829	NA	100%	0.01%	0%
WECC_NNV	521	305	NA	100%	0.01%	0%
WECC_PNW	6,672	3,296	NA	100%	0.01%	0%
WECC_SCE	9,416	5,197	NA	100%	0.01%	0%
WECC_SNV	772	1,000	NA	100%	0.01%	0%

IPM Region	Bound (MW)			Reserve Margin Contribution (%)		
	Step1	Step2	Step3	Step1	Step2	Step3
WECC_UT	1,276	1,062	NA	100%	0.01%	0%
WECC_WY	1,031	357	NA	100%	0.01%	0%
CN_AB	663	1,206	NA	100%	0.01%	0%
CN_BC	886	2,448	NA	100%	0.01%	0%
CN_MB	294	211	NA	100%	0.01%	0%
CN_NB	173	192	NA	100%	0.01%	0%
CN_NF	70	156	NA	100%	0.01%	0%
CN_NL	159	27	NA	100%	0.01%	0%
CN_NS	183	174	NA	100%	0.01%	0%
CN_ON	947	3,133	NA	100%	17.73%	0%
CN_PE	54	45	NA	100%	0%	0%
CN_PQ	5,167	1,632	NA	100%	0%	0%
CN_SK	212	381	NA	100%	0.01%	0%

Multiple U.S. states have instituted standalone targets and mandates for energy storage procurement. Table 4-32 summarizes the state-specific energy storage mandates that are included in EPA platform v6. 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.

Table 4-32 Energy Storage Mandates in v6

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.	
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

4.5 Nuclear Units

4.5.1 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 Platform v6 are represented by separate model plants. As noted in Table 4-7, the 91 nuclear units include 89 currently operating units plus Vogtle Units 3 and 4, which are scheduled to come online post 2022. All units are listed in Table 4-46. The population characteristics, plant location, and unit configuration data in the NEEDS v6 were obtained primarily from EIA Form 860 and AEO 2020.

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 Platform v6 uses capacity factor assumptions to define the upper bound on generation from nuclear units. Nuclear capacity factor assumptions in EPA Platform v6 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 is dependent on the age of the reactor.
- 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 (start before 1982) nuclear power plants, the performance peaks at 25 years:
  - Before 25 years: Performance increases by 0.5 percentage point per year;
  - 25- years: Performance remains flat; and
- For the newer vintage (start 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. Given historical capacity factors are above 90 percent, the assumed annual capacity factors range from 60 percent to 96 percent.

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 Platform v6 uses heat rate, variable O&M costs, and fixed O&M costs from AEO 2020 to characterize the cost of operating existing nuclear units. The fixed O&M costs from the AEO are increased by 20% to reflect general and administrative (G&A) costs. The data are shown in Table 4-46.

EPA Platform v6 also imposes lifetime extension costs for nuclear units (see Section 4.2.8). Nuclear units are not assumed to have a maximum lifetime (see Section 3.8).

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 v6 database. IPM provides nuclear units with the option to retire based on the economics.

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 Platform v6 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. 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, EPA Platform v6 does not model the impact of this provision on the Perry and Davis Besse nuclear plants.

Nuclear Retirement Limits: In EPA Platform v6, endogenous retirements of nuclear units are not limited.

Life Extension Costs: Attachment 4-1 summarizes the approach to estimate 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 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.

Carbon uncertainty considerations: The FOM costs of all existing US nuclear units are reduced by an amount of $13.86/ton for the period 2023-2031. This decrease parallels the carbon uncertainty adder for new fossil, and is calculated based on the difference between the emission rate for nuclear and an average natural gas plant CO_2 emission rate of 887 lbs/MWh. This adjustment reflects the potential impact of clean energy and/or carbon regulation optionality that nuclear units may consider while making retirement decisions.

4.5.2 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 2020.

List of tables that are uploaded directly to the web:

Table 4-33 Planned-Committed Units by Model Region in NEEDS for EPA Platform v6 2022 Reference Case

Table 4-34 Onshore Average Capacity Factor by Wind Class, Resource Class, and Vintage in EPA Platform v6 2022 Reference Case