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Renewable Fuels Module of the National Energy Modeling System: Model Documentation 2022

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Update Information

This edition of the Renewable Fuels Module—Model Documentation 2022 reflects changes made to the Renewable Fuels Module during the past year for the *Annual Energy Outlook 2022*. These changes include:

- Implemented solar photovoltaic-battery storage hybrid system as an option for generating technology expansion option
- Enabled retirements for onshore wind technologies
- Updated POLYSYS baseline

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1. Introduction

Purpose of this report

This report documents the objectives, analytical approach, and design of the National Energy Modeling System (NEMS) Renewable Fuels Module (RFM) as it relates to producing the *Annual Energy Outlook 2022* (AEO2022) forecasts. The report catalogues and describes modeling assumptions, computational methodologies, data inputs, and parameter estimation techniques. A number of off-line analyses used in place of RFM modeling components are also described.

This documentation report serves three purposes. First, it is a reference document for model analysts, model users, and the public interested in the construction and application of the RFM. Second, it meets EIA's legal requirement to provide adequate documentation in support of our models [Public Law 93-275, Federal Energy Administration Act of 1974, Section 57(b) (1)]. Third, this documentation facilitates continuity in our model development by providing information sufficient to perform model enhancements and data updates as part of our ongoing mission to provide analytical and forecasting information systems.

Renewable Fuels Module summary

The RFM consists of six submodules that represent major renewable electricity resources: biomass, landfill gas (LFG), solar (thermal and photovoltaic), wind, geothermal, and conventional hydroelectricity energy. The RFM also interacts with the REStore model to estimate the impact of energy storage on the dispatch of generation in each of the modeled electricity regions. The details of the REStore model are provided as an appendix to the Electricity Market Module (EMM) model documentation.

The RFM defines the technology, performance, and renewable resource supply for renewable electricity technologies in the NEMS, which is used by the EMM, along with the renewable cost assumptions that are provided in the EMM model documentation, in projecting grid-connected central-station electricity capacity planning and dispatch decisions. Projected characteristics include:

- Available generating capacity
- Location
- Unit size
- Capital cost
- Fixed operating cost
- Variable operating cost
- Capacity factor
- Heat rate
- Construction lead time
- Fuel price

Because of the extensive interaction between the RFM, REStore, and EMM, these three modules must be run together.

Renewable electricity technology cost and performance characteristics that are common to all electricity-generating technologies are input directly to the EMM via the input file ECPDAT. Unique characteristics such as renewable resource values for regional, seasonal, and hourly time segments of intermittent renewables are supplied in specific files and subroutines to specific renewable electricity technologies.

Other renewables modeled elsewhere in NEMS include:

- Biomass in the industrial sector
- Biofuels in the Liquid Fuels Market Module (LFMM)
- Wood and solar hot water heating in the residential sector
- Geothermal heat pumps and distributed (grid-connected) solar photovoltaics in the residential and commercial sectors

In addition, several areas, primarily nonelectric and off-grid electric applications, are not represented in NEMS. They include direct applications of geothermal heat, several types of solar thermal use, and off-grid photovoltaics. For the most part, the expected contributions from these sources are confined to niche markets; however, as these markets develop in importance, they will be considered for representation in NEMS.

The number and purpose of the associated technology and cost characteristics vary from one RFM submodule to another, depending on the modeling context. For example, renewable resources such as solar, wind, and geothermal energy are not fuels; rather, they are inputs to electricity or heat conversion processes. As a result, the Solar Submodule, Wind Submodule, and Geothermal Submodule do not provide fuel product prices.

Our Office of Long-Term Energy Modeling Electricity, Coal, and Renewables Modeling Team determines initial cost and performance values for renewable electricity technologies based on the examination of available information. For AEO2020, we re-evaluated and updated the cost and performance characteristics for all generating technologies, including non-renewables. The cost and performance characteristics include:

- Capital costs (excluding the construction financing and the process and project contingency components that are provided in the EMM)
- Fixed and variable operation and maintenance (O&M) costs
- Capacity factors
- Construction lead times

All cost values are converted to 1987 dollars.

The following sections provide summaries of the six RFM submodules that we use to produce the current projections:

- Landfill Gas Submodule (LFG)
- Wind Energy Submodule (WES)
- Solar Energy Submodule (SOLAR)
- Biomass Submodule
- Geothermal Energy Submodule (GES)
- Conventional Hydroelectricity Submodule (CHS)

Each sections concludes with information on the RFM archival package and EIA point of contact.

Landfill Gas Submodule (LFG)

The Landfill Gas Submodule provides annual projections of energy produced from estimates of U.S. landfill gas capacity. The submodule calculates the quantity of LFG produced, derived from an econometric equation that uses gross domestic product (GDP) and U.S. population as the principal drivers. We estimate the LFG capacity based on reported waste and landfill gas production data and judgment about future trends in recycling. The submodule uses LFG supply curves to reflect competition between new LFG-to-electricity capacity and other technologies in each projection period and in each EMM region.

Wind Energy Submodule (WES)

The Wind Energy Submodule (WES) projects the availability of undeveloped wind resources, expressed as megawatts (MW) of capacity in each region, which is passed to the EMM, which models for the building and dispatching of wind turbines that are competing with other electricity-generating technologies. The wind turbine data are expressed in the form of energy supply curves that provide the estimated maximum amount of turbine generating capacity that could be installed, given the available land area, average wind speed, and capacity factor. These variables are passed to the EMM in the form of nine time segments that are matched to respective electricity load curves within the EMM.[1]

Solar Energy Submodule (SES)

Solar technologies in RFM include solar thermal (also referred to as concentrating solar power, CSP) and photovoltaic. Starting in AEO2021, we include a combined solar PV and battery storage hybrid system as a generating technology option for capacity expansion. All three technologies are grid-connected and provided by electric utilities, small power producers, or independent power producers. Performance characteristics unique to solar technologies (such as season and region-dependent capacity factors) are passed to the EMM via the SES.

Biomass Energy Submodule (BES)

The Biomass Submodule provides biomass resource and performance characteristics for a biomass-burning, electricity-generating technology to the EMM. The submodule uses a regional biomass supply schedule that we use to determine the biomass fuel price; fuel prices are added to variable operating costs because renewable fuels have no fuel costs in the NEMS structure. The biomass supply schedule is based on the accessibility of wood resources by the consuming sectors from existing wood and wood residues, crop residues, and energy crops. The LFMM also accesses the biomass supply curve to determine availability of feedstocks for production of cellulosic ethanol, biomass pyrolysis oils, and biomass-to-liquids. Projected feedstocks for production of sugar- or starch-based ethanol (primarily from corn, or maize, in the United States) are determined within the LFMM. The Industrial Demand Module (IDM) model captive capacity in the wood products and paper industries as cogeneration.

[1] The nine time segments are derived from three eight-hour segments of the day for three seasons: winter, summer, and off-peak (spring/fall averaged). The data represent average capacities based on empirical analysis.

Geothermal Energy Submodule (GES)

The Geothermal Energy Submodule (GES) models current and future regional supply, capital cost, and operation and maintenance costs of electric-generating facilities. The GES uses hydrothermal resources (hot water and steam) and so-called near-field enhanced geothermal systems (EGS) sites, which are areas around the hydrothermal sites with high temperatures but less fluid as a basis for its model. The data are assembled from 125 known hydrothermal sites and the 125 corresponding near-field EGS areas, each represented by information that reflects the specific resource conditions of that location. The GES generates a three-part geothermal resource supply curve for geothermal capacity for each region in each forecast year for competition with fossil-fueled and other generating technologies.

Conventional Hydroelectricity Submodule (CHS)

The Conventional Hydroelectricity Submodule (CHS) models the supply (MW), capital cost, and operation and maintenance costs of conventional hydroelectric power available from adding new hydro generating capacity in increments of 1 MW or greater to:

- New sites without dams
- Sites with existing dams but without hydroelectricity
- Existing hydroelectricity sites that can accommodate additional capacity

The CHS uses the Idaho Hydropower Resource Economics Database (IHRED). The CHS does not account for:

- Pumped storage capacity
- Increments of capacity less than 1 MW available from refurbishing and upgrading existing hydro capacity
- Capacity available from new in-stream, offshore, or ocean technologies

Within each NEMS region, for each NEMS cycle, the CHS first identifies additional hydro capacity available at or less than an avoided cost specified by the EMM. It then segments the available capacity into three cost categories: lowest cost, midrange cost, and highest cost. The CHS then submits the megawatts of available capacity, expressed as average capital cost and operation and maintenance costs (each weighted by nameplate capacity) and capacity factors to the EMM for each of the three cost categories. After projecting capacity change decisions, the EMM informs the CHS of required decrements to potential available for selection in the next NEMS cycle.

Capacity credit for intermittent generation

The intermittent and battery storage generators can contribute some fraction of their rated capacity to the reserve margin because of the significant probability that at least some intermittent and battery storage generators will be available during peak-demand periods and the significant probability that some portion of operator-dispatched capacity will not be available during that time,. This fraction, referred to as the capacity credit, is a function of the correlation between the temporal generation pattern of the resource and the peak-load periods, as well as the fraction of intermittent generation compared with total regional output.

The intermittent capacity credit is determined in NEMS as a function of the estimated average contribution that all intermittent units will provide to meet an assumed system reliability goal of 99.999% availability. This contribution is, in turn, largely determined by the:

- Average, peak-load period capacity factor for the intermittent capacity
- Standard deviation around that average
- Degree to which the output at each individual site in a region is correlated with the output at other sites
- Reliability characteristics of the operator-dispatched (conventional) capacity in the region

The battery storage capacity credit is determined as a function of the available energy stored in batteries during the hours of peak net load using the load duration curve (LDC) calculation method.

Representation of depreciation for renewables-fueled generating technologies

Biomass, geothermal, solar (photovoltaic and thermal), and wind (onshore and offshore) are assigned five-year tax lives and five-year double declining balance capital depreciation in NEMS[2], accelerated cost recovery. Landfill gas and hydroelectric technologies are assumed to have 20-year tax lives during which the capital is depreciated, which is the same for most central-station, electricity-generating technologies except nuclear technologies, which are assigned a 15-year tax life.

Archival Media

The RFM is archived as part of the NEMS production runs.

Model Contact

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Report organization

Subsequent chapters of this report provide detailed documentation of capacity credit algorithm for intermittent generation and each of the RFM's six working submodules. Each chapter contains:

- Model Purpose—a summary of the submodule's objectives, detailing input and output quantities, and the relationship of the submodule to other NEMS modules
- Model Rationale—a discussion of the submodule's design rationale, including insights into assumptions used in the model development process, and alternative modeling methodologies considered during the submodule development phase

[2] Based on the Economic Recovery Tax Act of 1982 (ERTA, P.L. 97-34); see Internal Revenue Code, subtitle A, Chapter 1, Subchapter B, Part VI, Section 168 (e)(3)(vi)(1994)

- Model Structure—an outline of the model structure, using text and graphics to illustrate the major model data flows and key computations

This report also contains appendixes—supporting documentation for input data and parameter files currently residing on our computer network. Appendix A in each RFM submodule chapter lists and defines the input data used to generate parameters and endogenous projections. Appendix B contains a mathematical description of the computation algorithms, including model equations and variable transformations. Appendix C is a bibliography of reference materials used in the model development process. Appendix D is a model abstract. Appendix E discusses data quality and estimation methods.

2. Capacity credit for intermittent generation

Within the EMM, each region must have sufficient generating capacity to meet peak demand and an additional regional capacity reserve margin. For all operator-dispatched capacity types except battery storage, the summer-rated capacity for each generator unit is available for contribution to the capacity reserve margin requirement. However, intermittent generating capacity, such as wind or solar facilities, will not always generate during peak-demand periods and so cannot contribute its full rated capacity to the capacity reserve margin.

Intermittent generators can contribute some fraction of their rated capacity to the reserve margin because of the significant probability that at least some intermittent generators will be available during peak-demand periods and the significant probability that some portion of other operator-dispatched capacity will not be available during this time. This fraction, referred to as the capacity credit, is a function of the correlation between the temporal generation pattern of the resource and the peak-load periods, as well as the fraction of intermittent generation compared with total regional output. That is, a wind turbine in a region where the wind typically blows strongly during the peak-load period will contribute more to meeting peak-load system reliability than a wind turbine in a region with typically light peak-load winds. However, as wind or solar constitute more of the system capacity, the variability of the peak-load operation will have a decreasingly beneficial effect on system reliability.

The capacity credit for intermittent generators is determined in NEMS as a function of the estimated average contribution that all units of that type (wind or solar) will provide to meeting an assumed system reliability goal of 99.999% availability (that is, the system should have enough generation capacity installed to be able to meet full load requirements 99.999% of the time, sometimes approximated as achieving 1 hour of load shortage in 10 years, or 87,600 hours of operation). This contribution is, in turn, largely determined by the:

- Average, peak-load period capacity factor for the intermittent capacity
- Standard deviation around that average
- Degree to which the output at each individual site in a region is correlated with the output at other sites
- Reliability characteristics of the operator-dispatched (conventional) capacity in the region

The peak-load period capacity factor for each intermittent generator is determined as described in the Wind Energy Submodule and Solar Energy Submodule chapters of this report. The normalized standard deviations for wind and solar plants are exogenously determined. The intersite output correlation factors are also exogenously determined on a regional basis. The standard deviation for each conventional capacity type is based on binomial distribution using assumed forced-outage rates:

$$S = C \times \sqrt{\frac{(P \times (1-P))}{N}}$$

where;

C = the installed capacity of a specified type as calculated for that year

P = the forced outage rate (variable name UPFORT in the ECPDAT file)

N = the number of units for the specified plant type as calculated for that year and region.

The standard deviation of total capacity of all conventional generating-capacity technologies is calculated as:

$$S_{Conventional} = \sqrt{S_1^2 + S_2^2 \ldots + S_n^2}$$

where;

S_n = the standard deviation for the *n*th generating capacity type

The standard deviation for all intermittent units (wind, solar thermal, or photovoltaic):

$$S_{Intermittent} = C \times \sqrt{N * s^2 + (N^2 - N) * R * s^2}$$

where;

N and C = as above (for intermittent rather than conventional capacity types)

s = the technology-specific normalized standard deviation of hourly output for intermittent resource facilities (*INTSTDDV* variable in the WESAREA file)

R = the regional correlation factor for intermittent resources (*INTREGCRL* variable in the WESAREA file).

The total standard deviation of all generation (conventional and intermittent) is then calculated as:

$$S_{Total} = \sqrt{S_1^2 + S_2^2 \ldots + S_n^2 + S_{Intermittent}^2},$$

where;

S_n = as above

$S_{Intermittent}$ = the total standard deviation for the intermittent capacity type being evaluated (wind, solar thermal, or photovoltaic).

The reliable capacity is then calculated excluding the intermittent capacity, then again including all capacity types usingg:

$$C_{reliable} = \left(\sum C_{ave,n}\right) - Z \times S,$$

where;

$C_{ave,n}$ = the total annual average capacity for the *n*th capacity type and is evaluated for conventional-only capacity types and then again for conventional plus intermittent capacity types. For conventional resources, average capacity is the installed summer capacity multiplied by one minus the forced outage rate. For intermittent resources, it is the installed capacity times the peak-load period capacity factor.

Z = the statistical parameter for the number of standard deviations in a normal distribution that are needed to account for a specified fraction of the area under the distribution curve, specified as variable UPINTZ in the ECPDAT file[3].

S = as calculated above for $S_{conventional}$ or S_{Total} as appropriate for the conventional-only or the total reliable capacity calculation.

Although this approach accounts for the impacts of spatial diversity of resources on available capacity, it does not account for the tendency of variable renewable energy resources (VRE), especially solar, but to a lesser extent wind, to saturate certain time-of-day or seasonal demand hours. In particular, the net-load, or total demand minus average expected VRE generation, can decrease in a given hour of the day, month, or year once sufficient VRE generation from a particular source gets sufficiently large.

The net-load algorithm is used to reduce peak-load overestimation by accounting for the impact that the VRE generation has in suppressing effective demand to dispatchable generators during periods when the VRE is generating. The net-load curve is updated in each model year to represent the current penetration of the intermittent technology when calculating the capacity factor (see Appendix 1-A).

For each applicable intermittent resource, the capacity credit (*U*) is calculated as:

$$U_{Intermittent} = \frac{C_{reliable,net} - C_{reliable,conventional}}{C_{installed,Intermittent}}$$

where;

$C_{reliable}$ = as above for net and conventional-only generation

$C_{intalled,Intermittent}$ = the installed, nameplate capacity of the intermittent resource being evaluated (wind, solar thermal, or PV). Note that the capacity credit for each intermittent resource is evaluated separately. As a given intermittent resource is calculated, the other two are included in the *conventional capacity* calculations, using the capacity credit from the previous model iteration to determine availability.

Finally, for each VRE technology in each year, the capacity credit is updated by weighting the hours closest to the net peak that receive more than the hours further from the net peak:

$$wgt_h = daywgt * \ (net\ load_h \, / \, max\ net\ load)^{\ coeff}$$

$$cap\ credit = \frac{\sum_h credit_h * wgt_h}{\sum_h wgt_h}$$

[3] For AEO2014, the default Z value of 3.19 is used to represent 99.93% of the area under the Gaussian normal distribution. The use of 99.93% to represent 99.999% reliability is explained in Appendix 1-A.

The resulting capacity credit is the average value for all intermittent units of the specified type in that region in the current year. The EMM uses this value to determine total intermittent capacity to count toward the regional reserve margin. Because of the intra-regional power output correlation factor for the intermittent resources, the marginal capacity credit (that is, the contribution to reserve margin of the last unit built) actually declines, thus reducing the average capacity credit with increasing penetration. For capacity planning in NEMS, however, the intermittent plant vintage (age) does not affect the calculation, and each plant (the first through the last built) receives the average capacity credit for that resource type.

In addition, because the capacity credit is only calculated for the current year's installed capacity, it is not prospective, and the same number is evaluated within the EMM regardless of the amount of capacity ultimately constructed in the following years. Although this approximation is reasonable if the annual capacity additions for the resource are small, it can significantly overestimate the capacity credit in scenarios that result in the rapid build-up of intermittent renewable resources. As a result, the maximum limit on the regional fraction of intermittent generation is allowed to increase by 5 percentage points per year, but it can neither exceed 70% nor fall lower than 20%. That is, NEMS computes the maximum historical fraction of intermittent generation and then adds 5%. If this value exceeds 70% (as specified by the UPINTBND in ECPDAT), it is set to 70%. If this value falls lower than 20% (actually specified as one half of the ultimate upper bound on intermittent generation, or UPINTBND/2), it is set to 20%. This expanding limit, based on EIA analyst judgment, serves to ensure that capacity credit impacts are reasonably accounted for and simulates the time needed for regional system operators to adjust operating procedures to accommodate large amounts of intermittent generation. The final regional limit of 70% intermittent generation accounts for the uncertain system costs required to accommodate such large amounts of non-dispatched generation.

The statistical approximations used to describe the variance in output from both conventional and intermittent resources are reasonable over a wide range of capacity configurations. With extreme levels of intermittent capacity, the algorithm can, however, produce a negative capacity credit for intermittent resources. Because the instantaneous or long-term output of real-world intermittent resources cannot fall lower than zero, these resources cannot have a capacity credit less than or equal to zero. As a result, the capacity credit is constrained to be greater than zero.

An additional impact of intermittent generation on reliable grid operations is the potential for excessive generation during off-peak periods. Because solar resources do not operate during the lowest-load hours (which are typically at night), the treatment of this impact in NEMS is described in the Wind Energy Submodule.

Appendix 2-A: Background information on the capacity credit algorithm for intermittent generation

We updated the capacity credit algorithm for intermittent generation for AEO2019 by adding the REStore module, in order to incorporate higher fidelity time slices (864 representative hours each year—24 hours for 3 day types for 12 months). With a finer time slice, we can more closely examine the behavior of variable renewable energy capacity (VREs) occurring during non-peak-demand periods.

With the new algorithm, we use the net load to reduce peak-load overestimation by accounting for the impact that the VRE generation has on suppressing effective demand to dispatchable generators during periods when the VRE is generating. We update the net-load curve in each model year to represent the current penetration of the intermittent technology when calculating the capacity factor.

Net Load:

$$Net\_Load_{hour} = Total\_Load_{hour} - Net\_Imports_h - \sum VRE\_Capacity$$

where:

h	=	hour (*h* is each of 864 representative hours each year (24 hours for 3 day types for 12 months)
d	=	day type (weekday, peak day, or weekend day)
m	=	month
r	=	EMM region
y	=	NEMS year
s	=	season as represented in the Electricity Capacity Planning Submodule (ECP)

Net imports in hour *h* includes generation net of imports and export including purchases from CHP.

$$Net\ imports_h = UEITAJ\_ECP_{s,r} + BTCOGEN_r/8.760 + BMEXICAN_r/8.760$$

where:

$UEITAJ\_ECP_{s,r}$	=	net interregional firm trade, between regions (within the United States) in gigawatt (GW), and is a positive value if a region is a net exporter, and therefore, their demand requirement would need to be higher to meet the amount they are trading. If the variable value is negative, a region is a net importer, and it would reduce the required demand.
$BTCOGEN_r$	=	generation from traditional co-generators (outside the EMM, from residential/commercial/industrial sectors) that is sold to the grid. Provides an annual generation value that is divided by hours to convert to a fixed GW contribution to every season/time slice.

$BMEXICAN_r$	=	Similar concept as *UEITAJ* for energy traded from Canada and Mexico. This variable is in generation terms, and division by 8.760 (hours) converts to GW.

Available VRE capacity in hour *h* equals the installed capacity times its capacity factor in hour *h.*

$$\text{Available VRE capacity} = PV\_CAP\_ADJ_r \times WSSPVEL\_CF_{r,y,d,m,h} + PT\_CAP\_ADJ_r \times WSSPTEL\_CF_{r,y,d,m,h} + SO\_CAP\_ADJ_r \times WSSSTEL\_CF_{r,y,d,m,h} + WN\_CAP\_ADJ_r \times WSFWIEL\_CF_{r,y,d,m,h} + WL\_CAP\_ADJ_r \times WSFWLEL\_CF_{r,y,d,m,h} + WF\_CAP\_ADJ_r \times WSFWFEL\_CF_{r,y,d,m,h}$$

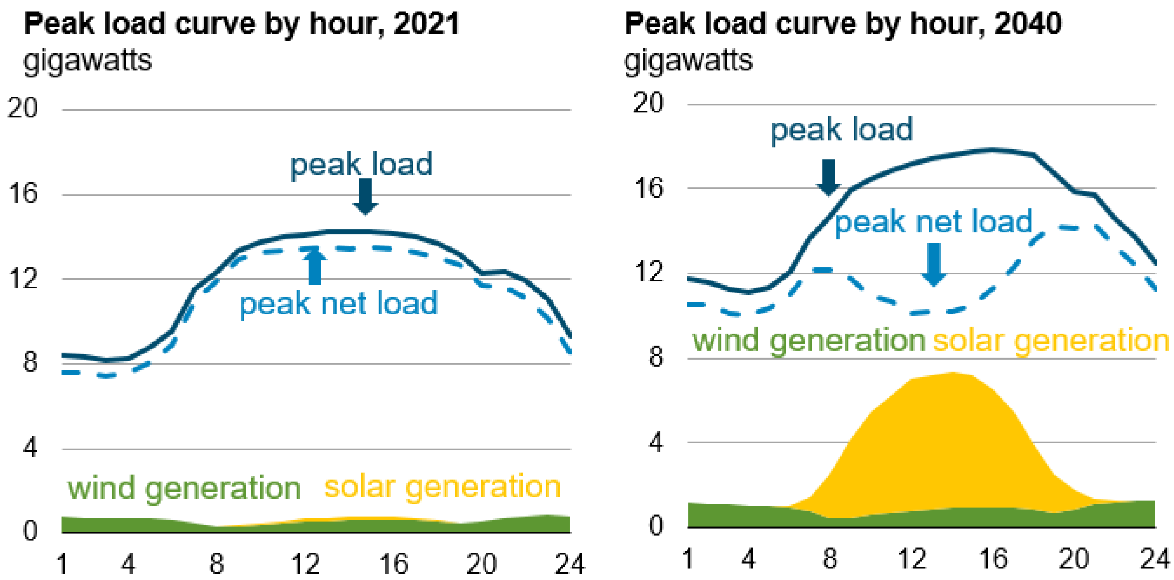
where:

$xx\_CAP\_ADJ_r$	=	Total VRE capacity by plant type adjusted so that *Actual Capacity* × *Actual CF* = *Adjusted Capacity* × *Plant Type Hourly Capacity Factor Patterns*, where xx is a two-character plant type indicator for tracking PV (PV), fixed tilt PV (PT, not currently used), concentrating solar thermal power (SO), onshore wind (WN), low-speed onshore wind (WL, not currently used), and offshore wind (WF)
$WSSxxEL\_CF_{r,y,d,m,h}$	=	Plant type hourly capacity factor patterns for solar technology types (xx as above)—input data into the Renewable Fuel Module.
$WSFxxEL\_CF_{r,y,d,m,h}$	=	[as above for wind]

Illustration of the potential shift in peak net-load within a day

In some cases, peak net-loads vary as more VRE capacity is added to the grid (Figure 1). In the example, as more solar generation is added to the system, the time of net-load peak shifts to later in the day when solar generation is less available. In practice, the time of net-load peak could shift to another season. Because many hours with similar net-loads may have significantly different VRE capacity factors, *a set of hours* is used to establish the VRE technology capacity credits rather than a single hour. Those hours in which the net-load is within a user-defined fraction from the absolute peak are also included in the set of hours.

Figure 1. Potential shift in peak net-load within a day



Source: Energy Information Administration

For each hour in this set of peak net-loads, the capacity credit for each VRE technology is computed using its capacity factor in that hour, the correlation factor of the VRE generation in a region, and total capacity of each VRE (see introduction for capacity credit calculation).

The capacity credits for each VRE are then averaged across the set of net-load peak hours. The capacity credits are weighted such that the hours closest to the net peak receive more than the hours further from the net peak. In addition, the hours are weighted by whether they occur in a weekday or weekend day and their occurrence within a month. A coefficient determines the relative weights across the hours.

For each VRE technology in each year:

$$wgt_h = daywgt * \ (net\ load_h \,/\, max\ net\ load)^{\ coeff}$$

$$cap\ credit = \frac{\sum_h credit_h * wgt_h}{\sum_h wgt_h}$$

where *h* represents each hour within a specified difference from the max net peak, the credit in hour *h* is the estimated contribution of the RE technology in the specified hour, and *daywgt* is the number of days per month of the day type in which the hour occurs.

Additional considerations

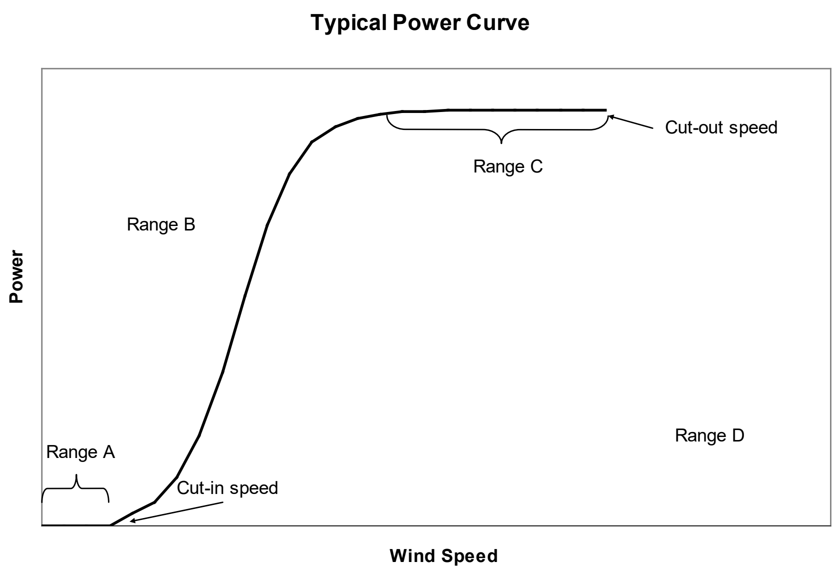
Reliability requirement

Although conventional generators do have occasional partial outages, modeling single-unit availability as a Bernoulli trial is a reasonable approximation of actual operations. The 99.999% reliability requirement is for the entire year, 24 hours a day, 7 days a week. In general, utilities are most concerned with having enough reliable capacity on-hand to meet peak-load requirements (with the working assumption that if they have enough capacity to meet peak requirements, they should have more than enough to meet off-peak requirements). A targeted reliability of 99.93% for peak-load should be sufficient to maintain reliability for all load hours—assuming an abundant excess of off-peak capacity will be available to cover both forced outages and planned maintenance. The targeted reliability is represented by the statistical parameter *Z* as previously described in the introduction section.

Wind reliability requirement

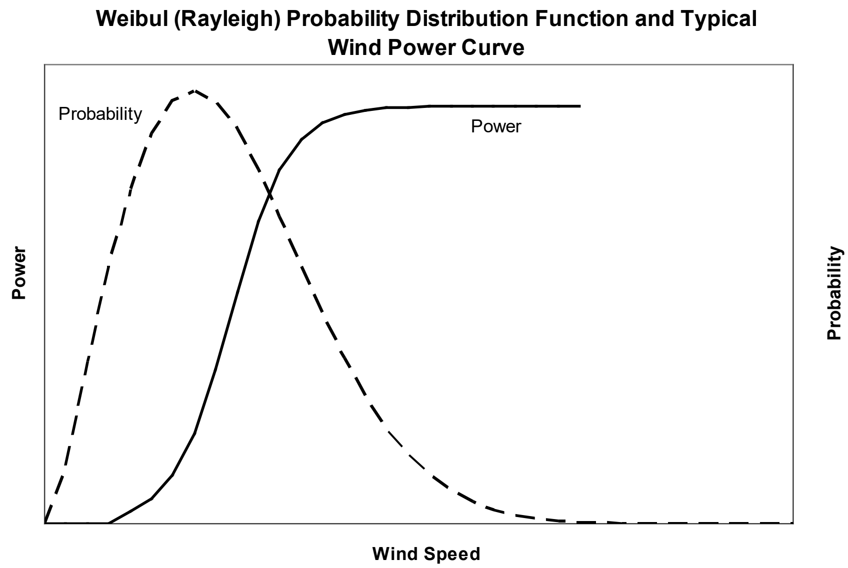
The availability of wind generation to the grid, however, cannot reasonably be modeled as an all-or-nothing event. A wind turbine may have zero output 10% or 20% of the time, when the wind is either too light to move the blades (common, shown as Range A in Figure 2) or too strong to allow the mechanism to operate without damage (rare, shown as Range D). However, 80% to 90% of the time, its output fluctuates more or less continuously as a nonlinear function of the wind speed.

Figure 2. Power output from a typical wind turbine as a function of ambient wind speed



Because wind speeds are not evenly distributed at a given site, the exact distribution of wind speeds varies from location to location. Even within a wind resource class, the Weibull distribution, with a shape parameter of about 2 (a Raleigh distribution), is frequently cited as a typical form (Figure 3). The resulting distribution of wind power output (that is, the average of the wind power curve as weighted by the Weibull probabilities at each wind speed) is not characteristic of a binomial, Weibull, or other common probability distribution. With sufficient numbers of wind plants, however, one would expect the aggregate statistical distribution of the output to assume an increasingly Gaussian form.

Figure 3. Weibull probability density function with a shape parameter of 2



Because the standard deviation of power output for a wind turbine or wind plant cannot be determined analytically, we estimate it through simulated output of a typical wind turbine power curve[4] in a Class 6 wind resource. The simulated statistical parameters for the single turbine are directly scaled up to represent the full site (assuming that, over the timeframe of interest, hourly-to-daily, all turbines in a relatively compact 50 MW site are perfectly correlated). The simulation indicates an average standard deviation is output of 38% of the nameplate capacity. For a 50 MW site, for example, the average hourly output would have a standard deviation of 19 MW. For solar resources, we assume a normalized standard deviation of 10% of nameplate capacity.

Although this assumption is reasonable when scaling up from a single turbine to a 50 MW wind farm spread over 325 square (sq) kilometers (km) of land (about 18 km by 18 km), for a region with multiple wind farms separated by hundreds of miles, it seems more reasonable to assume that the output of each farm is not perfectly correlated with the output of the other farms, at least over a time period of interest to grid reliability (one hour to one day).

Forced outage rate

In NEMS, each electric generation technology is assigned a class-typical forced outage rate. Although over 50 technology types are represented, over half are variations on coal-steam plants with different combinations of emission control technologies. The statistical outage properties for each dispatchable technology is described by the binomial distribution in the introduction section. You can find the availability parameters needed for each major capacity type grouping in the EMM in Table 2-1.

[4] Turbine power curve used in the simulation is a normalized approximation of the Vestas V-47 wind turbine. This turbine was selected because of the availability of independently verified data through the DOE/EPRI Turbine Verification Program and the substantial installed capacity base of that model in the United States. The use of the characteristics of this turbine is not an endorsement or statement of technological preference on the part of EIA.

Table 2-1. Forced outage rate by major group of NEMS capacity type

Plant type	Forced outage rate (fraction of annual hours)
Combined cycle	0.055
Coal	0.066
Nuclear	0.070
Combustion turbine	0.036
Hydro	0.036
Municipal solid waste	0.066
Other steam	0.071
Biomass	0.066
Geothermal	0.066
Intermittent*	0.036

Data source: Office of Electricity, Coal, Nuclear, and Renewable Analysis, ECPDAT file
*Not used in this calculation, intermittent capacity credit is calculated as described in text, not based on forced outage rate.

Although a typical conventional plant may have a forced outage rate of 5% (or conversely, an availability rate of 95%), we assume that utilities want to achieve an overall system availability rate of 99.999%, or an expected one hour of outage in 10 years. Achieving more than 95% system reliability for a single typical plant is not possible. What is the reliability if the system gets two completely redundant units (each capable of providing 100% load at 95% availability)? The answer is the probability that both units are operating (0.95 x 0.95=0.9025) plus the probability that Unit B is operating while Unit A is out (0.95 x 0.05=0.0475), plus the probability that Unit A is out while Unit B is operating (also 0.0475). The two-generator system achieves 99.75% availability to serve a load equal in size to the single generator. Note that simply doubling the capacity of the single unit would not improve system reliability because there would still only be a 95% chance of maintaining load (average capacity improves the same in both cases, but system reliability only improves when the number of generators is increased).

Because of the Bernoulli nature of the system, we can assume individual units of equal size and availability, and we can also assume an average availability for total capacity of 95% (or whatever the common availability is). The 99.999% availability level is then the mean available capacity minus 4.265 standard deviations (that is, 99.999% of the area under a standardized normal bell curve is within 4.265 standard deviations of the mean).

Wind power output

The regional wind power output correlation coefficient (*R* in the standard deviation for intermittent technologies) used in the model is derived from data provided by the National Renewable Energy Laboratory (NREL), using a resource data pre-processor for the Regional Energy Deployment System (ReEDS) model. You can find the parameters in Table 2-2. Note that for the solar technologies, we assume that regional correlation is relatively high, given the strong diurnal solar cycle that is consistent across regions of the size considered.

Table 2-2. Regional power correlation factors (dimensionless)

Region	Onshore wind	Offshore wind	Concentrating solar power (CSP)	Photovoltaic (PV)
1	0.89	0.89	0.7	0.7
2	0	0	0.7	0.7
3	0.84	0.84	0.7	0.7
4	0.87	0.87	0.7	0.7
5	0.74	0.74	0.7	0.7
6	0	0	0.7	0.7
7	0	0	0.7	0.7
8	0.69	0.69	0.7	0.7
9	0.87	0.87	0.7	0.7
10	0.77	0.77	0.7	0.7
11	0.73	0.73	0.7	0.7
12	0.96	0.96	0.7	0.7
13	0.55	0.55	0.7	0.7
14	0.55	0.55	0.7	0.7
15	0	0	0.7	0.7
16	0.55	0.55	0.7	0.7
17	0.89	0.89	0.7	0.7
18	0.77	0.77	0.7	0.7
19	0.86	0.86	0.7	0.7
20	0.87	0.87	0.7	0.7
21	0.77	0.77	0.7	0.7
22	0.77	0.77	0.7	0.7
23	0.87	0.87	0.7	0.7
24	0..89	0.89	0.7	0.7
25	0.87	0.87	0.7	0.7

Data source: Wind—National Renewable Energy Laboratory, Solar—estimates based on EIA expert judgment. For regional definitions, see https://www.eia.gov/outlooks/aeo/pdf/nerc_map.pdf

Although assuming a constant correlation between all sites within a region provides a simple, tractable model of these effects, it is important to note that actual intersite correlation is likely variable across space and time. Sites that are physically closer to each other will have more highly correlated outputs over shorter time spans. Sites that are more distant from each other will have lower correlation, which may only become evident over extended periods of time (seasons or years). Furthermore, this correlation is also a function of resource development. If few available wind resources have been developed, a new plant can easily be built in a location more distant (and hence, less correlated) from existing plants. As development increases, plants will eventually be built closer together, thus increasing the correlation.

3. Landfill Gas (LFG) Submodule

Model purpose

The Landfill Gas (LFG) Submodule provides the EMM with annual projections of electric power capacity of landfill-gas-to-energy plants. Starting in AEO2021, we model LFG capacity expansion as a function of gross domestic product (GDP) because LFG facilities are developed mainly to generate electricity as a useful byproduct of organic waste decomposition and as a way to reduce fugitive methane emissions from these facilities. The submodule projects the potential for the future electric power capacity from landfill gas.

We assume that no new mass burn, waste-to-energy facilities will be built and operated in the United States during the projection period, and existing mass burn, waste-to-energy facilities will continue to operate and retire as planned throughout the projection period. Overall, however, municipal solid waste (MSW) generation will increase as a result of the expansion of LFG facilities. Although these facilities use both biogenic and non-biogenic waste for electricity generation, only the biogenic portion is included in the renewable total. Although the renewable component of the waste has been diminishing, the forecast assumes it remains constant in the future.

Relationship of the LFG Submodule to other modules

The LFG Submodule passes estimates of landfill-gas-to-electricity technology capacity to the EMM to be included in capacity and generation projections. The LFG submodule also takes annual real GDP from the NEMS Macroeconomic Activity Module (MAM).

Modeling rationale

The modeling approach assumes that the LFG technology is a mature technology developed mainly as a system to recover and capture benefits from landfills methane emissions. We assume it depends entirely on the availability of landfills with greatest potential for energy recovery, which is correlated to the GDP. It depends less on the value of the resulting electricity to the grid.

Fundamental assumptions

The LFG submodule quantifies LFG generating capacity feasible to be developed based on landfill classifications[5], as provided in the U.S. Environmental Protection Agency (EPA) Landfill Methane Outreach Program (LMOP) database. New LFG generating capacity is estimated from landfills with Candidate status.[6] Landfills with Potential status[7] are included toward new LFG generation capacity only if GDP drives development at a fast pace.

We assume that only a portion of Candidate landfills will be developed into LFG projects. The share of landfill capacity available for energy recovery is estimated from LFG project development history using landfills classified as Operating or Under Construction. The share is expressed in percentage of landfill capacity. We determine the relationship between GDP growth and landfill capacity growth using

[5] U.S. Environmental Protection Agency's Project Status Definitions

[6] Includes active landfills or landfills that have been shut down for less than five years and have at least 1 million tons of waste.

[7] Includes landfills that do not meet technical criteria for Candidate status or those with potential for expansion of existing LFG capacity.

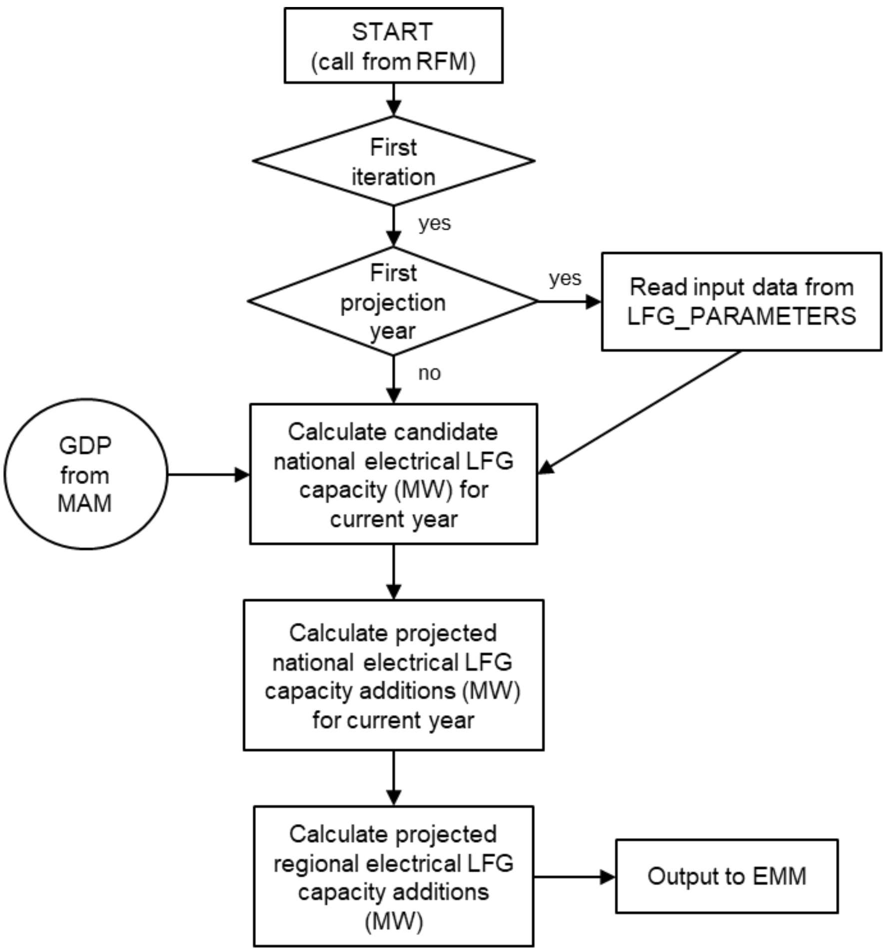
historical data of each series, and we use that to project future landfill capacity expected waste-in-place for each forecast year. We provide LFG generating capacity projection at the national level and allocate it to each EMM region based on the share of LFG generating capacity operating in each region.

LFG Submodule structure

Submodule flow diagram

This section presents a flow diagram of the LFG Submodule that shows the submodule's main computational steps and data relationships (Figure 4).

Figure 4. Landfill Gas Submodule flowchart



Appendix 3-A: Inventory of Variables, Data, and Parameters

This appendix describes the variables and data inputs associated with the LFG Submodule. You can find a tabular listing of model variables, input data, and parameters in Table 3A-1. The table contains columns with information on item definitions, modeling dimensions, data sources, and measurement units.

The remainder of Appendix 3-A consists of detailed descriptions of data inputs and variables, including discussions on supporting data assumptions and transformations.

Table 3-A1. NEMS landfill gas submodule inputs and outputs

Model variable	Definition and dimensions	Source	Units
INPUT DATA*			
*UPMCF**	Capacity factor of a LFG plant	EPRI TAG	Percent
*UPVOM**	Variable O&M cost for a LFG plant	EIA	Mills/kWh
LFG_development_periods_num	Number of years from landfill commence date to be ready for LFG project development	EIA	Year
Elec_cap_per_landfill_cap_multiple_projects	Average historical LFG generating capacity per landfill capacity (multiple projects on a single site)	EIA, EPA	Megawatts per million ton
Elec_cap_per_landfill_cap_single_project	Average historical LFG generating capacity per landfill capacity (single project on a single site)	EIA, EPA	Megawatts per million ton
Future_expansion_capacity_base_fraction	Fraction landfill capacity that will be expanded in projection years	EIA, EPA	Percent
Landfill_cap_ann_growth_rate	Landfill capacity growth rate	EIA, EPA	Percent
Landfill_cap_single_project_pct	Percentage of Candidate capacity with single project	EIA	Percent
Landfill_Cap_tot_for_LFG_last_hist_yr	Total landfill capacity available for LFG project development in last historical years	EPA	Thousand tons
LFG_GDP_ratio_reference_case	Percentage of the difference between GDP growth forecast and GDP projection	EIA, FRED	Percent
Pct_of_potential_LFG_Cap_for_Elec	Percentage of LFG landfill capacity development for electricity generation	EIA, EPA	Percent
Fraction_of_capacity_that_expands_by_future_5yr_periods	Fraction of LFG capacity after initial LFG project development in projection period	EIA	Percent
Elec_cap_expand_original	Historical capacity expansion from landfills in historical period used to	EIA	Megawatts

	develop percentage allocations for timing of expansion		
GDP_hist_growth_rate_compound_ann_pct	Historical compound annual GDP growth rate	EIA, FRED	Percent
CALCULATED VARIABLES			
GDP_AEO_GROWTH_RATE_CURRENT_YR	Real gross domestic product growth rate for year y		Percent
Landfill_Capacity_annual_for_LFG_Elec_reference	Annual landfill capacity available for LFG development in reference case		Megawatts
WIP_Cap_no_expansion_reference	Annual waste-in-place capacity (single project)		Megawatts
Cumulative_WIP_CAPACITY_expansion_only	Cumulative waste-in-place capacity (multiple projects)		Megawatts
Elec_cap_no_exapnd_candidate	LFG generating capacity from waste-in-place (single project) in year y_f		Megawatts
Elec_cap_expand_candidate	LFG generating capacity from waste-in-place (multiple projects) in year y_f		Megawatts
Elec_cap_additions_TOTAL	Total LFG generating capacity additions in year y_f		Megawatts

*Assigned in RFM input lfg_parameters.

MODEL INPUT: *UPMCF*

DEFINITION: Capacity factor for an LFG plant

SOURCE: Electric Power Research Institute, Technical Assessment Guide. EPRI TR102276S, Vol. 1: Rev. 7, Palo Alto, CA, June 1993.

MODEL INPUT: *UPVOM*

DEFINITION: Variable O&M costs for a LFG plant for EMM region *n* in year *y*

Unadjusted (excluding tipping fees) variable O&M cost for LFG plants.

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020.

MODEL INPUT: *LFG_development_periods_num*

DEFINITION: Number of LFG project development periods

SOURCE: EIA assumption

MODEL INPUT: *Elec_cap_per_landfill_cap_multiple_projects*

DEFINITION: Historical LFG generating capacity developed per landfill capacity (multiple projects on a single landfill site, MW per million ton)

SOURCE: EIA, based on U.S. Environmental Protection Agency, *Landfill Methane Outreach Program (LMOP) database* (2016)

MODEL INPUT: *Elec_cap_per_landfill_cap_single_project*

DEFINITION: Historical LFG generating capacity developed per landfill capacity (single project on a single landfill site, MW per million ton)

SOURCE: EIA, based on U.S. Environmental Protection Agency, *Landfill Methane Outreach Program (LMOP) database* (2016)

MODEL INPUT: *Future_expansion_capacity_base_fraction*

DEFINITION: Fraction of landfill capacity that will be expanded in projection years

SOURCE: EIA, based on U.S. Environmental Protection Agency, *Landfill Methane Outreach Program (LMOP) database* (2016)

MODEL INPUT: *Landfill_cap_ann_growth_rate*

DEFINITION: Landfill annual growth rate

SOURCE: EIA, based on U.S. Environmental Protection Agency, *Landfill Methane Outreach Program (LMOP) database* (2016)

MODEL INPUT: *Landfill_cap_single_project_pct*

DEFINITION: Percentage of Candidate capacity with single project

SOURCE: EIA, based on U.S. Environmental Protection Agency, *Landfill Methane Outreach Program (LMOP) database* (2016)

MODEL INPUT: *Landfill_Cap_tot_for_LFG_last_hist_yr*

DEFINITION: Total landfill capacity available for LFG project development in last historical years (thousand tonds)

SOURCE: U.S. Environmental Protection Agency, *Landfill Methane Outreach Program (LMOP) database* (2016)

MODEL INPUT: *LFG_GDP_ratio_reference_case*

DEFINITION: Percentage of the difference between GDP growth forecast and GDP projection

SOURCE: EIA, based on Federal Reserve Bank of St. Louis' Economic Database (FRED)

MODEL INPUT: *Pct_of_potential_LFG_Cap_for_Elec*

DEFINITION: Percentage of LFG landfill capacity development for electricity generation

The variable is determined from LFG project development history at landfills with Operating or Under Construction statuses. The characteristic is used to estimate future LFG generating capacity.

SOURCE: EIA analyst, based on U.S. Environmental Protection Agency, *Landfill Methane Outreach Program (LMOP) database* (2016)

MODEL INPUT: *Fraction_of_capacity_that_expands_by_future_5yr_periods*

DEFINITION: Fraction of LFG capacity after initial LFG project development in projection period

SOURCE: EIA

MODEL INPUT: *Elec_cap_expand_original*

DEFINITION: Capacity expansion from landfills in historical period (MW)

SOURCE: EIA

MODEL INPUT: *GDP_hist_growth_rate_compound_ann_pct*

DEFINITION: Historical compound annual GDP growth rate (%)

SOURCE: EIA, based on Federal Reserve Bank of St. Louis' Economic Database (FRED)

Appendix 3-B: Mathematical Description

This appendix provides the detailed mathematical specification of the LFG Submodule as presented in the RFM Fortran code.

The LFG Submodule calculates annual generating capacity as follows:

Elec_cap_additions_TOTAL = Elec_cap_expand_original + Elec_cap_expand_candidate + Elec_cap_no_expand_candidate Eq. 3B-1

where

Elec_cap_expand_original	=	Estimated generating capacity from landfills in historical period
Elec_cap_expand_candidate	=	Estimated generating capacity available from landfills that could support multiple projects
Elec_cap_no_expand_candidate	=	Estimated generating capacity available from landfills that could support single project

Appendix 3-C: Bibliography

Electric Power Research Institute, *Technical Assessment Guide.* EPRI TR-102276S, Vol. 1: Rev. 7, Palo Alto, CA, June 1993.

U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020.

U.S. Environmental Protection Agency, *Landfill Methane Outreach Program (LMOP) Database, 2016*.

Federal Reserve Bank of St. Louis, *Federal Reserve Economic Database*.

Appendix 3-D: Module Abstract

Module name

Landfill Gas Submodule

Module acronym

LFG

Description

The submodule estimates the quantity of LFG capacity available to produce projections of the production of electricity from landfill gas. Projections are disaggregated by region.

Purpose of the module

The LFG Submodule provides the NEMS EMM with annual regional projections of LFG capacity available for electricity generation. The submodule provides regional projections of electric capacity to be decremented from electric utility capacity requirements.

Most recent model update

November 2020

Part of another module

The LFG submodule is a component of the Renewable Fuels Module (RFM) of the National Energy Modeling System (NEMS).

Official module representative

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Documentation

Model Documentation Report, *Renewable Fuels Module of the National Energy Modeling System*, May 2017

Archive media and installation manual

Archived as part of the NEMS production runs

Energy system described

Generating capacity from landfill gas recovery

Coverage

- Geographic: 25 modified EMM regions
- Time unit/frequency: Annual through 2050
- Products: Generating capacity
- Economic sectors: Electric utility sector

Modeling features

- Model Structure: Sequential calculation of projected landfill gas to electricity generation, followed by derivation of regional and sector energy shares, based on estimates of the percentage of MSW combusted
- Modeling Technique: Econometric estimation of landfill capacity available for electricity generation, coupled with an energy share allocation algorithm for deriving electric generation capacity and energy quantities by region

Non-DOE input sources

U.S. Environmental Protection Agency, *Landfill Methane Outreach Program (LMOP) database*, 2016.

- Total landfill capacity available for LFG
- Landfill annual growth rate

Federal Reserve Bank of St. Louis, *Federal Reserve Economic Database*.

Electric Power Research Institute, TAG Technical Assessment Guide:

- Plant capacity factor

DOE input sources

U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020.

Independent expert reviews conducted

None

Status of evaluation efforts by sponsor

None

Appendix 3-E: Data Quality and Estimation Processes

This appendix discusses the quality of the principal sources of input data used in the LFG Submodule, along with a discussion of user-defined parameters and guidelines we used to select them.

A principal driver of the LFG projection is the estimation of the landfill capacity available for LFG project development. This process is done by examining historical LFG project development pattern and landfill status as classified by EPA and determining waste-in-place using historical GDP and landfill capacity growth rates. The weakness of this methodology is that the share of landfill capacity available for LFG development requires an assumption that the share will hold constant into the future, because historical data is much shorter than the projection horizon, when the share could be higher or lower than history.

4. Wind Energy Submodule (WES)

Module purpose

The Wind Energy Submodule (WES) contains information on U.S. regional wind energy resources and provides estimates of wind supplies by region and cost category to the Electricity Capacity Planning (ECP) component of the Electricity Market Module (EMM). We model two technologies for wind: onshore and offshore installations. The fundamental structure of the modules for onshore and offshore are very similar. This documentation will focus on the structure of the onshore technology, and it will note where the modeling of offshore resources differs.

The WES quantifies regional wind supplies by differences in average wind speed. General technology values—such as overnight capital cost, fixed operations and maintenance costs, generation subsidies, construction profiles, and optimism and learning characteristics—are input directly from the ECPDAT file in the EMM. The RFM data file RENDAT contains the short- and long-term cost adjustment factors. The combination of wind supplies and technology costs yields regional wind technology cost-supply information to the EMM.

After determining the projected new capacity builds for a given model year, the EMM provides to the WES the information on installed wind capacity. The WES then subtracts new capacity from the resource supply to determine the remaining wind resources available for future installations.

Relationship of the Wind Energy Submodule to other modules

As a submodule of the RFM, the WES receives data from and provides its output through the RFM. The WES is initiated by a call from the RFM. The RFM then provides input to and receives values from the EMM. The WES calculates values for two variable arrays for each of the onshore and offshore wind technologies modeled, which are then passed to the EMM for further processing. The calculated arrays are yearly available capacity per region and yearly capacity factors for each wind class, region, and subperiod (in other words, the slice of the load duration curve). The first array is calculated from the available land (or ocean) area divided into wind classes (average speed bins), the expected power generation per area of wind resource, and the annual capacity factor for each wind class. The second array is calculated from hourly capacity factors by month, as adjusted for estimated technology learning and surplus wind generation curtailed during hours of the year with high wind output and low demand. All other input data—such as economic life, tax life, construction profile, fixed operation and maintenance costs, the forced outage rate, and other values—are passed directly from ECPDAT to the EMM. The WES generates a wind capacity supply curve with a straightforward (deterministic) calculation from wind turbine performance projections. The uncertainties in the results are related to the technological cost and performance projections, the assumptions about the availability of wind, and other assumptions.

Modeling rationale

Theoretical approach

Wind resources are not a uniform supply for use in electricity generation. Winds vary geographically and temporally (by hour of the day and by season of the year), and factors such as access to transmission lines or site construction or access limitations show significant variation. The Wind Energy Submodule (WES) accounts for effects of these variables on wind supply in estimating the quantities of wind capacity (megawatts, or MW) available for new generating capacity in each region in each wind quality category.

All onshore cost parameters assume construction of a 200 MW wind plant (or wind farm), notionally consisting of 71 wind turbine generators, each with a rated capacity of 2.8 MW. U.S. wind plants range in size from single turbine, 1 MW (or less) installations to turbine arrays of more than 500 MW. Although wind turbine size has increased in recent years as a way of reducing plant costs, such improvements are implicitly modeled through the learning-by-doing function in the EMM, and so they are not explicitly reflected in the assumptions of the WES. Cost parameters for offshore turbines are based on a 400 MW facility, notionally consisting of 40 wind turbines each with a rated capacity of 10 MW. We assume that offshore wind developments will require a larger capacity to ensure sufficient economy of scale for installation and maintenance costs. Offshore wind also includes projects based on state-level requirements for offshore wind development. Customer-sited turbines or individual turbines and small turbine clusters connected directly to the distribution grid have significantly different costs, if not performance, characteristics than central-station facilities. Customer-sited wind turbines are modeled in the commercial and residential modules of NEMS.

The submodule begins with estimates of land area for onshore wind and of coastal area for offshore wind exhibiting specified ranges of average annual wind speed. It assumes the land-use exclusion scenario described in Appendix 4-E. The WESAREA input file contains nationwide resource data validated by the National Renewable Energy Laboratory (NREL).

The wind energy resource potential dataset for both onshore and offshore developments excludes lands assumed to be prohibited for other uses. Onshore wind energy potential includes land resources available in each of four wind quality classes (Classes 3 to 6), and offshore wind energy potential considers coastal areas with Classes 4 to 7 wind quality classes. All wind quality classes are as defined by NREL and measured at a height of 80 meters. The WES uses this data to calculate generating capacity available in each forecast year for each wind quality category, after accounting for current installed capacity. For calculating efficiencies and costs, WES also differentiates and projects regional average capacity factors by EMM load periods.

After estimating available megawatts regional capacity, the EMM uses general cost and performance values in ECPDAT and regional capacity factor values for the EMM load periods to calculate the net present value of the wind technology over its economic life. It then competes wind technology with fossil fuels and other alternative fuels in the capacity planning process.

U.S. commercial wind installations have existed since the early 1980s. Counts of these preexisting installations are used to adjust estimates of available windy land at the beginning of the NEMS model run. The WES tracks the quantity of windy land remaining by wind class that is available for future development after each run year. The module achieves this by calculating the amount of resource required to provide a given amount of wind installed capacity and subtracting that amount from the total resource available, assuming that the best economic resource (that is, highest average wind speed and closest proximity to the electric grid) is used first. The amount of resource used is then subtracted from the previous year's available amount to yield the current year's available windy land. The wind resource depletion scheme uses the lowest cost wind resource available in each region first, accounting for wind quality (as represented by wind class) and exogenously determined cost multipliers. The multipliers are established as described in *Revising the Long Term Multipliers in NEMS: Quantifying the Incremental Transmission Costs Due to Wind Power*, a 2007 report to EIA from Princeton Energy Resources International, although the data used in this estimation were updated in 2010. Distance from existing transmission, which in previous versions of NEMS was accounted for separately, is now included in the exogenous cost multipliers.

Offshore wind

The general modeling approach for offshore wind, and some key assumptions, are adopted from work done by the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy (EERE). The approach is substantially similar to the onshore model. We modified or substituted some assumptions based on EIA expert judgment and differences in EERE and EIA approaches to estimating future technology cost reductions. Resource quality (in terms of average annual wind power density) is generally more favorable offshore, although offshore performance for equivalent wind power classes is assumed to be somewhat reduced by reduced turbine availability (resulting from the more difficult maintenance challenge offshore). That is, Class 6 resources are available both onshore and offshore, but the offshore Class 6 resource has a slightly reduced capacity factor compared with the Class 6 onshore resource.[8] Like onshore resources, offshore resources are assumed to have an upwardly sloping supply curve influenced, in part, by the same factors that determine the onshore supply curve (such as distance to load centers, environmental or aesthetic concerns, variable terrain/seabed) but also explicitly by water depth. Cost reductions in the offshore technology result, in part, from learning reductions in onshore wind technology (which is a fairly mature technology) and from cost reductions unique to offshore installations.

Fundamental assumptions

WES wind capacity projections

The EMM requires capacity, performance, and cost data by EMM region. Overall technology cost and performance assumptions reside in the ECPDAT file of the EMM and not in the WES, such as:

- Capital cost

[8] As adopted by the Pacific Northwest National Laboratory in the Wind Energy Resource Atlas (http://rredc.nrel.gov/wind/pubs/atlas/tables/A-1T.html), and subsequently adopted by the National Renewable Energy Laboratory (NREL) in http://rredc.nrel.gov/wind/pubs/atlas/.

- Construction profile
- Fixed operations and maintenance costs
- Subsidies (for example, a renewable electricity production tax credit)
- Optimism and learning characteristics
- Other assumptions applicable to all regions

Values that vary by region and contribute to differences in generating costs and performance, along with the steps necessary to calculate overall cost differences for capacity decisions in EMM, are found in the WES. As in the EMM, values are provided for 25 EMM regions, excluding Alaska and Hawaii. WES also contains distinct time-of-day and monthly capacity factors for each EMM region. These capacity factors are mapped into nine load periods in the EMM, covering three seasons (winter, summer, and spring/fall) and three time-of-day periods (early morning, morning and evening, and peak).

The WES submodule converts estimates of wind supply in each EMM region to estimates of available capacity by wind quality group in three steps.

First, from the WESTECH file, WES obtains estimates of windy land and coastal areas (square kilometers) in each EMM region by wind class, all estimated at a rotor hub height of 50 meters:

Table 4-1. Wind class

Average annual wind speed	PNNL/NREL wind class
19.6 mph +	7
17.9 mph – 19.6 mph	6
16.8 –17.9 mph	5
15.7 – 16.8 mph	4
14.3 – 15.7 mph	3

Data source:

We extracted the data on land area available for wind plant development from data we produced with NREL. The WES input data exclude all:

- Environmentally protected lands (such as parks and wilderness areas)
- Lands with greater than 20% slope
- Lands known to be reserved by state or federal government that exclude wind power development (such as national parks)
- Urban lands
- Wetlands
- Airports
- Areas within 3 kilometers of otherwise excluded lands (except wetlands)
- 50% of non-ridgecrest forested lands
- Lands that do not have sufficient density of windy land to support utility-scale wind development (5 square kilometer of windy land within a 100 square kilometer area)

The development and application of the land exclusion criteria within the data are discussed in Appendix 4-E.

Second, all new technologies, including wind, are assigned an increment to capital cost to account for the cost of maintaining and expanding the transmission network. Because terrain, urbanization, and other factors affect costs, these costs are assigned in the EMM for each electric power region (Table 4-2).

Table 4-2. Transmission costs by region

Region number	Region	Transmission cost per kilowatt (1987 dollars)
1	TRE	$50
2	FRCC	$50
3	MISW	$50
4	MISC	$50
5	MISE	$75
6	MISS	$75
7	ISNE	$75
8	NYCW	$75
9	NYUP	$50
10	PJME	$50
11	PJMW	$50
12	PJMC	$50
13	PJMD	$50
14	SRCA	$50
15	SRSE	$50
16	SRCE	$50
17	SPPS	$50
18	SPPC	$50
19	SPPN	$75
20	SRSG	$75
21	CANO	$75
22	CASO	$75
23	NWPP	$75
24	RMRG	$75
25	BASN	$75

Data source: U.S. Energy Information Administration, Office of Energy Analysis, input file ECPDAT.
For regional definitions, see https://www.eia.gov/outlooks/aeo/pdf/nerc_map.pdf

Third, the WES subroutine CALMWA converts windy land areas (square kilometers) to estimates of wind energy (kilowatthours per square meter) by estimating the number of wind turbines to be placed per unit area[9] and the energy captured by each turbine. We assume an array of turbines spaced 5 rotor-diameters between turbines and 10 rotor-diameters between turbine rows. This assumption corresponds to the 6.5 MW per square kilometer power density factor we use to calculate the decrement to windy lands.

[9] This measure refers to the resource area eliminated from the wind resource base. The physical plant (turbine foundation, access roads, and associated power equipment) would occupy less than 5% of this land, and the remainder could still be useful for other activities such as agriculture or grazing.

Historical analysis of wind turbine performance for U.S. installations indicates a trend of improving capacity factors with each additional capacity increment. Detailed analysis of this apparent performance improvement is complicated by the wide variety of site-specific performance factors at each installation, but several factors could, in principle, contribute to the observed trend:

- Improvements in turbine reliability, thus ensuring that the turbines are available for generation when the wind is blowing
- Increases in rotor size and turbine height, which enable turbines to capture more consistent, higher quality winds at higher altitude
- Better micro-siting of turbines within wind farms to maximize resource capture and minimize aerodynamic interactions among turbines

Although the Betz limit[10] constrains the theoretical ultimate efficiency of a wind turbine (that is, the amount of energy captured as a fraction of total wind energy passing through the rotor disc), a wind turbine has no predetermined physical limit on its capacity factor. Because no such limit on capacity factor can be theoretically derived, the RFM allows the user to input a limiting capacity factor for each of the three wind classes modeled, based on the user's assessment of the economic trade-offs involved in turbine design and how these trade-offs are likely to be realized under future market conditions.

Typically, learning functions describe a decrease in cost as a function of cumulative units constructed or sold (sometimes in the functional form of a logarithmic decay, with each doubling of units resulting in some fractional decrease in cost). In the case of wind turbine performance, this typical functional form does not describe a process by which capacity factor increases (rather than decreases) toward some limiting level (absolutely limited to 100% but likely limited to a significantly lower fraction) with increasing cumulative capacity additions.

Learning-induced improvement in wind turbine capacity factor is assumed to asymptotically approach the user-specified capacity factor limit according to:

$$C = C_U e^{-b/G}$$

where C is the current capacity factor, C_U is the ultimate capacity factor for wind Class 6 (CFULT in the WESAREA input file), b is the decay factor, and G is the current capacity (as passed to the RFM).
The user can specify the decay factor, b, by indicating an assumed Class 6 wind capacity factor at a specified level of capacity installation. The decay factor is calculated as:

$$b = G_I \ln\left(\frac{C_I}{C_U}\right),$$

where G_I is the total installed wind capacity at some initial time I (FIXEDX in the WESAREA input file), C_I is the assumed capacity factor for Class 6 wind turbine installations at time I (CFATX in the WESAREA input file), and C_U is as above, the ultimate achievable Class 6 capacity factor. C_U must be greater than or equal to C_I.

[10] See https://energyeducation.ca/encyclopedia/Betz_limit for an explanation of the Betz limit.

Because of the wide variation observed in the capacity factor of actual wind plant installations and the uncertainty over the actual wind class each is constructed in, a reliable initial conditions measure of Class 6 capacity factor for any given year or level of installed capacity cannot be constructed. So, the user can specify the initial conditions based on the best available information or analysis.

The RFM directly calculates only the Class 6 capacity factor. Capacity factors for Class 5, 4, and 3 wind resources are scaled to the Class 6 value, based on the ultimate capacity factors specified for each class (CFULT in the WESAREA input file).

The derivation of the capacity factor learning algorithm is detailed in the report *Modeling wind and intermittent generation in the National Energy Modeling System (NEMS)*.[11]

We calculate capacity factors for each of the nine ECP load segments (three seasons, each with three time-of-day periods, as detailed in the EMM documentation) based on the capacity factor of the best available wind class in each region, as adjusted to account for surplus wind production curtailed to balance system demands during periods of high wind output and low demand. The file WESAREA provides a table of the fraction of annual hours and the fraction of total annual wind energy output in each load segment for each region. The time-specific capacity factor is calculated as:

$$C_t = C_T \frac{E_t}{H_t},$$

where C_t is the capacity factor for load segment *t*, C_T is the annual average capacity factor, E_t is the fraction of wind energy output for load segment *t*, and H_t is the fraction of annual hours in load segment *t*.

This surplus wind curtailment initially manifests itself when a high penetration of wind capacity produces higher-than-average generation during times of low system demand. Because other units, typically steam units fired by coal or nuclear fuels, may already be committed to generation during baseload hours, unexpected or especially large excess production from wind generators within a self-contained electricity supply region may require system operators to choose between cycling (turning down or off) thermal plants or curtailing wind plants (that is, shutting down some significant portion of capacity, despite available wind resource). Methodology regarding wind curtailment is available in the EMM documentation.

[11] Namovicz, C. “Modeling wind and intermittent generation in the National Energy Modeling System (NEMS).” Proceedings of WindPower 2003, Austin TX. American Wind Energy Association. May 2003.

For the reference case, the parameters for wind turbine capacity factor learning are in Table 4-3.

Table 4-3. Learning parameter for wind turbine capacity factor

	Wind class				
Variable	**Class 7**	**Class 6**	**Class 5**	**Class 4**	**Class 3**
Ultimate achievable capacity factor, *CFULT*					
Onshore	-	55%	50%	45%	40%
Offshore	58%	52%	47%	41%	-
Known capacity factor, *CFATX*					
Onshore (based on Class 6 capacity factor in 2015)	48% (all classes)				
Offshore (based on Class 7 capacity factor)	50% (all classes)				
Total installed wind capacity at which known capacity applies, *FIXEDX*					
Onshore and offshore	75 gigawatts (all classes)				
Power density of a turbine (5 × 10 rotor-diameter spacing), *PWRDEN*					
Onshore	6.5 megawatts (all classes)				
Offshore*	5 megawatts (all classes)				

Data source:
*Reflects the decreased directionality of the offshore wind resource compared with the typical inland resource.

After new wind-generating capacity is selected in the EMM, the WES decrements projected wind supplies to estimate remaining wind resources.

Cost adjustment factors

Capital costs for wind technologies increase as a function of either short-term or resource constraint cost-adjustment factors. The short-term factor in the model accounts for short-term bottlenecks in production, siting, and construction costs and is reflected in additional capital costs incurred in a specific year for all new units of U.S. wind capacity beyond a defined threshold. This adjustment is applied in the ECP and is documented in the EMM documentation. The resource constraint cost adjustment factor (also referred to as the long-term cost multiplier) is discussed below.

Rationale

Capital costs for generating technologies using wind resources are assumed to increase as a function of exhaustion of the most favorable resources. In general, capital costs are assumed to increase because of any or all of three broad conditions:

- Necessity of using less favorable natural resources
- Increasing costs of upgrading existing distribution and transmission networks—separate from costs of building an interconnection
- Increasing costs in meeting environmental concerns

As a result, each EMM region's total wind resources are parceled among five broad ranges, including an initial resource share incurring no capital cost penalty, a second share for which capital costs are assumed to increase 10%, a third share imposing increases of 25%, a fourth at 50%, and a final share (all remaining resources) for which capital costs increase 100% over initial cost. Resource proportions vary by technology and region.

Methodology

For wind, the resource-related cost adjustment factors account for the additional capital costs that are not reflected in the RFM cost characterizations. For inland wind resources, we estimate these cost adjustment factors based on work performed for EIA by Princeton Energy Resources, Inc. (PERI) and NREL, as adjusted to approximate revised regional boundaries.[12] This work specifically estimates the additional investment in transmission facilities needed to access wind resources and deliver the energy to load centers. Other factors, such as resource degradation or higher-value land uses, are implicitly included in the cost adjustment factors as well.

The cost-adjustment factors are applied on a regional basis as a function of the fraction of total resource for each relevant technology used in each of the 25 EMM regions. For each region/technology combination, the input file RENDAT allows the user to specify the start-point resource fraction and multiplier for each of the five steps. For example, if the cost of using wind resources in Region 1 is assumed to increase by 10% after 5% of the resource base has been used, then 1.1 would be entered for the cost multiplier and 0.05 would be entered for the current resource utilization fraction for the second step of the Region 1 table in RENDAT.

The resource cost multiplier is determined for each wind class based on the fraction of available windy land already used in that class. If desired, the capital cost for wind plant installation in each wind class for each year can be differentiated using a fixed ratio (using the Multiplier or Cost by Wind Class line in the WESAREA file). The default ratio is 1.0 for all years and wind classes. Based on the nine-step supply curve for each region in each year, the levelized cost of each combination of the class-specific capacity factor and class-specific resource multiplier is calculated using parameters passed from the EMM for fixed charge factor and wind cost learning. The supply steps are then ordered by cost. The supply step with the lowest levelized cost is used to establish the wind class and resource multiplier for the capacity available for that region. If the step with the lowest levelized cost does not have the minimum fraction of the previous year's regional capacity increment available (called Percent Tolerance in the WESAREA file and set as 1.0 for the current default), the lowest cost step where the cumulative available capacity meets this tolerance level is used instead. If sufficient resource is not available in any step to meet the tolerance, then the wind class, transmission adder, and resource multiplier are taken from the highest-cost step. The total capacity available for new builds in each region for each year is the lesser of the actual resource available and the maximum national wind capacity limit determined by the previous year's national capacity installations.

The short-term elasticity is determined in the EMM based on the past growth rate of wind capacity. This methodology is described in the EMM documentation.

[12] McVeigh, Jim. Revising the Long Term Multipliers in NEMS: Quantifying the Incremental Transmission Costs Due to Wind Power. Report to EIA, Princeton Energy Resources International, June 2007. Subsequent updates based on work performed by the National Renewable Energy Laboratory (NREL) for EIA in 2011.

Key computations and equations

For the first model year, the subroutine WINDIN3 is called. This routine reads in the data from the WESAREA file. Where necessary, data entered in five-year increments are linearly interpolated to produce annual values.

The subroutine WINDMISC3 is then called. This routine calculates cumulative builds and remaining windy land area in each region, wind class, and transmission buffer. The routine then determines the best wind class and buffer zone in each region based on currently available capacity factors for that wind class and region, as well as current technology costs and financial parameters passed from the EMM. The routine then calculates available capacity and capacity factors by time slice, and it determines the transmission and distribution (T&D) costs. Finally, the maximum capacity available and the amount of capacity currently used are calculated.

Subroutine WINDREPT3 writes the key parameters and calculation results to the output file WINDDBG.

Alternative approaches

NREL developed the Renewable Energy Deployment System model (ReEDS), which uses a similar capacity-planning approach as NEMS in determining expansion of grid resources. Although ReEDS lacks the robust, inter-sectoral feedbacks of NEMS, it does contain significantly more detail on the geographic and operational limitations of wind generation. Specifically, ReEDS uses a geographic information system to estimate the need for and cost of transmission capacity investment to support the development of wind resources that may be remote from load. This process also allows a somewhat higher resolution consideration of intermittency impacts on capacity credit and the need for operational reserves.

Computational run-time constraints preclude the incorporation of the full level of ReEDS detail into the NEMS wind module. To a large extent, NEMS and ReEDS have similar treatment of intermittency impacts, albeit at differing levels of detail. NEMS incorporates estimates of transmission grid expansion costs derived directly from the same geographical information system used as an input to ReEDS.[13]

Wind Energy Submodule structure

Submodule flow diagram

A flow diagram showing the main computational steps and relationships of the Wind Energy Submodule is shown in Figure 5.

Key computations and equations

Some of the input data are at five-year intervals. For the first year, a linear interpolation on these data is performed to calculate yearly values.

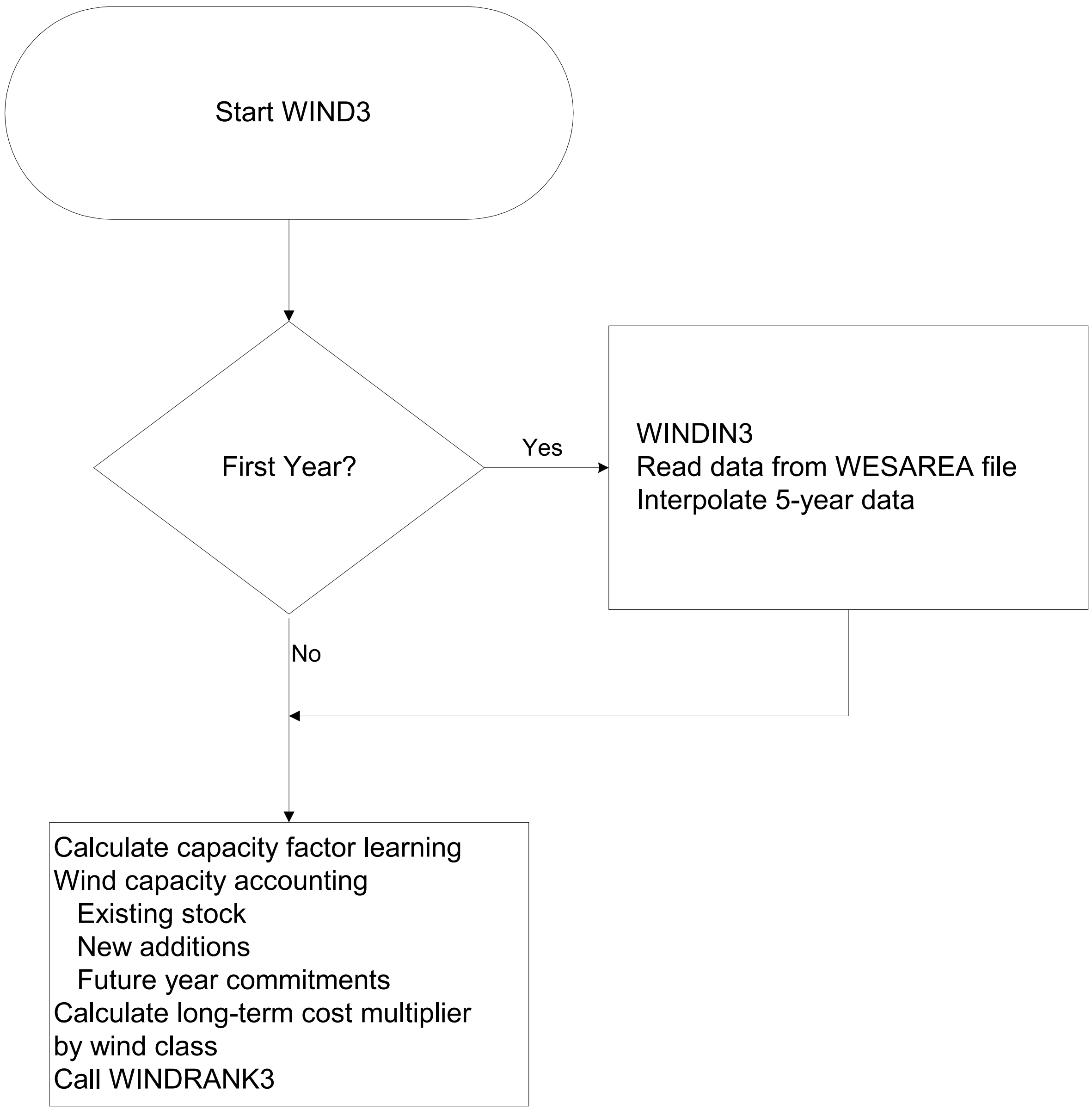
For all years after the first year, subroutine WINDMISC3 is called to calculate the land area remaining for wind energy development, based on the previous wind capacity build decision by the EMM. The

[13] This statement is valid as of AEO2011. Subsequent independent updating of either model may result in divergence of the two sets of assumptions.

previous build decision is passed as a capacity unit (MW), which must be converted into a land area required for developing a wind site of that size. The conversion method considers the wind class of the available land area that is being offered for wind development. The entire U.S. wind energy supply is subdivided into 25 EMM regions and five wind classes.

Subroutine WINDMISC3 calculates subperiod (season, time of day) regional capacity factors. For each year, the subroutine calculates the remaining available wind-generating capacity for each region. Finally, it assigns transmission and distribution cost adders for the remaining capacity in each distance zone.

Figure 5. Wind Energy Submodule flowchart



Appendix 4-A: Inventory of Variables, Data, and Parameters

This appendix describes the variables, parameter estimates, and data inputs associated with the Wind Energy Submodule. You can find a tabular listing of model variables and parameters in Table 4A-1. The table contains columns with information on item definitions, modeling dimensions, data sources, and measurement units. Because of the parallel data structures for onshore and offshore wind resources, many functionally equivalent variables are listed together. A prefix of *F* denotes the variable for offshore wind resources.

The remainder of Appendix 4-A consists of detailed descriptions of data inputs and variables, including discussions on supporting data assumptions and transformations.

Table 4A-1. NEMS wind energy submodule inputs and outputs

Model variable	Definition and dimensions	Source	Units
INPUT DATA			
CFANN, FCFNN	User specified annual capacity factor by wind class and year	No default value specified	Unitless
CFATX, FCFATX	Improvement capacity factor at initial capacity	EIA, expert judgment	Unitless
CFULT, FCFULT	Ultimate capacity factor by class	EIA, expert judgment	Unitless
CTURNDOWN, FCTURNDOWN	Minimum fraction of coal-fired capacity that must be kept running by region	EIA, expert judgment	Unitless
FIXEDX, FFIXEDX	Initial installed capacity used to determine slope of capacity factor	EIA, expert judgment	Gigawatt
ICCMETH	Method used to assign class-specific capital cost multipliers	N/A	Boolean
ICCMULT	Class-specific capital cost multipliers	No default value specified	Unitless
INTREGCRL, FINTREGCRL	Regional correlation factor for intermittent resources	EIA, expert judgment	Unitless
INTSTDDV, FINTSTDDV	Normalized standard deviation of hourly output for intermittent resource facilities	EIA, expert judgment	Unitless
NTURNDOWN, FNTURNDOWN	Minimum fraction of nuclear capacity that must be kept running by region	EIA, expert judgment	Unitless
OVERRIDECF	Switch to use user-specified capacity factors instead of capacity factor learning	N/A	Boolean
PercentTOL	Minimum wind resource required to be available to be selected as the typical wind resource for a given year	EIA, expert judgment	Unitless
PWRDEN, FPWRDEN	Power density of a 10x5 diameter turbine array	EIA, expert judgment	MW/km^2
SLICE, FSLICE	Hour fraction for subperiod *l* in EMM region *n*	NREL	Unitless

Table 4A-1. NEMS wind energy submodule inputs and outputs (cont.)

Model variable	Definition and dimensions	Source	Units
STAREA, FSTAREA	Land area available for wind plant development in EMM region *n* and wind class *w*	NREL	km^2
SUBPER, FSUBPER	Energy fraction for subperiod *l* in EMM region *n*	NREL	Unitless
UADDWNT, UADDWFT	Grid-connected onshore (UADDWNT) and offshore (UADDWFT) wind electric capacity additions in EMM region *n* in online year *y*	EMM output variable in UECPOUT COMMON block	MW
*UPCLYR**	Construction lead time	EIA expert judgment	Years
UPCPRO	Fraction of construction completed in each year of construction	EIA expert judgment	Unitless
*UPFOM**	Fixed O&M cost	EIA, 2020	$/kW
UPIRGSUB	Policy incentives for EMM region *n* in year *y*	Energy Policy Act of 1992 as amended	Mills/kWh
*UPOVR**	Installed capital cost of wind generation	EIA, 2020	$/kW
*UPVOM**	Variable O&M cost	EIA. 2020	Mills/kWh
WNTDBFCS	Additional T&D cost for wind technology in EMM region *n* and buffer zone *b*	Not used in default	$/kW
CALCULATED VARIABLES			
WCAWIEL	Available onshore capacity in EMM region *n* in year *y*	RFM output variable in WRENEW COMMON block	MW
WCAWFEL	Available offshore capacity in region onshore in year *y*	RFM output variable in WRENEW COMMON block	MW
WSFWIEL	Onshore capacity factor for EMM region *n* in year *y*, wind class *w*, and subperiod *l*	RFM output variable in WRENEW COMMON block	Unitless
WSFUFLL	Offshore capacity factor	RFM output variable in WRENEW COMMON block	Unitless
WWNTD	Additional T&D cost for onshore wind technology in EMM region *n* and year *y*	RFM output variable in WRENEW COMMON block	$/kW
WSFTD	Additional T&D cost for offshore wind	RFM output variable in WRENEW COMMON block	$/kW

Data source:
*Assigned in EMM input file ECPDAT.

MODEL INPUT: *CFANN, FCFANN*

DEFINITION: Contains overwrite values for annual capacity factor (in five-year increments) for wind classes 3 to 6, if preferred over having learning on capacity factor

SOURCE: No default input defined

MODEL INPUT: *CFATX, FCFATX*

DEFINITION: Capacity factor for Class 6 (onshore) or Class 7 (offshore) wind sites used to initialize the capacity factor learning function (unitless)

Historical analysis of wind capacity factors is complicated by the general inability to correlate individual sites with specific, independently determined wind class data. Even if a turbine can be located on a low-resolution wind resource map, such as the map NEMS uses, micro-siting issues within a wind farm can have significant effects on turbine performance. This variable is primarily intended to give a reasonable starting point for calculating future improvements to wind turbine performance and not necessarily to reflect absolute knowledge about the idealized state of wind turbine performance at a point in the historical record.

SOURCE: Form EIA-923, EIA expert judgment

MODEL INPUT: *CFULT, FCFULT*

DEFINITION: Ultimate achievable annual wind capacity factor by class (unitless)

Current wind turbine performance parameters are based on several factors. Discussions with experts from the DOE Wind Power Program and their consultants provided a general indication of recent trends and areas of expected performance increases. Analysis of wind power curves developed for the EPRI/DOE Wind Turbine Verification Program (TVP) provided a firm quantitative characterization of state-of-the-art turbine technology. Finally, analysis of historical trends provided a cross-check to these other sources. Over time, the trade-offs in the economics of increasing rotor size and tower height are expected to balance out. Improvements are assumed to occur as a result of experience in the design and construction of wind turbines.

SOURCES: EIA expert judgment based on data in Form EIA-923

MODEL INPUT: *CTURNDOWN, FCTURNDOWN*

DEFINITION: Maximum turndown limit for coal-fired capacity in a region, expressed as the minimum fraction of capacity that must be kept running

SOURCE: EIA expert judgment, following examination of PowerWorld transmission reliability data and conversations with system operators

MODEL INPUT: *FIXEDX, FFIXEDX*

DEFINITION: Installed capacity base at which variable CFATX is assumed (gigawatts, or GW)

Historical analysis of wind capacity factors is complicated by the general inability to correlate individual sites with specific, independently determined wind class data. Even if a turbine can be located on a low-resolution wind resource map, such the map NEMS uses, micro-siting issues within a wind farm can have significant effects on turbine performance. This variable is primarily intended to give a reasonable starting point for calculating future improvements to wind turbine performance and not necessarily to reflect absolute knowledge about the idealized state of wind turbine performance at a point in historical record.

SOURCES: EIA expert judgment based on Form EIA-860 data

MODEL INPUT: *ICCMETH*

DEFINITION: Method for determining incremental capital cost for wind by wind class

Cost multipliers are used with ICCMETH setting to 1, and actual capital costs are used with ICCMETH setting to 2.

SOURCE: Not used by default

MODEL INPUT: *ICCMULT*

DEFINITION: Capital cost factors for forcing capital cost for wind or differentiating capital cost by wind class

Allows for overwrite of capital cost decline factors (as a result of learning), as calculated by the EMM. The factors account for capital cost declines that can be differentiated by wind class to simulate separate technology and cost structures potentially used in each class.

SOURCE: No default input defined

MODEL INPUT: *NTURNDOWN, FNTURNDOWN*

DEFINITION: Maximum turndown limit for nuclear capacity in region, expressed as the minimum fraction of capacity that must be kept running

SOURCE: EIA expert judgment, following examination of PowerWorld transmission reliability data and conversations with system operators

MODEL INPUT: *INTSTDDV, FINTSTDDV*

DEFINITION: Standard deviation of hourly wind plant output within a region

Default setting of 38% of nameplate capacity is based on our simulation of a generic 1 MW turbine, assuming a Rayleigh distribution of wind resource in a Class 5 area. The standard deviation is assumed to scale to a 100 MW size, which assumes perfect correlation among turbines on an hourly basis within a 100 MW wind farm.

SOURCE: Internal EIA calculation based on simulated performance of a state-of-the-art wind turbine.

Analysis of wind power curves developed for the EPRI/DOE Wind Turbine Verification Program (TVP) provide a firm quantitative characterization of state-of-the-art turbine technology.

MODEL INPUT: *INTREGCRL, FINTREGCRL*

DEFINITION: Correlation coefficient of hourly wind output for wind turbines within a region (that is, the average correlation between the output of two turbines within the region)

Appendix 1-A of this document contains further derivation of this approximation and of the correlation coefficients used as default values.

SOURCE: EIA expert judgment (Appendix 1-A)

MODEL INPUT: *OVERRIDECF*

DEFINITION: Switch to overwrite capacity factor learning with user-specified capacity factors

SOURCE: Not used by default

MODEL INPUT: *PercentTOL*

DEFINITION: Minimum wind resource that must be available within a region, wind class, and transmission buffer for the region and wind class to be selected as the typical wind resource for a given year, expressed as a fraction of previous years' regional wind capacity installations

SOURCE: EIA expert judgment

MODEL INPUT: *PWRDEN, FPWRDEN*

DEFINITION: Specific power density of an average wind plant (MW per square kilometer)

This input is primarily used within the WES to convert projected measure of available area of windy land to available MW of wind resource and to decrement the available land area based on model builds. Although power efficiency varies somewhat from turbine model to turbine model, this factor is mostly a function of inter-turbine spacing within the turbine array. Some U.S. installations are placed on ridgelines and may have a linear arrangement with relatively tight lateral turbine spacing; however, the factor used here must consider more extensive exploitation of wind resources where the turbines would be placed in more rectangular arrays. The current assumption of 6.5 MW per square kilometer for onshore wind is consistent with spacing estimates from the Pacific Northwest Laboratory (PNL) that provides the WES wind resource and the performance estimates from DOE and EPRI.

SOURCES: EIA expert judgment

U.S. Department of Energy and Electric Power Research Institute. Renewable Energy Technology Characterizations. https://www.nrel.gov/docs/gen/fy98/24496.pdf

Elliott, D.L. et al. "An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States." August 1991. Pacific Northwest Laboratory. PNL-7789.

MODEL INPUT: *SLICE, FSLICE*

DEFINITION: Hour fraction for subperiod *l* in EMM region *n* (unitless)

Data for 20 subperiods of the year are provided. The EMM maps these data for 20 subperiods into nine subperiods used in the EMM and other NEMS modules. SLICE uses established NEMS subperiod definitions, daily and seasonal wind resource data, and a synthetic wind turbine power curve to estimate the fraction of the annual wind energy production that falls within the various subperiods.

SOURCE: National Renewable Energy Laboratory, work performed for EIA

MODEL INPUT: *STAREA, FSTAREA*

DEFINITION: Land area available for wind plant development in EMM region *n* and wind class *w* (sq. km)

SOURCE: National Renewable Energy Laboratory, work performed for EIA

MODEL INPUT: SUBPER, FSUBPER

DEFINITION: Wind energy fraction for subperiod *l* in EMM region *n* (unitless)

SOURCES: National Renewable Energy Laboratory, work performed for EIA

MODEL INPUT: *UADDWNT, UADDWFT*

DEFINITION: Total grid-connected wind electric capacity additions in EMM region *n* in online year *y* (MW)

SOURCE: EMM output variable in UECPOUT COMMON block

MODEL INPUT: *UPCLYR*

DEFINITION: Construction lead-time (years)

The construction period for a wind-generating station is currently set at three years.

SOURCE: EIA, expert judgment following discussions with industry, government, and national laboratory sources

MODEL INPUT: *UPCPRO*

DEFINITION: Fraction of construction completed in each year of construction (unitless)

The construction period for a new wind-generating station is currently set at three years, with most capital costs allocated in the annual proportion of 5% in the first year, 10% in the second year, and 85% in the final year.

SOURCE: EIA, expert judgment following discussions with industry, government, and national laboratory sources

MODEL INPUT: *UPFOM*

DEFINITION: Fixed O&M costs (dollars per kilowatt, or $/kW)

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020

MODEL INPUT: *UPOVR*

DEFINITION: Installed capital cost of wind generation ($/kW) in year *y*

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020

MODEL INPUT: *UPVOM*

DEFINITION: Variable O&M costs for EMM region n in year *y* at five-year intervals (mills per kilowatthour) (variable O&M costs are currently set at zero)

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020

MODEL INPUT: *WNTDBFCS*

DEFINITION: Additional T&D cost for wind development averaged for sites in buffer zone b and EMM region n ($/kW)

This input is not used in the current default version of NEMS. This factor is now expressly incorporated into the long-term cost adjustment factor.

SOURCES: Science Applications International Corporation, “Geographic Information System Analysis,” Report for EIA, Office of Integrated Analysis and Forecasting. May, 1995

U.S. Energy Information Administration, Washington, DC, September 1994. “Electric Trade in the United States 1992.” Table 42: Transmission Lines Added by Investor-Owned Utilities, 1992. DOE/EIA 0531 (92)

Bonneville Power Administration. “Transmission Line Estimating Data.” Internal Memorandum. BPA F 1325.01.e, December 3, 1993

Appendix 4-B: Mathematical Description

This appendix provides the detailed mathematical specification of the Wind Energy Submodule as presented in the RFM FORTRAN code execution sequence. Subscript definitions are also as they appear in the FORTRAN code.

Two variables are calculated in the WES for each of the onshore and offshore wind technologies modeled. The first array is calculated from the available land (or ocean) area divided into wind classes (average speed bins), the expected power generation per area of wind resource, and the annual capacity factor for each wind class. The second array is calculated from hourly capacity factors by month as adjusted for estimated technology learning and surplus wind generation curtailed during hours of the year with high wind output and low demand.

Equation 4B-1 calculates the land area (in sq. km) needed to supply the wind-generating capacity called for by the EMM for each EMM region and current year:

$$LDUSED_{n,y} = \frac{UADDWNT_{n,y+lead} \times CF_{y,w} \times 8760 \times \alpha_{sp}}{AREA_{y,w} \times \pi/4} \qquad \text{Eq. 4B-1}$$

where

$LDUSED_{n,y}$	=	Land area used to supply EMM-called-for wind-generating capacity in EMM region *n* in decision year *y*, in square kilometer;
$UADDWNT_{n,y+lead}$	=	Grid-connected wind electric capacity additions in EMM region *n* decision year *y+LEAD* in MW;
LEAD	=	Construction lead time, in years (decision year + lead time = online year);
$CF_{y,w}$	=	Annual capacity factor for wind class *w* in year *y*;
8760	=	The number of hours in a year;
$AREA_{y,w}$	=	Energy per unit swept rotor area for wind class *w* in decision year *y*, in kilowatthour per square meter;
π	=	3.141593; and
α_{sp}	=	Scalar derived from 5 by 10 rotor-diameter grid spacing of wind generator (see page 36) and is equal to 50.

Equation 4B-2 subtracts the land area needed to supply the wind-generating capacity called for by the EMM from the available land area:

$$LDAREA_{n,y,wc,bc} = LDAREA_{n,y-1,wc,bc} - LDUSED_{n,y} \qquad \text{Eq. 4B-2}$$

where

$LDAREA_{n,y,w,bc}$ = land area available for wind development in EMM region *n,* in year *y*, in currently offered wind class *w* and buffer zone *bc,* in square kilometers.

Equation 3B-4 computes the total swept area by turbines for a particular wind class, EMM region, and year:

$$SWAREA_{n,y,wc} = \frac{\frac{\pi}{4} * LDAREA_{n,y,wc,bc} * 10^6}{\alpha_{sp}} \qquad \text{Eq. 4B-4}$$

where

$SWAREA_{n,y,wc}$ = Swept rotor area available for currently offered wind class *wc* in EMM region *n* in year *y*, in square meters;

$LDAREA_{n,y,w,bc}$ = land area available for wind development in EMM region *n,* in year *y*, in currently offered wind class *w* and buffer zone *bc,* in square kilometers; and

α_{sp} = Scalar derived from 5 by 10 rotor-diameter grid spacing of wind generator (α_{sp} = 50).

Equation 3B-5 computes the available wind electric generation capacity (megawatts) in the best wind class and best access to transmission:

$$WCAWIEL_{n,y,w} = \frac{AREA_{y,wc} \times SWAREA_{n,y,wc}}{CF_{y,wc} \times 10^3 \times 8760} \qquad \text{Eq. 4B-5}$$

where

$WCAWIEL_{n,y}$ = Available capacity in EMM region *n* in year *y*, MW.

Subroutine WNDECR decrements the projected wind resources that are subdivided by wind classes and buffer zones according to an estimate of the least-cost combination of wind class and buffer zone. As wind resources in a given region are used, the model estimates the cost of the remaining resources based on capacity factor (a function of wind class) and any applicable adjustments to capital cost (long-term cost multipliers or, if used, buffer zones) and re-ranks the estimates of available resources to provide to the EMM.

Equation 3B-6 assigns the wind-specific T&D cost associated with wind resources of the buffer zone currently offered:

$$WWNTD_{n,y} = WNTDBFCS_{n,bc}$$

where

$WWNTD_{n,y}$	=	Wind specific T&D cost in EMM region *n* in year *y*, in dollars per kilowatt ($/kW); and
$WNTDBFCS_{n,bc}$	=	Wind specific T&D cost in EMM region *n* in currently offered buffer zone *bc,* ($/kW).

The capacity factors for wind must be adjusted to account for the probability of wind curtailment with increasing wind penetration. Equation 3B-7 computes the capacity factor in a particular load segment as adjusted for estimated learning and wind curtailment:

$$WSFWIEL\_CF_{n,y,t} = \frac{FullWn_{n,y,t} - ExcessWn_{n,y,t}}{Instwind_{n,y}} \qquad \text{Eq. 4B-7}$$

where

$WSFWIEL\_CF_{n,y,t}$	=	Adjusted capacity factor in EMM region *n* in year *y* during load segment *t*;
$FullWn_{n,y,t}$	=	Total wind energy output in EMM region *n* in year *y* during load segment *t* without curtailment;
$ExcessWn_{n,y,t}$	=	Wind energy curtailed in EMM region *n* in year *y* during load segment *t*; and
$Instwind_{n,y}$	=	Installed wind capacity in EMM region *n* in year *y*.

Appendix 4-C: Bibliography

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Appendix 4-D: Module Abstract

Module name

Wind Energy Submodule

Module acronym

WES

Description

Resource quality data and the yearly capacity factor are used to calculate wind farm performance data on a sub-yearly level, as required by the EMM. Calculations are made for each time slice, wind class, and region.

Purpose of the module

The Wind Energy Submodule (WES) projects the cost, performance, and availability of wind-generated electricity and provides this information to the Electricity Capacity Planning (ECP) component of the Electric Market Module (EMM) for projecting new wind capacity builds that will compete with other sources of electricity generation.

Most recent module update

October 2021

Part of another module

The Wind Energy Submodule is a component of the Renewable Fuels Module (RFM) of the National Energy Modeling System (NEMS).

Official module representative

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Documentation

NEMS Documentation Report: R*enewable Fuels Module of the National Energy Modeling System*, June 2022

Archive media and installation manual

Archived as part of the NEMS production runs

Energy system described

A hybrid of various existing and proposed horizontal axis wind turbines for both onshore and offshore application

Coverage

- Geographic: 25 EMM regions
- Time/unit frequency: Annual through 2050
- Product: Electricity
- Economic sectors: Electric utility sector, nonutility generators (NUGS)

Modeling features

- Model Structure: Sequential calculation of available wind capacity by EMM region, wind class, and year with a deduction of each projection year's installed capacity from the remaining available capacity
- Modeling Techniques: Accounting function of available windy land area and conversion of land area to swept rotor area and then to available generation capacity, taking system reliability effects into account
- Special Features: Accounting for policy incentives, production incentives, or both

DOE input sources:

U.S. Energy Information Administration, *Annual Energy Review*.

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National Renewable Energy Laboratory, Renewable Energy Deployment System (ReEDS) data pre-processor.

Non-DOE input sources

None

Independent expert reviews conducted

None

Status of evaluation efforts by sponsor

None

Appendix 4-E: Data Quality and Estimation Processes

This appendix discusses the quality of the principal sources of input data used in the Wind Energy Submodule, along with the user-defined parameters and guidelines used to select them, and the estimation methods used to derive parameters.

The Pacific Northwest National Laboratory (PNNL) has extensively charted and classified the wind resources of the United States[14] , and the National Renewable Energy Laboratory (NREL) is working to refine these estimates based on modern computer modeling and geographic information systems (GIS) techniques. Four classes of wind resources, based on average annual wind speeds, are generally used. These classes correspond to PNL Class 3 winds and higher (speeds greater than 5.1 meters per second, or 11.5 miles per hour), which represent the assumed lowest economic limit of wind speeds for grid-connected systems in the United States.

Data on wind resource quantity are maintained in the *WESAREA* input file. It contains regional data on the land area (in square kilometers) estimated to be available for wind plant development, accounting for the exclusion of some land as a result of legal, environmental, and land-use considerations. The methodology for these exclusions was developed with the assistance of wind resource modelers, meteorological consultants, the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, EIA, and NREL, based on previous versions of the NEMS wind resource data. The criteria are applied to data developed and collected by NREL include:

- 100% exclusions of areas with slope greater than 20% (updated data) or application of terrain exposure factor (1987 data)
- Environmental exclusions
- 100% exclusion of all National Park Service and Fish and Wildlife Service lands
- 100% exclusion of federal lands with a specific designation that seem incompatible with wind development (parks, wilderness, wilderness study area, wildlife refuge, wildlife area, recreation area, battlefield, monument, conservation areas, and wild and scenic rivers)
- 100% exclusion of state parks and conservation areas
- 50% exclusion of remaining Forest Service, Department of Defense, and state forest lands
- Land use exclusions
- 100% exclusion of water, wetlands, urban areas and airports/airfields
- 50% exclusion of non-ridge crest forest
- 100% exclusion of a 3 kilometer area surrounding 100% environmental and land use exclusions, except water exclusion
- Minimum density criteria of 5 square kilometers per 100 square kilometers of class 3 or better wind resource, after the 100% exclusions have been applied

The WESAREA input file describes the variations in wind resource on a daily and seasonal basis, and it estimates wind output during the different load condition subperiods to analyze the correlation with load profiles. NREL developed the data for this file for EIA. The file also contains information on Load Duration Curve (LDC) subperiod definitions outside of the WES and the subperiod energy percentages.

[14] See Elliott, 1986, in the Bibliography section of Appendix 4-C

From this information, WES estimates a capacity factor for a given subperiod. The specific subperiods correspond to seasons and times of day.

Data on the cost of installed wind turbines are based on a comprehensive report we published in 2020 that evaluated, on a consistent basis, the capital cost of a wide variety of electricity generation technologies. We achieved further validation of the estimates for wind energy technologies through peer review of the source data, as well as by a review of publicly available reports.

Data on the performance of wind turbines installed in the United States extend back to the mid-1980s. Estimates we used in NEMS result from analyzing historical performance of U.S. wind-generating stock, and we based capacity factor estimates for each wind class on a binning analysis of the observed capacity factor performance for plants in service and reporting generation data for each month of 2014.[15] Estimates for future capacity factor improvements are based on EIA analyst judgment from an analysis of vintage-wise performance from the historical record.

[15] Based on data collected in the Form EIA-923 and predecessor forms. See http://www.eia.gov/cneaf/electricity/page/eia906_920.html. Additional validation of these trends can be found in Wiser, et al., 2014 Wind Technologies Market Report. Lawrence Berkeley National Laboratory. August 2015. https://emp.lbl.gov/publications/2014-wind-technologies-market-report.

5. Solar Energy Submodule (SES)

Model purpose

The Solar Energy Submodule (SES) estimates supply characteristics for grid-connected central station photovoltaic (PV) and concentrating solar-thermal power (CSP) electricity-generating power plants. The representative PV technology is a 150 MW system with a single-axis tracking, flat-plate array tilted at an angle equal to the site's latitude. Starting in AEO2021, we also model the same PV system but with dedicated or co-located 200 MWh (4 hours of 50 MW output) DC-coupled lithium-ion battery storage system. The default CSP technology is a 100 MW solar-only central receiver (power tower) with a partial-load natural gas boiler for the startup cycle and temporary cloudy periods (no integrated storage). SES does not characterize distributed or off-grid solar technologies.

PV and CSP cost and performance characteristics, which are defined consistently with fossil-fuel and other generating technology characteristics, reside in ECPDAT in the Electricity Capacity Planning (ECP) Submodule of the EMM. Performance characteristics unique to these technologies (such as month- and region-dependent capacity factors), however, are passed to the EMM from the SES. Because solar radiation varies, capacity factors for solar technologies are assumed to vary by time of day, by month, and by region. Factors are provided for all regions for PV. Capacity factors for solar thermal are only provided for the regions with sufficient direct normal insolation to support potentially cost-effective solar thermal installations, including the following EMM regions:

Table 5-1. Concentrating solar-thermal power model regions

Region number	Region acronym	Region description
1	TRE	Texas
2	FRCC	Florida
17	SPPS	Southern Great Plains
18	SPPC	Central Great Plains
19	SPPN	Northern Great Plains
20	SRSG	Southwest
21	CANO	Northern California
22	CASO	Southern California
23	NWPP	Northwest
24	RMRG	Rockies
25	BASN	Basin

Data source:

Relationship of the SES to other modules

SES assigns performance data to global variables the EMM will use. SES does not interact with other submodules of the RFM or NEMS.

Modeling rationale

Theoretical approach

Given that the PV and CSP solar electric technologies generate electricity in fundamentally different ways, the nature of the solar resource for each technology is significantly different. The most important difference is the nature of the solar radiation (insolation) that each technology uses. CSP technology can use only direct normal insolation, but PV can use both direct and diffuse insolation. Direct normal insolation is defined as sunlight arriving at a location in a path directly from the sun onto a surface without being scattered or reflected. Diffuse insolation is sunlight that has been scattered by clouds, fog, haze, dust, or other substances in the atmosphere and arrives at a location indirectly. The sum of direct normal and diffuse insolation is also referred to as global insolation.

Accordingly, capital and O&M costs and the efficiency in converting sunlight into electric energy are held constant across regions. Differences in regional resources are captured through the capacity factor variable that represents the solar energy input to the technology.

Fundamental assumptions

The regional classification plan is the same for CSP and both PV systems. As an input to EMM, SES operates on the same 25 regions as EMM, which for the most part correspond to regions or subregions of the Regional Transmission Organizations (RTO) or Independent System Operators (ISO).

SES contains distinct time-of-day and monthly capacity factors for each EMM region for both CSP and PV, where applicable. The capacity factors are calculated based on our analysis of the solar irradiance database developed by NREL, using the System Advisor Model (SAM). For solar-battery hybrid system, the hours in which the battery charges from the co-located PV and discharges back to the grid are assumed fixed and determined exogenously to the EMM model by the SAM model.

Short-term cost adjustment factors

Both PV and CSP technologies are subject to short-term capital cost adjustment factors, so large annual increases in capacity are assumed to raise costs because of supply bottlenecks. No resource constraint cost, however, is associated with solar-generating technologies as it is for wind-generating technologies.

SES structure

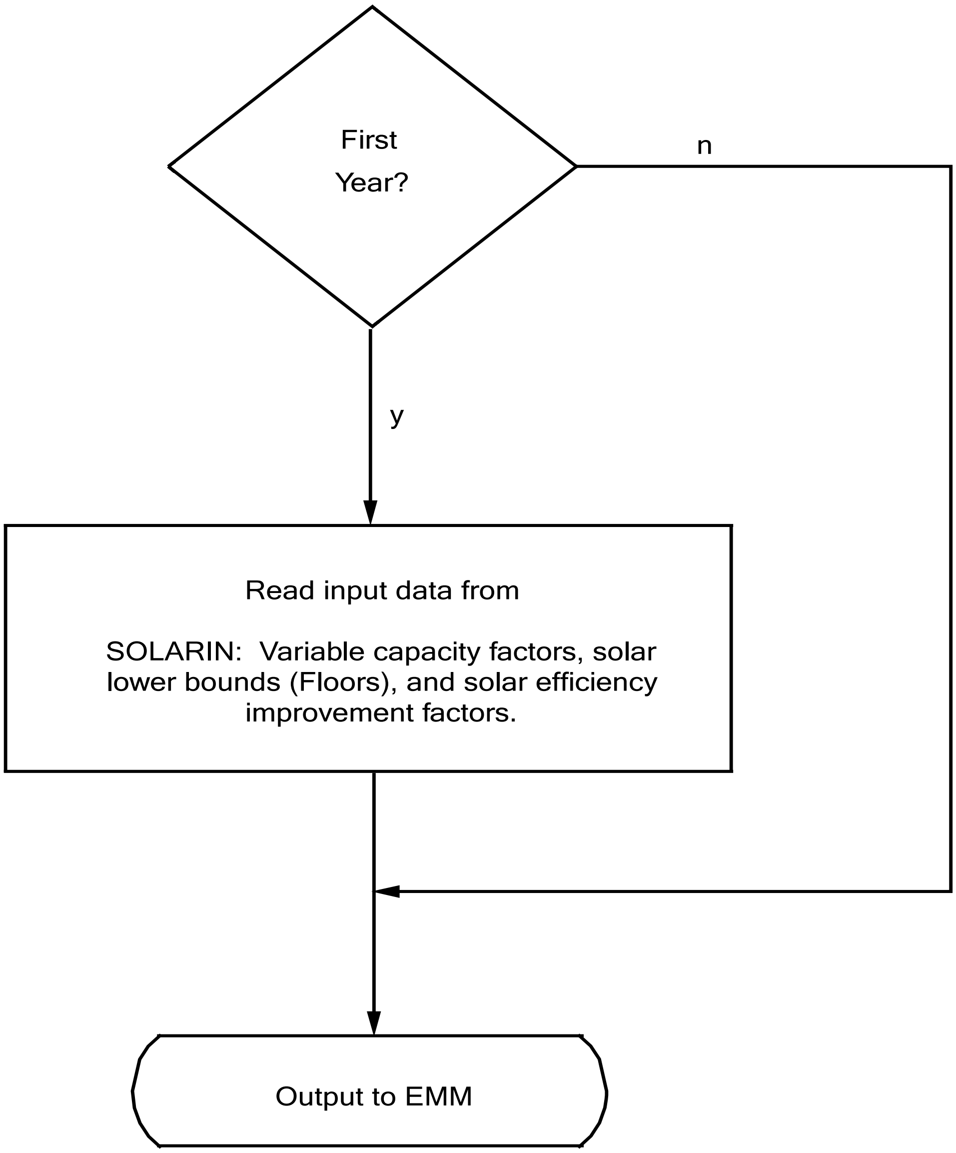
Submodule flow diagram

You can find a flow diagram showing the main computational steps and relationships of the SES in Figure 6.

Key computations and equations

SES passes data to EMM directly, without any computations, through assignments to the appropriate COMMON variables, which are the utility-generating capacities and subperiod capacity factors for each technology.

Figure 6. Solar Energy Submodule flowchart



Appendix 5-A: Inventory of Variables, Data, and Parameters

This appendix describes the variables, data inputs, and parameter estimates associated with the cost and performance characteristics of the two solar technologies. Standalone solar PV, solar PV-battery hybrid, and CSP cost and performance characteristics that are defined consistently with fossil-fuel and other generating technology characteristics reside in ECPDAT. Performance characteristics unique to these technologies (such as season and region-dependent capacity factors), however, are passed to the EMM from the solar submodule SOLAR.

You can find a tabular listing of model variables and parameters in Table 5A-1. The table contains columns with information on item definitions, data sources, and measurement units.

The remainder of Appendix 5-A consists of detailed descriptions of data inputs and variables, including discussions on supporting data assumptions and transformations.

Table 5A-1. NEMS solar module inputs and outputs

Model variable	Definition and dimensions	Source	Units
INPUT DATA			
EFFMULPV	Efficiency multiplier for standalone photovoltaic technology (currently set to 1)	EIA, expert judgment	Unitless
EFFMULPT	Efficiency multiplier for photovoltaic-battery storage hybrid system (currently set to 1)	EIA, expert judgment	Unitless
EFFMULST	Efficiency multiplier for solar thermal technology (currently set to 1)	EIA, expert judgment	Unitless
*UPCLYR**	Construction period	EIA, expert judgment	Years
*UPCPRO**	Completion fraction	EIA, expert judgment	Percent
*UPFOM**	Fixed O&M cost for concentrating solar power technology	EIA, 2020	Mills/kW
*UPFOM**	Fixed O&M cost for standalone photovoltaic technology	EIA, 2020	Mills/kW
*UPFOM**	Fixed O&M cost for photovoltaic-battery storage hybrid technology	EIA, 2020	Mills/kW
*UPOVR **	Capital cost of concentrating solar power technology	EIA, 2020	$/kW
*UPOVR **	Capital cost of standalone photovoltaic technology	EIA, 2020	$/kW
*UPOVR**	Capital cost of photovoltaic-battery storage hybrid technology	EIA, 2020	$/kW
*UPVOM **	Variable O&M cost for concentrating solar power technology	EIA, 2020	Mills/kWh
*UPVOM**	Variable O&M cost for standalone photovoltaic technology	EIA, 2020	Mills/kWh
*UPVOM**	Variable O&M cost for photovoltaic-battery storage hybrid technology	EIA, 2020	Mills/kWh
WCAPTEL	Capacity constraints for photovoltaic-battery storage hybrid technology in EMM region *n* in year *y*	EIA estimates	MW
WCAPVEL	Capacity constraints for photovoltaic technology in EMM region *n* in year *y*	EIA Estimates	MW
WCASTEL	Capacity constraints for solar thermal technology in EMM region *n* in year *y*	EIA Estimates	MW
WSSPTEL_CF	Prototype photovoltaic-battery storage hybrid system capacity factor for EMM region *n* in hour *h*, daytype *d*, month *m* in year *y*	NREL, 2021	Percent

WSSPVEL_CF	Prototype standalone photovoltaic system capacity factor for EMM region *n* in hour *h*, daytype *d*, month *m* in year *y*	NREL, 2021	Percent
WSSSTEL_CF	Prototype concentrating solar power system capacity factor for EMM region *n* in hour *h*, daytype *d*, month *m* in year *y*	NREL, 2021	Percent

*Assigned in EMM input file ECPDAT.

MODEL INPUT: *EFFMULPV*

DEFINITION: Standalone solar PV efficiency improvement factors

The efficiency multiplier with values greater than 1.0 allows SES to model system improvements that increase the capacity factor. The current efficiency multiplier is assumed to be 1.0 for all years. Not all efficiency improvements are captured in this variable. For example, improvements in PV cell conversion efficiency are reflected in the capital cost variable.

SOURCE: EIA, expert judgment following discussions with industry, government, and national laboratory sources

MODEL INPUT: *EFFMULPT*

DEFINITION: Solar PV-battery storage hybrid efficiency improvement factors

The efficiency multiplier with values greater than 1.0 allows SES to model system improvements that increase the capacity factor. The current efficiency multiplier is assumed to be 1.0 for all years. Not all efficiency improvements are captured in this variable. For example, improvements in PV cell conversion efficiency are reflected in the capital cost variable.

SOURCE: EIA, expert judgment following discussions with industry, government, and national laboratory sources

MODEL INPUT: *EFFMULST*

DEFINITION: Concentrating solar power efficiency improvement factors

The efficiency multiplier with values greater than 1.0 allows modeling system improvements that increase the capacity factor by using lower energy solar insolation. The current efficiency multiplier is assumed to be 1.0 for all years.

SOURCE: EIA, expert judgment following discussions with industry, government, and national laboratory sources.

MODEL INPUT: *UPCLYR*

DEFINITION: Construction period of technology *t*, years

The construction period for a PV facility is assumed to be two years

SOURCES: EIA, expert judgment following discussions with industry, government, and national laboratory sources

MODEL INPUT: *UPCPRO*

DEFINITION: Fraction of construction of technology *t* completed in year *y* (percent)

The model assumes new solar plants are constructed over a two-year period with most capital costs allocated in the annual proportions of 10% in the first year and 90% in the final year.

SOURCES: EIA, expert judgment following discussions with industry, government, and national laboratory sources

MODEL INPUT: *UPFOM (77)*

DEFINITION: Fixed O&M cost for photovoltaic-battery storage hybrid technology in EMM region *n* and year y ($/kW.

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020

MODEL INPUT: *UPFOM (76)*

DEFINITION: Fixed O&M cost for standalone photovoltaic technology in EMM region *n* and year y ($/kW)

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020

MODEL INPUT: *UPFOM (73)*

DEFINITION: Fixed O&M cost for concentrating solar power technology in EMM region *n* and year *y* ($/kW)

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020

MODEL INPUT: *UPOVR (77)*

DEFINITION: Capital cost for PV-battery storage hybrid technology in EMM region *n* and year *y* ($/kW)

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020

MODEL INPUT: *UPOVR (76)*

DEFINITION: Capital cost for standalone PV technology in EMM region *n* and year *y* ($/kW)

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020

MODEL INPUT: *UPOVR (73)*

DEFINITION: Capital cost for CSP technology in EMM region *n* and year *y* ($/kW)

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020

MODEL INPUT: *UPVOM (77)*

DEFINITION: Variable O&M costs for PV-battery storage hybrid in EMM region *n* and year *y*

The variable O&M costs for the PV-battery storage hybrid technology are set to zero for all EMM regions and all years.

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020

MODEL INPUT: *UPVOM (76)*

DEFINITION: Variable O&M costs for PV in EMM region *n* and year *y*

The variable O&M costs for the standalone PV technology are set to zero for all EMM regions and all years.

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020

MODEL INPUT: *UPVOM (73)*

DEFINITION: Variable O&M costs for CSP in EMM region *n* and year *y*

The variable O&M costs for the CSP technology are set to zero for all EMM regions and all years.

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020

MODEL INPUT: *WCAPTEL*

DEFINITION: Constraint for PV-battery storage capacity resource in EMM region *n*; and year *y* (MW)

The variable can be used to set minimum or maximum capacity constraints for PV on a regional and yearly basis, but it is not currently used to do either.

SOURCE: EIA, expert judgment following discussions with industry, government, and national laboratory sources

MODEL INPUT: *WCAPVEL*

DEFINITION: Constraint for standalone PV capacity resource in EMM region *n*; and year *y* (MW)

The variable can be used to set minimum or maximum capacity constraints for PV on a regional and yearly basis, but it is not currently used to do either.

SOURCE: EIA, expert judgment following discussions with industry, government, and national laboratory sources

MODEL INPUT: *WCASTEL*

DEFINITION: Constraint for concentrating solar power capacity resource in EMM region *n* and year *y* (MW)

The variable can be used to set minimum or maximum capacity constraints for CSP on a regional and yearly basis, but it is not currently used to do either.

SOURCE: EIA, expert judgment following discussions with industry, government, and national laboratory sources

MODEL INPUT: *WSSPTEL_CF*

DEFINITION: Time segment system capacity factor for PV-battery storage hybrid in EMM region *n* in hour h, daytype *d*, month *m* in year *y* (percent)

SOURCE: EIA analysis based on National Renewable Energy Laboratory's System Advisory Model (SAM)

MODEL INPUT: *WSSPVEL_CF*

DEFINITION: Time segment system capacity factor for standalone PV in EMM region *n* in hour h, daytype *d*, month *m* in year *y* (percent)

SOURCE: National Renewable Energy Laboratory, System Advisory Model (SAM)

MODEL INPUT: *WSSSTEL_CF*

DEFINITION: Time segment capacity factor for concentrating solar power system in EMM region *n* in hour h, daytype *d*, month *m* in year *y* (percent)

The concentrating solar power capacity factors by region and time segment are calculated using NREL data that are based on typical meteorological year (TMY3) solar resource data from the National Solar Radiation Database processed through the Solar Advisor Model.

SOURCE: EIA analysis based on National Renewable Energy Laboratory's System Advisory Model (SAM)

Appendix 5-B: Mathematical Description

The SES does not incorporate any modeling equations, but rather, it assigns values that are read from input files to the appropriate RFM common blocks.

Appendix 5-C: Bibliography

U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies*, February 2020

Appendix 5-D: Module Abstract

Module name

Solar Energy Submodule

Module acronym

SES

Description

SES defines costs and performance characteristics for photovoltaic and solar thermal electricity-generating systems by EMM region and year. EMM regions are based on the North American Electric Reliability Corporation (NERC) regions, as modified by EIA for NEMS. For PV technologies, all 25 EMM regions are represented in SES. For CSP technologies, however, only 11 selected regions are represented because insufficient direct normal insolation (sunlight) bars this technology from other regions of the country.

Purpose of the module

The NEMS Solar Energy Submodule (SES) defines the cost and performance characteristics of concentrating solar-thermal power (CSP) and photovoltaic (PV) electricity-generating technologies and passes them to the EMM for capacity planning decisions.

Most recent module update

December 2022

Part of another module

The Solar Energy Submodule (SES) is a component of the Renewable Fuels Module (RFM) of the National Energy Modeling System (NEMS).

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Documentation

Renewable Fuels Module of the National Energy Modeling System: Model Documentation 2020

Archive media and installation manual

Archived as part of the NEMS production runs

Energy system described

The default solar thermal electric technology is a 100-MW central receiver (power tower) with a partial-load natural gas boiler for the startup cycle and temporary cloudy periods and is without integrated storage. At low levels of insolation, the output of the central receiver system is zero, until the insolation exceeds a threshold level sufficient to overcome thermal losses. The representative PV technology is a 150-MW single-axis tracking, flat-plate array tilted at an angle equal to the site's latitude. Beginning in AEO2021, we also model the same PV technology with a dedicated 200 MWh (4 hours of 50 MW output) DC coupled lithium-ion battery storage system.

Coverage

- Geographic: 25 EMM regions for PV technologies and 11 regions for CSP technology (see EMM documentation)
- Time unit/frequency: Annual through 2050
- Product: Electricity

Modeling features

Non-DOE input sources

National Renewable Energy Laboratory: Regional capacity factors, by month and time of day

DOE input sources

U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity Generating Technologies*, February 2020

Independent expert reviews conducted

None

Status of evaluation efforts by sponsor

None

Appendix 5-E: Data Quality and Estimation Processes

This appendix discusses the quality of the principal sources of input data used in the Solar Energy Submodule.

Solar thermal performance

We base concentrating solar power performance (capacity factor) on a central receiver power tower without storage capacity. Because it uses concentrators, the concentrating solar power system can use only direct insolation. Solar thermal performance estimates are obtained from the National Renewable Energy Laboratory, which processed solar resource data through its technology-specific Solar Advisor Model to estimate capacity factors. Solar capital cost estimates are from our *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants* (February 2020).

Photovoltaic performance

Photovoltaic performance is based on a single-axis tracking PV system. Performance estimates are from the National Renewable Energy Laboratory, which processed typical meteorological year data from the National Solar Radiation Database solar resource data through its technology-specific Solar Advisor Model (SAM). Photovoltaic system cost estimates share the technology assumptions used to generate performance estimates and are based on our *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity-generating Technologies* (February 2020).

6. Biomass Submodule

Model purpose

The Biomass Submodule sends regional biomass fuel price and quantity information to support projected decisions for constructing and operating biomass electricity generation in the Electricity Market Module (EMM) and for constructing and operating cellulosic ethanol, pyrolysis oils, and biomass-to-liquids plants in the Liquid Fuels Market Module (LFMM) of the National Energy Modeling System (NEMS).

We base the biomass supply schedule on the accessibility of biomass resources to the consuming sectors from existing wood resources, agricultural residues, and biomass energy crops. The regional biomass supply schedule dynamically generates each model year using the Policy Analysis Model (POLYSYS), developed by the University of Tennessee. Urban wood waste and mill residue supply also have dynamically determined components calculated by using feedback data on the industrial waste wood supply from the Industrial Demand Module (IDM) in NEMS.

Cost and performance characteristics of a representative biomass combustion system represented in the RFM were based on our *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity Generating Technologies* (February 2020) and reside in the EMM input file ECPDAT. Cost and performance characteristics of biofuels production facilities reside in the LFMM. Performance characteristics unique to the biomass direct-combustion system (such as heat rates and variable O&M costs) are computed in the renewables submodule and then passed to the EMM. The fuel component of the cost characteristic is determined from the regional biomass supply schedules and then converted to a variable O&M cost.

Relationship of the Biomass Submodule to other modules

The Biomass Submodule interacts with EMM, LFMM, and the sectoral demand modules. It does not interact with other submodules in the RFM. Regional biomass consumption requirements from the petroleum and electricity modules are used in the Biomass Submodule to determine the regional biomass supply price, its use in biofuels production, and as a separate price for all other users. Information on the total biomass demand from liquid fuels and electricity is passed to the biomass supply subroutine with each complete solution cycle of NEMS so that the supply reflects the total available supply net of the consumption by other users.

In addition, projected regional supply of urban wood waste and mill residue interacts with the IDM. A portion of biomass that is generated as an industrial byproduct and is not consumed in the industrial sector is added to the biomass supply as an eligible resource for electricity generation or biofuels production. The urban wood waste supply from the IDM is then added to the noncaptive urban wood waste supply (see following sections) from the WODSUPP input file for each model year.

Modeling rationale

Theoretical approach

Biomass use is modeled in NEMS as two distinct markets: the captive and noncaptive biomass markets. The captive market includes users with dedicated biomass supplies, such as black liquor or other byproducts resulting from manufacturing processes. Biomass waste combustion in captive markets serves as both energy supplier and as a waste disposal method. The captive biomass market is modeled in the Industrial Demand Module (IDM) of NEMS. Leftover biomass that is not used in the industrial process is passed from the IDM to the RFM as eligible fuel for electric power plants.

The noncaptive biomass market includes the electric utility sectors and the biofuels production sector. The noncaptive markets serving residential and commercial uses of biomass are modeled in the residential and commercial demand modules, respectively.

The fuel supply schedule in each region defines the quantity and cost relationships of biomass resources accessible by all non-captive consumers (electric power and biofuels), after accounting for demand by each sector. The four sectors represented are: urban wood waste and mill residues, forestry residues from federal forests, agricultural residues and energy crops, and forestry residues from non-federal forests. You can find additional details on the biomass supply curves in Appendix 5-E.

Fundamental assumptions

The Biomass Submodule assumes all sectors using non-captive biomass will compete for the same supplies, subject to particular uses in each respective sector. As such, we assume that cellulosic ethanol plants will not be able to use supplies from urban wood and mill waste. We also assume that neither cellulosic ethanol, pyrolysis oils, nor biomass-to-liquids (biomass Fischer-Tropsch) will be able to use feedstocks from federal forests. The power sector, however, can use all biomass resources included in the model. Because urban wood and mill wastes are likely the lowest-cost biomass resources, we assume the cellulosic ethanol sector pays premium prices compared with the power sector for biomass resources. We also assume that there are no discounts for large orders of biomass.

To simplify the modeling of the resource's economic accessibility, the Biomass Submodule assumes a fixed typical transportation distance when calculating costs for agriculture residues and energy crops, forestry residues, and urban wood waste. The maximum distance to economically transport all biomass resources, except urban wood waste, is assumed to be 50 miles. Within this 50-mile radius, the transportation cost is $12/dry ton, which is added to the supply curves for both forestry and agricultural residues and to energy crops to reflect the transportation cost from the farm gate to the power plant. The transportation cost is expressed in 2008$, escalated by inflation rate annually and indexed to the price of crude oil.

Alternative approaches

Generally, biomass conversion can be modeled similar to other solid fuel technologies, such as coal, with appropriate attention to cost assumptions. The unique characteristics of this resource reside in the treatment of the fuel supply function, as well as interaction between the ethanol and power sector users of the biomass resource.

The Biomass Submodule of the RFM has several simplifying features of its supply functions or that may offer opportunities for improvement. The submodule treats only the marketed portion of the fuel, when possible interaction with entities that have captive biomass supply could occur, in other words, the forest products industry and the residential fuel market. Another simplification is that we assigned a constant factor for transportation costs. The fuel transport costs could be a significant share of the delivered costs and will vary considerably by terrain and distance to the conversion facility. A final limiting assumption pertains to how competing uses of the resource are treated, either as land or as other product uses. For example, the land could be used for other fiber or food crops or the wood could be used for construction, at alternative prices.

Biomass Submodule structure

Submodule flow diagram

A flow diagram showing the main computational steps and relationships of the Biomass Submodule is shown in Figure 4. Landfill Gas Submodule flowchart.

Key computations and equations

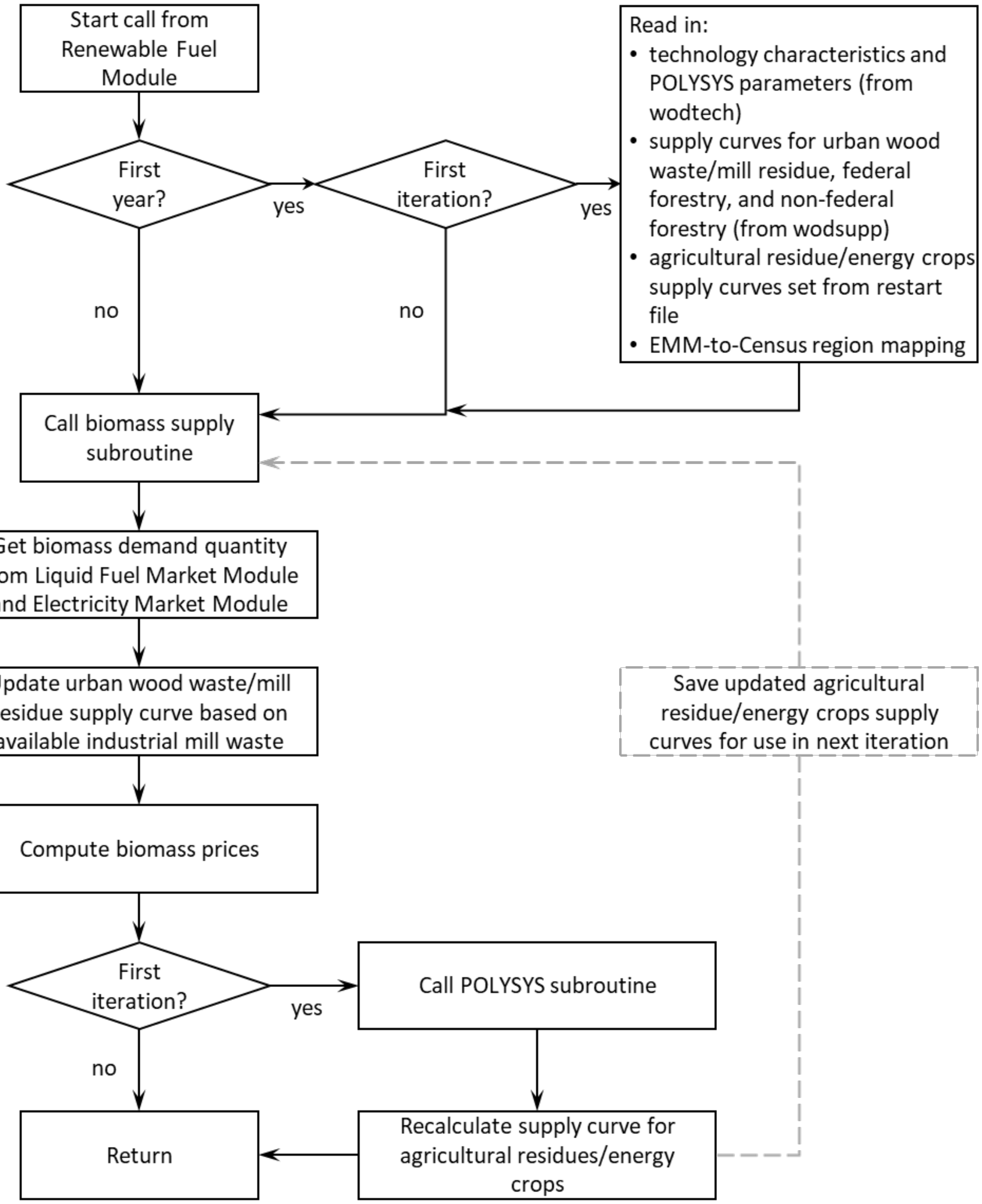
The Biomass Submodule consists of one Fortran subroutine and a call to the POLYSYS model, which runs as a separate submodule within the RFM. The regional biomass supply price is calculated based on the current regional biomass consumption passed from the Industrial Demand Module, Liquid Fuels Market Module, and Electricity Market Module. These biomass supplies are then passed back to the EMM and LFMM to provide price and availability data to these two modules.

Biomass resources come from four source categories (sectors): urban wood waste and mill residues, agricultural residues and dedicated energy crops, forestry residues from federal forests, and forestry residues from private forests. Because biofuels producers may be limited in their ability to use particular feedstocks, the user may specify a fraction of each sector to use to determine the ethanol feedstock price. The price of fuel to the power sector is determined from the residual biomass supply, after accounting for liquid fuels demand. Because each biomass sector might face different limitations in source of supply, the converged price for biomass will not necessarily be the same across the sectors, even though they share some amount of supply.

The biomass quantity-price relationships are implemented in a matrix representing the supply curve as step functions for each of the four resource sectors. These individual matrices are aggregated based on user specifications for the biofuels and (separately) the power sector. We use a linear interpolation scheme on the aggregate sector supply curve to determine the biomass price given a biomass quantity.

Because the biomass consumption data in the industrial and refining sectors are defined in NEMS by census divisions and the costs and quantities of biomass feedstocks are defined for coal market regions, a geographic mapping was necessary to generate biomass prices by census division.

Figure 7. Biomass Submodule flowchart



Appendix 6-A: Inventory of Variables, Data, and Parameters

Appendix 6-A provides information on variables used in the Biomass Submodule. You can find a complete listing of all variables, including definitions and dimensions, sources, measurement units, and page references, in Table 6A-1. Variables are classified as submodule data inputs, calculated variables, and submodule outputs.

Table 6A-1. NEMS Biomass Submodule inputs and variables

Variable	Definition and dimensions	Source	Units
INPUT DATA			
CDTOCLWDTI	Conversion factors for converting census division *r* to coal demand region *n*	EIA	Unitless
WDSUP_Q$_{n,y,l,,f}$[16]	Biomass quantity step function in coal demand region *n,* year *y*, step *l,* feedstock *f*	EIA	Trillion Btu
WDSUP_P$_{n,y,l,,f}$[16]	Biomass price step function in coal demand region *n*, year *y*, step *l,* feedstock *f*	EIA	$/MMBtu
*UPOVR**	Capital cost for biomass technology	EIA, 2020.	$/kW
*UPMCF**	Capacity factor for biomass technology electricity sector	EIA, 2020.	Unitless
*UPVOM**$_{n,y}$	Variable O&M cost component for biomass technology electricity sector in EMM region *n* in year *y*	EIA, 2020.	$/MMBtu
UPFOM$_{n,y}$*	Fixed O&M costs for biomass technology electricity sector in EMM region *n* in year *y*	EIA, 2020.	$/kW
WHRBMEL$_{n,y}$	Heat rate for biomass technology in EMM region *n* in year *y*	EIA, 2020.	Btu/kWh
VARIABLES			
QBMCM	Quantity of biomass consumed in the commercial sector in census division *r* in year *y*	NEMS	Trillion Btu
QBMIN	Quantity of biomass consumed in the industrial sector in census division *r* in year *y*	NEMS	Trillion Btu
QBMPWCL	Quantity of biomass consumed in the electric power sector in coal demand region *n* in year *y*	NEMS	Trillion Btu
QBMETCL	Quantity of biomass consumed in the refining sector (for cellulosic ethanol production) in coal demand region *n* in year *y*	NEMS	Trillion Btu
QBMBTCL	Quantity of biomass consumed in the refining sector (for biomass-to-liquids production) in coal demand region *n* in year *y*	NEMS	Trillion Btu
POLYPTQ	Demand quantity sent to POLYSYS for each coal demand region	NEMS	Trillion Btu
OUTPUTS			
PBMASCL$_{n,y,f}$	Price of biomass for all sectors in coal demand region *n* and year *y* for feedstock *f*.	NEMS	$/MMBtu

[16] Note that for the agricultural residues/energy crops feedstock, this variable is an output.

Variable	Definition and dimensions	Source	Units
PLYSUP_Q_AG	POLYSYS supply curve quantities for agricultural residues/energy crops, by coal region, step, and year	RFM/POLYSYS	Trillion Btu
PLYSUP_P_AG	POLYSYS supply curve prices for agricultural residues/energy crops, by coal region, step, and year	RFM/POLYSYS	$/MMBtu
$WCABMEL_{n,y}$	Capacity for utilities in EMM region *n* in year *y*	EMM	MW
$WVCBMEL_{n,y}$	Variable O&M costs for biomass technology electricity sector in EMM region *n* in year *y*. Incorporated the converted fuel cost for biomass.	RFM	Mills/kWh

Data source:
*Assigned in EMM input file ECPDAT.

MODEL INPUT: *CDTOCLWDTI*

DEFINITION: Conversion factors for converting data for census division *r* to data for coal demand region *n*

SOURCE: Oak Ridge National Laboratory, "Data and Sources Biomass Supply." Draft prepared for EIA under Contract No. DE-AC05-84OR21400, Oak Ridge, TN, June 27, 1993

MODEL INPUT: *WDSUP_Q*

DEFINITION: Quantity of biomass supply in coal demand region *n*, year *y*, and step *l*

WDSUP_Q is part of the biomass supply schedule. This variable represents quantity of a biomass composite consisting of the following biomass types: urban wood waste and mill residues, forest residues from federal forests, agricultural residues and energy crops, and forest residues from non-federal forests.

SOURCES: Output from POLYSYS model projections

MODEL INPUT: *WDSUP_P*

DEFINITION: Price of biomass supply in coal demand region *n*, year *y*, and step *l*

WDSUP_P is part of the biomass supply schedule. This variable represents the price of a biomass composite consisting of the following biomass types: urban wood waste and mill residues, forest residues from federal forests, agricultural residues and energy crops, and forest residues from non-federal forests.

SOURCES: Output from POLYSYS model projections

MODEL INPUT: *UPOVR*

DEFINITION: Capital costs for electricity sector.

UPOVR represents the nth-of-a-kind capital cost for a direct combustion biomass technology of unit size 50 MW. The cost estimates incorporate the removal of interest during construction and contingency costs, which are added later in EMM.

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity Generating Technologies*, February 2020

MODEL INPUT: *UPFOM*

DEFINITION: Fixed O&M costs for biomass technology

The fixed O&M cost is assumed to be constant across all regions and for all years.

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity Generating Technologies*, February 2020

MODEL INPUT: *UPVOM*

DEFINITION: Constant variable O&M costs for biomass technology

SOURCE: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity Generating Technologies*, February 2020

MODEL INPUT: *UPMCF*

DEFINITION: Capacity factor for the utility sector

Capacity factor is assumed to be constant for all years and all regions.

SOURCE: Craig, K.R.; Mann, M.K., 1993. Cost and Performance Analysis of Integrated Gasification Combined Cycle (IGCC) Power Systems Incorporating a Directly Heated Biomass Gasifier. Milestone Completion Report. NREL. December 1993

MODEL INPUT: *WHRBMEL*

DEFINITION: Heat rate for biomass technology in EMM region *n* in year *y*

The heat rate represents the biomass direct combustion technology.

SOURCES: U.S. Energy Information Administration, *Capital Cost and Performance Characteristic Estimates for Utility Scale Electricity Generating Technologies*, February 2020

MODEL INPUT: *QBMCM*

DEFINITION: Biomass/wood consumption in commercial sector in census division *r* and year *y*

NEMS variable, calculated in the Commercial Demand Module (CDM)

SOURCE: NEMS

MODEL INPUT: *QBMEL*

DEFINITION: Biomass/wood consumption in electric power sector in census division *r* and year.

NEMS variable, calculated in the Electricity Market Module (EMM)

SOURCE: NEMS

MODEL INPUT: *QBMIN*

DEFINITION: Biomass/wood consumption in industrial sector in census division *r* and year *y*

NEMS variable, calculated in the Industrial Demand Module (IDM)

SOURCE: NEMS

MODEL INPUT: *POLYPTQ*

DEFINITION: Demand quantity sent to POLYSYS for each coal demand region as midpoint for POLYSYS-generated supply curves

SOURCE: NEMS

MODEL OUTPUT: *WCABMEL*

DEFINITION: Available generating capacity in EMM region *n* and year *y*, in MW

The maximal generating capacity is determined by the maximal value in each regional supply curve and converted into MW using the performance characteristics of the biomass technology, represented in the RFM.

SOURCE: NEMS

MODEL OUTPUT: *WVCBMEL*

DEFINITION: Variable costs for biomass electricity generation for the utility sector in EMM region *n* in year *y*

Variable cost is model-determined and is the sum of two factors: fuel cost and a constant factor accounting for operational maintenance expenses. Because there is no way to pass fuel cost separately to the ECP, the cost for biomass fuel is converted into mills per kWh and added as an additional variable O&M cost component.

SOURCE: NEMS

MODEL OUTPUT: *PBMASCL*

DEFINITION: Price of biomass for all sectors for coal demand region *n*, year *y*, feedstock *f*

Price of biomass is model-determined in the RFM based on input biomass demand quantities

SOURCE: NEMS/RFM

MODEL OUTPUT: *PLYSUP_Q_AG*

DEFINITION: POLYSYS supply curve quantities for agricultural residues/energy crops, by coal region, step, and year

SOURCE: NEMS/RFM/POLYSYS

MODEL OUTPUT: *PLYSUP_P_AG*

DEFINITION: POLYSYS supply curve prices for agricultural residues/energy crops, by coal region, step, and year

SOURCE: NEMS/RFM/POLYSYS

Appendix 6-B: Mathematical Description

The Biomass Submodule does not incorporate any modeling equations. It allocates values that are read from input files and from other modules of NEMS to the appropriate RFM common blocks.

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Appendix 6-D: Module Abstract

Module name

Biomass Submodule

Module acronym

None

Description

The submodule passes projected cost and performance characteristics, by EMM region and year, to the EMM. The projected cost characteristic includes fuel cost, which is determined from the regional biomass supply curves and converted to a variable O&M cost.

Most recent module update

October 2019

Part of another module

The Biomass Submodule is a component of the Renewable Fuels Module (RFM) of the National Energy Modeling System (NEMS).

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Documentation

NEMS Documentation Report: Renewable Fuels Module of the National Energy Modeling System, May 2020

Archive media and installation manual

Archived as part of the NEMS production runs

Energy system described

Non-captive biomass supply and associated price

Coverage

- Geographic: 25 EMM regions (see EMM documentation).

- Time unit/frequency: Annual through 2050
- Product: Generating capacity
- Economic sectors: Electric utility and industrial sectors

Modeling features

Data from nine census divisions are restructured into 16 coal demand regions.

DOE input sources

None

Independent expert reviews conducted

None.

Status of evaluation efforts by sponsor

None

Appendix 6-E: Data Quality and Estimation Processes

Derivation of biomass supply curves

The biomass supply curve provides price and quantity information for four distinct feedstock categories. The four feedstocks are combined into one supply curve, representing available resources for each of the 16 coal demand regions. The four feedstocks represented in the supply curve include:

Agricultural residues and dedicated energy crops

This feedstock supply curve component is endogenously and dynamically calculated in our version of the POLYSYS model, which was purchased from the University of Tennessee. The dedicated energy crops and agricultural residues used in the supply curve include switchgrass, corn stover, and wheat straw.

In the POLYSYS model, the price-quantity solution from the previous year is the starting point for planting decisions in the following year's supply curves. The RFM designates additional quantities higher than and lower than the initial solution quantity to create the shape for the supply curves in that year. POLYSYS optimizes U.S. agricultural land-use patterns, iteratively solves for each of the corresponding prices, and returns that information to the RFM. This dynamic process results in a set of regional and annual supply curves, and this process is repeated in the first iteration for each year of each cycle.

Federal and non-federal forestry

Forestry feedstocks make up two separate supply curves, harvested from federal and non-federal forest lands. The supply curves include sustainably produced forest feedstocks, including logging residues and thinnings, other removal residues, and some use of pulpwood competitive against the paper industry. They generally exclude roundwood or logs used for lumber products. The data are used in our WODSUPP file as input to NEMS and are not modified endogenously. The totals from public and private forestry categories are separated within NEMS because only residues from private lands can meet the Federal Renewable Fuels Standard.

Urban wood waste and mill residues

The Industrial Demand Module (IDM) of NEMS models the captive biomass market, and projected quantities of leftover biomass not used in the industrial process or for onsite generation are passed from the industrial model to the RFM as eligible fuel for electric power plants. We used historical data to establish how much biomass was consumed directly by the paper and wood industries as a proportion of biomass consumed across all sectors. Historical data indicate that approximately two-thirds of waste consumption is in paper and wood industries, and because industrial use of biomass consists primarily of paper and wood industries, the remaining one-third of waste consumption is passed along to the RFM as urban wood waste. The WODSUPP file already includes a portion of the biomass waste consumption, and to prevent double-counting, the WODSUPP file incorporates only one-half of the consumption passed to the RFM from the IDM.

7. Geothermal Electricity Submodule

Module purpose

The Geothermal Electricity Submodule (GES) provides the projected supply of new geothermal generating capacity and its related average cost and performance characteristics to the Electricity Capacity Planning (ECP) Submodule of the Electricity Market Module (EMM) in the National Energy Modeling System (NEMS). The supply, costs, and performance characteristics are based on information for resources at known U.S. geothermal sites as well as those classified as having near-term Enhanced Geothermal System (EGS) potential, which indicates that the heat potential is there but additional fluids need to be injected for electricity production.

The supply available for future capacity is reduced as geothermal resources are used. These estimates include already chosen capacity identified from historical data reported to EIA, reported plans of future geothermal capacity, or resources already chosen in earlier estimates by the ECP.

Capacity (in MW) that can be built at any site in a specific year (annual build bounds) is limited to accurately represent industry practice of gradual expansion at geothermal sites; bounds may be modified by individual site by year. A maximum of 50 MW is allowed by the GES to be built at each site annually. This maximum reflects industry trends of relatively small power plant construction within the past several years.

Projected capital cost is reduced over time to reflect experience (learning-by-doing) and is increased as warranted to reflect increases in demand (short-term cost elasticities of supply). The model permits changes in the estimates of capital costs of specific sites by individual year (capital cost multipliers), enabling the GES to represent geothermal capital cost assumptions that are different from the Reference case. The capital cost multipliers are numeric weights affecting the total base capital cost of each of the traditional hydrothermal and near-field EGS sites. The cost multipliers can be less than, equal to, or greater than 1.00. The design allows different weights for different sites and different weights for different years for each site.

Relationship of the Geothermal Electricity Submodule to other modules

The GES interacts primarily with the ECP, providing new capacity availability, performance, and cost information to inform projected planning decisions. The GES also receives feedback on new capacity build decisions from the ECP to decrement available new geothermal resources and capacity. The GES uses financial parameters and tax data for calculations related to the competing geothermal resource sites and ECP-based avoided costs to determine the highest cost at which new geothermal supply can compete, setting the upper-cost bound of geothermal supply.

Modeling rationale

The GES develops estimates of regional geothermal capacity supplies (MW available in increasing order of cost per kilowatthour) used in competing geothermal technologies with fossil, nuclear, and other renewable energy-generating alternatives. We develop the estimates for each forecast year and region that needs new generating capacity. The model assumes that the only cost-effective and accessible geothermal resources available during the forecast period are the 125 water-based (hydrothermal) resources and the corresponding 125 areas of near-field EGS potential in five Western Electricity Coordinating Council EMM regions:

- Southwest (Region 20)
- Northern California (Region 21)
- Southern California (Region 22)
- Northwest Power Pool (Region 23)
- Great Basin (Region 25)

The near-field EGS potential was included for the first time in AEO2011 because NREL was able to quantify the costs of this technology in a credible manner. Unidentified hydrothermal sites, unidentified EGS sites, and deep EGS resources were not included in our geothermal supply curve because of high uncertainties in both capital cost and capacity estimates.

Each geothermal site is characterized by:

- A capital cost estimate
- Potential capacity available
- Capacity factor
- Heat rate
- Operation and maintenance costs

Within each region for each model iteration in each projection year, the GES:

- Subtracts resources already used
- Sorts all geothermal supply segments in increasing cost order
- Determines from the EMM the maximum price (avoided cost) likely to be competitive
- Provides the EMM a geothermal supply projection in the form of three levelized cost-quantity pairs of available capacity that compete with other technologies

Fundamental assumptions

Type of resource

The GES represents traditional hydrothermal geothermal resources, defined as large volumes of water trapped in permeable rock at depths of up to 33,000 feet and with temperatures higher than 110°C. These sites, which were largely identified by the U.S. Geological Survey (USGS) in their 2008 report, also contain dry, high-temperature areas that could be used with EGS development. Because estimated development costs of these EGS systems become available, these near-field EGS areas were included in the GES for the first time in 2011. Cost estimates are based on NREL data and rely heavily on the Geothermal Electricity Technology Evaluation Model (GETEM) provided by Idaho National Laboratory. GETEM uses information such as well temperature, depth, and fluid characteristics to calculate a cost estimate for each resource.

Estimates of resources and development costs

Beginning with AEO2011, we have been using a new source to model the geothermal energy supply curves used in NEMS. Previously, we used data from DynCorp, based on a 1992 report by Sandia

National Laboratory. These estimates elaborated on the USGS Circular 790, which was published in 1978. Through the years, we determined that the projects had become overly optimistic and began decreasing supply estimates without new information from comprehensive studies. To update our geothermal supply curves more consistently, we obtained data in 2007 from two studies: New Geothermal Site Identification and Qualification published by California Energy Commission in 2004, and Geothermal Task Force Report published by Western Governors' Association in 2006. Both of these studies represented updated geothermal capacity and cost data, which we used until 2011, when additional studies from NREL and the U.S. Department of Energy's Geothermal Program Office became available. Unlike the two previous studies we had used, the NREL study estimates the costs and available capacity from known and unknown hydrothermal resources, near-field EGS resources, and deep EGS resources. Because the AEO is a long-term energy outlook and the most accurate cost input data is a priority in the estimation, we include only the 125 known hydrothermal sites with temperatures higher than 110°C and their corresponding near-field EGS potential areas in our supply curve. We will re-evaluate this decision as additional cost and capacity estimates become available.

NREL's geothermal report included data based on the USGS's 2008 geothermal resource assessment, where they examined and evaluated hydrothermal potential. NREL included only 125 of the original 241 areas as likely to be developed using existing hydrothermal technology. Each of the sites has a temperature greater than 110°C and a resource depth ranging from 1,000 feet to 33,000 feet. USGS and NREL have an estimated 6,400 MW of exploitable capacity potential at these sites. The estimates from NREL used the USGS estimates and input the characteristics into the GETEM model to calculate the capital costs of exploiting each resource-potential area. We estimated the near-field EGS potential using the USGS report data along with NREL analysis.

Because geothermal resource areas possess wide-ranging, site-specific characterizations (not only in their temperatures and depths, but also the quality of the fluids in the ground), the GES uses the site-specific cost estimate analyzed by NREL instead of the cost estimate provided in the report.

Existing capacity and retirements

Existing capacity data are provided by the plant file of generating units, which is all U.S. utility and nonutility generating units that report on Form EIA-860, *Annual Electric Generator Report*. The capacity data are provided by facility name, online date, plant size, state, region, heat rate, and capacity factor. Starting with AEO2001, we no longer independently assume retirement dates for geothermal power plants at the end of a 40-year service life. Instead, we record retirements when a Form EIA-860 response, or other independent information externally, establishes the actual or planned retirement.

Heat rates

The energy in geothermal resources varies significantly from site to site. Furthermore, different measurement techniques can yield dramatically different heat rates. For example, heat rates can reflect the gross heat energy of the geothermal fluid at the surface or account for only the energy used at some later stage in the fluid's application. We use the average heat rate for fossil-fueled generators to represent the primary energy consumption of all renewable generation sources that do not require the combustion of a fuel, including geothermal. The heat rate for geothermal generating plants is currently set at 9,716 British thermal units (Btu) per kilowatthour, the heat rate for fossil-fueled, steam-electric plants.

Conversion technologies

Two geothermal energy generating technologies are represented in GES: dual-flash and binary.

The lower-cost dual-flash technology converts high-temperature fluids (greater than 200°C) to steam by flashing the liquid to steam at two different stages. The steam is used to drive a conventional turbine generator. The remaining liquid portion of the geothermal fluid is reinjected into the ground. Generally, higher-cost binary technologies circulate the lower-temperature geothermal fluid through a closed-loop system in which the fluid heats and vaporizes a second fluid with a low boiling point, such as isopentane. The vapor of the second fluid drives the turbine generator, and the low-temperature geothermal fluid is reinjected into the ground.

Dry steam resources, an additional geothermal technology that generates electricity solely with the use of steam, are extremely rare and not represented in the GES submodule.

Capacity factors

The GES assumes a 90% capacity factor for new dual flash plants and 95% for new binary-cycle plants.

Geothermal Electricity Submodule structure

The GES “SUBROUTINE GEO2000”has five basic components.

Incorporates data

On its initial iteration, subroutine GET-SITE-DATA reads the data from the WGESITE input data file that characterizes the 250 U.S. geothermal sites, including:

- Capacity
- Cost components
- Operations and maintenance (O&M) costs
- Capacity factor
- Heat rate
- Annual capital cost multipliers
- Build bounds

Subroutine GET_PARM_DATA reads geothermal parameters from the WGEPARM file. Together, the two subroutines build the GEOSITE geothermal data structure. Capital costs are the sum of estimates for exploration, confirmation, power plant costs, and transmission costs. Annual fixed O&M costs include pump, field, and power plant costs. Because geothermal energy does not require fuel, the GES submodule does not include a fuel charge. The annual capital cost multipliers are applied to the capital costs within the GET-SITE-DATA subroutine. The cost multipliers generally have a value of 1.00 for base cases and values less than 1.00 for alternate scenarios, including the low renewable technology cost case. Sites in Hawaii are not used in the modeling, leaving only sites in five Western Electricity Coordinating Council EMM regions (20, 21, 22, 23, and 25) contributing to geothermal supply.

Develops overall regional geothermal supplies

In each iteration, subroutine BUILD-GEO-CURVES first creates regional geothermal supply data for each of the five Western EMM regions with geothermal resources, using the 250 sites' data. The subroutine distributes each site's total available capacity (MW) among two increasing capital cost subgroups. The subroutine then arrays all sites' quantity-cost subgroups in each EMM region from lowest-to-highest cost, resulting in an aggregate regional geothermal supply array GEOCRV. The total available capacity for each site is limited to the annual build bound for the site.

Provides sub-supplies for specific regional demands

For each iteration of the EMM, the GES estimates a maximum levelized cost (avoided cost) at which geothermal supply in each of the regions can compete. The maximum value is the levelized cost of the highest-cost technology actually selected in the immediately previous iteration of the ECP plus an additional percentage representing the market-sharing algorithm.[17] As a result, all remaining geothermal capacity that can generate approximately at or lower than the previous iteration's highest cost selection plus the market-sharing tolerance, is offered as new geothermal supply in the current iteration.

Subroutine BUILD-GEO-CURVES selects only the unused supply available at or lower than the adjusted avoided cost from each aggregate regional supply GEOCRV. It distributes the unused supply among three increasing-cost geothermal cost-quantity pairs using capacity-weighted average per kilowatthour costs. The EMM receives, for each region, three quantities of available geothermal capacity at three (increasing) levelized costs, as well as an overall (over all three steps) capacity-weighted heat rate, O&M costs, and carbon dioxide and hydrogen sulfide emissions rates.

The lowest-cost group includes all unused capacity in the lowest-cost price quartile (capacity whose levelized cost is equal to or less than 25% of the cost difference between the least cost available unit and the ECP-avoided cost). The resulting quantity is not the lowest-cost 25% of unused capacity, but rather, all unused capacity in the first 25% of the cost range. The second group includes all capacity between the 25^{th} and the 75^{th} price percentile, and the third group includes all remaining highest-cost capacity. All available capacity in each cost group is then passed to the EMM as available supply, with one levelized cost associated with each group. The one levelized cost transmitted for each group is equal to the capacity-weighted levelized average cost for the individual sites' costs within the group. We assume that only the lowest-cost capacity group is available to the EMM.

Decrements available capacity

Within subroutine CRV-INFO, GES reduces the projected available geothermal capacity in each region for each iteration. The geothermal capacity is reduced in response to external reports of new geothermal builds or previous selection by the EMM in earlier iterations.

[17] The market-sharing algorithm exists because in real markets, technologies that are close in cost to the lowest-cost technology will occasionally be selected for economic and other reasons not represented in the modeling. Under the sharing algorithm, the closer in cost a specific other technology is to the lowest-cost technology, the greater (yet small) share of the available market will be taken by that technology.

Provides diagnostics

For each iteration, subroutine WRITE-DB provides diagnostic information on geothermal capacity and sites chosen and technology costs and performance.

Diagnostics provided through Excel output file geo_out.xls include the following:

- **Geo_Input_Data** display quantities of capacity available at each of 250 U.S. geothermal sites, including capacity in each of four potential cost categories (currently only two are used).
- **Geo_Curve_Data** display each geothermal subsite's available geothermal capacity and estimated cost per kilowatthour in lowest-to-highest cost order.
- **Geo_Curve_Info** display aggregate geothermal supplies and average cost per kilowatthour as available to each of four NEMS regions for each forecast year. The values are transmitted to the Electricity Market Module (EMM) as aggregate geothermal supply.
- **Geo_Builds** display quantities of geothermal capacity built in each of the three NEMS regions in each forecast year.

Key computations and equations

This section describes the most important equations in the GES.

Reading the data

In the first iteration, data for geothermal sites are read from the file **WGESITE** by the GES Subroutine GET_SITE_ DATA into the **GEOSITE** data structure. Subroutine **GET_PARM_DATA** reads the geothermal parameters from the parameter file **WGEPARM**.

GEOSITE Data Structure:

SITE_ID	
EIA_ID	
NAME	= Site Name
STATE	
AVAIL_SUPPLY	= Potential capacity -1990 capacity
CAP_COST _ADJ	= Drilling + Field + Plant Costs adjusted by capital cost multiplier (1987$/kW)
CAP_COST	= Drilling + Field + Plant costs
CAPACITY_1990	= Installed capacity 1990 (not currently used)
CAPACITY_FACTOR	= 0.00 to 1.00 (0.90 assumed for all plants)
CAPCOST_MULT	= Annual Capital Cost Multiplier for Site (Fraction)
CENSUS	= Census region of site
CO2_RATE	= Pounds per megawatthour
COE	= 4 levelized costs, (1987$) mills per kilowatthour
DRILL_CAP_COST	= Per kilowatt capital cost component (1987$)

DRILL_CAP_COST _ADJ = Capital cost component adjusted by capital cost multiplier (1987$/kW)
EXPLOR_CAP_COST = Per kilowatt capital cost component (1987$)
EXPLOR_CAP_COST_ADJ = Capital cost component adjusted by capital cost multiplier (1987$/kW)
FIELD_CAP_COST = Per kilowatt capital cost component (1987$)
FIELD_CAP_COST _ADJ = Capital cost component adjusted by capital cost multiplier (1987$/kW)
FIELD_OM-COST = Per kilowatt annual field O&M cost component (1987$)
H2S_RATE = Lbs. per megawatthour
HEAT_RATE = Btu per kilowatthour
NERC = NERC region of site
PFILE_EXCAP = Existing capacity (from EMM plant file)
PLANT_CAP_COST _ADJ = Capital cost component adjusted by capital cost multiplier (1987$/kW)
PLANT_CAP_COST = Per kilowatt capital cost component (1987$)
PLANT_OM-COST = Per kilowatt annual plant O&M cost component (1987$)
POTENTIAL_CAP = Four increasing-cost quantities of capacity at each site
SITE_BOUND = Annual Build Bound for Site (MW)
SUBSITEOM_COST = Field O&M + Plant O&M costs
TECHTYPE = Technology, 1- Binary; 2 – Dual Flash
TEMP = Temporary data structure for sorting geosites

In each iteration, the capital, fixed O&M, and levelized cost of energy for each of two increasing-cost subsites at each site are calculated. The capital costs are adjusted for learning and technological optimism. Existing capacity is subtracted from each site's available supply. Technological optimism and learning effects are estimated in subroutine ELEC_OPT in the electricity capacity planning (ECP) Submodule of the EMM.

Building regional geothermal supplies

In each iteration, projected available geothermal supplies at each site are merged with costs from other sites in the region and arrayed for competition in the ECP in each region. The GES submodule first constructs a complete array of increasing levelized cost/quantity pairs as the cumulative geothermal supply available for the region. The GES then segments the competitive part of that array into three generalized increasing cost segments, passing the total capacity available in each increasing cost segment to the ECP, along with the capacity-weighted average cost of energy (mills per kilowatthour) for the capacity in the segment.

In each iteration, the GES receives a maximum cost for each region from the EMM. This maximum cost is equal to the cost of electricity of the highest-cost capacity previously selected in each region, called the Regional Avoided Cost, plus the market-sharing tolerance. The avoided cost is defined as:

Avoided Cost = (Regional Maximum Prior COE) * (1.0 + Market-sharing Tolerance)

The subroutine **BUILD_GEO_CURVES** iterates within each region until the capacity available in the first (lowest cost) step is greater than zero or until 10 iterations have occurred. The threshold cost is incremented 10% for each iteration.

The subroutine **ECPLVCST** develops levelized cost groups to submit to the ECP. The levelized cost groups are defined as:

AVAIL_SUPPLY = Megawatts available for each record
CUM_SUPPLY = Cumulative sum available megawatts in each region
SYS_CAP_COST = Cumulative capacity-weighted capital cost, three segments
SYS_CAP_FAC = Cumulative capacity-weighted capacity factor, three segments
SYS_CO2_RATE = Cumulative capacity-weighted CO2 emissions rate, three segments
SYS_COST = Cumulative capacity-weighted COE, three segments
SYS_HEAT_RATE = Cumulative capacity-weighted heat rate, three segments
SYS_OM_COST = Cumulative capacity-weighted O&M cost, three segments

The subroutine BUILD_GEO_CURVES then determines the value for each variable for each of the three segments of available geothermal supply in each region. The following values are derived from the cumulative values output from the ECPLVCST subroutine described above:

CAP_COST = Capital cost
CAP_FAC = Capacity factor
CO2_RATE = CO2 emissions rate
HEAT_RATE = Heat rate
OM_COST = O&M cost

In fact, the GES passes the ECP actual values only for the first of the three segments; values for steps 2 and 3 are expressed as weights applicable to the values in the first segment:

EMM_CAP_COST
EMM_CAP_FAC
EMM_CAPACITY
EMM_CO2_RATE
EMM_HEAT_RATE
EMM_OM_COST

Average_Capital_Cost = $\left(\sum_{i=1}^{n} (Cap\_Cost(i) * Capacity(i) \right)$/ Cumulative_Capacity

Average_O&M_Cost = $\left(\sum_{i=1}^{n} (O\&M\_Cost(i) * Capacity(i) \right)$/ Cumulative_Capacity

Other features of the Geothermal Submodule

Regional labor cost weights

Because the capital costs for geothermal sites are already specific to individual sites, regional labor cost weights in the EMM are set to 1.00 for all geothermal sites.

Federal Tax Credit

The Energy Policy Act of 1992 (EPACT92) has authorized a permanent investment tax credit (ITC) of 10% to all geothermal capital costs for all projection years. Since 2004, geothermal technology is also eligible to receive production tax credit (PTC) in lieu of ITC. Projects that began construction and are beyond the exploratory drilling phase by that date are eligible for this PTC.

Land costs

Lands used for geothermal well fields can be either purchased and accounted for in the capital costs of the project or be leased and, therefore, included in the project's fixed operation and maintenance costs.

Construction lead time, construction cost profile, and first online year

In the GES, new geothermal plants are constructed over a four-year period with most capital costs allocated to the last two years in the annual proportions of 15%, 15%, 35%, and 35%.

Learning, short-term elasticities, and technological optimism

Capital costs for geothermal generating technologies are affected by learning-by-doing and technological optimism. You can find a description of these characteristics and assumptions and values assigned geothermal in *Assumptions for the Annual Energy Outlook*, *Learning Parameters for New Generating Technology Components*.

Appendix 7-A: Inventory of Variables, Data, and Parameters

Values for this inventory are included in the body of this chapter, along with the Excel files supporting the geothermal submodule. Questions about the submodule can be directed to the official model representative listed in Appendix 7-D.

Appendix 7-B: Mathematical Description

The Geothermal submodule computes the levelized cost of energy for four increasing-cost subsites at each geothermal site, and capital costs are adjusted for learning and technological optimism. The rationale and cost differentials for these four subsites are explained in the *Estimates of Resources* section in the *Fundamental Assumptions* portion of this documentation.

$$COE_{i,1,y,r} = \frac{\left[\left(DCST_{i,y} + FCST_{i,y} + ECST_{i,y} + PLNTCST_{i,y}\right) \times FCF_r \times LFACT_y \times OPFACT_y\right] + FOM_i + POM_i}{CF_i \times 8760 \times 1000}$$

$$COE_{i,2,y,r} = \frac{\left[\left(1.33 \times (DCST_{i,y} + FSCT_{i,y}) + ECST_{i,y} + PLNTCST_{i,y}\right) \times FCF_r \times LFACT_y \times OPFACT_y\right] + FOM_i + POM_i}{CF_i \times 8760 \times 1000}$$

$$COE_{i,3,y,r} = \frac{\left[\left(DCST_{i,y} + FCST_{i,y} + 2 \times ECST_{i,y} + PLNTCST_{i,y}\right) \times FCF_r \times LFACT_y \times OPFACT_y\right] + FOM_i + POM_i}{CF_i \times 8760 \times 1000}$$

$$COE_{i,4,y,r} = \frac{\left[\left(1.33 \times (DCST_{i,y} + FSCT_{i,y}) + 2 \times ECST_{i,y} + PLNTCST_{i,y}\right) \times FCF_r \times LFACT_y \times OPFACT_y\right] + FOM_i + POM_i}{CF_i \times 8760 \times 1000}$$

where

i = Geothermal Site i
y = Current Year
r = NEMS Region
$COE_{i,1,y,r}$ = Levelized Cost of energy for subsite 1 for geothermal site i
$COE_{i,2,y,r}$ = Levelized Cost of energy for subsite 2 for geothermal site i
$COE_{i,3,y,r}$ = Levelized Cost of energy for subsite 3 for geothermal site i
$COE_{i,4,y,r}$ = Levelized Cost of energy for subsite 4 for geothermal site i
$DCST_{i,y}$ = Drilling component of capital costs for geothermal site i in year y, \$/kW
$ECST_{i,y}$ = Exploration component of capital costs for geothermal site i in year y, \$/kW
$FCST_{i,y}$ = Field component of capital costs for geothermal site i in year y, \$/kW
$PLNCST_{i,y}$ = Plant component of capital costs for geothermal site i in year y, \$/kW
FCF_r = Fixed Charge Factor in EMM region r for geothermal technology, fraction
$LFACT_y$ = Learning Factor for geothermal technology in year y, fraction
$OPFACT_y$ = Technological Optimism Factor for geothermal technology in year y
FOM_i = Field component of fixed O&M costs for geothermal site i, \$/kW
POM_i = Plant component of fixed O&M costs for geothermal site i, \$/kW
CF_i = Capacity Factor for geothermal site i, fraction

The levelized costs by geothermal site and subsite are then sorted from least to highest cost, resulting in an aggregate regional geothermal supply array. These regional supply arrays are then used to generate the three-step EMM supply curves. Although the model still incorporates the structure to break down the total capital costs into discrete components, this capability is no longer used because the data from which we gather our estimates do not have separate cost estimates for each of these categories.

Appendix 7-C: Bibliography

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Western Governors' Association, "Geothermal Task Force Report: Clean and Diversified energy Initiative," January 2006.

Appendix 7-D: Module Abstract

Module name

Geothermal Electric Submodule

Module acronym

GES

Description

The GES projects regional geothermal capacity supplies and cost and performance characteristics used in competing geothermal technologies with fossil, nuclear, and other renewable electricity-generating alternatives for each forecast year and region that needs new generating capacity in the EMM. We base regional geothermal supplies on each region's share of geothermal resources estimated for 250 identified U.S. geothermal sites, with

- Capital cost estimates for each geothermal site
- Two-step, low-to-high cost estimates of the megawatts of capacity available at select sites
- Assumptions for increasing capital costs for increasing portions of the high estimates of each site
- Capacity factors
- Fixed operation and maintenance costs
- Heat rates
- CO2 emissions rates for each site

Within each region for each model iteration in each forecast year, the GES:

- Decrements the already-selected resources
- Arrays all unused geothermal supply in increasing cost order
- Determines from the EMM the maximum price (avoided cost) likely to be competitive in the EMM
- Provides the EMM with three increasing levelized cost-quantity pairs of available capacity in each region for competing with other technologies

Purpose of the module

The GES provides the Electricity Capacity Planning SubModule (ECP) with the projected amounts of available geothermal generating capacity and the cost and performance characteristics for competing in the ECP for new regional electricity supply in the western United States.

Most recent module update

March 2016

Part of another module

The GES submodule is a component of the Renewable Fuels Module (RFM) of the National Energy Modeling System (NEMS).

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Documentation

This chapter constitutes the documentation of the GES.

Archive media and installation manual:

The GES is archived as part of the NEMS production runs.

Energy system described

Hydrothermal geothermal and near-field EGS energy resources of the western United States and the costs and performance characteristics of the technologies converting them to electricity supply.

Coverage

- Geographic: EMM regions 20, 21, 22, 23, and 25
- Time unit/frequency: Annual through 2050
- Product: Electricity
- Economic sector: Electricity generators

Modeling features

- Modeling structure: The model operates at the level of individual geothermal sites aggregated to segmented EMM regional averages.
- Model technique: Levelized electricity costs from each supply segment of each site in each region are arrayed in increasing cost order, then aggregated into three increasing average-cost segments in each iteration in each year, along with attendant quantities (megawatts) and average heat rates and capacity factors.
- Incorporates short-term cost elasticities of supply, technological optimism, and learning.

Independent expert reviews conducted

None. However, during development of the submodule, we received ongoing review and comment from the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy; Office of Power Technologies; the National Renewable Energy Laboratory; and from DynCorp Corporation, among others. See Appendix 7-C: Bibliography.

Status of evaluation efforts by sponsor

None

8. Conventional Hydroelectricity Submodule

Module purpose

The Conventional Hydroelectricity Submodule (CHS) represents U.S. conventional hydroelectricity (hydro) resources supply along with each site's technology cost and performance characteristics used to project new conventional hydroelectric capacity for central station electricity supply through the mid-term future. More specifically, the CHS:

- Provides the Electricity Market Module (EMM) Electricity Capacity Planning (ECP) Submodule the available supply (MW) of new conventional hydroelectric-generating capacity 1 MW or greater (and not more than 10 cents per kilowatthour) as well as its related average cost and performance characteristics, based on information about known conventional hydroelectric sites
- Reduces supply available for additional future capacity as conventional hydroelectric capacity resources are used, including capacity identified from historical data, from reported plans, and from resources already chosen in earlier forecasting iterations by the ECP
- Adjusts estimated levelized costs of hydroelectricity from each site based on its public acceptance and the probability of meeting environmental requirements (environmental suitability factor)
- Changes average calculated hydroelectric capital costs, reducing them to reflect experience (learning-by-doing); short-term elasticities are not applied for conventional hydroelectric
- Permits changes in the assumed hydroelectric capital costs for use in alternative cases through the use of capital-cost coefficients by individual site or for all sites in a specific year or multiple years

Identifying sites and estimating costs for the CHS was originally done by the Idaho National Engineering and Environmental Laboratory from lists assembled from Federal Energy Regulatory Commission license applications and other survey information.[18] Starting with AEO2006, we eliminated some large sites we found no longer existed and, for retained sites 100 MW or greater, replaced generalized site capacity factors with individual site capacity factors estimated by the Federal Energy Regulatory Commission.

Relationship of the Conventional Hydroelectricity Submodule to other modules

The CHS interacts primarily with the ECP. Relationships between the CHS and other NEMS components include:

- CHS provides new capacity availability, performance, and cost information to the ECP for making planning decisions.
- CHS uses new capacity build decisions from the ECP to decrement available new conventional resources and capacity.
- CHS uses financial parameters and tax data for calculating ECP-based avoided costs to determine the highest cost at which new hydro supply can compete, setting the upper-cost bound of hydro supply.

[18] Douglas G. Hall, 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 (Idaho Falls, Idaho, June 2003).

Modeling rationale

For each NEMS region, the Conventional Hydroelectricity Submodule develops three-part estimates of regional conventional hydroelectric supplies—total MW available in order of three increasing-cost price and quantity pairs. These estimates are used to compete conventional hydroelectric technologies with fossil, nuclear, and other central-station renewable electricity generating alternatives for each forecast year and region that needs new generating capacity.

Fundamental assumptions

In the underlying hydro resource database, each named hydroelectric site is characterized by its:

- Name
- Location
- Ownership
- Resource
- Cost
- Performance characteristics, notably including its:
    - Components of capital cost
    - Average monthly and annual capacity factors
    - Fixed and variable operating costs
    - Estimated probability of meeting legal, cultural, and environmental barriers
    - Additional identifying information

For each model iteration within each forecast year and region, the CHS arrays all available hydro sites from lowest- to highest-cost at or lower than the avoided cost (plus an additional percentage to account for market-sharing to allow some capacity that is close to competitive) determined in the previous model iteration (an estimate of the upper bound of likely acceptable cost in the current iteration). The CHS then segments the array into three parts—a lowest-cost, middle-cost, and upper-cost segment—and determines the capacity-weighted average capital cost, operations and maintenance costs, and capacity factors for each group. It then provides the EMM with three increasing levelized cost-quantity pairs of available hydroelectric capacity.

Users can adjust the CHS to influence forecasts of new hydroelectric capacity by adjusting the proportions of the overall cost range attributed to each segment. A downward adjustment to the proportion of the array (share of the overall range of cost) characterized in the lowest-cost segment, for example, would lower both the average cost of the first segment—thereby increasing the probability of being selected, but relatively decreasing the quantity of capacity likely to be selected. Increasing the proportion of the overall cost range in a segment increases the amount of capacity available in that range but also increases the average capital cost of the capacity. Moreover, because each of the three segments characterizes an average, the decisions regarding proportions also influence the magnitude of the increase in cost between steps; large proportions can yield large cost increases, and small steps can yield small average increases.

Input data for the supplies were initially provided by the Idaho National Engineering and Environmental Laboratory (INEEL) under a project jointly funded by EIA and the U.S. Department of Energy's Office of

Energy Efficiency and Renewable Energy.[19] The effort is described in *Estimation of Economic Parameters of U.S. Hydropower Resources* INEEL/EXT-03-00662 (Idaho Falls, Idaho, June 2003). The original database, named IHRED (Idaho Hydropower Resource Economics Database) is available through INEEL or EIA as an appendix to the report. The INEEL database, represents an initial effort to assign cost attributes to an already-developed site database [Hydropower Evaluation Software (HES)], based on the:

- Federal Energy Regulatory Commission's Hydropower Resource Assessment database developed from hydropower licensing actions
- Nationwide Rivers Inventory Database developed and maintained by the National Park Service
- Supporting information from state resource and energy agencies[20]

The more recent INEEL IHRED effort supplemented the HES by providing generalized estimates of capital and other costs, as well as generalized (regional) estimates of capacity factors. Costs and other monetary values in IHRED are expressed in 2002 dollars (NEMS expresses these same values in 1987 dollars).

For AEO2006 and subsequent reports, we modified the IHRED in several ways. First, HES-estimated capacity factors specific to each hydro site replaced the regional generalized estimates from IHRE. In general, the site-specific estimated capacity factors are lower than the IHRED factors but are considered superior, based on specific assessments of the sites. Second, to reduce workload, we eliminated from consideration all sites for which an off-line estimate of the levelized cost of generation exceeded 10 cents per kilowatthour (2002 dollars), given the near impossibility of any such site being selected in any conceivable scenario. Third, the IHRED database was separated into two groups, small sites (100 MW or less) and large sites (greater than 100 MW). We accepted data on all small sites for use. Finally, large sites were arrayed from lowest to highest cost and then individually reviewed, to the extent permitted by time and resources (by contacting site owners or state agencies to verify the existence and viability of such sites). Many large sites were found unavailable (already developed, otherwise developed, now precluded by Wild and Scenic Rivers, or other circumstance making development naturally or legally impossible). We did not examine all large sites. Documentation of calculations and modifications are available in our Excel files HydroLessThan10cents033004.xls and HydroCritiqueTop100041904.xls.

Resources

The CHS characterizes economic supply of both run-of-river and storage dams for conventional hydroelectric power at new or existing sites 1 MW or greater. The model incorporates data on some—although not all—potential hydroelectricity supply, including:

- Undeveloped sites with no dam
- Opportunities for adding hydroelectric capacity at existing dams without hydropower
- Opportunities to increase capacity at existing hydroelectric facilities

[19] Contract DE-AC007-99ID13727, completed June, 2003.

[20] Alison M. Conner, James E. Francfort, and Ben N. Rinehart, Idaho National Engineering and Environmental Laboratory, *U.S. Hydropower Resource Assessment, Final Report*, Contract DE-AC07-94ID13223 (Idaho Falls, Idaho, December 1998).

Exclusions

The CHS does not represent all hydroelectric potential. First, the CHS does not represent opportunities of less than 1 MW capacity. Second, the CHS does not enumerate new pumped storage hydroelectricity potential (an energy storage technology using off-peak coal or nuclear-powered electricity to lift water to an upper pool for later peaking hydro generation); however, the EMM does model existing pumped storage. Third, the supply also omits sites excluded from development by federal statutes and policies, including hydro resources:

- Excluded by the Wild and Scenic Rivers Act
- Sited at the upstream or downstream ends of wild and scenic streams or on a tributary
- In National Parks
- Otherwise excluded by federal or state law or in a federally designated exclusion zone

Furthermore, the CHS does not represent offshore (ocean) hydro, in-stream (non-impoundment) potential, additional potential from refurbishing existing hydro capacity, or increased output opportunities from efficiency or operational improvements. In addition, the CHS does not represent any sites for which off-line EIA estimates made in 2004 indicated levelized per-kilowatthour costs (in 2002 dollars) greater than 10 cents per kilowatthour. We also eliminated a number of sites of 100 MW or greater that, based on contacts with owning firms, were concluded to not be available today but were already developed, excluded from development by law, or otherwise unable to offer additional potential today. Finally, the CHS does not account for any unknown additional conventional hydroelectric potential that might become available at known sites included in these estimates.

Capital costs

Overnight capital costs—and all other costs—are expressed in 2002 dollars. Components of overnight capital costs include licensing, construction, and a range of individual environmental mitigation costs, as they apply to individual sites. Construction costs include:

- Land and rights
- Structures and improvements
- Reservoirs
- Dams
- Waterways
- Equipment
- Access roads
- Rail
- Bridges

Construction costs were derived by INEEL primarily from 1990–2000 FERC Form 1, *Annual Report of Major Electric Utilities, Licensees, and Others*.

Learning by doing

Learning by doing refers to reductions in a technology's capital costs as experience with the technology is gained, expressed in NEMS as a function of the total amount of capacity in place. The capital costs of conventional hydroelectric plants decrease in NEMS as additional capacity is built.

You can find a description of learning by doing in NEMS in either the *Electricity Market Module Assumptions for the Annual Energy Outlook* or *Electricity Market Module of the National Energy Modeling System, Model Documentation Report* for the relevant *Outlook* year. Conventional hydroelectricity is considered a mature technology, meaning that hydroelectricity is already well developed and that capital costs will likely decrease at the slowest rate.

NEMS also includes a minimum decrease in capital costs independent of actual builds.

Short-term elasticities

In NEMS, capital costs for most technologies are assumed to increase if capacity increases rapidly within a given year, thereby temporarily putting pressure on supply resources (such as skilled labor, materials, and manufacturing). You can find more information on these elasticities in the Assumptions and Documentation reports. These short-term elasticities are not applied to conventional hydroelectricity because U.S. and global infrastructure are currently considered fully capable of meeting all demand for the mature technology.

Mitigation costs—construction component

For sites not prohibited from development but nevertheless facing environmental mitigation requirements, the construction costs of such mitigation are individually estimated and included among capital costs derived from a variety of sources documented in the INEEL report. Individual categories of potential mitigation costs include:

- Archeological requirements
- Fish and wildlife protection
- Scenic or recreation requirements
- Water quality monitoring
- Fish passage requirements

All are expressed in 2002 dollars per kilowatt and are included among capital costs.

Mitigation costs—public acceptance component

IHRED-estimated mitigation costs account for the brick and mortar construction costs of mitigation requirements. To account for the litigation, licensing, and public acceptance costs of mitigation, we adapted the HES environmental suitability factor to estimate the probability of a hydroelectric project's successful development in light of all individual environmental characteristics of the site. Suitability factors range from 0.90 (the greatest probability of meeting environmental requirements and being developed), and descend to 0.75, 0.50, 0.25, and finally, 0.10. The HES included no estimates of the costs of overcoming likely objections, but we incorporated into our submodule an arbitrary estimate of levelized additional costs per kilowatthour to represent the added costs of meeting environmental requirements—legal challenges, studies, and public outreach—in addition to the engineering costs already accounted for:

- If Site Probability = 0.90, then add 0.00 mills to levelized cost (1987$)
- If Site Probability = 0.75, then add 3.00 mills to levelized cost (1987$)
- If Site Probability = 0.50, then add 5.00 mills to levelized cost (1987$)

- If Site Probability = 0.25, then add 8.00 mills to levelized cost (1987$)
- If Site Probability = 0.10, then add 10.00 mills to levelized cost (1987$)

These cost adjustments almost certainly eliminate most of the 0.25 and 0.10 probability sites from practical consideration and greatly reduce the competitive potential of 0.50 sites as well. Changing the costs associated with site probabilities offers another opportunity for analyst influence on hydroelectric supply costs.

Fixed operation and maintenance costs

Fixed Operation and Maintenance (O&M) costs include operation and maintenance supervision and engineering, as well as maintenance of structures, reservoirs, dams, waterways, and electric plants. Where applicable, fixed O&M includes the Federal Energy Regulatory Commission (FERC) annual charge noted below. Fixed O&M costs were derived from FERC Form 1 data for 1990 to 2001 and are expressed in 2002 dollars per kilowatt per year.

FERC annual charge

For plants with a capacity greater than 1.5 MW, FERC charges plant owners an annual fee based on plant capacity and annual generation. We consider the FERC annual charge part of fixed O&M, and we estimate the charge using an estimate of constant annual generation derived by INEEL, based on 1999 charges.

Variable operation and maintenance costs

Variable O&M maintenance costs, also derived from FERC Form 1 data, include estimates for charges for water for power, hydraulic and electric expenses, miscellaneous hydraulic power expenses, and rents. Variable O&M is expressed in 2002$ mills per kilowatthour.

Capacity factors

The IHRED database contains both estimated monthly and annual capacity factors for each site. We replaced these regional average annual capacity factors with the individually determined annual capacity factors established by FERC or in other specific studies underlying the HES database. We modified monthly IHRED capacity factors were in proportion to the annual factor adjustment. In general, the individual capacity factors are lower than the generalized estimates. We also applied exceptions and used the IHRED estimate or 65% (whichever was lower) for undeveloped sites for which no FERC capacity factor was available and 35% for incremental capacity for which no FERC capacity factor was available. Where the FERC capacity factor exceeded 65% for new sites or 35% for incremental capacity, we assigned either 65% or 35%, given that the EIA bound, although arbitrary, is higher than the averages for known sites, and the FERC values appear to often be in error (at times exceeding 100%).

Regional adjustment factors are used in the CHS to enable modification of projected hydroelectric output on a regional level. This adjustment may be necessary for years where projected hydroelectric generation is anomalously high or low. Current regional adjustment factors are set so that the result of multiplying them by the site-specific capacity factors approaches a 20-year average.

Heat rates

Conventional hydroelectric facilities tend to be highly efficient; the Federal Energy Regulatory Commission cites modern hydroelectric turbines to be about 90% efficient (90% of input energy converted to output electricity), suggesting an average input heat rate equivalent under 3800 Btu per kilowatthour.[21] We use the average heat rate for fossil-fueled generators to represent the primary energy consumption of all renewable generation sources that do not require the combustion of a fuel, including hydroelectric. This convention is currently set at the heat rate for fossil-fueled steam-electric plants of 9,756 Btu per kilowatthour.[22]

Alternative approaches

Before developing the Conventional Hydroelectric Submodule, we extensively polled hydroelectricity analysts and organizations and conducted ongoing exchanges with contacts at the National Hydropower Association, Oak Ridge National Laboratory, the Bonneville Power Administration, the Tennessee Valley Authority, and others. Although many annual and short-term regional forecasting models of expected output from existing hydroelectric capacity are available, we found no models of mid- or longer-term hydroelectric supply, either of resources expressed in terms of economic supply or in terms of their competition with other central station electricity supplies.

Conventional Hydroelectric Submodule structure

The CHS **SUBROUTINE HYDRO** has five basic components.

Incorporates data

On its initial iteration, subroutine GET_HYSITE_DATA reads the hydroelectric site data from the HYDSITE.TXT input data file that contains records of each individual hydroelectric site, including state and NEMS region, nameplate capacity, capital and O&M cost components, and capacity factors. Subroutine GET_HYDATA reads in the annual capital cost multipliers, build-bounds, public acceptance mitigation costs, and the supply curve cost segment ranges from the input data file WHYDRO.TXT. Together, the two build the HYDSITE conventional hydroelectric supply structure. Capital costs are the sum of:

- Licensing, construction, and environmental mitigation costs
- Both fixed and variable O&M costs
- The FERC annual charge, where applicable, with fixed O&M

The annual capital cost multipliers are applied to the capital costs before leaving the GET_HYSITE_DATA subroutine. The cost multipliers will usually have the value 1.00 for reference cases and various values less than 1.00 for alternative scenarios such as high renewables cases.

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[21] Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States, Developed and Undeveloped* (Washington, DC January 1, 1992), page xx. Applying the 90% efficiency cited by FERC to the 3412-Btu-per-kilowatthour energy content of electricity yields an input heat rate of 3,791 input Btu per kilowatthour.

[22] See Table A6 at http://www.eia.gov/totalenergy/data/annual/#appendices .

Develops NEMS overall regional conventional hydroelectric supplies

In each iteration, subroutine BLD_HYD_CURVES first creates NEMS regional conventional supplies for each NEMS region (Alaska and Hawaii are processed in the hydroelectric submodule but not used by the EMM). Within each NEMS region, sites are arrayed from least to greatest in order of estimated levelized cost, resulting in an aggregate conventional hydroelectric supply for each region in each iteration, in the array HYDCURVE.

Provides sub-supplies for specific regional demands

For each iteration of the EMM, the CHS determines the maximum levelized cost (avoided cost) at which hydroelectric supply in each region can compete. The maximum competitive value is the levelized cost of the highest-cost technology selected in the immediately previous iteration of the ECP plus an additional percentage representing the market-sharing algorithm.[23] As a result, all remaining hydroelectric capacity that can generate at or lower than the previous iteration's maximum competitive value is offered as new hydroelectric supply in the current iteration.

Next, the subroutine BUILD_HYD_CURVES segments each region's aggregate hydroelectric supply among three increasing-cost quantity pairs using capacity-weighted average costs per kilowatthour. This segmentation provides the EMM three quantities of available conventional hydroelectric capacity, as well as their respective O&M costs and seasonal and annual capacity factors at three increasing levelized costs for each region. The gross cost difference between the lowerst-cost unused hydroelectric capacity and the ECP-adjusted avoided cost is used to identify the three groups. The lowest-cost group includes all unused capacity in the lowest-cost quartile (capacity whose levelized cost is equal to or less than +25% of the gross cost difference). The quantity in this group is not the lowest-cost 25% of capacity, but instead, whatever proportion of capacity occurs in the lowest 25% of the cost range. The second group includes all capacity between the 25th percentile and the 75th percentile, and the third group includes all remaining capacity higher than the 75th cost percentile.

All available capacity in each cost group is then conveyed to the EMM as available supply, with one levelized cost associated with each group. The one levelized cost transmitted for each group equals the capacity-weighted levelized average cost for the individual sites' costs within the group. A module variable enables the analyst to vary the initial percentage thresholds. The result of lower thresholds is lower average costs—and greater ability to compete—but reduced quantities available to compete. Higher thresholds yield greater supplies but higher (and less-competitive) average costs. Recognizing that the three segments yield significant increases in average costs (discontinuities) from one step to the next, the choice of thresholds can result in significant differences in NEMS selections of conventional hydroelectric capacity, particularly if choices have the effect of limiting supply to one (or none) of the segments.

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[23] The market-sharing algorithm exists in recognition that in real markets technologies that are close in cost to the least-cost technology will occasionally be selected for economic and other reasons not represented in the modeling. Under the sharing algorithm, the closer in cost a specific other technology is to the least-cost technology, the greater (yet small) share of the available market will be taken by that technology.

Decrements available capacity

Within subroutine BUILD_HYD_CURVES, for each iteration, CHS reduces available conventional hydroelectric capacity in each region in response to external reports of new hydroelectric builds in the region or selection by the EMM in earlier iterations.

Provides diagnostics

For each iteration, subroutine WRITE-HYDB provides diagnostic information on hydroelectric capacity, sites chosen, technology costs, and performance. Diagnostics provided through Excel output file HYDRO_OUT.XLS include the following datasets:

- **Hyd_Input_Data** displays quantities of capacity available at each hydroelectric site.
- **Hyd_Curve_Data** displays, in lowest-to-highest cost order, each hydroelectric site's capacity and estimated cost per kilowatthour.
- **Hyd_Curve_Info** displays aggregate conventional hydro supplies and average cost per kilowatthour as available in each NEMS region for each forecast year and transmits values to the Electricity Market Module (EMM) as aggregate hydroelectric supply
- **Hyd_Builds** displays quantities of conventional capacity built in each NEMS region in each forecast year

Key computations and equations

This section describes the most important equations in the CHS.

Reading the data

In the first iteration, data for the hydroelectric sites are read in from the HYDSITE input file by the CHS subroutine, GET_HYSITE_DATA. The site data are stored in the HYDSITE data structure, which is defined below. Subroutine GET_HYDATA reads the hydro parameters from the input file WHYDRO.

HYDSITE Data Structure

PROJNAME	Project Name
PROJNUM	Project Number
STATE	State Location
SITE_ID	Site ID
NERC	EMM Region
LATITUDE	Latitude
LONGITUDE	Longitude
CLASS	Site Class Code: C=Coop, F=Federal, I=Industrial, M=Municipal, P=Private Utility, R=Private Non-Utility, N/A=Not Available
UNITTYPE	C=Conventional, R=Reversible, Z=Missing
PLNTTYPE	Plant Type
PROJSTATUS	Project Status
DAMSTATUS	Dam Status
WSPROT	Wild/Scenic Protection Y=Yes, N=No

WSTRIB	Wild/Scenic Tributary, Location Y=Yes, N=No
ENVVALUES	Environmental Values, Y=Yes, N=No
	1=Cultural Value, 2=Fish, 3=Geological, 4=Historical,
	5=Other, for example, rare wetland, wilderness designation, 6=Recreation
	7=Scenic, 8=Wildlife, 9=Threatened/Endangered Wildlife
	10=Threatened/Endangered Fish
LANDCODES	Federal Land Codes, Y=Yes, N=No
	1=FLC103, National Park, Monument, Rec area, etc.,
	2=FLC104, National Forest or Grassland,
	3=FLC105, National Wildlife Refuge, Game Preserve, or Fish Hatchery
	4=FLC106, National Scenic Waterway or Wilderness Area
	5=FLC107, Indian Reservation
	6=FLC108, Military Reservation
	7=FLC198, Not on Federal Land
SITEPROB	Project Environmental Suitability Factor
	0.10 = Development prohibited or highly unlikely
	0.25 = Major reduction in likelihood of development
	0.50 = Likelihood of development reduced by half
	0.75 = Minor reduction in likelihood of development
	0.90 = Little effect on likelihood of development
LISCCOST	Licensing Cost 2002 $K
CONSCOST	Construction Cost 2002 $K
DEVCOST	Overnight Development Cost 2002 $K
MIT_ARCH	30-Year Archaeological and Historical mitigation cost 2002 $K
MIT_FISH	30-Year Fish and Wildlife mitigation cost 2002 $K
MIT_SCEN	30-Year Scenic and Recreation mitigation cost 2002 $K
MIT_WATER	30-Year Water Quality Monitoring Cost 2002 $K
MIT_PASS	30-Year Fish Passage cost 2002 $K
MIT_TOTAL	Total mitigation cost 2002 $K
TOTDEV_COST	Total Development Costs (Mit_Total + Devcost) 2002 $K
UNITDEV_COST	Total Unit Development Costs 2002$/kW
COE	Levelized Cost 2002$/MWh
CAP_COST	Capital Cost 2002$/kW
TOTFOM_COST	Average Annual Fixed O&M Cost 2002 $K
TOTVOM_COST	Average Annual Variable O&M Cost 2002 $K
FOM_COST	Average Annual Fixed O&M Unit Cost 2002$/kW
VOM_COST	Average Annual Variable O&M Unit Cost 2002$/MWh
FERC_COST	FERC Annual Charge (Applicable if >= 1.5 MW) 2002 $K
UNITFERC_COST	FERC Annual Charge Unit Cost (Applicable if >= 1.5 MW) 2002$/KW
POTENTIAL_CAP	Potential Capacity (MW)
CAPCOST_MULT	Yearly Capital Cost Multipliers by Hydro Sites
CAP_COST_ADJ	Capital Cost Adjustment Factors

MON_CAPACITY_FACTOR(12)	0.00 TO 1.00	- monthly capacity factors
AVG_CAPACITY_FACTOR	0.00 TO 1.00	- average annual capacity factors

In each iteration, the capital, O&M, and levelized cost of energy for each site is calculated, and capital costs are adjusted for learning and technological optimism. Technological optimism and learning effects are estimated in subroutine ELEC_OPT in the Electricity Capacity Planning (ECP) Submodule of the EMM.

Building regional hydroelectric supplies

In each iteration, data on supplies at each site are merged with cost data from other sites in each region and arrayed for competition in the ECP within the region. The CHS first constructs a hydroelectric supply curve of levelized cost of energy and capacity available for each EMM region. CHS then segments the competitive part of that array into three generalized increasing cost segments (as described in the Conventional Hydroelectric Submodule Structure section), passing to the ECP the total capacity available in each increasing cost segment along with the capacity-weighted cost and performance parameters for the segment.

For each region and in each iteration, the CHS receives a maximum cost from the EMM, a value equal to the COE of the highest-cost capacity previously selected in each region, called the Regional Avoided Cost, plus the market-sharing tolerance. This avoided cost is used to determine the competitive part of the arrayed costs.

Avoided Cost = (Regional Maximum Prior COE) * (1.0 + Market-sharing Tolerance)

The subroutine BUILD_HYD_CURVES iterates within each region until the capacity available in the first (lowest cost) step is greater than zero or 10 iterations have occurred, incrementing the threshold cost 10% for each iteration. The cumulative values calculated in this subroutine include:

AVAIL_SUPPLY	= Megawatts available for each record
CUM_SUPPLY	= Cumulative sum available megawatts in each region
SYS_CAP_COST	= Cumulative capacity-weighted capital cost, three segments
SYS_CAP_FAC	= Cumulative capacity-weighted capacity factor, three segments
SYS_MON_CAP_FAC	= Cumulative capacity-weighted monthly capacity factors, three segments
SYS_COST	= Cumulative capacity-weighted COE, three segments
SYS_VOM_COST	= Cumulative capacity-weighted Variable O&M cost, three segments
SYS_FOM_COST	= Cumulative capacity-weighted Fixed O&M cost, three segments

From these cumulative values BUILD_HYD_CURVES then determines the specific value for the cost and performance variables for each of the three segments of available hydroelectric supply in each region. The cost and performance variables calculated include:

CAP_COST	= Capital cost
CAP_FAC	= Capacity factor
MON_CAP_FAC	= Monthly capacity factors
FOM_COST	= Fixed O&M cost
VOM_COST	= Variable O&M cost

The above values are calculated as weighted averages as shown in the equations below, where *i* represents each individual site:

Average_Capital_Cost = $(\sum_i (CAP\_COST_{(i)} * Capacity_{(i)}))/ Cumulative\_Capacity$
Average_FOM_Cost = $(\sum_i (FOM\_COST_{(i)} * Capacity_{(i)}))/ Cumulative\_Capacity$
Average_VOM_Cost = $(\sum_i (VOM\_COST_{(i)} * Capacity_{(i)}))/ Cumulative\_Capacity$
Average_Cap Fac = $(\sum_i (CAP\_FAC_{(i)} * Capacity_{(i)}))/ Cumulative\_Capacity$
Average_Mon_Cap Fac = $(\sum_i (MON\_CAP\_FAC_{(i)} * Capacity_{(i)}))/ Cumulative\_Capacity$

The CHS passes the ECP actual values only for the first of the three segments; values for steps 2 and 3 are expressed as weights applicable to the values in the first segment. The variables passed to the EMM include:

EMM_CAP_COST
EMM_CAP_FAC
EMM_MON_CAP_FAC
EMM_CAPACITY
EMM_VOM_COST
EMM_FOM_COST

Other features of the Hydroelectric Submodule

Construction Lead Time, Construction Cost Profile, and First Online Year

In the CHS, new hydroelectric plants are constructed over a four-year time period, and capital costs are allocated in the annual proportions 15%, 22%, 30%, and 33%.

Learning, Short-Term Elasticities, and Technological Optimism

Capital Costs for hydroelectric-generating technologies are affected by learning-by-doing (as are all generating technologies), as well as by technological optimism. You can find a description of these characteristics and assumptions and values used for hydroelectric in *Assumptions to the Annual Energy Outlook 2020: Electricity Market Module*.

Appendix 8-A: Inventory of Variables, Data, and Parameters

Values for this inventory are included in the body of this chapter, along with reference to the Excel files supporting the Conventional Hydroelectricity Submodule. If you have questions about the submodule, contact the Official Model Representative, listed in Appendix 8-D. Data files for the CHS are maintained in the Office of Electricity, Coal, Nuclear, and Renewables Analysis (OECNRA). The INEEL deliverable is also available through OECNRA.

Appendix 8-B: Mathematical Description

If you have questions about the CHS algorithm, contact the Official Model Representative, listed in Appendix 8-D. The Conventional Hydroelectricity Submodule computes the levelized cost of energy for three increasing cost segments of conventional hydroelectric supply in each NEMS region in each NEMS iteration for each forecast year. Rationales are explained in the Module Purpose and Fundamental Assumptions portion of this documentation. The levelized cost for each site is calculated as:

$$COE_{i,y,r} = \frac{\left(CCST_{i,y} + LCST_{i,y} + MCST_{i,y}\right) \times FCF_r \times LFACT_y \times OPFACT_y + FOM_i + FERC_i}{CF_i \times 8760 \times 1000} + VOM_i + PUBCOST_i$$

where

i	= Hydroelectric Site
y	= Current Year
r	= NEMS Region
COE_i	= Levelized cost of energy for hydroelectric site *i*.
$CCST_{i,y}$	= Construction costs for hydroelectric site *i* in year *y*, $/kW.
$LCST_{i,y}$	= Licensing costs for hydroelectric site *i* in year *y*, $/kW.
$MCST_{i,y}$	= Total mitigation costs for hydroelectric site *i* in year *y*, $/kW.
FCF_r	= Fixed Charge Factor in EMM region *r* for hydroelectric technology, fraction.
$LFACT_y$	= Learning Factor for hydroelectric technology in year *y*, fraction.
$OPFACT_y$	= Technological Optimism Factor for hydroelectric technology in year *y*, fraction.
FOM_i	= Fixed O&M costs for hydroelectric site *i*, $/kW.
$FERC_i$	= FERC Annual Charge for hydroelectric site *i*, 1987 $/kW.
CF_i	= Capacity Factor for hydroelectric site *i*, fraction.
VOM_i	= Variable O&M costs for hydroelectric site *i*, $/MWh.
$PUBCOST_i$	= Public Acceptance Cost for hydroelectric site *i*, $/MWh.

The levelized costs by hydroelectric site are then sorted from lowest to highest cost, resulting in an aggregate regional hydroelectric supply array. These regional supply arrays are then used to generate the three-step EMM supply curves.

Appendix 8-C: Bibliography

Conner, Alison M. , Francfort, James E., and Rinehart, Ben N., Idaho National Engineering and Environmental Laboratory, *U.S. Hydropower Resource Assessment*, *Final Report*, Contract DE-AC07-94ID13223 (Idaho Falls, ID, December 1998).

Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States, Developed and Undeveloped* (Washington, DC, January 1, 1992).

Hall, Douglas G., Hunt, Richard T., Reeves, Kelly S., and Carroll, Greg R., Idaho National Engineering and Environmental Laboratory, *Estimation of Economic Parameters of U.S. Hydropower Resources* INEEL/EXT-03-00662 (Idaho Falls, ID, June 2003).

Appendix 8-D: Module Abstract

Module name

Conventional Hydroelectricity Submodule

Module acronym

CHS

Description

The CHS converts lists of identified available U.S. conventional hydroelectric potential and costs into three-part, increasing-cost regional supply projections (quantity-cost pairs) for each NEMS region for each forecast year. Input data for each site include its state and NEMS region, components of capital cost, fixed and variable operations and maintenance costs, and capacity factors. All sites that can produce electricity at or lower than an avoided cost determined by NEMS in the previous forecast cycle (adjusted upward for market-sharing) become eligible to compete as new hydroelectric supply averaged among one of the three increasing cost groups. After selecting some capacity, the CHS decrements the available supply for the next iteration by the amount taken in the current cycle.

Purpose of the module

The CHS provides the Electricity Capacity Planning (ECP) module the amounts of available conventional hydroelectric-generating capacity, their costs, and performance characteristics for competition in the ECP for new regional electricity supply.

Most recent module update

October 2019

Part of another module

The CHS submodule is a component of the Renewable Fuels Module (RFM) of the National Energy Modeling System (NEMS).

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Documentation

This chapter constitutes the documentation of the CHS.

Archive media and installation manual

The CHS is archived as part of NEMS production runs.

Energy system described

Conventional hydroelectric supply includes potential 1 megawatt or greater for impoundment sites that are undeveloped, with dams but no hydroelectric, or with potential for additional hydroelectric. The supply does not include pumped storage opportunities, in-stream (non-impoundment) potential, ocean-current potential, or refurbishments of existing capacity or operational changes that increase output.

Coverage

- Geographic: 25 EMM regions (Alaska and Hawaii are included in the database and processed in the submodule, but they are excluded from the EMM)
- Time unit/frequency: Annual through 2050
- Product: Electricity
- Economic sector: Central Station Electricity Generators

Modeling features

- Modeling Structure: The model operates at the level of individual conventional hydroelectric sites aggregated to segment-level EMM regional averages.
- Model Technique: Levelized electricity costs of each site in each region are arrayed in increasing cost order, then aggregated into three increasing average-cost segments in each iteration in each year, along with corresponding capacity quantities (megawatts), average heat rates, and capacity factors.
- Incorporates short-term cost elasticities of supply, technological optimism, and learning.

Input sources

The primary data input for the conventional hydroelectricity supply is a dataset prepared specifically to support the modeling. The dataset is prepared under contract by the Idaho National Engineering and Environmental Laboratory. The INEEL contract work integrated data published by Hall, Douglas G., Hunt, Richard T., Reeves, Kelly S., and Carroll, Greg R., (INEEL) in *Estimation of Economic Parameters of U.S. Hydropower Resources* INEEL/EXT-03-00662 (Idaho Falls, Idaho, June 2003), along with information from other documents cited in Appendix 8-C.

Independent expert reviews conducted

None. However, we presented the CHS methodology at a May 10, 2005, Renewable Electricity Modeling Forum to expose the submodule to independent expert review.

Status of evaluation efforts by sponsor

None