ReEDS Model Documentation: Base Case Data and Model Description

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Contents

1 Introduction **2**
1.1 Qualitative Model Description . . . 2
1.2 Linear Program Formulation . . . 4
1.3 Qualitative Details on Transmission . . . 7
1.4 Qualitative Details on Wind Variability . . . 8

2 ReEDS Base Case Data **11**
2.1 Financials . . . 11
2.2 Power System Characteristics . . . 11
2.2.1 ReEDS Regions . . . 11
2.2.2 Electric System Loads . . . 13
2.2.3 Growth Rate . . . 14
2.2.4 Capacity Requirements . . . 14
2.3 Wind . . . 16
2.3.1 Wind Resource Definition . . . 16
2.3.2 Wind Resource Data . . . 16
2.3.3 Wind Technology Cost and Performance . . . 16
2.4 Concentrated Solar Power . . . 24
2.4.1 CSP Resource Definition . . . 24
2.4.2 CSP Technology Cost and Performance . . . 24
2.5 Conventional Generation . . . 27
2.5.1 Generator Types . . . 27
2.5.2 Cost and Basic Performance . . . 29
2.5.3 Fuel Prices . . . 29
2.6 Storage Technologies . . . 32
2.7 Transmission . . . 34
2.8 Federal and State Energy Policy . . . 35
2.8.1 Federal Emission Standards . . . 35
2.8.2 Federal Energy Incentives . . . 36
2.8.3 State Energy Incentives . . . 36

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2.8.4 Federal Renewable Portfolio Standards . . . 36
2.8.5 State Renewable Portfolio Standards . . . 37
2.9 Future Work . . . 38

3 Simplified Model Description **39**
3.1 Subscripts . . . 39
3.1.1 Geographical Sets: . . . 39
3.1.2 Temporal Sets: . . . 39
3.1.3 Other Sets: . . . 40
3.2 Major Decision Variables . . . 40
3.3 Objective Function . . . 41
3.4 Constraints . . . 42
3.4.1 Constraints on Wind . . . 42
3.4.2 Constraints on CSP . . . 42
3.4.3 General Renewable Constraints . . . 43
3.4.4 Constraints on System Operation . . . 43
3.4.5 Constraints on Storage . . . 45
3.4.6 Others . . . 45

Appendix A Detailed Model Description **47**
A.1 Subscripts . . . 47
A.1.1 Geographical Sets: . . . 47
A.1.2 Temporal Sets: . . . 47
A.1.3 Other Sets: . . . 47
A.2 Major Decision Variables . . . 49
A.3 Objective Function . . . 52
A.4 Constraints . . . 55
A.4.1 Constraints on Wind . . . 55
A.4.2 Constraints on CSP . . . 57
A.4.3 General Renewable Constraints . . . 59
A.4.4 Constraints on System Operation . . . 62
A.4.5 Constraints on Storage . . . 66
A.4.6 Others . . . 68
A.5 Glossary of Parameters . . . 71

Appendix B Electricity Price Calculation **76**

Appendix C Elasticity Calculations **79**
C.1 Fuel Price Elasticities . . . 79
C.2 Demand Elasticities . . . 80

Appendix D Resource Variability Parameters **81**
D.1 Data inputs for the calculation of resource variability parameters . . . 81
D.2 Capacity Value . . . 84
D.3 Operating Reserve Requirement . . . 85
D.4 Surplus . . . 86

Appendix E Retirement of Capacity **89**

Appendix F Financial Calculations **90**
F.1 General Economic Parameters . . . 90
F.2 Financial Parameters Specific to Wind . . . 90
F.3 Setting the Finanace Fraction in ReEDS . . . 93
F.4 Financial Parameters Specific to Conventional Technologies . . . 93
F.5 Transmission Cost Parameters . . . 95

Appendix G Geographic Information System (GIS) Calculations **96**

4 References **97**

List of Tables

1 Base Case Financial Assumptions . . . 11
2 NERC Regions Used in ReEDS . . . 13
3 ReEDS Demand Time-Slice Definitions . . . 13
4 Base Load and Load Growth in the ReEDS Base Case . . . 15
5 National Capacity Requirements in the ReEDS Base Case . . . 15
6 Classes of Wind Power Density . . . 16
7 Data Source for Wind Resource . . . 17
8 Wind-Resource Exclusion Database — Standard Version, January 2004 . . . 18
9 Data Source for Offshore Wind Resource . . . 20
10 Onshore Wind Cost and Performance Projections . . . 21
11 Shallow Offshore Turbines . . . 22
12 Deep Offshore Turbines . . . 23
13 Classes of Wind Power Density . . . 24
14 CSP Cost and Performance Projections . . . 25
15 CSP Plant Capacity Factors . . . 25
16 Construction Parameters for Conventional Generation . . . 28
17 Performance Parameters for Conventional Generation . . . 28
18 Cost and Performance Characteristics for Conventional Generation I . . . 30
19 Cost and Performance Characteristics for Conventional Generation II . . . 31
20 Cost and Performance Characteristics for Storage Technologies . . . 33
21 National SO_2 Emission Limit Schedule in ReEDS . . . 35
22 Federal Renewable Energy Incentives . . . 36
23 State Renewable Energy Incentives . . . 36
24 State Renewable Portfolio Standards . . . 37
25 Rankings of Distributions . . . 82

List of Figures

1 Base Case Capacity Buildout in ReEDS . . . 2
2 Correlation in Wind Output . . . 9
3 Regions used in ReEDS . . . 12
4 National Load Duration Curve in ReEDS . . . 14
5 Wind Resource in ReEDS . . . 19
6 Solar Resource in ReEDS . . . 26
7 Base Fuel Price Trajectories . . . 32
8 Areas with geology favorable to CAES, overlaid with class 4+ wind resource . . . 34
9 Actual conventional capacity less load and fitted beta PDF . . . 83
10 Wind farm power output from a single site (left) and combined output from eight sites (right) with fitted beta PDFs . . . 83

1 Introduction

The **Re**gional **E**nergy **D**eployment **S**ystem (ReEDS) model is a multiregional, multitime-period, Geographic Information System (GIS), and linear programming model of capacity expansion in the electric sector of the United States. The model, developed by NREL's Strategic Energy Analysis Center (SEAC), is designed to conduct analysis of the critical energy issues in today's electric sector with detailed treatment of the full potential of conventional and renewable electricity generating technologies as well as electricity storage. The principal issues addressed include access to and cost of transmission, access to and quality of renewable resources, the variability of wind and solar power, and the influence of variability on the reliability of the grid. ReEDS addresses these issues through a highly discretized regional structure, explicit accounting for the variability in wind and solar output over time, and consideration of ancillary services requirements and costs.

1.1 Qualitative Model Description

ReEDS minimizes systemwide costs of meeting electric loads, reserve requirements, and emission constraints by building and operating new generators and transmission in 23 two-year periods from 2006 to 2050. The primary outputs of ReEDS are the amount of capacity and generation of each type of prime mover—coal, natural gas, nuclear, wind, etc.—in each year of each 2-year period. Figure 1 shows an example of ReEDS capacity estimates for the United States for different generation technologies over the 44 year evaluation period.

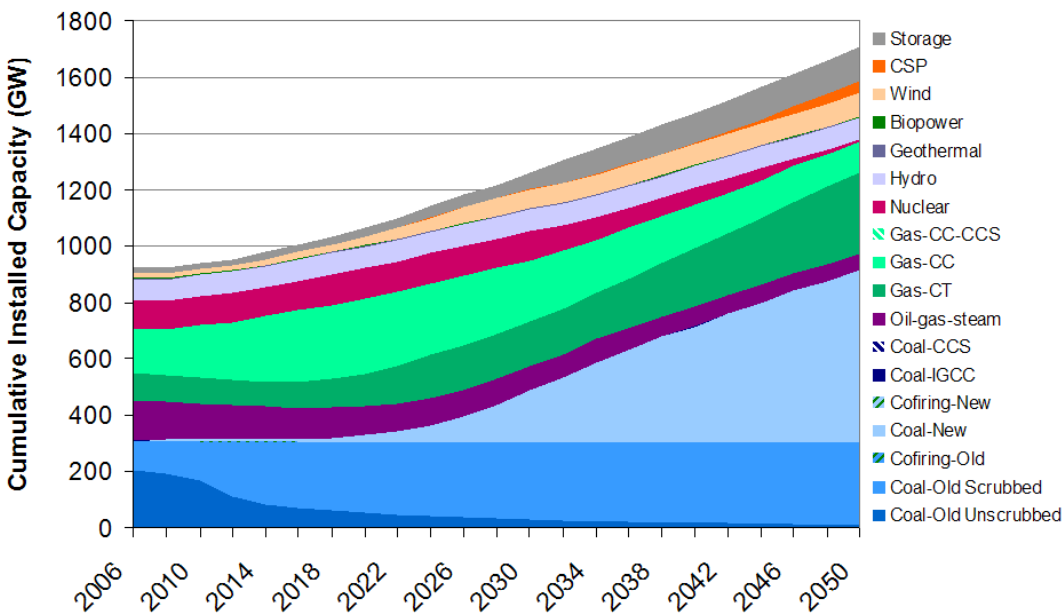

Figure 1: Base Case Capacity Buildout in ReEDS

Time in ReEDS is also subdivided within each two-year time period; each year is divided into four seasons, and each season into four diurnal time-slices. There is also one superpeak time-slice. These 16 annual time-slices (spring has only three time-slices) allow ReEDS to capture the intricacies of meeting electric loads that vary throughout the day and year both with conventional and renewable generators.

While ReEDS includes all major generator types, it has been designed primarily to address the market issues of greatest significance to carbon-constrained scenarios—Renewable Portfolio Standards (RPS), carbon taxes, and carbon caps. As a result, renewable and carbon-free energy technologies are a focus.

Diffuse resources, such as wind and solar power, come with concerns that conventional dispatchable power plants do not have, particularly regarding transmission and variability. The ReEDS model examines these issues primarily by using a much higher level of geographic disaggregation than other models: 356 different regions in the continental United States. These 356 resource supply regions are then grouped into four levels of larger regional groupings—balancing authorities, Regional Transmission Operators (RTO), North American Electric Reliability Council (NERC) regions, and national interconnect regions. States are also represented for the inclusion of state policies.

Much of the data inputs to ReEDS are tied to these regions and derived from a detailed GIS model/database of the wind and solar resource, transmission grid, and existing plant data. The geographic disaggregation of renewable resources allows ReEDS to calculate transmission distances, as well as the benefits of dispersed wind farms or CSP plants supplying power to a demand region. Both the wind and solar supply curves are broken up into 5 resource classes, based on the quality of the resource—strength and dependability of wind or solar insolation—that are further described in the appropriate sections of this document.

Regarding resource variability and grid reliability, ReEDS also allows electric storage to be built—either co-located with wind farms or sited at load centers—and used for load shifting, resource firming, and ancillary services. Three varieties of storage are supported: pumped hydropower, batteries, and compressed air energy storage.

Along with wind and solar power, ReEDS has supply curves for biomass and geothermal resource and allows biopower and geothermal plants to be built in each balancing authority. The geothermal supply curve is in MW of recoverable capacity while the biomass supply curve is in MMBtu of annual feedstock production.

Other carbon-reducing options are considered as well. Nuclear power is an option, as is carbon capture and sequestration (CCS) on some coal and natural gas plants. For now, CCS is treated simply, with only an additional capital cost for the extra equipment and an efficiency penalty to account for the parasitic loads of the separation process. In the future, it is intended that ReEDS will have geographically varying costs for CCS as well as piping and sequestering constraints on the CO_2.

The major conventional electricity generating technologies considered in ReEDS include: hydropower; both simple- and combined-cycle natural gas; several varieties of coal; oil/gas steam; and nuclear. These technologies are characterized in ReEDS by their:

- equipment lifetime (years)
- capital cost ($/MW)
- fixed and variable operating costs ($/MWh)
- fuel costs ($/MMbtu)
- heat rate (MMbtu/MWh)
- escalation in operating costs and heat rates with plant aging (%/year)
- construction period (years)
- financing costs (nominal interest rate, loan period, debt fraction, debt-service-coverage ratio)
- tax credits (investment or production)
- minimum turndown ratio (%)

- quick-start capability and cost (%, $/MW)
- operating reserve capability
- planned and unplanned outage rates (%).

Renewable and storage technologies are governed by similar parameters, accounting for fundamental differences, of course. For instance, heat rate is replaced with round-trip-efficiency for storage technologies, and the dispatchability parameters—fuel cost, heat rate, turndown ratio, quickstart, and operating reserve capability—are not used for non-dispatchable wind and solar.

The model includes consideration of distinguishing characteristics of each conventional generating technology. For example, there are several types of coal-fired power plants within ReEDS, including gasification, biomass cofiring, and CCS options. Any of these plants can burn either high-sulfur or, for a cost premium, low-sulfur coal. Generation by coal plants is restricted to be base- and intermediate load with cost penalties (representing ramping/spinning costs) if power production during peak load periods exceeds production in shoulder-peak hours. New coal plants are assumed to be able to provide more spinning reserve capability than older units. Combined-cycle natural-gas plants are considered to be able to provide some operating/spinning reserve and quick-start capability, while simple-cycle gas plants can be cheaply and easily used for reserves and quick-starts. Nuclear power is considered to be base load. Hydroelectricity is not allowed to increase in capacity, due to resource and environmental limitations. Hydropower is also energy-constrained, due to water resource limitations, but is assumed to be able to provide both quick-start capability and operating/spinning reserve.

Retirements of conventional generation can be modeled either through exogenous specification of planned retirements (currently used for nuclear, hydro, and oil/gas steam plants), economic retirements, or as a fraction of remaining capacity each period. All retiring wind turbines are assumed to be refurbished or replaced immediately—because the site is already developed with transmission access and other wind farm infrastructure. Similarly, any storage at the wind site is assumed to be replaced immediately upon retirement while grid-sited storage retires automatically when its assumed lifetime has elapsed but is not automatically replaced.

ReEDS tracks emissions from both generators and storage technologies of carbon, sulfur dioxide, nitrogen oxides, and mercury. Caps can be imposed at the national level on any of these emissions (and constraints could be writted to impose caps at state or regional levels as well). There is also the option of applying a carbon tax instead of a cap; the tax level and ramp-in pattern can be exogenously defined.

ReEDS is a national electric capacity expansion model, not a general equilibrium model. To define each time period of the optimization, the model requires that the scenario be exogenously specified in terms of fuel costs and electric loads for each NERC region over the 44-year time horizon of ReEDS. To allow for the evaluation of scenarios that might depart significantly from the scenario used to develop the input fuel prices and electricity demands, there are price elasticities of demand and demand elasticities of fuel prices integrated into the model. For demand, the exogenously defined demand escalation is adjusted up or down based on the price of electricity; while for coal and natural gas, the price is adjusted based on how the calculated fuel usage compares to the usage assumed in the inputs.

1.2 Linear Program Formulation

This section qualitatively describes the basic LP formulation of ReEDS, followed by additional qualitative detail on transmission and variability. Section 3 (simplified) and Appendix A (detailed) contain the actual equations/constraints used in the linear program.

The objective function in the ReEDS linear program is a minimization of all the costs of the U.S. electric sector including:

- the present value of the cost for both generation and transmission capacity installed in each period

- the present value of the cost for operating that capacity during the next 20 years to meet load, i.e., fixed and variable operation and maintenance (O&M) and fuel costs
- the cost of several categories of ancillary services and storage.

By minimizing these costs while meeting the system constraints (discussed below), the linear program determines which types of new capacity are the most economical to add in each period, in each balancing authority. Simultaneously, the linear program determines what capacity should be dispatched to provide the necessary energy in each of the 16 annual time-slices. Therefore, the capacity factor for each dispatchable technology in each region is an output of the model, not an input.

The cost minimization that occurs within ReEDS is subject to more than 70 different types of constraints, which result in hundreds of thousands of equations in the model (due primarily to the large number of regions). These constraints fall into several main categories, including:

- Resource constraints: The total amount of wind capacity of each type (onshore, offshore shallow, offshore deep) installed in each region, in each wind class must be less than the wind resource potentially available.

  Similarly, the total amount of CSP capacity installed in each region, in each insolation class must be less than the solar resource potentially available; geothermal capacity installed in each balancing authority in each price bin must be less than the recoverable geothermal resource in the area; and annual generation from biofuels—whether in dedicated biomass plants or cofired in coal plants—is constrained by the amount of biomass produced in each balancing authority.

- Transmission constraints: In ReEDS, there are several forms of constraints on transmission of both renewable and conventional generation:

  - General transmission in any given time-slice is constrained by the capacity of all transmission lines between any two balancing authorities.
  - General transmission capacity must also be available to accommodate the transfer of firm power between balancing authorities (these are transfers to ensure adequate capacity is available to meet reserve margin requirements).
  - Wind and CSP transmission on the existing grid is constrained by:

    The cost to build transmission from the wind/CSP site to the nearest existing transmission line with adequate capacity to carry the expected generation.

    The total available capacity of all existing transmission lines out of the supply region and into a demand region.

    The transmission capacity between balancing authorities available for generation from renewable or conventional sources.
  - Wind and CSP can also be transmitted on new transmission lines constructed specifically to carry them. Although these lines are not constrained in ReEDS, the model does include a cost for their construction that varies with the length and capacity of the line, as well as the slope of the terrain in the origination and destination regions, and the population density of those regions. New transmission built for wind and CSP can be constructed between supply/demand regions and/or within a supply region.

- Load constraints: The primary load constraint is that the electric load in each balancing authoritiy (there are 134 of them in ReEDS) must be met in each time-slice (of which there are 16) throughout a year. While the load in 2006 is based on actual loads in each balancing authority, the annual rate of load growth must be input and is assumed to be uniform over time and within each NERC region.

There is an option in ReEDS to subdivide certain time-slices in certain regions if there are substantial amounts of both wind and baseload capacity compared to load. The mini-slices are a 20%-60%-20% hourly division and the wind capacity factor is adjusted for the 20% segments to represent those hours when the wind blows most and least. This allows ReEDS to more finely capture the variations in wind resource and their impact on base, intermediate, and peaking generation.

- Reserve margin constraint: There are two types of reserve constraints: planning reserve margin and operating reserve. For the planning reserve margin constraint, each period ReEDS updates its estimate of the marginal capacity value of the next wind farm or CSP plant built in each region, using a detailed statistical approach. The capacity value is set equal to the amount of load that could be added—along with the wind or CSP—without changing the risk of a shortage in generation capacity at peak load times (Effective Load Carrying Capability or ELCC). The approach accounts for the dispersion of the wind and CSP sites contributing to the load and the correlation in the output of those sites.

- Operating reserve constraint: The operating reserve requirement induced by each new wind farm is also modified each period for each region. It is assumed that the operating reserve requirement induced by wind is statistically independent from the normal operating reserve requirement induced by load variability and forced outages. Thus, the additional operating reserve requirements due to wind are not proportional to the amount of wind, but rather to the variance in the sum of the normal operating reserve and that due to only the wind generation. This means that the operating reserves induced by wind are generally low per unit of wind capacity initially, but can grow quickly if the wind capacity becomes a significant part of system capacity—especially if the output of the new wind capacity is highly correlated with that of existing wind capacity.

  CSP facilities, as presently modeled, are assumed to have six hours of thermal storage, so CSP capacity does not increase the operating reserve requirement the way wind does.

- Wind Surplus: ReEDS also accounts for surplus wind-generated electricity that is curtailed if wind plus must-run conventional output exceeds the load. In reality, when demand is low and the wind is blowing, there can be instances where the wind generation can not all be used. ReEDS uses the variance of the sum of all wind generation in the interconnect—together with a load duration curve and the forced outage rates of conventional technologies—to stochastically compute the expected amount of wind that can not be used. This loss in useful wind output is taken into account when ReEDS expands capacity by choosing between different generation technologies.

  The six-hour thermal storage assumed for CSP capacity also means that CSP does not have an issue with surplus.

- Emissions constraints: At the national level, ReEDS caps the emissions from fossil-fueled generators for sulfur dioxide, nitrogen oxides, mercury, and carbon dioxide. The annual national emission caps and the emissions per MWh by fuel and plant type are inputs to the model.

  In carbon-constrained scenarios, CO_2 can be either capped or taxed, and either a cap or tax can be finely adjusted to match proposed legislation.

- RPS constraints: ReEDS allows the user to input Renewable Portfolio Standard (RPS) constraints at either the national or state level. All non-hydroelectric renewable generation counts toward this requirement, a category that includes wind, CSP, geothermal, and biopower (including the biomass fraction of cofiring plants). The RPS can ramp in either linearly over time or according to an externally defined profile. A penalty can also be imposed for each MWh shortfall in the nation or state.

1.3 Qualitative Details on Transmission

ReEDS considers the availability of capacity on existing transmission lines, the cost of accessing and using those lines, and the cost of building new transmission lines for new generation (e.g. dedicated to new wind or CSP farms) when existing lines are not available. To determine how much wind or CSP can access existing transmission lines and the cost of building a line from the wind site to the grid, we use a Geographic Information System (GIS) database to develop a four-step supply curve for each class of wind/solar in each supply region that presents the amount of capacity that can access the grid at each of four different costs. (The supply curve is formed of discrete steps, with each step represented by a different variable within the linear program.)

The costs increase with increasing distance from the resource to an existing transmission line that has adequate remaining capacity available to accommodate the generation. Although the lines are usually carrying generation from other sources, at any given instant, they may or may not have the capacity to transmit additional power from new wind or CSP generators. It is practically impossible at the national level to assess the capacity available at any given time on each line in the country. Thus, ReEDS requires that the user input the fraction of the capacity of each line that will be available for wind or CSP; the default fraction is set at 10% for all lines. This transmission availability constraint severely limits the amount of wind or CSP that can be transmitted on existing lines, well below that found in previous studies (Parsons and Wan 1995) that required only that the wind resource be within 20 miles of an existing transmission line.

In addition to the cost of building a line from the wind/CSP site to the grid, ReEDS also allows the user to input a cost for the use of the grid. That cost can be based on the distance the power is transmitted or on the number of power control areas that the electricity must pass through (called a "pancake rate").

ReEDS also verifies that the existing transmission lines crossing the border of a supply/demand region have enough capacity to carry the wind and CSP generation into and out of the region. In addition, all generation (that from both renewable and conventional generators) is constrained from flowing between any two balancing authorities in each time-slice by the capacity of lines that connect the two balancing authorities. ReEDS does not account for loop-flows, contingencies, etc. that could further restrict transmission on existing lines.

While new transmission lines dedicated to renewables are not constrained by the remaining transmission capacity available, they do have additional cost. For lines built to serve remote sites, the entire cost of constructing and maintaining a new line is attributed to the wind or CSP capacity at that site. This means that the lines are used only when the wind is blowing (or sun is shining), and their costs must be amortized over that intermittent power. The costs of new transmission lines can vary significantly based on terrain, congestion, labor costs, etc. Currently, ReEDS assumes a single cost for new lines expressed in $/MW-mile, which is increased for rough terrain and population congestion. In the future, we anticipate modifying ReEDS to vary the new transmission line cost per mile with the length of the transmission line and the amount of renewable capacity potentially available within the supply region.

New transmission lines dedicated to wind or CSP can be built either between supply/demand regions as described above or within a region. Dedicated inregion transmission lines are assumed to transport the electricity generation directly from the wind/CSP site to a load center within the region, bypassing the transmission grid and connecting to the distribution system within the load center. As with the construction of lines connecting renewables to the grid described above, the GIS is used to develop supply curves for each resource class in each supply region for the cost of building these intraregional transmission lines directly to load centers.

New transmission lines are also built in ReEDS to transmit power from one balancing authority to another. These lines can be accessed by either conventional or renewable generators. ReEDS builds these lines when it is cost-effective and there is a need for more transmission capacity between the balancing authorities in one or more of the 16 time-slices in each year;

or when it is needed to ensure capacity reserve margins are met in the different balancing authorities, NERC regions, or interconnection regions.

Transmission losses are modeled in ReEDS as a linear function of the distance the power is transmitted. These losses apply to the transmission of both renewable and conventional generation, and are currently specified in terms of the fraction of power lost per MWh-mile.

1.4 Qualitative Details on Wind Variability

Wind power, because the resource is variable and unpredictable and neither the resource nor the resulting electricity can readily be stored, is complicated to model. ReEDS, in an attempt to capture the peculiarities of wind power, has a detailed, stochastic treatment of wind power that is unique among power sources. CSP, were it not assumed in ReEDS to have six hours of thermal storage, would have similar issues; as it is, for now, only wind has such involved variability calculations. (NREL is in the process of modifying ReEDS to accommodate photovoltaics and CSP without storage.) The variability of the wind resource can impact the electric grid in several ways. One useful way to examine these impacts is to categorize them in terms of time, ranging from multiyear planning issues to small instantaneous fluctuations in output.

At the longest time interval, a utility's capacity-expansion plans may call for the construction of more nameplate generation capacity. To meet this need, the planners can plan to build dispatchable capacity or wind. The variability of wind precludes the planners from considering a MW of nameplate of wind capacity to be the same as a MW of nameplate of dispatchable capacity: wind capacity can not be counted on to be available when peak demand for electricity occurs. Actually, conventional capacity also can not be considered 100% reliable. The difference is in the degree of reliability and the correlation in that reliability between sites/plants; conventional generators experience forced outages on the order of 2%-20% of the time, while wind energy is available at varying levels that average about 30%-45% of the time depending on the quality of the wind site. For planning purposes, this lack of reliability is handled in the same way—a statistical treatment that calculates how much more load can be added to the system for each MW of additional nameplate wind capacity, or Effective Load Carrying Capability (ELCC).

Effective Load Carrying Capability is less for wind than for conventional capacity; first, because the wind availability is less than that of conventional generators. And second, because at any given instant, the generation from a new wind farm can be heavily correlated with the output from the existing wind farms—if the wind isn't blowing at one wind site, there is a reasonable chance it is also not blowing at another nearby site. On the other hand, there is essentially no correlation between the outputs of any two conventional generation plants.

Fortunately, there are ways to partly mitigate both the low availability of the wind resource and its correlation between sites. In the past 20 years, there has been considerable improvement in wind capacity factor (the ratio of actual output over a period of time to its output had it operated at full capacity over that same interval) of new wind installations. This is attributable to both better site exploration/characterization and to improvements in the wind turbines themselves (largely higher towers).

The correlation in wind output between sites also can be reduced. Increasing the distance between sites and the terrain features that separate them reduces the chances that two sites will experience the same winds at the same time. Figure 2 shows this correlation as a function of distance between sites in both an east-west direction and a north-south direction. With its multiple regions, ReEDS is able to approximate the distance between sites and, therefore, the correlation between their outputs. ReEDS uses the correlation between sites to estimate the variation in wind output from the total set of wind farms supplying power to a particular region. NREL is in the process of improving these correlation estimates by using recently-developed wind and solar hourly resource data for thousands of sites around the country.

Between each 2-year-period optimization and for each demand region, ReEDS updates its estimate of the marginal ELCC associated with adding wind of each resource class in each

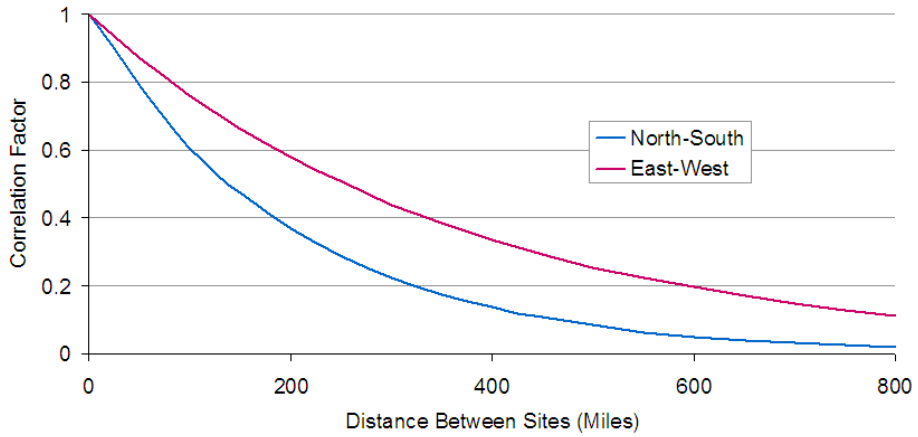

Figure 2: Correlation in Wind Output

wind supply region to meet demand within a region. This marginal ELCC is a strong function of the wind capacity factor and the distance from the existing wind systems to the new wind site for which the ELCC is being calculated. It is also a weak function of the demand region's load-duration curve and the size and forced outage rates of the conventional capacity. This marginal ELCC is assumed to be the capacity value of each MW of that wind class added in the next period in that wind supply region to serve the RTO's demand.

Everything else being equal, when expanding wind capacity, ReEDS will select the next site in a region that is as far from the existing sites as possible to ensure the lowest correlation and the highest ELCC for the next wind site. (More practically, everything else is never "equal," and ReEDS considers the tradeoffs between ELCC and wind site quality, transmission availability/cost, and local siting costs.)

Generally, for the first wind site supplying a demand region, these capacity values (ELCC) are almost equal to the capacity factor. However, as the wind penetrates to higher levels, the ELCC can decline to almost zero in an individual wind supply region.

No matter the market structure, however, the imbalances must be offset with adequate operating reserves. Therefore, to capture the essence of the unit-commitment issue, ReEDS estimates the impact of wind variability on the need for operating reserves (includes quick-start and spinning reserves) that can rapidly respond to changes in wind output. The operating reserves are assumed to be a linear function of the variance in the sum of generation (both wind and conventional) minus load. Because the variability of wind is statistically independent of the load variability and forced outages, the total variance with wind can be calculated as the sum of the variance associated with the normal (i.e., no wind) operating reserve and the total (over all the wind supply regions) variance in the wind output over the reconciliation period. Before each 2-year optimization, ReEDS calculates the marginal operating reserve additions required by the next unit of wind (added in a particular wind supply region from a particular wind class) as the difference between the operating reserve required by the total system with that new wind and the operating reserve required by the total system, if there were no new wind installations in that wind supply region. This value is then used throughout the next 2-year linear program optimization as the marginal operating reserve requirement induced by the next MW of wind addition in that region of that wind resource class.

At the shortest time interval, instantaneous changes in wind output must be compensated for by regulation reserves. Regulation reserves are normally provided by automatic generation control of conventional generators whose output can be automatically adjusted to compensate

for small changes in voltage on the grid. Fortunately, these instantaneous changes in wind output do not all occur at the same time, even from wind turbines within the same wind farm. This lack of correlation over time and the ease with which conventional generators can respond allows us to reasonably ignore this second order cost.

ReEDS assumes that any wind generation delivered to a specific demand region in a specific time-slice that exceeds the total electric load in that region/time-slice will be lost. In addition, as mentioned above, ReEDS also statistically accounts for surplus wind lost within a time-slice due to variations in load and wind within the time-slice.

ReEDS has three endogenous options for mitigating the impact of variability. The first is to add conventional generators that can provide spinning reserve (e.g. gas combined-cycle) and quick-start capabilities (combustion turbines).The second, and usually least costly, is to allow the dispersion of new wind installations reducing the correlation of the outputs from the different wind sites. The third, and usually most costly, is to allow for storage of electricity at the wind site. If it is cost-effective, ReEDS will build storage capacity at an onshore[1] wind site that can be used during peak electric demand periods to generate electricity when the wind is not blowing to its full capacity. Storage options available in ReEDS are pumped hydro, compressed air, and batteries.

ReEDS endogenously selects the capacity of the turbines at a site, the transmission capacity to the site, and the capacity of the storage. It assumes that all output from wind turbines is used either to provide power directly to the grid or to charge storage. ReEDS also assumes that power can be delivered to a wind site from the grid (with industrial-power-purchase retail markups) to charge storage even when the onshore wind turbines are not generating power. This allows the storage facility to be used for general load-shifting within the grid, even when wind energy is not available. The energy stored at a wind site can be discharged in any time-slice.

ReEDS also allows the electricity storage technology to be placed at the load centers rather than at wind sites. General storage at the load centers would have greater capacity value than that located at an onshore wind site because it would not be constrained by the availability of transmission capacity from the wind site. On the other hand, as mentioned above, storage at an onshore wind site allows for the downsizing of transmission-line capacity.

[1]To keep the number of variables in the LP to a minimum, storage at offshore wind sites is not simulated. Such systems are assumed to be less likely, due to the relatively higher costs of offshore wind and storage.

2 ReEDS Base Case Data

This section summarizes the key data inputs to the Base Case of the ReEDS model. The Base Case was developed simply as a point of departure for other analyses to be conducted with the ReEDS model. It does not represent a forecast of the future, but rather is a consensus scenario whose inputs depend strongly on others' results and forecasts. For example, the ReEDS Base Case derives many of its inputs from the EIA's *Annual Energy Outlook* (EIA 2008)—in particular, its fossil fuel price forecasts, and its electric-sector load-growth rates.

2.1 Financials

ReEDS optimizes the build-out of the electric power system based on projected life-cycle costs, which include capital costs and cumulative discounted operating costs over a fixed evaluation period. The "overnight" capital costs are adjusted to reflect the actual total cost of construction, including tax effects, interest during construction, and financing mechanisms. Table 1 provides a summary of the financial values used to produce the net capital and operating costs.

Table 1: Base Case Financial Assumptions

Name	Value	Notes and Sources
InflationRate	3%	Based on recent historical inflation rates.
Real Discount Rate	8.5%	Equivalent to weighted cost of capital. Based on EIA assumptions (EIA 2008c).
Debt/Equity Ratio	0	Consistent with the use of a weighted cost of capital for the real discount rate.
Real Interest Rate	0	Consistent with the use of a weighted cost of capital for the real discount rate.
Marginal Income Tax Rate	40%	Combined Federal/State Corporate Income Tax Rate.
Evaluation Period	20 years	Base Case Assumption.
Depreciation Schedule:		
Conventionals	15 year	MACRS
Wind	5 year	MACRS
Nominal Interest Rate		
During Construction	10%	Base Case Assumption.
Dollar Year	2004	All costs are expressed in year 2004 dollars.

2.2 Power System Characteristics

2.2.1 ReEDS Regions

There are five types of regions used in the ReEDS model; these are:

1. Interconnects — There are three major interconnects in the United States: Eastern interconnect, Western interconnect, and ERCOT (Electric Reliability Council of Texas) interconnect. These are electrically asynchronous regions, isolated from each other except for a limited number of AC-DC-AC connections.

2. National Electric Reliability Council (NERC) Subregions — There are 13 NERC subregions used in ReEDS. Table 2 provides a listing of NERC region names and locations.

3. Regional Transmission Operators (RTOs) — There are 32 RTOs as shown in Figure 3.

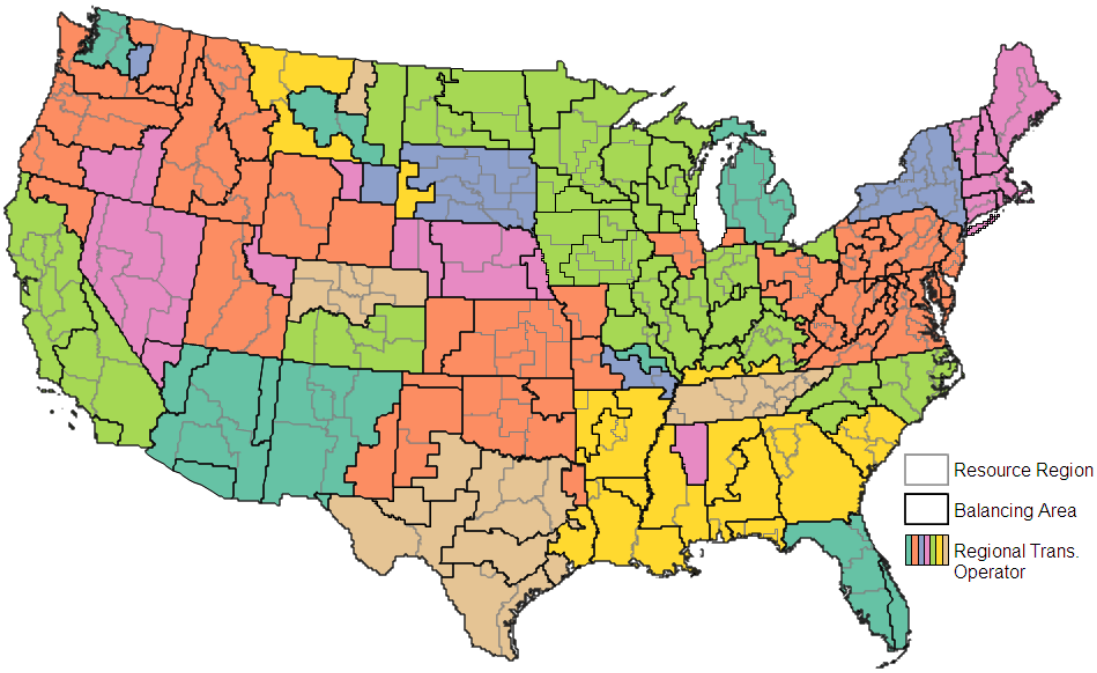

Figure 3: Regions used in ReEDS

4. Balancing Areas — There are 134 balancing areas.

5. Resource Regions — There are 356 resource regions.

Interconnects, NERC regions, RTOs, and balancing authorities are defined by various regulatory agencies (see Table 2 for a definition of NERC regions). Wind Resource Regions were created specifically for the ReEDS model. The regions have been selected using the following rules and criteria:

- Build up from counties (so that electric load can be determined for each wind supply/demand region based on county population).
- Avoid crossing state boundaries (so that state-level policies can be modeled).
- Conform to balancing areas as much as possible (to better capture the competition between wind and other generators).
- Separate concentrations of wind and solar resource from load centers where possible (so that the distance from a wind resource to a load center can be better approximated).
- Conform to NERC region/subregion boundaries (so that the results are comparable to results produced by integrating models that use the NERC regions/subregions).

A detailed map with all resource regions and balancing authorities is provided in Figure 3.

The need for multiple levels of geographical resolution is based on several different components of the ReEDS model. For example, load growth rates are based on data from the NERC region level, while wind-generator performance is modeled at the wind-resource region level. The use of these various regions is discussed in further detail in Section 3.

Table 2: NERC Regions Used in ReEDS

Number	Abbreviation	Region Name
1	ECAR	East Central Area Reliability Coordination Agreement
2	ERCOT	Electric Reliability Council of Texas
3	MAAC	Mid-Atlantic Area Council
4	MAIN	Mid-America Interconnected Network
5	MAPP	Mid-Continent Area Power Pool
6	NY	New York
7	NE	New England
8	FRCC	Florida Reliability Coordinating Council
9	SERC	Southeast Reliability Council
10	SPP	Southwest Power Pool
11	NWP	Northwest
12	RA	Rocky Mountain Area
13	CNV	California/Nevada

Note: NERC regions in ReEDS are based on the pre-2006 regional definitions defined by the EIA (2008c). In January 2006, NERC regions were redefined. The EIA has not incorporated these changes through publication of AEO 2008; therefore, ReEDS will continue to use pre-2006 definitions until the EIA modifies its data. Similarly, some of the recent changes to balancing area boundaries (now referred to as balancing authorities) are not yet reflected in ReEDS (e.g. the formation of the Texas Regional Transmission Organization) but will be when the NERC regions are updated.

2.2.2 Electric System Loads

Loads are defined by region and by time-slice. ReEDS meets both the energy requirement and the power requirement for each of the 134 balancing areas. Load requirements are set for each balancing authority in each of 16 time-slices, for each year modeled by ReEDS. Table 3 defines these time-slices.

Table 3: ReEDS Demand Time-Slice Definitions

Slice Name	Hours Per Year	Season	Time Period
H1	736	Summer	11PM-6AM
H2	644	Summer	7AM-1PM
H3	328	Summer	2PM-5PM
H4	460	Summer	6PM-10PM
H5	504	Fall	11PM-6AM
H6	441	Fall	7AM-1PM
H7	252	Fall	2PM-5PM
H8	315	Fall	6PM-10PM
H9	952	Winter	11PM-6AM
H10	833	Winter	7AM-1PM
H11	476	Winter	2PM-5PM
H12	595	Winter	6PM-10PM
H13	728	Spring	11PM-6AM
H14	1092	Spring	7AM-1PM
H15	364	Spring	2PM-5PM
H16	40	Summer	Superpeak

The electric load in 2006 for each balancing authority and time-slice is derived from the Platts Energy Markets database (2006). Figure 4 illustrates the ReEDS load duration curve for

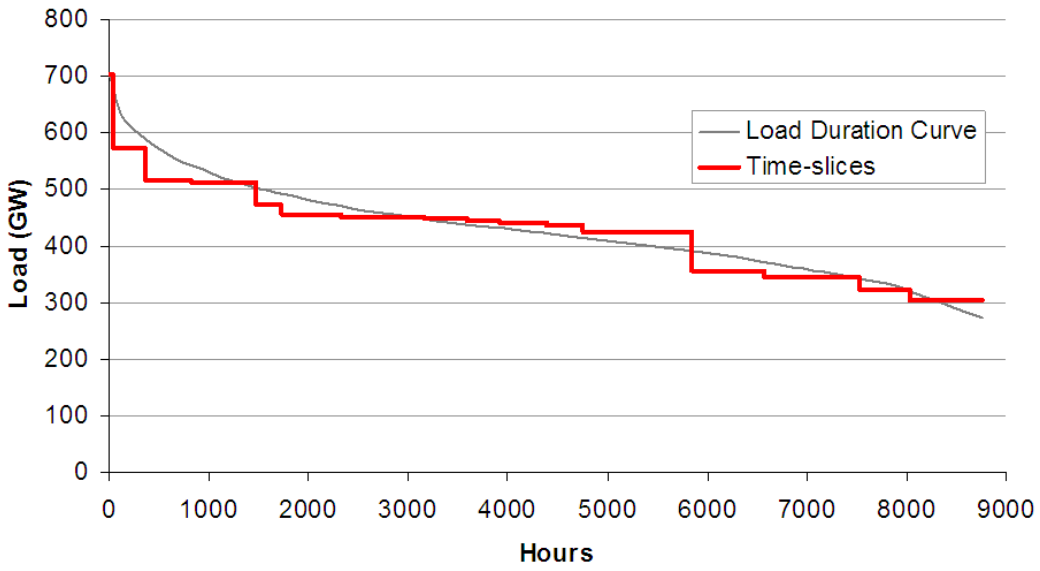

Figure 4: National Load Duration Curve in ReEDS

the entire United States for the base year, illustrating the 16 load time-slices. As a reference, the actual U.S. coincident load duration curve—also derived from the Platts database—is depicted in the figure as well. The aggregated data for the United States that are shown in Figure 4 are not used directly in ReEDS, as the energy requirement is met in each balancing area. This curve does, however, give a general idea of the ReEDS energy requirement.

2.2.3 Growth Rate

Load growth rates are taken from AEO forecasts at the NERC region level. Loads in all balancing areas within each NERC region are assumed to grow at the same rate to 2050 for the baseline, though demand elasticities are applied to the growth rate based on electricity price (see Appendix C). Table 4 contains the 2006 load and annual growth rates for each NERC region. ReEDS assumes that the growth rate in each time-slice is constant; i.e. the load shape remains the same throughout time.

2.2.4 Capacity Requirements

For each RTO, ReEDS requires sufficient capacity to meet the peak instantaneous demand throughout the course of the year, plus a peak reserve margin. The reserve margin requirement can be met by any generator type, although the generator must have the appropriate capacity value. In the cases of wind and solar power, the actual capacity value is a minority fraction of the nameplate capacity; section D describes how this capacity value fraction is calculated for generators with variable resources like wind and solar.

While these capacity requirements are implemented regionally, they have been aggregated up to national totals/averages in Table 5 for illustration.

The peak reserve margin for each RTO is provided in Table 4. The reserve margin frction is ramped from its actual value in 2006 to the 2010 requirement, and is maintained at the 2010 level thereafter. It is assumed that energy growth and peak demand grow at the same rate, and the load shape stays constant from one year to the next.

Table 4: Base Load and Load Growth in the ReEDS Base Case

NERC Region/Subregion		2006 Load (TWh/year)[a]	Annual Load Growth (%)[b]	Reserve Margin (%)[c]
1	ECAR	553	0.8	12
2	ERCOT	323	1.2	15
3	MAAC	292	0.8	15
4	MAIN	274	0.7	12
5	MAPP	165	0.6	12
6	NY	159	0.6	18
7	NE	142	0.7	15
8	FL	228	1.1	15
9	SERC	920	1.3	13
10	SPP	202	0.8	12
11	NWP	278	1.1	08
12	RA	158	1.8	14
13	CNV	315	1.0	13

[a](Platts 2006), [b](EIA 2008), [c](PA Consulting Group 2004)

Table 5: National Capacity Requirements in the ReEDS Base Case

	Capacity (GW)		Annual Growth
	2006	2050	Rate (%)
Average load in summer peak time-slice	620	1,159	1.4
Annual peak instantaneous load	762	1,416	1.4
Peak capacity to meet reserve margin	923	1,602	1.3

2.3 Wind

2.3.1 Wind Resource Definition

Wind power classes are defined as in Table 6. Wind power density and speed are not used explicitly in ReEDS. Instead, the different classes of wind power are distinguished in ReEDS through the resource levels, capacity factors, turbine costs, etc., all of which are discussed below.

Table 6: Classes of Wind Power Density

Wind Power Class	Wind Power Density (W/m^2)	Speed (m/s)
3	300-400	6.4-7.0
4	400-500	7.0-7.5
5	500-600	7.5-8.0
6	600-800	8.0-8.8
7	>800	>8.8

Note: Wind speed measured at 50 m above ground level
Source: Elliott and Schwartz (1993)

A map of wind resource by class is shown in figure 5. The supply curve used in ReEDS includes both onshore and offshore wind resources and distinguishes between shallow and deep offshore wind turbines. Shallow-water turbines are assumed to have lower initial costs than deep offshore turbines, because they employ a solid tower with an ocean bottom pier; while deep-water turbines are assumed to be mounted on floating platforms tethered to the ocean floor.

These different classes and types of wind have different costs and performance characteristics. Generally, the higher wind class sites (i.e. Class 7) are the preferred sites. However, in selecting the installation sites, ReEDS considers not only the resource quality, but also includes factors such as transmission availability, costs, and losses; correlation of the wind output with neighboring sites; environmental exclusions; site slope; and population density. As a result, in any given period, the wind turbines installed will be at a mix of sites with different wind resource classifications.

2.3.2 Wind Resource Data

The wind-resource dataset for the ReEDS model is based on separate sets of supply curves for each of onshore, shallow offshore, and deep offshore. This regional wind-resource dataset is generated by multiplying the total available area of a particular wind resource by an assumed wind-farm density of 5 MW/km^2 (NREL 2006). The amount of land available for each class is based on a dataset for each of the 356 resource regions for onshore, shallow offshore, and deep offshore. The resource data is derived from a variety of sources outlined in Table 7 for onshore wind and Table 9 for offshore wind. The wind resouce data are for 50m hub-height.

The wind-resource availability in ReEDS includes many land exclusions described in Table 8.

2.3.3 Wind Technology Cost and Performance

Black & Veatch analysts developed wind technology cost and performance projections for the model in consultation with the American Wind Energy Association's (AWEA) industry experts (O'Connell and Pletka 2007). Costs for turbines, towers, foundations, installation, profit, and interconnection fees are included. Capital costs are based on an average installed capital cost

Table 7: Data Source for Wind Resource

State	Data Source	State	Data Source
Arizona	2003, N/AWST	Nebraska[a]	2005, N/AWST
Alabama	1987, PNL	Nevada	2003, N/AWST
Arkansas	2006, N/AWST[p]	New Hampshire	2002, N/AWST
California	2003, N/AWST	New Jersey	2003, N/AWST
Colorado	2003, N/AWST	New Mexico	2003, N/AWST
Connecticut	2002, N/AWST	New York[a]	2004, N/AWST
Delaware	2003, N/AWST	North Carolina	2003, N/AWST
Florida	1987, PNL	North Dakota	2000 NREL
Georgia	2006, AWST	Ohio[a]	2004, N/AWST
Idaho	2002, N/AWST	Oklahoma[a]	2002, OTH
Illinois	2001, NREL	Oregon	2002, N/AWST
Indiana[a]	2004, N/AWST	Pennsylvania[a]	2003, N/AWST
Iowa	1997, OTH	Rhode Island	2002, N/AWST
Kansas	2004, OTH	South Carolina	2005, AWST
Kentucky	1987, PNL	South Dakota	2000 NREL
Louisiana	1987, PNL	Tennessee	1987, PNL
Maine	2002, N/AWST	Texas	2004, OTH/2000, NREL
Maryland	2003, N/AWST	Utah	2003, N/AWST
Massachusetts	2002, N/AWST	Vermont	2002, N/AWST
Michigan[a]	2005, N/AWST	Virginia	2003, N/AWST
Minnesota	2006, OTH	Washington	2002, N/AWST
Mississippi	1987, PNL	West Virginia	2003, N/AWST
Missouri[a]	2004, N/AWST	Wisconsin	2003, OTH
Montana	2002, N/AWST	Wyoming	2002, N/AWST

Notes on Sources:
PNL data resolution is 1/4 degree of latitude by 1/3 degree of longitude, each cell has a terrain exposure percent (5% for ridgecrest to 90% for plains) to define base resource area in each cell. Ridgecrest areas have 10% of the area assigned to the next higher power class. (PNL 1987)
NREL data was generated with the WRAMS model, and does not account for surface roughness. Resolution is 1 km. Texas includes the Texas mesas study area updated by NREL using WRAMS.
N/AWST data was generated by AWS TrueWind and validated by NREL. Resolution is 400 m for the northwest states (WA, OR, ID, MT, and WY) and 200 m everywhere else. These data consider surface roughness in their estimates.
N/AWST[p] data was generated by AWS TrueWind and will be validated by NREL. Data used is preliminary.
OTH data from other sources. The methods, resolution, and assumptions vary. These results have not been validated by NREL For most states, the data was taken at face value. However, some datasets were not available as 50 m power density. In those cases, assumptions were made to adjust the data to 50 m power density.
[a] In these states, the class 2, 3 and 4 wind power class estimates were adjusted upwards by 1/2 power class to better represent the likely wind resource at wind turbine height. For Nebraska, only the portion of the state east of 102 degrees longitude was adjusted.

Table 8: Wind-Resource Exclusion Database — Standard Version, January 2004

Criteria for Defining Available Windy Land (numbered in the order they are applied):

Environmental Criteria	Data/Comments:
2. 100% exclusion of National Park Service and Fish and Wildlife Service managed lands	USGS Federal and Indian Lands shapefile, Jan 2005
3. 100% exclusion of federal lands designated as park, wilderness, wilderness study area, national monument, national battlefield, recreation area, national conservation area, wildlife refuge, wildlife area, wild and scenic river or inventoried roadless area.	USGS Federal and Indian Lands shapefile, Jan 2005
4. 100% exclusion of state and private lands equivalent to criteria 2 and 3, where GIS data is available.	State/GAP land stewardship data management status, from Conservation Biology Institute Protected Lands database, 2004
8. 50% exclusion of remaining USDA Forest Service (FS) lands (incl. National Grasslands)*	USGS Federal and Indian Lands shapefile, Jan 2005
9. 50% exclusion of remaining Dept. of Defense lands*	USGS Federal and Indian Lands shapefile, Jan 2005
10 50% exclusion of state forest land, where GIS data is available*	State/GAP land stewardship data management status 2, from Conservation Biology Institute Protected Lands database, 2004
Land Use Criteria	**Data/Comments:**
5. 100% exclusion of airfields, urban, wetland and water areas.	USGS North America Land Use Land Cover (LULC), version 2.0, 1993; ESRI airports and airfields (2003)
11. 50% exclusion of non-ridgecrest forest*	Ridge-crest areas defined using a terrain definition script, overlaid with USGS LULC data screened for the forest categories.
Other Criteria	**Data/Comments:**
1. Exclude areas of slope > 20%	Derived from elevation data used in the wind resource model.
6. 100% exclude 3 km surrounding criteria 2-5 (except water)	Merged datasets and buffer 3 km
7. Exclude resource areas that do not meet a density of 5 km^2 of class 3 or better resource within the surrounding 100 km2 area.	Focalsum function of class 3+ areas (not applied to 1987 PNL resource data)

* 50% exclusions are not cumulative; i.e. if an area is non-ridgecrest forest on FS land, it is just excluded at the 50% level one time.

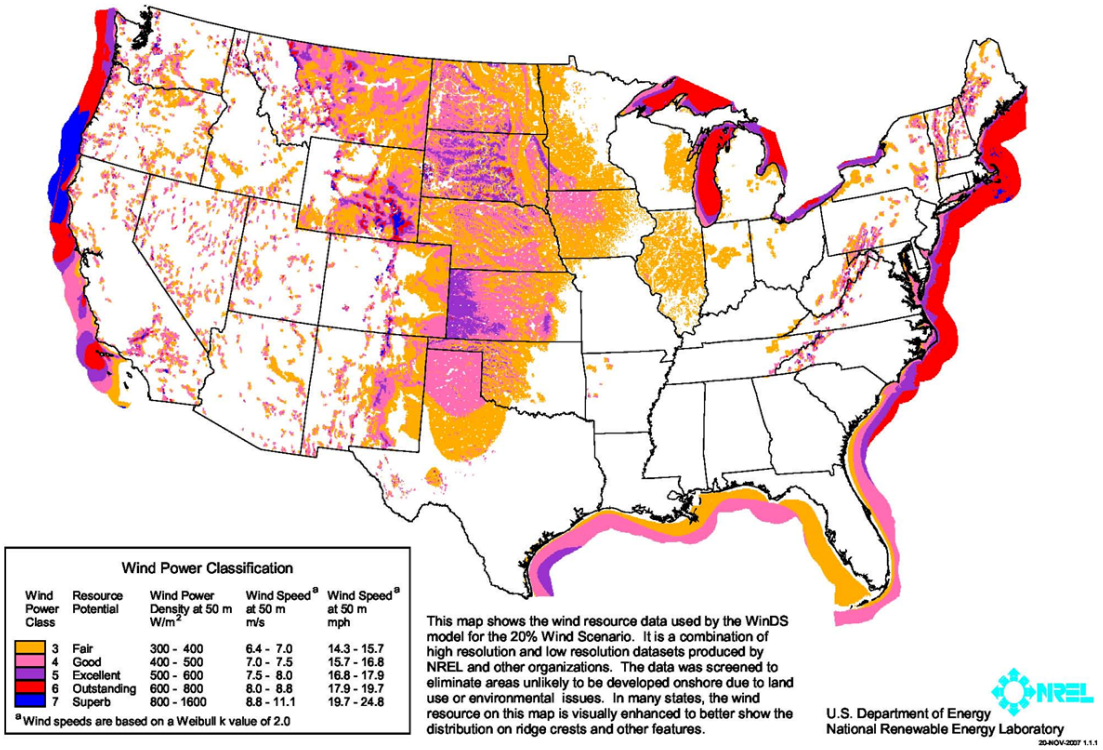

Figure 5: Wind Resource in ReEDS

of $1,775 per kilowatt (kW) in 2007, which reduces to $1,570/kW in 2004$ after adjusting for inflation and removing the construction financing charge. Additional costs reflecting terrain slope and regional population density are described later in this section.

Technology development is projected to reduce wind capital costs by 10% by 2030. Black & Veatch used historical capacity factor data to create a logarithmic best-fit line, which is then applied to each wind power class to project future performance improvements.[2] The capacity factors in Table 10 are annual averages for each class. Seasonal and diurnal wind data were exploited to develop seasonal and diurnal capacity factor corrections for each region; allowing the model to better address the variability of wind. Variable and fixed operations and maintenance (O&M) costs represent an average of recent project costs according to Black & Veatch's experience. Approximately 50% of variable O&M cost is the turbine warranty. These costs are expected to decline as turbine reliability improves and the scale of wind turbines increases. Other variable O&M expenses are tied to labor rates, royalties, and other costs that are expected to be stable. Fixed O&M costs, including insurance, property taxes, site maintenance, and legal fees, are projected to stay the same because they are not affected by technology improvements. Table 10 lists cost and performance projections for land-based wind systems (O'Connell and Pletka 2007).

Tables 11 and 12 lists cost and performance projections prepared by Black & Veatch for shallow and deep offshore wind technology ("shallow" denotes in water shallower than 30 m). Capital costs for 2005 were based on publicly available cost data for European offshore wind farms. Capital costs are assumed to decline 12.5% as a result of technology development and a maturing market. The capacity factor projection, which is based on the logarithmic best-fit lines

[2]Capacity factors for 2005 fit to actual data. For the higher wind power classes (6 and 7), however, limited data are available for operating plants, so capacity factors were extrapolated from the linear relationships between wind classes.

Table 9: Data Source for Offshore Wind Resource

State	Data Source	State	Data Source
Alabama	2006, NREL3	Mississippi	2006, NREL3
California	2003, NREL1	New Hampshire	2002, NREL1
Connecticut	2002, NREL1	New Jersey	2003, NREL1
Delaware	2003, NREL1	New York	2003, NREL1
Florida	2006, NREL3	North Carolina	2003, NREL1
Georgia	2006, NREL3	Ohio	2006, NREL2
Illinois	2006, NREL2	Oregon	2002, NREL1
Indiana	2006, NREL2	Pennsylvania	2006, NREL2
Louisiana	2006, NREL3	Rhode Island	2002, NREL1
Maine	2002, NREL1	South Carolina	2006, NREL3
Maryland	2003, NREL1	Texas	2006, NREL3
Massachusetts	2003, NREL1	Virginia	2003, NREL1
Michigan	2006, NREL2	Washington	2002, NREL1
Minnesota	2006, NREL2	Wisconsin	2006, NREL2

Notes on Sources: All data from NREL, different methods detailed below
NREL1: Validated near-shore data was supplemented with offshore resource data from earlier, preliminary runs which extended further from shore. In most cases, this still did not fill the modeling area of interest of 50 nautical miles from shore. The resource estimates were extended linearly to obtain full coverage at 50 nautical miles with little or no change in spatial pattern.
NREL2: Similar to NREL1, but available resource data estimates and areas not covered by validated and preliminary data were evaluated by NREL meteorologists to establish a best estimate of resource distribution based on expert knowledge and available measured/modeled data sources.
NREL3: No validated resource estimates existed to provide a baseline. NREL meteorologists generated an initial best estimate of resource distribution to be used in the model, based on expert knowledge and available measured/modeled data sources.

generated for land-based turbines, was increased 15% to account for larger rotor diameters and reduced wind turbulence over the ocean. By 2030 this adjustment factor is reduced to 5% as land-based development allows larger turbines to be used in turbulent environments. O&M costs are assumed to be three times those of land-based turbines (Musial and Butterfield 2004) with a learning rate commensurate to that projected by the U.S. Department of Energy (DOE; NREL 2006).

A number of adjustments, including financing, interest during construction, terrain slope, population density, and rapid growth were applied to the capital cost. Although financing has not been treated explicitly, it is assumed to be captured by the weighted cost of capital (real discount rate) of 8.5%. Additionally, there is a "learning factor" applied to wind costs and capacity factors. Specifically, for each doubling of wind capacity, there is an 8% improvement applied to capital costs and capacity factors. (Learning-based improvements on the installation cost depend on domestic wind capacity while the costs of the turbines themselves benefit from the expansion of capacity worldwide.)

A slope penalty that increases the installation cost by 2.5% per degree of terrain slope was used to represent expected costs associated with installations on mesas or ridge crests. (Costs associated with installation represent 25% of the capital cost.) Wiser and Bolinger (2007) present regional variations in installed capital cost for projects constructed in 2006. Applying a multiplier related to population density within each of the 356 resource regions results in regional variations similar to that observed in data. An additional 20% is applied to the base capital cost in New England to reflect observed capital cost variations. Slope and population density penalties have been applied to the capital cost listed in Tables 10-12 within the model to represent topographical and regional variations across the United States.

There are also "excessive growth" penalties applied to wind costs if the demand for new wind capacity significantly exceeds that supplied in earlier years. Specifically, if new wind

Table 10: Onshore Wind Cost and Performance Projections

Resource Class	Install Year	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
3	2005	0.320	1570	10.95	6.66
3	2010	0.335	1570	10.95	5.68
3	2020	0.350	1517	10.95	5.16
3	2030	0.350	1466	10.95	4.99
3	2040	0.350	1466	10.95	4.99
3	2050	0.350	1466	10.95	4.99
4	2005	0.360	1570	10.95	6.66
4	2010	0.375	1570	10.95	5.68
4	2020	0.390	1517	10.95	5.16
4	2030	0.395	1466	10.95	4.99
4	2040	0.395	1466	10.95	4.99
4	2050	0.395	1466	10.95	4.99
5	2005	0.401	1570	10.95	6.66
5	2010	0.416	1570	10.95	5.68
5	2020	0.426	1517	10.95	5.16
5	2030	0.431	1466	10.95	4.99
5	2040	0.431	1466	10.95	4.99
5	2050	0.431	1466	10.95	4.99
6	2005	0.440	1570	10.95	6.66
6	2010	0.450	1570	10.95	5.68
6	2020	0.460	1517	10.95	5.16
6	2030	0.465	1466	10.95	4.99
6	2040	0.465	1466	10.95	4.99
6	2050	0.465	1466	10.95	4.99
7	2005	0.470	1570	10.95	6.66
7	2010	0.485	1570	10.95	5.68
7	2020	0.495	1517	10.95	5.16
7	2030	0.500	1466	10.95	4.99
7	2040	0.500	1466	10.95	4.99
7	2050	0.500	1466	10.95	4.99

installations are more than 20% greater than those of the preceding year, there is a 1% increase in capital cost for each 1% growth above 20% per year (EIA 2004).

Table 11: Shallow Offshore Turbines

Resource Class	Install Year	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
3	2005	0.340	2284	14.28	20.0
3	2010	0.355	2219	14.28	18.1
3	2020	0.360	2130	14.28	15.5
3	2030	0.370	2101	14.28	13.6
3	2040	0.380	2101	14.28	13.6
3	2050	0.380	2101	14.28	13.6
4	2005	0.380	2284	14.28	20.0
4	2010	0.395	2219	14.28	18.1
4	2020	0.410	2130	14.28	15.5
4	2030	0.415	2101	14.28	13.6
4	2040	0.415	2101	14.28	13.6
4	2050	0.415	2101	14.28	13.6
5	2005	0.420	2284	14.28	20.0
5	2010	0.440	2219	14.28	18.1
5	2020	0.453	2130	14.28	15.5
5	2030	0.460	2101	14.28	13.6
5	2040	0.460	2101	14.28	13.6
5	2050	0.460	2101	14.28	13.6
6	2005	0.460	2284	14.28	20.0
6	2010	0.470	2219	14.28	18.1
6	2020	0.485	2130	14.28	15.5
6	2030	0.485	2101	14.28	13.6
6	2040	0.485	2101	14.28	13.6
6	2050	0.485	2101	14.28	13.6
7	2005	0.500	2284	14.28	20.0
7	2010	0.510	2219	14.28	18.1
7	2020	0.520	2130	14.28	15.5
7	2030	0.525	2101	14.28	13.6
7	2040	0.525	2101	14.28	13.6
7	2050	0.525	2101	14.28	13.6

Table 12: Deep Offshore Turbines

Resource Class	Install Year	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
3	2005	0.380	3046	14.28	22.8
3	2010	0.380	3046	14.28	22.8
3	2020	0.385	2792	14.28	20.9
3	2030	0.390	2665	14.28	17.8
3	2040	0.390	2538	14.28	16.5
3	2050	0.390	2538	14.28	16.5
4	2005	0.430	3046	14.28	22.8
4	2010	0.430	3046	14.28	22.8
4	2020	0.435	2792	14.28	20.9
4	2030	0.440	2665	14.28	17.8
4	2040	0.440	2538	14.28	16.5
4	2050	0.440	2538	14.28	16.5
5	2005	0.460	3046	14.28	22.8
5	2010	0.460	3046	14.28	22.8
5	2020	0.467	2792	14.28	20.9
5	2030	0.473	2665	14.28	17.8
5	2040	0.473	2538	14.28	16.5
5	2050	0.473	2538	14.28	16.5
6	2005	0.500	3046	14.28	22.8
6	2010	0.500	3046	14.28	22.8
6	2020	0.505	2792	14.28	20.9
6	2030	0.505	2665	14.28	17.8
6	2040	0.505	2538	14.28	16.5
6	2050	0.505	2538	14.28	16.5
7	2005	0.540	3046	14.28	22.8
7	2010	0.540	3046	14.28	22.8
7	2020	0.545	2792	14.28	20.9
7	2030	0.545	2665	14.28	17.8
7	2040	0.545	2538	14.28	16.5
7	2050	0.545	2538	14.28	16.5

2.4 Concentrated Solar Power

2.4.1 CSP Resource Definition

For CSP, a certain level of average annual radiation is needed before the resource can be considered viable. In the United States, those viable resource areas are located primarily within the southwestern states. Therefore, in the ReEDS model, this subset of regions is the area in which CSP solar plants are allowed. This reduction in the number of regions significantly reduces the run-time requirements of ReEDS, as well as the amount of solar GIS inputs.

Similar to the model's breakdown of wind resource into five standard classes, the solar resource appropriate for CSP systems has also been divided into five classes that are defined by the annual average direct normal radiation. The breakdown by class is oulined in Table 13.

Table 13: Classes of Wind Power Density

CSP Power Class	Solar Power Density (kWh/m^2/day)
1	6.75-6.99
2	7.00-7.24
3	7.25-7.49
4	7.50-7.74
5	7.75-8.06

Additionally, a variety of exclusions are applied to the solar resource if the slope exceeds 1%, average annual radiation is less than 6.75 kWh/m^2/day, the area is a major urban or wetland area or a protected federal land. If the remaining resource lands are less than 5 contiguous sq. km, they are excluded. Figure 6 maps the location of the solar resource that is used within ReEDS.

2.4.2 CSP Technology Cost and Performance

As of November 2008, CSP in ReEDS consists of a single technology (parabolic trough Rankine cycle, similar to the SEGS plants installed in California) with a preselected thermal storage capacity (six hours of thermal storage). These factors, combined with an assumed scale of 100 MW plant size, determine the initial cost and performance characteristics.

The storage assumption greatly simplifies the treatment of resource variability. Because the plant is assumed to be dispatchable, the capacity value for the plant is assumed to be equal to the capacity factor during the summer peak load period, which is essentially the nameplate capacity. Additionally, no operating reserve is necessary for this plant, and surplus is assumed to be negligible due to the alignment of the solar resource and load.

Excelergy was also used outside of ReEDS to determine the performance of the assumed system for a variety of locations, representing all five solar classes. For each location, the hourly output of *Excelergy* was aggregated into the 16 time-slices within ReEDS to determine the average capacity factor for each time-slice of the year, for each solar class (Table 14). For the Base Case, it is conservatively assumed that these capacity factors (i.e. solar plant performance) were unchanged in the future. In reality, it is expected that these would improve through R&D and shared operational improvements.

Based on the 2005 DOE Solar Program Multiyear Technology Plan (EERE 2005), we assume that 54% of the cost improvements projected by DOE will occur through R&D (Table 14). In addition to the improvements over time shown in Table 14, ReEDS also allows for "learning" improvements in the cost values. For each doubling of installed worldwide CSP capacity (a scenario of CSP installations outside the United States reaching 120 GW by 2040 is input), there is an 8% reduction in costs.

Table 14: CSP Cost and Performance Projections

Resource Class	Install Year	Capacity Factor	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)
1	2005	0.4088	5850	55.72	0.1
1	2010	0.4088	5572	51.07	0.1
1	2020	0.4088	4179	44.57	0.1
1	2030	0.4088	4179	44.57	0.1
1	2040	0.4088	4179	44.57	0.1
1	2050	0.4088	4179	44.57	0.1
2	2005	0.4132	5850	55.72	0.1
2	2010	0.4132	5572	51.07	0.1
2	2020	0.4132	4179	44.57	0.1
2	2030	0.4132	4179	44.57	0.1
2	2040	0.4132	4179	44.57	0.1
2	2050	0.4132	4179	44.57	0.1
3	2005	0.4274	5850	55.72	0.1
3	2010	0.4274	5572	51.07	0.1
3	2020	0.4274	4179	44.57	0.1
3	2030	0.4274	4179	44.57	0.1
3	2040	0.4274	4179	44.57	0.1
3	2050	0.4274	4179	44.57	0.1
4	2005	0.4415	5850	55.72	0.1
4	2010	0.4415	5572	51.07	0.1
4	2020	0.4415	4179	44.57	0.1
4	2030	0.4415	4179	44.57	0.1
4	2040	0.4415	4179	44.57	0.1
4	2050	0.4415	4179	44.57	0.1
5	2005	0.4570	5850	55.72	0.1
5	2010	0.4570	5572	51.07	0.1
5	2020	0.4570	4179	44.57	0.1
5	2030	0.4570	4179	44.57	0.1
5	2040	0.4570	4179	44.57	0.1
5	2050	0.4570	4179	44.57	0.1

Table 15: CSP Plant Capacity Factors

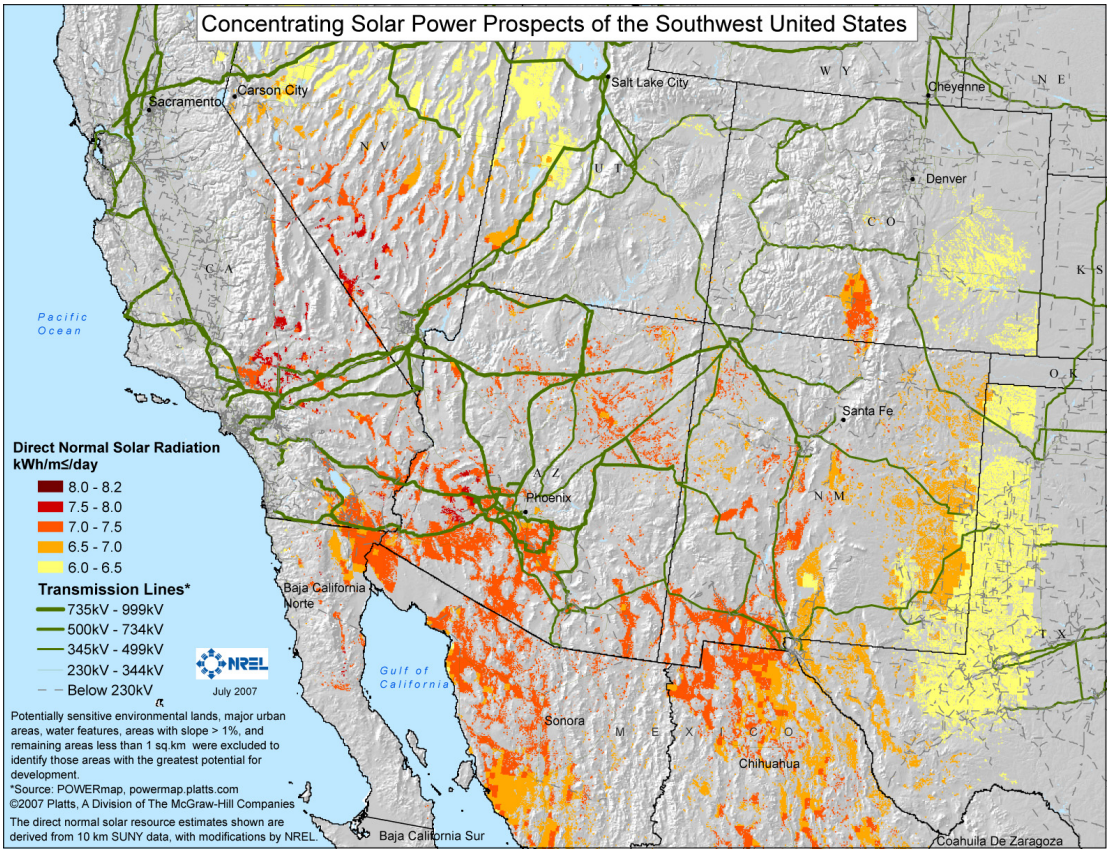

Figure 6: Solar Resource in ReEDS

2.5 Conventional Generation

2.5.1 Generator Types

Available generator types that may be built are based on the most likely types as determined by the DOE Energy Information Administration (EIA 2008a). The generator types, with shorthand notation, are as follows:

- Conventional hydropower, hydraulic turbine — Hydro
- Natural gas combustion turbine — Gas-CT
- Combined cycle gas turbine — Gas-CC
- Combined cycle gas turbine with carbon capture and sequestration (CCS) — Gas-CCS
- Conventional pulverized coal steam plant (no SO_2 scrubber) — CoalOldUns
- Conventional pulverized coal steam plant (with SO_2 scrubber) — CoalOldScr
- Conventional pulverized coal steam plant (with SO_2 scrubber and biomass cofiring) — CofireOld
- Advanced supercritical coal steam plant (with SO_2 and NO_x controls) — CoalNew
- Advanced supercritical coal steam plant (with biomass cofiring) — CofireNew
- Integrated gasification combined cycle (IGCC) coal — Coal-IGCC
- IGCC with carbon capture and sequestration (CCS) — Coal-CCS
- Oil/gas steam turbine — OGS
- Nuclear plant — Nuclear
- Municipal solid waste/landfill gas plant — MSW
- Biomass gasification plant — Biomass
- Geothermal plant — Geothermal

Several adjustments are applied to the capital cost, including financing, interest during construction, learning, and rapid growth. In the Base Case, financing is not treated explicitly[3]. It is assumed to be captured by the real discount rate of 8.5%, which is a weighted cost of capital. As the capital costs of conventional technologies are acquired from Black & Veatch and have, already been adjusted for learning, no additional learning is assumed for these technologies in the Base Case.

Interest during construction can increase the effective capital cost for each technology. Table 16 indicates the construction time and schedule for each conventional technology. Lifetimes for conventional generating facilities are used for retirement calculations, not as a financial evaluation period (the evaluation period is 20 years for all technologies).

ReEDS considers the outage rate when determining the net capacity available for generation described among the calculations in Section 3.4.4, and in determining the capacity value of each technology. Planned outages are assumed to occur in all seasons except the summer. Table 17 provides the outage rate for each conventional technology (NERC 2008).

Emission rates are estimated for SO_2, NO_x, Mercury (Hg), and CO_2. Table 17 provides the input emission rates (lbs/MMBtu of input fuel) for plants that use combustible fuel. Output emission rates (lb/MWh) may be calculated by multiplying input emission rate by heat rate.

Sources and Notes on Emissions:

[3] A full range of financing options are built into the model as detailed in Appendix F.

Table 16: Construction Parameters for Conventional Generation

Plant Type	New builds in ReEDS?	Construction Time (years)	Construction Schedule (Fraction of cost in each year)						Lifetime (years)
Hydro	No	NA	-	-	-	-	-	-	100
Gas-CT	Yes	3	0.8	0.1	0.1	-	-	-	30
Gas-CC	Yes	3	0.5	0.4	0.1	-	-	-	30
Gas-CCS	Yes	3	0.5	0.4	0.1	-	-	-	30
CoalOldUns	No	NA	-	-	-	-	-	-	60
CoalOldScr	No	NA	-	-	-	-	-	-	60
CofireOld	No	NA	-	-	-	-	-	-	60
CoalNew	Yes	4	0.4	0.3	0.2	0.1	-	-	60
CofireNew	Yes	4	0.4	0.3	0.2	0.1	-	-	60
Coal-IGCC	Yes	4	0.4	0.3	0.2	0.1	-	-	60
Coal-CCS	Yes	4	0.4	0.3	0.2	0.1	-	-	60
OGS	No	NA	-	-	-	-	-	-	50
Nuclear	Yes	6	0.1	0.2	0.2	0.2	0.2	0.1	30
MSW	No	NA	-	-	-	-	-	-	30
Biomass	Yes	4	0.4	0.3	0.2	0.1	-	-	45
Geothermal	Yes	4	0.4	0.3	0.2	0.1	-	-	20

Table 17: Performance Parameters for Conventional Generation

Plant Type	Forced Outage Rate (%)	Planned Outage Rate (%)	Emissions Rates (lbs/MMBtu fuel input)			
			SO_2	NO_x	Hg	CO_2
Hydro	4.44	9.40	0	0	0	0
Gas-CT	8.14	4.23	6e-4	0.08	0	121.83
Gas-CC	6.73	6.53	6e-4	0.02	0	121.83
Gas-CCS	6.73	6.53	6e-4	0.02	0	12.18
CoalOldUns	6.56	8.09	1.57	.448	4.6e-6	204.12
CoalOldScr	6.56	8.09	.236	.448	4.6e-6	204.12
CofireOld	6.56	8.09	.236	.448	4.6e-6	204.12
CoalNew	6.56	8.09	.157	.02	4.6e-6	204.12
CofireNew	6.56	8.09	.157	.02	4.6e-6	204.12
Coal-IGCC	6.56	8.09	.0184	.02	4.6e-6	204.12
Coal-CCS	6.56	8.09	.0184	.02	4.6e-6	20.41
OGS	10.36	11.57	0.026	0.1	0	121.83
Nuclear	3.88	8.05	0	0	0	0
MSW	5.0	5.0	0	0	0	0
Biomass	5.0	5.0	.08	0	0	0
Geothermal	0.65	2.36	0	0	0	0

SO_2: SO_2 emissions result from the oxidization of sulfur contained in the fuel. Natural gas emissions rates are from an EPA air pollution study (1996); SO_2 input emissions rate for coal is based on the sulfur content of the fuel, and the use of post-combustion controls. The "base" emissions rate for existing and new conventional coal plants is based on a national average sulfur content of 0.9 lbs/MMBtu (1.8 lb SO_2/MMBtu). ReEDS assumes the national average for "low sulfur" coal is 0.5 lbs SO_2/MMBtu from values based on national averages from AEO Assumptions (EIA 2006 - Table 73). Scrubber removal efficiency is assumed to be 90% for retrofits, 95% for new plants. (EPA 2006)

NO_x: NO_x emissions result from the oxidization of Nitrogen in the air. It is not a result of the type of fuel burned, but the combustion characteristics of the generator. NO_x emissions can be reduced through a large variety of combustion controls, or post combustion controls. NO_x emissions are not restricted in the ReEDS Base Case (see Section 2.8.1 on federal emissions standards). The emissions rates in Table 17 are national averages. (EPA 2005b)

Hg: Mercury is a trace constituent of coal. Mercury emissions are unrestricted in the ReEDS Base Case (see section on federal emissions standards). Emissions rates in Table 17 are averages and do not consider control technologies. (EPA 2005b)

CO_2: CO_2 emissions result from the oxidization of carbon in the fuel, and the emissions rate is based solely on fuel type, and therefore constant (per fuel input) for all plants burning the same fuel type. Natural gas emissions rates are from an EPA air pollution study (1996); CO_2 content for coal is based on the national average from AEO Assumptions (EIA 2006 - Table 73). Biofuels are assumed to be carbon neutral. Landfill gas is assumed to have zero carbon emissions, since the gas would be flared otherwise. CSP plants burn a small amount of natural gas, resulting in CO_2 emissions. CO_2 emissions are not constrained in the ReEDS Base Case.

2.5.2 Cost and Basic Performance

Values for capital cost, heat rate (efficiency), fixed O&M, and variable O&M for conventional technologies that can be added to the electric system are provided in Tables 18 and 19. Cost and performance values for natural gas, nuclear, and coal technologies are based on recent project costs according to Black & Veatch experience. Pulverized coal plants continue to operate in ReEDS, and SO_2 scrubbers can be added to unscrubbed coal plants for $200/kW. Oil/gas steam, and unscrubbed coal plants can not be added to the electric system, but those currently in operation are maintained until retired. ReEDS sites conventional generation technology in the balancing area that is closest to the load being served and does not require new transmission. California law prohibits building new coal plants or purchasing power from out-of-state coal plants. ReEDS approximates that by outlawing new coal plants in the state and by restricting coal generation in other western states to only what they themselves can consume.

Roughly accounting for construction times, capital costs for 2005, 2010, and 2015 are based on proposed engineering, procurement, and construction (EPC) estimates for plants that will be commissioned in 2010, 2015, and 2020. A wet scrubber is included in the EPC costs for new pulverized coal plants. Owners' costs of 20% for coal, nuclear, and combined-cycle gas plants and 10% for simple-cycle gas plants provide an "all-in" cost. These owners' costs are based on national averages and include transmission and interconnection, land, permitting, and other costs. As with wind systems, 20% is added to the capital cost of coal and nuclear builds in New England, representing siting difficulties.

2.5.3 Fuel Prices

Base fuel prices for natural gas and coal are derived from projections from the AEO 2008 report (EIA 2008 - Energy Prices by Sector and Source). These tables provide the prices in each census region, which are then assigned to a NERC subregion used in ReEDS. Prices in the AEO are

Table 18: Cost and Performance Characteristics for Conventional Generation I

Plant Type	Install Year	Capital Cost ($/kW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)	Heat Rate MMbtu/MWh
Hydro	2005	1320	12720	3.20	10.34
Hydro	2010	1320	12720	3.20	10.34
Hydro	2020	1320	12720	3.20	10.34
Hydro	2030	1320	12720	3.20	10.34
Hydro	2040	1320	12720	3.20	10.34
Hydro	2050	1320	12720	3.20	10.34
Gas-CT	2005	595	7329	11.42	11.56
Gas-CT	2010	714	6282	2.67	8.90
Gas-CT	2020	714	6282	2.67	8.90
Gas-CT	2030	714	6282	2.67	8.90
Gas-CT	2040	714	6282	2.67	8.90
Gas-CT	2050	714	6282	2.67	8.90
Gas-CC	2005	742	13706	2.86	6.87
Gas-CC	2010	742	13706	2.86	6.87
Gas-CC	2020	742	13706	2.86	6.87
Gas-CC	2030	742	13706	2.86	6.87
Gas-CC	2040	742	13706	2.86	6.87
Gas-CC	2050	742	13706	2.86	6.87
Gas-CCS	2005	1371	0	8.09	7.79
Gas-CCS	2010	1334	0	8.09	7.79
Gas-CCS	2020	1238	0	8.09	7.79
Gas-CCS	2030	1122	0	8.09	7.79
Gas-CCS	2040	1122	0	8.09	7.79
Gas-CCS	2050	1122	0	8.09	7.79
CoalOldUns	2005	1000	27156	4.35	10.00
CoalOldUns	2010	1000	27156	4.81	10.00
CoalOldUns	2020	1000	27156	5.86	10.00
CoalOldUns	2030	1000	27156	7.14	10.00
CoalOldUns	2040	1000	27156	8.71	10.00
CoalOldUns	2050	1000	27156	10.62	10.00
CoalOldScr	2005	1204	23410	3.75	10.00
CoalOldScr	2010	1204	23410	4.14	10.00
CoalOldScr	2020	1204	23410	5.05	10.00
CoalOldScr	2030	1204	23410	6.16	10.00
CoalOldScr	2040	1204	23410	7.51	10.00
CoalOldScr	2050	1204	23410	9.15	10.00
CofireOld	2005	1404	23410	3.75	10.00
CofireOld	2010	1404	23410	4.14	10.00
CofireOld	2020	1404	23410	5.05	10.00
CofireOld	2030	1404	23410	6.16	10.00
CofireOld	2040	1404	23410	7.51	10.00
CofireOld	2050	1404	23410	9.15	10.00
CoalNew	2005	2018	33599	1.62	9.47
CoalNew	2010	2075	33599	1.62	9.20
CoalNew	2020	2132	33599	1.62	9.00
CoalNew	2030	2132	33599	1.62	9.00
CoalNew	2040	2132	33599	1.62	9.00
CoalNew	2050	2132	33599	1.62	9.00

Table 19: Cost and Performance Characteristics for Conventional Generation II

Plant Type	Install Year	Capital Cost ($/kW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)	Heat Rate MMbtu/MWh
CofireNew	2005	2218	33599	1.62	9.47
CofireNew	2010	2275	33599	1.62	9.20
CofireNew	2020	2332	33599	1.62	9.00
CofireNew	2030	2332	33599	1.62	9.00
CofireNew	2040	2332	33599	1.62	9.00
CofireNew	2050	2332	33599	1.62	9.00
Coal-IGCC	2005	2617	36264	3.71	9.00
Coal-IGCC	2010	2703	36264	3.71	9.00
Coal-IGCC	2020	2703	36264	3.71	8.90
Coal-IGCC	2030	2703	36264	3.71	8.58
Coal-IGCC	2040	2703	36264	3.71	8.58
Coal-IGCC	2050	2703	36264	3.71	8.58
Coal-CCS	2005	3475	30000	8.09	9.70
Coal-CCS	2010	3412	30000	8.09	9.70
Coal-CCS	2020	3245	30000	8.09	9.59
Coal-CCS	2030	3043	30000	8.09	9.25
Coal-CCS	2040	3043	30000	8.09	9.25
Coal-CCS	2050	3043	30000	8.09	9.25
OGS	2005	396	25256	3.49	9.23
OGS	2010	390	25256	3.85	9.46
OGS	2020	370	25256	4.70	9.94
OGS	2030	351	25256	5.73	10.45
OGS	2040	351	25256	6.98	10.99
OGS	2050	351	25256	8.51	11.55
Nuclear	2005	3103	85663	0.48	10.40
Nuclear	2010	3016	85663	0.48	10.40
Nuclear	2020	2874	85663	0.48	10.40
Nuclear	2030	2801	85663	0.48	10.40
Nuclear	2040	2801	85663	0.48	10.40
Nuclear	2050	2801	85663	0.48	10.40
Geothermal	2005	3093	237950	0.00	32.32
Geothermal	2010	3093	237950	0.00	32.32
Geothermal	2020	3093	237950	0.00	32.32
Geothermal	2030	3093	237950	0.00	32.32
Geothermal	2040	3093	237950	0.00	32.32
Geothermal	2050	3093	237950	0.00	32.32
Biopower	2005	2617	66626	9.52	9.73
Biopower	2010	2617	66626	9.52	9.73
Biopower	2020	2617	66626	9.52	8.67
Biopower	2030	2617	66626	9.52	8.00
Biopower	2040	2617	66626	9.52	8.00
Biopower	2050	2617	66626	9.52	8.00
Landfill Gas	2005	2200	359000	0.00	13.65
Landfill Gas	2010	2200	359000	0.00	13.65
Landfill Gas	2020	2200	359000	0.00	13.65
Landfill Gas	2030	2200	359000	0.00	13.65
Landfill Gas	2040	2200	359000	0.00	13.65
Landfill Gas	2050	2200	359000	0.00	13.65

Notes: New nuclear plants may not be constructed before 2016. O&M costs do not include fuel. Heat rate is net heat rate (including internal plant loads). (O'Connell and Pletka 2007)

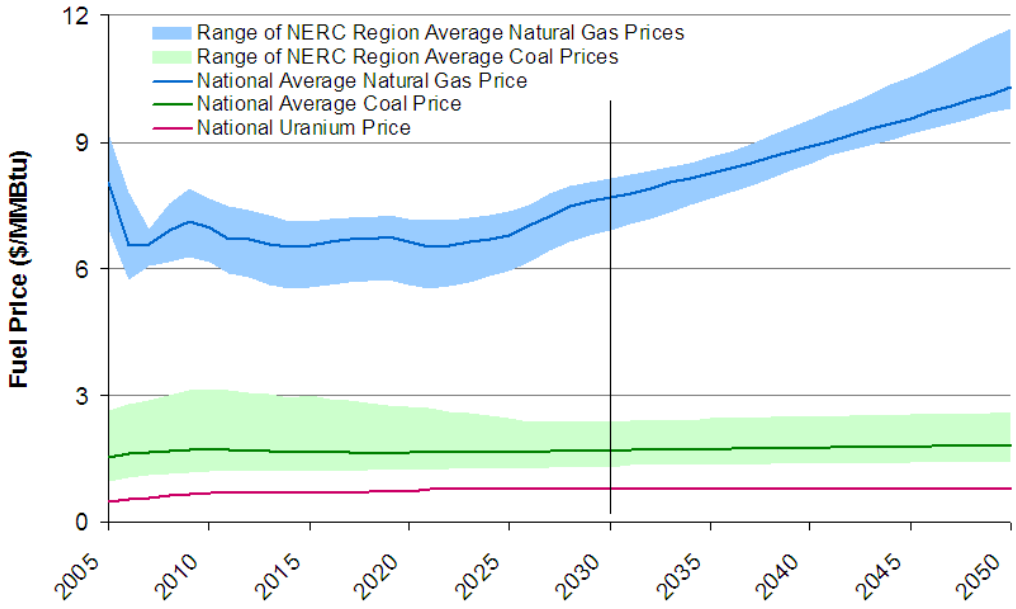

Figure 7: Base Fuel Price Trajectories

projected to 2030. Beyond 2030, ReEDS increases fuel prices at the same national annual average rate as projected by the AEO between 2020 and 2030. In the Base Case, ReEDS uses the AEO's standard fuel price projection for coal and the high fuel price projection for natural gas.

Figure 7 illustrates the projected fossil fuel prices in constant 2004$. Values to the right of the vertical line in Figure 7 (at 2030) are extrapolations of EIA fuel price projections. The bands around the national averages are the range of average fuel prices for the NERC regions.

As mentioned, these are the baseline fuel price trajectories. ReEDS readjusts these forecasts annually based on demand, via short-term and long-term price elasticities. The elasticity calculations are explained in detail in Appendix C.

The price forecast for uranium is uniform across the country and is, like gas and coal, extracted from AEO 2008. Price elasticities are not applied to uranium.

2.6 Storage Technologies

There are three storage technologies currently implemented in ReEDS: pumped hydro storage (PHS), compressed air energy storage (CAES), and batteries. The battery chemistry assumed in the model—chosen on the basis of the current robustness of the technology and well-established and competitive costs—is sodium-sulfur. The cost/performance parameters for the storage technologies are in Table 20, below. Costs for each technology are for systems with eight hours of storage.

CAES is not a pure storage technology; for the storage portion, off-peak electricity is used to charge the reservoir, in this case by pumping high-pressure air into an underground cavern (e.g., a salt dome). Upon discharging, however, the compressed air is mixed with natural gas and combusted before expanding it through a turbine to generate power. In effect, CAES is a

Table 20: Cost and Performance Characteristics for Storage Technologies

Plant Type	Install Year	Capital Cost ($/kW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)	Round Trip Efficiency	Heat Rate MMbtu/MWh
PHS	2005	1500	12720	5.0	0.80	-
PHS	2010	1500	12720	5.0	0.80	-
PHS	2020	1500	12720	5.0	0.80	-
PHS	2030	1500	12720	5.0	0.80	-
PHS	2040	1500	12720	5.0	0.80	-
PHS	2050	1500	12720	5.0	0.80	-
Battery	2005	1964	51000	5.0	0.77	-
Battery	2010	1964	51000	5.0	0.77	-
Battery	2020	1810	47002	5.0	0.78	-
Battery	2030	1668	43317	5.0	0.80	-
Battery	2040	1537	39921	5.0	0.81	-
Battery	2050	1417	36791	5.0	0.82	-
CAES	2005	840	10310	3.1	1.38	4.40
CAES	2010	840	10310	3.1	1.38	4.40
CAES	2020	820	10105	3.1	1.39	4.30
CAES	2030	820	10105	3.1	1.40	4.30
CAES	2040	820	10105	3.1	1.40	4.30
CAES	2050	820	10105	3.1	1.40	4.30

Source for Batteries: (EPRI-DOE 2003), CAES: (Holst 2005)

hybrid technology that uses electrical-to-physical storage to power a highly efficient combustion turbine; the heat rate of a CAES plant is roughly half that of a traditional natural gas plant. Because there are two inputs (electricity and natural gas), it is difficult to create a single performance metric, so the table above includes both round-trip efficiency and heat rate. For every 0.72 MWh of electricity and 4.4 MMbtu of gas, the plant will provide 1 MWh of electricity.

ReEDS can choose to build storage either co-located with wind farms or sited at the load. In either case, the storage can be charged in ReEDS by either wind-generated electricity or electricity from the general grid. The primary advantage of co-locating with wind is the potential to save money by downsizing a long transmission line. (With a 100 MW wind farm, a 20 MW battery allows the developer to build a transmission line of only 80 MW without risking losing energy generated by the top 20 MW.) There is a trade-off in that the maximum capacity the combined wind-storage system can generate is then limited by the transmission line. Storage at the load does not allow downsized transmission, but the storage will always be able to discharge at full power. Storage at load also assists the movement of wind power to load centers by charging overnight when transmission lines are relatively free, rather than trying to move the power during peak hours when the lines are congested. Storage at the load also allows slightly more wind energy to be stored for the same storage capacity since transmission losses are incurred before the load-sited storage. Similarly, storage at the load site charged from the general grid does not incur transmission losses to and from a remote wind-sited storage facility.

There are 21 GW of utility-scale electric storage in use in the United States as of 2008, the vast bulk of which is PHS. A single 110 MW CAES plant operates in McIntosh, Alabama. For further expansion, the model restricts PHS to load-located only, assuming that the odds of finding appropriate hydrological features at many attractive wind sites are slim. Because much of the country has geological features appropriate to CAES caverns (e.g., aquifers, domal salt, or bedded salt), wind-located CAES is permitted. However, CAES of either type is restricted in regions without appropriate geology (Figure 8 shows where suitable geology exists). Batteries

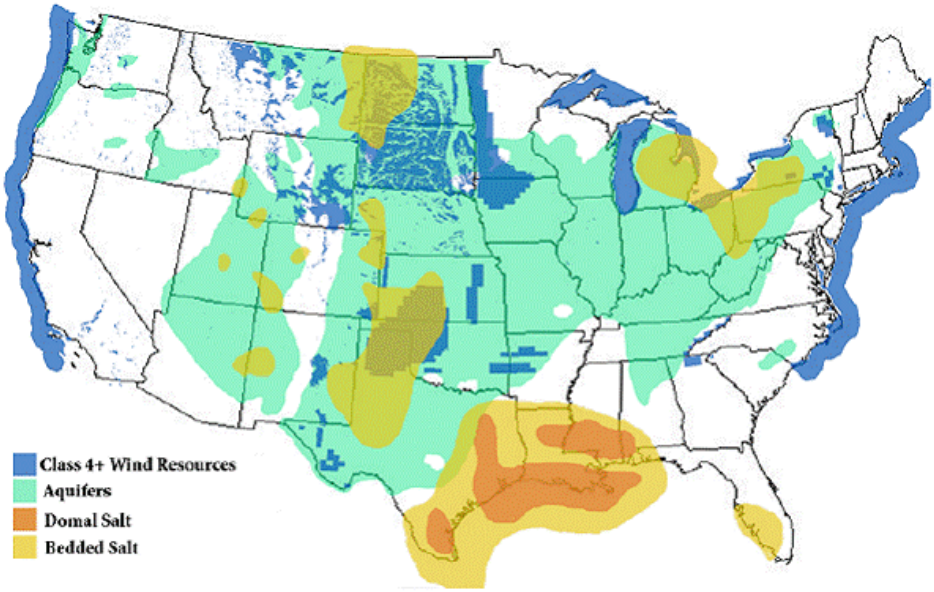

Figure 8: Areas with geology favorable to CAES, overlaid with class 4+ wind resource

can be installed anywhere.

2.7 Transmission

Three types of transmission systems can be used to transport wind power around the country, existing grid, new lines, and inregion transmission. In the case of transmission, "existing" means in existence at the start of the model, in 2006.

It is assumed that 10% of the existing grid can be used for new wind capacity, either by improving the grid or by tapping existing unused capacity (DOE 2008). A GIS optimization determines the distance at which a particular wind farm will have to be built to connect to the grid (based on the assumption that the closest wind installation will access the grid first at the least cost). In this way, a supply curve of costs to access the grid is created for each class of wind in each region. Additionally, a pancake-type fee for crossing between balancing areas may be charged within the model. The supply curves described earlier are based on this type of transmission and the GIS optimization described here. In the near term, one can expect that most of the wind that is built will use the existing grid, but as higher penetration levels are reached, the existing grid will be insufficient and new wind installation will require construction of new transmission lines.

Existing transmission capacity is estimated using a database of existing lines (length and voltage) from Platts Energy Market Data (2006). This database is translated into a megawatt capacity as a function of kilovolt (kV) rating and length (Weiss and Spiewak 1998).

Regarding new lines, the model has the ability to build straight-line transmission lines between the centers of any of the 356 resource regions. The line is built exactly to the size necessary to transmit the desired megawatts and the cost of building that transmission line is accounted for in the model.

Experts on an AWEA panel for the "20% Wind Energy by 2030" report (DOE 2008) indicate that new transmission line capacity might be constructed for any generation technology for an average cost of $1,600/MW-mile. Based on input from the AWEA expert panel, regional transmission cost variations include an additional 40% in New England and New York; 30% in

PJM East (New Jersey and Delaware); 20% in PJM West (Maryland, West Virginia, Pennsylvania, Ohio, parts of Illinois, Indiana, and Virginia); and 20% in California.

The base case assumes that 50% of the cost of new transmission is borne by the generation technology for which the new transmission is being built (wind or conventional); the other half is borne by the ratepayers within a region (because of the reliability benefits to all users associated with new transmission). This 50-50 allocation, which is common in the industry, was recently adopted for the 15-state Midwest Independent Transmission System Operator (Midwest ISO) region. New wind transmission lines that carry power across the main interconnects are not cost-shared with other technology. In the base case, this sharing of costs is implied by reducing the cost of new transmission associated with a particular capacity by 50%. The remaining 50% of transmission costs are integrated into the final cost value outputs from the model, resulting in accurate total transmission costs.

In-region transmission: Within any of the 356 resource regions around the country, the model can build directly from a wind resource location to a load within the same region. A second GIS-generated supply curve is used within the model to assign a cost for this transmission.

The model treats a fourth type of transmission, used predominantly by conventional capacity and called general transmission. This is not frequently deployed because conventional capacity can generally be built in the region where it is needed, thereby obviating the need for new transmission.

ReEDS uses a transmission loss rate of 0.168 kW/MW-mile. This value is based on the loss estimates for a typical transmission circuit (Weiss and Spiewak 1998). The assumed typical line is a 200-mile, 230-kV line rated at 170 megavolt amperes (MVA; line characteristics derived from EPRI [1983]).

To emulate large regional planning structures based on that of the Midwest ISO, there is essentially no wheeling fee between balancing areas used in the base case (although the model has the capability to model such a fee).

2.8 Federal and State Energy Policy

2.8.1 Federal Emission Standards

The following emissions are tracked in ReEDS: SO_2, CO_2, NO_x, and Hg. All emissions are point-source emissions from the plant only (not "life-cycle" emissions).

ReEDS has the ability to impose a national cap on CO_2 emissions from electricity generation, or a CO_2 emission charge (tax). Neither a carbon cap nor charge is implemented in the Base Case.

Emissions of SO_2 are capped at the national level. The base case uses a cap that corresponds roughly to the 2005 Clean Air Interstate Rule (CAIR; EPA 2005a), replacing the previous limits established by the 1990 Clean Air Act Amendments. The CAIR rule divides the United States into two regions. ReEDS uses the EPA's estimate of the effective national cap on SO_2 resulting from the CAIR rule. Table 21 provides the SO_2 cap used in ReEDS. Because CAIR was struck down in the courts in 2008, we moved the ReEDS SO_2 limits schedule back four years; we will update the limits as more information becomes available or as developments occur.

Table 21: National SO_2 Emission Limit Schedule in ReEDS

	2003	2014	2019	2024	2034
SO_2 Cap (MTons)	10.6	6.1	5.0	4.3	3.5

Source: `http://www.epa.gov/cair/charts_files/cair_emissions_costs.pdf`

NO_x emissions are currently unconstrained in ReEDS. The NO_x cap based on the CAIR may be added, but the net effect on the overall competitiveness of coal is expected to be relatively

small (EIA 2003). Also, adding a NO_x cap is complicated by the wide array of options available for NO_x control.

Mercury emissions are currently unconstrained in ReEDS. As of November, 2008, the Clean Air Mercury Rule (see `http://www.epa.gov/camr/index.htm`) is a cap-and-trade regulation, expected to be met largely via the requirements of CAIR. Control technologies for SO_2 and NO_x that are required for CAIR are expected to capture enough mercury to largely meet the cap goals. As a result, the incremental cost of mercury regulations is very low and is not modeled in ReEDS (EIA 2003).

2.8.2 Federal Energy Incentives

Two federal tax incentives for renewable energy are included in the ReEDS base case as shown in Table 22

Table 22: Federal Renewable Energy Incentives

	Value	Notes and Source
Renewable Energy PTC	$19/MWh	Applies to wind. No limit to the aggregated amount of incentive. Value is adjusted for inflation to US$2006. Expires end of 2009.
Renewable Energy ITC	10%	Applies to CSP. Expires end of 2016.

2.8.3 State Energy Incentives

Several states also have production and investment incentives for renewable energy sources. The values used in ReEDS are listed in Table 23.

Table 23: State Renewable Energy Incentives

State	PTC ($/MWh)	ITC (%)	Assumed State Corporate Tax Rate (%)
Iowa	-	5.0	10.0
Idaho	-	5.0	7.6
Minnesota	-	6.5	9.8
New Jersey	-	6.0	9.0
New Mexico	10	-	7.0
Oklahoma	2.5	-	6.0
Utah	-	4.75	5.0
Washington	-	6.5	0.0
Wyoming	-	4.0	0.0

Investment and production tax credit data from IREC (2006) Tax rates from: `http://www.taxadmin.org/fta/rate/corp_inc.html`

2.8.4 Federal Renewable Portfolio Standards

A renewable portfolio standard (RPS) requires that a certain fraction of a region's energy be derived from renewable sources. While there is no federal RPS in place (as of October, 2008)

or in the ReEDS Base Case, ReEDS can accommodate a national RPS, with input values for fraction of energy to be provided by renewables, RPS start year, duration, and shortfall penalty.

2.8.5 State Renewable Portfolio Standards

A number of states have legislated RPS requirements, and states can put capacity mandates in place as an alternative or supplement to an RPS. A capacity mandate requires a utility to install or generate a certain fixed amount of renewable capacity or energy. Unless prohibited by law, a state might also meet requirements by importing electricity. The ReEDS Base Case enforces the legislated state standards listed in Table 24.

Table 24: State Renewable Portfolio Standards

State	RPS Start[2]	Full Implementation[3]	Penalty ($/MWh)	Assumed RPS (%)[4]	Legislated RPS (%)[5]	Load Fraction[6]
Arizona	2001	2025	5	15	15	0.59
California	2003	2011	50	20	20	0.75
Colorado	2007	2015	5	30	30	0.51
Connecticut	2004	2020	55	23	27	0.93
Delaware	2007	2020	5	36	40	0.36
Illinois	2004	2025	5	25	25	0.46
Iowa	1999	1999	5	105 MW	105 MW	1
Massachusetts	2003	2020	59	15	15	0.85
Maryland	2006	2022	20	20	20	0.97
Michigan	2007	2015	5	10	10	1
Minnesota	2002	2025	5	55	55	0.50
Missouri	2007	2021	5	15	15	0.70
Montana	2008	2015	10	15	15	0.67
Nevada	2003	2015	5	20	20	0.88
New Hampshire	2008	2025	54	23.8	23.8	1
New Jersey	2005	2021	50	22.5	22.5	0.98
New Mexico	2006	2020	5	29.4	30	0.52
New York	2006	2013	5	23.7	23.8	0.73
North Carolina	2007	2021	5	21	22.5	0.53
Ohio	2007	2024	45	12.5	12.5	0.89
Oregon	2002	2025	5	40	40	0.51
Pennsylvania	2007	2021	45	17.5	18	0.97
Rhode Island	2007	2019	59	16	16	0.99
Texas	2003	2015	50	5,880 MW	5,880 MW	1
Washington	2007	2020	50	15	15	0.85
Wisconsin	2001	2015	10	10.1	10.1	1

Notes: 1) RPS data as of 8/16/05. (IREC 2006)
2) RPS Start Year is the "beginning" of the RPS program. The RPS is ramped up to the full implementation level beginning in the start year. The ramp is linear unless specified otherwise in the legislation.
3) RPS Full Implementation is the year that the full RPS fraction must be met.
4) Assumed RPS is the fraction of state demand that must be met by renewable resources included in the ReEDS model. The value is based on the total state RPS requirement and adjusted to estimate the fraction actually provided by technologies in ReEDS; for instance, new or small hydropower is not included in ReEDS so a state with a hydro set-aside would have its RPS lowered by the appropriate amount.
5) Legislated RPS is the full value of the RPS as legislated by the individual states.
6) Load fraction is the fraction of the total state load that must meet the RPS. In many locations, municipal or cooperative power systems may be exempt from the RPS. The final level used in ReEDS is the assumed RPS multiplied by the applicable load fraction.

2.9 Future Work

We continue to update and improve the data in the ReEDS Base Case as it becomes available. The data relating to electric loads, fuel prices, and conventional technology costs and performance are updated annually, coincident with the release of the full Annual Energy Outlook dataset.

As mentioned above, it is our intent to improve the treatment—particularly where regional differences are concerned—of carbon capture and sequestration. Regions where there are geological features suitable for sequestration will have lower CO_2 transportation costs than regions that have to ship their exhaust hundreds of miles. Ideally, we would also put annual and total capacity caps on the amount of CO2 a given area would be able to sequester and force ReEDS to build a piping network complete with flow limits to transport the CO_2.

3 Simplified Model Description

This section describes—in simplified form—the variables, constraints, and other attributes in the linear program formulation of ReEDS. It outlines, in order:

1. Subscripts (variables and constraints)
2. Major decision variables
3. The objective function
4. Constraints

A fully detailed listing of the variables and constraints is contained in Appendix A.

3.1 Subscripts

Variables, parameters, and constraints are all subscripted to describe the space over which they apply. The various sets are listed below.

3.1.1 Geographical Sets:

- i, j—356 supply/demand regions track where wind and solar power are generated and to where they are transmitted. Source regions are generally noted 'i' and destinations, 'j.'
- n, p—134 balancing authorities (abbreviated PCA, for Power Control Authority), each of which contains one or more supply/demand regions, track dispatchable generation. Source regions are generally noted 'n' and destinations, 'p.'
- *states*—There are 48 states (no Alaska or Hawaii).
- *rto*—32 regional transmission organizations, each of which contains one or more balancing authorities. In the base case, reserve margin requirements, operating reserve requirements, and wind curtailments are monitored at the RTO level, though there is an option in the code to use balancing areas, NERC regions, or interconnects instead of RTOs.
- r—There are 13 NERC regions/subregions.
- *in*—There are 3 interconnects that are electrically isolated from each other.

3.1.2 Temporal Sets:

- *year*—2006 to 2050
- *period*—There are 23 2-year periods
- s—4 annual seasons
- m—16 time-slices during each year, with four seasons and four daily time-slices in each season plus one superpeak time-slice. (Spring has only 3 slices.)

3.1.3 Other Sets:

- c—5 wind classes
- l—3 wind locations (*onshore, shallow offshore, deep offshore*)
- $cCSP$—5 Concentrated Solar Power (CSP) classes
- pol—4 pollutants (SO_2, NO_x, Hg, CO_2)
- q—Conventional generating technologies:
  - hydropower
  - natural gas
    - combustion turbine
    - combined cycle
    - combined cycle with carbon capture and sequestration (CCS)
  - coal
    - traditional pulverized coal, unscrubbed, scrubbed, or cofiring
    - modern pulverized, with or without cofiring
    - integrated gasification combined cycle (IGCC) with or without CCS
  - oil-gas-steam
  - nuclear
  - dedicated biomass
  - geothermal
  - landfill gas/municipal solid waste
  - others
- st—There are 3 storage technologies:
  - pumped hydropower (PHS)
  - batteries
  - compressed air energy storage (CAES)

3.2 Major Decision Variables

The major decision variables include capacity of conventionals, renewables, and storage along with transmission; and dispatch of conventional capacity and storage. Unless otherwise noted, capacity variables are expressed in megawatts and energy variables are expressed in megawatt-hours.

- $\mathrm{Wtur}_{c,i,l}$ — new wind capacity
- $\mathrm{WN}_{c,i,j,l}$ — new wind transmission capacity between regions
- $\mathrm{WS}_{n,m}$ — wind curtailments (surplus)
- $\mathrm{CSPtur}_{cCSP,i}$ — new CSP capacity
- $\mathrm{CSPN}_{cCSP,i,j}$ — new CSP transmission capacity
- $\mathrm{CSPS}_{n,m}$ — CSP curtailments (surplus)
- $\mathrm{ReT}_{n,p}$ — new transmission capacity for wind and CSP (renewables) between balancing areas

- $\mathrm{CONV}_{n,q}$ — conventional capacity
- $\mathrm{CONVgen}_{n,m,q}$ — conventional generation
- $\mathrm{SR}_{n,m,q}$ — spinning reserve capacity
- $\mathrm{QS}_{n,q}$ — quickstart capacity
- $\mathrm{CONVT}_{n,p,m}$ — conventional transmission needs
- $\mathrm{STOR}_{n,st}$ — new storage capacity
- $\mathrm{STORin}_{n,m,st}$ — energy into storage
- $\mathrm{STORout}_{n,m,st}$ — energy from storage
- $\mathrm{STOR_OR}_{n,m,st}$ — storage operating reserve capacity
- $\mathrm{TPCAN}_{n,p}$ — new transmission capacity for dispatchable sources
- $\mathrm{CONTRACTcap}_{n,p}$ — firm capacity contracted from another region
- RPSshortfall

3.3 Objective Function

In the objective function we minimize z where

$$
\begin{aligned}
z \quad = \quad & \sum_{c,i,l} \mathrm{Wtur}_{c,i,l} \cdot \$capacity_l \\
+ \quad & \sum_{c,i,j,l} \mathrm{WN}_{c,i,j,l} \cdot \$capacity_l \\
+ \quad & \sum_{cCSP,i} \mathrm{CSPtur}_{cCSP,i} \cdot \$capacity \\
+ \quad & \sum_{cCSP,i,j} \mathrm{CSPN}_{cCSP,i,j} \cdot \$capacity \\
+ \quad & \sum_{n,q} \mathrm{CONV}_{n,q} \cdot \$capacity_q \\
+ \quad & \sum_{n,p} \mathrm{TPCAN}_{n,p} \cdot \$capacity \\
+ \quad & \sum_{n,m,q} \mathrm{CONVgen}_{n,m,q} \cdot (\$operation_q + \$fuel_q) \\
+ \quad & \sum_{n,m,q} \mathrm{SR}_{n,m,q} \cdot \$operation_q \\
+ \quad & \sum_{n,q} \mathrm{QS}_{n,q} \cdot \$capacity_q \\
+ \quad & \sum_{n,st} \mathrm{STOR}_{n,st} \cdot \$capacity_{st} \\
+ \quad & \sum_{n,m,st} \mathrm{STORout}_{n,m,st} \cdot (\$operation_{st} + \$fuel_{st}) \\
+ \quad & \sum_{n,m,q} \mathrm{CONVgen}_{n,m,q} \cdot \$pollution_q \\
+ \quad & \mathrm{RPSshortfall} \cdot \$penalty
\end{aligned}
$$

3.4 Constraints

The minimization of cost in ReEDS is subject to a large number of different constraints, involving limits on resources, transmission constraints, ancillary services, and pollution, along with requirements to meet capacity and generation needs. Unless specifically noted otherwise (see, for example, the wind resource limit below), these constraints apply to new generating capacity built in the time period being optimized.

The constraint name is shown with the subscripts over which the constraint applies. For example, in the constraint immediately below, the subscript 'c, i, l' immediately following the name of the constraint implies that this constraint is applied for every class of wind c, every region i, and every location l. Because there are 356 regions, five classes of wind, and three locations, this first type of constraint is repeated 5,340 times (356x5x3). The variables may have the same subscripts, but, for simplicity, the subscripts of the constraint are omitted in the variables.

3.4.1 Constraints on Wind

Wind Resource Constraint: all wind capacity installed must be less than the total wind resource in the region.

$WIND_RES_UC_{c,i,l}$

$$\text{Wtur} + Wtur_old \quad \leq \quad total\ wind\ resource$$

Wind Transmission Constraint: New wind power transmitted from a region must be less than or equal to the total amount of new wind capacity built in that region.

$WIND_2_GRID_{c,i,l}$

$$\sum_{j} \text{WN}_j \quad \leq \quad \text{Wtur}$$

Wind Curtailments: Wind that can not be absorbed by the load is considered surplus and will be subtracted from wind generation in the load constraint.

$WIND_DEMAND_LIMIT_{n,m}$

$$\text{WS} \quad \geq \quad \sum_{c,i,j,l}^{j \in n} \text{WN}_{c,i,j,l} - load$$

3.4.2 Constraints on CSP

CSP Resource Limit: all CSP capacity installed must be less than the total solar resource in the region.

$CSP_RES_UC_{cCSP,i}$

$$\text{CSPtur} + CSPtur_old \quad \leq \quad total\ CSP\ resource$$

CSP Transmission Constraint: New CSP transmitted from a region must be less than or equal to the total amount of new CSP capacity built in that region.

CSP_2_GRID$_{cCSP,i}$

$$\sum_{j} \mathrm{CSPN}_j \quad \leq \quad \mathrm{CSPtur}$$

CSP Curtailments: CSP that can not be absorbed by the load is considered surplus and will be subtracted from CSP generation in the load constraint.

CSP_DEMAND_LIMIT$_{n,m}$

$$\mathrm{CSPS} \quad \geq \quad \sum_{c,i,j}^{j \in n} \mathrm{CSPN}_{c,i,j} - load$$

3.4.3 General Renewable Constraints

Limits on Existing Transmission: New wind and CSP imported into a region can not exceed the amount of transmission available to transport it.

WIND_interregion_trans$_j$

$$\sum_{c,i,l} \mathrm{WN}_{c,i,l} + \sum_{cCSP,i} \mathrm{CSPN}_{cCSP,i} \quad \leq \quad \sum_{i} available\ transmission\ capacity_i$$

RPS Requirement: Total national annual renewable generation must exceed a specified fraction of the national electricity load or a penalty (defined here, levied in the objective function) must be paid on the shortfall.

RPSConstraint

$$\begin{aligned}
\sum_{c,i,j,l} (\mathrm{WN}_{c,i,j,l} + WN_old_{c,i,j,l}) \cdot CF_{c,i,l} - \sum_{n,m} \mathrm{WS}_{n,m} \quad &+ \\
\sum_{cCSP,i,j} (\mathrm{CSPN}_{st} + CSPN_old_{c,i,j}) \cdot CF_{cCSP} - \sum_{n,m} \mathrm{CSPS}_{n,m} \quad &+ \\
\sum_{n} \mathrm{CONVgen}_{n,geothermal} + \sum_{n} \mathrm{CONVgen}_{n,biopower} \quad &+ \\
\mathrm{RPSshortfall} \quad &\geq \quad \sum_{n,m} load_{n,m} \cdot RPS\ fraction
\end{aligned}$$

A duplicate of this constraint exists at the state level and can be seen in the detailed model description, below. It should be noted that legislated requirements of this type—emissions, RPS, etc.—can be constrained at any of the regional levels contained in the model, though such constraints are not generally included in the current version.

3.4.4 Constraints on System Operation

Generation Requirement: Generation plus net imports plus net storage must meet load requirements in each balancing authority in each time-slice.

$LOAD_PCA_{n,m}$

$$\begin{aligned}
&\sum_{q} \mathrm{CONVgen}_q + \sum_{p} \mathrm{CONVT}_{n,p,m} \quad + \\
&\sum_{c,i,j,l}^{j \in n} (\mathrm{WN}_{c,i,j,l} + WN_old_{c,i,j,l}) \cdot CF_{c,m,l} - \mathrm{WS} \quad + \\
&\sum_{cCSP,i,j}^{j \in n} (\mathrm{CSPN}_{st} + CSPN_old_{c,i,j}) \cdot CF_{cCSP,m} - \mathrm{CSPS} \quad + \\
&\sum_{st} \mathrm{STORout}_{st} \quad \geq \quad load + \sum_{p} \mathrm{CONVT}_{p,n,m} + \sum_{st} \mathrm{STORin}_{st}
\end{aligned}$$

Reserve Margin Requirement: Dispatchable capacity plus capacity value of wind and CSP plus storage capacity plus net contracted firm capacity must exceed the peak annual load plus a reserve margin.

RES_MARG_{rto}

$$\begin{aligned}
&\sum_{n,q}^{n \in rto} \mathrm{CONV}_{n,q} \quad + \\
&\sum_{c,i,j,l}^{j \in rto} \mathrm{Wtur}_{c,i,j,l} \cdot CV_{c,i,l} \quad + \\
&\sum_{cCSP,i,j}^{j \in rto} \mathrm{CSPtur}_{cCSP,i,j} \cdot CV_{cCSP,i} \quad + \\
&\sum_{n,st}^{n \in rto} \mathrm{STOR}_{n,st} \cdot CV_{n,st} \quad + \\
&\sum_{n,p}^{n \in rto} (\mathrm{CONTRACTcap}_{p,n} - \mathrm{CONTRACTcap}_{n,p}) \quad \geq \quad \sum_{n}^{n \in rto} peak\ load_n \cdot (1 + reserve\ margin_n)
\end{aligned}$$

Operating Reserve Requirement: Spinning reserve plus quick-start capacity plus storage capacity must meet the normal operating reserve requirement plus that imposed by wind.

$OPER_RES_{rto,m}$

$$\begin{aligned}
\sum_{n,q}^{n \in rto} (\mathrm{SR}_{n,q} + \mathrm{QS}_{n,q}) + \sum_{st} \mathrm{STOR_OR}_{n,st} \quad \geq \quad & \sum_{n}^{n \in rto} normal\ operating\ reserve\ reqt_n \\
& + \sum_{c,i,l} wind\text{-}induced\ operating\ reserve\ reqt_{c,i,l}
\end{aligned}$$

Spinning Reserve Constraint: Spinning reserve available in a given time-slice is limited to a fraction of the peak seasonal output of that plant.

$SPIN_RES_CAP_{n,m,q}$

$$\mathrm{SR} \quad \leq \quad \mathrm{CONVgen}_{seasonpeak} \cdot SR\ fraction_q$$

Capacity Dispatch Constraint: Conventional capacity (after outages) must be sufficient to supply all the firm power, spinning reserve, and quickstart capacity demanded in each time-slice.

$CAP_FO_PO_{n,m,q}$

$$\text{CONVgen} + \text{SR} + \text{QS} \quad \leq \quad \text{CONV} \cdot (1 - \textit{outage rate})$$

Minimum Load Constraint: Conventional plants with minimum load requirements can not operate below the prescribed level.

$MIN_LOADING_{n,m,q}$

$$\text{CONVgen} \quad \geq \quad \text{CONVgen}_{peak} \cdot \textit{minimum load fraction}$$

3.4.5 Constraints on Storage

Energy Balance: Energy discharged from storage must not exceed the energy used to charge storage (after accounting for round-trip efficiency) within a single season.

$ENERGY_FROM_STORAGE_{n,s,st}$

$$\sum_{m}^{m \in s} \text{STORout}_m \quad \leq \quad \sum_{m}^{m \in s} \text{STORin}_m \cdot \textit{round-trip efficiency}$$

Dispatch Constraint: Storage capacity (after outages) must be sufficient to supply all charging power, discharging power, and operating reserve demanded in each time-slice.

$STORE_FO_PO_{n,m,st}$

$$\text{STORout} + \text{STORin} + \text{STOR_OR} \quad \leq \quad \text{STOR} \cdot (1 - \textit{outage rate})$$

3.4.6 Others

Hydropower Energy Constraint: The energy generated from hydroelectric capacity must conform to the historical availability of water.

$HYDRO_ENERGY_n$

$$\sum_{m} \text{CONVgen}_{m,hydro} \quad \leq \quad \textit{annual hydro energy available}$$

SO_2 Scrubber Constraints: Combined capacity of the scrubbed and unscrubbed coal plants must be equal to the total of the two from the last period minus retirements. Furthermore, unscrubbed coal capacity can not exceed the unscrubbed capacity of the last period minus retirements. This allows the unscrubbed to become scrubbed, i.e., the unscrubbed capacity can decrease but the total can not.

$SCRUBBER_n$

$$\mathrm{CONV}_{scrubbedcoal} + \mathrm{CONV}_{unscrubbedcoal} = CONVold_{scrubbedcoal} + CONVold_{unscrubbedcoal} - retirements$$

-and-

$$\mathrm{CONV}_{unscrubbedcoal} = CONVold_{unscrubbedcoal} - retirements$$

Emissions Constraint: National annual emissions of each pollutant (CO_2, SO_2, NO_x, Hg) by all generators do not exceed their respective national caps.

$EMISSIONS_{pol}$

$$\sum_{n,q} \mathrm{CONVgen}_{n,q} \cdot emissions_q + \sum_{n} \mathrm{STORout}_{n,CAES} \cdot emissions_{CAES} \leq emissions\ limits$$

Transmission Constraint: Transmission between balancing authorities must be sufficient to carry all wind, CSP, and conventional energy being sent between those areas.

$CONV_TRAN_PCA_{n,p,m}$

$$\mathrm{TPCAN} \geq \mathrm{ReT} + \mathrm{CONVT}$$

Appendix A Detailed Model Description

This report describes the variables, constraints, and other attributes in the linear program formulation of ReEDS. It outlines, in order:

1. Subscripts (variables and constraints)
2. Major decision variables
3. The objective function
4. Constraints
5. Glossary of parameters

A.1 Subscripts

Variables, parameters, and constraints are all subscripted to describe the space over which they apply. The various sets are listed below.

A.1.1 Geographical Sets:

- i, j—356 supply/demand regions track where wind and solar power are generated and to where they are transmitted. Source regions are generally noted 'i' and destinations, 'j.'
- n, p—134 balancing authorities (abbreviated PCA, for Power Control Authority), each of which contains one or more supply/demand regions, track conventional generation. Source regions are generally noted 'n' and destinations, 'p.'
- *states*—There are 48 states (no Alaska or Hawaii).
- *rto*—32 regional transmission organizations, each of which contains one or more balancing authorities. Reserve margin requirements, operating reserve requirements, and wind curtailments are monitored at the RTO level.
- r—There are 13 nerc regions/subregions.
- *in*—There are 3 interconnects.

A.1.2 Temporal Sets:

- *year*—2006 to 2050.
- *period*—There are 23 2-year periods.
- s—4 annual seasons.
- m—16 time-slices during each year, with four seasons and four daily time-slices in each season plus one superpeak time-slice. (Spring has only 3 slices.)

A.1.3 Other Sets:

- c—5 wind classes.
- l—3 wind locations (*onshore, shallow offshore, deep offshore*).
- *wscp*—level of wind supply curve.
- g, *bp*—wind growth bracket and break points.

- *ginst*, *bpinst*—wind installations growth bracket and break points.
- *cCSP*—5 Concentrated Solar Power (CSP) classes.
- *cspscp*—level of csp supply curve.
- *gCSP*, *bpCSP*—CSP growth bracket and break points.
- *gCSPinst*, *bpCSPinst*—CSP installations growth bracket and break points.
- *escp*—level of intraregion electricity supply curve.
- *bioclass*—level of biomass supply curve.
- *geoclass*—level of geothermal resource supply curve.
- *egsclass*—level of conductive Enhanced Geothermal Systems (EGS) supply curve.
- *tpca_g*, *tpcabp*—transmission growth bracket and break points.
- *pol*—4 pollutants (SO_2, NO_x, Hg, CO_2).
- *q*—Conventional generating technologies:
  - hydropower
  - natural gas
    - combustion turbine
    - combined cycle
    - combined cycle with carbon capture and sequestration (CCS)
  - coal
    - traditional pulverized coal, unscrubbed, scrubbed, or cofiring
    - modern pulverized, with or without cofiring
    - integrated gasification combined cycle (IGCC) with or without CCS
  - oil-gas-steam
  - nuclear
  - dedicated biomass
  - geothermal
  - landfill gas/municipal solid waste
  - others.
- *st*—There are 3 storage technologies:
  - pumped hydropower (PHS)
  - batteries
  - compressed air energy storage (CAES).

A.2 Major Decision Variables

The major decision variables include capacity of conventionals, renewables, and storage along with transmission; and dispatch of conventional capacity and storage. Unless otherwise noted, capacity variables are expressed in megawatts and energy variables are expressed in megawatt-hours.

Wind Variables

- $\mathrm{WturN}_{c,i,l,wscp}$ — new[4] wind capacity that will access pre-2006[5] transmission lines at a cost associated with step *wscp* of the transmission supply curve.[6]
- $\mathrm{WturTN}_{c,i,l}$ — New wind turbine capacity that can be transmitted only on new transmission lines dedicated to wind transmission from region i to another region.
- $\mathrm{Wtur_inregion}_{c,i,l}$ — New wind turbine capacity whose transmitted electricity will move on new transmission lines dedicated to wind from a class c wind site within region i to a load center also within region i.
- $\mathrm{WN}_{c,i,j,l}$ — Wind energy sent from new turbines in region i to region j that must be accomodated on pre-2006 lines.
- $\mathrm{WTN}_{c,i,j,l}$ — Wind energy sent from new turbines in region i to region j on new lines dedicated to wind.
- $\mathrm{Welec_inregion}_{c,i,l,escp}$ Wind energy sent from new turbines in region i to a load center also within region i.
- $\mathrm{WS}_{n,m}$ — The amount by which the wind power supplied to balancing area n exceeds the electricity demand in balancing area n in time-slice m.
- WCt_{g} — New national wind turbine capacity in bin g; used for estimating the increase in wind turbine price with rapid world growth.
- $\mathrm{WCtinst}_{i,ginst}$ — New wind turbine capacity from bin *ginst* in region i; used for estimating the increase in installation costs with rapid regional growth.
- $\mathrm{WNSC}_{i,l,wscp}$ — New wind turbine capacity to be connected to the grid in region i from step *wscp* of the supply curve, which provides the cost of building transmission from region i to the grid.

CSP Variables

- $\mathrm{CSPturN}_{cCSP,i,cspscp}$ — new CSP capacity that will access pre-2006 transmission lines at a cost associated with step *cspscp* of the transmission supply curve.
- $\mathrm{CSPturTN}_{cCSP,i,j}$ — New CSP capacity that can be transmitted only on new transmission lines dedicated to CSP transmission from region i to another region.
- $\mathrm{CSPtur_inregion}_{cCSP,i}$ — New CSP capacity whose transmitted electricity will move on new transmission lines dedicated to CSP from a class *cCSP* site within region i to a load center also within region i.
- $\mathrm{CSPN}_{cCSP,i,j}$ — CSP energy sent from new plants in region i to region j that must be accomodated on pre-2006 lines.

[4] New capacity means capacity built in this period, i.e. in this period's optimization run of the linear program.

[5] To reduce confusion, in the detailed model description, existing prior to the start of the model (2006) will be called "pre-2006" while existing prior to the start of a given period will be called "existing."

[6] in the model itself, WturN, WturTN, WN, and WTN are not actually subscripted with c. Instead, to reduce the solve time, a parameter $class_{c,i,l}$ keeps track of which class is the most attractive available in each region in that period. For this document, $class_{c,i,l}$ has been elided and c has been integrated directly into the variables for simplicity.

- $\text{CSPTN}_{cCSP,i,j}$ — CSP energy sent from new plants in region i to region j on new lines dedicated to CSP.
- $\text{CSPelec_inregion}_{cCSP,i,escp}$ — CSP energy sent from new plants in region i to a load center also within region i.
- $\text{CSPS}_{n,m}$ — The amount by which the CSP power supplied to balancing area n exceeds the electricity demand in balancing area n in time-slice m.
- CSPCt_{gCSP} — New national CSP capacity in bin *gCSP*; used for estimating the increase in CSP price with rapid world growth.
- $\text{CSPCtinst}_{i,gCSPinst}$ — New CSP capacity from bin *gCSPinst* in region i; used for estimating the increase in installation costs with rapid regional growth.
- $\text{CSPNSC}_{cspscp,i}$ — New CSP capacity to be connected to the grid in region i from step *cspscp* of the supply curve, which provides the cost of building transmission from region i to the grid.
- $\text{ReT}_{n,p}$ — New transmission capacity for wind or CSP (renewable) between balancing areas n and p.

Conventional Variables

- $\text{CONV}_{n,q}$ — Dispatchable (primarily conventional) capacity of technology q in balancing area n.[7]
- $\text{CONVgen}_{n,m,q}$ — Conventional generation in time-slice m by technology q in balancing area n.
- $\text{CONVP}_{n,m,q}$ — Peaking conventional generation in time-slice m by technology q in balancing area n.
- $\text{CCt}_{g,q}$ — Growth in conventional capacity per year.
- $\text{SR}_{n,m,q}$ — Spinning reserve capacity in time-slice m by technology q in balancing area n.
- $\text{QS}_{n,q}$ — Available quickstart capacity of technology q in balancing area n.
- $\text{CONVT}_{n,p,m}$ — New transmission capacity for conventionals between balancing areas n and p.
- $\text{GeoBin}_{geoclass,n}$ — New geothermal capacity by step on resource supply curve.
- $\text{GeoEGSBin}_{egsclass,n}$ — New EGS capacity by step on resource supply curve.
- $\text{BioBin}_{bioclass,n}$ — Biomass consumption by step on resource supply curve.
- $\text{BioGeneration}_{bioclass,n}$ — Generation from dedicated biomass plants by step on resource supply curve.
- $\text{CofireGen}_{bioclass,n}$ — Biomass-generated energy from coal-cofiring plants by step on resource supply curve.

[7] Note that, for conventional capacity, the decision variable is not the new capacity, but the total capacity. This was done to simplify bookkeeping and to eliminate the need for vintaging of capacity built after 2006. To ensure that conventional capacity from previous periods (minus retirements) is built, a lower bound is specified for each of these variables. Thus the objective function value from the LP includes the full cost of all conventional capacity as well as the cost of their operation over the 20-year investment analysis period. This does not affect the amount of conventional capacity installed, because anything built beyond the lower bound must pay the marginal cost of new capacity. It does affect the amount of conventional fuel purchased, in that any capacity built in previous periods will have the same heatrate as the new capacity.

Storage Variables

- $\text{STOR}_{n,st}$ — Load-sited storage capacity of technology st in balancing area n.
- $\text{STORin}_{n,m,st}$ — Energy used to charge load-sited storage in time-slice m.
- $\text{STORout}_{n,m,st}$ — Energy discharged from load-sited storage in time-slice m.
- $\text{STORor}_{n,m,st}$ — Operating reserve capacity of load-sited storage in time-slice m.
- $\text{WSTOR}_{i,st}$ — Wind-sited storage capacity of technology st in resource region i.
- $\text{WSTORin_grid}_{i,m,st}$ — Grid energy sent to charge wind-sited storage in region i in time-slice m.
- $\text{WSTORin_wind}_{c,i,m,st}$ — Energy sent directly from wind turbines to charge wind-sited storage in time-slice m.
- $\text{WSTORout_source}_{i,m,st}$ — Energy discharged from wind-sited storage in source region i in time-slice m.
- $\text{WSTORout_dest}_{i,m,p}$ — Energy discharged from wind-sited storage in source region i to destination balancing authority p in time-slice m.
- $\text{WSTORout_inregion}_{i,m,p}$ — Energy discharged from wind-sited storage in source region i and consumed to a load center also within region i.
- $\text{WSTOROr}_{n,m,st}$ — Operating reserve capacity of wind-sited storage in time-slice m.

Miscellaneous Variables

- $\text{TPCAN}_{n,p}$ — Transmission capacity between balancing areas n and p.
- TPCACt_{tpca_g} — Growth in new transmission capacity per year.
- $\text{CONTRACTcap}_{n,p}$ — Firm capacity contracted from balancing authority n to p.
- $\text{COALLOWSUL}_{n,q}$ — Annual generation from low-sulfur coal by (coal-burning) technology q.
- RPS_shortfall — Unmet amount of RPS requirement. A penalty is assessed on the shortfalls in the objective function.
- $\text{St_RPS_shortfall}_{states}$ — Unmet amount of state RPS requirement.
- $\text{St_CSPRPS_shortfall}_{states}$ — Unmet amount of state CSP requirement.
- $\text{Oper_Res_Reqt}_{rto,m}$ — Operating reserve capacity required in rto rto.

A.3 Objective Function

In the objective function we minimize the following costs:

$$
\begin{aligned}
z \;=\;& \text{Capital and operating costs of new wind plants}\\
+\;& \text{Cost of new transmission for wind}\\
+\;& \text{Capital and operating costs of new CSP plants}\\
+\;& \text{Cost of new transmission for CSP}\\
+\;& \text{Capital cost of conventional generators}\\
+\;& \text{Fuel and operating costs of conventional generation}\\
+\;& \text{Capital cost of new transmission lines}\\
+\;& \text{Capital cost of new storage capacity}\\
+\;& \text{Fuel and operating costs of storage}\\
+\;& \text{Cost of a } CO_2 \text{ tax}
\end{aligned}
$$

In equation form, with explanatory notes in brackets (below the lines to which they refer):[8] [9]

$$
\begin{aligned}
z \;=\;& \sum_{c,i,l} (\mathrm{WturN}_{c,i,l} + \mathrm{WturTN}_{c,i,l} + \mathrm{Wtur_inregion}_{c,i,l})\\
& \cdot \begin{pmatrix} CW_c \cdot cpop_{c,i,l} \cdot (1 + cslope_{c,i,l} \cdot Cost_Inst_Frac) \\ \cdot (1 - st_Invincent_{i \in states}) \\ + CWOM_c + CF_{c,l} \cdot (1 - st_Prodincent_{i \in states}) \end{pmatrix}\\
& \qquad \text{[wind capital and O\&M costs]}\\
+\;& \sum_{c,i,l} \left(\sum_{j} \left(\mathrm{WN}_{c,i,j,l} + \mathrm{WTN}_{c,i,j,l} \right) + \mathrm{Welec_inregion}_{c,i,l} \right) \cdot GridConCost\\
& \qquad \text{[wind capital and O\&M costs]}\\
+\;& \sum_{c,i,j,l} \mathrm{WN}_{c,i,j,l} \cdot CF_{c,l} \cdot (TOWCOST \cdot Distance_{i,j} + PostStamp_{i,j})\\
& \qquad \cdot (1 - SurplusMar_{c,i}) \cdot 8760/CRF\\
& \qquad \text{[cost to connect wind to grid on pre-2006 lines]}\\
+\;& \sum_{c,i,l} \mathrm{WTN}_{c,i,j,l} \cdot TNWCOST \cdot Distance_{i,j}\\
& \qquad \text{[cost to connect wind to grid on new lines]}\\
+\;& \sum_{g} \mathrm{WCt}_g \cdot CG_g\\
& \qquad \text{[excessive growth penalty on wind turbines]}\\
+\;& \sum_{ginst,i} \mathrm{WCtinst}_{ginst,i} \cdot CGinst_{ginst}\\
& \qquad \text{[excessive growth penalty on wind installation]}
\end{aligned}
$$

[8] some subscripts, e.g. *wscp* on WturN in the first line of the objective function are elided here and in constraints, below, when they are immediately summed over and therefore have no bearing on the equation.

[9] All parameters used in the objective function and constraints can be found in the glossary, below.

$$+ \quad \sum_{c,i,l} \left(\sum_{wscp} \mathrm{WNSC}_{i,l,wscp} \cdot WR2GPTS_{c,i,l,wscp} \right) \cdot CF_{c,l} \cdot 8760/CRF$$

[cost of spur line to connect new wind capacity to pre-2006 grid]

$$+ \quad \sum_{c,j,l} \left(\sum_{escp} \mathrm{Welec_inregion}_{c,j,l,escp} \cdot MW_inregion_dis_{c,j,escp} \right) \cdot CF_{c,l} \cdot 8760/CRF$$

[cost of spur line to connect new wind capacity to inregion load]

$$+ \quad \sum_{cCSP,i} \left(\mathrm{CSPturN}_{cCSP,i} + \mathrm{CSPturTN}_{cCSP,i} + \mathrm{CSPtur_inregion}_{cCSP,i} \right) \cdot (CCSP_{cCSP} + CSPOM_{cCSP})$$

[CSP capital and O&M costs]

$$+ \quad \sum_{cCSP,i,j} \left(\mathrm{CSPN}_{cCSP,i,j} + \mathrm{CSPTN}_{cCSP,i,j} + \mathrm{CSPelec_inregion}_{cCSP,i,j} \right) \cdot CSPGridConCost$$

[inregion CSP capital and O&M costs]

$$+ \quad \sum_{cCSP,i,j,m} \mathrm{CSPN}_{cCSP,i,j} \cdot H_m \cdot CF_{cCSP,m} \cdot (TOWCOST \cdot Distance_{i,j} + PostStamp_{i,j})$$

$$\cdot (1 - CSPSurplusMar_{cCSP,i})/CRF$$

[cost to connect CSP to grid on pre-2006 lines]

$$+ \quad \sum_{cCSP,i,j} \mathrm{CspTN}_{cCSP,i,j} \cdot TNWCOST \cdot Distance_{i,j}$$

[cost to connect CSP to grid on new lines]

$$+ \quad \sum_{cCSP,i,j,m} \left(\sum_{cspscp} \mathrm{CspNSC}_{cCSP,i,cspscp} \cdot CSP2GPTS_{cCSP,i,cspscp} \right) \cdot CF_{cCSP,m} \cdot H_m/CRF$$

[cost of spur line to connect new wind capacity to pre-2006 grid]

$$+ \quad \sum_{cCSP,i,j,m} \left(\sum_{escp} \mathrm{CspELEC_inregion}_{cCSP,j,escp} \cdot CSP_inregion_dis_{cCSP,j,escp} \right) \cdot \frac{CF_{cCSP,m} \cdot H_m}{CRF}$$

[cost of spur line to connect new CSP capacity to inregion load]

$$+ \quad \sum_{gCSP} \mathrm{CSPCt}_{gCSP} \cdot CGcsp_{gCSP}$$

[excessive growth penalty on CSP hardware]

$$+ \quad \sum_{gCSPinst,i} \mathrm{CSPCtinst}_{gCSPinst,i} \cdot CGcspinst_{gCSPinst}$$

[excessive growth penalty on CSP installation]

$$+ \quad \sum_{n,q} \mathrm{CONV}_{n,q} \cdot (CCONV_q + CCONVF_q + Ctranadder_q + GridConCost)$$

[capital and O&M costs for conventional generators]

$$+ \quad \sum_{n,p} \mathrm{CONVT}_{n,p,m} \cdot H_m/CRF \cdot \left(TOCOST \cdot Distance_{n,p} + PostStamp_{n,p} \right)$$

[variable costs for transmission]

$$+ \quad \sum_{q,g} \mathrm{CGconv}_{q,g} \cdot CCt_{q,g}$$

[excessive growth penalty on conventional capacity]

$$+ \sum_{n,p} \mathrm{TPCAN}_{n,p} \cdot TNCOST \cdot Distance_{n,p}$$

[capital cost of new transmission lines]

$$+ \sum_{TPCA_G} \mathrm{TPCA_CG}_{TPCA_G} \cdot \mathrm{TPCA_Ct}_{TPCA_G}$$

[excessive growth penalty on new transmission]

$$+ \sum_{n,m,q} \mathrm{CONVgen}_{n,m,q} \cdot H_m \cdot CCONVV_{n,q}$$

[operating and fuel costs for conventional generators]

$$+ \sum_{n,m,q} \mathrm{CONVP}_{n,m,q} \cdot H_m \cdot CCONVV_{n,q} \cdot PcostFrac_q$$

[increased operating cost for peaking power]

$$+ \sum_{n,m,q} \mathrm{SR}_{n,m,q} \cdot H_m \cdot CSRV_{n,q}$$

[operating and fuel costs for spinning reserve]

$$+ \sum_{n,q} \mathrm{QS}_{n,q} \cdot CQS$$

[cost for quickstart capacity]

$$+ \sum_{geoclass,n} \mathrm{GeoBin}_{geoclass,n} \cdot GeoAdder_{geoclass,n} \cdot CCONV_{geothermal} / CCC_{geothermal}$$

$$+ \sum_{egsclass,n} \mathrm{GeoEGSBin}_{egsclass,n} \cdot GeoAdder_{egsclass,n} \cdot CCONV_{geothermal} / CCC_{geothermal}$$

[supply curve-based cost for geothermal capacity]

$$+ \sum_{bioclass,n} \mathrm{BioGeneration}_{bioclass,n} \cdot CHeatRate_{biopower} \cdot BioFeedstockLCOF_{bioclass,n}$$

$$+ \sum_{bioclass,n} \mathrm{CofireGen}_{bioclass,n} \cdot CHeatRate_{cofire} \cdot (BioFeedstockLCOF_{bioclass,n} - Fprice_{coal,n})$$

[supply curve-based cost for biomass feedstock]

$$+ \sum_{st,n} (\mathrm{STOR}_{st,n} + \mathrm{WSTOR}_{st,n}) \cdot (CSTOR_{st} + FSTOR_{st} / CRF)$$

[capital and O&M costs for storage]

$$+ \sum_{n,m,st} (\mathrm{STORin}_{n,m,st} + \mathrm{WSTORin_grid}_{n,m,st} + \mathrm{WSTORin_wind}_{n,m,st}) \cdot H_m$$

$$\cdot (VSTOR_{st} \cdot STOR_RTE_{st} + Fprice_{CAES,n} \cdot CAESHeatRate)$$

[operating and fuel costs for storage]

$$+ \sum_{st,storagebp} \mathrm{STORAGEBIN}_{st,storagebp} \cdot CGStorage_{st,storagebp}$$

[excessive growth penalty on new storage]

$$+ \sum_{n,m,q} (\mathrm{CONVgen}_{n,m,q} + \mathrm{CONVP}_q) \cdot H_m \cdot CONVpol_{q,CO2} \cdot CHeatRate_q \cdot CarbTax$$

[cost of carbon tax on conventional generation]

$$+ \sum_{n,m,st} \mathrm{STORout}_{n,m,st} \cdot H_m \cdot STORpol_{st,CO2} \cdot CHeatRate_{st} \cdot CarbTax$$

[cost of carbon tax on storage generation]

$$+ \quad \sum_{n,q} \text{COALLOWSUL}_{n,q} \cdot lowsuladd_LCF_n \cdot CHeatRate_q$$

[surcharge for using low sulfur coal]

$$+ \quad \text{RPS_shortfall} \cdot RPSSCost$$

$$+ \quad \sum_{states} \text{St_RPSshortfall}_{states} \cdot St_RPSSCost$$

$$+ \quad \sum_{states} \text{St_CSPRPSshortfall}_{states} \cdot St_CSPRPSCost_{states}$$

[costs of shortfalls in failing to meet RPS requirements]

A.4 Constraints

The minimization of cost in ReEDS is subject to a large number of different constraints, involving limits on resources, transmission constraints, national growth constraints, ancillary services, and pollution. Unless specifically noted otherwise (see, for example, the wind resource limit below), these constraints apply to new generating capacity built in the time period being optimized.

The constraint name is shown with the subscripts over which the constraint applies. For example, in the constraint immediately below, the subscript 'c, i, l' immediately following the name of the constraint implies that this constraint is applied for every class of wind c, every region i, and every location l. Because there are 356 regions, five classes of wind, and 3 locations, this first type of constraint is repeated 5,340 times (356x5x3).

A.4.1 Constraints on Wind

Wind Resource Constraint: For every wind class c and wind supply region i, the sum of all wind capacity installed in this and preceding time periods must be less than the total wind resource in the region.

$WIND_RES_UC_{c,i,l}$

$$\text{WturN}_{c,i,l} + \text{WturTN}_{c,i,l} + \text{Wtur_inregion}_{c,i,l} \quad \leq \quad \max(0, WRuc_{c,i,l} - WturO_{c,i,l} - WTturO_{c,i,l})$$

Wind Supply Curve: New wind of class c in region i at interconnection cost step $wscp$ must be less than the remaining wind resource in that cost step.[10] The second constraint balances the wind on pre-2006 lines across the different supply curve points and is used to determine the cost of transmission required to reach the grid.

$WIND_supply_curves_{c,i,l,wscp}$

$$\text{WturN}_{c,i,l,wscp} \quad \leq \quad \max(0, WR2G_{c,i,l,wscp})$$

$WIND_EXISTRANS_BALANCE_{i,l}$

$$\sum_{wscp} \text{WNSC}_{i,l,wscp} \quad = \quad \sum_{j} \text{WN}_{i,j,l}$$

[10] A preliminary optimization is performed outside and prior to the main model to construct a supply curve for onshore wind, shallow offshore wind, and deep offshore wind for each wind class c and region i. This supply curve is comprised of four quantity/cost pairs ($WR2G_{c,i,l,wscp}$ / $WR2GPTS_{c,i,l,wscp}$). The "curve" provides the amount of class c wind $WR2G_{c,i,l,wscp}$ that can be connected to the pre-2006 grid for a cost between $WR2GPTS_{c,i,l,wscp-1}$ and $WR2GPTS_{c,i,l,wscp}$. This "pre-LP" optimization is described in more detail in Appendix G. The quantity $WR2G_{c,i,l,wscp}$ is reduced after each period's LP optimization by the amount of wind used in the time period from that cost step.

Wind Transmission Constraint: The new class c wind transmitted from a region i to all regions j must be less than or equal to the total amount of new region i class c wind used from the class c wind supply curve.

WIND_2_GRID$_{c,i,l}$

$$\sum_{j} \mathrm{WN}_{c,i,j,l} \quad \leq \quad \sum_{wscp} \mathrm{WturN}_{c,i,l,wscp}$$

WIND_2_NEW$_{c,i,l}$

$$\sum_{j} \mathrm{WTN}_{c,i,j,l} \quad \leq \quad \sum_{wscp} \mathrm{WturTN}_{c,i,l,wscp}$$

WIND_INREGION$_{c,i,l}$

$$\sum_{escp} \mathrm{Welec_inregion}_{c,i,l,escp} \quad \leq \quad \mathrm{Wtur_inregion}_{c,i,l}$$

Wind Growth Constraint: These two constraints allocate new wind capacity (MW) to bins that have turbine prices that are higher than the costs during periods of rapidly growing demand. The bins are defined as a fraction of the national wind capacity (MW) at the start of the period.

WIND_GROWTH_TOT

$$\sum_{c,i,l} (\mathrm{WturN}_{c,i,l} + \mathrm{WturTN}_{c,i,l} + \mathrm{Wtur_inregion}_{c,i,l}) \quad \leq \quad \sum_{g} \mathrm{WCt}_{g}$$

WIND_GROWTH_BIN$_{g}$

$$\mathrm{WCt}_{g} \quad \leq \quad Gt_{g} \cdot BASE_WIND$$

Wind Installation Growth Constraint: These two constraints allocate new wind capacity (MW) to bins that have installation costs associated with them over and above the base costs of installation. The bins are defined as a fraction of the regional wind capacity (MW) at the start of the period.

WIND_GROWTH_INST$_{i}$

$$\sum_{c,l} (\mathrm{WturN}_{c,i,l} + \mathrm{WturTN}_{c,i,l} + \mathrm{Wtur_inregion}_{c,i,l}) - 200 \quad \leq \quad \sum_{ginst} \mathrm{WCtinst}_{i,ginst}$$

WIND_GROWTH_BIN_INST$_{i,ginst}$

$$\mathrm{WCtinst}_{i,ginst} \quad \leq \quad Gtinst_{ginst} \cdot BASE_WIND_inst_{i}$$

Wind Curtailments: This constraint defines wind curtailments to be the maximum of zero and the difference between the wind-generated electricity consumed in region j in time-slice m and all the electricity consumed in region j (i.e., $\mathrm{WS}_{n,m}$ is non-zero only if the wind power consumed in balancing area n is greater than the total demand in time-slice m. This can occur in off-peak time-slices if large amounts of wind are sent to n to meet the demand in other time-slices). $\mathrm{WS}_{n,m}$ is then subtracted from the wind contribution to meeting the *LOAD_PCA* constraint for time-slice m. In effect, these two constraints impose a penalty on excessive shipments of wind

to an individual region j by not counting the wind power that exceeds the demand in any individual time-slice. This precludes the model from shipping wind to a region near the wind production region and then shipping the wind generation out with conventional generation to other balancing authorities using conventional lines, i.e. without taking account of the fact that any transmission reserved for wind will only be used when the wind is blowing.

$WIND_DEMAND_LIMIT_{n,m}$

$$\begin{aligned}
\mathrm{WS}_{n,m} \quad \geq \quad & \sum_{c,i,j,l}^{j\in n} (\mathrm{WN}_{c,i,j,l} + \mathrm{WTN}_{c,i,j,l} + \mathrm{Welec_inregion}_{c,j,l}) \cdot (1 - TWLOSSnew \cdot Distance_{i,j}) \\
+ \quad & \sum_{c,i,j,l}^{j\in n} (WO_{c,i,j,l} + WTO_{c,i,j,l}) \cdot (1 - TWLOSSold \cdot Distance_{i,j}) \\
- \quad & \sum_{st} \mathrm{STORin}_{n,m,st} \\
- \quad & \sum_{j,st}^{j\in n} \mathrm{WSTORin_grid}_{j,m,st} + old_WSTORin_grid_{j,m,st} \\
- \quad & \sum_{j}^{j\in n} L_{j,m}
\end{aligned}$$

A.4.2 Constraints on CSP

CSP Resource Limit: For every CSP class and supply region i, the sum of all CSP capacity installed in this and preceding time periods must be less than the total solar resource in the region.

$CSP_REC_UC_{cCSP,i}$

$$\begin{aligned}
\mathrm{CSPturN}_{cCSP,i} + \mathrm{CSPturTN}_{cCSP,i} \quad + \\
\mathrm{CSPtur_inregion}_{cCSP,i} \quad \leq \quad \max(0, CSPRuc_{cCSP,i} - CSPturO_{cCSP,i} - CSPTturO_{cCSP,i})
\end{aligned}$$

CSP Supply Curve: New CSP of class cCSP in region i at interconnection cost step *cspscp* must be less than the remaining solar resource in that cost step. The second constraint balances the CSP on pre-2006 lines across the different supply curve points and is used to determine the cost of transmission required to reach the grid.

$CSP_supply_curves_{cCSP,i,cspscp}$

$$\mathrm{CSPturN}_{cCSP,i,cspscp} \quad \leq \quad \max(0, CSP2G_{cCSP,i,cspscp})$$

$CSP_EXISTRANS_BALANCE_{i}$

$$\sum_{cspscp} \mathrm{CspNSC}_{i,cspscp} \quad = \quad \sum_{j} \mathrm{CspN}_{i,j}$$

CSP Transmission Constraints: New CSP transmitted from a region i to all regions j must be less than or equal to the total amount of new region i CSP used from the solar supply curve.

$CSP_2_GRID_{cCSP,i}$

$$\sum_{j} \mathrm{CSPN}_{cCSP,i,j} \quad \leq \quad \sum_{cspscp} \mathrm{CSPturN}_{cCSP,i,cspscp}$$

$CSP_2_NEW_{cCSP,i}$

$$\sum_{j} \mathrm{CSPTN}_{cCSP,i,j} \quad \leq \quad \sum_{cspscp} \mathrm{CSPturTN}_{cCSP,i,cspscp}$$

$ELEC_inregioncsp_{cCSP,i}$

$$\sum_{escp} \mathrm{CSPELEC_inregion}_{cCSP,i,escp} \quad \leq \quad \mathrm{CSPtur_inregion}_{cCSP,i}$$

CSP Growth Constraint: These two constraints allocate new CSP capacity (MW) to bins that have plant costs associated with them over and above the costs of the solar plants themselves. The bins are defined as a fraction of the national CSP capacity (MW) at the start of the period.

CSP_GROWTH_TOT

$$\sum_{cCSP,i} (\mathrm{CSPturN}_{cCSP,i} + \mathrm{CSPturTN}_{cCSP,i} + \mathrm{CSPtur_inregion}_{cCSP,i}) \quad \leq \quad \sum_{gCSP} \mathrm{CSPCt}_{gCSP}$$

$CSP_GROWTH_BIN_{gCSP}$

$$\mathrm{CSPCt}_{gCSP} \quad \leq \quad GtCSP_{gCSP} \cdot BASE_CSP$$

CSP Installation Growth Constraint: These two constraints allocate new CSP capacity (MW) to bins that have installation costs associated with them over and above the base costs of installation. The bins are defined as a fraction of the regional CSP capacity (MW) at the start of the period.

$CSP_GROWTH_INST_{i}$

$$\sum_{cCSP} (\mathrm{CSPturN}_{cCSP,i} + \mathrm{CSPturTN}_{cCSP,i} + \mathrm{CSPtur_inregion}_{cCSP,i}) - 200 \quad \leq \quad \sum_{gCSPinst} \mathrm{CSPCtinst}_{i,gCSPinst}$$

$CSP_GROWTH_BIN_INST_{i,gCSPinst}$

$$\mathrm{CSPCtinst}_{i,gCSPinst} \quad \leq \quad GtCSPinst_{gCSPinst} \cdot BASE_CSP_inst_{i}$$

CSP Curtailments:

$CSP_DEMAND_LIMIT_{n,m}$

$$\begin{aligned}
\mathrm{CSPS}_{n,m} \quad \geq \quad & \sum_{cCSP,i,j}^{j \in n} (\mathrm{CSPN}_{cCSP,i,j} + \mathrm{CSPTN}_{cCSP,i,j} + \mathrm{CSPelec_inregion}_{cCSP,j}) \\
& \qquad \cdot CF_{cCSP,m} \cdot (1 - CspSurplusMar_{cCSP,i}) \cdot (1 - TWLOSSnew \cdot Distance_{i,j}) \\
+ \quad & \sum_{cCSP,i,j}^{j \in n} (CSPO_{cCSP,i,j} + CSPTO_{cCSP,i,j}) \\
& \qquad \cdot CFO_{cCSP,m} \cdot (1 - CspSurplusOld_{i}) \cdot (1 - TWLOSSold \cdot Distance_{i,j}) \\
- \quad & \sum_{j}^{j \in n} L_{j,m}
\end{aligned}$$

A.4.3 General Renewable Constraints

RPS Requirement: This allows the model to include a national Renewable Portfolio Standard (RPS), wherein the total national annual renewable generation must exceed a specified fraction of the national electricity load or a penalty must be paid on the shortfall.

RPSConstraint

$$
\begin{aligned}
RPSfraction \cdot \sum_{n,m} L_{n,m} \cdot H_m \quad \leq \quad & \sum_{c,i,j,m,l} (\mathrm{WN}_{c,i,j,l} + \mathrm{WTN}_{c,i,j,l}) \cdot CF_{c,i,m,l} \cdot H_m \\
& \qquad \cdot (1 - TWLOSSnew \cdot Distance_{i,j})(1 - SurplusMar_{c,j}) \\
+ \quad & \sum_{c,i,j,m,l} (WO_{c,i,j,l} + WTO_{c,i,j,l}) \cdot CF_{c,i,m,l} \cdot H_m \\
& \qquad \cdot (1 - TWLOSSSold \cdot Distance_{i,j})(1 - SurplusOld_{c,j}) \\
+ \quad & \sum_{c,j,m,l} \mathrm{Welec_inregion}_{c,j,l} \cdot CF_{c,j,m,l} \cdot H_m \\
& \qquad \cdot (1 - SurplusMar_{c,j}) \\
+ \quad & \sum_{cCSP,i,j,m} (\mathrm{CSPN}_{cCSP,i,j} + \mathrm{CSPTN}_{cCSP,i,j}) \cdot CF_{cCSP,m} \cdot H_m \\
& \qquad \cdot (1 - TWLOSSnew \cdot Distance_{i,j}) \\
+ \quad & \sum_{cCSP,i,j,m} (CSPO_{cCSP,i,j} + CSPTO_{cCSP,i,j}) \cdot CF_{cCSP,m} \cdot H_m \\
& \qquad \cdot (1 - TWLOSSSold \cdot Distance_{i,j}) \\
+ \quad & \sum_{cCSP,j,m} \mathrm{CSPelec_inregion}_{cCSP,j} \cdot CF_{cCSP,m} \cdot H_m \\
+ \quad & \sum_{c,i,m,st} (\mathrm{WSTORin_wind}_{c,i,m,st} + old_WSTORin_wind_{c,i,m,st}) \cdot H_m \\
+ \quad & \sum_{n,m} (\mathrm{CONV}_{n,m,geothermal} + \mathrm{CONVP}_{n,m,geothermal}) \cdot H_m \\
+ \quad & \sum_{n,m} (\mathrm{CONV}_{n,m,biopower} + \mathrm{CONVP}_{n,m,biopower}) \cdot H_m \\
+ \quad & \sum_{bioclass,n} \mathrm{CofireGen}_{bioclass,n} \\
- \quad & \sum_{n,m} \mathrm{WS}_{n,m} \cdot H_m - \sum_{n,m} \mathrm{CSPS}_{n,m} \cdot H_m \\
+ \quad & \mathrm{RPS_Shortfall}
\end{aligned}
$$

State RPS Requirement: This allows the model to include state Renewable Portfolio Standards (RPS), wherein the total annual renewable generation must exceed a specified fraction of the state electricity load or a penalty must be paid on the shortfall.

$ST_RPSConstraint_{states}$

$St_RPSfraction_{states}$·

$$
\begin{aligned}
\sum_{n,m}^{n\in states} L_{n,m} \cdot H_m \quad \leq \quad & \sum_{c,i,j,m,l}^{j\in states} (\mathrm{WN}_{c,i,j,l} + \mathrm{WTN}_{c,i,j,l}) \cdot CF_{c,i,m,l} \cdot H_m \\
& \cdot (1 - TWLOSSnew \cdot Distance_{i,j})(1 - SurplusMar_{c,j}) \\
+ \quad & \sum_{c,i,j,m}^{j\in states} (WO_{c,i,j,l} + WTO_{c,i,j,l}) \cdot CF_{c,i,m,l} \cdot H_m \\
& \cdot (1 - TWLOSSold \cdot Distance_{i,j})(1 - SurplusOld_{c,j}) \\
+ \quad & \sum_{c,j,m}^{j\in states} \mathrm{Welec_inregion}_{c,j,l} \cdot CF_{c,j,m,l} \cdot H_m \\
& \cdot (1 - SurplusMar_{c,j}) \\
+ \quad & \sum_{cCSP,i,j,m}^{j\in states} (\mathrm{CSPN}_{cCSP,i,j} + \mathrm{CSPTN}_{cCSP,i,j}) \cdot CF_{cCSP,m} \cdot H_m \\
& \cdot (1 - TWLOSSnew \cdot Distance_{i,j}) \\
+ \quad & \sum_{cCSP,i,j,m}^{j\in states} (CSPO_{cCSP,i,j} + CSPTO_{cCSP,i,j}) \cdot CF_{cCSP,m} \cdot H_m \\
& \cdot (1 - TWLOSSold \cdot Distance_{i,j}) \\
+ \quad & \sum_{cCSP,j,m}^{j\in states} \mathrm{CSPelec_inregion}_{cCSP,j} \cdot CF_{cCSP,m} \cdot H_m \\
+ \quad & \sum_{c,i,m,st}^{j\in states} (\mathrm{WSTORin_wind}_{c,i,m,st} + old_WSTORin_wind_{c,i,m,st}) \cdot H_m \\
+ \quad & \sum_{n,m}^{n\in states} (\mathrm{CONV}_{n,m,geothermal} + \mathrm{CONVP}_{n,m,geothermal}) \cdot H_m \\
+ \quad & \sum_{n,m}^{n\in states} (\mathrm{CONV}_{n,m,biopower} + \mathrm{CONVP}_{n,m,biopower}) \cdot H_m \\
+ \quad & \sum_{bioclass,n} \mathrm{CofireGen}_{bioclass,n} \\
- \quad & \sum_{n,m}^{n\in states} \mathrm{WS}_{n,m} \cdot H_m - \sum_{n,m}^{n\in states} \mathrm{CSPS}_{n,m} \cdot H_m \\
+ \quad & \mathrm{St_RPS_Shortfall}
\end{aligned}
$$

Limits on Existing Transmission: Due to extant transmission capacity usage and other limitations, the amount of wind power able to be transported on pre-2006 lines is limited. This constraint limits the wind imports on pre-2006 lines to some fraction of the capacity of the transmission lines crossing the boundaries of demand region j.

$WIND_interregion_trans_j$

$$\sum_{c,i,l}(\mathrm{WN}_{c,i,j,l} + WO_{c,i,j,l}) - \sum_{c,l}(\mathrm{WN}_{c,j,j,l} + WO_{c,j,j,l}) \quad +$$
$$\sum_{cCSP,i}(\mathrm{CspN}_{cCSP,i,j} + CspO_{cCSP,i,j}) - \sum_{cCSP}(\mathrm{CspN}_{cCSP,j,j} + CspO_{cCSP,j,j}) \quad \leq \quad \sum_{k} a_k \cdot Tk_k$$

Regional Balancing Constraint: This constraint is a transmission capacity balance that defines the transmission capacity needed to handle wind and CSP transmission between balancing authorities. This transmission capacity required for wind/CSP is combined with that required by conventional generation to identify bottlenecks between balancing authorities. The left-hand side of the constraint is the sum of all wind and CSP generation transmitted into the balancing authority plus all that generated within. The right-hand side is the sum of all the wind and CSP generation consumed in- plus all that transmitted from the balancing authority.

$WIND_BALANCE_PCAS_n$

$$\sum_{p}\mathrm{ReT}_{n,p} \quad +$$
$$\sum_{c,i,j,l}^{i\in n}(\mathrm{WN}_{c,i,j,l} + WO_{c,i,j,l}) \quad +$$
$$\sum_{cCSP,i,j}^{i\in n}(\mathrm{CSPN}_{cCSP,i,j} + CspO_{cCSP,i,j}) \quad = \quad \sum_{p}\mathrm{ReT}_{p,n}$$
$$+ \quad \sum_{c,i,j,l}^{j\in n}(\mathrm{WN}_{c,i,j,l} + WO_{c,i,j,l})$$
$$+ \quad \sum_{cCSP,i,j}^{j\in n}(\mathrm{CSPN}_{cCSP,i,j} + CspO_{cCSP,i,j})$$

Conventional Transmission Constraint: Ensures that there is sufficient transmission capacity between contiguous balancing authorities n and p within the same grid interconnect to transmit wind generation and conventional generation in each time-slice m. Transmission capacity added this period is included in both directions p-to-n and n-to-p because transmission lines are bidirectional.[11]

$CONV_TRAN_PCA_{n,p,m}$

$$\mathrm{CONVT}_{n,p,m} + \mathrm{ReT}_{n,p} \quad \leq \quad \mathrm{TPCAN}_{n,p} + \mathrm{TPCAN}_{p,n} + TPCAO_{n,p}$$

[11]The $\mathrm{ReT}_{n,p}$ variable prevents ReEDS from shipping wind or CSP from supply region i to the closest demand region j; and, from there, continue to ship it as conventional power to other balancing authorities where generation is needed. The problem with this is that if new lines are required for this extended wind transmission to a different balancing authority, the wind will not have to pay for a dedicated transmission line, i.e. the transmission line cost will be spread over more hours than only those during which the wind blows.

Contracted Transmission Constraint: Ensures that there is sufficient transmission capacity between contiguous balancing authorities n and p within the same grid interconnect to transmit wind generation and contracted conventional capacity. Transmission capacity added this period is included in both directions p-to-n and n-to-p because transmission lines are bidirectional.

CONTRACT_TRAN_PCA$_{n,p}$

$$\text{CONTRACTcap}_{n,p} + \text{WT}_{n,p} + \text{CspT}_{n,p} \quad \leq \quad \text{TPCAN}_{n,p} + \text{TPCAN}_{p,n} + \mathit{TPCAO}_{n,p}$$

Transmission Growth Constraints: These two constraints allocate new transmission capacity (MW) to bins that have costs associated with them over and above the cost of the transmission lines themselves. The bins are defined as a fraction of the national transmission capacity at the start of the period.

TPCA_GROWTH_TOT

$$\text{TPCAN}_{n,p} + \sum_{c,i,j} \text{WTN}_{c,i,j} + \sum_{cCSP,i,j} \text{CspTN}_{cCSP,i,j} \quad \leq \quad \sum_{TPCA_g} \text{TPCA_Ct}_{TPCA_g}$$

TPCA_GROWTH_BIN$_{TPCA_g}$

$$\text{TPCA_Ct}_{TPCA_g} \quad \leq \quad \mathit{TPCA_Gt}_{TPCA_g} \cdot \mathit{BASETPCA}$$

A.4.4 Constraints on System Operation

Generation Requirement: This constraint ensures that the load (MW) in time period m in balancing authority n is met with power from conventional and renewable generators plus net imports from balancing authorities contiguous to n ($\text{CONVT}_{n,p,m}$). Long-distance transmission from wind and CSP facilities and imports are decremented for transmission losses. Wind and CSP output are also decreased by wind curtailments. Storage can also contribute, but the charging of storage adds to the load requirement.
The *LOAD_PCA* constraint is the constraint that is affected by the mini-slices; for (n, m) pairs that qualify, it is split into three independent constraints (each with a different set of wind capacity factors) that must be dispatched separately.

$LOAD_PCA_{n,m}$

$$
\begin{aligned}
L_{n,m} \quad \leq \quad & \sum_{q} (\mathrm{CONVgen}_{n,m,q} + \mathrm{CONVP}_{n,m,q}) \\
+ \quad & \sum_{p} (\mathrm{CONVT}_{p,n,m} \cdot (1 - TWLOSS \cdot Distance_{n,p}) - \mathrm{CONVT}_{n,p,m}) \\
+ \quad & \sum_{c,i,j}^{j \in n} (\mathrm{WN}_{c,i,j,l} + \mathrm{WTN}_{c,i,j,l}) \cdot CF_{c,i,m,l} \cdot (1 - SurplusMar_{c,i,n}) \\
& \qquad \cdot (1 - TWLOSSnew \cdot Distance_{i,j}) \\
+ \quad & \sum_{c,j,l}^{j \in n} \mathrm{Welec_inregion}_{c,j,l} \cdot CF_{c,j,m,l} \cdot (1 - SurplusMar_{c,i,n}) \\
+ \quad & \sum_{c,i,j,l}^{j \in n} (WO_{c,i,j,l} + WTO_{c,i,j,l}) \cdot CFO_{c,i,m,l} \cdot (1 - SurplusOld_{c,i,n}) \\
& \qquad \cdot (1 - TWLOSSold \cdot Distance_{i,j}) \\
- \quad & \mathrm{WS}_{n,m} \\
+ \quad & \sum_{cCSP,i,j}^{j \in n} (\mathrm{CSPN}_{cCSP,i,j} + \mathrm{CSPTN}_{cCSP,i,j}) \cdot CF_{cCSP,m} \cdot (1 - TWLOSSnew \cdot Distance_{i,j}) \\
+ \quad & \sum_{cCSP,j}^{j \in n} \mathrm{CSPelec_inregion}_{cCSP,j} \cdot CF_{cCSP,m} \\
+ \quad & \sum_{cCSP,i,j}^{j \in n} (CSPO_{cCSP,i,j} + CSPTO_{cCSP,i,j}) \cdot CF_{cCSP,m} \cdot (1 - TWLOSSold \cdot Distance_{i,j}) \\
- \quad & \mathrm{CSPS}_{n,m} \\
+ \quad & \sum_{st} (\mathrm{STORout}_{n,m,st} - \mathrm{STORin}_{n,m,st}) \\
+ \quad & \sum_{i,st} (\mathrm{WSTORout_dest}_{i,n,m} + old_WSTORout_dest_{i,n,m}) \\
& \qquad \cdot (1 - TWLOSSnew \cdot Distance_{i,n}) \\
+ \quad & \sum_{i,st}^{i \in n} \mathrm{WSTORout_inregion}_{i,m,st} + old_WSTORout_inregion_{i,m,st} \\
- \quad & \sum_{j,st}^{j \in n} \mathrm{WSTORin_grid}_{j,m,st} + old_WSTORin_grid_{j,m,st}
\end{aligned}
$$

Reserve Margin Requirement: Ensures that the conventional and storage capacity (MW) and capacity value of wind and CSP during the peak summer period is large enough to meet the peak load plus a reserve margin and any storage input requirements. Peak-load requirements in NERC region r can also be met by contracting for capacity located in other NERC regions.

RES_MARG_{rto}

$$
\begin{aligned}
\sum_{n}^{n\in rto} P_{rto}\cdot(1+RM_{rto}) \quad \leq \quad & \sum_{n,q}^{n\in rto} \mathrm{CONV}_{n,q} \\
+ \quad & \sum_{c,i,j}^{j\in rto} (\mathrm{WN}_{c,i,j}+\mathrm{WTN}_{c,i,j})\cdot CVmar_{c,i,rto} \\
& \qquad \cdot(1-TWLOSSnew\cdot Distance_{i,n}) \\
+ \quad & \sum_{c,i,j}^{j\in rto} (WO_{c,i,j}+WTO_{c,i,j})\cdot CVold_{c,i,rto} \\
& \qquad \cdot(1-TWLOSSold\cdot Distance_{i,n}) \\
+ \quad & \sum_{c,j,escp}^{j\in rto} \mathrm{Welec_inregion}_{c,j,escp}\cdot CVmar_{c,i,rto} \\
+ \quad & \sum_{cCSP,i,j}^{j\in rto} (\mathrm{CspN}_{cCSP,i,j}+\mathrm{CspTN}_{cCSP,i,j})\cdot CspCVmar_{cCSP,i,rto} \\
& \qquad \cdot(1-TWLOSSnew\cdot Distance_{i,n}) \\
+ \quad & \sum_{cCSP,i,j}^{j\in rto} (CspO_{cCSP,i,j}+CspTO_{cCSP,i,j})\cdot CspCVold_{cCSP,i,rto} \\
& \qquad \cdot(1-TWLOSSold\cdot Distance_{i,n}) \\
+ \quad & \sum_{cCSP,j,escp}^{j\in rto} \mathrm{CSPelec_inregion}_{cCSP,j,escp}\cdot CspCVmar_{cCSP,i,rto} \\
+ \quad & \sum_{n,st}^{n\in rto} \mathrm{STOR}_{n,st}+old_STOR_{n,st} \\
+ \quad & \sum_{n}^{i\in rto} \mathrm{WSTORout_dest}_{i,n,H16}+old_WSTORout_dest_{i,n,H16} \\
& \qquad \cdot(1-TWLOSSold\cdot Distance_{i,n}) \\
+ \quad & \sum_{i,st}^{i\in n} \mathrm{WSTORout_inregion}_{i,H16,st}+old_WSTORout_inregion_{i,H16,st} \\
+ \quad & \sum_{n,p}^{n\in rto} \mathrm{CONTRACTcap}_{p,n}\cdot(1-TLOSS\cdot Distance_{n,p}) \\
- \quad & \sum_{n,p}^{n\in rto} \mathrm{CONTRACTcap}_{n,p}
\end{aligned}
$$

Operating Reserve Requirement: Ensures that the spinning reserve, quick-start capacity, and storage capacity are adequate to meet the normal operating reserve requirement and that imposed by wind. The second and third constraints work together to ensure that no more than a set fraction (*qsfrac*) of the operating reserve requirement be met by quickstart capacity.

$OPER_RES_{rto,m}$

$$\begin{aligned} Oper_Res_Reqt_{rto,m} \quad \leq \quad & \sum_{n,q}^{n \in rto} \mathrm{SR}_{n,m,q} + \mathrm{QS}_{n,q} \cdot F_q \\ + \quad & \sum_{n,st}^{n \in rto} \mathrm{STOR_OR}_{n,m,st} + \sum_{i,st}^{i \in rto} \mathrm{WSTOR_OR}_{i,m,st} + old_WSTOR_OR_{i,m,st} \end{aligned}$$

$OPER_RES2_{m,rto}$

$$\begin{aligned} Oper_Res_Reqt_{rto,m} \quad = \quad & TOR_{rto,m} \\ & + \sum_{c,i,j}^{j \in rto} (\mathrm{WN}_{i,j} + \mathrm{WTN}_{i,j}) \cdot ORmar_{c,i,rto,m} \\ & + \sum_{c,j}^{j \in rto} \mathrm{Welec_inregion}_{c,j} \cdot ORmar_{c,j,rto} \Big) \end{aligned}$$

$OPER_RES3_{rto,m}$

$$\sum_{n,q}^{n \in rto} \mathrm{QS}_{n,q} \cdot F_q \quad \leq \quad qsfrac \cdot Oper_Res_Reqt_{rto,m}$$

Spinning Reserve Constraint: Ensures that the useful generation from a conventional plant of type q comprises at least a minimum fraction of the total generation in time-slice m in balancing authority n.

$SPIN_RES_CAP_{n,m,q}$

$$\mathrm{SR}_{n,m,q} \quad \leq \quad \mathrm{CONVgen}_{n,seasonpeak,q} \cdot FSRV_q$$

Capacity Dispatch Constraint: Ensures that the capacity (MW) in balancing authority n of type q—derated by the average forced outage rate for type q generators—is adequate to meet the load, quick-start, and spinning reserve required in time-slice m.

$CAP_FO_PO_{n,m,q}$

$$\mathrm{CONVgen}_{n,m,q} + \mathrm{SR}_{n,m,q} + \mathrm{QS}_{n,q} \quad \leq \quad \mathrm{CONV}_{n,q} \cdot (1 - FO_q)(1 - PO_{m,q})$$

Peaking Constraint: To prevent unrealistic cycling, base-load plants are constrained in peak time-slices to generate no more electricity than the average of that which is generated in the shoulder time-slices. Additional power is available through *CONVP*, at increased cost.

$B_peak_12_{n,m,q}$

$$\begin{aligned}
\text{CONVgen}_{n,H3,q\in baseload} &\leq (\text{CONVgen}_{n,H2,q\in baseload} + \text{CONVgen}_{n,H4,q\in baseload})/2 \\
\text{CONVgen}_{n,H7,q\in baseload} &\leq (\text{CONVgen}_{n,H6,q\in baseload} + \text{CONVgen}_{n,H8,q\in baseload})/2 \\
\text{CONVgen}_{n,H12,q\in baseload} &\leq (\text{CONVgen}_{n,H10,q\in baseload} + \text{CONVgen}_{n,H11,q\in baseload})/2 \\
\text{CONVgen}_{n,H15,q\in baseload} &\leq \text{CONVgen}_{n,H14,q\in baseload} \\
\text{CONVgen}_{n,H16,q\in baseload} &\leq (\text{CONVgen}_{n,H2,q\in baseload} + \text{CONVgen}_{n,H4,q\in baseload})/2
\end{aligned}$$

Minimum Load Constraint: To prevent baseload plants from ramping down to unrealistic levels, minimum power output can not fall below a set fraction of peak power output.

$MIN_LOADING_{n,m,q}$

$$\text{CONVgen}_{n,m,q} + \text{CONVP}_{n,m,q} \geq \text{CONVgen}_{n,seasonpeak,q} \cdot minplantload_q$$

A.4.5 Constraints on Storage

Storage Charging Constraint, Wind: Generation from wind turbines can either go onto the grid immediately or directly into wind-sited storage.

$WIND_2_STORAGE_{c,i,m}$

$$\begin{aligned}
&\sum_j (\text{WN}_{c,i,j} + \text{WTN}_{c,i,j}) \cdot CF_{c,i,m} \quad + \\
&\quad WELEC_inregion_{c,i} \cdot CF_{c,i,m} \quad + \\
&\qquad \sum_{st} \text{WSTORin_wind}_{c,i,m,st} \leq (\text{WturN}_{c,i} + \text{WturTN}_{c,i} + \text{Wtur_inregion}_{c,i}) \cdot CF_{c,i,m}
\end{aligned}$$

Storage Charging Constraint, Grid: There must be sufficient transmission capacity to wind farms in region i to accept any energy being used to charge wind-sited storage in that region.

$GRID_2_STORAGE_{i,m}$

$$\sum_{st} \text{WSTORin_grid}_{i,m,st} \leq \sum_{c,j} (\text{WN}_{c,i,j} + \text{WTN}_{c,i,j}) + \sum_c \text{WELEC_inregion}_{c,i}$$

Storage Charging Constraint, Competition: Wind-energy gets precedence over grid-energy for charging storage.

$GRID_LIMIT_{i,s}$

$$\sum_{m,st}^{m\in s} WSTORin_grid_{i,m,st} \leq \sum_{c,m,st}^{m\in s} WSTORin_wind_{c,i,m,st} \cdot \frac{1 - CF_{c,i,s}}{CF_{c,i,s}}$$

Storage Power Constraint: Transmission lines for wind may downsize compared to the capacity of the wind farm if there is storage at the site. Storage power must compensate for any shortfall, i.e. all wind power must be able to go into either the grid or storage.

STORAGE_INPUT_CAPACITY$_i$

$$\begin{aligned}\sum_{st} \mathrm{WSTOR}_{i,st} \quad &\geq \quad \sum_{c} (\mathrm{WturN}_{c,i} + \mathrm{WturTN}_{c,i} + \mathrm{Wtur_inregion}_{c,i}) \\ &- \quad \sum_{c,j} (\mathrm{WN}_{c,i,j} + \mathrm{WTN}_{c,i,j} + \mathrm{WELEC_inregion}_{c,i})\end{aligned}$$

Storage Power Constraint: Power discharged from storage during the peak period of each season may not exceed the expected amount of available transmission once wind has taken its share.

STORAGE_PEAK_OUT$_{i,p,s}$

$$\mathrm{WSTORout_dest}_{i,p,seasonpeak} \quad \leq \quad \sum_{c,j}^{j \in p} (\mathrm{WN}_{c,i,j} + \mathrm{WTN}_{c,i,j}) \cdot (1 - CF_{c,i,s})$$

STORAGE_PEAK_IN$_{p,s}$

$$\mathrm{WSTORout_dest}_{i,p,seasonpeak} \quad \leq \quad \sum_{c,i,j}^{j \in p} (\mathrm{WN}_{c,i,j} + \mathrm{WTN}_{c,i,j}) \cdot (1 - CF_{c,i,s})$$

STORAGE_PEAK_INREGION$_{i,s}$

$$\mathrm{WSTORout_inregion}_{i,seasonpeak,st} \quad \leq \quad \sum_{c} \mathrm{WELEC_inregion}_{c,i} \cdot (1 - CF_{c,i,seasonpeak})$$

Storage Discharge Constraint: To reduce the overall variable count, the variable governing energy discharged from storage, $\mathrm{WSTORout}_{i,p,m,st}$, was broken down into two, $\mathrm{WSTORout_dest}_{i,m,p}$ and $\mathrm{WSTORout_source}_{i,m,st}$. This constraint ties those two variables together.

STORAGE_SOURCE_MATCH$_{i,m}$

$$\sum_{p} \mathrm{WSTORout_dest}_{i,p,m} \quad = \quad \sum_{st} \mathrm{WSTORout_source}_{i,m,st}$$

Energy Balance: Energy discharged from storage type *st* in each area *i* or *n* must not exceed the energy used to charge storage—multiplied by the round-trip efficiency for type *st* generators—within a single season.

ENERGY_FROM_GRID_STORAGE$_{n,s,st}$

$$\sum_{m}^{m \in s} \mathrm{STORout}_{n,m,st} \cdot H_m \quad \leq \quad \sum_{m}^{m \in s} \mathrm{STORin}_{n,m,st} \cdot H_m \cdot STOR_RTE_{st}$$

$ENERGY_FROM_WIND_STORAGE_{i,s,st}$

$$\sum_{m}^{m\in s}\Big(\text{WSTORout_source}_{i,m,st}+ \text{WSTORout_inregion}_{i,m,st}\Big)\cdot H_m \quad\leq\quad \sum_{m}^{m\in s}\Big(\sum_{c}\text{WSTORin_wind}_{c,i,m,st}+ \text{WSTORin_grid}_{i,m,st}\Big)H_m\cdot STOR_RTE_{st}$$

Storage Dispatch Constraint: Ensures that storage capacity of type *st*—derated by the average forced outage rate for type *st* generators—is adequate to supply all charging power, discharging power, and operating reserve demanded in each time-slice *m*.

$STORE_FO_PO_GRID_{n,m,st}$

$$\text{STORout}_{n,m,st}+\text{STORin}_{n,m,st}+\text{STOR_OR}_{n,m,st} \quad\leq\quad (\text{STOR}_{n,st}+old_STOR_{n,st})(1-FO_{st})(1-PO_{m,st})$$

$STORE_FO_PO_WIND_{i,m,st}$

$$\begin{aligned}\text{WSTORin_wind}_{i,m,st}+\text{WSTORin_grid}_{i,m,st} &+\\ \text{WSTORout_source}_{i,m,st}+\text{WSTORout_inregion}_{i,m,st} &+\\ \text{WSTOR_OR}_{i,m,st} &\leq \text{WSTOR}_{i,st}(1-FO_{st})(1-PO_{m,st})\end{aligned}$$

Storage Growth Constraint: These two constraints allocate new storage capacity (MW) to bins that have costs associated with them over and above the cost of the storage capacity itelf. The bins are defined as a fraction of the national storage capacity at the start of the period.

$STORAGE_GROWTH_TOT_{st}$

$$\sum_{i}\text{WSTOR}_{i,st}+\sum_{n}\text{STOR}_{n,st} \quad\leq\quad \sum_{storagebp}\text{STORAGEBIN}_{st,storagebp}$$

$STORAGE_GROWTH_BIN_{st,storagebp}$

$$\text{STORAGEBIN}_{st,storagebp} \quad\leq\quad STORAGEBINCAP_{st,storagebpt}\cdot BASE_STORAGE_{st};$$

A.4.6 Others

Hydropower Energy Constraint: Restricts the energy available from hydroelectric capacity to conform to the historical availability of water.

$HYDRO_ENERGY_n$

$$\sum_{m}\text{CONVgen}_{n,m,hydro} \quad\leq\quad Hen_n$$

California Coal Restriction: Western states can generate no more energy from coal or ogs (plants that are dirtier than gas-cc) than they can consume in-state. This is to prevent them from shipping coal-generated electricity to California.

$CALIFORNIA_COAL_{WECCstates,m}$

$$\sum_{dirty,n}^{n\in states} \left(\mathrm{CONVgen}_{n,m,dirty} + \mathrm{CONVP}_{n,m,dirty}\right) \quad \leq \quad \sum_{n}^{n\in states} L_{n,m}$$

Generation from Low Sulfur Coal: This constraint essentially adds all the coal used in the different time slices throughout the year into a single variable.

$LOWSULCOAL_{n,q}$

$$\mathrm{coallowsul}_{n,q\in coaltech} \quad \leq \quad \sum_{m}(\mathrm{CONVgen}_{n,m,q} + \mathrm{CONVP}_{n,m,q}) \cdot H_m$$

SO_2 Scrubbers Constraint: Combined capacity of the scrubbed and unscrubbed coal plants must be equal to the total of the two from the last period minus retirements. Furthermore, unscrubbed coal capacity can not exceed the unscrubbed capacity of the last period minus retirements. This allows the unscrubbed to become scrubbed, i.e., the unscrubbed capacity can decrease but the total can not. Scrubbed coal plants can be converted to cofiring via the same mechanism,

$SCRUBBER_n$

$$\begin{aligned}
\mathrm{CONV}_{n,scr} + \mathrm{CONV}_{n,uns} + \mathrm{CONV}_{n,cofire} \quad &= \quad CONVold_{n,scr} - CONVret_{n,scr} \\
&+ \quad CONVold_{n,uns} - CONVret_{n,uns} \\
&+ \quad CONVold_{n,cofire} \\
\text{-and-} \\
\mathrm{CONV}_{n,uns} \quad &\leq \quad CONVold_{n,uns} - CONVret_{n,uns}
\end{aligned}$$

$COFIRE_CAPACITY_n$

$$\mathrm{CONV}_{n,scr} + \mathrm{CONV}_{n,cofire} \quad \geq \quad CONVold_{n,src} - CONVret_{n,scr} + CONVold_{n,cofire}$$

Emissions Constraint: Ensures that the national annual emission of each pollutant (CO_2, SO_2, NO_x, Hg) by all generators is lower than a national cap.

$EMISSIONS_{pol}$

$$\begin{aligned}
\mathrm{LP}_{pol} \quad \geq \quad & \sum_{n,m,q} (\mathrm{CONVgen}_{n,m,q} + \mathrm{CONVP}_{n,m,q}) \cdot H_m \cdot CONVpol_{q,pol} \cdot CHeatrate_q \\
+ \quad & \sum_{n,m} \mathrm{STORout}_{n,m,st} \cdot STORpol_{st,pol} \cdot CHeatrate_{st} \\
- \quad & \sum_{q,n,pol}^{pol=SO_2} \mathrm{coallowsul}_{n,q} \cdot CONVpol_{q,pol} \cdot CHeatrate_q \cdot coallowsulpolred \\
- \quad & \sum_{bioclass,n} \mathrm{CofireGen}_{bioclass,n} \cdot CHeatrate_{cofire} \cdot (CONVpol_{coal,pol} - CONVpol_{biomass,pol})
\end{aligned}$$

Geothermal Constraints: These constraints regulate the expansion of geothermal capacity. Regional capacity is constrained by a recoverable capacity supply curve. Geothermal capacity, as shown below, is linked directly to $\mathrm{CONV}_{q,n}$ and, through it, the model's framework for dispatchable conventional technologies.

GEOTHERMAL_GROWTH$_n$

$$\mathrm{CONV}_{n,geothermal} - CONVold_{n,geothermal} = \sum_{geoclass} \mathrm{GeoBin}_{geoclass,n} + \sum_{egsclass} \mathrm{GeoEGSbin}_{egsclass,n}$$

GEOTHERMAL_GROWTH_BIN$_{geoclass,n}$

$$\mathrm{GeoBin}_{geoclass,n} + GeoOld_{geoclass,n} \leq GeoMax_{geoclass,n}$$

GEOEGS_GROWTH_BIN$_{egsclass,n}$

$$\mathrm{GeoEGSbin}_{egsclass,n} + GeoEGSOld_{egsclass,n} \leq GeoEGSmax_{egsclass,n}$$

Biofuel Constraints: These constraints regulate the capacity expansion of dedicated biomass and coal-biomass cofiring plants. Total bio-fired generation is limited by a regional feedstock supply curve. In cofired plants, biomass can contribute up to 15% of the feedstock. Biomass, like geothermal, is linked directly to the conventional variables such as $\mathrm{CONV}_{n,q}$ and $\mathrm{CONVgen}_{n,m,q}$.

BIOPOWER_GROWTH$_n$

$$\mathrm{CONV}_{n,biopower} - CONVold_{n,biopower} = \sum_{bioclass} \mathrm{BioBin}_{bioclass,n}$$

COFIRE_GENERATION$_n$

$$\sum_{bioclass} \mathrm{CofireGen}_{bioclass,n} \leq 0.15 \cdot \sum_{q,m} \mathrm{CONVgen}_{n,m,cofire}$$

BIOPOWER_GENERATION$_{bioclass,n}$

$$\mathrm{BioGeneration}_{bioclass,n} \cdot CHeatrate_{biopower} + \mathrm{CofireGen}_{bioclass,n} \cdot CHeatrate_{cofire} \leq BioSupply_{bioclass,n}$$

A.5 Glossary of Parameters

This is a glossary of all parameters that appear in the objective function and constraints of the detailed model description.

a_k The fraction of pre-2006 transmission line k's capacity available to wind.

BASE_CSP National CSP capacity at the start of the period. (MW)

$BASE_CSP_inst_i$ Regional CSP capacity at the start of the period. (MW)

BASETPCA National transmission capacity at the start of the period. (MW)

BASE_WIND National wind capacity at the start of the period. (MW)

$BASE_WIND_inst_i$ Regional wind capacity at the start of the period. (MW)

$BioFeedstockLCOF_{bioclass,n}$ Levelized cost of feedstock at each step of the biomass supply curve.

$BioSupply_{bioclass,n}$ Amount of feedstock available at a given step on the biomass supply curve.

CarbTax Amount of carbon tax. (\$/ton CO_2)

CCC_q Overnight capital cost of conventional generating capacity. (\$/MW)

$CCONV_q$ Present value of the revenue required to pay the capital cost of conventional generating capacity (\$/MW) including interest, construction, finance, and taxes.

$CCONVF_q$ Present value of the annual fixed operating costs over the evaluation period for conventional generating capacity. (\$/MW)

$CCONVV_{n,q}$ Present value over the evaluation period of the variable operating and fuel costs for generation from conventional capacity. (\$/MWh)

$CCSP_{cCSP}$ Capital cost of class *cCSP* CSP capacity. (\$/MW)

$CCt_{q,g}$ The present value of the cost of transmitting 1 MWh of power for each of E years between balancing authorities n and p.

$CF_{c,i,m,l}$ Capacity factor by time-slice for new wind of at a class c, location l site in supply region i.

$CF_{cCSP,m}$ Capacity factor by time-slice for new CSP at a class *cCSP* site.

$CFO_{c,i,m,l}$ Average capacity factor of all existing type l, class c wind on pre-2006 lines in region i.

$CFO_{cCSP,m}$ Average capacity factor of all existing class *cCSP* CSP on pre-2006 lines.

$CFTO_{c,i,m,l}$ Average capacity factor of all existing type l, class c wind on new lines in region i.

$CFTO_{cCSP,m}$ Average capacity factor of all existing class *cCSP* CSP on new lines.

CG_g Increase in turbine price due to rapid growth in wind capacity. (\$/MW)

$CGcsp_{gCSP}$ Increase in CSP plant cost due to rapid growth in CSP capacity. (\$/MW)

$CGcspinst_{gCSPinst}$ Increase in CSP installation cost due to rapid growth in CSP capacity. (\$/MW)

$CGinst_{ginst}$ Increase in wind installation cost due to rapid growth in wind capacity. (\$/MW)

$CGStorage_{st,storagebp}$ Increase in storage cost due to rapid growth in storage capacity. (\$/MW)

$CHeatRate_q$ Heat rate (inverse efficiency) of conventional technology. (MMbtu/MWh)

$CHeatrate_{st}$ Heat rate (inverse efficiency) of storage technology. (MMbtu/MWh)

$CONVpol_{q,pol}$ Emissions of pollutant for each MWh of generation by conventional technology q. (ton/MWh)

$CONVold_{n,q}$ Existing conventional generating capacity, prior to the current period. (MW)

$CONVret_{n,q}$ Retirements of aging conventional capacity in a given period.

Cost_Inst_Frac Fraction of wind farm capital cost assigned to installation rather than the turbines themselves.

$cpop_{c,i,l}$ Fractional increase in wind capital cost due to population density.

CQS Cost to modify a combustion turbine to provide a quick-start capability. ($/MW)

CRF Capital recovery factor, i.e. the fraction of the capital cost of an investment that must be returned each year to earn a given rate of return if income taxes and financing are ignored.

$cslope_{c,i,l}$ Fractional increase in wind capital cost per degree of topographical slope.

$CSP2G_{cCSP,i,cspscp}$ New class *cCSP* CSP resource in region *i* available at interconnection cost step *cspscp*.

$CSP2GPTS_{cCSP,i,cspscp}$ Cost to build transmission from a CSP site to the closest available grid transmission capacity.

$CspCVmar_{cCSP,i,rto}$ (CSP Capacity Value - marginal) The effective load-carrying capacity of 1 MW at a new CSP plant at a class *cCSP* site in region *i* delivered to an *rto*.

$CspCVold_{cCSP,i,rto}$ (CSP Capacity Value - old) The effective load-carrying capacity of all the CSP capacity installed in previous periods whose generation is transmitted to an *rto*.

CSPGridConCost Cost to connect a CSP plant to the grid. ($/MW)

$CSP_inregion_dis_{cCSP,j,escp}$ Levelized cost—from the *escp* step of the supply curve—for building a transmission line from a CSP site to a load center in the same region.

$CSPO_{cCSP,i,j}$ Existing class *cCSP* CSP capacity on pre-2006 transmission lines from region *i* to region *j*.

$CSPOM_{cCSP}$ Present value of operations and maintenance costs over the evaluation period for CSP capacity ($/MW)

$CSPRuc_{cCSP,i}$ Amount of solar resource available. (MW)

$CSPTO_{cCSP,i,j}$ Existing class *cCSP* CSP capacity on new transmission lines from region *i* to region *j*.

$CSPTturO_{cCSP,i}$ Existing CSP capacity for which new transmission capacity was built. (MW)

$CSPturO_{cCSP,i}$ Existing CSP capacity that utilizes pre-2006 lines. (MW)

$CSRV_{n,q}$ Present value of the variable cost of spinning reserve provided over the evaluation period ($/MWh)

$CSTOR_{st}$ Capital cost of storage capacity. ($/MW)

$Ctranadder_q$ Transmission cost adder by conventional technology. ($/MW)

$CVmar_{c,i,rto}$ (Capacity Value - marginal) The effective load-carrying capacity of 1 MW at a new wind or solar farm at a class *c* site in region *i* delivered to an *rto*.

$CVold_{c,i,rto}$ (Capacity Value - old) The effective load-carrying capacity of all the wind or solar capacity installed in previous periods whose generation is transmitted to an *rto*.

CW_c Present value of the revenue required to pay for the capital cost of class *c* wind capacity—including interest during construction, finance, and taxes. ($/MW)

$CWOM_c$ Present value of operations and maintenance costs over the evaluation period for wind capacity—including property taxes, insurance, and production tax credit. ($/MWh)

$Distance_{i,j}$ Distance between regions. (miles)

$Distance_{n,p}$ Distance between balancing authorities. (miles)

F_q Fraction of capacity that can be available as quickstart.

FO_q Forced outage rate of technology *q*.

$Fprice_{q,n}$ Cost of input fuel for given technology. ($/MWh)

$FSRV_q$ Fraction of capacity available for spinning reserve.

$FSTOR_{st}$ Present value of the annual fixed operating costs over the evaluation period for storage capacity. ($/MW)

$GeoAdder_{geoclass,n}$ Additional capital cost for recoverable geothermal capacity along supply curve. ($/MW)

$GeoEGSadder_{egsclass,n}$ Additional capital cost for recoverable geothermal capacity along supply curve. ($/MW)

$GeoEGSmax_{egsclass,n}$ Amount of recoverable capacity at a given step on the EGS supply curve. (MW)

$GeoEGSOld_{egsclass,n}$ Existing EGS capacity, prior to the current period. (MW)

$GeoMax_{geoclass,n}$ Amount of recoverable capacity at a given step on the geothermal supply curve. (MW)

$GeoOld_{geoclass,n}$ Existing geothermal capacity, prior to the current period. (MW)

GridConCost cost to connect a wind farm or CSP plant to the grid. ($/MW)

Gt_g A fractional multiplier on the national wind capacity that defines the national wind capacity in step g of the wind turbine price multiplier for rapid growth.

$GtCSP_{gCSP}$ A fractional multiplier on the national CSP capacity that defines the national CSP capacity in step *gCSP* of the CSP plant price multiplier for rapid growth.

$GtCSPinst_{gCSPinst}$ A fractional multiplier on the CSP capacity in a region that defines the region's CSP capacity in step *gCSPinst* of the CSP installation price multiplier for rapid growth.

$Gtinst_{ginst}$ A fractional multiplier on the wind capacity in a region that defines the region's wind capacity in step *ginst* of the wind installation price multiplier for rapid growth.

H_m Number of hours per year in time-slice m.

Hen_n Annual hydro energy available in balancing authority n. (MWh)

$L_{j,m}$ Load by region and time-slice. (MW)

$L_{n,m}$ Load by balancing authority and time-slice. (MW)

$L_{rto,m}$ Load by rto and time-slice. (MW)

$lowsuladd_LCF_n$ Present value of 20-year expected additional levelized cost of fuel for using low sulfur coal.

$minplantload_q$ The minimum level at which a conventional technology can run.

$MW_inregion_dis_{c,j,escp}$ Levelized cost—from the *escp* step of the supply curve—for building a transmission line from a wind site to a load center in the same region.

$NERCRm_r$ Reserve margin requirement in the nerc region containing each balancing authority.

$nor2rto_{rto}$ The variance of the usual operating reserve requirement in RTO *rto*.

NRRfrac The fraction of the normal reserve requirement.

$old_STOR_{n,st}$ Existing grid-based storage at the start of the period. (MW)

$old_WSTOR_{i,st}$ Existing wind-based storage at the start of the period. (MW)

$old_WSTORin_grid_{j,m,st}$ Energy from the grid used to charge existing wind-based storage in region j in time-slice m. (MWh)

$old_WSTORin_wind_{c,i,m,st}$ Energy from wind in region i used to charge existing wind-based storage in time-slice m. (MWh)

$old_WSTOR_OR_{i,m,st}$ Existing wind-based storage generating capacity in region i held back as operating reserve in time-slice m. (MW)

$old_WSTORout_dest_{i,m,p}$ Energy discharged in time-slice m from existing wind-based storage in region i to a destination in balancing area p. The storage technology from which the energy comes is tracked by $old_WSTORout_source_{i,m,st}$. (MWh)

$old_WSTORout_inregion_{i,m,st}$ Energy discharged in time-slice m from existing wind-based storage in region i to a load center in the same region. (MWh)

$old_WSTORout_source_{i,m,st}$ Energy discharged in time-slice m from existing wind-based storage of technology st in region i. The destination of this energy is tracked by $old_WSTORout_dest_{i,n,m}$. (MWh)

$ORMAR_{c,i,rto,m}$ The operating reserve requirement induced by the marginal addition of one MW of class c wind or solar capacity in region i that is consumed in an rto.

P_n Peak load in balancing authority n. (MW)

P_{rto} Peak load in rto rto. (MW)

$PcostFrac_q$ multiplier on the operating costs of conventional generating capacity for use as a peaker.

PO_q planned outage rate

$PostStamp_{i,j}$ the number of balancing authorities that must be crossed to transmit wind between two supply regions.

qsfrac minimum fraction of operating reserve that can be met by quickstart technologies

Resconfint (Reserve Confindence Interval) Operating reserve minimum expressed in terms of the number of standard deviations of operating reserve required.

RPSfraction national renewable portfolio standard level as a fraction of national electric generation.

RPSSCost penalty imposed for not meeting the national RPS requirement. ($/MWh)

$St_CSPRPSCost_{states}$ penalty imposed for not meeting the state RPS requirement for solar. ($/MWh)

$st_Invincent_{states}$ Before-tax value of state-level investment incentive for wind. ($/MW)

$STORpol_{st,pol}$ Emissions of pollutant for each MWh of generation by storage technology st. (ton/MWh)

$STOR_RTE_{st}$ round-trip efficiency for storage technologies

$st_Prodincent_{states}$ Before-tax value of state-level production incentive for wind. ($/MW-yr)

$St_RPSfraction_{states}$ state renewable portfolio standard level as a fraction of state electric generation.

St_RPSSCost penalty imposed for not meeting the state RPS requirement. ($/MWh)

$SurplusMar_{c,i,rto,m}$ Fraction of renewable (wind or solar) output (from a new class c source in region i to rto rto) curtailed in time slice m because must-run conventionals plus renewable output exceeds load.

$SurplusOld_{rto,m}$ Fraction of renewable (wind or solar) output from all existing sources feeding rto rto curtailed in time slice m because must-run conventionals plus renewable output exceeds load.

Tk_k Capacity of transmission line k. (MW)

TLOSS Fraction of conventional power lost in each mile of transmission.

TOCOST cost for wind to use pre-2006 transmission lines ($/MWh-mile)

$TOR_{rto,m}$ The operating reserve requirement induced by the load, conventional generation, and existing wind capacity in an rto. (MW)

TOWCOST cost of wind transmission on pre-2006 lines ($/MWh-mile)

TNCOST cost of new transmission lines ($/MW-mile)

TNWCOST cost to build a new transmission line. ($/MW-mile)

$TPCA_Gt_{TPCA_g}$ A fractional multiplier of the national transmission (MW) capacity *BASETPCA* used to establish the size of growth bin *tpca_g*.

$TPCAO_{n,p}$ The transmission capacity between n and p that existed at the start of the period.

$TWLOSSnew$ The fraction of wind power lost in each mile of transmission, for new wind.

$TWLOSSold$ The fraction of wind power lost in each mile of transmission, for existing wind.

$VSTOR_{st}$ present value over the evaluation period of the variable operating and fuel costs for generation from storage capacity ($/MWh)

$WO_{c,i,j,l}$ Existing class c wind of type l on pre-2006 transmission lines from region i to region j.

$WR2G_{c,i,l,wscp}$ New class c wind resource of type l in region i available at step $wscp$ on the supply curve. (MW)

$WR2GPTS_{c,i,l,wscp}$ Cost associated with step $wscp$ on the supply curve to build transmission from a wind site in region i to the closest available grid transmission capacity. ($/MW)

$WRuc_{c,i,l}$ amount of wind resource available. (MW)

$WTO_{c,i,j}$ Existing class c wind on new transmission lines from region i to region j.

$WturO_{c,i,l}$ Existing wind capacity that utilizes pre-2006 lines. (MW)

$WTturO_{c,i,l}$ Existing wind capacity for which new transmission capacity was built. (MW)

Appendix B Electricity Price Calculation

The electricity price in ReEDS is calculated after the optimization, based on the installed capacity and dispatch in that period. The output electricity price, reported by balancing area, is a weighted average of the electricity prices for each time-slice. Electricity prices within time slices are calculated differently depending on whether the region is a net-importer or -exporter.

$$ElecPrice_n = \frac{\sum_m \begin{cases} Pelec_{n,m} \cdot gen_{n,m} & \text{if } gen_{n,m} \geq load_{n,m}, \\ Pelec2_{n,m} \cdot load_{n,m} & \text{if } gen_{n,m} < load_{n,m}. \end{cases}}{\sum_m \begin{cases} gen_{n,m} & \text{if } gen_{n,m} \geq load_{n,m}, \\ load_{n,m} & \text{if } gen_{n,m} < load_{n,m}. \end{cases}}$$

$gen_{n,m}$ is generation in balancing area n in time-slice m. (MWh)

$load_{n,m}$ is the load in balancing area n in time-slice m. (MWh)

If the region is a net-exporter in timeslice m, $Pelec_{n,m}$, the unadorned cost of generation, is used as the price of electricity:

$$Pelec_{n,m} = pgen_{n,m} + NGTC_n$$

If the region is a net-importer in the timeslice, however, $Pelec2_{n,m}$—which includes the price of imports, $pimports_{n,m}$—is used as the price of electricity instead:

$$Pelec2_{n,m} = (gen_{n,m} \cdot pgen_{n,m} + (load_{n,m} - gen_{n,m}) \cdot pimports_{n,m}) / load_{n,m} + NGTC_n$$

$NGTC_n$ (Non-Generation Transaction Cost) is a scalar set after the first time period to normalize the calculated 2006 electricity prices with historical data. It represents components of the electricity price not explicitly represented in ReEDS (e.g. distribution costs, administration costs, etc.). ($/MWh)

The price of generation, $pgen_{n,m}$ is calculated from various components: return on ratebase, O&M costs for renewable and conventional technologies, and fuel costs. Calculations of the components of $pgen_{n,m}$ are shown in a separate section below.

$$pgen_{n,m} = \left(Ratebase_n \cdot disc + WindOM_n + CSPOM_n + \sum_q CfixOMtot_{n,q} + \sum_{st} FSTORtot_{n,st} \right) / ngen_n + (CfuelvOM_{n,m} + STORfuelOM_{n,m}) / gen_{n,m}$$

$ngen_n = \sum_m gen_{n,m}$, total generation in area n, summed over time-slices. (MWh)

$disc$ is the real discount rate, 8.5% in the Base Case.

$Ratebase_n$: book value of all installed capacity in area n. ($)

$WindOM_n$: O&M costs for all wind feeding balancing area n. ($)

$CSPOM_n$: O&M costs for all CSP feeding balancing area n. ($)

$CfixOMtot_{n,q}$: fixed O&M costs for conventional technology q in area n. ($)

$FSTORtot_{n,st}$: fixed O&M costs for storage technology st in area n. ($)

$CfuelvOM_{n,m}$: variable O&M and fuel costs for conv. in area n in time-slice m. ($)

$STORfuelOM_{n,m}$: variable O&M and fuel costs for storage in area n, time-slice m. ($)

The price of imports in region n, $pimports_{n,m}$, is calculated from the wheeling price, $pwheeled_{n,m}$, the cost of generation in source region p in time-slice m.

$$pimports_{n,m} = \frac{\sum_p CONVT_{p,n,m} \cdot H_m \cdot (pwheeled_{p,m} + translcoe_{p,n})}{\sum_p CONVT_{p,n,m} \cdot H_m}$$

$CONVT_{p,n,m}$ is transmission of conventionals from balancing area p to n in time-slice m. (MW)

$pwheeled_{p,m}$ is the cost of electricity either generated in or transmitted through region p in time-slice m. ($/MWh)

$translcoe_{p,n}$ is a cost adder for transmission. ($/MWh)

The Components of pgen

Ratebase$_{y,n}$ is the book value of all installed capacity in balancing area n in time period y.

$$\begin{aligned} Ratebase_{y_o,n} &= Ratebase_{y_o-1,n} + Investment_{y_o,n} \\ &\quad - .066 \cdot Ratebase_{2006,n} - \sum_{y_o-lt/2<y<y_o} .066 \cdot Investment_{y,n} \end{aligned}$$

(n.b. We only subtract off the 2006 Ratebase piece through 2036.)

y_o is the time period (year).

lt is the investment lifetime, 30 years in the Base Case.

$Investment_{y,n}$ is the total capital investment (for wind, CSP, conventionals, and storage) in area n in period y.

WindOM$_n$: The total O&M costs for wind are simply capacity multiplied by the sum of the fixed and variable O&M costs for class c wind. An average O&M cost for existing wind in class c by region j is updated after each time period to account for new builds ($CWOMold_{c,j}$, $CWOMTold_{c,j}$). Many of the quantities in the following formulae are outputs from the optimization, so definitions and explanations can be found among the variables in Section A.2 or in the glossary, Section A.5.

$$\begin{aligned} WindOM_n &= \sum_{c,i,j,l}^{j\in n} (WN_{c,i,j,l} + WTN_{c,i,j,l} + Wtur_inregion_{c,j,l}) \cdot CWOM_{c,l} \\ &\quad + \sum_{c,i,j,l}^{j\in n} (WO_{c,i,j,l} \cdot CWOMold_{c,j,l} + WTO_{c,i,j,l} \cdot CWOMTold_{c,j,l}) \end{aligned}$$

CspOM$_n$: O&M costs for CSP are calculated the same way as for wind:

$$\begin{aligned} CspOM_n &= \sum_{cCSP,i,j}^{j\in n} (CspN_{cCSP,i,j} + CspTN_{cCSP,i,j} + CSPtur_inregion_{cCSP,j}) \cdot CspOM_{cCSP} \\ &\quad + \sum_{cCSP,i,j}^{j\in n} (CspO_{cCSP,i,j} \cdot CspOMold_{cCSP,j} + CspTO_{cCSP,i,j} \cdot CspOMTold_{cCSP,j}) \end{aligned}$$

$\mathbf{CfixOMtot_{n,q}}$: The fixed O&M costs for conventionals are calculated by adding the costs for new capacity to the tracked expenses from existing capacity.

$$CfixOMtot_{n,q} = \sum_{q} CfixOM_{n,q} \cdot (CONV_{n,q} - CONVold_{n,q} - CONVret_{n,q}) + CfixOMold_{q} \cdot CONVold_{n,q}$$

$\mathbf{FSTORtot_{n,st}}$: Fixed O&M costs for storage are also calculated by adding costs for new installations to the previous time period's costs.

$$FSTORtot_{n,st} = \sum_{st} FSTORold_{n,st} \cdot old_STOR_{n,st} + FSTOR_{st} \cdot STOR_{n,st}$$

$\mathbf{CfuelvOM_{n,m}}$, $\mathbf{STORfuelOM_{n,m}}$: The variable O&M and fuel cost calculations use fuel prices for the period, not life cycle fuel costs, and include applicable carbon taxes.

$$CfuelvOM_{n,m} = \sum_{q} (CONVgen_{n,m,q} + CONVP_{n,m,q} \cdot Pcostfrac) \cdot H_m \cdot (CConvVOMold_{n,q} + Heatrateold_{n,q} \cdot (Fprice_{n,q} + CarbTax \cdot CONVpol_{q,CO2}))$$

$$STORfuelOM_{n,m} = \sum_{st} (STORout_{n,m,st} \cdot H_m \cdot (VSTORold_{n,st} + StHeatrateold_{n,st} \cdot (Fprice_{n,st} + CarbTax \cdot STORpol_{st,CO2}))$$

Appendix C Elasticity Calculations

C.1 Fuel Price Elasticities

The prices and price projections for coal and natural gas used in ReEDS are subject to demand elasticities. Baseline price and fuel demand projections are inputs to the model, and between optimizations the computed usage from the previous period is compared with the latest forecast for that year to update both price and usage projections. The updated prices are then used in the following year's optimization (and the updated forecasts are then compared to the outcome of that optimization).

The baseline price and fuel demand projections and the elasticities are all based on the AEO reference scenario and one or more other AEO scenarios (e.g. carbon tax, high renewables). By this method the baseline projections and elasticities are self-consistent. Short-term and long-term elasticities differ to account for varying flexibility of price compensation—i.e. short-term behavioral adjustments vs. long-term infrastructure improvements.

Equations for the two fuels are identical, so only the calculations for natural gas will be shown below. The adjusted fuel price forecast, $GasCost_{y,y_o,r}$ (the first subscript, y, varies over the set of time-periods 2006-2050 while the second subscript, y_o, marks the current time-period; so the subscripts indicate that this is the forecast for natural gas price in year y as forecast in y_o), is calculated by applying short-term and long-term multipliers, $Delta_gasprice_{y_o,term}$, to the fuel price forecast determined for the preceeding period. ReEDS tracks a fuel price forecast for each NERC region, but only a national elasticity.

$$GasCost_{y,y_o,r} = \begin{cases} (1 + Delta_gasprice_{y_o,st}) \cdot GasCost_{y,y_o-1,r} & \text{if } y_o \leq y \leq y_o + shortterm, \\ (1 + Delta_gasprice_{y_o,lt}) \cdot GasCost_{y,y_o-1,r} & \text{if } y > y_o + shortterm. \end{cases}$$

where the percentage change for the gas price has been calculated as (actual - expected)/(expected):

$$Delta_gasprice_{y_o,term} = gasprice_elas_{term} \cdot \left(\frac{gas_usage_{y_o-1} - Fcast_Gasusage_elec_{y_o-1,y_o-1}}{Fcast_Gasusage_elec_{y_o-1,y_o-1} + Fcast_Gasusage_nonelec_{y_o-1}} \right)$$

where

$gasprice_elas_{term}$ are short-term and long-term elasticity coefficients—percentage change in price for each one percent change in demand.

$gas_usage_{y_o-1}$ is the actual demand in the previous time-slice, $y_o - 1$.

$Fcast_Gasusage_elec_{y_o-1,y_o-1}$ is the forecasted demand for the previous time-slice, $y_o - 1$ as forecast in the previous time-slice, $y_o - 1$.

$Fcast_Gasusage_nonelec_{y_o-1}$ is the demand outside the electric sector for the previous time-slice, $y_o - 1$. Non-electric demand is not included in ReEDS and is not adjusted from the baseline forecast.

The new demand forecast, likewise, is an adjustment of the previous year's demand forecast, again calculated from (actual - expected)/(expected). By adjusting the price and demand forecasts simultaneously, ReEDS keeps the two trajectories paired: a given year's price trajectory is matched with the corresponding usage forecast; when the demand varies from that forecast, both trajectories are recalculated based on the new information.

$$Fcast_gasusage_elec_{y,y_o} = Fcast_gasusage_elec_{y,y_o-1} \cdot \left(\frac{gas_usage_{y_o-1}}{Fcast_gasusage_elec_{y_o-1,y_o-1}} \right)$$

Note that all updates to the fuel price and demand forecasts only impact subsequent years of simulation because ReEDS solves every two year period individually and sequentially.

C.2 Demand Elasticities

Electricity demand, as exemplified by the average and peak load parameters, $L_{n,m}$ and P_n, respectively, in ReEDS is subject to price elasticity. There is a regional internal electricity price calculation in ReEDS that adjusts the load growth forecast based on changes in electricity price.

The elasticity calculations are inverted compared to the fuel price elasticities—because here demand is adjusted based on price instead of price being adjusted because of changes in demand—but are otherwise very similar. The load forecasts are adjusted from the previous year's forecast via short-term and long-term multipliers, $Delta_demand_{r,term}$, which are computed based on differences between expected and actual electricity prices. Where the fuel price elasticities were uniform nationally, electricity demand elasticities can vary among NERC regions. The demand elasticities were determined based on differences between alternative AEO scenarios (e.g. reference case vs. carbon tax or high fuel prices) and so are consistent with the baseline demand trajectory. As with the fuel price elasticities, these calculations are completed between optimizations, using results from the previous time period's solution to generate data that is used in the next time period.

$$L_{y,y_o,n,m} = \begin{cases} (1 + Delta_demand_{y_o,n\in r,st}) \cdot L_{y,y_o-1,n,m} & \text{if } y_o \leq y \leq y_o + shortterm, \\ (1 + Delta_demand_{y_o,n\in r,lt}) \cdot L_{y,y_o-1,n,m} & \text{if } y > y_o + shortterm. \end{cases}$$

$$P_{y,y_o,n} = \begin{cases} (1 + Delta_demand_{y_o,n\in r,st}) \cdot P_{y,y_o-1,n} & \text{if } y_o \leq y \leq y_o + shortterm, \\ (1 + Delta_demand_{y_o,n\in r,lt}) \cdot P_{y,y_o-1,n} & \text{if } y > y_o + shortterm. \end{cases}$$

where the multipliers are calculated, again, as (actual - expected)/(expected):

$$Delta_demand_{y_o,r,term} = demand_elas_{r,term} \cdot \left(\frac{elec_price_{y_o-1,r} - Fcast_elec_price_{y_o-1,y_o-1,r}}{Fcast_elec_price_{y_o-1,y_o-1,r}} \right)$$

where

$demand_elas_{r,term}$ are short-term and long-term elasticity coefficients—percentage change in price for each one percent change in demand—for NERC region r.

$elec_price_{y_o-1,r}$ is the regional average electricity price computed in the previous time-slice, $y_o - 1$.

$Fcast_elec_price_{y_o-1,y_o-1,r}$ is the regional average electricity price for the previous time-slice, $y_o - 1$ as forecast in the previous time-slice, $y_o - 1$.

Appendix D Resource Variability Parameters

There are three basic resource variability parameters for renewables with variable resources (i.e. wind and solar) that are calculated for each period in ReEDS before the linear program optimization is conducted for that period. These include capacity value, operating reserve, and surplus. For each, a marginal value is calculated, which applies to new installations in the period, and an "old" value is calculated, which applies to all the capacity built in previous periods. This section describes the statistical assumptions and methods used to calculate these values.

These variable-resource parameters are calculated for a source from which the variable-resource renewable energy (VRRE) is generated and a sink to which the energy is supplied. The source is always a supply region. The user must specify the regional level for the sink. It can be a balancing authority (BA), a regional transmission organization (RTO), a NERC region, or an entire interconnect. The "old" values for these variable-resource parameters are calculated for each sink but not for each source since the old value is a single value for all the variable resource supplied to the sink.

D.1 Data inputs for the calculation of resource variability parameters

The inputs required for calculating the resource variability parameters describe the probability distributions associated with loads, conventional generator availability, and VRRE generation. For each, an expected value and standard deviation are calculated.

For loads the expected value, μ_L, is the same as the values used in the "LOAD_PCA" constraint. The standard deviation of the load, μ_L, is found from the load-duration curve of the sink region.

For conventional generator availability, the expected value is the nameplate capacity times 1 minus the forced outage rate.

$$\mu_C = \sum_q CONVCAP_{q,r} \cdot (1 - fo_q)$$

Variance of conventional generator availability is calculated thus:

$$\sigma_C^2 = \sum_q numplants_{q,r} \cdot plantsize_q^2 \cdot fo_q \cdot (1 - fo_q)$$

where

$plantsize_q$ is the input typical size of a generator of type q

$numplants_{q,reg} = CONVCAP_{q,r} / plantsize_q$

The probability distribution associated with conventional generator availability is complicated by the fact that there are can be many conventional generators and each one's availability is a binomial random variable with probability $(1 - fo_q)$ of being one. We largely avoid this complication by first combining the random variables for conventional generator availability, C, with loads, L, in the form of a random variable X where:

$$X = C - L$$

The expected value of X, μ_X, is the sum of the expected values of the other two random variables

$$\mu_X = \mu_C - \mu_L$$

and, since C and L are statistically independent:

$$\sigma_X^2 = \sigma_C^2 + \sigma_L^2$$
$$\sigma_X = \sqrt{\sigma_C^2 + \sigma_L^2}$$

where σ denotes standard deviation and σ^2 is the variance.

We investigated several standard distributions for their ability to fit X. We considered only those distributions that could be bounded below - Beta, Weibull, Gamma, Erlang, Rayleigh, Triangular, Log-logistic, Pareto, Exponential, Uniform, Log-normal, Inverse, Gaussian, and χ^2 To do this we used empirical data from the ERCOT region of Texas and computed three statistics of the goodness-of-fit for this data - χ^2, Anderson-Darling, and Kolmogorov-Smirnov statistics. We based the conventional generation data upon a random sampling of forced generator outages, using empirical outage rate data obtained for ERCOT in 2005. The load data is based upon a Markov chain model we developed from actual empirical data.

Table 25 ranks the distributions as to how well they fit the data relative to each of the three statistics. The beta distribution provides the best fit for the Anderson-Darling statistic and the second best fit for the other two statistics. The beta distribution has the additional advantage that it is bounded both from below and above, similar to the data itself. Figure 9 visually shows how well the PDF of the fitted beta distribution matches the actual data; note that the fit is relatively better at the tails of the distributions which are the areas of greatest interest in our calculations of the resource variability parameters that will be described later.

Table 25: Rankings of Distributions

Ranking		Statistic	
	χ^2	Anderson-Darling	Kolmogorov-Smirnov
1	Triangular	Beta	Weibull
2	Beta	Triangular	Beta
3	Weibull	Gamma	Triangular
4	Gamma	Log-normal	Gamma
5	Log-normal	Uniform	Log-normal
6	Uniform	Exponential	Uniform
7	Exponential	Weibull	Exponential
8	Inverse-Gaussian	Inverse-Gaussian	Inverse-Gaussian

Thus we approximate the combined distribution for $X = C - L$ as a beta distribution with mean μ_X and standard deviation σ_X.

The statistical representation of the output of the VRREs is similar to that of $X = C - L$, although perhaps more complicated due to resource variation, correlations between the VRRE plants and technology change. The standard deviation associated with an individual VRRE site is derived from the hourly data available from the Wind and Solar Integration Study (WSIS) led by NREL (`http://mercator.nrel.gov/wwsi`) The standard deviation of the generation within each ReEDS time slice is easily calculated by standard statistics. To perform a distribution analysis similar to that performed on X, we randomly selected a number of wind sites from the WSIS study and tested how well various standard distributions matched the data. As with X, the beta distribution was a clear winner. Figure 10 shows the power output of, on the left, a single wind site, and, on the right, the combined output of eight randomly selected sites. Other random site selections produced similar charts. Both charts have been fitted with beta probability distribution functions.

Future improvements in the performance of wind and solar technologies are captured in ReEDS through increased capacity factors. These improved capacity factors translate directly

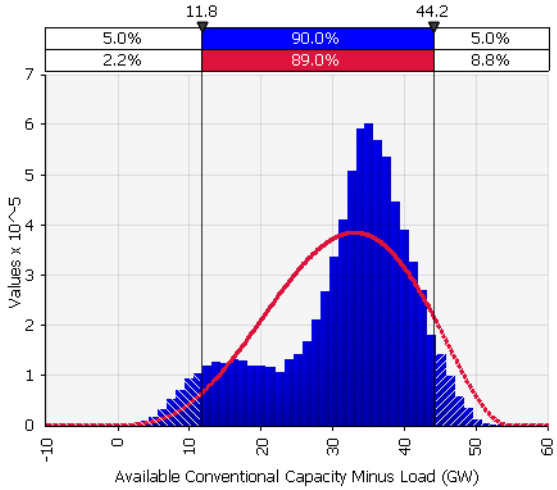

Figure 9: Actual conventional capacity less load and fitted beta PDF

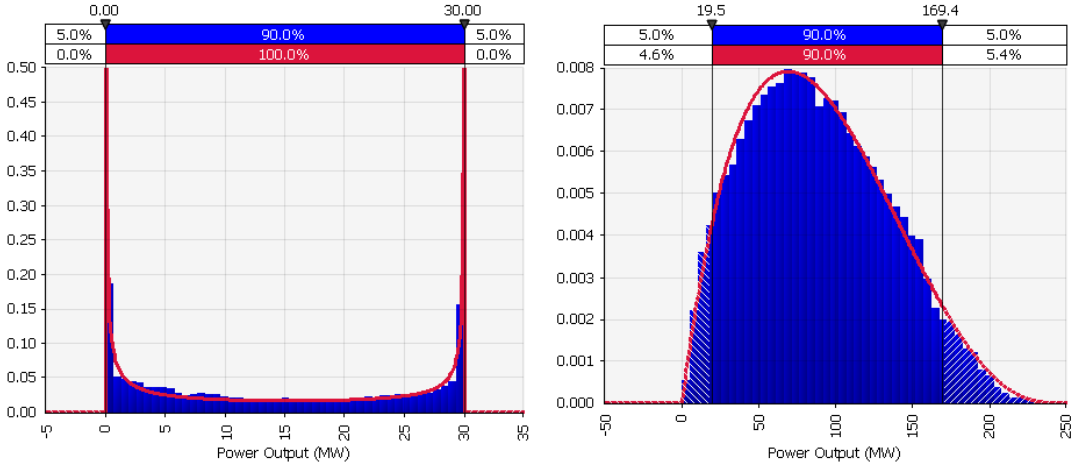

Figure 10: Wind farm power output from a single site (left) and combined output from eight sites (right) with fitted beta PDFs

into improvements in the mean of a VRRE plant's generation output. ReEDS also estimates a new standard deviation for a VRRE plant based on regressions that estimate the new standard deviation as a function of the old standard deviation and the new capacity factor.

In the variable-resource parameters described below the input distributions must represent the generation from all VRRE plants contributing to a sink region, not simply a single plant. The mean value μ_R is easily calculated as the sum of the mean values of the output of the individual contributing VRRE plants. The standard deviation is complicated by the fact that the outputs of the VRRE plants are correlated with one another. For each ReEDS time slice, we have used the WSIS data to develop a correlation matrix (P_{kl}) of the Pearson correlation between each possible pair k,l of region, class, and VRRE, e.g. the peak-time slice correlation matrix has an entry for the correlation between peak-time slice generation from class 5 wind in region 3 and class 2 PV generation in region 14. This P_{kl} matrix is an input to ReEDS. The variance of the VRRE arriving at a sink region r ($\sigma^2_{R_r}$) is then calculated from this correlation matrix P_{kl} through the standard statistical formula:

$$\sigma^2_{R_r} = \sum_{k \in R_r} \sum_{l \in R_r} P_{kl} \cdot \sigma_k \cdot \sigma_l$$

where

R_r is the set of VRRE's contributing to region r

Armed with the mean and standard deviation of all VRRE contributing to a region r, we now have to assume a distribution for the VRRE generation. As with the conventional generation and load, we again used the beta distribution to approximate the VRRE generation with mean μ_R and standard deviation σ_R. This selection of the beta distribution was based on the facts that the beta is a two-parameter distribution with support bounded by a minimum and maximum level, i.e. for VRRE generation the minimum is zero and the maximum is the total nameplate VRRE capacity.

With the probability distributions of the VRRE and of conventional output minus load determined, we can now calculate the variable-resource parameters - capacity value, operating reserve, and surplus.

D.2 Capacity Value

This is the capacity credit given to the VRRE contribution to meeting the reserve margin constraint in each sink region. It is a function of the amount and type of VRREs consumed in the sink region, the dispersion of the VRRE plants contributing the energy, the electric load in the sink region, the variability of the load and the amount and reliability of conventional capacity contributing to the load in the sink region. Generally, as more VRREs are used by the sink region, their capacity value decreases. And as more renewable energy from a particular source is used, the marginal capacity value from that source decreases.

CVold$_r$ For the total VRRE generation that is to be consumed in sink region r, the capacity credit, $CVold_r$, is the amount of load that can be added in every hour without changing the system reliability in sink region r, i.e. without changing the loss-of-load probability. This added load is the effective load-carrying capability associated with the VRRE contributed to the sink region. Generally, utilities desire to keep this loss-of-load probability close to the equivalent of one day in 10 years or 2.4 hours per year, or per 8760 hours. This equates to a loss-of-load probability of $2.74x10^{-4} = 2.4/8760$.

The first step in estimating CVold is to determine when the maximum allowable loss of load probability is reached without any VRRE in the system. To do this we use the random variable X defined above as the sum of all the conventional generation capacity C available to the sink region r, minus the load L in the sink region r.

$$X = C - L$$

Without any VRRE in the system, the maximum allowable loss of load probability is reached when $B(x) = 2.74x10^{-4}$, where $B(x)$ is the cumulative beta distribution function for the random variable X.

The second step in finding CVold is to find a similar value when VRRE is included in the system. To do this we define a new random variable Y as follows:

$$Y = X + R = C - L + R$$

where

R_r is the random variable representing the VRRE contribution to sink region r.

As before, the maximum allowable loss of load probability is reached when $F(y) = 2.74x10-4$, where $F(y)$ is the cumulative distribution function for the random variable Y. $F(y)$ can be determined by convolving the distributions for X and R. Once Y is determined, the capacity value associated with R is simply Y - X, and the capacity value of the VRRE expressed as a fraction of the total VRRE nameplate capacity, R_r, is

$$CVold_r = (Y - X)/R_r$$

Since convolving two random variables can be a computer intensive calculation and because it must be done many times in a single ReEDS optimization, convolutions are done outside of ReEDS for a range of points with the results saved in tabular format as a function of five parameters—VRRE nameplate capacity divided by peak load, conventional nameplate capacity divided by peak load, VRRE capacity factor, standard deviation of all VRRE generation delivered to sink region r, and the standard deviation of conventional generation minus load ($C - L$). During a ReEDS run this five-dimensional table is accessed by linear interpolation with these 5 independent inputs to find the capacity value of the VRRE capacity contributing to sink region r, $CVold_r$.

$CVmar_{c,i,r}$ is the marginal capacity value associated with the addition of class c VRRE capacity in a source region i delivered to a sink region r, is simply the difference in *CVold* before and after the marginal VRRE addition, $\Delta R_{c,i,r}$.

$$CVmar_{c,i,r} = (CVold_r(R_r) - CVold_r(R_r + \Delta R_{c,i,r}))/\Delta R_{c,i,r}$$

D.3 Operating Reserve Requirement

Operating reserve includes spinning reserve, quick-start capability, and interruptible load that can be dispatched to meet unanticipated changes in loads and/or power availability. There is no standard approach for estimating the level of operating reserve required. Some NERC regions assume that operating reserve must be at least as large as the largest single system contingency, e.g. the failure of a nuclear power plant. Others have reasoned that a system should have enough operating reserve to meet 7% of peak load (reduced if hydro is available). We assume in ReEDS that the normal operating reserve ($NOR_{r,m}$) required by a sink region r is proportional to the load ($L_{r,m}$) and conventional generation ($G_{r,m}$) in the region.

VRREs can induce a need for additional operating reserve beyond the usual requirement. ReEDS calculates the total operating reserves induced by all load, conventional generation, and VRREs in the system ($TOR_{r,m}$) and the operating reserves induced at the margin ($ORmar_{r,m}$) by the addition of an increment of VRRE capacity.

$TOR_{r,m}$ is the total operating reserve required in region r due to load, conventional generation, and all existing VRRE capacity contributing to sink region r (R_r). By assuming that the normal operating reserve is a 2-sigma reserve, we can estimate the sigma, $\sigma_{NOR_{r,m}}$, associated with the normal system operation (operating reserve required for load and conventional generation) as:

$$NOR_{r,m} = \frac{0.03 \cdot (L_{r,m} + G_{r,m})}{2 \cdot L_{r,m}}$$

$$\sigma_{NOR_{r,m}} = NOR_{r,m} \cdot (L_{r,m} - R_r)$$

Since the normal system issues that require the normal operating reserve occur independently of the resource variability of VRREs, the variances of the two can be added to give the variance of the total. The total operating reserve is then assumed to be twice the standard deviation of the total.

$$TOR_{r,m} = 2 \cdot \sqrt{\sigma^2_{NOR_{r,m}} + \sigma^2_{R_r}}$$

where

σ_{R_r} is assumed to be the standard variation of the output of all existing VRREs contributing to sink region r.

$ORmar_{c,i,r}$ is the marginal operating reserve requirement induced by the next MW of class c VRRE installed in region i that contributes generation to sink region r. It is calculated as the difference in the operating reserve required with an increment $\Delta R_{c,i,r}$ of additional VRRE capacity, minus that required with only the existing VRRE with the difference divided by the incremental VRRE capacity $\Delta R_{c,i,r}$.

$$ORmar_{c,i,r,m} = \frac{2}{\Delta R_{c,i,r}} \cdot \left(\sqrt{\sigma^2_{NOR_{r,m}} + \sigma^2_{R_r + \Delta R_{c,i,r}}} - \sqrt{\sigma^2_{NOR_{r,m}} + \sigma^2_{R_r}} \right)$$

D.4 Surplus

At high levels of VRRE penetration, there are times when the VRRE generation exceeds that which can be used in the system. This "surplus" VRRE generation must then be curtailed. ReEDS calculates the fraction of VRRE generation from existing VRRE plants ($Surplusold_r$) that is surplus as well as the fraction of generation from new VRRE plants ($Surplusmar_r$) that is surplus. ReEDS uses these surplus values to reduce the useful energy contributed by VRREs, making them less coss-effective generators.

$SurplusOld_r$ is the expected fraction of generation from all the VRREs consumed in sink region r that cannot be productively used, because the load is not large enough to absorb both the VRRE generation and the must-run generation from existing conventional sources. This situation occurs most frequently in the middle of the night when loads are small, base-load conventional plants are running at their minimum levels, and the wind is blowing.

To calculate $Surplusold_r$, we use the random variable Y defined in the capacity value discussion above as the must-run conventional base-load generation M minus the load L plus the VRRE generation R.

$$Y = M - L + R$$

Next, we define the surplus VRRE at any point in time, S, as

$$\text{If } Y < 0, S = 0$$
$$\text{If } Y > 0, S = Y$$

Then the expected surplus μ_S can be calculated from the density function of Y, g(y) as follows:

$$\mu_S = \int_{-\infty}^{\infty} sf(s)ds$$
$$\mu_S = \int_{-\infty}^{0} sf(s)ds + \int_{0}^{\infty} sf(s)ds$$
$$\mu_S = 0 + \int_{0}^{\infty} yg(y)dy$$

The density function of y can be found by convolving the density function of $M - L$ together with the density function of the VRREs, similar to that which was done for the calculation of the VRRE capacity value above. However we found that the expected value of the surplus can be well approximated assuming normal distributions for both $M - L$ and R. With the normal distribution assumption, the value of μ_S can be quickly found in ReEDS with the analytical formula derived below:

Now if we assume, as we did in the *CVmar* and *ORmar* calculations above, that by the central limit theorem, Y can be well approximated by a normal distribution, and we define the standard normal variable Y' as $Y' = (Y - \mu_Y)/\sigma_Y$, then

$$Y = Y' \cdot \sigma_Y + \mu_Y, \text{ and}$$
$$dY = \sigma_Y dY'$$

Thus

$$\mu_S = \int_{0}^{\infty} yg(y)dy$$
$$\mu_S = \int_{-\mu_Y/\sigma_Y}^{\infty} (y'\sigma_Y + \mu_Y) \cdot g(y'\sigma_Y + \mu_Y) \cdot \sigma_Y dy'$$
$$\mu_S = \int_{-\mu_Y/\sigma_Y}^{\infty} \sigma_Y^2 \cdot y' \cdot g(y'\sigma_Y + \mu_Y)dy' + \int_{-\mu_Y/\sigma_Y}^{\infty} \mu_Y \cdot \sigma_Y \cdot g(y'\sigma_Y + \mu_Y)dy'$$

Assuming Y is normally distributed, as stated above:

$$\mu_S = \int_{-\mu_Y/\sigma_Y}^{\infty} \sigma_Y^2 \cdot y' \left(\frac{1}{\sigma_Y\sqrt{2\pi}}\right) \exp\left(\frac{(-y'\sigma_Y + \mu_Y - \mu_y)^2}{2\sigma_Y^2}\right) dy'$$
$$+ \int_{-\mu_Y/\sigma_Y}^{\infty} \mu_Y \cdot \sigma_Y \left(\frac{1}{\sigma_Y\sqrt{2\pi}}\right) \exp\left(\frac{(-y'\sigma_Y + \mu_Y - \mu_y)^2}{2\sigma_Y^2}\right) dy'$$
$$\mu_S = \int_{-\mu_Y/\sigma_Y}^{\infty} \frac{\sigma_Y \cdot y'}{\sqrt{2\pi}} \exp\left(\frac{-y'^2}{2}\right) dy' + \int_{-\mu_Y/\sigma_Y}^{\infty} \frac{\mu_Y}{\sqrt{2\pi}} \exp\left(\frac{-y'^2}{2}\right) dy'$$
$$\mu_S = \frac{\sigma_Y}{\sqrt{2\pi}} \exp\left(\frac{-\mu_Y^2}{2\sigma_Y^2}\right) + \mu_Y\left(1 - N_{0,1}(-\mu_Y/\sigma_Y)\right)$$

Where $N_{0,1}$ is the standard normal distribution with mean 0 and standard deviation 1.

Then $Surplusold_r$ is the difference between the expected surplus with VRRE, μ_S and the expected surplus were there no VRRE generation consumed in sink region r, μ_{SN}, divided by the total VRRE capacity contributing to sink region r, R_r. Or

$$Surplusoldr = (\mu_S - \mu_{SN})/R_r$$

Normally μ_{SN} would be zero, as the conventional must-run units would not be constructed in excess of the minimum load. However, with our assumption of a normal distribution for Y, we do introduce some non-zero probability that Y could be positive even if there were no VRREs, i.e. that the generation from must-run units could exceed load. Thus, it is important to calculate μ_{SN} and to subtract it from μ_S to remove the bulk of the error introduced by the normal distribution assumption. μ_{SN} is calculated in exactly the same way as μ_S, but with no VRREs included.

Must-run conventional capacity is defined as existing available (i.e., not in a forced outage state) coal and nuclear capacity in sink region r times a minimum turn-down fraction, *MTDF*. The expected value of the must-run capacity of type q available at any given point in time, μ_{M_q}, is thus:

$$\mu_{M_q} = CONVCAPq, r * (1 - FOq) * MTDFq$$

where

$CONVCAP_{q,r}$ is the existing conventional capacity in sink region r of type q.
$MTDF_q$ is 0.45 for old (pre-2006) coal plants,
0.35 for new (post-2006) coal plants,
1.0 for nuclear plants.

SurplusMar$_{c,i,r}$ is the fraction of generation from a small addition $\Delta R_{c,i,r}$ of class c VRRE installed in supply region i destined for sink region r that cannot be productively used because the load is not large enough to absorb both the VRRE generation and the must-run generation from existing conventional sources. It is calculated as:

$$Surplusmar_{c,i,r} = (\mu_{SR+\Delta R_{c,i,r}} - \mu_S)/\Delta R_{c,i,r}$$

Where $\mu_{SR+\Delta R_{c,i,r}}$ is calculated in exactly the same way as μ_S, but with $\Delta R_{c,i,r}$ MW of VRRE added in region i.

Appendix E Retirement of Capacity

All retiring wind turbines are assumed to be refurbished or replaced immediately, because the site is already developed with transmission access and other wind farm infrastructure. Wind capacity is replaced simply by assuming the wind capacity never decreases, i.e. the turbine capacity lasts indefinitely.[12] This does introduce a small error that is currently ignored. At the time that retiring wind turbines are replaced, they will most likely be replaced by state-of-the-art turbines, which can be expected to produce more energy and power per land area, and have higher capacity factors and lower costs than the machines they replace. This upgrading is not currently accounted for.

Similarly, storage at the wind site is assumed to be replaced immediately upon retirement. On the other hand, grid storage retires automatically when its assumed lifetime has elapsed.

Retirements of conventional generation can be modeled either as a fraction of remaining capacity each period (gas plants), through exogenous specification of planned retirements (currently used for nuclear, hydro, and oil/gas steam plants), or economic retirements (coal plants built before 2006).

Gas-fired Capacity Retirements: Because gas combustion turbines have been—and continue to be—used extensively as peaking plants, gas-CT capacity retirement is assumed to have reached a steady state condition, best modeled by assuming a fixed fraction of existing capacity is retired each year. The fraction retired is set equal to 1/assumed plant operational lifetime.

$$CONVRET_{n,CT} = CONVOLD_{n,CT} \cdot \left(\frac{2}{ltime_{CT}}\right)$$

After 2020, gas combined-cycle power plants are also retired at the fractional rate of 1/assumed plant operation lifetime. However, because such a high fraction of these plants were built in the four years between 2000 and 2004, the annual retirements before 2020 are restricted to 1/20 of the capacity that existed before 2006.

Nuclear, hydroelectricity, and oil/gas steam turbines: In reality, the retirement of these plants is determined by a host of factors other than their operational viability and economics. Thus, in ReEDS, where it is known that plants are scheduled to retire, that schedule is used. All capacity that does not have a scheduled retirement date is assumed to retire at a rate of 1/assumed plant operational lifetime.

$$CONVRET_{n,q} = PRETIRE_{n,q} + (CONVOLD_{n,q} - REMSCHED_{n,q}) \cdot \left(\frac{2}{ltime_q}\right)$$

Coal-fired capacity retirements: Existing coal plants are retired based on both their assumed operational lifetimes and their variable operating costs relative to the costs of constructing and operating new gas combined-cycle plants.

$$CONVRET_{n,q} = CONVOLD_{n,q} \cdot \left(\frac{2}{ltime_q}\right)\left(1 + \frac{CONRETkn_pgas_n}{VCcoal_{n,q}}\right)^{-3}$$

New coal plants are assumed to last beyond 2050, so there are no retirements of these plants.

[12] In deciding whether to invest in wind, the model uses a 20-year evaluation period, i.e. the turbines are not assumed to last indefinitely.

Appendix F Financial Calculations

This section presents all the major financial parameters of ReEDS. It begins with general economic parameters that are used in the ReEDS economic calculations.

F.1 General Economic Parameters

Fundamental parameters

d, the real discount rate.

E, the evaluation period or investment lifetime, in years.

CRF, the capital recovery factor, is computed from d and E and represents the fraction of the capital cost of an investment that must be returned each year to earn a rate of return equal to d, ignoring income taxes and financing.

$$CRF = \left(\sum_{t=1}^{E} (1+d)^t \right)^{-1} = \frac{d}{1-(1+d)^{-E}}$$

F.2 Financial Parameters Specific to Wind

This subsection includes many of the cost parameters that are calculated for wind.

CW_c is the present value of the revenue required to pay for the capital cost of one MW of wind capacity ($/MW) including interest during construction, finance, and taxes.

$$CW_c = WCC_c \cdot \frac{IDC}{1-TR} \cdot \begin{pmatrix} (1-FF) + FF \cdot PVDebt \\ -TR \cdot (1 - ITCW/2) \cdot PVDep - ITCW \end{pmatrix}$$

where

WCC_c is the overnight capital cost ($/MW) of a class c wind plant. WCC_c can be either a direct input ($IWLC = 0$) or calculated based on a production learning curve ($IWLC = 1$). If learning-based improvements are allowed, then

$$WCC_c = WCC_c^0 \cdot \begin{pmatrix} (1-costinstfrac)(1-learnpar_{wind})^{\log_2\left(WROW + \frac{WindCap_{T_delay}}{W_0}\right)} \\ +constinstfrac \cdot (1-learnpar_{wind})^{\log_2\left(\frac{WindCap_{T_delay}}{W_UScapyr2000}\right)} \end{pmatrix}$$

where

WCC_c^0 is the overnight capital cost ($/MW) of a class c wind plant without learning as input for the time period (i.e., includes any R&D driven changes over time, but not learning).

costinstfrac is the fraction of the capital cost associated with installation.

$learnpar_{wind}$ is the learning parameter for wind, the % reduction in the capital cost of wind for each doubling of the installed capacity.

WROW is the wind capacity installed in the rest of the world T_delay periods ago.

T_delay is the time required for learning to impact the market, i.e. the learning delay in periods between installations and cost reductions.

$WindCap_{T_delay}$ is the total national installed wind capacity T_delay periods ago.

*W_UScapyr*2000 is the total national capacity in the year 2000.

W_o is the total world wind capacity in the year 2000.

IDC is a multiplier to capture after-tax value of interest during construction.

$$IDC = \sum_{t=1}^{CP} CONSF_t \cdot \left(1 + (1 - TR) \cdot ((1 + i_c)^{CP-t} - 1)\right)$$

where

$CONSF_t$ is the fraction of the capital cost incurred in year t of construction.

i_c is the construction loan nominal interest rate.

CP is the construction period.

TR is the combined federal and state marginal income tax rate.

FF is the fraction of the plant capital cost financed. It can be input or calculated as shown below (see DSCR discussion) to ensure that the required debt service coverage ratio (DSCR) is met.

ITCW = investment tax credit for wind.

PVDebt is the after-tax present value of debt payments. [13]

$$\begin{aligned} PVDebt &= \sum_{t=1}^{L} \frac{P_t + (1 - TR)I_t}{(1 + d_n)^t} \\ &= CRF_{i,L} \cdot (1 - TR) \cdot PVA_{d_n,L} + TR \cdot \left(\frac{CRF_{i,L} - i}{1 + i}\right) \cdot PVA_{d_n,L} \end{aligned}$$

where

[13] Closed-form expression for the after-tax present value of the loan payments. Define Pt as the principal payment in year t, and i as the nominal interest rate, then the cost of the loan payments over the life L of the loan is:

P_t is the principal portion of the finance payment made after the loan has been in place t years.

I_t is the interest portion of the finance payment made after the loan has been in place t years.

i = nominal interest rate for debt.

L = financing period.

$PVA_{d_n,L}$ is the present value of annual \$1 payments for L years.

PVDep is the present value of depreciation

$$PVDep = \sum_{t=1}^{DP} \frac{Depf_t}{(1+d_n)^t}$$

where

$Depf_t$ = depreciation fraction in year t

DP = depreciation period

$CWOM_c$ is the present value of E years of operating costs including property taxes, insurance, and production tax credit (\$/MW).

$$CWOM_c = WOMF_c \cdot PVA_{d,E} + 8760 \cdot CF_c \cdot (WOMV_c \cdot PVA_{d,E} - \frac{WPTC}{1-TR} \cdot PVA_{d,PTCP})$$

where[14]

$WOMF_c$ is the fixed annual O&M cost of class c wind (\$/MW-yr)

$WOMV_c$ is the variable O&M cost of class c wind (\$/MWh)

$WPTC$ is the production tax credit (\$/MWh)

$PTCP$ is the period over which the production tax credit is received (years)

CG_g is the increase in turbine price over cost due to rapid growth in wind deployment. (\$/MW)

$$\begin{aligned}
CG_1 &= 0.01 \\
CG_2 &= (1 - Cost_Inst_Frac) \cdot CW_6 \cdot GP \cdot (BP_2 - BP_1)/2 \\
CG_3 &= (1 - Cost_Inst_Frac) \cdot CW_6 \cdot GP \cdot (BP_2 - BP_1 + (BP_3 - BP_2)/2) \\
CG_4 &= (1 - Cost_Inst_Frac) \cdot CW_6 \cdot GP \cdot (BP_3 - BP_1 + (BP_4 - BP_3)/2) \\
CG_5 &= (1 - Cost_Inst_Frac) \cdot CW_6 \cdot GP \cdot (BP_4 - BP_1 + (BP_5 - BP_4)/2) \\
CG_6 &= (1 - Cost_Inst_Frac) \cdot CW_6 \cdot GP \cdot (BP_5 - BP_1)
\end{aligned}$$

where

CW_6 is the cost of a class 6 wind machine

GP is the growth penalty for each percent growth above the breakpoint

BP_k are breakpoints that discretize the growth price penalty: $(1 < BP_1 < BP_2 < BP_3 < BP_4 < BP_5 < BP_6)$

[14] The use of a real discount rate in all the O&M calculations presumes that the O&M costs increase with inflation, i.e. that the real O&M cost is unchanging.

$CGinst_{ginst}$ is the increase in wind installation price over cost in growth bin ginst, due to rapid growth in wind deployment. ($/MW)

$$
\begin{aligned}
CGinst_1 &= 0.01 \\
CGinst_2 &= Cost_Inst_Frac \cdot CW_6 \cdot GPinst \cdot (BP_2 - BP_1)/2 \\
CGinst_3 &= Cost_Inst_Frac \cdot CW_6 \cdot GPinst \cdot (BP_2 - BP_1 + (BP_3 - BP_2)/2) \\
CGinst_4 &= Cost_Inst_Frac \cdot CW_6 \cdot GPinst \cdot (BP_3 - BP_1 + (BP_4 - BP_3)/2) \\
CGinst_5 &= Cost_Inst_Frac \cdot CW_6 \cdot GPinst \cdot (BP_4 - BP_1 + (BP_5 - BP_4)/2) \\
CGinst_6 &= Cost_Inst_Frac \cdot CW_6 \cdot GPinst \cdot (BP_5 - BP_1)
\end{aligned}
$$

where

GPinst is the growth penalty for each percent growth above the breakpoint

F.3 Setting the Finanace Fraction in ReEDS

The fraction of the capital cost of a wind farm that is financed can be input or endogenously estimated based on debt-service requirements. If calculated endogenously, the maximum fraction that can be financed is used. The fraction that can be financed is restricted by the Debt Service Coverage Ratio (DSCR). DSCR is the ratio of net pre-tax revenue to the debt payment (Debtpayment). ReEDS assumes the net pre-tax revenue is equal to the revenue required to recover capital cost plus profit and tax benefits (e.g., production tax credit).

$$
DSCR = \frac{CRF_{d_n,E}}{Debtpayment} \cdot \left(CW_c + \frac{WPTC \cdot 8760 \cdot CF_c}{(1 - TR) \cdot PVA_{d,PTCP}} \right)
$$

where

$$
Debtpayment = FF \cdot WCC \cdot IDC \cdot CRF_{i,L}
$$

Solving the DSCR equation for the finance fraction (which is embedded in CW_c, above) yields:

$$
FF = CRF_{d,E} \cdot \frac{\frac{WPTC \cdot 8760 \cdot CF_c}{1 - TR} \cdot PVA_{d,PTCP} + \frac{WCC \cdot IDC}{1 - TR} \cdot \left(1 - TR \cdot (1 - \frac{ITCW}{2}) \cdot PVDep - ITCW\right)}{WCC \cdot IDC \cdot \left(DSCR \cdot CRF_{i,L} + \frac{(1 - PVDebt) \cdot CRF_{d,E}}{1 - TR}\right)}
$$

F.4 Financial Parameters Specific to Conventional Technologies

This section includes many of the cost parameters that are calculated in ReEDS for conventional technologies. Inasmuch as some of these are substantively the same as those calculated for wind, the reader will be referred to the above wind parameter subsection.

$CCONV_q$ is the present value of the revenue required to pay for the capital cost of one MW of capacity of generating technology q ($/MW) including interest during construction, finance, and taxes. It is calculated in a manner analogous to that for wind.

$$
\begin{aligned}
CCONV_q = CCC_c \cdot \frac{CRF_{d,E}}{CRF_{d,L_q}} \cdot \frac{IDC}{1 - TR} \\
\cdot ((1 - FF) + FF \cdot PVDebt - TR \cdot (1 - ITC_q/2) \cdot PVDep - ITC_q)
\end{aligned}
$$

where

CCC_c is the overnight capital cost ($/MW) of the generation plant. CCC_c can be either a direct input ($ILC = 0$) or calculated based on a production learning curve ($ILC = 1$). If learning-based improvements are allowed, then

$$CCC_c = CCC_0 \cdot (1 - costinstfrac)(1 - learnpar_{wind})^{\log_2\left(\frac{CONVOLDdelay_q}{USCapyear2000_q}\right)}$$

where

CCC_o is the overnight capital cost ($/MW) of generating technology without learning as input for the time period (i.e., includes any R&D driven changes over time, but not learning).

$CONVOLDdelay_q$ is the learning delay between installations and cost reductions.

$learndelay$ is the learning delay between installations and cost reductions.

$learnpar_q$ is the learning parameter for generation technology q, the % reduction in the capital cost for each doubling of the installed capacity.

$UScapyr2000_q$ is the total national capacity of generation technology q in the year 2000.

L_q is the economic lifetime of technology q (years).

FF is the finance fraction which must be input for conventional technologies (unlike the endogenous calculation option for wind described above).

See the calculation of CW_c for the definition of the other inputs for CCC_q

$CCONVV_{n,q}$ is the present value of the variable cost of operating technology q in balancing authority n for E years.

$$CCONVV_{n,q} = CVarOM_q \cdot PVA_{d,E} + Fprice_{q,n} \cdot cheatrate_q \cdot PVA(n,q)_{d,E,e}$$

where

$CvarOM_q$ is the variable O&M cost for technology q ($/MWh).

$Fprice_{q,n}$ is the cost of the input fuel ($/MMBtu).

$cheatrate_q$ is the heat rate for technology q.

$CCONVF_q$ is the present value of the fixed costs of operating technology q for E years ($/MW).

$$CCONVF_q = COMF_q \cdot PVA_{d,E}$$

where

$COMF_q$ is the annual fixed O&M cost for plant type q ($/MW-yr).

$CSRV_{n,q}$ is the present value of the variable cost of spinning reserve provided for E years in balancing authority n ($/MWh). The cost represents the cost of operating the plant at part-load. A linear program can not ordinarily capture part-load efficiency, because it is highly nonlinear with the level of operation. ReEDS assumes that if spinning reserve is provided, the maximum amount is provided in the time-slice, the plant is operating

at $MinSR_q \cdot CONV_{n,q}$. Thus, the cost of spinning reserve can be estimated by solving the following for $CSRV_{n,q}$:

$$CCONVV_{n,q} \cdot \frac{MinSR_q \cdot CONV_{n,q}}{PLEffFactor_q} = CCONVV_{n,q} \cdot MinSR_q \cdot CONV_{n,q} + (1 - MinSR_q) \cdot CONV_{n,q} \cdot CSRV_{n,q}$$

or

$$CSRV_{n,q} = \frac{MinSR_q}{1 - MinSR_q} \cdot CCONVV_{q,n} \cdot \left(\frac{1}{PLEffFactor_q} - 1 \right)$$

F.5 Transmission Cost Parameters

$CCT_{n,p}$ is the present value of transmitting 1 MWh of power for each of E years between balancing authorities n and p (\$/MWh).

$$CCT_{n,p} = (Dis_{n,p} \cdot TOCOST + POSTSTWCOST \cdot PostStamp_{n,p}) \cdot PVA_{d_n,E}$$

where

> $Dis_{n,p}$ is the distance in miles between the center of balancing authorities n and p.
>
> $TOCOST$ is the cost per mile for using existing transmission lines (\$/MWh-mile).
>
> $POSTSTWCOST$ is the cost of using transmission that crosses a balancing authority (\$/MWh).
>
> $PostStamp_{n,p}$ is the number of balancing authorities that must be crossed to move from n to p. If p is adjacent to n, getting to p is considered to be crossing one balancing authority.

$TN_CG_{tn_g}$ is the difference between the price and cost of transmission in transmission growth bin tn_g (\$/MW-mile).

$$\begin{aligned}
TN_CG_1 &= 0.01 \\
TN_CG_2 &= TNCost \cdot TNGP \cdot (TNBP_2 - TNBP_1))/2 \\
TN_CG_3 &= TNCost \cdot TNGP \cdot (TNBP_2 - TNBP_1) + (TNBP_3) - TNBP_2))/2) \\
TN_CG_4 &= TNCost \cdot TNGP \cdot (TNBP_3 - TNBP_1) + (TNBP_4) - TNBP_3))/2) \\
TN_CG_5 &= TNCost \cdot TNGP \cdot (TNBP_4 - TNBP_1) + (TNBP_5) - TNBP_4))/2) \\
TN_CG_6 &= TNCost \cdot TNGP \cdot (TNBP_5 - TNBP_1))
\end{aligned}$$

where

> $TNCost$ is the cost per mile of building new transmission lines (\$/MW-mile).
>
> $TNGP$ is the percent increase in the cost of transmission for each percent growth over the base amount.
>
> $TNBP_k$ are breakpoints that discretize the growth price penalty: $(1 < TNBP_1 < TNBP_2 < TNBP_3 < TNBP_4 < TNBP5 < TNBP_6)$

Appendix G Geographic Information System (GIS) Calculations

Using Geographic Information Systems (GIS), a preliminary optimization is performed outside and prior to the linear programming model to construct a supply curve for onshore wind, shallow offshore wind, and deep offshore wind for each region i and wind class c.

The pre-optimization minimizes:

$$\sum_{c,i,l,h,k} (GC_{c,l} + TC_{c,i,l,h,k}) \cdot W_{c,i,l,h,k} + \sum_{k} M \cdot D_k$$

Subject to:

$$\sum_{c,i,l,h,k} W_{c,i,l,h,k} + D_k \leq a_k \cdot T_k$$

where

$GC_{c,l}$ is the levelized cost of generation from a wind farm of type l at a class c wind resource site.

$TC_{c,i,l,h,k}$ is the levelized cost of building a transmission spur for class c wind of type l from grid square h in region i to transmission line k.

$W_{c,i,l,h,k}$ is class c wind of type l transported from grid square h in region i on transmission line k.

M is a large number (very high cost).

D_k is a dummy variable to ensure feasibility in the constraint below.

a_k is the fraction of the capacity (T_k) of line k available

Using the results of this pre-optimization, supply curves are constructed for each region i, for each type of wind resource l (onshore, shallow offshore, and deep offshore) and for each class of wind resource within that type. Each supply curve is made up of four wind resource/cost pairs identified by the subscript $wscp$ where $wscp$ takes on the values 1 through 4. The amount of wind resource in each step is set initially so that for each type of wind l:

$$WR2G_{c,i,l,wscp} = f_{wscp} \cdot \sum_{h,k} W_{c,i,l,h,k}$$

$$\text{where:} \quad f_i = 0.1 \cdot i$$

Thus, the first step on the supply curve is comprised of the 10% of all the class c wind grid squares in region i with the lowest cost to build transmission spurs to the grid. The next step consists of the 20% with the next lowest set of costs, etc. The cost, $WR2GPTS_{c,i,l,wscp}$, associated with each point or step on the supply curve is the mean levelized transmission spur cost for that step.

The supply curve quantity/price pairs—$WR2G_{c,i,l,wscp}$ and $WR2GPTS_{c,i,l,wscp}$—from this pre-LP optimization are input to the linear programming ReEDS model within the "Wind Supply Curve" constraints. In each period, the quantities, $WR2G_{c,i,l,wscp}$, are decremented by the amount of wind resource in that step deployed in previous periods.

Ideally, this preoptimization should be performed for each period of the ReEDS run with the costs of wind generation specific to that period (wind generation costs generally decrease from one period to the next either because of exogenously specified R&D-driven reductions in capital and operating costs, and/or because of learning through industrial experience). This is not possible because of time and computer resources required to conduct this optimization in GIS for the large number of wind grid squares considered. Currently, the optimization is conducted once using the wind cost/performance characteristics for the first period.

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