Assumptions to the Annual Energy Outlook 2026: Renewable Fuels Module

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Overview

The National Energy Modeling System's (NEMS) Renewable Fuels Module (RFM) provides supply and technology inputs for natural resources. We use these inputs to project new utility-scale U.S. electric-generating capacity that uses renewable energy resources. The RFM has six submodules[1] that represent various renewable energy resources:

- Biomass
- Geothermal
- Conventional hydroelectricity
- Landfill gas (LFG) and Municipal Solid Waste (MSW)
- Solar (thermal and photovoltaic)
- Wind (offshore and onshore)

The submodules of the RFM interact primarily with the Electricity Market Module (EMM) within NEMS. The EMM represents electricity capacity planning, dispatching, and pricing. Because the EMM is highly integrated with the RFM, the final outputs (consumption and market penetration over time) for renewable energy technologies depend largely on the EMM. The RFM also interacts with the Renewable Storage Submodule (REStore) to estimate the impact of energy storage on dispatching electricity and the hourly capacity factors of non-dispatchable renewable technologies for capacity credit calculations for each of the modeled electricity regions.

Because some types of biomass fuel can be used for either electricity generation or for liquid fuels production (such as ethanol), the RFM also interacts with the Liquid Fuels Market Module (LFMM). The LFMM represents some additional biomass feedstocks that are used primarily for liquid fuels production.

We developed projections for residential and commercial grid-connected photovoltaic (PV) systems in the end-use demand modules, and they are not included in the RFM; more details are available in the Commercial Demand Module (CDM) and Residential Demand Module (RDM) sections of this report. Descriptions of biomass energy production in industrial settings, such as the pulp and paper industries, are in the Industrial Demand Module (IDM) section of the report.

Technologies

Utility-scale electric power generation

The RFM considers only grid-connected, central-station electric-generating systems that use renewable electricity sources:

- Biomass
- Geothermal
- Conventional hydroelectricity
- LFG and MSW
- Solar (thermal and PV)
- Wind (offshore and onshore)

Each submodule provides specific data or estimates that characterize the respective renewable source. The EMM evaluates technologies, including the build and dispatch decisions. Table 3 in the Assumptions to EMM summarizes the technology cost and performance values.

Non-utility-scale renewable energy uses

In addition to projections for renewable energy used in central-station electricity generation, the *Annual Energy Outlook 2026* (AEO2026) projects non-utility-scale renewable energy consumption for:

- Solar residential and commercial electricity production
- Solar residential and commercial hot water heating
- Wood burning for industrial and residential space heating
- Biofuels blending for transportation fuels
- Residential and commercial geothermal (ground-source) heat pumps

Assumptions for these projections are in the Residential Demand Module, Commercial Demand Module, Industrial Demand Module, and Liquid Fuels Market Module reports. The projections do not include additional, minor renewable energy applications that occur outside of energy markets, such as:

- Direct solar thermal industrial applications
- Direct lighting
- Off-grid electricity generation
- Heat from geothermal resources used directly (for example, district heating and greenhouses)

Capital costs

The EMM assumptions documentation describes the methodology we used to determine initial capital costs, which are based on cost estimates developed in a 2024 report prepared by Sargent & Lundy. The costs are adjusted for assumed technology learning from any capacity added since 2023 and for general inflation and cost escalation for key commodity inputs. These cost estimates used a consistent estimation methodology across nearly all electric-generating technologies to develop cost and performance characteristics for technologies that we wanted to consider in the EMM. We did not use the costs the consultant developed for geothermal and hydroelectric plants because we used previously developed site-specific costs for those technologies. We updated inputs for all other technologies listed in Table 3 in the Assumptions to EMM.

Except where noted, the overnight costs shown in Table 3 in the Assumptions to EMM represent the estimated cost of building a plant before adjusting for regional cost factors. Overnight costs exclude interest expenses during plant construction and development. Although not presented separately, as in previous AEOs, the base overnight costs include project contingency, which accounts for undefined project scope and pricing uncertainty and for owners' cost components. Technologies with limited commercial experience may include a technological optimism factor to account for the tendency during technology research and development to underestimate the full engineering and development costs for new technologies or to represent first-of-a-kind costs needed to develop the infrastructure required to support future development.

Several factors affect capital costs for renewable fuels technologies. For geothermal, hydroelectric, solar PV, and wind resources, we assume capital costs to develop the resources depend on the quality, accessibility, or other site-specific factors in the areas with usable resources. These factors can include:

- Additional costs associated with reduced resource quality
- The need to build or upgrade transmission capacity from remote resource areas to load centers
- Local impediments to permitting, equipment transport, and construction in good resource areas
- Inadequate infrastructure
- Rough terrain

To accommodate unexpected demand growth as a result of a rapid nationwide buildup in a single year, we use short-term cost adjustment factors to increase technology capital costs, reflecting limitations on the infrastructure (for example, limits on manufacturing, resource assessment, and construction expertise). These factors, which we apply to all new electric-generating capacity, are a function of past production rates and are further described in *Electricity Market Module of the National Energy Modeling System: Model Documentation*.

We also assume costs associated with construction commodities, such as bulk metals and concrete, affect all new capacity types. Although a generic construction cost index is not available within NEMS, capital costs are specifically linked to the projections for the metals producer-price index found in the Macroeconomic Activity Module of NEMS. Independent of the other two factors, we assume capital costs for all electric-generating technologies, including renewable technologies, decline because of growth in installed capacity for each technology. For a description of NEMS algorithms that reduce generating technologies' capital costs as more units enter service (learning), see *Technological optimism and learning* in the Assumptions to EMM.

Renewable technologies may also qualify for certain tax credit provisions that reduce taxes paid, based on either initial investment costs or on annual energy production. More detailed description of tax credit and other regulatory assumptions are described in the Legislation and Regulation section of this report. A detailed description of the RFM is available in *Renewable Fuels Module of the National Energy Modeling System: Model Documentation*.

Solar Submodule

Background

The RFM Solar Submodule primarily sets the capacity factors for solar technologies and tracks available solar resources for use in capacity expansion decision by the EMM. It represents both utility-scale solar PV and solar thermal (also referred to as concentrating solar power, or CSP) resources. In addition to the standalone solar PV system, we include a combined solar PV and battery-storage hybrid system as a generating technology option for capacity expansion. The RFM tracks solar capacity within a region by groups based on both resource quality and upgrade costs, moving to the next best solar resource and cost group when one category is exhausted. Initial solar resources are based on annual average solar irradiation. The upgrade costs are based on spur line and grid reinforcement costs. The solar resource data for the available land area, average annual capacity factors, and added costs are derived from the National Laboratory of the Rockies (NLR, formerly the National Renewable Energy Laboratory, or NREL).[2]

A fixed power density assumption converts the available land area to capacity. Solar sub-annual capacity factor profiles are represented by 12-month by 24-hour annual averages derived from NLR data.

The Solar Submodule passes the economically available solar capacity, capital cost multipliers, and its associated capacity factors to the EMM for capacity planning and dispatch decisions. Based on these characteristics, the EMM determines how much power generation capacity is built from solar energy. We do not model solar thermal as a capacity expansion option, but existing units are available for dispatch with capacity factors as determined by the RFM.

Assumptions

Technology

- The RFM includes only grid-connected utility-scale generation. The CDM and RDM include projections for small-scale solar PV generation.
- The solar PV technology represented includes a 150-megawatt (MW) AC (alternating current) array of flat-plate PV modules with single-axis tracking. All EMM regions assume that solar PV is available.
- The solar PV plus battery storage hybrid technology (PV-battery hybrid) includes the same 150 MW AC array as the PV with single-axis tracking technology. It also includes a 50-MW capacity, 200-megawatthour (four-hour duration) lithium-ion battery storage system. The PV-battery hybrid system is DC (direct current) tightly coupled, meaning both the PV and battery share a single DC-to-AC inverter and the battery can only charge using energy from the solar PV, not the grid.
- The PV-battery hybrid uses the same constant generation profile as the standalone PV technology, but the battery can store additional available PV energy, which the inverter would otherwise clip in a standalone PV system. We created this additional available energy profile for each EMM region by modeling a standalone PV system using NLR's System Advisor Model (SAM)[3] and then converting the clipped energy into 12x24 (average hour for each month of the year) capacity factor matrices as input for the RFM.

Cost

- For the single-axis tracking PV and PV-battery hybrid systems used in NEMS, we based the cost data on a report by Sargent & Lundy called *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies,* published in 2024. We furthermore adjusted the PV-battery hybrid systems to reflect DC-coupled system, instead of AC-coupled as assumed in the Sargent & Lundy report.
- Regional cost adjustments reflect location-based cost adjustments in each EMM region for PV technologies, as provided by Sargent & Lundy.
- As with all technologies, solar technology capital costs decline with increasing market builds (learning). The levelized capital costs may also change in response to:
  - Average solar irradiance
  - Availability of quality resources
  - Distance from existing transmission lines (for example, spur lines)
  - Transmission network upgrade costs

  - Other market variables
- Upgrade costs include transmission spur line costs and network reinforcement costs determined regionally based on NLR data.[2] The upgrade costs are converted into capital-cost multipliers and start at a 100% multiplier applied to the overall capital cost (that is, unchanged). The multiplier then increases to 110%, 125%, 150%, and finally 200% to represent the aggregation of these factors.

Resources

- Available land for developing solar projects is based on solar resource data developed by NLR. We reduce available solar resources by excluding all lands not suited for solar installations because of items related to airspace and defense, environmental protections, infrastructure, regulatory requirements, and terrain. You can find a complete list of exclusions in the NLR Reference Access Assumptions documentation.[4]
- Most utility-scale solar PV systems are built with an array-to-inverter power ratio (inverter loading ratio, or ILR) of between 1.2 and 1.3.[5] Increased ILRs introduce solar clipping, where solar generation is lost by exceeding the inverter's rated output power. We model solar PV capacity factors with an ILR of 1.3 by using the NLR's SAM to develop a more accurate time-of-day and seasonal output profile.
- We represent six resource classes for solar PV. Solar resource Class 6 represents resources with a capacity factor of 34%. The interval between resources classes is 3%, with Class 1 representing resources with a capacity factor of 18%.
- Table 1 summarizes, for all EMM regions combined, the land available area by resource quality and cost multiplier for solar development. Proportions of total solar resources in each category vary by EMM region.

Table 1. National solar energy resource supply curve assumptions by resource class and capital cost multiplier

square kilometers

Capital cost multiplier	Resource Class 6	Resource Class 5	Resource Class 4	Resource Class 3	Resource Class 2	Resource Class 1
1.00	1,096	30,805	30,576	59,900	40,671	8,446
1.10	4,116	115,659	114,799	224,896	152,700	31,712
1.25	5,372	150,951	149,829	293,520	199,294	41,389
1.50	2,279	64,029	63,553	124,502	84,534	17,556
2.00	732	20,563	20,410	39,984	27,148	5,638

Data source: U.S. Energy Information Administration

Other

- Power density assumptions for solar PV facilities are based on values taken from NLR's System Advisory Model (SAM),[3] which assumes 32 MW of solar capacity can be developed over a square kilometer of land.
- For utility-scale solar PV projects (both stand-alone and hybrid systems), we assume a two-year construction lead time for start of development to project completion.

- Existing capacity and planned capacity additions are based on our survey data from Form EIA-860, *Annual Electric Generator Report*, and Form EIA-860M, *Monthly Update to the Annual Electric Generator Report*. The module includes planned capacity additions with an expected completion date before the end of 2027 or currently under construction, according to respondents' planned completion dates.

Wind Energy Submodule

Background

The RFM Wind Submodule primarily sets the capacity factors for wind technologies and tracks available wind resources for use in capacity expansion decision by the EMM. It represents both offshore and onshore wind resources. The RFM tracks wind capacity within a region by groups based on both resource quality and upgrade costs, moving to the next best wind resource and cost group when one category is exhausted. Initial wind resources are based on annual average wind speeds at a hub height of 90 meters.[6] The upgrade costs are based on spur line and grid reinforcement costs. The wind resource data for the available land area, average annual wind speeds, and added costs are derived from National Laboratory of the Rockies (NLR, formerly NREL).[7] A fixed power density assumption converts the available land area to capacity. Wind resource groups increase over time based on learning. Onshore wind sub-annual capacity factor profiles are represented with 12-month by 24-hour annual averages derived from NLR data.

The Wind Energy Submodule in the RFM passes the economically available wind capacity, capital cost multipliers, and its associated capacity factors to the EMM for capacity planning and dispatch decisions. Based on these characteristics, the EMM decides how much capacity is built from wind energy.

Assumptions

Technology

- The RFM includes only grid-connected utility-scale wind generation. We include projections for distributed wind generation in the CDM and RDM.
- Initial cost and performance assumptions are based on a 200-MW onshore wind facility. The wind turbines are rated at 2.8 MW with 125-meter rotor diameters and 90-meter hub heights. But given that the model has endogenous capacity factor learning-by-doing for wind technologies that is implying for combination of larger turbines, longer rotor diameters, and taller hub heights, it is likely that projected wind facilities coming online in 2050 would have different technology and performance configurations.
- In terms of technology improvements, we calculate the capacity factors for each wind class as a function of overall wind market growth (learning). We implement an algorithm that increases the capacity factor within a wind class as more units enter service.
- Despite increasing performance of the technology, the modeled capacity factors for new builds may decline within a given region as better wind resources are developed first, and less desirable sites remain.

Cost

- We base the cost estimates for this technology on the Sargent & Lundy report, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies,* published in 2024.
- Regional cost adjustments reflect location-based cost adjustments in each EMM region for wind technologies, as provided by Sargent & Lundy.
- As with all technologies, wind technology capital costs decline with increasing market builds (learning). The levelized capital costs may also change in response to:
    - Average wind speed
    - Availability of quality resources
    - Distance from existing transmission lines
    - Transmission network upgrade costs (for example, spur lines)
    - Other market variables
- Upgrade costs include transmission spur line costs and network reinforcement costs determined regionally based on NLR data.[7] The upgrade costs are converted into capital cost multipliers and start at a 100% multiplier to the overall capital cost (that is, unchanged) and then increase to 110%, 125%, 150%, and finally 200% to represent the aggregation of these factors.
    - Transmission spur line costs and network reinforcement costs are regionally determined

Resources

- Available land for developing wind projects is based on wind resource data developed by NLR. We reduce available wind resources by excluding all windy lands not suited for wind turbines because of items related to airspace and defense, environmental protections, infrastructure, regulatory requirements, and terrain. You can find a complete list of exclusions in the NLR Reference Access Assumptions documentation.[4] We further reduce available land area by excluding low-speed wind class areas less than Class 3.
- We represent four resource classes for onshore wind. We assume the capacity factors for an onshore wind Class 6 site start at 47% and increase to as high as 55% over the projection period. Wind classes increase incrementally by five percentage points and include wind Classes 3 to 6.
- Table 2 summarizes for all EMM regions combined, the available land area by resource quality and cost multiplier for onshore wind development. Proportions of total onshore wind resources in each category vary by EMM region.

Table 2. National onshore wind energy resource supply curve assumptions by resouce class and capital cost multiplier

square kilometers

Capital cost multiplier	Resource Class 6	Resource Class 5	Resource Class 4	Resource Class 3
1.00	55	2,073	12,267	16,195
1.10	403	15,204	89,968	118,771
1.25	644	24,298	143,780	189,810
1.50	170	6,418	37,977	50,135
2.00	37	1,388	8,215	10,846

Data source: U.S. Energy Information Administration

Other

- Because of downwind turbulence and other aerodynamic effects, the model assumes an average spacing between turbine rows of 5 rotor diameters and a lateral spacing between turbines of 10 rotor diameters. This spacing requirement determines the amount of power that wind resources can generate (about 6 MW per square kilometer of windy land), which the EMM factors into requests for generating capacity.
- We assume a three-year construction lead time for start of project development to completion for onshore wind and four years for offshore wind.
- Existing capacity and planned capacity additions are based on our survey data from Form EIA-860, *Annual Electric Generator Report*, and Form EIA-860M, *Monthly Update to the Annual Electric Generator Report*. The model includes planned capacity additions with an expected completion date before the end of 2027 or that are currently under construction, according to respondents' planned completion dates.

Offshore wind

The RFM represents offshore wind resources as a separate technology from onshore wind resources, although they are modeled with a similar model structure as onshore wind, as described in more detail above. Because of the unique challenges of offshore construction and the somewhat different resource quality, the assumptions for capital cost, learning-by-doing cost reductions, and the resource access cost differ significantly from onshore wind.

Technology

- Initial cost and performance assumptions are based on a 900-MW offshore wind facility. The wind turbines are rated at 15 MW and have fixed-bottom monopile foundations.
- Because of maintenance challenges in the offshore environment, we assume that performance for a given annual average wind power density is somewhat decreased by reduced turbine availability. Offsetting this challenge, however, are resource areas with higher overall turbine power density than what we assume is available onshore.

Cost

- We base the cost estimates for this technology on the Sargent & Lundy report, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies,* published in 2024.
- Regional cost adjustments reflect location-based cost adjustments in each EMM region for wind technologies, as provided by Sargent & Lundy.
- Cost reductions in offshore technology result, in part, from learning reductions in onshore wind technology as well as from cost reductions unique to offshore installations, such as foundation design and construction techniques. Because offshore technology is significantly less mature than onshore wind technology, offshore-specific technology learning occurs at a somewhat faster rate than for onshore technology. A technological optimism factor is included for offshore wind to account for the substantial cost of establishing the unique construction infrastructure required for this technology, as indicated in *The Electricity Market Module of the National Energy Modeling System: Model Documentation*.

Resources

- As with onshore wind resources, we assume offshore wind resources have an upward-sloping cost supply curve, which is affected primarily by water depth. Offshore supply costs are also affected by the same factors, in part, that determine the onshore supply curve (such as distance to load centers, environmental concerns, and variation in terrain [in this case, seabed]).
- We represent four resource classes for offshore wind. We assume the capacity factors for an offshore wind Class 7 site start at 50% and increase to as high as 58% over the projection period. Wind classes increase incrementally between five and six percentage points and include wind Classes 4 to 7.

Other

- We assume the spacing requirement that determines the amount of power offshore wind resources can generate is about 5 MW per square kilometer of windy area, which the EMM factors into requests for generating capacity.
- We assume a four-year construction lead time from start of project development to completion.
- Existing capacity and planned capacity additions are based on our survey data from Form EIA-860, *Annual Electric Generator Report*, and Form EIA-860M, *Monthly Update to the Annual Electric Generator Report*. The model includes planned capacity additions with an expected completion date before the end of 2027 or that are currently under construction, according to respondents' planned completion dates.

Geothermal Electricity Submodule

Background

We base the geothermal supply curve data on a 2011 U.S. geothermal supply curve assessment. The resource assessment from NREL (now NLR) uses the Geothermal Electricity Technology Evaluation Model (GETEM) (a techno-economic systems analysis tool) to estimate the costs for hydrothermal.[8, 9]

Assumptions

Technology

- We assume a four-year construction lead time for start of project development to completion for a geothermal facility.
- We base existing capacity and planned capacity additions on our survey data from Form EIA-860, *Annual Electric Generator Report*, and Form EIA-860M, *Monthly Update to the Annual Electric Generator Report*. The model includes planned capacity additions with an expected completion date before the end of 2027 or that are currently under construction, according to respondents' planned completion dates.
- NLR data also include two types of technology—flash and binary cycle–and their capacity factors range from 90% to 95%. We model only binary cycle as our geothermal capacity technology.

Resources

- We only consider resources with temperatures higher than 110°C. We use 125 of these known hydrothermal resources in the geothermal supply curve. NLR classified each of these sites as *near-field enhanced geothermal energy system potential*, which are areas around the identified site that lack the permeability of fluids that are present in the hydrothermal potential. We assume, therefore, that the supply curve has 250 total points because each of the 125 hydrothermal sites has corresponding enhanced geothermal system (EGS) potential.

Biomass Submodule

Background

NEMS models biomass consumed for electricity generation in two parts. The IDM includes capacity in the wood products and paper industries (also known as captive capacity) as cogeneration. We represent generation in the electric power sector in the EMM. The RFM calculates the fuel costs and passes them to the EMM, and we assume capital and operating costs and performance characteristics, as shown in Table 3 of the Assumptions to EMM. The EMM provides fuel costs in sets of regional supply schedules. The LFMM projects ethanol production and gradually decreases the quantities and prices of biomass consumed for ethanol from the EMM regional supply schedules.

Assumptions

Technology

- The conversion technology represents a 50-MW dedicated combustion plant, both with a 95% carbon capture and sequestration (CCS) system and without CCS. The total auxiliary power required by the biomass with CCS plant is approximately 15.5 MW, of which 9 MW is used by the carbon capture system, reducing the plant's 65.5-MW (gross) steam turbine generator to 50 MW of net output. The net plant heat rate for the 95% carbon capture case is 19,965 British thermal units per kilowatt hour (Btu/kWh), on a Higher Heating Value (HHV) basis, compared with the heat rate of 13,300 Btu/kWh for biomass plant without CCS.

Cost

- We base the cost estimates for this technology on the Sargent & Lundy report, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies,* published in 2024.
- Regional cost adjustments reflect location-based cost adjustments in each EMM region for biomass technologies, as provided by Sargent & Lundy.

Resources

- Fuel supply schedules consist of four fuel sources: forestry materials from federal forests, forestry materials from non-federal forests, wood residues, and agricultural residues and energy crops. We calculate feedstock potential from agricultural residues and dedicated energy crops from a version of the Policy Analysis Systems Model (POLYSYS) that uses the same oil price information as the rest of NEMS.
- We calculate forestry residues from inventories conducted by the U.S. Forest Service and Oak Ridge National Laboratory (ORNL). The forestry materials component is made up of logging residues, rough rotten salvageable dead wood, and excess small pole trees.[10] The maximum resource from forestry is fixed, based on *U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry*, prepared by ORNL.[10]

- The wood residue component consists of primary mill residues; silvicultural trimmings; and urban wood, such as pallets, construction waste, and demolition debris that are not otherwise used.[11] Urban wood waste is determined dynamically based on activity in the industry sectors that produces usable biomass feedstocks, passed to the RFM from the IDM.
- Agricultural residues are wheat straw, corn stover, and a number of other major agricultural crops.[10] Energy crop data are for hybrid poplar, willow, and switchgrass grown on existing cropland. Agricultural resource supply (agricultural residues and energy crops) is determined dynamically and available supplies within the model at any point may not reflect the maximum potential for that region. POLYSYS assumes that the additional cropland needed for energy crops will displace existing pasturelands.

Other

- Biomass cofiring can account for up to 15% of fuel used in coal-fired generating plants.
- We assume a four-year construction lead time for start of construction to project completion for biomass facilities.
- We base existing capacity and planned capacity additions on our survey data from Form EIA-860, *Annual Electric Generator Report*, and Form EIA-860M, *Monthly Update to the Annual Electric Generator Report*. The model includes planned capacity additions with an expected completion date before the end of 2027 or that are currently under construction, according to respondents' planned completion dates.

Landfill Gas (LFG) Submodule

Background

LFG-to-electricity capacity competes with other technologies using supply curves that are based on the amount of high, low, and very low methane-producing landfills in each EMM region. We model LFG generation facilities as primarily built to serve municipal waste disposal markets with electric power generation as a secondary product rather than as a capacity expansion option to the electric power sector. Based on the historical ratio between generation and municipal waste landfill capacity, the LFG Submodule produces year-specific streams of national landfill capacity for LFG development from both new landfills and landfills with existing LFG projects. The national LFG generation estimates are proportioned to EMM regions.

Assumptions

Resources

- GDP and population are the drivers in the econometric equation that establishes the LFG supply.
- We use EPA's Landfill Methane Outreach Program (LMOP) landfill database[12] to determine available methane resources (in tonnage and five-year increments) and project-development timelines. We use LMOP's *Candidate* landfills for new landfills and use *Probable* landfills only if the module has exhausted the potential from *Candidate* landfills.

Other

- We base existing capacity and planned capacity additions on our survey data from Form EIA-860, *Annual Electric Generator Report*, and Form EIA-860M, *Monthly Update to the Annual*

Electric Generator Report. The model includes planned capacity additions that we expect to be completed before the end of 2027 or that are currently under construction, according to respondents' planned completion dates.

Conventional Hydroelectricity Submodule

Background

The Conventional Hydroelectricity Submodule represents potential for new U.S. conventional hydroelectric capacity of 1 MW or greater from new dams, from existing dams without hydroelectricity, and from additional capacity at existing hydroelectric dams.

Assumptions

Technology

- The supply curve of potential new hydroelectric capacity includes both seasonal storage and run-of-river applications. It also includes both undeveloped sites and sites with existing dam, diversion, or generating facilities.
- The supply excludes pumped-storage hydroelectric capacity, which is not a technology option for capacity expansion. The operation of existing pumped hydro facilities is modeled by the EMM.
- The supply neither considers efficiency or operational improvements without capital additions or does it consider additional potential from refurbishing existing hydroelectric capacity.

Cost

- We estimate costs for each site in the resource database, as indicated in the Resources section.

Resources

- We derive the summary hydroelectric potential from reported lists of potential new sites assembled from Federal Energy Regulatory Commission (FERC) license applications and other survey information and from estimates of capital and other costs prepared by the Idaho National Engineering and Environmental Laboratory (INEEL).[13]
- We use resource characteristics for existing non-powered dams based on ORNL's 2012 *An Assessment of Energy Potential at Non-Powered Dams in the United States*.[14]

Other

- For annual performance estimates (capacity factors), we use the generally lower, but site-specific, FERC estimates rather than the general estimates prepared by INEEL, and the supply includes only sites with estimated costs of 10 cents per kilowatthour (kWh) or lower.
- We base existing capacity and planned capacity additions on our survey data from Form EIA-860, *Annual Electric Generator Report*, and Form EIA-860M, *Monthly Update to the Annual Electric Generator Report*. The model includes planned capacity additions that we expect to be completed before the end of 2027 or that are currently under construction, according to respondents' planned completion dates.

Legislation and regulations

AEO2026 represents, to the extent possible within the NEMS model framework, current laws and regulations related to renewable generating technologies. Because of the time lags involved in model development and publication, laws and regulations in effect as of December 2025, are included in the Reference case and other applicable cases of AEO2026. Changes to laws and regulations resulting from executive action, judicial review, or the legislative process after December 2025, are not included in AEO2026 but will be included as possible in future AEO publications.

A more detailed list of tax credit provisions, state-level requirements, and other legislation is included in the *Summary of Legislation and Regulations Included in the Annual Energy Outlook* report. Provisions related to the new EPA regulations under Section 111 of the Clean Air Act are described in *The Electricity Market Module of the National Energy Modeling System: Model Documentation*.

Renewable electricity tax credits

The federal tax credits available to certain renewable electric-generating technologies initiated in the Energy Policy Act of 1992 (EPACT1992) and amended in the Energy Policy Act of 2005 (EPACT2005) have been further amended through a series of acts that we have implemented in NEMS over time. AEO2026 reflects the most recent changes implemented through the One Big Beautiful Bill Act of 2025 (OBBBA).[15]

The production tax credit (PTC) is a per-kilowatthour tax credit on electricity sold for a specific number of years after the facility has been placed in service. The investment tax credit (ITC) is a tax credit applied, on a percentage basis, to the cost of building certain electric-generating assets. The OBBBA modifies and reduces the tax credits eligibility period that was previously extended for certain technologies through the Inflation Reduction Act (IRA) of 2022. The ITC and PTC are exclusive of one another, and the same facility cannot claim both. The clean energy ITC has a base value of 6%, and the clean energy PTC has a base value of 0.3 cents/kWh and is adjusted for inflation each year. We assume all qualifying technologies meet the prevailing wage and apprenticeship requirements for a bonus credit, increasing the base tax credits by five times for an effective ITC value of 30% and PTC value of 1.5 cents/kWh (prior to inflation adjustment).

Onshore and offshore wind technologies and biomass facilities are also assumed to meet the domestic content requirements for a 10% additional bonus tax credit as allowed under the IRA. The 10% bonus credit for the energy communities for solar and wind technologies made available through the IRA is no longer represented in AEO2026 as the OBBBA eliminated the tax credits for the technologies in the long-term. In addition, the OBBBA introduced additional foreign entity of concern (FEOC) restrictions to be eligible for the tax credits. To reflect the additional FEOC restrictions, we implemented a three-percentage-point adder to the cost of capital (both equity and debt) for solar and wind technologies during the period in which they are eligible for the tax credits.

We specifically implement the tax credits for qualifying sources as follows:

- Along with the guidance on the beginning-of-construction requirement and the Continuity Safe Harbor provided in Internal Revenue Service (IRS) Notice 2025-42,[16] we assume standalone solar PV facilities with an online year of 2028 will begin construction before July 4, 2026, and be eligible to claim the PTC for the first 10 years of operation; solar facilities entering service after

2028 are assumed to be ineligible for the tax credit. For PV-battery hybrid facility, we assume it has similar eligibility criteria as the standalone solar PV system, except that it continues to be eligible for the ITC for the battery portion of the system through 2035 before it begins to phasedown.

- Along with the guidance on the beginning of construction requirement and the Continuity Safe Harbor provided in IRS Notice 2025-42,[16] we assume both onshore and offshore wind projects entering service through 2029 begin construction before July 4, 2026, in order to claim the PTC during the plant's first 10 years of service; wind projects entering service after 2029 are assumed ineligible for the tax credit. In addition, we assume onshore wind projects meet the domestic content requirements for additional tax credits. We assume that offshore wind projects will claim the ITC because of the high capital costs for those projects and that they have through 2030 to be placed in service and to be eligible for the tax credit.
- Starting in the 2026 first construction year, we assume:
  - Biomass projects placed in service by 2038 will claim the full PTC for the first 10 years of operation and also receive a 10% bonus credit for domestic content before phasing down and expiring entirely in 2040.
  - Geothermal and hydroelectric projects placed in service by 2037 will claim the full ITC before phasing down and expiring entirely in 2039.

Domestically manufactured components also qualify for the Advanced Manufacturing Production Tax Credit (45X),**Error! Bookmark not defined.** a PTC that provides an incentive to produce and sell eligible components for certain qualifying energy systems. The Advanced Manufacturing Tax Credit is transferable and is intended for all or some of the credit to be passed to the end installer of the components for the energy systems. We assume that capital costs for onshore wind facilities will fall slightly as a result of this credit. We assume that after legal and administrative fees, the residual value of the credit is split evenly between the manufacturer and the end installer of the energy system. The value to the end installer is realized as a reduction in overnight capital cost equal to the value of their credit share, which we assume equals $12.60/kW and is applied to the starting capital cost assumptions. These cost savings are assumed to continue after the expiration of the credit. For other generating technologies, we assume the tax credit value would be offset by the increased cost for domestic manufacturing.

Bioenergy with carbon capture and sequestration (BECCS) is eligible to receive the Credit for Carbon Oxide Sequestration determined under Section 45Q of the IRA.[17] The credit amount is based on the per metric ton of qualified carbon oxide captured and sequestered. You can find more information on the value of the Section 45Q tax credit assumed in NEMS in Carbon Capture, Allocation, Transportation, and Sequestration (CCATS) Module Assumptions and Legislative and Regulation Assumptions, both available on the Assumptions page.

State clean energy standard programs and capacity targets

To the extent possible, AEO2026 reflects state laws and regulations enacted as of December 2025, which establish minimum requirements for renewable generation or capacity for load-serving entities operating in the state. These requirements represent clean energy standards (CES). AEO2026 projections do not include voluntary goals but do include actionable clean energy targets set forth by state-level executive branch entities.

We estimate zero-emission generation targets by using the zero-emission generation targets in each state within the NEMS region. In many cases where regional boundaries intersect state boundaries, state requirements are divided among relevant regions based on sales. Required generation in each state is then summed to the regional level for each year to determine a regional compliant generation share of total sales.

We model any non-discretionary limitations on meeting the generation or capacity target to the extent possible. However, because of the complexity of the various requirements, the regional target aggregation, and the nature of some of the limitations, we estimate compliance.

Compliance enforcement provisions vary significantly across states, and most states have procedures for waiving compliance, such as alternative compliance payments, penalty payments, discretionary regulatory waivers, or retail price impact limits. Because of the variety of mechanisms, even within a given electricity market region, we do not model these limits.

Most states already meet or exceed their required renewable generation mix based on requirements for compliant generation in 2025 and qualified generation or purchases of renewable energy credits (RECs).[18] Several factors have helped make CES compliance attainable for generators, including:

- New CES-qualified generation capacity timed to take advantage of federal incentives
- Lower cost of wind, solar, and other renewable technologies
- State and local policies that either reduce costs (for example, equipment rebates) or increase revenue streams (for example, net metering) associated with CES-eligible technologies
- Credit trading among compliant entities within a state and across state boundaries

AEO2026 also reflects capacity mandates for battery storage and offshore wind for states with specified requirements for those technologies. State-level targets are aggregated for the respective electricity market module region. Targets may be adjusted based on installed or planned capacity assumed to come online. Assigned capacity by state may also be adjusted so that adjacent states may contribute toward another state-level mandate, based on analyst assessment of the rule and of available offshore land area. State goals with no enforcement mechanism are not included. The totals for additional capacity added by region are summarized in Table 3.

Table 3. Additional offshore wind and battery storage state-level mandated capacity by 2050 by electricity market module region

gigawatts

	ISNE	NYCW	NYUP	PJME	PJMD	MISE	Total
Battery storage	4	0	6	5	3	3	21
Offshore wind	11	9	0	20	5	0	45
Offshore wind (adj)	11	7	0	13	5	0	36

Data source: U.S. Energy Information Administration

Note: ISNE=Northeast Power Coordinating Council/ New England; NYCW=Northeast Power Coordinating Council/ New York City & Long Island; NYUP=Northeast Power Coordinating Council/Upstate New York; PJME= PJM/East; PJMD=PJM/Dominion;

MISE=Midcontinent ISO/East. *Offshore wind (adj)* is the adjusted target due to the Presidential Executive Order to halt permits and leases for offshore wind projects in federal waters.

Notes and Sources

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[1] For a comprehensive description of each submodule, see U.S. Energy Information Administration, *Renewable Fuels Module of the National Energy Modeling System: Model Documentation*, available here: https://www.eia.gov/outlooks/aeo/nems/documentation.

[2] National Renewable Energy Laboratory, *United States Utility-Scale PV Supply Curves 2023, Reference Access 2030 Moderate Supply Curve,* (November 2024), https://data.openei.org/submissions/6001.

[3] National Laboratory of the Rockies, System Advisor Model, https://sam.nlr.gov.

[4] National Renewable Energy Laboratory, *Solar Photovoltaics and Land-Based Wind Technical Potential and Supply Curves for the Contiguous United States: 2023 Edition*, (January 2024), https://docs.nlr.gov/docs/fy24osti/87843.pdf.

[5] The inverter loading ratio (ILR) is the ratio between the rated capacity of the DC (direct current) solar array and the AC (alternating current) power rating of the inverter.

[6] The resource data provided from National Laboratory of the Rockies (NLR, formerly NREL) is based on a hub height of 115 meters and a rotor diameter of 175 meters. We apply a 2.3 percentage point reduction in the NLR capacity factors to align the capacity factor assumptions with the rest of the model's wind assumptions based on a wind plant with a hub height of 90 meters and a rotor diameter of 125 meters.

[7] National Renewable Energy Laboratory, *United States Land-based Wind Supply Curves 2023, Reference Access 2030 Moderate 115hh 170rd Supply Curve,* (November 2024), https://data.openei.org/submissions/6119.

[8] Augustine, C., *Updated U.S. Geothermal Supply Characterization and Representation for Market Penetration Model Input*, NREL/TP-6A20-47459 (October 2011), https://docs.nlr.gov/docs/fy12osti/47459.pdf.

[9] The one exception applies to the Salton Sea resource area, for which we used cost estimates provided in a 2010 report on electric power sector capital costs rather than NREL (now NLR).

[10] U.S. Department of Energy, *U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry*, (August 2011), https://www1.eere.energy.gov/bioenergy/pdfs/billion_ton_update.pdf.

[11] De la Torre Ugarte, D., *Biomass and bioenergy applications of the POLYSYS modeling framework*. Biomass and Bioenergy, Vol. 18 (April 2000), pp. 291–308.

[12] U.S. Environmental Protection Agency, *Landfill Methane Outreach Program (LMOP)*, https://www.epa.gov/lmop.

[13] Hall, Douglas G., Richard T. Hunt, Kelly S. Reeves, and Greg R. Carroll, Idaho National Engineering and Environmental Laboratory, *Estimation of Economic Parameters of U.S. Hydropower Resources* INEEL/EXT-03-00662 (June 2003), https://www1.eere.energy.gov/water/pdfs/doewater-00662.pdf.

[14] Oak Ridge National Laboratory, *An Assessment of Energy Potential at Non-powered Dams In the United States*, (April 2012), https://www.ornl.gov/publication/assessment-energy-potential-non-powered-dams-united-states-0.

[15] The One Big Beautiful Bill Act (Pub. L. No. 119-21 (2025)), https://www.congress.gov/bill/119th-congress/house-bill/1

[16] Internal Revenue Service, *Beginning of Construction Requirements for Purposes of the Termination of Clean Electricity Production Credits and Clean Electricity Investment Credits for Applicable Wind and Solar Facilities, Notice 2025-42*, (August 2025), https://www.irs.gov/pub/irs-drop/n-25-42.pdf.

[17] The Inflation Reduction Act (Pub. L. No. 117-169 (2022)), Sections 45Q, Clean Electricity Production and Investment Tax Credits, https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

[18] Barbose, G., *U.S. Renewables Portfolio Standards: 2021 Annual Status Report*, Lawrence Berkley National Laboratory (February 2021), https://eta-publications.lbl.gov/sites/default/files/rps_status_update-2021_early_release.pdf.