APPENDIX E:

METHODS FOR ESTIMATING REASONABLY FORESEEABLE DEVELOPMENT SCENARIOS FOR SOLAR ENERGY DEVELOPMENT

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APPENDIX E:

METHODS FOR ESTIMATING REASONABLY FORESEEABLE DEVELOPMENT SCENARIOS FOR SOLAR ENERGY DEVELOPMENT

To aid in impact analysis for the "Programmatic Environmental Impact Statement for Solar Energy Development in Six Southwestern States" (Solar PEIS), a reasonably foreseeable development scenario (RFDS) for solar energy development in the six-state study area was incorporated into the analyses. Two methods of estimating the RFDS are detailed in this appendix: one using the National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment System (ReEDS) model (Section E.1), the other based on each state's Renewable Portfolio Standard (RPS) requirements (Section E.2). The RFDS estimates resulting from these methods are presented in Section 2.4 of the Solar PEIS, in terms of total megawatts (MW) of solar facility capacity available by the year 2030.

E.1 RFDS ESTIMATES USING THE ReEDS MODEL

The ReEDS model was developed at NREL. It is a model of the current U.S. electric sector and its expansion potential that includes detailed treatment of renewable energy technologies. A detailed description of the model prepared by NREL is provided as Attachment 1 to this Appendix.

The ReEDS model was used to estimate the growth in both concentrating solar power (CSP) and photovoltaic (PV) solar capacity in the six-state study area through 2030 for aid in analyses for the Solar PEIS. The values obtained for CSP are presented in Table E.1-1; those for PV are presented in Table E.1-2.

E.2 RFDS ESTIMATES USING STATE RPS LEVELS TO PREDICT SOLAR CAPACITY

RPSs have been passed in many states and require that a certain percentage of that state's electricity capacity requirements be supplied from renewable sources (e.g., solar, wind, geothermal, or biomass) by a given year. The six states in the Solar PEIS study area all have RPSs; these standards are mandatory in each of the states except Utah. Meeting these RPS levels likely would require solar energy development either within those states or in the region.

To establish a RFDS to support analyses in the PEIS, the levels of solar energy development within each of the six states were developed by (1) using state-level RPSs and regional growth rates to establish the basic amounts of new renewable generation needed in each state and (2) applying various assumptions about the amount of each RPS to be provided from solar energy versus other renewable sources.

TABLE E.1-1 ReEDS Model Estimates of CSP Solar Development on BLM and Non-BLM Administered Lands, May 11, 2010

		Cumulative MW by year (assumes 31 MW/km^2)		
State		2010	2014	2030
Arizona	Non-BLM[a]	0.000	0.000	0.000
	BLM	0.000	0.000	0.000
California	Non-BLM	0.000	203.893	305.087
	BLM	0.000	123.792	173.761
Colorado	Non-BLM	0.000	0.000	0.000
	BLM	0.000	0.000	0.000
New Mexico	Non-BLM	0.000	0.000	0.000
	BLM	0.000	0.000	0.000
Nevada	Non-BLM	41.683	159.700	159.700
	BLM	0.000	0.000	0.000
Texas	Non-BLM	0.000	0.000	0.000
	BLM	0.000	0.000	0.000
Utah	Non-BLM	0.000	0.000	0.000
	BLM	0.000	0.000	0.000

[a] BLM = Bureau of Land Management.

TABLE E.1-2 ReEDs Model Estimates of PV Solar Development on BLM and Non-BLM Administered Lands, May 10, 2010

		Cumulative MW by year		
State		2010	2014	2030
Arizona	Non-BLM[a]	0.00	190.02	1,724.06
	BLM	0.00	194.89	1,768.23
California	Non-BLM	0.00	649.53	8,181.56
	BLM	0.00	109.89	2,033.49
Colorado	Non-BLM	83.44	306.71	2,197.31
	BLM	3.74	13.73	98.39
New Mexico	Non-BLM	174.57	891.73	3,204.23
	BLM	19.76	97.08	353.00
Nevada	Non-BLM	0.00	91.99	387.78
	BLM	0.00	273.60	1,153.31
Utah	Non-BLM	0.00	0.00	0.00
	BLM	0.00	0.00	0.00

[a] BLM = Bureau of Land Management.

Estimates of future levels of solar energy development in each state depend on a number of factors not well-defined at this time. For example, most of the RPSs do not specify the amount of renewable energy to be generated by the different qualifying resources, which creates uncertainty regarding the mix of solar energy within each state. In addition, the total RPS requirements are expressed in terms of percentage of future electricity sales, and projections of these future sales (11 to 16 years out) are not readily available for each state. Also, the potential exists for utilities to import renewable energy in order to meet RPS requirements, or to develop renewable energy specifically for export to other states. Developments such as these are difficult to predict with accuracy. Consequently, the estimates of future solar development levels in each state required approximation methods and assumptions and, as a result, there are significant uncertainties in the final results for the solar generation and capacity estimates.

The following sections present the analytical approach and results. For perspective, Section E.2.3 presents these results in the context of projections from other sources.

E.2.1 Overview

The overall approach that was adopted for estimating solar capacity and energy futures for each of the six states included:

1. Identifying the percentages of total future electricity sales to be supplied by renewable energy sources (i.e., the RPS requirements) for each state;

2. Identifying current capacities, generation, and electricity sales statistics for each state;

3. Applying regional projected growth rates to determine anticipated total electricity sales for each state in the designated RPS years;

4. Applying RPS requirements to determine anticipated renewable energy development;

5. Making adjustments for contributions to the RPS requirements, as allowed, for existing conventional hydroelectric sources or other qualifying technologies;

6. Postulating several fractional "market shares" for solar as percentages of total renewable generation/sales needed to satisfy the RPS requirements in each state;

7. Deriving the amounts of energy associated with each of the postulated fractions that might be anticipated from solar contributions; and

8. Deriving the associated capacities for solar power based on the results from Step 7 and estimated capacity factors.

Additional details for these steps are described in the sections that follow.

E.2.1.1 RPS Requirements for Each State

The first step in estimating future solar power development for each state was a review of the RPS requirements. Table E.2-1 summarizes the RPS specifications for all six states. While RPS requirements provided a reasonable starting point for this analysis, it was recognized that many dynamic factors will affect actual outcomes for renewable power development. Issues such as siting, permitting, technology costs, transmission linkages, and other utility integration factors, will all influence whether RPSs are met and how they might evolve over time. The uncertainties in using RPS requirements for estimating renewable energy development, and in particular solar energy development, were recognized and acknowledged for the analysis that follows. With those considerations in mind, the approach described yielded a range of possible outcomes for solar development that are intended to cover the realm of feasible and likely development scenarios.

Table E.2-1 illustrates that each of the six states has adopted different types of renewable energy requirements. Three of the six states designate a percentage that applies to total electricity sales in the state, while the other three make distinctions between requirements for investor-owned utilities (IOUs) and publicly owned utilities (POUs).[1] Four of the states (Arizona, Colorado, Nevada, and New Mexico) have included additional specifications for types of total renewable sources to be developed. Two of the states (Nevada, and New Mexico) provide specific requirements for solar energy contributions, and one state (New Mexico) specifies minimum requirements for other renewable technologies (wind, biomass, and geothermal) needed to meet RPSs.

E.2.1.2 Treatment of Hydroelectric Sources

One important criterion for estimating future solar contributions is whether "conventional" hydroelectric generation, or hydropower, is considered as a qualifying option. Conventional hydropower refers to standard hydroelectric dams as contrasted with pumped storage, tidal, wave, or ocean thermal technologies. For most of the six states, conventional hydropower represents a significant fraction of existing "renewable" energy generation and could potentially deliver a large share of the future RPS requirements. However, Arizona, California, Nevada, and New Mexico have all included stipulations for limiting hydroelectric contributions to meet RPSs.[2] In general, these four states require that the hydroelectric facilities be relatively new (i.e., installed after a given year) or be of limited capacity/generation (such as used to "firm" the generation from other variable output renewable technologies like wind or solar).

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[1] POUs include municipal and cooperative entities. In Nevada, RPS summaries use notation that a requirement "[applies to] Investor-Owned Utility and Retail Supplier," which raises some question about the requirements' applicability to POUs. Most of the other states specifically identify POUs when they are included in the RPS requirements; thus, in this analysis, it was assumed that POUs are not mandated to meet the RPS requirements in Nevada.

[2] The RPS summaries for California and Nevada include references to "certain hydro" sources as qualifying sources for RPS requirements, but do not define which types of hydropower sources would qualify.

TABLE E.2-1 RPS Requirements Summary as of July 2010

RPS Specification[a]	Arizona	California	Colorado	Nevada	New Mexico	Utah
Designated RPS year	2025	2020	2020	2025	2020	2025
Primary RPS specifications						
Total renewables (% of sales)	15%	33%[b]	–[c]	–	–	20%
Total renewables for IOUs (% of sales)	–	–	30%	25%	20%	–
Total renewables for POUs (% of sales)	–	–	10%	–	10%	–
Additional RPS specifications						
Distributed generation (% of sales)	4.5% (by 2012)	–	3.0% (IOUs)	–	0.6% (IOUs)	–
Wind (% of sales)	–	–	–	–	4% (IOUs)	–
Solar (thermal and photovoltaic [PV]) (% of sales)	–	–		1.5% (IOUs)	4% (IOUs)	–
Biomass and geothermal (% of sales)	–	–	–	–	2% (IOUs)	–
Mandatory (M) or voluntary (V)	M	M[b]	M	M	M	V
Requirements for hydroelectric sources to be new/small (Y/N)	Y	Y	N	Y	Y	N

[a] Where presented, % of sales refers to % of electricity sales.

[b] In 2006, Senate Bill 107 established a mandatory standard of 20% renewable energy by 2010. In 2009, Governor Schwarzenegger established a higher goal of 33% by 2020 in Executive Order S-21-09. Although the 33% goal has not been adopted by law or regulation, it is used in this analysis to provide a conservatively high projection of future renewable energy development in California.

[c] A dash indicates no standard has been established for this specification.

Source: Database of State Incentives for Renewables & Efficiency (North Carolina Solar Center and Interstate Renewable Energy Council 2010).

These stipulations for hydroelectric power were recognized in deriving the results described in Section E.2.2. The approach used in this analysis estimated total electricity sales for the RPS years and subtracted existing hydroelectric generation from those totals for Colorado and Utah, where it appears that conventional and existing hydroelectric sources are allowed to contribute to the RPSs.

E.2.1.3 Additional Considerations

Also of potential significance in the renewable estimation process is Utah's allowance of (1) nuclear power, (2) demand-side management (DSM), and (3) carbon-sequestered fossil generation (CSFG) in directly subtracting from total electricity sales figures to which RPS requirements apply. Thus in Utah, if nuclear power, DSM, and CSFG were responsible for a total of 1,000 GWh and total sales were 10,000 GWh, then the 20% RPS requirement would translate into a need for 1,800 GWh from qualifying renewable sources (20% of 9,000 GWh). Currently, there are no nuclear generating facilities in Utah, and DSM and CSFG programs are highly uncertain; thus these issues are subject to considerable variability for long-term projections. As a result, no adjustments were made in this analysis to the Utah RPS requirements for these other qualifying technologies.

E.2.1.4 Current Capacities, Generation, and Electricity Sales for Each State

Table E.2-2 summarizes the existing capacity, generation, and sales numbers for each of the six states.

E.2.1.5 Regional Electricity Growth Rates

In translating the RPS requirements into anticipated electricity sales, generation, and capacity estimates for future years, this analysis relied on long-term growth rate projections developed by the U.S. Department of Energy's (DOE's) Energy Information Administration (EIA). The annual growth rates were derived for each electric region that cover the six-state study area and for each end-year that was designated in the state-specific RPS requirements. The

TABLE E.2-2 Existing Capacity, Generation, and Electricity Sales in 2007

Parameter/State	Arizona	California	Colorado	Nevada	New Mexico	Utah
Capacity (MWe)						
Hydroelectric	2,720	10,041	665	1,048	82	255
Solar/PV	9	404	8	79	0	0
Other renewables	7	5,329	1,073	189	500	38
Total renewables	2,736	15,774	1,746	1,316	582	293
Total capacity[a]	25,579	63,813	12,288	9,954	7,202	7,122
Generation (GWh)						
Hydroelectric	6,598	27,328	1,730	2,003	268	539
Solar/PV	9	557	2	44	0	0
Other renewables	32	24,288	1,322	1,253	1,409	195
Total renewable	6,639	52,173	3,054	3,300	1,677	734
Total generation[a]	113,341	210,848	53,907	32,670	35,985	45,373
Total state sales (GWh)	77,193	264,235	51,299	35,643	22,267	27,785

[a] Includes both renewable and non-renewable electricity sources.

Sources: EIA (2007a) for capacity and generation and EIA (2007b) for total state sales.

use of regional growth rates (rather than state-specific rates) was necessary because EIA does not develop or publish long-term projections on a state basis. Still, the EIA projections were chosen because of the consistency in projection methodologies and assumptions as they apply across the six-state study area.

Figure E.2-1 illustrates the EIA electric market regions and shows the level of regional detail that is available for forecasted electricity sales, generation, and capacity estimates from the EIA. These regions also correspond approximately to North American Electric Reliability Corporation (NERC) sub-areas. For the six-state study area, the alignments between states and regions are as follows:

Arizona, Colorado, New Mexico, and Nevada	Region 12 (Rocky Mountain Sub-Area),
California	Region 13 (California Sub-Area), and
Utah	Region 11 (Northwest Sub-Area).

(Note: While the majority of land area from Nevada is in Region 11, the majority of electrical load is located in Region 12. Thus for this analysis, Nevada was treated as being part of Region 12.)

Table E.2-3 shows the existing and projected statistics for each of the three relevant electric market regions that are aligned with the six states. The end-year data reflect different RPS target years; thus even though a common EIA market region may apply to multiple states, the statistics can vary because of different RPS years.

E.2.1.6 Application of Regional Growth Rates to State-Level Generation and Electricity Sales Estimates

The regional annual average electricity sales growth rates provided in Table E.2-3 can be used to estimate state-level projections for future years. Table E.2-4 shows total state-level electric sales estimates for the various RPS years. The bottom row of results in Table E.2-4 provides a basis for estimating renewable energy development in each state for each of the RPS years.

E.2.1.7 Derivation of Combined Investor-Owned and Publicly Owned RPS Multipliers

In those states where there are different RPS requirements for IOUs and POUs (i.e., Colorado, Nevada, and New Mexico), it is necessary to develop a weighted average RPS requirement in order to calculate the amount of electricity that must be derived from renewable resources. Weighted averages were derived by using the relative percentages of IOUs and POUs for historical generation, as shown in Table E.2-5. These derivations are based on 1999 estimates because data for POU sales and total state sales were available for that year.

1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6 New York (NY)
7 New England (NE)
8 Florida Reliability Coordinating Council (FRCC)
9 Southeastern Electric Reliability Council (SERC)
10 Southwest Power Pool (SPP)
11 Northwest Power Pool (NWPP)
12 Rocky Mountain Power Area (RMPA)
13 California (CA)

FIGURE E.2-1 EIA Electricity Market Module Regions (Source: EIA 2009a)

TABLE E.2-3 Regional Generation and Electricity Sales Growth Rates

EIA Electricity Market Module Region[a]	RMPA (12)	CA (13)	RMPA (12)	RMPA (12)	RMPA (12)	NWPP (11)
Parameter/state	Arizona	California	Colorado	Nevada	New Mexico	Utah
RPS year	2025	2020	2020	2025	2020	2025
Total regional sales (1,000 GWh)						
In 2007	185	257	185	185	185	223
In RPS year	226	285	209	226	209	263
Average annual regional sales growth rate (%/yr)	1.118	0.799	0.943	1.118	0.943	0.921

[a] CA = California; NWPP = Northwest Power Pool; RMPA = Rocky Mountain Power Area.

Source: EIA (2009b; Tables 82–84) for total regional sales.
Average annual regional sales growth =
$(10^{(\log[\text{total regional sales in RPS year} \div \text{total regional sales 2007}] \div (\text{RPS year} - 2007))} - 1) \times 100$.

TABLE E.2-4 Projected Electric Sales for Each State

EIA Electricity Market Module Region[a]	RMPA (12)	CA (13)	RMPA (12)	RMPA (12)	RMPA (12)	NWPP (11)
Parameter/state	Arizona	California	Colorado	Nevada	New Mexico	Utah
RPS year	2025	2020	2020	2025	2020	2025
Total state sales in 2007 (GWh)	77,193	264,235	51,299	35,643	22,267	27,785
Average annual regional sales growth rate (%/yr)	1.118	0.799	0.943	1.118	0.943	0.921
Years between 2007 and RPS year	18	13	13	18	13	18
Estimated total state sales in RPS year (GWh)	94,295	293,036	57,956	43,540	25,157	32,770

[a] CA = California; NWPP = Northwest Power Pool; RMPA = Rocky Mountain Power Area.

Sources: EIA 2007b for total state sales in 2007 and Table E.2-3 for average annual growth rate.

TABLE E.2-5 Net IOU/POU-Weighted Average RPS Requirements

Parameter	Arizona	California	Colorado	Nevada	New Mexico	Utah
Total state sales (GWh) (1999)	57,662	234,831	40,571	26,253	18,041	21,879
POU sales (GWh) (1999)	NA[a]	NA	11,123	2,264	1,630	NA
Percentage IOU	NA	NA	72.6	91.4	91.0	NA
Percentage POU	NA	NA	27.4	8.6	9.0	NA
Designated RPS year	2025	2020	2020	2025	2020	2025
Primary RPS specifications						
Total renewables (% of sales)	15%	33%	–[b]	–	–	20%
Total renewables for IOUs (% of sales)	–	–	30%	25%	20%	–
Total renewables for POUs (% of sales)	–	–	10%	–	10%	–
Weighted average RPS requirement (% of total state sales)	15%	33%	24.5%	22.8%	19.1%	20%

[a] NA = not applicable. (The relative percentages of POU/IOU generation are only needed for Colorado, Nevada, and New Mexico.)

[b] A dash indicates no standard has been established for this specification.

Sources: EIA (2007c) for total state sales and EIA (1999) for POU sales.

E.2.2 Results

To estimate state-level solar power generation and capacity, several calculations were made: (1) total electricity sales estimates from Table E.2-4 were multiplied by the weighted-average RPS requirements from Table E.2-5 to derive total sales expected to be generated from renewable power sources in the RPS year; (2) electricity sales estimates were translated into generation requirements by applying a uniform factor for line losses and internal use; (3) adjustments were made for Colorado and Utah, where conventional hydroelectric sources qualify for meeting the RPS; (4) resulting electricity sales estimates were multiplied by alternative solar market share assumptions to yield several estimates for the generation to be derived from solar power in each state; and (5) resulting generation levels were translated into capacity estimates by using representative solar capacity factors published by the EIA.

The details for these final steps and the corresponding outcomes are described in the following sections.

E.2.2.1 Electricity Sales and Generation Estimates to Meet State RPS Requirements

Table E.2-6 combines total state sales estimates from Table E.2-4 with the weighted RPS percentages of Table E.2-5, and displays the state-specific results for estimated total renewable electricity sales in the RPS years. The values in the bottom row of Table E.2-6 present the estimated total generation required to satisfy the renewable energy sales, taking into consideration a loss factor of 12.5% to account for internal use and line losses (EIA 2008).

TABLE E.2-6 Estimated Total Renewable Energy Sales and Generation for Each State

Parameter	Arizona	California	Colorado	Nevada	New Mexico	Utah
RPS year	2025	2020	2020	2025	2020	2025
Estimated total state sales in RPS year (GWh)	94,295	293,036	57,956	43,540	25,157	32,770
Weighted average RPS requirement (% of total state sales)	15%	33%	24.5%	22.8%	19.1%	20%
Total estimated renewable energy sales in RPS year (GWh)	14,144	96,701	14,199	9,927	4,805	6,554
Total estimated renewable generation in RPS year (GWh)[a]	15,912	108,789	15,974	11,168	5,405	7,373

[a] Assumed to be 112.5% of the energy sales to adjust for projected internal use and line loss (EIA 2008).

Sources: Table E.2-4 for estimated total state sales in RPS year and Table E.2-5 for weighted average RPS requirement.

E.2.2.2 Adjustments for Hydroelectric Generation

Table E.2-7 shows the adjustments made for two states (Colorado and Utah) that allow conventional hydroelectric generation to contribute to RPSs. The underlying assumption for this adjustment is that a portion of the RPS requirements would be offset by the conventional hydropower generation, assuming it will be delivered in similar magnitudes in future years.

E.2.2.3 Postulated Solar Market Shares

Because of uncertainties and market forces that will shape the long-term trends in solar energy and other renewable technology developments, different scenarios were evaluated to reflect the large range of possibilities. The amount of solar energy generation, relative to other renewable energy generation to meet RPSs, was set at three levels to represent a high-solar scenario (50% solar/50% other renewables), medium-solar scenario (25% solar/75% other renewables), and low-solar scenario (10% solar/90% other renewables).[3] By choosing these types of specific values, a range of alternatives was quantified in terms of the corresponding solar generation and capacity outcomes.

Table E.2-8 shows the estimated solar generation results for each state and for each of the three alternate renewable mix levels. The table also shows the generation that would need to be supplied by other renewable technologies in order to satisfy the overall RPS requirements.

TABLE E.2-7 Net Renewable Generation after Adjustments for Conventional Hydroelectric Power (GWh)

Parameter	Arizona	California	Colorado	Nevada	New Mexico	Utah
RPS year	2025	2020	2020	2025	2020	2025
Total estimated generation in RPS year	15,912	108,789	15,974	11,168	5,405	7,373
Hydroelectric generation in 2007	NA[a]	NA	1,730	NA	NA	539
Total net renewable generation (total minus hydroelectric)	15,912	108,789	14,244	11,168	5,405	6,834

[a] NA = not applicable (these states have provisions excluding conventional hydroelectric generation from RPSs).

Sources: Table E.2-6 for total estimated generation in RPS year and EIA (2007a) for hydroelectric generation in 2007.

[3] The "high," "medium," and "low" labels represent relative magnitudes for the percentage ranges as applied uniformly across the entire study area. These labels do not represent state-specific expectations for solar implementation.

TABLE E.2-8 Solar Generation Needed to Meet RPS Requirements at Selected Market Share Levels

Parameter/State	Arizona	California	Colorado	Nevada	New Mexico	Utah
RPS year	2025	2020	2020	2025	2020	2025
Total net renewable generation (GWh)	15,912	108,789	14,244	11,168	5,405	6,834
Solar generation at alternate renewable mix levels (GWh) (percent of total net renewable generation provided by solar/other renewables)						
50% Solar	7,956	54,394	7,122	5,584	2,702	3,417
50% Other renewables	7,956	54,394	7,122	5,584	2,702	3,417
25% Solar	3,978	27,197	3,561	2,792	1,351	1,708
75% Other renewables	11,934	81,592	10,683	8,376	4,054	5,126
10% Solar	1,591	10,879	1,424	1,117	540	683
90% Other renewables	14,321	97,910	12,820	10,051	4,864	6,151

Source: Table E.2-7 for total net renewable generation.

E.2.2.4 Translation of Solar Generation into Corresponding Capacity Estimates

For purposes of potential impact analysis, the solar generation estimates (GWh) provided in Table E.2-8 were translated into corresponding installed capacity estimates (MWe). This translation is dependent on the annual capacity factor(s) expected for solar technologies. Because the population of solar generators is likely to span a significant range of designs, performance characteristics, electric utility environments, and other factors, the annual capacity factor can vary significantly. To keep this portion of the estimating procedure as straightforward as possible, generic capacity factors projected by EIA through 2030 were adopted and applied to the derivations. For solar PV technologies the capacity factor is 21%, and for solar thermal (ST) technologies the capacity factor is 31% (EIA 2009c).

Two approaches were examined for estimating capacity on the basis of these capacity factors. One approach applied the average capacity factor for PV and ST options of 26% to the generation estimates in Table E.2-8. The other approach applied the assumptions of 21% for PV and 31% for ST to EIA's regional projections for the relative amounts of PV and ST expected for future years (EIA 2009b) to derive a weighted solar capacity factor. Table E.2-9 presents the capacity factors based on these two approaches.

In Table E.2-10, the weighted average capacity factors from Table E.2-9 were applied, in combination with the solar generation estimates in Table E.2-8, to derive estimated solar capacities needed to provide the associated generation levels.

TABLE E.2-9 Average Solar Capacity Factors[a]

Parameter	Arizona	California	Colorado	Nevada	New Mexico	Utah
RPS year	2025	2020	2020	2025	2020	2025
50/50 PV/ST ratio assumption						
PV/ST ratio	50/50	50/50	50/50	50/50	50/50	50/50
Average solar capacity factor	26%	26%	26%	26%	26%	26%
PV/ST ratio from regional EIA projections						
EIA Electricity Market Module Region[b]	RMPA (12)	CA (13)	RMPA (12)	RMPA (12)	RMPA (12)	NWPP (11)
PV/ST ratio[c]	29/71	8/92	32/68	29/71	32/68	70/30
Weighted average solar capacity factor	28.1%	30.2%	27.8%	28.1%	27.8%	24.0%

[a] PV generic capacity factor = 21%, ST generic capacity factor = 31% (EIA 2009c).

[b] CA = California; NWPP = Northwest Power Pool; RMPA = Rocky Mountain Power Area.

[c] Regional PV/ST ratio from EIA (2009b; Tables 98–100).

TABLE E.2.10 Solar Generation and Capacity Needed to Meet RPS Requirements at Selected Market Share Levels

Parameter	Arizona	California	Colorado	Nevada	New Mexico	Utah
RPS year	2025	2020	2020	2025	2020	2025
Total net renewable generation (GWh)	15,912	108,789	14,244	11,168	5,405	6,834
Weighted average solar capacity factor	28.1%	30.2%	27.8%	28.1%	27.8%	24.0%
Solar generation and capacity required at alternate renewable mix levels						
50% Solar						
Solar generation (GWh)	7,956	54,394	7,122	5,584	2,702	3,417
Solar capacity (MWe)	3,232	20,561	2,925	2,268	1,110	1,625
25% Solar						
Solar generation (GWh)	3,978	27,197	3,561	2,792	1,351	1,708
Solar capacity (MWe)	1,616	10,280	1,462	1,134	555	813
10% Solar						
Solar generation (GWh)	1,591	10,879	1,424	1,117	540	683
Solar capacity (MWe)	646	4,112	585	454	222	325

Sources: Table E.2-7 for total net renewable generation, Table E.2-8 for solar generation, and Table E.2-9 for weighted average solar capacity factor. For solar capacity derivations, capacity(MWe) = (generation(GWh) × 1000) ÷ (capacity factor × 8760).

E.2.3 Perspective

For perspective, the outcomes shown in Table E.2-10 are represented in this section as percentages of total estimated sales. The results are also displayed in context with other sources of solar development projections.

E.2.3.1 Results Expressed As Percentages of Total Electricity Sales

Table E.2-11 displays the solar generation estimates as percentages of total future sales (all in the RPS year for a given state). With the exception of California, for the high-solar case (50% solar/50% other), the projected solar generation estimates represent 8 to 12% of total state sales. And for the low-solar case (10% solar/90% other), the projected solar generation estimates represent approximately 2% of total state sales.

For California, the percentages are nearly double those of the other states, with results for the high-solar case (50% solar/50% other) representing 19% of total sales, and 4% for the low-solar case (10% solar/90% other). The reasons California shows significantly higher results are (1) the RPS total renewable requirement of 33% is significantly higher than any of the other states, (2) the “weighted average RPS requirement” as calculated in Table E.2-5 is substantially higher than for the other states, and (3) there are no adjustments for conventional hydroelectric contributions as shown for Colorado and Utah in Table E.2.7.

TABLE E.2-11 RPS Solar Generation Estimates Relative to Total Electricity Sales and Solar-Specific Provisions

RPS Specification	Arizona	California	Colorado	Nevada	New Mexico	Utah
Designated RPS year	2025	2020	2020	2025	2020	2025
Estimated total state sales in RPS year (GWh)	94,295	293,036	57,956	43,540	25,157	32,770
Estimated solar generation (% of total state sales)						
50% Solar case	8.4	18.6	12.3	12.8	10.7	10.4
25% Solar case	4.2	9.3	6.1	6.4	5.4	5.2
10% Solar case	1.7	3.7	2.5	2.6	2.1	2.1

Source: Table E.2-4 for estimated total state sales in RPS year.

Estimated solar generation (as % of total state sales) was calculated as the percentage of total state sales in the RPS year derived from the estimated solar generation presented in Table E.2-10 for each case.

E.2.3.2 Comparisons of Results with Solar-Specific RPS Requirements

For Nevada and New Mexico, the estimates can be compared with the solar-specific RPS specifications (Arizona, California, Colorado, and Utah have not adopted solar-specific RPS requirements). Table E.2-12 displays the results for these comparisons. Because both Nevada and New Mexico assign solar-specific RPS specifications for IOUs (shown in Table E.2-1), the comparisons in Table E.2-12 for these states are expressed as percentages of IOU sales.

For Nevada, the estimated percentages of IOU sales that would be derived from solar generation are larger than the RPS requirement, even in the low-solar case in which solar generation is assumed to provide only 10% of the total renewable needs. This observation does not constitute a contradiction, because the RPS solar-specific specifications represent lower bounds for solar development rather than expected penetration levels or upper bounds. Relative economics of solar and other renewable technology costs, land use issues, tax credits, and a host of other factors will determine the final development levels for each renewable technology.

TABLE E.2-12 Solar Generation Estimates Relative to Solar-Specific RPS Provisions

RPS Specification	Arizona	California	Colorado	Nevada[a]	New Mexico[a]	Utah
Designated RPS year	2025	2020	2020	2025	2020	2025
Estimated total state sales in RPS year (GWh)	94,295	293,036	57,956	43,540	25,157	32,770
Estimated IOU sales in RPS year (GWh)	NA[b]	NA	NA	39,796	22,893	NA
Solar-specific RPS Specifications						
Solar (thermal and PV) (% of sales)	NA	NA	NA	1.5% (IOUs)	4% (IOUs)	NA
Estimated solar generation (percent of IOU sales)[c]						
50% Solar case	NA	NA	NA	14.0	11.8	NA
25% Solar case	NA	NA	NA	7.0	5.9	NA
10% Solar case	NA	NA	NA	2.8	2.4	NA

[a] Comparisons for Nevada and New Mexico are based on IOU sales.

[b] NA = not applicable.

[c] Estimated solar generation (% of IOU sales) was calculated from: Estimated solar generation (%) = (solar generation [from Table E.2-10] ÷ estimated IOU sales in RPS year) × 100.

Source: Estimated IOU sales =
(Estimated total state sales [from Tables E.2-4] × Percentage IOU [from Table E.2-5]) ÷ 100.

For New Mexico, the RPS stipulation for 4% of IOU sales from solar generation falls within the range covered by high-, medium- and low-solar assumptions of this study. The low-solar case (10% solar/90% other) yields a solar penetration of 2.4% of total sales, well below the 4% RPS stipulation. The medium-solar case (25% solar/75% other) results in 5.9% of total sales, slightly higher than the 4% RPS specification. The high-solar case (50% solar/50% other) yields a net result of 11.8% of total sales being supplied by solar generation. As noted for Nevada above, the cases showing higher penetrations of solar than the RPS specifications are not in conflict with the RPS requirements, since those specifications represent minimum requirements rather than expected outcomes.

E.2.3.3 Comparisons with NREL Projections

As another source for comparison, NREL has developed projections for future distributed solar capacity development (i.e., rooftop PV). Table E.2-13 shows how those estimates compare with the range of estimates found in this six-state analysis. While the estimates in this report are for utility-scale applications, the table shows that these estimates fall within the range of NREL's "base-case" results and "technical potential" for distributed rooftop installations. The projection years do not match in these comparisons; they are presented here as a relative indicator for the order of magnitudes of estimates. As might be expected, all of the low-solar utility-scale results (10%-solar) developed in this analysis are higher than the NREL base-case distributed generation results. All of the high-solar utility-scale results (50%-solar) are lower than the technical resource potential as estimated by NREL.

TABLE E.2-13 Solar Capacity Estimates Relative to NREL Projections

Parameter	Arizona	California	Colorado	Nevada	New Mexico	Utah
RPS year	2025	2020	2020	2025	2020	2025
Solar capacity required at alternate renewable mix levels (MWe)						
50% Solar/50% other	3,232	20,561	2,925	2,268	1,110	1,625
25% Solar/75% other	1,616	10,280	1,462	1,134	555	813
10% Solar/90% other	646	4,112	585	454	222	325
NREL distributed capacity – base case (MWe) for 2015	408	3,202	146	203	110	2
NREL distributed capacity – technical potential (MWe) for 2015	19,671	80,798	13,184	9,911	4,549	6,407

Sources: Table E.2-10 for solar capacity at alternate renewable mix levels and Paidipati et al. (2008) for NREL distributed capacity projections.

E.2.3.4 Comparisons with EIA Projections

For additional perspective, Table E.2-14 presents the solar capacity estimates from Table E.2-10 along with regional projections from EIA. Because the EIA projections are not prepared at the state level, it is more difficult to draw any clear conclusions. Table E.2-14, however, provides some degree of benchmarking, at least for general order of magnitude comparisons.

For example, in California (which basically constitutes a separate EIA region), the estimated solar capacities from this analysis (4,112 to 20,561 MWe) are significantly higher than the EIA projections for solar (710 MWe). These differences are reconciled by recognizing that the EIA projection for total renewable capacity (including hydropower) in the California region (21,400 MWe) only represents half of the capacity required to satisfy the total RPS requirement (i.e., roughly 41,500 MWe operating at 30% capacity factor would be needed to generate 109,000 GWh), and that EIA projections for wind and solar combined capacities only account for one-fourth of the capacity needed to meet the RPS in California by 2020.

For states in the Rocky Mountain Power Area (RMPA) (Arizona, Colorado, Southern Nevada, and New Mexico), comparisons with regional projections are somewhat similar to observations for California. In general, the solar capacity estimates derived in this study are significantly higher than shown in the EIA projections. The total renewable capacity estimates

TABLE E.2-14 Solar Capacity Estimates Relative to EIA Projections

Parameter	Arizona	California	Colorado	Nevada	New Mexico	Utah
RPS year	2025	2020	2020	2025	2020	2025
Solar capacity required at alternate renewable mix levels (MWe)[a]						
50% Solar/50% other	3,232	20,561	2,925	2,268	1,110	1,625
25% Solar/75% other	1,616	10,281	1,462	1134	555	812
10% Solar/90% other	646	4,112	585	454	222	325
EIA regional renewable energy capacity projections (MWe)[b]	RMPA	CA	RMPA	RMPA	RMPA	NWPP
Solar	220	710	210	220	210	100
Wind	1,660	10,820	1,660	1,660	1,660	12,140
Hydroelectric	(5,470)[c]	(9,870)[c]	(5,470)[c]	5,470	(5,470)[c]	34,230
Total Solar, Wind, and Hydroelectric	7,350	21,400	7,340	7,350	7,340	46,470

[a] Solar capacity required at alternate renewable mix levels from Table E.2-10.

[b] CA = California; NWPP = Northwest Power Pool ; RMPA = Rocky Mountain Power Area.

[c] Hydroelectric sources must be new and small to contribute to RPS requirements in these states. Most of these capacities do not qualify.

Source: EIA (2009b; Tables 98–100) for regional renewable energy capacity projections.

for the four states sum to more than 19,000 MWe based on RPS requirements. This is more than double the EIA projection of 7,340 MWe for the corresponding RMPA region in 2020. And since three of the four states also require hydroelectric sources to be new and small, subtracting hydropower (5,470 MWe) from the EIA total projected renewables only leaves about 1,870 MWe for nonhydropower sources (i.e., only 10% of the total renewable requirements based on RPS specifications).

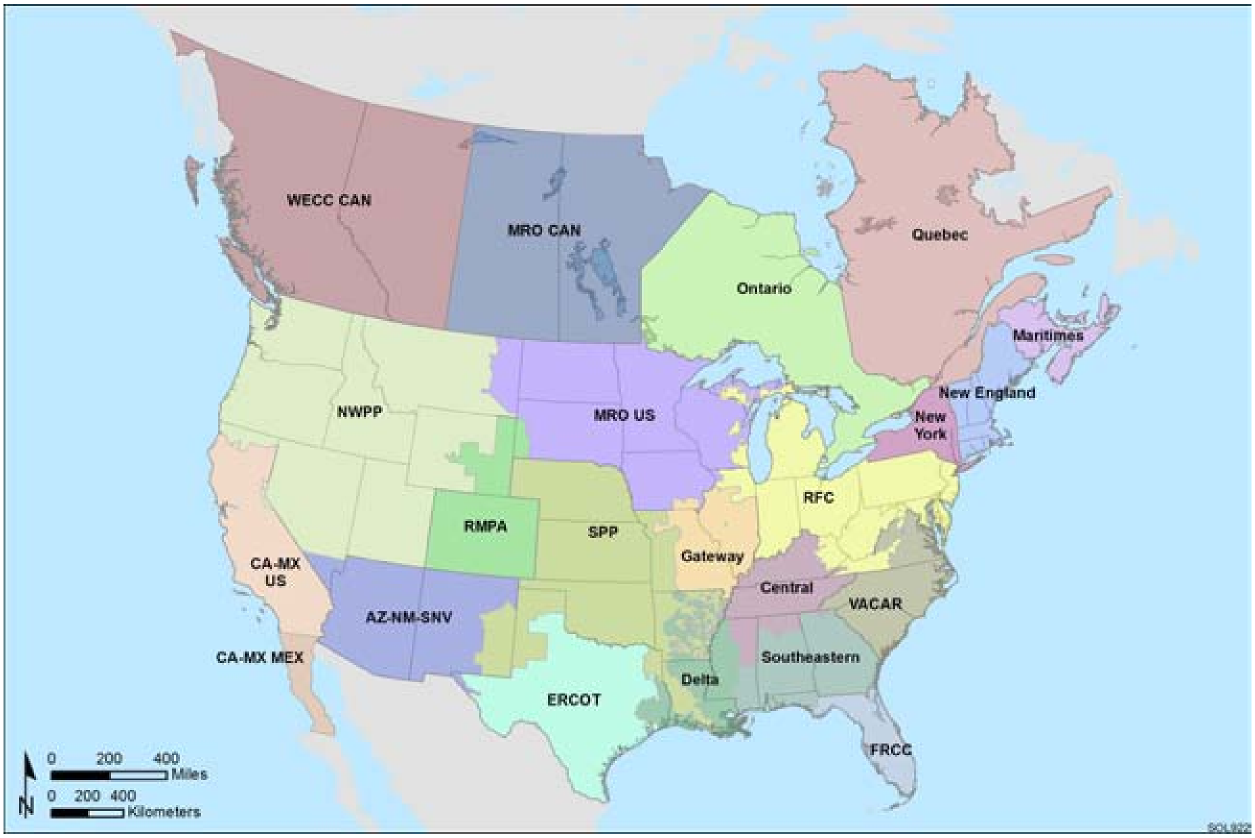
Comparisons for Utah are difficult to make because that state represents only a small portion of the regional totals for the Northwest Power Pool (NWPP). EIA does not publish long-term projections for states or regions smaller than the regions shown in Figure E.2-1.

Across each of the regions, if the EIA total renewable projections were scaled up to match the RPS requirements, the corresponding solar capacity projections would likely fall within the ranges developed for this analysis.

E.2.3.5 Comparisons with NERC Projections

As a final comparison, NERC makes annual assessments and projections of national electric power system adequacy and reliability. As part of its assessments, it has estimated renewable generating capacity expectations on a regional basis; Figure E.2-2 shows the NERC subregions. Table E.2-15 compares the NERC estimates for the regions that overlap the PEIS study area with the results of this RPS capacity analysis. These comparisons are not precise because of the state-level orientation for this analysis and mismatches between the reference years. Nonetheless, the comparisons lend additional perspective to the range of estimates developed in this analysis.

The NERC projections show a total of 16,164 MWe of solar generating capacity to be installed for the entire Western Electricity Coordinating Council (WECC) region (which encompasses all four subregions AZ-NM-SNV, CA-MX, NWPP, and Rocky Mountain Power Area [RMPA]) by the year 2018 (NERC 2009). Most of that capacity, 15,076 MWe, is projected for the CA-MX US subregion, and 1,075 MWe is anticipated for the Arizona-New Mexico-Southern Nevada subregion. These estimates fall well within the ranges prepared for this six-state analysis. For CA-MX US, the NERC estimates are mid-way between the 50% solar and 25% solar scenarios. For Arizona-New Mexico-Southern Nevada, the NERC estimate compares roughly to the combined 10% solar scenario outcomes for those three states in this six-state analysis. The two noteworthy differences are in the NERC estimates for: (1) the Northwest Power Pool (NWPP), and (2) the RMPA. The NWPP region shows zero solar capacity by 2018 in NERC projections. This contrasts with the estimates for Utah in this analysis, which range from a low of 325 MWe to a high of 1,625 MWe. And for RMPA, NERC projections only show 13 MWe by 2018 as contrasted with the low estimate in this analysis for Colorado of 585 MWe.



United States Subregions
AZ-NM-SNV = Arizona, New Mexico, Southern Nevada Subregion
CA-MX US = California-Mexico Subregion – U.S.
Central = Central Subregion
Delta = Delta Subregion
ERCOT = Electric Reliability Council of Texas
FRCC = Florida Reliability Coordinating Council
Gateway = Gateway Subregion
MRO US = Midwest Reliability Organization – U.S.
New England = New England Subregion
New York = New York Subregion
NWPP = Northwest Power Pool
RFC = Reliability First Corporation
RMPA = Rocky Mountain Power Area Subregion
Southeastern = Southeastern Subregion
SPP = Southwest Power Pool
VACAR = Virginia-Carolinas Subregion

Mexico and Canada Subregions
CA-MX MEX = California-Mexico Subregion – Mexico
Maritimes = Maritimes Subregion– Canada
MRO CAN = Midwest Reliability Organization – Canada
Ontario = Ontario Subregion – Canada
Quebec = Quebec Subregion – Canada
WECC CAN = Western Electricity Coordinating Council – Canada

FIGURE E.2-2 NERC Subregions (Sources: NERC 2009 and Platts 2010 [region boundaries])

TABLE E.2-15 Solar Capacity Estimates Relative to NERC Projections

Parameter	Arizona	California	Colorado	Nevada	New Mexico	Utah
RPS year	2025	2020	2020	2025	2020	2025
Solar capacity required at alternate renewable mix levels (MWe)[a]						
50% Solar/50% other	3,232	20,561	2,925	2,268	1,110	1,625
25% Solar/75% other	1,616	10,281	1,462	1,134	555	812
10% Solar/90% other	646	4,112	585	454	222	325
NERC regional solar capacity projections[b] (MWe)	AZ-NM-SNV (2018)	CA-MX US (2018)	RMPA (2018)	AZ-NM-SNV (2018)	AZ-NM-SNV (2018)	NWPP (2018)
Solar	1,075	15,076	13	1,075	1,075	0

[a] Solar capacity required at alternate renewable mix levels from Table E.2-10.

[b] AZ-NM-SNV = Arizona-New Mexico-Southern Nevada; CA-MX US = California-Mexico; NWPP = Northwest Power Pool; RMPA = Rocky Mountain Power Area (Colorado-Eastern Wyoming).

Source: NERC (2009).

E.2.4 Additional Considerations

E.2.4.1 Timelines in RPS Schedules

It is noteworthy that many of the states include additional detail in the compliance schedules. Some (like Arizona) include annual targets beginning upon implementation of the RPS and continuing through the RPS time horizon. Other states (such as California) do not include annual schedules, but do include interim targets for specific years (such as for 2010). These details may have subtle or unpredictable impacts on the ultimate sources of generation adopted to meet the RPS requirements. For utilities that postpone their actions until close to the deadlines, the choices may be limited to technologies with the shortest lead times or stocks of available equipment.

E.2.4.2 Hydroelectric Facility Qualification for Meeting RPS Standards

As noted in Sections E.2.1 and E.2.2, each state has adopted alternative criteria for what technologies can qualify for meeting RPS requirements. For hydroelectric sources, as discussed in Section E.2.1.2, the following gives a brief overview of state-by-state treatments:

- Arizona: Only allows "incremental generations from hydroelectric, …or hydroelectric output used to firm intermittent renewables." Facilities installed before January 1, 1997, are not eligible.

- California: Only “certain” hydro facilities are eligible. For most technologies, facilities must have been installed after September 26, 1996, or represent a small qualifying facility.

- Colorado: Hydroelectric contributions to RPS appear to be unrestricted.

- Nevada: Only “certain” hydroelectric sources qualify.

- New Mexico: Only hydroelectric sources brought on line after July 1, 2007, qualify.

- Utah: Hydroelectric contributions to RPS appear to be unrestricted.

E.3 REFERENCES

Note to Reader: This list of references identifies Web pages and associated URLs where reference data were obtained for the analyses presented in this PEIS. It is likely that at the time of publication of this PEIS, some of these Web pages may no longer be available or their URL addresses may have changed. The original information has been retained and is available through the Public Information Docket for this PEIS.

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ATTACHMENT 1:

ReEDS Model Documentation:
Base Case Data and Model Description

ReEDS Model Documentation: Base Case Data and Model Description

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1. Introduction

The Regional Energy Deployment Systems (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 renewable electric technologies. 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 system-wide costs of meeting electric loads, reserve requirements, and emission constraints by building and operating new generators and transmission in 23 two-year periods from 2008 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 42 year evaluation period.

[1]NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy

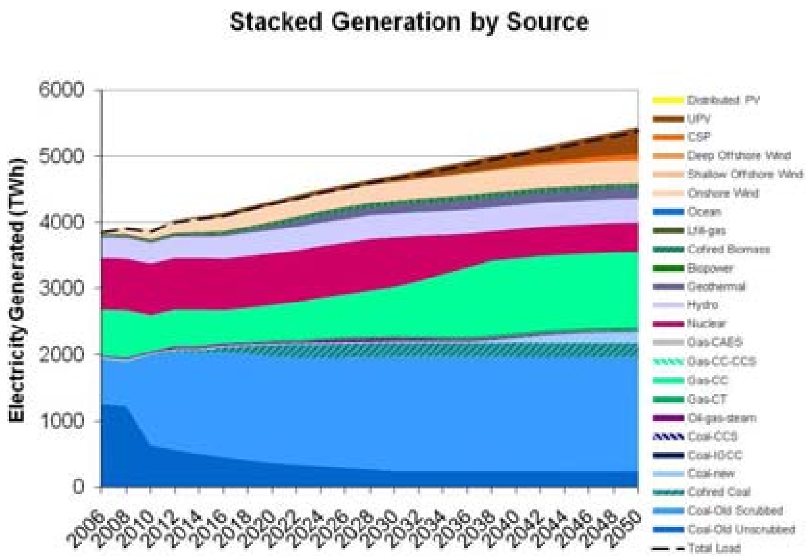

Figure 1. Capacity Buildout in ReEDS

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 17 annual 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—carbon taxes or 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.

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 solar 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 CO2.

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 the cost of wind energy technology is only getting cheaper while the fuel cost of conventional generation is generally assumed to continue to climb. 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. 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.

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 17 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 80 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 reach region, in each

1

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 generated 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 authority (there are 134 of them in ReEDS) must be met in each time-slice throughout a year. While the load in 2008 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. With this, we hope to more closely match the tail of the load-duration curve (Figure 4) by explicitly including hours when load minus wind cuts into baseload generation forcing curtailment of either wind or coal.

Reserve margin constraint: Operating reserve requirements ensure that there is enough responsive demand (interruptible load) and flexible generator capacity (spinning or quick-start capable) online that can be dispatched to meet unanticipated changes in loads and/or power availability. In ReEDS, these requirements must be satisfied in each region transmission operator (RTO) in each timeslice.

The resources that can contribute to these reserve requirements in ReEDS are:

- ***Spinning reserves:*** Conventional and storage technologies that are generating power can operate below maximum capacity and keep the remainder on reserve. The amount of capacity that may be counted toward the requirements depends on the amount that can be ramped up rather quickly (0-10 minutes).

- ***Quick-start reserves:*** These are technologies that can start up quickly (~10 minutes) from an off state, such as gas-combustion turbines.

- ***Interruptible load:*** Agreements between utilities and consumers that allow partial utility control of demand times.

- Operating reserve constraint: There are three types of operating reserve requirements in the model including:
  - ***Contingency reserve requirement:*** Large power plant failures, for example. Contingency reserve requirements vary by utility, and are approximated as 7% of average time-slice demand in ReEDS. At least half of this requirement must be met by spinning reserves and interruptible load.
  - ***Frequency regulation reserve requirement:*** Rapid fluctuations in demand. In ReEDS, this is approximated as 1.5% of average time-slice demand. Only spinning reserves can be used to meet this requirement.
  - ***VRRE forecasting error reserve requirement:*** fluctuations in wind and PV power output (CSP without storage is considered to have enough thermal inertia (~30 minutes) to not require additional operating reserves). This requirement explained in more detail below. Quick-start reserves can account for up to 5/6 of this requirement in ReEDS. The forecasting error reserve requirements for wind and PV were estimated at 2 standard deviations of the forecast errors. The forecasts for wind were simple hourly persistence forecasts, based on simulated wind power output data for each power class of each ReEDS region. In other words, the wind forecast errors were simply the differences between simulated power output from one hour to the next. Forecasts for PV were based on simulated PV power output for each region from the Solar Advisor Model (SAM). Forecasts for a given hour were estimated as the output from the previous hour plus the average change between those two hours over the previous fifteen days.

- 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, $CO2$ 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 thatthe 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 Resource 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. Variable resource renewable energy (VRRE) technologies, which include wind, CSP without storage, and distributed and central PV, produce power that is both variable and non-dispatchable. Greater penetrations of these technologies leads to greater levels of curtailment, required operating reserves, as well as potentially more requirements for capacity to fulfill reserve margin requirements. These requirements are explained more in-depth in the following sub-sections.

In ReEDS, the variability of each VRRE technology is derived from simulated hourly power output data. For the solar VRRE technologies, the Solar Advisor Model (SAM) was used to develop hourly power output profiles in each region and, in the case of CSP, for each class. These were used to characterize the standard deviation of power output from the mean output in each of the ReEDS time-slices.

Correlation statistics were also calculated between the power outputs of geographically separated wind, CSP, and PV plants. In general, greater geographic distance between two CSP, PV, or wind plants leads to a lower degree of correlation between power outputs, which decreases the variability of their combined generation. Because of this, all else being equal, ReEDS will choose to separate generators of a given type to reduce variability of the output.

The standard deviations and correlation statistics, along with the capacity factors for each technology in each time-slice, were used in calculations of curtailment, capacity value, and operating reserve requirements, described below.

Electric power demand requirements and VRRE curtailment

In ReEDS, demand requirements must be met in each power control authority (PCA) region in each time-slice. This demand is met through a combination of conventional power generators, renewable generators, storage, and power transmitted from other PCAs.

The expected capacity factors from VRRE technologies in each time-slice cannot be counted in full toward fulfilling demand in, however, since there are certain times that VRRE power exceeds that which can be used in the system. This is often due to higher-than-expected VRRE outputs, lower-than-expected electrical demand, transmission constraints, and minimum loading constraints that force other generators to stay online. At these times the generated power is in excess of the demand, and the excess power must be curtailed.

ReEDS estimates expected levels of curtailment induced by VRRE technologies (as a fraction of VRRE generation) for each time-slice in each Regional Transmission Operator (RTO) region through a statistical expected value calculation. This calculation depends on the probability distributions of electrical demand and VRRE output to that RTO, minimum loading requirements of other generators, and the amount of electrical storage, since storage may be used to shift power that would otherwise have been curtailed to times in which the power is needed.

Reserve margin requirements and VRRE capacity value

Reserve margin requirements ensure that adequate generating capacity is available during times of peak demand. In ReEDS, reserve margin requirements must be satisfied in each Regional Transmission Operator (RTO) for the peak demand of each time-slice. The specific reserve margin that must be satisfied depends on the region, and Table 1 shows these requirements by NERC region.

Table 1. Reserve margin requirements (above peak demand) by NERC region

nr1	ECAR	12%
nr2	ERCOT	15%
nr3	MAAC	15%
nr4	MAIN	12%
nr5	MAPP	12%
nr6	NY	18%
nr7	NE	15%
nr8	FL	15%
nr9	STV	13%
nr10	SPP	12%
nr11	NWP	8%
nr12	RA	14%
nr13	CNV	13%

Most generator-types count their full capacity toward the reserve margin requirement. This is also true for CSP systems with storage in ReEDS. This is not the case for VRRE technologies (wind, CSP without storage, and PV). These technologies can contribute no more than their capacity factor (as a fraction of capacity) toward the reserve margin, and most often contribute even less. The amount they contribute is called the "capacity value". To determine the capacity value given to VRRE technologies, a statistical "effective load carrying capability" (ELCC) calculation is performed in ReEDS. The ELCC is the amount of electrical demand that may be added (in MW) in each time-slice for an increase in capacity of a given VRRE technology, without increasing the probability of a loss of load event.

In a given RTO, for a given year, there will be only one time-slice for which the reserve margin requirement is "binding" in ReEDS. In other words, in this time-slice the requirement will be only just met, whereas in the other timeslices the requirement will be exceeded. As

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variable solar penetration increases, as in the Solar Vision scenarios, the binding time-slice often switches from H3 (summer, 1:00pm-5:00pm) to H4 (5:00pm-10:00pm), because the capacity value contribution of variable solar is very high during H3and very low luring H4.

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 2 provides a summary of the financial values used to produce the net capital and operating costs.

Table 2. Base Case Financial Assumptions

Name	Value	Notes and Sources
Inflation Rate	3%	Based on recent historical inflation rates.
Investment Discount Rate (real)	10.5%	Basecase assumption
rate of return on equity (real)	10.5%	Basecase assumption
interest rate (nominal)	8%	Basecase assumption
loan term (renewables and natural gas)	15 yrs	Basecase assumption
loan term (coal and nuclear)	20 yrs	Basecase assumption
maximum debt fraction	60%	Basecase assumption
Marginal Income Tax Rate	40%	Combined Federal/State Corporate Income Tax Rate.
Evaluation Period	20 years	Base Case Assumption.
Depreciation Schedule:		
Conventionals and Hydropower	15 year	MACRS
Non-Hydro Renewables	5 year	MACRS
Nominal Interest Rate During Construction	10%	Base Case Assumption.

2.2. Power System Characteristics

2.2.1. ReEDS Regions

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

- ***CSP/Wind resource regions:*** There are 356 CSP and wind resource regions. This is the level at which CSP and wind capacity expansion occurs.

- ***Power Control Authorities (PCAs):*** There are 134 PCAs. This is the regional level at which demand requirements are set and must be satisfied.

- ***Regional Transmission Operator (RTO) regions:*** There are 20 RTOs. This is the regional level at which reserve margin and operating reserve requirements must be met, and the level at which curtailment is calculated

- ***National Electric Reliability Council (NERC) regions:*** There are 13 NERC regions, defined in Table 3. This is the regional level at which most fuel costs are adjusted.

- ***Interconnect regions:*** There are three major interconnects in the United States: The Eastern Interconnect, Western Interconnect, and the ERCOT (Electric Reliability Council of Texas) Interconnect. Transmission capacity must pay an additional cost to cross interconnect boundaries.

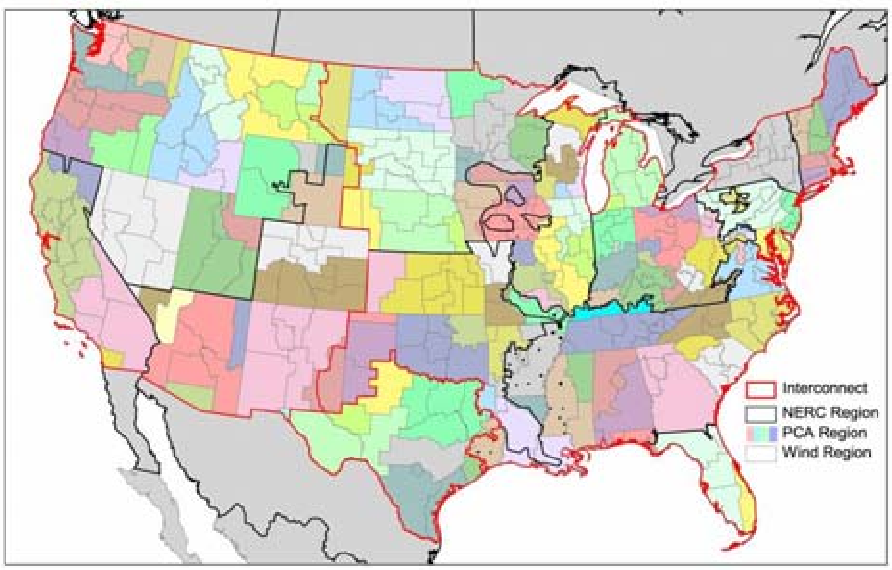

Figure 3. Regions used in ReEDS

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Table 3. 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.

Interconnects, NERC regions, RTOs, and balancing authorities are defined by various regulatory agencies (see Table 3 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.

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 4 defines these time-slices.

Table 4. ReEDS Demand Time-Slice Definitions

Slice Name	Hours Per Year	Season	Time Period
H1	736	Summer	10:00 p.m. to 6:00 a.m.
H2	644	Summer	6:00 a.m. to 1:00 p.m.
H3	328	Summer	1:00 p.m. to 5:00 p.m.
H4	460	Summer	5:00 p.m. to 10:00 p.m.
H5	488	Fall	10:00 p.m. to 6:00 a.m.
H6	427	Fall	6:00 a.m. to 1:00 p.m.
H7	244	Fall	1:00 p.m. to 5:00 p.m.
H8	305	Fall	5:00 p.m. to 10:00 p.m.
H9	960	Winter	10:00 p.m. to 6:00 a.m.
H10	840	Winter	6:00 a.m. to 1:00 p.m.
H11	480	Winter	1:00 p.m. to 5:00 p.m.
H12	600	Winter	5:00 p.m. to 10:00 p.m.
H13	736	Spring	10:00 p.m. to 6:00 a.m.
H14	644	Spring	6:00 a.m. to 1:00 p.m.
H15	368	Spring	1:00 p.m. to 5:00 p.m.
H16	460	Summer	5:00 p.m. to 10:00 p.m.
H17	40	Summer	40 highest demand summer hours

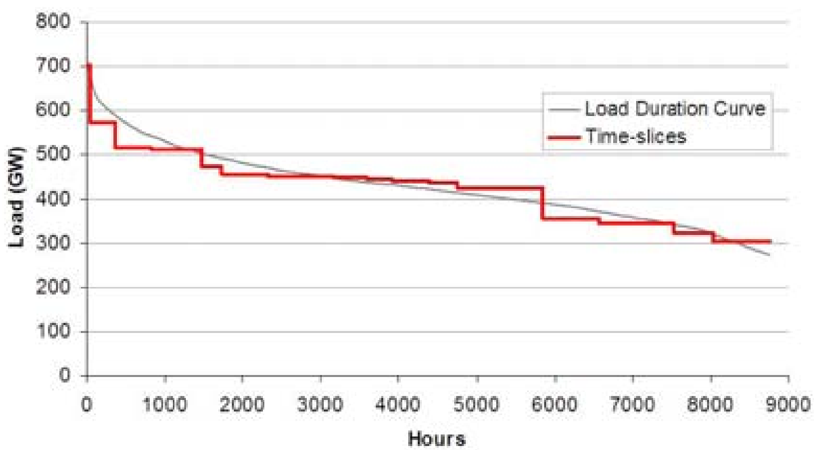


Figure 4. National Load Duration Curve in ReEDS

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 the entire United States for the base year, illustrating the 17 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 onelectricity price (see Appendix 6). Table 5 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.

The peak reserve margin for each RTO is provided in Table 4. The reserve margin fraction 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 5. Base Load and Load Growth in the ReEDS Base Case

NERC Region/Subregion		2006 Load (TWh/year) 1	Annual Load Growth (%) 2	Reserve Margin (%) 3
1	ECAR	553	0.7	12
2	ERCOT	323	1.0	15
3	MAAC	292	0.6	15
4	MAIN	274	0.6	12
5	MAPP	165	0.8	12
6	NY	159	0.3	18
7	NE	142	0.7	15
8	FL	228	1.1	15
9	SERC	920	1.0	13
10	SPP	202	0.6	12
11	NWP	278	0.8	08
12	RA	158	1.3	14
13	CNV	315	1.1	13

[1] (Platts 2006), [2] (EIA 2008), [3] (PA Consulting Group 2004)

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.

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.

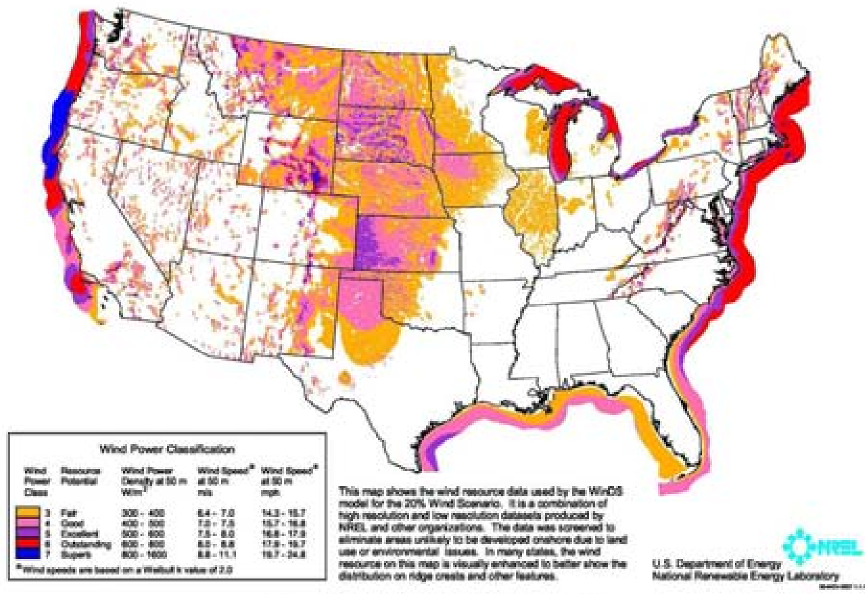


Figure 5. Wind Resource in ReEDS

2.3.3. Wind Technology Cost and Performance

ReEDS considers five power classes of wind, shown in Table 7, based on wind power density and wind speed.

Table 7. Classes of wind power density

Wind Class	Wind Power Density, W/m2	Speed, m/s
1	5-6.25	6.4-7.0
2	6.25-7.25	7.0-7.5
3	7.25-7.5	7.5-8.0
4	7.5-7.75	8.0-8.8
5	>7.75	>8.8

Notes: W/m^2 = watts per square meter; m/s = meters per second. Wind speed measured at 50 m above ground level.
Source: Elliott and Schwartz (1993)

Available land area of each wind class in each CSP/wind resource region is derived from state wind resource maps and modified for environmental and land-use exclusions. These maps are the most recent available from the Wind Powering America (WPA) initiative (EERE) and individual state programs. The maps depict estimates of the wind resource at 50 m above the ground. The available wind area is converted to available wind capacity using the constant multiplier of 5 MW/km^2.

Wind cost and performance parameters were developed by Black and Veatch in conjunction with the Renewable Electricity Futures (REF) study, and are shown in Table 8. Capacity factor adjustments by timeslice were made for each class of each region, derived from AWST text supplemental database files and the National Commission on Energy Policy/National Center for Atmospheric Research (NCEP/NCAR) global reanalysis mean values (Kalnay et al. 1996).

Table 8. Land-based wind technology cost and performance projections

		capital costs ($/kW)	fixed O&M ($/kW-yr)	variable O&M ($/MWh)	capacity factor (%)
onshore wind	2010	1980	59.4	0	0.32-0.46
	2030	1980	59.4	0	0.35-0.46
	2050	1980	59.4	0	0.35-0.46
(fixed bottom) offshore wind	2010	3310	99	0	0.36-0.50
	2030	2990	99	0	0.38-0.50
	2050	2990	99	0	0.38-0.50

In each CSP/wind resource region, a supply curve for cost of connecting the wind resource to the existing grid, as well as to local demand centers, was developed from GIS data of the resource, existing grid, and demand centers. In these supply curves, the availability of the existing grid was limited to 10%. Wind resource was also allowed to connect to the grid at a cost equivalent to construction of a transmission line from the center of the respective CSP/wind region to the demand center* of the larger Power Control Authority (PCA) region.

2.4. Solar Power

2.4.1 Solar PV

There are three PV technologies modeled in ReEDS, listed here.

- Central PV
- Distributed Wholesale PV
- Distributed PV

Each of these technologies is described in its own section.

2.4.1.1: Central PV

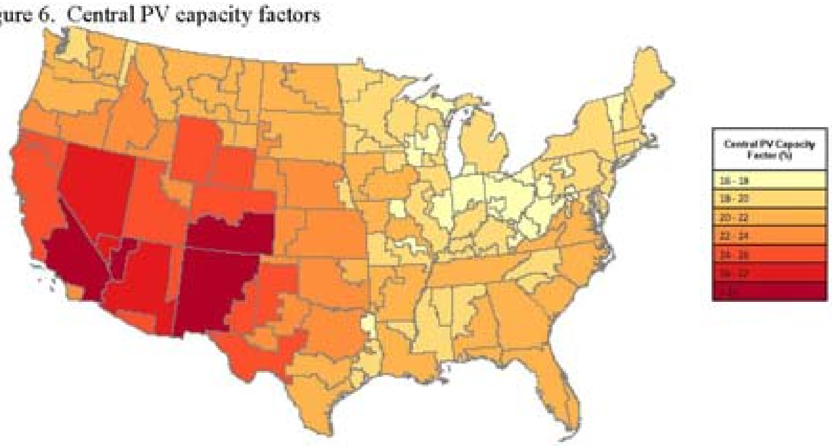
Costs for Central PV derived from the DOE Solar Program, shown in table 9. The costs represent 100 MW systems. Linear interpolations on the costs are used for the intermediate years.

Table 9. Central PV technology cost projections

		capital costs ($/kW)	fixed O&M ($/kW-yr)	variable O&M ($/MWh)	capacity factor (%)	heat rate (MMBtu/MWh)
utility-scale (1-axis) PV	2010	2940	36.6	0	0.16-0.28	n/a
	2030	2310	29.8	0	0.16-0.28	n/a
	2050	2030	24.3	0	0.16-0.28	n/a

Performance characteristics for Central PV were developed with the PV module of the Solar Advisor Model (SAM) using weather TMY files located at all TMY3 stations throughout the contiguous United States. The TMY site that had the highest predicted annual capacity factor in each ReEDS Power Control Authority (PCA) region was used to represent the performance of a Central PV plant in that PCA (i.e. capacity factors in each time-slice). A map of the resulting annual capacity factors for Central PV by PCA is shown in Figure 6.

Figure 6. Central PV capacity factors



2.4.1.2: Distributed Wholesale PV

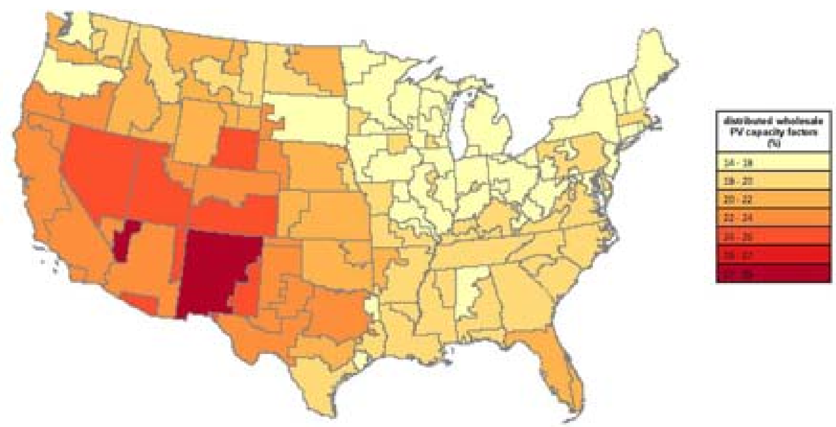
Distributed wholesale PV in ReEDS represents utility-scale systems (~50 MW) that are located within and directly connected to distribution networks. Capacity of these systems is limited to less than 15% of the distribution network capacity. Costs for distributed wholesale PV are an estimated 8.5% higher than Central PV costs (Black and Veatch), shown in table 10. Linear interpolations on the costs are used for the intermediate years. Partly offsetting this additional cost, interconnection fees for distributed wholesale PV are an estimated 100$/kW less than those for central PV.

Table 10. Distributed wholesale PV technology cost projections

		capital costs ($/kW)	fixed O&M ($/kW-yr)	variable O&M ($/MWh)	capacity factor (%)	heat rate (MMBtu/MWh)
commercial rooftop PV	2010	4790	34.7	0	0.10-0.18	n/a
	2030	2960	28.2	0	0.10-0.18	n/a
	2050	2620	23	0	0.10-0.18	n/a

Similar to central PV, performance characteristics for distributed wholesale PV were developed with the PV module of the Solar Advisor Model (SAM) using weather TMY files located at all TMY3 stations throughout the contiguous United States. The average power output across all TMY sites in each ReEDS Power Control Authority (PCA) region was used to represent the performance of a distributed wholesale PV plant in that PCA (i.e. capacity factors in each time-slice). A map of the resulting annual capacity factors for distributed wholesale PV by PCA is shown in Figure 7. Note that the distribution losses that apply to central technologies (estimated at 5.3%) as well as transmission losses do not apply to distributed wholesale PV.

Figure 7. Distributed Wholesale PV capacity factors



2.4.1.3: Distributed Rooftop PV

Capacity expansion of distributed rooftop PV is handled in SolarDS (a secondary model for residential PV market penetration) and is passed exogenously into ReEDS. Capacity factors of distributed rooftop PV in each ReEDS time-slice reflect the mix of orientations built in SolarDS within each ReEDS PCA. As with distributed wholesale PV, distribution losses (estimated at 5.3%) and transmission losses that apply to central technologies do not apply to distributed rooftop PV.

2.4.2: Concentrating Solar Power (CSP)

There are three CSP technologies modeled in ReEDS, listed here:

- Troughs with no storage
- Troughs with at least 5 hours storage
- Towers with at least 5 hours storage

The particulars of each technology are discussed more in-depth in individual sections.

2.4.2.1 CSP Resource

ReEDS considers five power classes of CSP, shown in table 11, based on direct normal insolation (DNI) (Perez). Available land area of each CSP class in each CSP/wind resource region was limited to area with less than 3% slope.

Table 11. CSP power classes

CSP Class	Insolation (kWh/m2/day)
1	5-6.25
2	6.25-7.25
3	7.25-7.5
4	7.5-7.75
5	>7.75

In each CSP/wind resource region, a supply curve for cost of connecting the CSP resource to the existing grid, as well as to local demand centers, was developed from GIS data of the resource, existing grid, and demand centers. In these supply curves, the availability of the existing grid was limited to 10%. CSP resource was also allowed to connect to the grid at a cost equivalent to construction of a transmission line from the center of the respective CSP/wind region to the demand center* of the larger Power Control Authority (PCA) region.

CSP performance for each CSP power class was developed using a single site's typical DNI year (TDY) hourly resource data from each CSP/wind resource region (selected by hand, as close as possible to the center of the resource of that class in the region). The TDY weather files were processed through the CSP modules of the Solar Advisor Model (SAM) for each type of CSP system considered in ReEDS. From this, capacity factors for each ReEDS class in each ReEDS time-slice were developed.

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/m2/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 8 maps the location of the solar resource that is used within ReEDS.

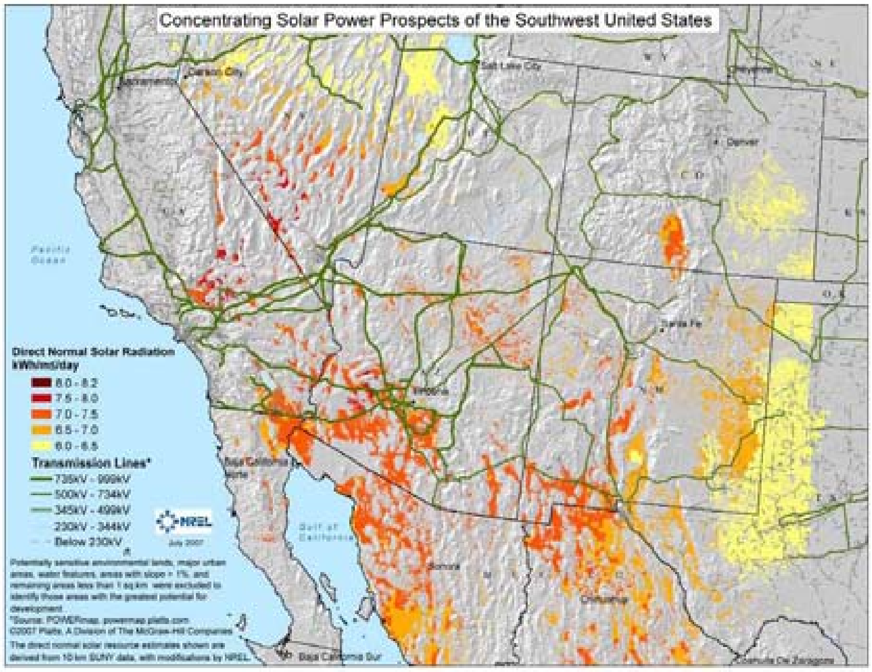


Figure 8. Solar Resource in ReEDS

2.4.2.2: CSP without storage

The CSP system without storage in ReEDS was represented as a trough with a solar multiple of 1.4. Cost projections were developed by the DOE solar program, and are shown in table 12. Linear interpolations on the costs are used for the intermediate years.

Table 12. CSP without storage technology cost projections

		capital costs ($/kW)	fixed O&M ($/kW-yr)	variable O&M ($/MWh)	capacity factor (%)	heat rate (MMBtu/MWh)
concentrated solar power (no storage)	2010	4910	49.5	0	0.19-0.29	n/a
	2030	4170	49.5	0	0.19-0.29	n/a
	2050	3430	49.5	0	0.19-0.29	n/a

Performance characteristics for CSP without storage were developed with the CSP module of the Solar Advisor Model (SAM), configured with a 100 MW turbine and solar multiple of 1.4, using the weather TDY files located at the hand-picked sites of each class in each CSP/wind region. The average power output across all sites of each class was used to represent the performance of a CSP plant with no storage of that particular class (i.e., capacity factors in each time-slice). The average annual capacity factors of each class are shown in table 13.

1

Table 13. CSP without storage average annual capacity factors for each class

CSP Class	Average CF
1	0.20
2	0.26
3	0.29
4	0.30
5	0.31

2.4.2.3: CSP with storage

There are two CSP-with-storage systems represented in ReEDS. Troughs with at least 5 hours of storage, and towers with at least 5 hours of storage. Only troughs are allowed to be built before 2020, and only towers are allowed to be built after 2020.

In ReEDS, each CSP-with-storage system is represented by three separate components: the field (collectors), storage, and turbine (power block). Systems are allowed to have variable solar multiples and variable amounts of storage, within boundaries discussed later. These systems are allowed to dispatch optimally, under the restriction that they abide by the appropriate energy balance between the components, i.e. that the energy in storage at the end of a time-slice is equal to the energy in storage at the beginning of the time-slice plus the energy input from the field (collectors) during the time-slice minus the energy output to the grid during the time-slice.

Capacity factors by time-slice of with-storage CSP systems in ReEDS are an output of the model, not an input, since ReEDS is allowed to dispatch CSP plants optimally. Instead, the profile of power input from the collectors (field portion) of the with-storage CSP plants are the inputs, and these profiles were developed with the CSP module of the Solar Advisor Model (SAM), using the weather TDY files located at the hand-picked sites of each class in each CSP/wind region. Profiles were averaged across all sites of a given class to represent performance of the field portion of the CSP-with-storage systems for each class. In ReEDS, input from the field is then scaled with the solar multiple of the CSP plant.

The CSP-with-storage system configurations must abide by a few restrictions. First, both systems must have at least 5 hours of storage and at least a 40% capacity factor. Under this restriction, these systems are given full capacity credit. These systems are also restricted to capacity factors of less than 70% and solar multiples of less than 3.4 for troughs and 2.7 for towers, as hourly and sub-hourly curtailment effects (which are not captured well by the broad ReEDS time-slices) become significant at these higher solar multiples. SAM was used to develop a linear relationship between required hours of storage and solar multiple, displayed here for troughs and towers:

Troughs: (Hours of storage) > 6.4*(Solar multiple) – 7.9
Towers: (Hours of storage) > 7.8*(Solar multiple) – 8

Average annual capacity factors for example CSP-with-storage systems are shown in table 14.

Table 14: Average annual capacity factors for CSP-with-storage example trough and tower systems.

CSP Class	Trough SM=2, 5 hrs	Tower SM =2.45, 11 hrs
1	0.29	0.45
2	0.37	0.59
3	0.42	0.64
4	0.44	0.67
5	0.46	0.70

Costs for CSP systems with storage are shown in Table 15 and are higher (as well as capacity factors) than CSP troughs with no storage.

Table 15 Costs for CSP systems with storage

		capital costs ($/kW)	fixed O&M ($/kW-yr)	variable O&M ($/MWh)	capacity factor (%)	heat rate (MMBtu/MWh)
concentrated solar power (6 hrs storage)	2010	7060	49.5	0	0.27-0.43	n/a
	2030	5310	49.5	0	0.35-0.54	n/a
	2050	4700	49.5	0	0.35-0.54	n/a

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 SO2 scrubber) — CoalOldUns
- Conventional pulverized coal steam plant (with SO2 scrubber) — CoalOldScr
- Conventional pulverized coal steam plant (with SO2 scrubber and biomass cofiring) — CofireOld
- Advanced supercritical coal steam plant (with SO2 and NO2 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).

[3] A full range of financing options are built into the model as detailed in Appendix 10.

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

ReEDS considers the outage rate when determining the net capacity available for generation described among the calculations in Section 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 SO2, NOx, Mercury (Hg), and CO2. 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.

Table 17. Outage rates, minimum plant loading requirements, and emissions rates of conventional technologies in ReEDS.

	Forced Outage	Planned Outage	Minimum Plant Loading	SO2	Emission Rates (lbs/MMBtu fuel NOx	Hg	CO2
Hydro	0.05	0.02	0.55	0	0	0	0
Gas-CT	0.03	0.05	0.00	0.0006	0.08	0	122
Gas-CC	0.04	0.06	0.00	0.0006	0.02	0	122
CoalOldScr	0.06	0.10	0.40	0.157	0.448	4.6E-06	204
CoalOldUns	0.06	0.10	0.40	1.57	0.448	4.6E-06	204
CoalNew	0.06	0.10	0.40	0.0785	0.02	4.6E-06	204
Coal-IGCC	0.08	0.12	0.50	0.0184	0.02	4.6E-06	204
OGS	0.10	0.12	0.40	0.026	0.1	0	122
Nuclear	0.04	0.06	1.00	0	0	0	0
Geothermal	0.13	0.02	0.90	0	0	0	0
Biomass	0.09	0.08	0.40	0.08	0	0	0
CofireOld	0.07	0.09	0.40	0.157	0.448	4.6E-06	204
CofireNew	0.07	0.09	0.40	0.0785	0.02	4.6E-06	204
lfill-gas	0.05	0.05	0.00	0	0	0	-157

Sources and Notes on Emissions:

1. SO2 emissions result from the oxidization of sulfur contained in the fuel. Natural gas emissions rates are from an EPA air pollution study (1996); SO2 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 SO2/MMBtu). ReEDS assumes the national average for "low sulfur" coal is 0.5 lbs SO2/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)
2. NO2 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. NO2 emissions can be reduced through a large variety of combustion controls, or post combustion controls. NO2 emissions are not restricted in the ReEDS Base Case (see Section 1 on federal emissions standards). The emissions rates in Table 17 are national averages. (EPA 2005b)
3. 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)
4. CO2 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); CO2 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 CO2 emissions. CO2 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 Table 18. 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 Sulfur dioxide scrubbers can be added to unscrubbed coal plants for $200/kW. Oil/gas steam, and unscrubbed coal plants cannot 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 2010, 2030, and 2050 are based on proposed engineering, procurement, and construction (EPC) estimates for plants that will be commissioned in 2010, 2030, and 2050. A wet scrubber is included in the EPC costs for new pulverized coal plants.

Table 18. Cost and Performance Characteristics for Conventional Generation

Technology	Cost Variable (2009$	2010	2030	2050
pulverized coal	investments ($/kW)	2890	2490	2490
	fixed O&M ($/kW-yr)	22.8	22.8	22.8
	variable O&M ($/MWh)	3.67	3.67	3.67
	heat rate (MBtu/MWh)	9.37	8.99	8.99
coal IGCC-CCS*	investments ($/kW)	n/a	6600	6600
	fixed O&M ($/kW-yr)	n/a	44	44
	variable O&M ($/MWh)	n/a	10.5	10.5
	heat rate (MBtu/MWh)	n/a	10.4	10.4
natural gas combined cycle	investments ($/kW)	1230	1230	1230
	fixed O&M ($/kW-yr)	6.25	6.25	6.25
	variable O&M ($/MWh)	3.63	3.63	3.63
	heat rate (MBtu/MWh)	6.04	6.04	6.04
natural gas CC-CCS*	investments ($/kW)	n/a	3750	3750
	fixed O&M ($/kW-yr)	n/a	18.2	18.2
	variable O&M ($/MWh)	n/a	9.9	9.9
	heat rate (MBtu/MWh)	n/a	9.07	9.07
natural gas combustion turbine	investments ($/kW)	645	645	645
	fixed O&M ($/kW-yr)	5.21	5.21	5.21
	variable O&M ($/MWh)	29.6	29.6	29.6
	heat rate (MBtu/MWh)	9.36	9.36	9.36
nuclear	investments ($/kW)	6100	6100	6100
	fixed O&M ($/kW-yr)	126	126	126
	heat rate (MBtu/MWh)	9.72	9.72	9.72
fuel**	coal ($/MBtu)	2.15	2.32	2.32
	natural gas ($/MBtu)	7.49	9.82	9.82
	uranium ($/MBtu)	0.8	0.85	0.85

* Carbon capture and sequestration technologies assumed to have a 90% capture rate

** Fuel prices indicated here are base fuel prices input to ReEDS, which has an endogenous fuel price elasticity for coal and natural gas

2.6. Storage Technologies

There are four storage technologies currently implemented in ReEDS: pumped hydro storage (PHS), compressed air energy storage (CAES), batteries and thermal storage in buildings. 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 19, below. Costs for each technology are for systems with eight hours of storage.

Table 19. Cost and Performance Characteristics for Storage Technologies

		capital costs ($/kW)	fixed O&M ($/kW-yr)	variable O&M ($/MWh)	round trip efficiency (%)	heat rate (MMBtu/MWh)
pumped hydropower storage	all years	2230	30.5	0	0.87	n/a
batteries	2010	4110	24.9	7.92	0.9	n/a
	2030	3590	24.9	7.92	0.9	n/a
	2050	3200	24.9	7.92	0.9	n/a
compressed air energy storage	all years	900-1200	11.5	1.53	1.25	4.42
thermal storage in buildings	2010	n/a	n/a	n/a	n/a	n/a
	2030	1900-2920	16.7	0	1	n/a
	2050	1590-2450	15.8	0	1	n/a

Source for PHS: red(source?), Batteries: (EPRI-DOE 2003), CAES: (Holst 2005)

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 hybrid technology that uses electrical-to-physical storage to power a highly efficient combustion turbine; the heat rate of a CAES plantis 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 9 shows where suitable geology exists). Batteries can be installed anywhere.

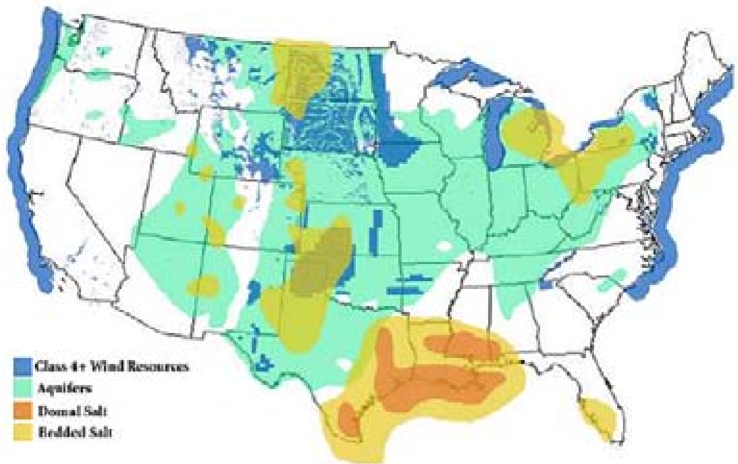


Figure 9. Areas with geology favorable to CAES, overlaid with class 4+ wind resource

Finally, the model has the ability to model thermal storage in buildings. Typically, this is ice storage used to shift the building peak load from peak summer periods (typically associated with high air-conditioning loads) to off-peak periods with cheaper electricity.

2.7. Transmission

Three types of transmission systems can be used to transport wind power around the country, existing grid, new lines, and in-region 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 or CSP 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 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.

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.

A fourth type of transmission, used predominantly by conventional capacity and called general transmission, can be built as well. 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.

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).

There are several transmission related assumptions in the model as indicated in the following table. Note that certain transmission issues are treated differently depending on the region that the line is in:

Table 20: Transmission Inputs

Variable	Cost (2009$)	Regions
line costs ($/MW-mile)	$1,480	WECC, TRE, SPP, FRCC
	$1,140	all other regions
regional line cost multipliers	3.56x	CA, NE, NY, east PJM
	1.58x	west PJM
substation costs ($/MW)	$10,700-$24,000	
intertie (AC-DC-AC) costs ($/MW)	$230,000	
grid interconnection costs ($/MW)	110000	
transmission losses	1% per 100 miles	

2.8. Federal and State Energy Policy

2.8.1. Federal Emission Standards

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 SO2 Emission Limit Schedule in ReEDS

	2003	2014	2019	2024	2034

SO2 Cap (MTons)	10.6	6.1	5.0	4.3	3.5

Source: http://www.epa.gov/cair/charts

NO2 emissions are currently unconstrained in ReEDS. The NO2 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 NO2 cap is complicated by the wide array of options available for NO2 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 SO2 and NO2 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	$21/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	30%	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	Full Imple-mentation	Assumed RPS (%)
Arizona	2001	2025	6.17
California	2003	2017	32.4
Colorado	2007	2015	19.4
Connecticut	2004	2010	1.3
Delaware	2007	2019	5.6
Illinois	2004	2013	6.2
Kansas	2006	2020	15.6
Massachusetts	2003	2009	19.5
Maryland	2006	2019	19.34
Minnesota	2002	2015	27.4
Montana	2008	2015	9.9
North Carolina	2008	2021	11.1
New Hampshire	2007	2025	23.3
New Jersey	2005	2021	24.9
New Mexico	2006	2020	15.2
Nevada	2003	2025	22.0
New York	2006	2015	20.9
Oregon	2002	2025	20.4
Pennsylvania	2007	2021	17.5
Rhode Island	2007	2019	15.8
Washington	2008	2020	12.7
Wisconsin	2001	2015	10.125

Notes:
1) RPS data as of Fall 2009. (IREC 2006)
2) RPS Start Year is the "beginning" of the RPS program. The RPS is ramped linearly to the full implementation year.
3) RPS Full Implementation is the year that the full RPS fraction must be met.

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3. References

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