Chapter 13. Renewable Fuels Module

The NEMS Renewable Fuels Module (RFM) provides natural resources supply and technology input information for projections of new central-station U.S. electricity generating capacity using renewable energy resources. The RFM has six submodules representing various renewable energy sources: biomass, geothermal, conventional hydroelectricity, landfill gas (LFG), solar (thermal and Photovoltaic), and wind [115].

Some renewables, such as landfill gas LFG from municipal solid waste (MSW) and other biomass materials, are fuels in the conventional sense of the word, while others, such as water, wind, and solar radiation, are energy sources that do not involve the production or consumption of a fuel. Commercial market penetration of renewable technologies varies widely.

The submodules of the RFM interact primarily with the Electricity Market Module (EMM). Because of the high level of integration with the EMM, the final outputs (levels of consumption and market penetration over time) for renewable energy technologies are largely dependent upon the EMM. Because some types of biomass fuel can be used for either electricity generation or for the production of liquid fuels, such as ethanol, there is also some interaction with the Liquid Fuels Market Module (LFMM), which contains additional representation of some biomass feedstocks that are used primarily for liquid fuels production.

Projections for residential and commercial grid-connected photovoltaic systems are developed in the end-use demand modules and not in the RFM; see the Distributed Generation and Combined Heat and Power description in the “Commercial Demand Module” and “Residential Demand Module” sections of the report. Descriptions for biomass energy production in industrial settings, such as the pulp and paper industries, can be found in the “Industrial Demand Module” section of the report.

Key assumptions

Nonelectric renewable energy uses

In addition to projections for renewable energy used in central station electricity generation, AEO2016 contains projections of nonelectric renewable energy consumption for industrial and residential wood heating, solar residential and commercial hot water heating, biofuels blending in transportation fuels, and residential and commercial geothermal (ground-source) heat pumps. Assumptions for these projections are found in the Residential Demand, Commercial Demand, Industrial Demand, and LFMM sections of this report. Additional minor renewable energy applications occurring outside of energy markets, such as direct solar thermal industrial applications, direct lighting, off-grid electricity generation, and heat from geothermal resources used directly (for example, district heating and greenhouses) are not included in the projections.

Electric power generation

The RFM considers only grid-connected central station electricity generation systems. The RFM submodules that interact with the EMM are the central station grid-connected biomass, geothermal, conventional hydroelectricity, LFG, solar (thermal and photovoltaic), and wind submodules, which provide specific data or estimates that characterize the respective resources. A set of technology cost

and performance values is provided directly to the EMM and is central to the build and dispatch decisions of the EMM. The technology cost and performance values are summarized in Table 8.2 in the chapter discussing the EMM.

Capital costs

Chapter 8 describes the methodology used to determine initial capital costs and cost-learning assumptions. Regional variation in costs for wind is based on EIA analysis of the actual variation in the installation cost of recently built wind projects. For hydropower and geothermal resources, costs are based on site-specific supply curves as described in the hydropower and geothermal sections of this document.

Capital costs for renewable technologies are affected by several factors. Capital costs for technology to exploit some resources, especially geothermal, hydroelectric, and wind power resources, are assumed to be dependent on the quality, accessibility, and/or other site-specific factors in the areas with exploitable resources. These factors can include additional costs associated with reduced resource quality, the need to build or upgrade transmission capacity from remote resource areas to load centers or local impediments to permitting, equipment transport, and construction in good resource areas due to siting issues, inadequate infrastructure, or rough terrain.

Short-term cost adjustment factors increase technology capital costs as a result of a rapid U.S. buildup in a single year, reflecting limitations on the infrastructure (for example, limits on manufacturing, resource assessment, and construction expertise) to accommodate unexpected demand growth. These factors, which are applied to all new electric generation capacity, are a function of past production rates and are further described in “The Electricity Market Module of the National Energy Modeling System: Model Documentation 2014” report, available at www.eia.gov/forecasts/aeo/nems/documentation/electricity/pdf/m068(2014).pdf.

Also assumed to affect all new capacity types are costs associated with construction commodities. Through much of 2000 to 2008, the installed cost for most new plants was observed to increase. Although several factors contributed to this cost escalation, some of which may be more or less important to specific types of new capacity, much of the overall cost increase was correlated with increases in the cost of construction materials, such as bulk metals, specialty metals, and concrete. Capital costs are specifically linked to the projections for the metals producer price index found in the Macroeconomic Module of NEMS. Independent of the other two factors, capital costs for all electric generation technologies, including renewable technologies, are assumed to decline as a function of growth in installed capacity for each technology.

For a description of NEMS algorithms lowering generating technologies’ capital costs as more units enter service (learning), see “Technological optimism and learning” in the EMM chapter of this report. A detailed description of the RFM is provided in the EIA publication, Renewable Fuels Module of the National Energy Modeling System, Model Documentation 2014, DOE/EIA-M069(2014) Washington, DC, 2014, available at www.eia.gov/forecasts/aeo/nems/documentation/renewable/pdf/m069(2014).pdf.

Solar Submodule

Background

The solar submodule currently includes both solar thermal (also referred to as concentrating solar power or CSP) and photovoltaic (PV) technologies. The representative solar thermal technology assumed for cost estimation is a 100-megawatt central-receiver tower without integrated energy storage, while the representative solar PV technology is a 150-megawatt array of flat plate PV modules using single-axis tracking. PV is assumed to be available in all EMM regions, while CSP is available only in the Western regions with the arid atmospheric conditions that result in the most cost-effective capture of direct sunlight. Cost estimates for PV are based on a report by Leidos Engineering, LLC entitled "EOP III Task 10388, Subtask 4 and Task 10687 Subtask 2.3.1 – Review of Power Plant Cost and Performance Assumptions for NEMS: Technology Documentation Report," published in 2016, http://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf. The cost estimates for CSP are based on the SAIC report entitled "EOP III Task 1606, Subtask 4 – Review of Power Plant Cost and Performance Assumptions for NEMS: Technology Documentation Report," published in 2013 and available at http://www.eia.gov/analysis/studies/powerplants/capitalcost/archive/2013/pdf/updated_capcost.pdf. Technology-specific performance characteristics are obtained from information provided by the National Renewable Energy Laboratory (NREL).

Assumptions

- Only grid-connected (utility and nonutility) generation is included. Projections for distributed solar PV generation are included in the commercial and residential modules.
- NEMS represents the investment tax credit (ITC) for solar electric power generation by tax-paying entities. The ITC provides a credit to federal income tax liability as a percentage of initial investment cost for a qualified renewable generating facility. The recently passed Consolidated Appropriations Act of 2016 extended the availability of the ITC such that solar projects under construction before the end of 2019 qualify to receive the full 30% ITC, while those starting construction in 2020 and 2021 qualify for credits of 26% and 22% ITC, respectively. Utility-scale solar projects beginning construction after 2021 receive 10% ITC. EIA assumes a two-year lead time for utility-scale solar production, and thus assumes that plants entering service by [2020] will receive the full 30% credit, and that plants entering service after [2022] will receive only the 10% credit.
- Existing capacity and planned capacity additions are based on EIA survey data from the Form EIA-860, "Annual Electric Generator Report" and Form EIA-860M, "Monthly Update to the Annual Electric Generator Report." Planned capacity additions under construction or having an expected completion date prior to 2018were included in the model's planned capacity additions, according to respondents' planned completion dates.
- Capacity factors for solar technologies are assumed to vary by time of day and season of the year, such that nine separate capacity factors are provided for each modeled region, three for time of day and three for each of three broad seasonal groups (summer, winter, and spring/fall). Regional capacity factors vary from national averages based on climate and latitude.

- Solar resources are well in excess of conceivable demand for new capacity; energy supplies are considered unlimited given solar irradiance within regions (at specified daily, seasonal, and regional capacity factors). Therefore, sub-regional variations of solar resources are not estimated in NEMS. In the regions where CSP technology is not modeled, the level of direct, normal insolation (the kind needed for that technology) is assumed to be insufficient to make that technology commercially viable through the projection horizon.

Wind Energy Power Submodule

Background

Because of limits to windy land areas, wind is considered a finite resource, so the submodule calculates maximum available capacity by NEMS EMM (Electricity Market Module) regions. The minimum economically viable average wind speed is about 15 miles-per-hour at a hub-height of 80 meters (m), and wind speeds are categorized by annual average wind speed based on a classification system originally from the Pacific Northwest Laboratory (see http://rredc.nrel.gov/wind/pubs/atlas/tables/1-1T.html). The RFM tracks wind capacity by resource quality and costs within a region, and moves to the next best wind resource when one category is exhausted. Wind resource data on the amount and quality of wind per EMM region come from NREL [116]. The technological performance, cost, and other wind data used in NEMS are based on a report by Leidos Engineering, LLC entitled “EOP III Task 10388, Subtask 4 and Task 10687 Subtask 2.3.1 – Review of Power Plant Cost and Performance Assumptions for NEMS: Technology Documentation Report”, published in 2016. To access, please see http://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf. Maximum wind capacity, capacity factors, and incentives are provided to the EMM for capacity planning and dispatch decisions. These form the basis on which the EMM decides how much power generation capacity is available from wind energy. The fossil-fuel heat rate equivalents for wind are used for primary energy consumption calculation purposes only.

Assumptions

- Only grid-connected (utility and nonutility) generation is included. Projections for distributed wind generation are included in the commercial and residential modules.
- In the wind energy submodule, wind supply costs are affected by factors such as average wind speed, distance from existing transmission lines, resource degradation, transmission network upgrade costs, and other market factors.
- Available wind resource is reduced by excluding all windy lands not suited for the installation of wind turbines because of excessive terrain slope (greater than 20%) reservation of land for non-intrusive uses (such as national parks, wildlife refuges, etc.) inherent incompatibility with existing land uses (such as urban areas, areas surrounding airports and water bodies, including offshore locations) and insufficient contiguous windy land to support a viable wind plant (less than 5 square-kilometer of windy land in a 100 square-kilometer area). Half of the wind resource located on military reservations, U.S. Forest Service land, state forested land, and all non-ridge-crest forest areas is excluded from the available resource base to account for the uncertain ability to site projects at such locations. These assumptions are detailed in Appendix 3-E of the “The Renewable Fuels Module of the National Energy Modeling System: Model

Documentation”, DOE/EIA-MO69 (2014), Washington, DC, 2014. To access please see http://www.eia.gov/forecasts/aeo/nems/documentation/renewable/pdf/m069(2014).pdf

- Capital costs for wind technologies are assumed to increase in response to: (1) declining natural resource quality, such as terrain slope, terrain roughness, terrain accessibility, wind turbulence, wind variability, or other natural resource factors, as the best sites are utilized, (2) increasing costs of upgrading existing local and network distribution and transmission lines to accommodate growing quantities of remote wind power, and (3) market conditions, such as the increasing costs of alternative land uses, including aesthetic or environmental reasons. Capital costs are left unchanged for some initial share, then increased by 10%, 25%, 50%, and finally 100%, to represent the aggregation of these factors.
- Proportions of total wind resources in each category vary by EMM region. For all EMM regions combined, about 0.9% of windy land (106 GW of 11,600 GW in total resource) is available with no cost increase, 3.3% (387 GW) is available with a 10% cost increase, 2% (240 GW) is available with a 25% cost increase, and over 90% is available with a 50% or 100% cost increase.
- Because of downwind turbulence and other aerodynamic effects, the model assumes an average spacing between turbine rows of 5 rotor diameters and a lateral spacing between turbines of 10 rotor diameters. This spacing requirement determines the amount of power that can be generated from wind resources, about 6.5 megawatts per square kilometer of windy land, and is factored into requests for generating capacity by the EMM.
- Capacity factors for each wind class are calculated as a function of overall wind market growth. EIA implements an algorithm increasing the capacity factor within a wind class as more units enter service (learning). The capacity factors for each wind class were increased for AEO2016 and are assumed to start at 48% and are limited to 55% for a Class 6 site. However, despite increasing performance, as better wind resources are depleted, the modeled capacity factors decline, corresponding with the use of less-desirable sites.
- Due to the Consolidated Appropriation Act of 2016 passed in December 2015, AEO2016 allows plants under construction by the end of 2015 to claim the full 2.3 cents per kilowatt-hour (cent/kWh) federal Production Tax Credit (PTC) through the end of 2016. The PTC reduces for wind projects under construction after December 31, 2016 as follows:
    - 80% of the current PTC value (1.8 cent/kWh) for projects with construction beginning in 2017 and commencing service before 2022;
    - 60% of the current PTC value (1.4 cent/kWh) for projects with construction beginning in 2018 and commencing service before 2023;
    - 40% of the current PTC value (0.9 cent/kWh) for projects with construction beginning in 2019 and commencing service before 2024;
    - No PTC for those projects that begin construction after December 2019.
- Wind plants are assumed to depreciate capital expenses using the Modified Accelerated Cost Recovery System with a 5-year tax life and 5-year double declining balance depreciation.
- Wind plants are assumed and modeled to be in-service 3 years from the start of construction.

Offshore wind

Offshore wind resources are represented as a separate technology from onshore wind resources. Offshore resources are modeled with a similar model structure as onshore wind. However, because of the unique challenges of offshore construction and the somewhat different resource quality, the assumptions with regard to capital cost, learning-by-doing cost reductions, and resource access cost differ significantly from onshore wind.

- Like onshore resources, offshore resources are assumed to have an upwardly sloping cost supply curve, in part influenced 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.
- Because of the more difficult maintenance challenges offshore, performance for a given annual average wind power density level is assumed to be somewhat decreased by reduced turbine availability. Offsetting this, however, is the availability of resource areas with higher overall power density than is assumed available onshore. Capacity factors for offshore start at 50% and are limited to 58% for a Class 7 site.
- Cost reductions in the offshore technology result in part from learning reductions in onshore wind technology as well as from cost reductions unique to offshore installations, such as foundation design and construction techniques. Because offshore technology is significantly less mature than onshore wind technology, offshore-specific technology learning occurs at a somewhat faster rate than on-shore technology. A technological optimism factor (see EMM documentation: www.eia.gov/forecasts/aeo/nems/documentation/electricity/pdf/m068(2014).pdf) is included for offshore wind to account for the substantial cost of establishing the unique construction infrastructure required for this technology.

Geothermal Electricity Submodule

Background

Beginning in AEO2011, all geothermal supply curve data come from the NREL's updated U.S. geothermal supply curve assessment. The most recent report, released in October 2011, assigns cost estimates to the U.S. Geological Survey's (USGS) 2008 geothermal resource assessment [117]. Some data from the 2006 report, "The Future of Geothermal Energy," prepared for Idaho National Laboratory by the Massachusetts Institute of Technology, were also incorporated into the NREL report; however, this would be more relevant to deep, dry, and unknown geothermal resources, which EIA did not include in its supply curve. NREL took the USGS data and used the Geothermal Electricity Technology Evaluation Model (GETEM), a techno-economic systems analysis tool, to estimate the costs [118]. Only resources with temperatures above 110 degrees Celsius were considered. There are approximately 125 of these known, hydrothermal resources which EIA used in its supply curve. Each of these sites also has what NREL classified as "near-field enhanced geothermal energy system potential" which are in areas around the identified site that lack the permeability of fluids that are present in the hydrothermal potential. Therefore, there are 250 total points on the supply curve since each of the 125 hydrothermal sites has corresponding enhanced geothermal system (EGS) potential.

In the past, EIA cost estimates were broken down into cost-specific components. However, this level of detail was not available in the NREL data. A site-specific capital cost and fixed operations and maintenance cost were provided. Two types of technology, flash and binary cycle, are also included with capacity factors ranging from 90% to 95%. While the source of the data was changed beginning in AEO2011, the site-by-site matrix input that acts as the supply curve has been retained.

Assumptions

- Existing and identified planned capacity data are obtained directly by the EMM from Form EIA-860 and Form EIA-860M.
- The permanent investment tax credit of 10% available in all projection years, based on Energy Policy Act of 1992 (EPACT92), applies to all geothermal capital costs, except through December 2016 when the 2.3-cent/kWh PTC is available to this technology and is assumed chosen instead. Projects that began construction and are beyond the exploratory drilling phase by that date are eligible for this PTC.
- Plants are not assumed to retire unless their retirement is reported to EIA. The Geysers units are not assumed to retire but instead are assigned the 35% capacity factors reported to EIA reflecting their reduced performance in recent years.

Biomass Submodule

Background

Biomass consumed for electricity generation is modeled in two parts in NEMS. Capacity in the wood products and paper industries, the so-called captive capacity, is included in the Industrial Demand Module as cogeneration. Generation in the electricity sector is represented in the EMM. Fuel costs are calculated in NEMS and passed to EMM, while capital and operating costs and performance characteristics are assumed as shown in Table 8.2, available at http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf. Fuel costs are provided in sets of regional supply schedules. Projections for ethanol production are produced by the LFMM, with the quantities of biomass consumed for ethanol decremented from, and prices obtained from, the EMM regional supply schedules.

Assumptions

- Existing and planned capacity data are obtained from Form EIA-860 and Form EIA-860M.
- The conversion technology represented is a 50 megawatt dedicated combustion plant. The cost estimates for this technology are based on a report by Leidos Engineering, LLC entitled "EOP III Task 10388, Subtask 4 and Task 10687 Subtask 2.3.1 – Review of Power Plant Cost and Performance Assumptions for NEMS: Technology Documentation Report," published in 2016, http://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf.
- Biomass co-firing can occur up to a maximum of 15% of fuel used in coal-fired generating plants.

Fuel supply schedules are a composite of four fuel sources: forestry materials from federal forest, forestry materials from non-federal forest, wood residues, and agricultural residues and energy crops. Feedstock potential from agricultural residues and dedicated energy crops are calculated from a version

of the Policy Analysis (POLYSYS) agricultural model that uses the same oil price information as the rest of NEMS. Forestry residues are calculated from inventories conducted by the U.S. Forest Service and Oak Ridge National Laboratory. The forestry materials component is made up of logging residues, rough rotten salvageable dead wood, and excess small pole trees [119]. The wood residue component consists of primary mill residues, silvicultural trimmings, and urban wood such as pallets, construction waste, and demolition debris that are not otherwise used [120]. Agricultural residues are wheat straw, corn stover, and a number of other major agricultural crops [121]. Energy crop data are for hybrid poplar, willow, and switchgrass grown on existing cropland. POLYSYS assumes that the additional cropland needed for energy crops will displace existing pasturelands. The maximum amount of resources from forestry is fixed based on “U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry” prepared by Oak Ridge National Laboratory [122]. Urban wood waste is determined dynamically based on activity in the industry sectors that produce usable biomass feedstocks. Agricultural resource (agricultural residues and energy crops) supply is determined dynamically, and supplies available within the model at any point in time may not reflect the maximum potential for that region. In 2040, the estimated supplies of the feedstock categories are as follows: agricultural residues and energy crops are estimated at 5,061 trillion British thermal unit (Btu); wood residues are estimated at 1,211 trillion Btu; forestry materials (from public and private lands) are estimated at 1,915 trillion Btu. For 2040, supplies of 304 trillion Btu from all sectors could be available given prevailing demand in the AEO2016 Reference case.

Landfill Gas (LFG) Submodule

Background

Landfill-gas-to-electricity capacity competes with other technologies using supply curves that are based on the amount of “high,” “low,” and “very low” methane-producing landfills located in each EMM region. An average cost of electricity for each type of landfill is calculated using gas collection system and electricity generator costs and characteristics developed by EPA’s “Energy Project Landfill Gas Utilization Software” (E-PLUS) [123].

Assumptions

- Gross domestic product (GDP) and population are used as the drivers in an econometric equation that establishes the supply of landfill gas.
- Recycling is assumed to account for 50% of the waste stream in 2010 (consistent with EPA’s recycling goals).
- The waste stream is characterized into three categories: readily, moderately, and slowly decomposable material.
- Emission parameters are the same as those used in calculating historical methane emissions in EIA’s “Emissions of Greenhouse Gases in the United States 2003” [124].
- The ratio of “high,” “low,” and “very low” methane production sites to total methane production is calculated from data obtained for 156 operating landfills contained in the Governmental Advisory Associates Inc., METH2000 database [125].

- Cost of electricity for each site was calculated by assuming each site to be a 100-acre by 50-foot deep landfill and by applying methane emission factors for “high,” “low,” and “very low” methane-emitting wastes.

Conventional Hydroelectricity Submodule

The conventional hydroelectricity submodule represents U.S. potential for new conventional hydroelectric capacity of 1 megawatt or greater from new dams, existing dams without hydroelectricity, and from adding capacity at existing hydroelectric dams. Summary hydroelectric potential is derived from reported lists of potential new sites assembled from Federal Energy Regulatory Commission (FERC) license applications and other survey information, plus estimates of capital and other costs prepared by the Idaho National Engineering and Environmental Laboratory (INEEL) [126]. Annual performance estimates (capacity factors) were taken from the generally lower but site-specific FERC estimates rather than from the general estimates prepared by INEEL, and only sites with estimated costs of 10 cents per kilowatthour or lower are included in the supply. Pumped storage hydroelectric, considered a nonrenewable storage medium for fossil and nuclear power, is not included in the supply; moreover, the supply does not consider offshore or in-stream hydroelectric, efficiency or operational improvements without capital additions, or additional potential from refurbishing existing hydroelectric capacity.

In the hydroelectricity submodule, sites are first arrayed by NEMS region from least to highest cost per kilowatthour. For any year’s capacity decisions, only those hydroelectric sites whose estimated levelized costs per kilowatthour (kWh) are equal to or less than an EMM-determined avoided cost (the least cost of other technology choices determined in the previous decision cycle) are submitted. Next, the array of below-avoided-cost sites is parceled into three increasing cost groups, with each group characterized by the average capacity-weighted cost and performance of its component sites. Finally, the EMM receives from the conventional hydroelectricity submodule the three increasing-cost quantities of potential capacity for each region, providing the number of megawatts potential along with their capacity-weighted average overnight capital cost, operations and maintenance cost, and average capacity factor. After choosing from the supply, the EMM informs the hydroelectricity submodule, which decrements available regional potential in preparation for the next capacity decision cycle.

The RFM incorporates the extended PTC expiration date for incremental hydroelectric generation as enacted by the 2016 Consolidated Appropriation Act. Qualifying facilities receive the PTC if they were built within the timeframe specified by the law and its various extensions and can claim the tax credit on generation sold during their first 10 years of operation.

Legislation and regulations

Renewable electricity tax credits

The RFM includes the investment and energy production tax credits codified in EPACT92 as amended.

The ITC provides a credit to federal income tax liability as a percentage of initial investment cost for a qualified renewable generating facility. The Consolidated Appropriations Act of 2016 extended the ITC so that it provides solar projects under construction before the end of 2019 a tax credit currently valued at 30% of initial investment costs. Solar projects starting construction in 2020 and 2021 qualify for

credits of 26% and 22% of initial investment costs, respectively. Utility-scale solar projects beginning construction after 2021 receive a 10% ITC. This change is reflected in the RFM, Commercial Demand Module, and Residential Demand Module.

The PTC is a per-kWh tax credit available for qualified wind, geothermal, closed-loop and open-loop biomass, landfill gas, municipal solid waste, hydroelectric, and marine and hydrokinetic facilities. The value of the credit, originally 1.5 cents/kWh, is adjusted for inflation annually and is available for 10 years after the facility has been placed in service. For AEO2016, wind, poultry litter, geothermal, and closed-loop [127] biomass resources receive a tax credit of 2.3 cents/kWh; all other renewable resources receive a 1.1 cent/kWh (that is, one-half the value of the credit for other resources) tax credit. EIA assumes that biomass facilities obtaining the PTC will use open-loop fuels, as closed- loop fuels are assumed to be unavailable and/or too expensive for widespread use during the period that the tax credit is available. The PTC has been recently extended by the 2016 Consolidated Appropriation Act passed in December 2015 for wind projects through 2016. The PTC is scheduled to phase down in value for wind projects as follows: 80% of the current PTC if begin construction in 2017; 60% of the current PTC if begin construction in 2018; and 40% of the current PTC if begin construction in 2019.

The ITC and PTC are exclusive of one another, and thus may not both be claimed for the same facility.

Further details on the PTC and ITC modeling assumptions can be found in the technology-specific sections of this document. A history of these tax credits is described in AEO2016 Legislation and Regulations LR3 - Impact of a Renewable Energy Tax Credit extension and phaseout [128].

The AEO2016 reference case also includes assumptions reflecting the regulations set in place by the Clean Power Plan (CPP). These assumptions are discussed in greater detail in the Electricity Market Module portion of the documentation. While renewables are considered to be an integral part of the CPP rule, the rule specifically applies to fossil generators.

State Renewable Portfolio Standards programs

EIA represents various state-level policies generally referred to as Renewable Portfolio Standards (RPS). These policies vary significantly among states, but typically require the addition of renewable generation to meet a specified share of state-wide generation. Any non-discretionary limitations on meeting the generation or capacity target are modeled to the extent possible. However, because of the complexity of the various requirements, the regional target aggregation, and the nature of some of the limitations, the measurement of compliance is assumed to be approximate.

Regional renewable generation targets were estimated using the renewable generation targets in each state within the region. In many cases where regional boundaries intersect state boundaries; in these cases state requirements were apportioned among relevant regions based on sales. Using state-level RPS compliance schedules and preliminary estimates of projected sales growth, EIA estimated the amount of renewable generation required in each state within a region. Required generation in each state was then summed to the regional level for each year, and a regional renewable generation share of total sales was determined, as shown in Table 13.1.

Only targets with established enforcement provisions or established state funding mechanisms were included in the calculation; non-enforceable goals were not included. Compliance enforcement provisions vary significantly among states, and most states have established procedures for waiving compliance through the use of alternative compliance payments, penalty payments, discretionary regulatory waivers, or retail price impact limits. Because of the variety of mechanisms, even within a given electricity market region, these limits are not modeled.

Table 13.1. Aggregate regional renewable portfolio standard requirements

percentage share of total values

Region[1]	2020	2030	2040
Texas Reliability Entity	4.4%	4.4%	4.4%
Midwest Reliability Organization East	13.0%	13.1%	13.1%
Midwest Reliability Organization West	7.1%	8.6%	8.6%
Northeast Power Coordinating Council / New England	17.9%	20.4%	22.4%
Northeast Power Coordinating Council / NYC Westchester	24.5%	24.6%	24.6%
Northeast Power Coordinating Council / Long Island	24.6%	24.6%	24.6%
Northeast Power Coordinating Council / Upstate New York	24.5%	24.5%	24.5%
Reliability First Corporation/ East	14.0%	15.4%	15.4%
Reliability First Corporation/Michigan	10.0%	10.0%	10.0%
Reliability First Corporation/West	7.1%	10.9%	10.9%
SERC Reliability Corporation / Delta	0.6%	0.6%	0.6%
SERC Reliability Corporation / Gateway	11.1%	17.1%	17.1%
SERC Reliability Corporation / Virginia Carolina	4.4%	5.2%	5.2%
Southwest Power Pool Regional Entity / North	2.6%	3.8%	3.8%
Southwest Power Pool Regional Entity / South	2.1%	2.2%	2.2%
Western Electricity Coordinating Council / Southwest	9.1%	11.8%	11.8%
Western Electricity Coordinating Council / California	33.0%	50.0%	50.0%
Western Electricity Coordinating Council / Northwest Power Pool Area	9.7%	11.1%	11.1%
Western Electricity Coordinating Council / Rockies	17.1%	17.1%	17.1%

[1]See chapter on the Electricity Market Module for a map of the electricity market module supply regions.
Regions not shown do not have renewable portfolio standard requirements.

Notes and sources

[115] For a comprehensive description of each submodule, see U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting, Model Documentation, Renewable Fuels Module of the National Energy Modeling System, DOE/EIA-M069(2014), (Washington, DC, August 2014), http://www.eia.gov/forecasts/aeo/nems/documentation/renewable/pdf/m069(2014).pdf.

[116] Revising the Long Term Multipliers in NEMS: Quantifying the Incremental Transmission Costs Due to Wind Power, Report to EIA from Princeton Energy Resources International, LLC. May 2007.

Notes and sources (cont.)

[117] Augustine, C. ”Updated U.S. Geothermal Supply Characterization and Representation for Market Penetration Model Input,” NREL/TP-6A20-47459 (Golden, CO, October 2011), http://www.nrel.gov/docs/fy12osti/47459.pdf.

[118] The one exception applies to the Salton Sea resource area. For that site, EIA used cost estimates provided in a 2010 report on electric power sector capital costs rather than NREL.

[119] U.S. Department of Energy. “U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry”, August 2011.

[120] Ibid.

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

[122] U.S. Department of Energy. “U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry”, August 2011.

[123] U.S. Environmental Protection Agency, Atmospheric Pollution Prevention Division, Energy Project Landfill Gas Utilization Software (E-PLUS) Version 1.0, EPA-430-B-97-006 (Washington, DC, January 1997).

[124] U.S. Energy Information Administration, “Emissions of Greenhouse Gases in the United States 2003,” DOE/EIA- 0573(2003) (Washington, DC, December 2004), www.eia.gov/oiaf/1605/archive/gg04rpt/index.html.

[125] Governmental Advisory Associates, Inc., METH2000 Database, Westport, CT, January 25, 2000.

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

[127] Closed-loop biomass are crops produced explicitly for energy production. Open-loop biomass are generally wastes or residues that are a byproduct of some other process, such as crops grown for food, forestry, landscaping, or wood milling.

[128] U.S. Energy Information Administration, *Annual Energy Outlook 2016*, Legislation and Regulations LR3, DOE/EIA-0383(2016) (Washington, DC, August 2016), accessed September 23, 2016.