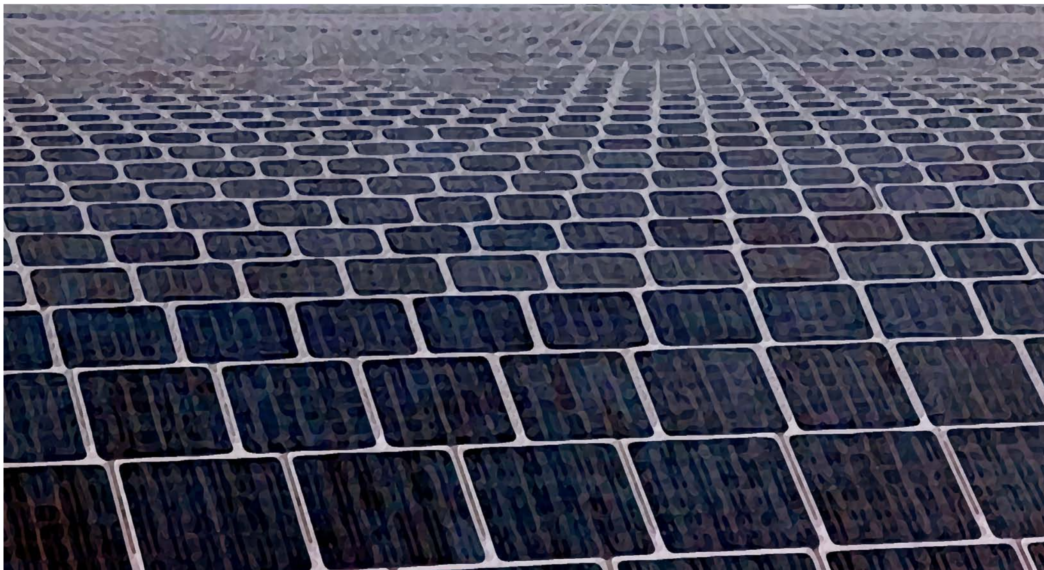
SunShot
U.S. Department of Energy

# SunShot Vision Study

February 2012



# Appendix A. Model Descriptions

## A.1 Modeling Overview

There were three primary models used in this study: the Regional Energy Deployment System (ReEDS) model (Short et al. 2011), the Solar Deployment System (SolarDS) model (Denholm et al. 2009), and the GridView model (ABB 2008). ReEDS uses regional cost and performance characteristics of the major electricity generation and storage technologies throughout the contiguous United States, regional resource limitations, and electricity demand and grid reliability requirements to select the cost-optimal regional deployment of technologies. Additionally, ReEDS optimizes transmission capacity expansion to accommodate the regional deployment of technologies. Through this economic optimization, ReEDS examines one possible set of impacts on the U.S. electric sector resulting from achieving the SunShot price targets. Major impacts include regional solar deployment levels, additional transmission capacity expansion requirements, additional firm and flexible resource requirements, emissions reductions, and electricity price and overall system cost impacts.

Because ReEDS is not designed to account for distributed rooftop photovoltaic (PV) generation, the penetration of distributed (residential and commercial) PV capacity is exogenously input into ReEDS from the SolarDS model. SolarDS is a market penetration model for commercial and residential rooftop PV, which takes as input regional electricity prices, financial incentives, regional solar resource quality, and rooftop availability.

Finally, the GridView model is used to determine the feasibility of operation of the systems projected by the ReEDS model by performing hourly simulations of the ReEDS system, subject to more rigorous treatment of power-flow transmission constraints than can be captured by ReEDS.

## A.2 Regional Energy Deployment System

ReEDS is a generation and transmission capacity expansion model of the electricity system of the contiguous United States. ReEDS is unique among capacity expansion models for its highly discretized regional structure and detailed statistical treatment of the impact of variability of wind and solar resources on capacity planning, operating reserve requirements, and curtailment levels.

More specifically, ReEDS is a linear program that minimizes overall electric system cost subject to a large number of constraints. The major constraints include meeting electricity demand and reserve requirements within specific regions, regional resource supply limitations, state and federal policy demands, technology growth constraints, and transmission constraints. In satisfying these constraints in a least cost manner, the ReEDS optimization routine chooses from a broad portfolio of conventional generation, renewable generation, and storage technologies, as well as demand-side management, and the routine simultaneously optimizes technology capacity expansion, generator dispatch, and transmission capacity expansion. In the optimization, ReEDS considers the present value cost of its investment and operation decisions over an assumed financial lifetime (20 years for the present study). This cost minimization routine is applied for each 2-year period through 2050.

ReEDS represents the contiguous United States using 356 concentrating solar power (CSP)/wind resource regions and 134 power control areas (PCAs). This level of geographic detail enables the model to account for geospatial differences in resource quality, transmission needs, electrical (grid-related) boundaries, and political boundaries. ReEDS dispatches generation within 17 different time slices, including four time slices for each season representing morning, afternoon, evening, and nighttime, with an additional summer-peak time slice. This level of temporal detail—though not as sophisticated as an hourly chronological dispatch model—enables ReEDS to consider seasonal and diurnal changes in demand and resource availability. Moreover, because there are still significant demand and resource variations that can occur within each of these time slices, ReEDS utilizes statistical calculations derived from hourly data to estimate the capacity value, operating reserve requirements, and curtailment of variable wind and solar resources; these calculations also consider the correlations of hourly output profiles between resources in different locations. These measures are used to help ensure that the results that ReEDS provides are as geographically and temporally detailed as computational constraints allow, while also being consistent with an electricity system that is able to maintain an overall balance between supply and demand.



Major outputs of ReEDS are the regional deployment and dispatch of generator technologies, regional transmission capacity expansion, and power transfers between regions in the 17 different time slices. ReEDS also calculates the impacts of each scenario, including the total electric-sector cost, electricity price, fuel use and price, and direct combustion carbon dioxide ($CO_2$) emissions.

Additional detail for ReEDS can be found in the ReEDS model documentation (Short et al. 2011). Note that certain assumptions cited in the model documentation are different than those used in the SunShot study.

### A.2.1 ReEDS Calculations

The cost-minimization routine in ReEDS is performed from 2006 to 2050 in 2-year steps (i.e., every 2 years). The equations below provide a simple representation of the ReEDS model for a single year's cost-minimization solve. ReEDS minimizes the total system cost ("*Total_Cost*") of meeting all of the constraints of the system by choosing the cost-optimal values of each of the variables (shown in all caps), including new generation capacity, time-slice-dependent electricity generation, and transmission capacity. After each modeled year's solve, ReEDS updates values—such as existing capacity of each technology ("*old_cap*") and costs and performances of new technologies—and continues on to the next year's solve. In the following equations, "*old"* refers to technologies or transmission that are already in existence at the time of the current solve year, and "*new*" refers to potential new technology or transmission builds. Below the listing of equations are definitions of the sets (subscripts), parameters (constants), and variables shown in the equations.

Additional features in ReEDS not shown here include minimum loading requirements and planned and forced outages for dispatchable technologies, curtailment from renewable and must-run technologies, different types of operating reserves, renewable supply curves and resource constraints, and contracts of variable renewable power. In addition, this representation does not show the often non-linear calculations that occur between the model year solves. These and other features of ReEDS are discussed elsewhere in this appendix and in the ReEDS documentation (Short et al. 2011).

### A.2.1.1 Objective Function [*Total_Cost* ($)]

The objective of each ReEDS solve is to minimize total cost of the system while abiding by all constraints. The total cost consists of fixed costs for new technologies, variable costs for all technologies, and transmission costs for new transmission builds. These costs represent the 20-year present value of a stream of costs. The following is the objective function:

$$
\begin{aligned}
Total\_Cost \;=\; \min\Bigg[ & \sum_{tech,reg} [NEW\_CAP_{tech,reg} \times new\_fix\_cost_{tech,reg}] \\
& + \sum_{tech,reg,ts} [NEW\_ELEC\_GEN_{tech,reg,ts} \times (new\_var\_om_{tech} \\
& + fuel_{tech,reg}) \times hrs_{ts} + \; OLD\_ELEC\_GEN_{tech,reg,ts} \\
& \times (old\_var\_om_{tech} + fuel_{tech,reg}) \times hrs_{ts}] \\
& + \sum_{reg,reg'} [NEW\_TRANS\_CAP_{reg,reg'} \times new\_trans\_cost_{reg,reg'}] \Bigg]
\end{aligned}
$$

### A.2.1.2 Constraints

ReEDS minimizes overall electric system cost subject to a large number of constraints. Equations for major constraints are shown below.

***Electricity_Demand**$_{reg,ts}$* (MW): In each region in each time slice, electricity generation from all technologies plus electricity imports minus electricity exports must be greater than demand for electricity. ReEDS reduces the contribution of electricity from each technology by the amount of curtailments that that technology induces in the system, although this has been left out of the equations below for simplicity. Curtailments are discussed in Section A.2.7.1.

$$
\begin{aligned}
& \boldsymbol{Electricity\_Demand_{reg,ts}}: \sum_{dtech} [NEW\_ELEC\_GEN_{dtech,reg,ts} + OLD\_ELEC\_GEN_{dtech,reg,ts}] \\
& + \sum_{ndtech} [NEW\_CAP_{ndtech,reg} \times new\_cf_{ndtech,reg,ts} + \; old\_cap_{ndtech,reg} \\
& \times old\_cf_{ndtech,reg,ts}] \; + \sum_{reg'} [ELEC\_TRANS_{reg',reg,ts}] \;\; > elec\_demand_{reg,ts}
\end{aligned}
$$

***Planning_Reserves**$_{reg,ts}$* (MW): In each region in each time slice, firm capacity provided by all technologies plus firm capacity imports minus firm capacity exports must be greater than the planning reserve margin times peak demand. Dispatchable technologies contribute full nameplate capacity toward firm capacity, whereas non-dispatchable technologies contribute only a fraction of nameplate capacity (i.e., capacity value).

$$\begin{aligned}\boldsymbol{Planning\_Reserves_{reg,ts}}\colon & \sum_{dtech}[NEW\_CAP_{dtech,reg} + old\_cap_{dtech,reg}] \\ & + \sum_{ndtech}[NEW\_CAP_{ndtech,reg} \times new\_cv_{ndtech,reg,ts} \\ & + old\_cap_{ndtech,reg} \times old\_cv_{ndtech,reg,ts}] \\ & + \sum_{reg'}[CAP\_TRANS_{reg',reg}] \\ & > peak\_demand_{reg,ts} \times plan\_res\_marg_{reg}\end{aligned}$$

***Operating_Reserves**$_{reg,ts}$* (MW): In each region in each time slice, the operating reserves provided by all technologies must exceed the operating reserve requirements. In ReEDS, there are multiple types of operating reserve requirements, as well as different types of operating reserves (e.g., quick-start or spinning), with each requirement having specific requirements for the type of operating reserves that can be used. Operating reserves are discussed in Section A.2.7.3.

$$\begin{aligned}\boldsymbol{Operating\_Reserves_{reg,ts}}\colon & \sum_{dtech}[NEW\_RES\_CAP_{dtech,reg,ts} \\ & + OLD\_RES\_CAP_{dtech,reg,ts}] > oper\_res\_req_{reg,ts}\end{aligned}$$

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***Capacity_Use_Old**$_{dtech,reg,ts}$* (MW): Existing dispatchable electricity generators in each region and time slice must divide their electricity generation capacity into either providing electricity generation or providing operating reserves. In ReEDS, there are additional restrictions on the ability of dispatchable generators to provide operating reserves, depending on the level of flexibility of those generators.

$$\begin{aligned}\boldsymbol{Capacity\_Use\_Old_{dtech,reg,ts}}\colon & old\_cap_{dtech,reg} > OLD\_ELEC\_GEN_{dtech,reg,ts} \\ & + OLD\_RES\_CAP_{dtech,reg,ts}\end{aligned}$$

***Capacity_Use_New**$_{dtech,reg,ts}$* (MW): New dispatchable electricity generators in each region and time slice must divide their electricity generation capacity into either providing electricity generation or providing operating reserves. In ReEDS, there are additional restrictions on the ability of dispatchable generators to provide operating reserves, depending on the level of flexibility of those generators.

$$\begin{aligned}\boldsymbol{Capacity\_Use\_New_{dtech,reg,ts}}\colon & NEW\_CAP_{dtech,reg} \\ & > NEW\_ELEC\_GEN_{dtech,reg,ts} + NEW\_RES\_CAP_{dtech,reg,ts}\end{aligned}$$

***Transmission_Capacity_1**$_{reg,reg',ts}$* (MW): Installed existing and new transmission capacity must exceed the power that is transferred between regions in each time slice.

$$\boldsymbol{Transmission\_Capacity\_1_{reg,reg',ts}}: NEW\_TRANS\_CAP_{reg,reg'} + old\_trans\_cap_{reg,reg'} > ELEC\_TRANS_{reg,reg',ts}$$

***Transmission_Capacity_2***$_{reg,reg'}$ (MW): Installed existing and new transmission capacity must exceed the capacity that is contracted between regions. These capacity contracts are annual, so they do not depend on time slice.

$$\boldsymbol{Transmission\_Capacity\_2_{reg,reg'}}: NEW\_TRANS\_CAP_{reg,reg'} + old\_trans\_cap_{reg,reg'} > CAP\_TRANS_{reg,reg'}$$

### A.2.1.3 Sets (subscripts)

The following are descriptions of the sets in the ReEDS equations, which appear as subscripts in the equations.

***reg, reg'***: Regions. ReEDS has various levels of regional disaggregation, discussed in Section A.2.2.

***ts***: Time slices. ReEDS has 17 time slices in each year, discussed in Section A.2.3.

***tech***: The set of all electricity generation technologies including storage. For ReEDS, these are discussed in Section A.2.4.

***dtech***: Dispatchable technologies such as coal, nuclear, natural gas, and storage.

***ndtech***: Non-dispatchable technologies such as wind and PV.

### A.2.1.4 Parameters (constants)

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The following are descriptions of the parameters or constants that appear in the ReEDS equations.

***old_cap***$_{tech,reg}$ (MW): Electricity generation capacity of each technology in each region that is already in existence at the start of the solve year.

***old_cf***$_{ndtech,reg,ts}$ (dimensionless): Average capacity factor for each existing non-dispatchable technology in each time slice in each region.

***new_cf***$_{ndtech,reg,ts}$ (dimensionless): Average capacity factor for new potential capacity of each non-dispatchable technology in each time slice in each region.

***elec_demand***$_{reg,ts}$ (MW): Average electricity demand in each time slice in each region.

***old_cv***$_{ndtech,reg,ts}$ (dimensionless): Average capacity value of existing capacity for each non-dispatchable technology in each time slice in each region. Capacity values of non-dispatchable technologies are limited by time-slice-dependent capacity factors and variability.

$\boldsymbol{new\_cv}_{ndtech,reg,ts}$ (dimensionless): Average capacity value of new potential capacity for each non-dispatchable technology in each time slice in each region. Capacity values of non-dispatchable technologies are limited by time-slice-dependent capacity factors and variability.

$\boldsymbol{peak\_demand}_{reg,ts}$ (MW): Peak simultaneous electricity demand in each time slice in each region.

$\boldsymbol{plan\_res\_marg}_{reg}$ (dimensionless): Planning reserve margin in each region.

$\boldsymbol{oper\_res\_req}_{reg,ts}$ (MW): Operating reserve margin requirement in each region in each time slice. In ReEDS, there are multiple types of operating reserve requirements that must be satisfied, discussed in Section A.2.7.3.

$\boldsymbol{old\_trans\_cap}_{reg,reg'}$ (MW): Existing transmission capacity connecting each region to neighboring regions.

$\boldsymbol{new\_fix\_cost}_{tech,reg}$ ($/MW): Fixed costs associated with potential new electricity generation capacity of each technology in each time slice. This includes capital costs as well as fixed operation and maintenance (O&M) costs.

$\boldsymbol{old\_var\_om}_{tech}$ ($/MWh): Variable costs associated with electricity generation from existing capacity. This includes variable O&M costs.

$\boldsymbol{new\_var\_om}_{tech}$ ($/MWh): Variable costs associated with electricity generation from new potential capacity. This includes variable O&M costs.

$\boldsymbol{fuel}_{tech,reg}$ ($/MWh): Cost of fuel associated with electricity generation from a specific technology in a given region. Fuel costs depend on technology-specific heat rates and regional fuel prices.

$\boldsymbol{hrs}_{ts}$ (hrs): The hours contained in each time slice.

$\boldsymbol{new\_trans\_cost}_{reg,reg'}$ ($/MW): Cost of new transmission connecting each region to its neighboring regions. This depends on regional differences in cost of transmission and differences in the distances between center-points of the regions.

#### A.2.1.5 Variables

The following are descriptions of the variables that appear in the ReEDS equations.

$\boldsymbol{NEW\_ELEC\_GEN}_{tech,reg,ts}$ (MW): Average electricity generation from new technologies in each region in each time slice.

$\boldsymbol{OLD\_ELEC\_GEN}_{tech,reg,ts}$ (MW): Average electricity generation from existing technologies in each region in each time slice.

$\boldsymbol{NEW\_CAP}_{tech,reg}$ (MW): New electricity generation capacity of each technology in each region.

***ELEC_TRANS***$_{reg,reg',ts}$ (MW): Average net electricity transmitted from each region, *reg*, to each neighboring region, *reg'*, in each time slice. A negative value of this would indicate that electricity is being transmitted on average from *reg'* to *reg*.

***CAP_TRANS***$_{reg,reg'}$ (MW): Firm capacity contracts from *reg* to *reg'*.

***NEW_RES_CAP***$_{dtech,reg,ts}$ (MW): Electricity generation capacity from new dispatchable technologies that has been committed to providing operating reserves in each region in each time slice.

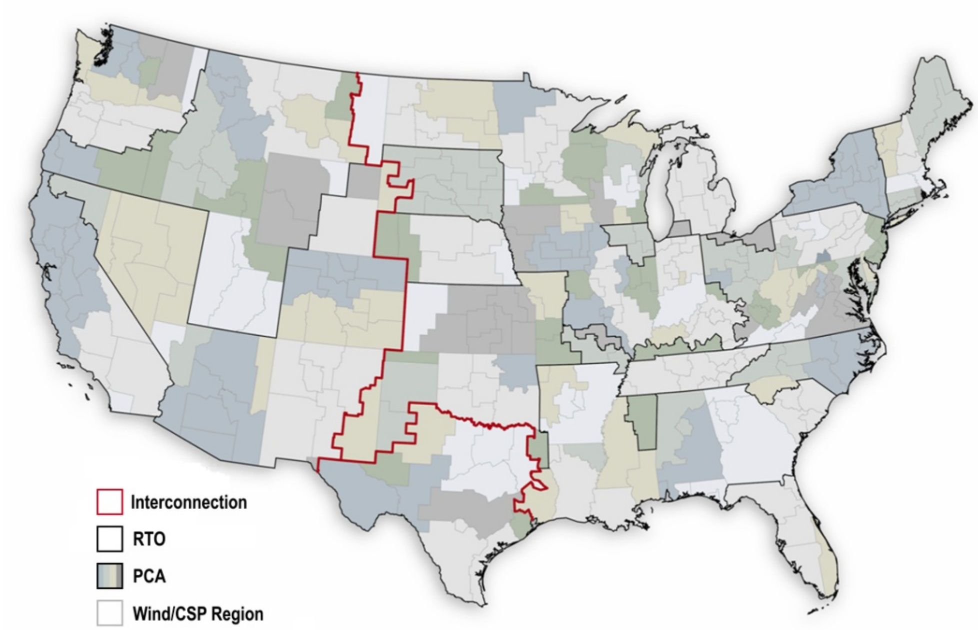
***OLD_RES_CAP***$_{dtech,reg,ts}$ (MW): Electricity generation capacity from existing dispatchable technologies that has been committed to providing operating reserves in each region in each time slice.

***NEW_TRANS_CAP***$_{reg,reg'}$ (MW): New transmission capacity built between each region, *reg*, and each neighboring region, *reg'*.

### A.2.2 ReEDS Regions

The geographical scope of the ReEDS model covers the contiguous United States. There are five types of regions included in ReEDS, listed below. Each type of region has various functions, and major examples of these functions are given in the list. A map of selected region types is shown in Figure A-1.

**Figure A-1. ReEDS CSP/Wind Regions, PCA Regions, Regional Transmission Organization (RTO) Regions, and Interconnection Regions**




- *CSP/wind resource regions*. There are 356 CSP/wind resource regions. This is the level at which CSP and wind capacity expansion occur, CSP and wind resource availability and quality are evaluated, and wind and CSP resources have access to local demand centers and transmission lines. CSP/wind resource regions are bounded by gray lines in Figure A-1.

- *PCAs.* There are 134 PCAs. This is the regional level at which electric power demand and reserve margin requirements must be satisfied, and at which all non-wind/CSP technology capacity expansion occurs, including PV expansion. Furthermore, the national transmission grid is represented in ReEDS as connections between the PCAs. PCA boundaries reflect electrical (grid-related) boundaries, political and jurisdictional boundaries, and demographic distributions.[79] The PCAs are shown in Figure A-1 as color shaded groups of CSP/wind resource regions.
- *Regional Transmission Organization (RTO) regions.* There are 21 RTOs. This is the regional level at which operating reserve requirements must be met, and the level at which capacity value and curtailment of variable renewable power is calculated. Figure A-1 shows the different RTOs assumed for the present study. Some of the model RTOs include existing RTOs[80] and others (particularly those in the western states) are assumed for modeling purposes based on current transmission plans.
- *North American Electric Reliability Corporation (NERC) regions*. There are 13 NERC regions/subregions (not shown in figure). Generally, inputs to the model from the U.S. Energy Information Administration (EIA) and the National Energy Modeling System (NEMS) model are provided at the NERC subregional level. These inputs include fuel prices and demand profiles over time.
- *Interconnection regions.* There are three asynchronous interconnections in the United States: the Eastern Interconnection, Western Interconnection, and Electric Reliability Council of Texas (ERCOT) Interconnection. Due to the asynchronicity of the three interconnections, new transmission lines across interconnection boundaries require installations of new alternating current (AC)-direct current (DC)-AC intertie capacity (and their associated costs). Interconnection boundaries are shown in Figure A-1 by the solid red lines.

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### A.2.3 ReEDS Time Slices

ReEDS represents seasonal and diurnal variations in demand and non-dispatchable generator output profiles via 17 time slices, shown in Table A-1. There are four time slices in each of the four different seasons,[81] as well as a “peak” time slice in the summer. In ReEDS, dispatch of dispatchable generators is optimized to satisfy demand and operating reserve requirements in each of these time slices. Variability of electrical generation and demand is characterized within each time slice as well to calculate capacity value, curtailment levels, and additional operating reserve

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[79] Although existing boundaries for Balancing Authority Areas (BA Areas) are considered in the design of the power control areas (PCAs), the PCA boundaries are generally not aligned with the boundaries of real BA Areas.
[80] Examples of existing Regional Transmission Organizations (RTOs) include Midwest Independent Transmission System Operator (MISO), Independent System Operator New England (ISO-NE), PJM Interconnection LLC (PJM), Southwest Power Pool (SPP), and California Independent System Operator Corporation (CAISO).
[81] The seasons are defined based on the following definitions: Summer = June, July, and August; Fall = September and October; Winter = November, December, January, and February; Spring = March, April, and May.

**Table A-1. ReEDS Time Slice Definitions**

| Slice Name | Number of 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 | Spring | 5:00 p.m. to 10:00 p.m. |
| H17 | 40 | Summer Peak | 40 highest demand hours of summer 1:00 p.m. to 5:00 p.m. |

requirements from variable energy resource (VER) technologies. For more detail, see Section 0.

## A.2.4 ReEDS Technologies

This section describes each ReEDS technology considered in this study, and provides tables of major cost and performance characteristics.

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### A.2.4.1 Photovoltaics

There are three PV technologies modeled in ReEDS:

- Central PV
- Distributed utility-scale PV
- Distributed rooftop PV.

All PV technologies are sited at the PCA regional level in ReEDS. Central PV and distributed utility-scale PV are both handled endogenously in ReEDS, whereas distributed rooftop PV capacity projections are developed by the SolarDS model and are passed exogenously into ReEDS at the PCA level. Capacity factors of distributed rooftop PV in each ReEDS time slice reflect the mix of orientations built in SolarDS within each ReEDS PCA by 2050. See Section A.3 for more information on the SolarDS model.

Central PV and distributed utility-scale PV are described separately in the following sub-sections.

### *A.2.4.1.1 Central PV*

Central PV in ReEDS represents utility-scale 1-axis-tracking systems with a representative size of 100 megawatts (MW). Costs for central PV in the SunShot and reference scenarios are shown in Table A-2. Costs for the SunShot scenario are discussed in greater detail in Chapter 4 of this report, while costs for the reference scenario were developed by Black & Veatch (forthcoming). In addition, central PV is assumed, upon installation, to have a grid connection cost of $120/kilowatt (kW).

**Table A-2. Central PV Technology Cost Projections (2010$)**

| Install Year | SunShot Central PV Costs | | | Reference Central PV Costs | | |
|---|---|---|---|---|---|---|
| | Capital | Fixed O&M | Variable O&M | Capital | Fixed O&M | Variable O&M |
| | $/kW [a] | $/kW/yr | $/MWh | $/kW | $/kW/yr | $/MWh |
| 2010 | 4,000 | 20 | 0 | 4,000 | 51 | 0 |
| 2015 | 2,200 | 15 | 0 | 2,700 | 49 | 0 |
| 2020 | 1,000 | 7 | 0 | 2,500 | 46 | 0 |
| 2025 | 1,000 | 7 | 0 | 2,400 | 44 | 0 |
| 2030 | 1,000 | 7 | 0 | 2,400 | 42 | 0 |
| 2035 | 1,000 | 7 | 0 | 2,300 | 40 | 0 |
| 2040 | 1,000 | 7 | 0 | 2,200 | 38 | 0 |
| 2045 | 1,000 | 7 | 0 | 2,100 | 36 | 0 |
| 2050 | 1,000 | 7 | 0 | 2,100 | 34 | 0 |

O&M: operation and maintenance; kW: kilowatt; yr: year; Mwh: megawatt-hour

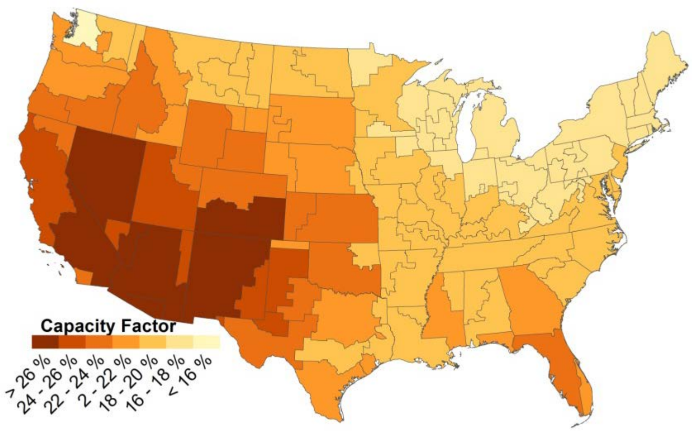
[a] The 2010 capital costs for utility-scale (central) PV were originally entered in 2009 dollars. In the final run on which this report is based, the 2010 capital costs for utility-scale PV were adjusted to 2010 dollars, i.e., $4,100/kilowatt (kW). A subsequent model run using the values included in this table indicated that this adjustment did not change the results substantially, i.e., less than 1%.



Performance characteristics for central PV were developed with the System Advisor Model (SAM) (NREL 2010a) using annual hourly weather files from the National Solar Radiation Database (NSRDB) for 939 sites throughout the contiguous United States from 1998 to 2005 (NREL 2007). For each site, generation profiles were averaged across the 8-year time period. The site with the highest average annual PV capacity factor[82] in each PCA was used to represent the performance (i.e., capacity factor in each time slice) of central PV capacity installed in that area. A map of the resulting annual capacity factors for central PV by PCA is shown in Figure A-2.

[82] Capacity factors are defined as the ratio of electrical energy generated by a unit over a given period of time divided by the maximum amount of electrical energy that could have been produced by the same unit if it were operated at maximum capacity. Annual PV capacity factors represent the average annual alternating current (AC) electrical power [megawatt (MW)] generated by a given unit of direct current (DC)-rated PV capacity (MW). Annual concentrating solar power (CSP) capacity factors represent the average annual AC electrical power (MW) generated by a given unit of AC-rated CSP capacity (MW).

**Figure A-2. Central PV Capacity Factors**




### A.2.4.1.2 *Distributed Utility-Scale PV*

Distributed utility-scale PV in ReEDS represents utility-scale 1-axis-tracking systems with a representative size of 1–20 MW located within and directly connected to distribution networks. Capacity of these systems is limited to less than 15% of the distribution network capacity.[83] Capital costs for distributed utility-scale PV (Table A-3) are assumed to be about 8.5% higher than central PV costs.

**Table A-3. Distributed Utility-Scale PV Technology Cost Projections (2010$)**

| Install Year | SunShot Distributed Utility-Scale PV Costs | | | Reference Distributed Utility-Scale PV Costs | | |
|---|---|---|---|---|---|---|
| | Capital | Fixed O&M | Variable O&M | Capital | Fixed O&M | Variable O&M |
| | $/kW | $/kW/yr | $/MWh | $/kW | $/kW/yr | $/MWh |
| 2010 | 4,400 | 20 | 0 | 4,400 | 51 | 0 |
| 2015 | 2,400 | 15 | 0 | 2,900 | 49 | 0 |
| 2020 | 1,100 | 7 | 0 | 2,800 | 46 | 0 |
| 2025 | 1,100 | 7 | 0 | 2,700 | 44 | 0 |
| 2030 | 1,100 | 7 | 0 | 2,600 | 42 | 0 |
| 2035 | 1,100 | 7 | 0 | 2,500 | 40 | 0 |
| 2040 | 1,100 | 7 | 0 | 2,400 | 38 | 0 |
| 2045 | 1,100 | 7 | 0 | 2,300 | 36 | 0 |
| 2050 | 1,100 | 7 | 0 | 2,200 | 34 | 0 |

Similar to central PV, performance characteristics for distributed utility-scale PV were developed using SAM, except the performance in each PCA used the average PV power output across all NSRDB sites within that PCA. The reason for this difference in approach is that distributed utility-scale PV is limited to distribution centers, and therefore siting options are more limited than for central PV. Regional

[83] Distribution network capacity is tracked at the power control area (PCA) regional level in ReEDS.



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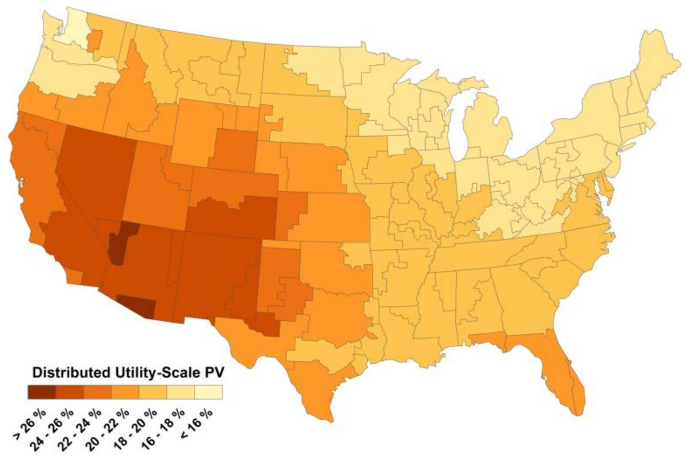
**Figure A-3. Distributed Utility-Scale PV Capacity Factors**




capacity factors for distributed utility-scale PV are similar to central PV but consequently reduced, as shown in Figure A-3. However, ReEDS assumes all electric power generated by distributed PV (both rooftop and distributed utility-scale) systems is effectively consumed within the distribution networks and does not incur transmission and distribution (T&D) losses.

### A.2.4.2 Concentrating Solar Power

There are two main CSP technologies modeled in ReEDS: CSP without thermal energy storage (TES), and CSP with at least 6 hours of TES, each described in the following sections. Both technologies rely on the same resource, which is divided into five resource classes based on direct-normal irradiance (DNI):

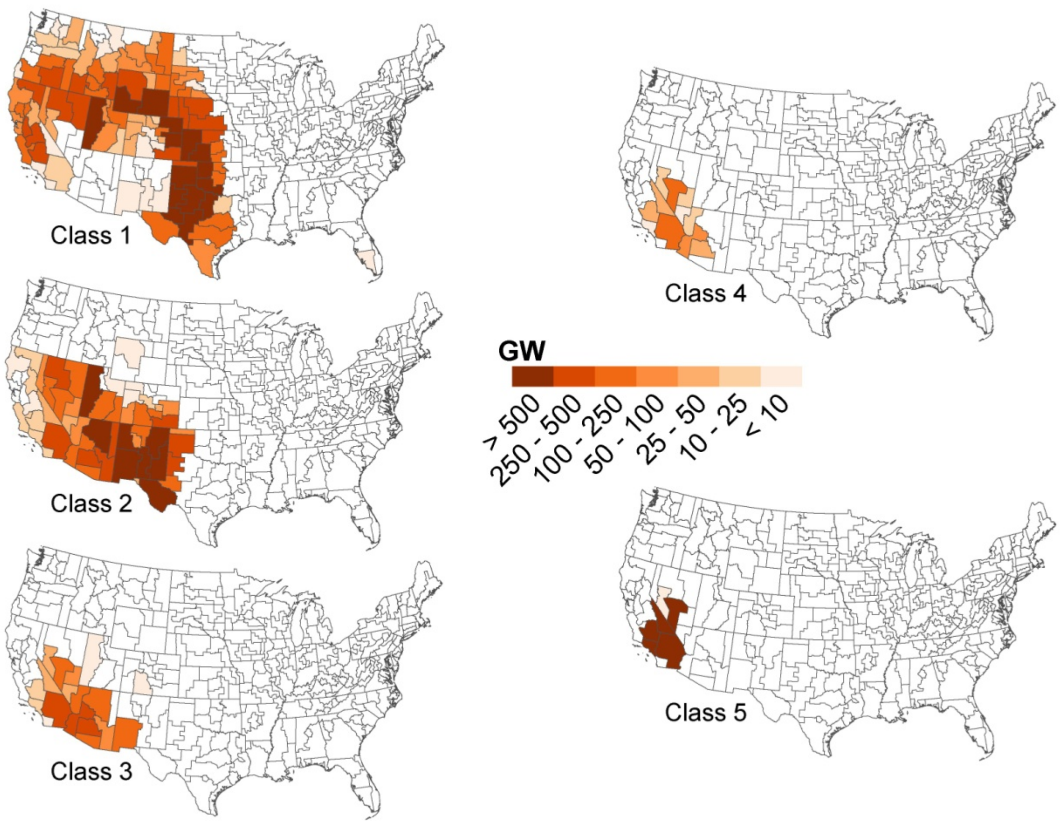
- Class 1: 5–6.25 kilowatt-hours (kWh)/square meter ($m^2$)/day
- Class 2: 6.25–7.25 kWh/$m^2$/day
- Class 3: 7.25–7.5 kWh/$m^2$/day
- Class 4: 7.5–7.75 kWh/$m^2$/day
- Class 5: > 7.75 kWh/$m^2$/day.

Figure A-4 shows the CSP resource available at each wind/CSP resource region[84] assuming a solar multiple[85] of two. Since only regions with DNI greater than 5 kWh/$m^2$/day are considered, CSP resource is predominantly found in the western states. In addition to DNI, available land area and slope also limits the available CSP resource. In particular, regions having a slope greater than 3% are excluded. The available land area for each CSP resource class is converted into gigawatts (GW) of available capacity assuming a plant density of 31 MW/square kilometer ($km^2$) for a system with a solar multiple of two. Plant density for systems with other solar

[84] Note that although the resource is quantified at the 356 CSP/wind region level, only CSP without thermal energy storage (TES) is located at this level. CSP with TES is located at the 134 PCA region level.

[85] Solar multiple is defined as the ratio of the power capacity of the collection field to the capacity of the power block. For CSP systems with storage, the number of hours of storage is based on the capacity of the power block.

**Figure A-4. CSP Available Resource by Class (for Solar Multiples of Two)**




multiples is assumed to scale inversely with solar multiple. As an example, a CSP system with a solar multiple of one would be assumed to have a plant density of 62 MW/km$^2$, or twice that of a system with a solar multiple of two.

CSP performance for each CSP resource class was developed using typical DNI year (TDY) hourly resource data (NREL 2010b) from representative sites of each CSP/wind resource region. The TDY weather files were processed through the CSP modules of SAM (NREL 2010a) for each type of CSP system considered in ReEDS. Performance characteristics for each CSP system are explained in more detail in Section A.2.4.2.1 and A.2.4.2.2.

In addition to the capital and O&M costs discussed in the following sub-sections, a supply curve representing the cost of connecting individual CSP sites to the existing grid as well as to local demand centers was developed based on a geographic information system (GIS) database of the resource, existing grid,[86] and loads. A similar supply curve was developed for wind. In addition to the transmission costs associated with the supply curves, a $120/kW fee for connection to the grid is applied to new CSP plants in ReEDS.

[86] Ten percent of the total carrying capacity of each transmission line was assumed to be available for CSP spur lines.

#### A.2.4.2.1 CSP without Storage

The CSP system without TES in ReEDS is represented as a dry-cooled trough plant with a solar multiple of 1.4. Cost projections were developed by Black & Veatch (forthcoming) and are shown in Table A-4. Note that CSP without TES was not modeled with different costs for the SunShot and reference scenarios, as SunShot costs were only used for CSP with TES.

**Table A-4. CSP without TES Technology Cost Projections (2010$)**

| Install Year | Capital $/kW | Fixed O&M $/kW/yr | Variable O&M $/MWh |
|---|---|---|---|
| 2010 | 5,000 | 50 | 0 |
| 2015 | 4,800 | 50 | 0 |
| 2020 | 4,600 | 50 | 0 |
| 2025 | 4,400 | 50 | 0 |
| 2030 | 4,200 | 50 | 0 |
| 2035 | 4,100 | 50 | 0 |
| 2040 | 3,900 | 50 | 0 |
| 2045 | 3,700 | 50 | 0 |
| 2050 | 3,500 | 50 | 0 |

Performance characteristics (i.e., capacity factors in each time slice) for CSP without TES of each resource class were developed with the CSP module of SAM, configured with a dry-cooled 100-MW turbine and solar multiple of 1.4, using the weather TDY files located at representative sites of each resource class. The average annual capacity factors of each class are shown inTable A-5.



**Table A-5. CSP without TES Average Annual Capacity Factors for Each Class**

| CSP Class | Average Capacity Factor |
|---|---|
| 1 | 0.20 |
| 2 | 0.25 |
| 3 | 0.28 |
| 4 | 0.28 |
| 5 | 0.29 |

#### A.2.4.2.2 CSP with Storage

ReEDS considers CSP systems with TES to have at least 6 hours of storage, for which ReEDS assumes full capacity credit valuations. Although a mix of trough and tower technologies are expected to be built throughout the timeframe of the study, for modeling simplicity ReEDS assumes cost and performance characteristics of towers for the current study. The towers are assumed to be dry-cooled.

In ReEDS, CSP systems with TES are represented by three separate components: the field (collectors), storage, and turbine (power block). The model is allowed to choose solar multiples and amounts of storage, within boundaries discussed later in this section. Greater solar multiples result in higher capacity factors, and greater amounts of storage allow the systems to be more flexible, although both increase capital costs per kilowatt of installed turbine capacity. Average costs for CSP systems with TES in the SunShot and reference scenarios are shown in Table A-6, and average annual capacity factors are shown in Table A-7 for each resource class. The costs and performance characteristics represent systems with a solar multiple of 2.5 and 11 hours of storage, which are the average characteristics for systems built by 2050 in the SunShot scenario. SunShot costs are described in more detail in Chapter 5, while reference costs were developed by Black & Veatch (forthcoming). SunShot costs and performance characteristics shown here will deviate slightly from those in Chapter 5 of the report, as the systems have slightly different configurations.

**Table A-6. CSP with 11 Hours of TES Base Characteristics and Costs (2010$)**

| | SunShot CSP with TES Costs | | | Reference CSP with TES Costs | | |
|---|---|---|---|---|---|---|
| Install Year | Capital | Fixed O&M | Variable O&M | Capital | Fixed O&M | Variable O&M |
| | $/kW | $/kW/yr | $/MWh | $/kW | $/kW/yr | $/MWh |
| 2010 | 9,200 | 75 | 3 | 9,200 | 49 | 0 |
| 2015 | 7,900 | 60 | 3 | 8,800 | 49 | 0 |
| 2020 | 3,400 | 45 | 3 | 8,500 | 49 | 0 |
| 2025 | 3,400 | 45 | 3 | 7,500 | 49 | 0 |
| 2030 | 3,400 | 45 | 3 | 6,700 | 49 | 0 |
| 2035 | 3,400 | 45 | 3 | 5,900 | 49 | 0 |
| 2040 | 3,400 | 45 | 3 | 5,900 | 49 | 0 |
| 2045 | 3,400 | 45 | 3 | 5,900 | 49 | 0 |
| 2050 | 3,400 | 45 | 3 | 5,900 | 49 | 0 |

**Table A-7. Average Annual Capacity Factors for CSP Systems with 11 Hours of TES**

| CSP Resource Class | Average Capacity Factor |
|---|---|
| 1 | 0.45 |
| 2 | 0.54 |
| 3 | 0.59 |
| 4 | 0.60 |
| 5 | 0.62 |

CSP systems with TES are assumed to be fully dispatchable within the energy limitations imposed by the time-profile of the solar insolation, solar multiple, and hours of thermal storage. Because of this, capacity factors by time slice of CSP with TES are an output of the model, not an input. Instead, the profile of power input from the solar field of the CSP plants are model inputs, based on SAM simulations from the TDY weather files that span the range of solar multiples allowed in ReEDS.

While solar multiple and hours of storage are allowed to be system-specific in ReEDS, the system configurations must abide by certain restrictions. First, to ensure that these systems are capable of providing firm capacity to the system during peak demand periods, they are restricted to have at least a capacity factor of 40% in addition to the minimum 6 hours of storage. These systems are also restricted to capacity factors of less than 65% and solar multiples of less than 2.5 to limit curtailment effects that become significant at these higher solar multiples. In addition, prescribed amounts of storage as a function of solar multiple were developed using SAM, as the broad time slices and typical-day profiles in ReEDS disallow it from fully capturing the amount of storage required for a given plant performance. For towers, at the highest allowed solar multiple of 2.5, a minimum of 11.25 hours of storage is required.

#### A.2.4.3 Wind

ReEDS considers five resource classes of wind, shown in Table A-8, based on wind power density and wind speed at 50 meters above ground. 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. The available wind area is converted to available wind capacity using the constant multiplier of 5 MW/km$^2$. Available wind capacity is shown in Figure A-5. The colored areas just outside of the coastal regions represent offshore wind.

**Table A-8. Classes of Wind Power Density**

| Wind 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 |

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)

Wind cost and performance parameters were developed by Black & Veatch (forthcoming), and are shown in Table A-9 (for onshore wind) and Table A-10 (for offshore wind). Capacity factor adjustments by time slice were made for each class of each region based on AWS Truepower text supplemental database files and the National Commission on Energy Policy/National Center for Atmospheric Research (NCEP/NCAR) global reanalysis mean values.

To account for the higher degree of variability in resource quality and land availability for wind technologies (as compared to other technologies), a supply curve representing the cost of connecting individual wind sites to the existing grid as well as to local demand centers was developed based on a GIS database of the

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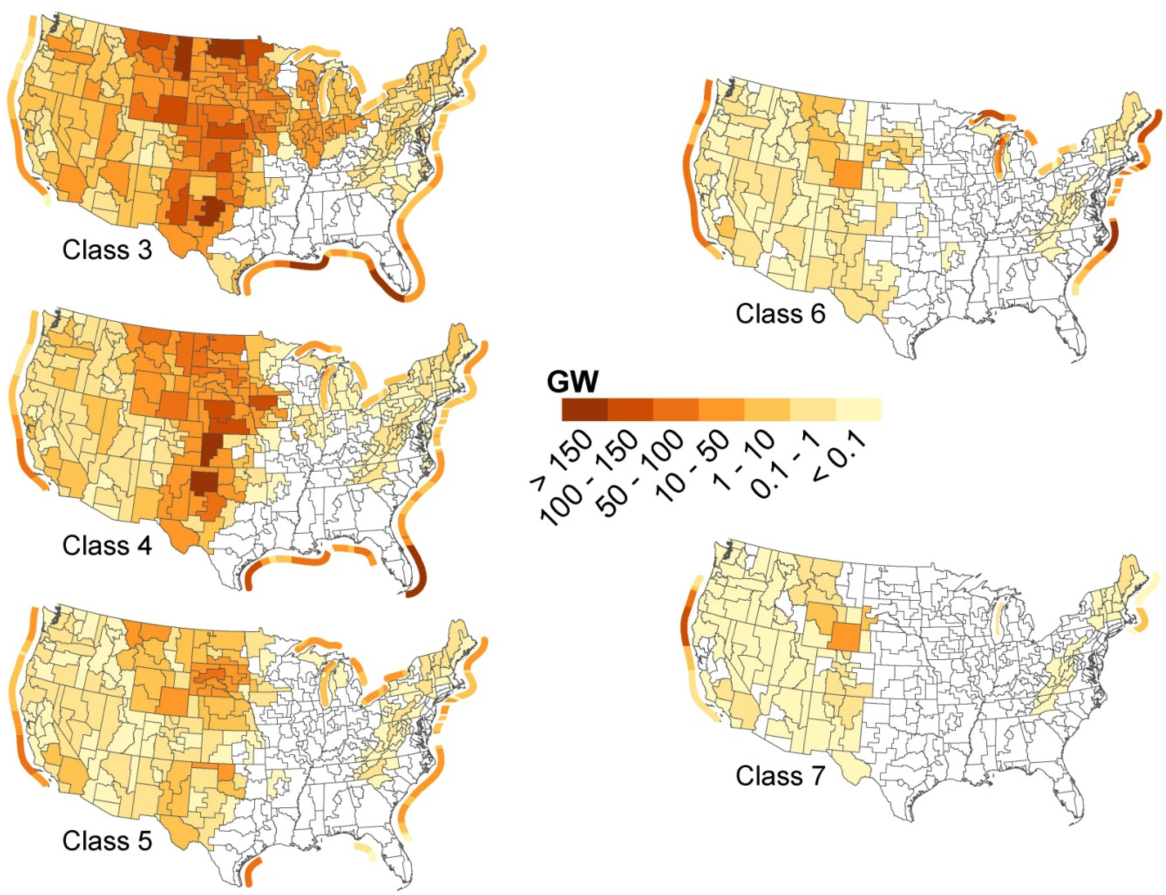
**Figure A-5. Wind Available Resource by Class**




resource, existing grid,[87] and loads. A similar supply curve was developed for CSP. In addition to the transmission costs associated with the supply curves, a $120/kW fee for connection to the grid is applied to new wind plants in ReEDS.

### A.2.4.4 Conventional and Other Renewable Generators

ReEDS includes all major technologies that contribute to electricity generation in the United States. ReEDS is allowed to build new power plants of certain types, but not all. The following is a complete list of additional technologies considered in ReEDS for the *SunShot Vision Study*, as well as designations if new plants are allowed to be built or not. All existing and new plants in ReEDS are sited at the 134 PCA region level.

- Hydropower: existing plants only
- Gas-combustion turbine (gas-CT): new and existing plants
- Gas-combined cycle (gas-CC): new and existing plants

[87] Ten percent of the total carrying capacity of each transmission line was assumed to be available for wind spur lines.

**Table A-9. Land-Based Wind Technology Cost (2010$) and Performance Projections**

| Wind Class | Install Year | Capacity Factor | Capital Cost ($/kW) | Fixed O&M ($/kW/yr) | Variable O&M ($/MWh) |
|---|---|---|---|---|---|
| 3 | 2010 | 0.32 | 2,000 | 60 | 0 |
| 3 | 2015 | 0.33 | 2,000 | 60 | 0 |
| 3 | 2020 | 0.33 | 2,000 | 60 | 0 |
| 3 | 2025 | 0.34 | 2,000 | 60 | 0 |
| 3 | 2030 | 0.35 | 2,000 | 60 | 0 |
| 3 | 2035 | 0.35 | 2,000 | 60 | 0 |
| 3 | 2040 | 0.35 | 2,000 | 60 | 0 |
| 3 | 2045 | 0.35 | 2,000 | 60 | 0 |
| 3 | 2050 | 0.35 | 2,000 | 60 | 0 |
| 4 | 2010 | 0.36 | 2,000 | 60 | 0 |
| 4 | 2015 | 0.37 | 2,000 | 60 | 0 |
| 4 | 2020 | 0.37 | 2,000 | 60 | 0 |
| 4 | 2025 | 0.38 | 2,000 | 60 | 0 |
| 4 | 2030 | 0.38 | 2,000 | 60 | 0 |
| 4 | 2035 | 0.38 | 2,000 | 60 | 0 |
| 4 | 2040 | 0.38 | 2,000 | 60 | 0 |
| 4 | 2045 | 0.38 | 2,000 | 60 | 0 |
| 4 | 2050 | 0.38 | 2,000 | 60 | 0 |
| 5 | 2010 | 0.42 | 2,000 | 60 | 0 |
| 5 | 2015 | 0.42 | 2,000 | 60 | 0 |
| 5 | 2020 | 0.42 | 2,000 | 60 | 0 |
| 5 | 2025 | 0.42 | 2,000 | 60 | 0 |
| 5 | 2030 | 0.43 | 2,000 | 60 | 0 |
| 5 | 2035 | 0.43 | 2,000 | 60 | 0 |
| 5 | 2040 | 0.43 | 2,000 | 60 | 0 |
| 5 | 2045 | 0.43 | 2,000 | 60 | 0 |
| 5 | 2050 | 0.43 | 2,000 | 60 | 0 |
| 6 | 2010 | 0.44 | 2,000 | 60 | 0 |
| 6 | 2015 | 0.44 | 2,000 | 60 | 0 |
| 6 | 2020 | 0.44 | 2,000 | 60 | 0 |
| 6 | 2025 | 0.45 | 2,000 | 60 | 0 |
| 6 | 2030 | 0.45 | 2,000 | 60 | 0 |
| 6 | 2035 | 0.45 | 2,000 | 60 | 0 |
| 6 | 2040 | 0.45 | 2,000 | 60 | 0 |
| 6 | 2045 | 0.45 | 2,000 | 60 | 0 |
| 6 | 2050 | 0.45 | 2,000 | 60 | 0 |
| 7 | 2010 | 0.46 | 2,000 | 60 | 0 |
| 7 | 2015 | 0.46 | 2,000 | 60 | 0 |
| 7 | 2020 | 0.46 | 2,000 | 60 | 0 |
| 7 | 2025 | 0.46 | 2,000 | 60 | 0 |
| 7 | 2030 | 0.46 | 2,000 | 60 | 0 |
| 7 | 2035 | 0.46 | 2,000 | 60 | 0 |
| 7 | 2040 | 0.46 | 2,000 | 60 | 0 |
| 7 | 2045 | 0.46 | 2,000 | 60 | 0 |
| 7 | 2050 | 0.46 | 2,000 | 60 | 0 |

**Table A-10. Shallow Offshore Wind Technology Cost (2010$) and Performance Projections**

| Wind Class | Install Year | Capacity Factor | Capital Cost ($/kW) | Fixed O&M ($/kW/yr) | Variable O&M ($/MWh) |
|---|---|---|---|---|---|
| 3 | 2010 | 0.36 | 3,700 | 100 | 0 |
| 3 | 2015 | 0.36 | 3,500 | 100 | 0 |
| 3 | 2020 | 0.37 | 3,400 | 100 | 0 |
| 3 | 2025 | 0.37 | 3,200 | 100 | 0 |
| 3 | 2030 | 0.38 | 3,000 | 100 | 0 |
| 3 | 2035 | 0.38 | 3,000 | 100 | 0 |
| 3 | 2040 | 0.38 | 3,000 | 100 | 0 |
| 3 | 2045 | 0.38 | 3,000 | 100 | 0 |
| 3 | 2050 | 0.38 | 3,000 | 100 | 0 |
| 4 | 2010 | 0.39 | 3,700 | 100 | 0 |
| 4 | 2015 | 0.39 | 3,500 | 100 | 0 |
| 4 | 2020 | 0.39 | 3,400 | 100 | 0 |
| 4 | 2025 | 0.40 | 3,200 | 100 | 0 |
| 4 | 2030 | 0.40 | 3,000 | 100 | 0 |
| 4 | 2035 | 0.40 | 3,000 | 100 | 0 |
| 4 | 2040 | 0.40 | 3,000 | 100 | 0 |
| 4 | 2045 | 0.40 | 3,000 | 100 | 0 |
| 4 | 2050 | 0.40 | 3,000 | 100 | 0 |
| 5 | 2010 | 0.45 | 3,700 | 100 | 0 |
| 5 | 2015 | 0.45 | 3,500 | 100 | 0 |
| 5 | 2020 | 0.45 | 3,400 | 100 | 0 |
| 5 | 2025 | 0.45 | 3,200 | 100 | 0 |
| 5 | 2030 | 0.45 | 3,000 | 100 | 0 |
| 5 | 2035 | 0.45 | 3,000 | 100 | 0 |
| 5 | 2040 | 0.45 | 3,000 | 100 | 0 |
| 5 | 2045 | 0.45 | 3,000 | 100 | 0 |
| 5 | 2050 | 0.45 | 3,000 | 100 | 0 |
| 6 | 2010 | 0.48 | 3,700 | 100 | 0 |
| 6 | 2015 | 0.48 | 3,500 | 100 | 0 |
| 6 | 2020 | 0.48 | 3,400 | 100 | 0 |
| 6 | 2025 | 0.48 | 3,200 | 100 | 0 |
| 6 | 2030 | 0.48 | 3,000 | 100 | 0 |
| 6 | 2035 | 0.48 | 3,000 | 100 | 0 |
| 6 | 2040 | 0.48 | 3,000 | 100 | 0 |
| 6 | 2045 | 0.48 | 3,000 | 100 | 0 |
| 6 | 2050 | 0.48 | 3,000 | 100 | 0 |
| 7 | 2010 | 0.50 | 3,700 | 100 | 0 |
| 7 | 2015 | 0.50 | 3,500 | 100 | 0 |
| 7 | 2020 | 0.50 | 3,400 | 100 | 0 |
| 7 | 2025 | 0.50 | 3,200 | 100 | 0 |
| 7 | 2030 | 0.50 | 3,000 | 100 | 0 |
| 7 | 2035 | 0.50 | 3,000 | 100 | 0 |
| 7 | 2040 | 0.50 | 3,000 | 100 | 0 |
| 7 | 2045 | 0.50 | 3,000 | 100 | 0 |
| 7 | 2050 | 0.50 | 3,000 | 100 | 0 |

- Pulverized coal: existing plants with and without scrubbers; new plants with scrubbers
- Coal-integrated gasification combined cycle (IGCC): new and existing plants
- Oil/gas/steam (OGS): existing plants only
- Nuclear: new and existing plants.
- Geothermal: new and existing plants
- Biopower: new and existing plants
- Cofire: new plants and retrofits of coal plants
- Landfill gas and municipal solid waste: existing plants only.

Costs and heat rates for conventional technologies that are allowed new plant construction in ReEDS were developed by Black & Veatch (forthcoming) and are shown in Table A-11.

Outage rates, minimum plant loading requirements, and emissions rates of all conventional technologies are shown in Table A-12. "Forced outage rates" represent unplanned outage events, and effectively reduce capacity factors of these plants during all ReEDS time slices of the year. "Planned outage rates" represent planned maintenance events, and are assumed in ReEDS to reduce capacity factors only in non-summer time slices. Together, the outage rates define the availability of the plants, though a plant's capacity factor is an output of the model as the optimum solution may require a plant to operate below this maximum availability. Though conventional technologies in ReEDS are dispatchable, they must pay a penalty for ramping significantly to their peaks and must abide by minimum plant loading requirements, which specify the minimum level of output of plants that are operating in each season. However, plants are allowed to shut down for entire seasons. For example, nuclear plants have a minimum plant loading of 100%, which means that active nuclear capacity in each season must generate at peak output. However, national nuclear power output may vary between seasons as nuclear capacity is brought online or offline between seasons.



#### *A.2.4.4.1 Retirements*

Retirements of generators are handled in multiple ways in ReEDS, depending on the particular technology.

- *Coal retirements*. Existing coal units retire based roughly on an 80-year lifetime; one-eightieth of existing coal capacity is assumed to retire annually.
- *Oil/gas/steam retirements***.** Existing OGS units retire based on a 50-year service life; each unit is assumed to retire 50 years from its year of installation.
- *Nuclear retirements.* Existing nuclear plants are retired according to their specific year of installation. Plants built prior to 1980 have an assumed 60-year lifetime, and plants built after 1980 have an assumed 80-year lifetime (beyond the timeframe of this study).

**Table A-11. Cost (2010$) and Performance Characteristics for Conventional Generation**

| | Install Date | Capital Cost $/kW | Fixed O&M $/kW/yr | Var O&M $/MWh | Heat Rate $10^6$ Btu/MWh |
|---|---|---|---|---|---|
| Gas-CT | 2010 | 660 | 5 | 30 | 13 |
| Gas-CT | 2015 | 660 | 5 | 30 | 10 |
| Gas-CT | 2020 | 660 | 5 | 30 | 10 |
| Gas-CT | 2025 | 660 | 5 | 30 | 10 |
| Gas-CT | 2030 | 660 | 5 | 30 | 10 |
| Gas-CT | 2035 | 660 | 5 | 30 | 10 |
| Gas-CT | 2040 | 660 | 5 | 30 | 10 |
| Gas-CT | 2045 | 660 | 5 | 30 | 10 |
| Gas-CT | 2050 | 660 | 5 | 30 | 10 |
| Gas-CC | 2010 | 1,200 | 6 | 4 | 8 |
| Gas-CC | 2015 | 1,200 | 6 | 4 | 7 |
| Gas-CC | 2020 | 1,200 | 6 | 4 | 7 |
| Gas-CC | 2025 | 1,200 | 6 | 4 | 7 |
| Gas-CC | 2030 | 1,200 | 6 | 4 | 7 |
| Gas-CC | 2035 | 1,200 | 6 | 4 | 7 |
| Gas-CC | 2040 | 1,200 | 6 | 4 | 7 |
| Gas-CC | 2045 | 1,200 | 6 | 4 | 7 |
| Gas-CC | 2050 | 1,200 | 6 | 4 | 7 |
| Coal | 2010 | 2,900 | 23 | 4 | 10 |
| Coal | 2015 | 2,900 | 23 | 4 | 9 |
| Coal | 2020 | 2,900 | 23 | 4 | 9 |
| Coal | 2025 | 2,900 | 23 | 4 | 9 |
| Coal | 2030 | 2,900 | 23 | 4 | 9 |
| Coal | 2035 | 2,900 | 23 | 4 | 9 |
| Coal | 2040 | 2,900 | 23 | 4 | 9 |
| Coal | 2045 | 2,900 | 23 | 4 | 9 |
| Coal | 2050 | 2,900 | 23 | 4 | 9 |
| Coal-IGCC | 2010 | 4,100 | 32 | 7 | 9 |
| Coal-IGCC | 2015 | 4,100 | 32 | 7 | 9 |
| Coal-IGCC | 2020 | 4,100 | 32 | 7 | 9 |
| Coal-IGCC | 2025 | 4,100 | 32 | 7 | 8 |
| Coal-IGCC | 2030 | 4,100 | 32 | 7 | 8 |
| Coal-IGCC | 2035 | 4,100 | 32 | 7 | 8 |
| Coal-IGCC | 2040 | 4,100 | 32 | 7 | 8 |
| Coal-IGCC | 2045 | 4,100 | 32 | 7 | 8 |
| Coal-IGCC | 2050 | 4,100 | 32 | 7 | 8 |
| Nuclear | 2010 | 6,200 | 130 | 0 | 10 |
| Nuclear | 2015 | 6,200 | 130 | 0 | 10 |
| Nuclear | 2020 | 6,200 | 130 | 0 | 10 |
| Nuclear | 2025 | 6,200 | 130 | 0 | 10 |
| Nuclear | 2030 | 6,200 | 130 | 0 | 10 |
| Nuclear | 2035 | 6,200 | 130 | 0 | 10 |
| Nuclear | 2040 | 6,200 | 130 | 0 | 10 |
| Nuclear | 2045 | 6,200 | 130 | 0 | 10 |
| Nuclear | 2050 | 6,200 | 130 | 0 | 10 |

$10^6$ Btu: million British thermal units

Table A-11. Cost (2010$) and Performance Characteristics for Conventional Generation (Continued)

| | Install Date | Capital Cost $/kW | Fixed O&M $/kW/yr | Var O&M $/MWh | Heat Rate $10^6$ Btu/MWh |
|---|---|---|---|---|---|
| Geothermal | 2010 | 3,000 to >10,000 | 230 | 0 | 0 |
| Geothermal | 2015 | 3,000 to >10,000 | 230 | 0 | 0 |
| Geothermal | 2020 | 3,000 to >10,000 | 230 | 0 | 0 |
| Geothermal | 2025 | 3,000 to >10,000 | 230 | 0 | 0 |
| Geothermal | 2030 | 3,000 to >10,000 | 230 | 0 | 0 |
| Geothermal | 2035 | 3,000 to >10,000 | 230 | 0 | 0 |
| Geothermal | 2040 | 3,000 to >10,000 | 230 | 0 | 0 |
| Geothermal | 2045 | 3,000 to >10,000 | 230 | 0 | 0 |
| Geothermal | 2050 | 3,000 to >10,000 | 230 | 0 | 0 |
| Biopower | 2010 | 3,900 | 96 | 15 | 15 |
| Biopower | 2015 | 3,900 | 96 | 15 | 14 |
| Biopower | 2020 | 3,900 | 96 | 15 | 14 |
| Biopower | 2025 | 3,900 | 96 | 15 | 14 |
| Biopower | 2030 | 3,900 | 96 | 15 | 14 |
| Biopower | 2035 | 3,900 | 96 | 15 | 13 |
| Biopower | 2040 | 3,900 | 96 | 15 | 13 |
| Biopower | 2045 | 3,900 | 96 | 15 | 13 |
| Biopower | 2050 | 3,900 | 96 | 15 | 13 |
| Cofired Coal/Bio | 2010 | 3,100 | 26 | 6 | 10 |
| Cofired Coal/Bio | 2015 | 3,100 | 26 | 6 | 9 |
| Cofired Coal/Bio | 2020 | 3,100 | 26 | 7 | 9 |
| Cofired Coal/Bio | 2025 | 3,100 | 26 | 7 | 9 |
| Cofired Coal/Bio | 2030 | 3,100 | 26 | 8 | 9 |
| Cofired Coal/Bio | 2035 | 3,100 | 26 | 9 | 9 |
| Cofired Coal/Bio | 2040 | 3,100 | 26 | 10 | 9 |
| Cofired Coal/Bio | 2045 | 3,100 | 26 | 11 | 9 |
| Cofired Coal/Bio | 2050 | 3,100 | 26 | 12 | 9 |



- *Gas-CC and gas-CT retirements.* Gas plants are retired according to their year of installation. One twenty-fourth of existing gas-CC and gas-CT capacity built before 2000 is retired annually until 2030 to reflect a 24-year lifetime of that gas capacity. Then, starting in 2030, one-thirtieth of cumulative gas capacity is retired annually through 2050.
- *Renewable retirements.* All new and existing CSP, utility PV, wind, and geothermal plants are assumed to retire according to their specific lifetimes.[88] After retirement, the capacity is automatically rebuilt in ReEDS, with the appropriate capital costs incurred at that time.

[88] In determining system cost impacts, lifetimes of CSP, utility-scale PV, and geothermal are assumed to be 30 years. Lifetime of wind is 20 years.

**Table A-12. Outage Rates, Minimum Plant Loading Requirements, and Emissions Rates of Conventional Technologies in ReEDS**

| | Forced Outage Rate | Planned Outage Rate | Minimum Plant Loading | Emission Rates (lbs/$10^6$ Btu Fuel Input) | | | |
|---|---|---|---|---|---|---|---|
| | | | | $SO_2$ | $NO_x$ | Hg | $CO_2$ |
| Hydro[89] | 5% | 2% | 55% | 0 | 0 | 0 | 0 |
| Gas-CT | 3% | 5% | 0% | 0.0006 | 0.08 | 0 | 122 |
| Gas-CC | 4% | 6% | 0% | 0.0006 | 0.02 | 0 | 122 |
| Old Coal | 6% | 10% | 40% | 1.57 | 0.448 | 4.6E-06 | 204 |
| New Coal | 6% | 10% | 40% | 0.0785 | 0.02 | 4.6E-06 | 204 |
| Coal-IGCC | 8% | 10% | 50% | 0.0184 | 0.02 | 4.6E-06 | 204 |
| OGS | 10% | 12% | 40% | 0.026 | 0.1 | 0 | 122 |
| Nuclear | 4% | 12% | 100% | 0 | 0 | 0 | 0 |
| Geothermal | 13% | 12% | 90% | 0 | 0 | 0 | 0 |
| Biomass | 9% | 6% | 40% | 0.08 | 0 | 0 | 0 |
| Cofired Old | 7% | 2% | 40% | 0.157 | 0.448 | 4.6E-06 | 204 |
| Cofired New | 7% | 8% | 40% | 0.0785 | 0.02 | 4.6E-06 | 204 |
| Landfill Gas | 5% | 9% | 0% | 0 | 0 | 0 | -157 |

$SO_2$: sulfur dioxide
$NO_x$: nitrogen oxides
Hg: mercury

### A.2.4.4.2 Fuel Prices

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National average coal, natural gas, and nuclear fuel prices in the SunShot and reference scenarios are shown in Figure A-6. These prices are based on the *Annual Energy Outlook 2010 (AEO 2010)* (EIA 2010),[90] but natural gas and coal fuel prices are adjusted upward from *AEO 2010* if demand for that fuel is increased in ReEDS with respect to *AEO 2010* forecasted demand, and adjusted downward if demand is decreased with respect to *AEO* forecasted demand. The levels of adjustment are based on the differences in economy-wide fuel usage and price in the *AEO 2010* reference, low economic growth, and high economic growth cases. These adjustments result in different natural gas and coal fuel prices between the SunShot and reference scenarios. Nuclear fuel prices, on the other hand, are assumed to be independent of nuclear fuel demand.

Fuel costs are also adjusted by the 13 modeled NERC regions/subregions to reflect regional variation in fuel cost.

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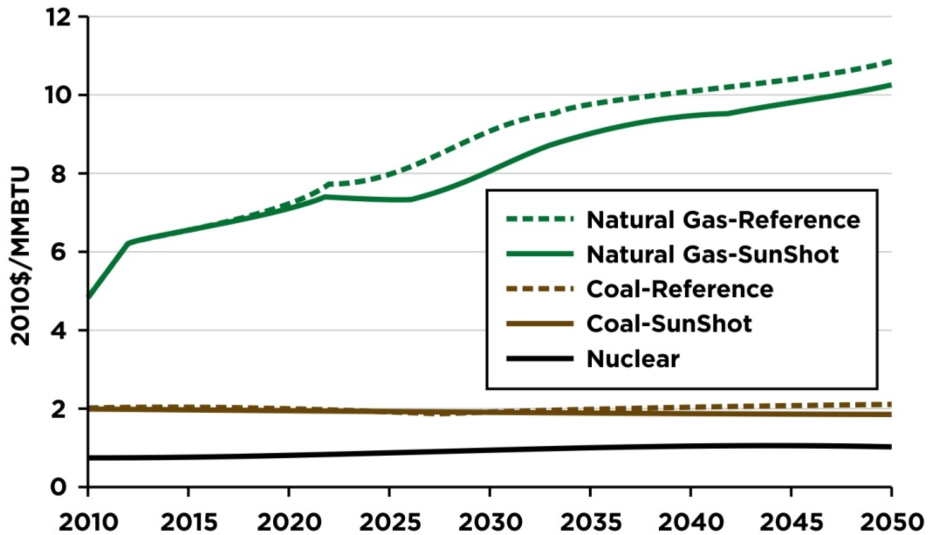
[89] Hydropower has additional seasonal generation limits, based on the GridView database of hydropower capacity located in the Western Electricity Coordinating Council (WECC). Hydropower generation elsewhere is assumed to be distributed evenly across seasons.
[90] The *Annual Energy Outlook* (AEO) forecasts fuel prices through 2035, and a linear interpolation between 2015 and 2035 is used to extrapolate AEO natural gas and coal fuel prices through 2050. Nuclear fuel prices are assumed to remain constant after 2035.

**Figure A-6. Natural Gas, Coal, and Nuclear Fuel Prices (2010$)**




### A.2.4.5 Storage and Interruptible Load

ReEDS considers three utility-scale electricity storage options: pumped hydropower storage (PHS), batteries, and compressed air energy storage (CAES). Storage technologies are capable of providing a variety of services to the system. These technologies can shift daily demands, provide planning and operating reserves (see Section A.2.7.2 and A.2.7.3), and reduce levels of curtailment from VERs (see Section A.2.7.1).

Storage technologies are located at the PCA region level in ReEDS. PHS and CAES are location-restricted due to hydrology and topography—for PHS—and geology—for CAES. In contrast, utility-scale batteries are not restricted to any subset of regions. The 21 GW of existing PHS capacity is included in the model, and new PHS resource is conservatively limited to those sites identified in the Federal Energy Regulatory Commission (FERC) licensing process (FERC 2010).

Cost and performance characteristics for storage technologies were developed by Black & Veatch (forthcoming), and are shown in Table A-13. Round-trip efficiency (RTE) is defined as electrical power out divided by electrical power in, and is generally less than one due to storage inefficiencies. However, since CAES uses natural gas, its RTE is greater than one. Outage rates and emissions rates of all storage technologies are shown in Table A-14. These parameters are described in the preceding section. Note that only CAES has emissions, since it operates on natural gas.

**Table A-13. Costs (2010$) and Performance Characteristics for Storage Technologies**

| | Install Date | Capital Cost $/kW | Fixed O&M $/kW/yr | Var O&M $/MWh | Round-Trip Efficiency | Heat Rate $10^6$ Btu/MWh |
|---|---|---|---|---|---|---|
| Pumped hydro | 2010 | 2,000 | 31 | 0 | 0.80 | 0 |
| Pumped hydro | 2015 | 2,000 | 31 | 0 | 0.80 | 0 |
| Pumped hydro | 2020 | 2,000 | 31 | 0 | 0.80 | 0 |
| Pumped hydro | 2025 | 2,000 | 31 | 0 | 0.80 | 0 |
| Pumped hydro | 2030 | 2,000 | 31 | 0 | 0.80 | 0 |
| Pumped hydro | 2035 | 2,000 | 31 | 0 | 0.80 | 0 |
| Pumped hydro | 2040 | 2,000 | 31 | 0 | 0.80 | 0 |
| Pumped hydro | 2045 | 2,000 | 31 | 0 | 0.80 | 0 |
| Pumped hydro | 2050 | 2,000 | 31 | 0 | 0.80 | 0 |
| Batteries | 2010 | 4,100 | 26 | 60 | 0.75 | 0 |
| Batteries | 2015 | 4,000 | 26 | 60 | 0.75 | 0 |
| Batteries | 2020 | 3,900 | 26 | 60 | 0.75 | 0 |
| Batteries | 2025 | 3,700 | 26 | 60 | 0.75 | 0 |
| Batteries | 2030 | 3,600 | 26 | 60 | 0.75 | 0 |
| Batteries | 2035 | 3,500 | 26 | 60 | 0.75 | 0 |
| Batteries | 2040 | 3,400 | 26 | 60 | 0.75 | 0 |
| Batteries | 2045 | 3,300 | 26 | 60 | 0.75 | 0 |
| Batteries | 2050 | 3,200 | 26 | 60 | 0.75 | 0 |
| CAES | 2010 | 900–1,200 | 12 | 2 | 1.25 | 5 |
| CAES | 2015 | 900–1,200 | 12 | 2 | 1.25 | 5 |
| CAES | 2020 | 900–1,200 | 12 | 2 | 1.25 | 5 |
| CAES | 2025 | 900–1,200 | 12 | 2 | 1.25 | 5 |
| CAES | 2030 | 900–1,200 | 12 | 2 | 1.25 | 5 |
| CAES | 2035 | 900–1,200 | 12 | 2 | 1.25 | 5 |
| CAES | 2040 | 900–1,200 | 12 | 2 | 1.25 | 5 |
| CAES | 2045 | 900–1,200 | 12 | 2 | 1.25 | 5 |
| CAES | 2050 | 900–1,200 | 12 | 2 | 1.25 | 5 |

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**Table A-14. Outage Rates and Emissions Rates of Storage Technologies in ReEDS**

| | Forced Outage Rate | Planned Outage Rate | Emission Rates (lbs/$10^6$ Btu fuel input) | | | |
|---|---|---|---|---|---|---|
| | | | $SO_2$ | $NO_x$ | Hg | $CO_2$ |
| Pumped-hydro | 4% | 3% | - | - | - | - |
| Batteries | 2% | 1% | - | - | - | - |
| CAES | 3% | 4% | 0.0006 | 0.08 | 0 | 122 |

Interruptible load represents the annual load that utilities can use as operating reserves under conditions set forth by contracts between the utilities and the demand entity. In ReEDS, interruptible load can only be used to satisfy contingency and forecast error reserve requirements; interruptible load cannot be used to satisfy frequency regulation reserve requirements.

In ReEDS, interruptible load is represented by PCA-level supply curves that range in cost from $3/kW/year (yr) to $38/kW/yr for each PCA region. The total amount of load that may be used as interruptible load varies by region and over time. In 2010, the region with the least abundant interruptible load resource only allows 1% of peak demand, whereas the region with the highest amount of resource allows 8% of peak demand. In 2030, these numbers increase to 11% and 17%, respectively. The interruptible supply curves are based on a resource assessment by FERC (FERC 2009) and cost data from EIA (EIA 2009).

### A.2.5 Transmission

Transmission in ReEDS follows a “pipeline” methodology, meaning power shipped directly between regions is simply constrained by the size of the transmission lines and Kirchoff’s current law (i.e., energy conservation), but not by Kirchoff’s voltage law. In more realistic depictions of transmission systems, the flow of electric power is determined by the topology of the transmission network and the characteristics of the lines that make up the network, meaning that flows between regions can actually be constrained by transmission lines far from the connecting regions in question. Though ReEDS does not explicitly include power-flow analysis, the existing transmission network for ReEDS was derived based on analysis from the GridView model (Section A.4), which includes more realistic DC power flow algorithms. The GridView analysis was used to determine transmission interface limits among neighboring PCAs.[91] ReEDS represents the grid as a network of connections between the center points of neighboring PCAs.



In addition to the existing grid, ReEDS is allowed to expand transmission capacity along both existing and new corridors between neighboring PCAs. This expansion allows power to be shipped from any PCA to any other that is connected by this network. Costs of transmission were developed by the National Renewable Energy Laboratory (NREL), and are shown in Table A-15. Different regions have different costs of transmission, due to the assumed prevalence of either 500-kilovolt (kV) or 765-kV lines, as well as regional cost multipliers (EnerNex 2010) which reflect additional siting costs. The transmission line costs include a 25% contingency factor, which accounts for the fact that lines are overbuilt to accommodate greater power transfers only during contingency events. In addition to the cost of transmission lines, regional supply curves of costs for substation construction, which primarily include cost of transformers to step between transmission line voltages and distribution network voltages, are included. The substation supply curves were developed from the GridView database. An additional cost of $230/kW of transmission capacity is charged for building capacity across interconnections, to account for the necessary AC-DC-AC intertie construction.

[91] Neighboring PCAs correspond to geographically contiguous PCAs and PCAs that are currently connected via transmission lines (e.g., long distance direct-current lines).

**Table A-15. Transmission Costs (2010$) Used in ReEDS**

| | Value | Applicable Regions |
|---|---|---|
| 500-kV Line Costs [$/MW-mile(mi)] | 1,500 | WECC, TRE, SPP, FRCC, SERC |
| 765-kV Line Costs ($/MW-mi) | 1,200 | Rest of the country |
| Line Cost Multiplier | 3.56x | CA, NY, NE, East PJM |
| Line Cost Multiplier | 1.58x | West PJM |
| Substation Costs ($/kW) | 11–25 | All |
| AC-DC-AC Intertie Costs ($/kW) | 230 | Crossing Interconnects |

WECC: Western Electricity Coordinating Council
TRE: Texas Reliability Entity
SPP: Southwest Power Pool
FRCC: Florida Reliability Coordinating Council
SERC: Southeastern Electric Reliability Corporation

In addition to the transmission costs discussed above, grid interconnection costs are applied to most generation and storage technologies upon construction. As described previously, these costs are not applied to distributed utility-scale PV and rooftop PV installations. For conventional technologies in which siting and transmission may be more significant issues (e.g., hydropower, nuclear, and coal), grid interconnection costs are twice as high.

In addition to the grid interconnection costs in Table A-16, since CSP and wind resource quality depends heavily on location, supply curves for each CSP/wind region—of which there are 356—in the United States were developed to account for the additional transmission line construction for connecting these resources to the

**Table A-16. Grid Connection Costs (2010$) for All ReEDS Technologies**

| | Grid Connection Cost ($/kW) |
|---|---|
| Hydro | 230 |
| Gas-CT | 120 |
| Gas-CC | 120 |
| Coal | 230 |
| Coal-IGCC | 230 |
| OGS | 120 |
| Nuclear | 230 |
| Geothermal | 230 |
| Biomass | 120 |
| Cofire | 230 |
| Wind | 120 |
| Central PV | 120 |
| Distributed Utility-scale PV | 0 |
| CSP | 120 |
| Pumped Hydro | 120 |
| Batteries | 120 |
| CAES | 120 |

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grid as well as to local demand centers. These supply curves are explained in the CSP (A.2.4.2) and wind (A.2.4.3) sections.

Transmission power losses are characterized by a factor of 1%/100 miles. In other words, 1% of electrical power is lost for every 100 miles that power travels. Note that distribution losses are not considered endogenously in ReEDS, and are estimated at 5.3% of end-use demand.[92] Distribution losses do not apply to distributed utility-scale and rooftop PV, however, as these technologies are assumed to be located within distribution networks.

### A.2.6 Financial Parameters

General financial parameters used in ReEDS are shown in Table A-17. The 5.5% real discount rate is based on a weighted average cost of capital (WACC) using a 15% nominal rate of return on equity (RROE), 7% nominal interest rate, 3% inflation rate, 35% federal tax rate, and 5% state tax rate. These financial assumptions are described in more detail in Chapter 8.

**Table A-17. General Financial Parameters in ReEDS**

| | |
|---|---|
| Inflation | 3% |
| Nominal Interest Rate | 7% |
| Nominal Rate of Return On Equity (RROE) | 15% |
| Debt Fraction | 60% |
| Federal Tax | 35% |
| State Tax | 5% |
| Real Discount Rate [weighted average cost of capital (WACC)] | 5.5% |



Technology-specific financial parameters used in ReEDS are shown in Table A-18. The construction cost multiplier, when multiplied by overnight capital costs of each technology, represents the adjustment on capital cost due to the interest payments during the construction period. All technologies use the general interest rate and required RROE (Table A-17), except that 6% carbon risk premiums (real) on interest rate and required RROE are applied to coal technologies.[93] Renewable technologies also have modified accelerated cost recovery system (MACRS) depreciation schedules. Solar technologies have a 30% investment tax credit (ITC) until 2016 and 0% ITC thereafter. Wind technologies receive a production tax credit of about $21/megawatt-hours (MWh) through 2012. The capital cost financial multiplier encompasses the effects of all financial parameters on the capital cost (e.g., construction costs, depreciation, financing, and taxes) and, when multiplied by overnight capital cost, represents the present value of revenue that a project must have to recover all costs over a 20-year evaluation period. This is the adjustment to

[92] Distribution losses were estimated based on the difference between AEO 2010 projections of transmission and distribution (T&D) losses through 2030 and ReEDS reference case projections of transmission losses alone through 2030. ReEDS only models interzonal transmission losses (between PCAs), so the distribution loss estimates also include intrazonal transmission losses (within PCAs).
[93] The 6% carbon premium is equivalent to the medium range of values being used by utilities in long-term resource planning (Barbose et al. 2008).

**Table A-18. Financial Parameters by Technology in ReEDS**

| Plant Type | Construction Cost Multiplier | Interest/RROE Real Risk Adjustment | ITC | Depreciation (years) | Capital Cost Financial Multiplier |
|---|---|---|---|---|---|
| Hydro | 1.03 | 0.00 | 0.0 | 15 | 1.32 |
| Gas-CT | 1.03 | 0.00 | 0.0 | 15 | 1.32 |
| Gas-CC | 1.05 | 0.00 | 0.0 | 15 | 1.34 |
| Coal | 1.14 | 0.06 | 0.0 | 15 | 2.06 |
| Coal-IGCC | 1.14 | 0.06 | 0.0 | 15 | 2.06 |
| OGS | 1.14 | 0.00 | 0.0 | 15 | 1.46 |
| Nuclear | 1.14 | 0.00 | 0.0 | 15 | 1.46 |
| Geothermal | 1.07 | 0.00 | 0.1 | 15 | 1.06 |
| Biomass | 1.07 | 0.00 | 0.0 | 15 | 1.21 |
| Cofire | 1.14 | 0.06 | 0.0 | 15 | 2.06 |
| Wind | 1.03 | 0.00 | 0.0 | 5 | 1.17 |
| CSP (pre-2016) | 1.03 | 0.00 | 0.3 | 5 | 0.74 |
| CSP (post-2016) | 1.03 | 0.00 | 0.0 | 5 | 1.17 |
| Util. PV (pre-2016) | 1.02 | 0.00 | 0.3 | 5 | 0.73 |
| Util. PV (post-2016) | 1.02 | 0.00 | 0.0 | 5 | 1.16 |
| Pumped Hydro | 1.03 | 0.00 | 0.0 | 15 | 1.32 |
| Battery | 1.02 | 0.00 | 0.0 | 15 | 1.31 |
| CAES | 1.05 | 0.00 | 0.0 | 15 | 1.34 |

ITC: investment tax credit

capital cost used by ReEDS for each technology as the technologies compete to minimize overall 20-year present value costs of the system.

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### A.2.6.1 State Renewable Portfolio Standards and Incentives

Table A-19 presents the RPS goals used in ReEDS as obtained from the Database of State Incentives for Renewables & Efficiency (DSIRE) (DSIRE 2010). The state RPS 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 the requirement by importing electricity. In addition, the states of Delaware, Illinois, Maryland, Missouri, North Carolina, New Hampshire, New Jersey, New Mexico, Nevada, Ohio, and Pennsylvania have solar set-asides, which require that a certain fraction of the RPS be met specifically with solar resources. In the SunShot scenario, the deployment of solar and wind in the long-term in general vastly exceeds the state RPS targets.

In addition to the federal wind production tax credit, the states of Iowa, Idaho, Minnesota, New Jersey, New Mexico, Oklahoma, Washington, and Wyoming have state-level production or investment incentives for wind.

**Table A-19. State RPS Requirements as of July 2010**

| State | RPS Start Year | RPS Full Implementation | RPS (%) |
|---|---|---|---|
| AZ | 2006 | 2025 | 6.2 |
| CA | 2004 | 2020 | 32.4 |
| CO | 2007 | 2020 | 19.4 |
| CT | 2006 | 2020 | 21.5 |
| DE | 2008 | 2021 | 13.9 |
| IL | 2008 | 2025 | 22.1 |
| KS | 2011 | 2020 | 15.6 |
| MA | 2004 | 2020 | 19.5 |
| MD | 2006 | 2022 | 19.3 |
| ME | 2000 | 2017 | 39.3 |
| MI | 2012 | 2015 | 10.0 |
| MN | 2010 | 2020 | 27.4 |
| MO | 2011 | 2021 | 9.8 |
| MT | 2008 | 2015 | 10.0 |
| NC | 2010 | 2021 | 11.1 |
| NH | 2008 | 2025 | 23.4 |
| NJ | 2005 | 2021 | 24.9 |
| NM | 2006 | 2020 | 15.2 |
| NV | 2005 | 2025 | 22.0 |
| NY | 2003 | 2015 | 20.9 |
| OH | 2009 | 2024 | 11.0 |
| OR | 2011 | 2025 | 20.4 |
| PA | 2007 | 2021 | 17.5 |
| RI | 2007 | 2019 | 15.8 |
| WA | 2012 | 2020 | 12.7 |
| WI | 2006 | 2015 | 10.1 |

Source: DSIRE (2010)

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## A.2.7 Resource Variability and System Reliability

Variable energy resource (VER) technologies, which include wind, CSP without storage, and PV, produce power that is variable, non-dispatchable, and uncertain. Generally, greater penetrations of these technologies lead to greater levels of curtailment and required operating reserves and a diminished contribution to planning reserve requirements per unit of VER capacity. These requirements are explained more in-depth in the following sub-sections.

In ReEDS, the variability of each VER technology is characterized using simulated hourly power output data, described in the PV, CSP, and wind sections: A.2.4.1 – A.2.4.3. The hourly data were used to calculate the standard deviation of power output for each VER technology in each of the ReEDS time slices. The standard deviation was used to characterize variability of individual technologies, but reserve sharing entities—in ReEDS, the 21 RTO regions shown in Figure A-1—are more concerned with the aggregate variability of all demand and generation on the system. To more fully capture aggregate variability, 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 VER technology in each time slice, were used in calculations of curtailment, capacity value, and operating reserve requirements, each described in the following sections.

#### A.2.7.1 Variable Energy Resource Curtailment

Because VER generation is variable, there are certain times that VER power exceeds that which can be used by the system. This is often due to higher-than-expected VER outputs, lower-than-expected electrical demand, transmission constraints, and minimum loading constraints that force other generators to stay online. At these times the total generated power is in excess of the demand, and the excess power must be non-economically curtailed.

ReEDS estimates expected levels of curtailment induced by VER technologies (as a fraction of VER generation) for each time slice in each RTO region through a statistical expected value calculation. This calculation depends on the probability distributions of electrical demand and VER electrical 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.



#### A.2.7.2 Planning Reserve Requirements and VER Capacity Value

Planning reserve requirements ensure that adequate generating capacity is available during all times of the year by requiring that this capacity be higher than peak demand plus some margin (“reserve margin”). In ReEDS, planning reserve requirements must be satisfied in each PCA in every time slice—with respect to that time slice’s peak expected demand. The specific reserve margin that must be satisfied depends on the NERC region/subregion associated with each PCA. Table A-20 shows these requirements by NERC region.

All dispatchable generator-types, including CSP systems with storage, count their full capacity toward the reserve margin requirement. This is not the case, however, for VER technologies such as wind, CSP without storage, and PV, since these technologies certainly cannot be relied on to contribute more than their expected output, which is simply based on the technology’s capacity factor during each time slice. In addition, the variability of VER technologies about their expected output further reduces the amount they can contribute. The fraction of capacity that can be reliably counted toward the planning reserve requirement is referred to as the “capacity value” of the plant. To determine the capacity value associated with a VER technology, a statistical effective load-carrying capability (ELCC) calculation

**Table A-20. Reserve Margin Requirements (Above Peak Time Slice Demand) by NERC Region**

| | |
|---|---|
| East Central Area Reliability Coordination Agreement (ECAR) | 15% |
| Electric Reliability Council of Texas (ERCOT) | 13% |
| Mid-Atlantic Area Council (MAAC) | 15% |
| Mid-America Interconnected Network (MAIN) | 15% |
| Mid-Continent Area Power Pool (MAPP) | 15% |
| New York (NY) | 15% |
| New England (NE) | 15% |
| Florida Reliability Coordinating Council (FRCC) | 16% |
| Southeastern Electric Reliability Council (SERC) | 15% |
| Southwest Power Pool (SPP) | 14% |
| Northwest Power Pool (NWP) | 17% |
| Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA) | 17% |
| California (CA) | 17% |

is performed in ReEDS between every 2-year optimization period. The ELCC is defined as the amount of electrical demand that may be added in each time slice for an incremental increase in capacity of a given VER technology without increasing the loss of load probability.

The capacity value for wind, PV, and CSP without storage is calculated independently for each time slice. In general, for a given PCA, the planning reserve constraint is only important in the most stringent time slice, whereas in the other time slices, the requirement will be exceeded. For example, in a PCA with a summer peak demand, the planning reserve constraint is usually most stringent in the summer afternoon time slice. However, with large-scale solar deployment, the constraint could become more stringent in the summer evening time slice than in the summer afternoon. Because of this, as PV penetration increases, its capacity value can drop dramatically from relatively high values (in the summer afternoon) to very low values (during the evening hours).

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### A.2.7.3 Operating Reserves

In addition to ensuring adequate capacity to satisfy long-term planning reserve requirements, ReEDS requires adequate operating reserve capacity to meet daily operating reserve requirements. Operating reserve requirements ensure that there is enough flexible generator capacity (spinning or quick-start capable) or responsive demand (interruptible load) that can be dispatched to meet unanticipated changes in loads and/or power availability. In ReEDS, these requirements must be satisfied in each RTO in all time slices.

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 (e.g., in less than 10 minutes).

- *Quick-start reserves.* Technologies that can start up quickly (~10 minutes) from an off state, such as gas-CT.
- *Interruptible load.* Agreements between utilities and consumers that allow partial utility control of demand.

Operating reserve requirements included in ReEDS are:

- *Contingency reserve requirements.* These requirements ensure that an unanticipated change to the operational status of generators or transmission lines (e.g., due to unforeseen outages) will not cause an extended disruption to electricity end users. In ReEDS, the contingency reserve requirement is set at 6% of average demand in each time slice. At least half of this requirement must be met with spinning reserves or interruptible load whereas the other half can be met by quick-start units. The relevant time scale for contingency events is about 10 minutes.
- *Frequency regulation reserve requirements.* These requirements ensure that sub-minute deviations between demand and generation can be minimized. Due to the short time scales involved, only spinning reserves can satisfy the frequency regulation requirements. In ReEDS, this requirement is set at 1.5% of average demand in each time slice.
- *Additional VER regulation reserve requirements.* These requirements ensure that additional spinning reserves, beyond the 1.5% of average demand, are available to handle minute-level wind and PV[94] variability. In ReEDS, this requirement is assumed to be three standard deviations of 10-minute wind persistence forecast error (Ela et al. 2011). Sample wind data were used to develop a relationship between wind capacity factor and standard deviation per capacity of wind. Due to a lack of 10-minute PV data, the same relationship was assumed between PV capacity factor and standard deviation.
- *VER forecast error reserve requirements.* These requirements ensure stability of the system despite uncertainties in forecasting for wind and PV. Generally, forecast error reserve requirements increase as wind and PV penetration grows. The forecast error reserve requirements for wind and PV in ReEDS are assumed to be two standard deviations (Zavadil et al. 2004) of their respective average forecast errors in each RTO in each time slice. Forecasts for wind are assumed to be simple hourly persistence forecasts, based on simulated wind power output data (EnerNex 2010, GE 2010) for each wind resource class of each ReEDS region. In other words, wind forecast errors are simply the differences between simulated power output from one hour to the next. PV forecasts for a given hour are modified persistence forecasts, using the output from the previous hour as well as the average change between those 2 hours over the previous 15 days to account for the known apparent daily solar trajectory. Since forecast errors occur over longer time scales (roughly an hour) than contingency or frequency regulation events, ReEDS assumes that up to five-sixth of the requirement can be met by quick-start units, and the remainder must be met by a combination of spinning reserves and interruptible load.

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[94] CSP without storage is considered to have enough thermal inertia (about 30 minutes) to not require additional operating reserves.

## A.2.8 Direct Electric-Sector Costs

Overall system costs (see Chapter 3) include investments in electrical power generating capacity, reserve capacity, and transmission capacity, as well as fuel and operation and maintenance (O&M) costs. To better reflect overall societal cost, these costs do not include financing or financial incentives (for instance, the federal ITC), nor do they include taxes.

Overall present value of system costs through 2030 include all capital investments until 2030 as well as operation costs of the 2030 system until 2050. Likewise, present value costs through 2050 include all capital investments through 2050 as well as operation costs of the 2050 system through 2070. This methodology captures the additional fuel cost savings of the SunShot scenario over the reference scenario post 2030 and post 2050, respectively.

To calculate the present value of costs, a 7% discount rate was used, under guidance from the U.S. Office of Management and Budget (OMB 2003), with 2010 as the base year.

## A.2.9 Electricity Price

Electricity price is calculated in ReEDS for every 2-year time period of the model. The electricity price is meant to reflect a regulated electricity market structure. There are three main components of electricity price:

- *Rate-base.* The rate-base includes annual payments on all investments in electrical power generator capacity, reserve capacity, and transmission capacity. The investments made in each 2-year time period of the model are assumed to be paid off over the next 30 years.
- *Generation Costs.* Generation costs include all fuel and O&M costs.
- *Non-Generation Transaction Costs.* The two components above are used to determine wholesale electricity prices, and this component includes all utility maintenance fees, administrative fees, and profit margins that mark-up wholesale rates to retail rates. ReEDS does not endogenously calculate non-generation transaction costs, and these costs are assumed to be fixed over time in ReEDS. The costs are assumed to be equal to the difference between historical retail rates in the start year of the model (2006) and the ReEDS-calculated wholesale rates (i.e., rate-base plus generation costs) in 2006.

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## A.2.10 Electric Power Demand Projections

The electrical demand forecast for the SunShot and reference scenarios was taken from the reference scenario of the *AEO 2010* (EIA 2010) and represents a "business as usual" growth in electricity demand. As ReEDS does not represent on-site generation technologies, this electricity demand projection does not include demand met by on-site generation. This NERC-level demand data were distributed among ReEDS PCAs using county-level demand data in 2006 (Ventyx 2006) and assuming that the fraction of NERC-level demand met by each PCA in each NERC region remains constant at 2006 levels through 2050.

# A.3 Solar Deployment System Model

The SolarDS model was used in the *SunShot Vision Study* to simulate the evolution of residential and commercial rooftop PV markets. SolarDS is a bottom-up, market-penetration model that simulates residential and commercial rooftop PV markets in the continental United States through 2050 (Denholm et al. 2009). SolarDS was developed by NREL to examine the market competitiveness of rooftop PV based on regional solar resources, capital costs, financing structures, electricity prices, utility rate structures, net metering, carbon policy, and federal and local incentives.

SolarDS simulates PV markets at a high level of regional disaggregation by calculating hourly PV generation in 216 solar resource regions (Figure A-7) and combining PV output with state-based electricity rate distributions calculated using rate data from thousands of electric service providers. Regional PV economic performance is used to simulate PV adoption rates for six residential customer types (new and retrofit construction on three building types) and 28 commercial customer types (new and retrofit construction for 14 different customer/building types). Adoption rates are combined with a residential and commercial building stock database—accounting for building type,[95] roof orientation, roof shading, and building ownership—to calculate the annual and cumulative installed PV capacity. More detail on this methodology can be found in the SolarDS model documentation (Denholm et al. 2009).

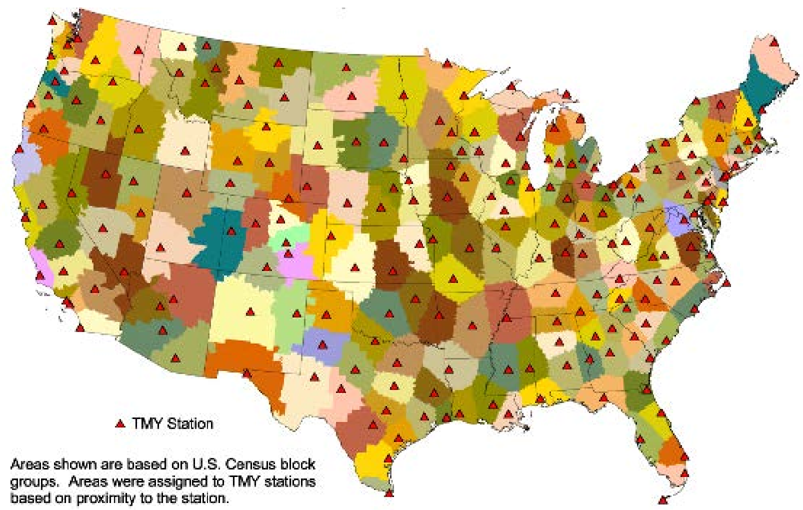
## A.3.1 Rooftop PV Economics

PV revenues are characterized by combining regional PV generation, state-based retail electricity rate distributions, tax burdens, incentives, and net-metering[96] parameters. Regional PV generation is characterized using data from 216 Typical Meteorological Year (TMY) stations, as shown in Figure A-7. PV output is calculated for several roof orientations, including flat-mounted modules and tilted modules (representative of a common roof tilt) with azimuth orientations ranging from ±90° from the south in 30° increments. Alternating current PV output is calculated for each location and orientation using the PVFORM/PVWATTS model (Marion et al. 2005).

Local retail electricity rates vary significantly within and between states. SolarDS characterizes the distribution of customer rate structures (flat, time-of-use, and demand-based rates) using tariff sheets from the largest service providers in each state. SolarDS characterizes the distribution of retail electricity rates for each state using Energy Information Administration (EIA) form 861 data (EIA 2007), which provide total revenue and sales for more than 3,000 electric service providers in the United States. Electricity rate escalations are projected through 2035 using EIA's *Annual Energy Outlook 2010* (EIA 2010) and extrapolated from 2035 to 2050 using

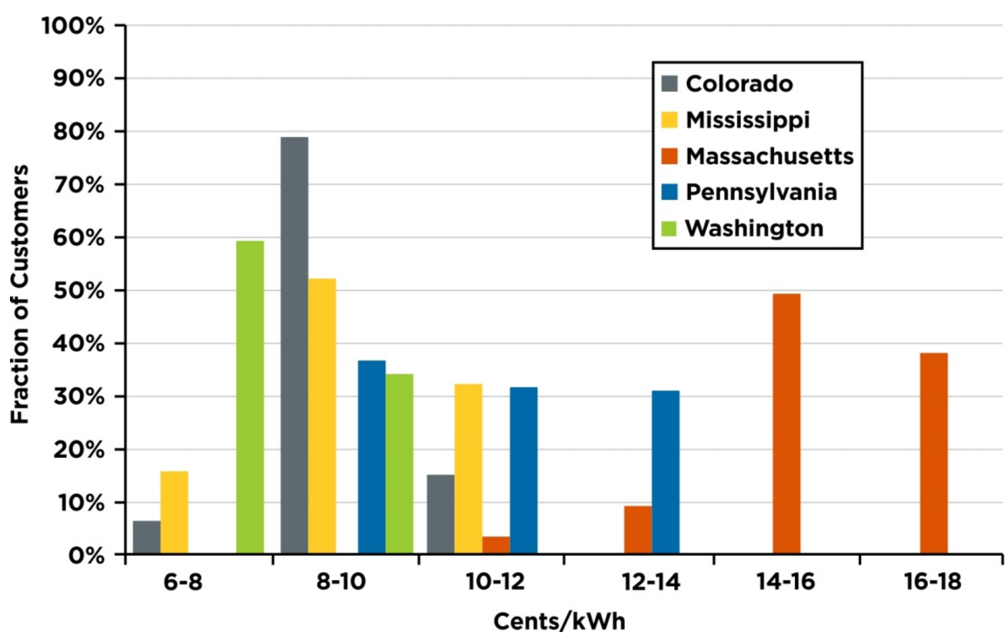
[95] The size of residential rooftop PV installations varies by building type, ranging from 4–6 kilowatts (kW) for single family homes. Commercial PV installation size also varies by building type, ranging from about 30–200 kW.
[96] A fraction of PV generation directly offsets electricity purchased from the grid and receives retail electricity rates, and the remaining fraction of PV generation is exported to the grid. In this analysis, exported electricity is valued at the marginal cost of electricity from combined-cycle natural gas generation.

**Figure A-7. The 216 Solar Resource Regions Used in SolarDS, with Observation Stations Shown as Red Triangles**




Source: NREL

**Figure A-8. Distribution of State-Level Retail Electricity Rates for Residential Customers Calculated Using Utility Rate Sheets**

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the mean *AEO* growth rates from 2025 to 2035. Figure A-8 illustrates the distribution of retail electricity rates for residential customers in five U.S. states and the differences among the states.

Rooftop PV prices and financing costs were simulated for the *SunShot Vision Study* using PV price projections from Chapter 4 and financing terms from Chapter 8. Current state and federal PV incentives were included in all SolarDS scenarios. Both the reference and SunShot scenarios were simulated using conservative assumptions, including no future incentives that are not currently in place, conservative net metering, and no carbon policy.

PV revenue streams and price projections are combined into annual cash flows that are used to generate PV payback times. Annual PV cash flows are calculated as follows:

Annual Cash Flow (t) = – Loan Down payment (t = 0)
+ State and Federal Tax Incentives (t = 1)
+ Avoided Electricity Costs (t)
+ Tax Savings on Loan Interest (t)
– Loan Payment (t)
– Operations and Maintenance Costs (t)

The loan down payment is assumed to be an upfront cost paid before the first year of ownership. State and federal incentives are assumed to be earned during the first year of ownership. All other costs and revenues are calculated annually. Annual cash flows are used to calculate region-specific PV payback times. Payback time is defined differently for residential and commercial systems following EIA (2010). Residential payback is defined as the time required for the money invested in a PV project to be recouped through system revenues and to stay positive for the remainder of the investment period. This measure of payback is frequently used in the PV literature (Nofuentes et al. 2002, Sidiras and Koukios 2005, Audenaert et al. 2010) and is calculated by finding the minimum time required to satisfy the following two constraints:

$$\sum_{t=0}^{Payback\ Time} \frac{Revenue_t - Cost_t}{(1+d)^t} > 0$$

$$\sum_{t=Payback\ Time}^{N} \frac{Revenue_t - Cost_t}{(1+d)^t} > 0$$

The first constraint identifies the time required for the cumulative system revenues to exceed cumulative system costs, and the second constraint ensures that this condition is met for the duration of the PV investment.

Commercial PV payback times are defined based on the internal rate of return (IRR) of project cash flows following EIA (2010). IRR represents the discount rate at which the project net present value (NPV) equals zero and is calculated using the following relationship:

$$NPV = \sum_{t=0}^{N} \frac{Revenue_t - Cost_t}{(1+IRR)^t} = 0$$

IRRs are frequently interpreted as annualized investment returns, and we define an IRR-based payback time by calculating the time required for an investment accruing at the system IRR to double in value, following EIA (2010):

$$(1+IRR)^{Payback\ Time} = 2$$

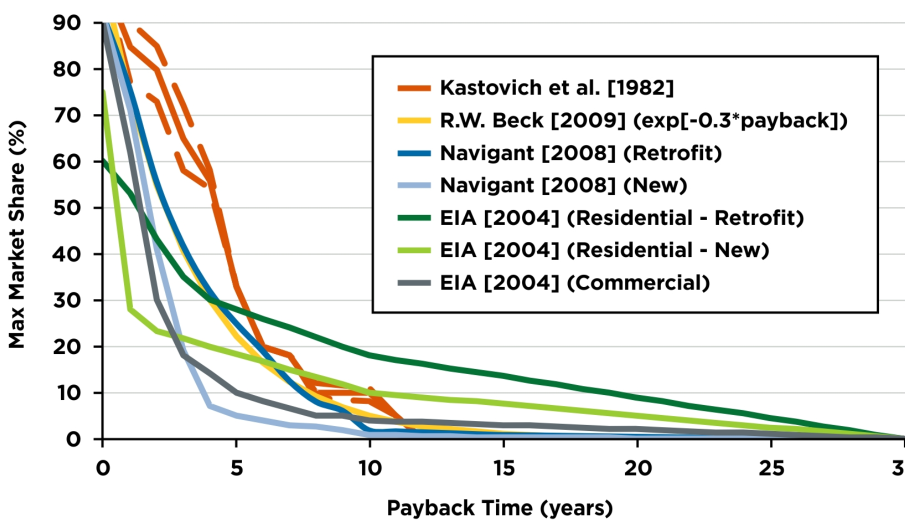
$$Payback\ Time = \frac{log(2)}{log(1+IRR)}$$

These equations are used to calculate PV payback times, which are then used to simulate customer adoption behavior as described in the next section.

## A.3.2 Rooftop PV Adoption

PV adoption is simulated using a semi-empirical relationship between PV payback time and the maximum fraction of customers that might adopt PV (Kastovich et al. 1982, EIA 2004, Navigant 2008, R.W. Beck 2009). Maximum customer adoption fractions are approximated based on survey studies and expert elicitations from industry participants. Figure A-9 shows maximum market share relationships derived and used in previous studies. The reference and SunShot scenarios use the market share adoption curves developed by Navigant Consulting (2008).[97]

**Figure A-9. Relationship between PV Maximum Market Share and PV Payback Time, Representing the Fraction of Customers Likely to Invest in PV for a Range of Payback Times**




After the maximum market share is estimated, PV is diffused into this maximum market using a Bass diffusion model (Bass 1969). The Bass model represents the interaction of early technology adopters and late adopters to simulate a characteristic S-shaped technology-diffusion relationship. The following equation expresses a solution to the differential Bass equation,[98] and it represents the potential diffusion of PV technology into the maximum market share estimated by the relationships in Figure A-9:

[97] For a description of the impacts of using different market-adoption assumptions, see Drury et al. (2010).

[98] The Bass diffusion characteristics depend on the economics of a PV system, with quicker adoption for more economic systems. See Denholm et al. (2009) for a detailed description.

$$Adoption\ Rate\,(t) = \frac{1 - e^{-(p+q)T}}{1 + \left(\frac{q}{p}\right) e^{-(p+q)T}}$$

Where $t$ represents the model year, $T$ represents the total number of years that PV has been commercially available in the market, $p$ represents the *coefficient of innovation* (used to characterize the impact of early PV adopters), and $q$ represents the *coefficient of imitation* (used to characterize the impact of late PV adopters). The $p$ and $q$ parameters are varied in the SolarDS model based on the economics of PV systems such that PV diffuses more quickly as payback times decrease. The $T$ parameter is also modified to better represent early and late adopters for each region independently (Denholm et al. 2009).

The final step in simulating rooftop markets is to calculate PV capacity additions from the customer adoption characteristics. This is done using a residential and commercial building stock database and statistically filtering this database to remove shaded roofs, obstructed roof space, and roofs that are unsuitable for PV adoption. The remaining building stock is scaled by the associated market adoption fractions using a distribution of customer- and building-dependent PV system sizes; residential systems have mean sizes of approximately 5 kW, and commercial systems have mean sizes of approximately 75–100 kW, depending on the deployment scenario. Using this methodology, the technical potential of the residential and commercial rooftop PV markets is approximately 300 GW each. Approximately 132 GW of commercial and 108 GW of residential rooftop PV capacity is deployed in the SunShot scenario by 2050.

The distributed rooftop PV capacity projections from SolarDS are exogenously input into the ReEDS model for each year of the simulation. Rooftop PV capacity is characterized for each ReEDS PCA region, and hourly PV generation profiles are calculated based on the mix of rooftop orientations that are deployed in SolarDS.



## A.4 GridView Model

Designed and marketed by ABB, Inc., GridView is a commercial unit commitment and hourly economic dispatch model that simulates the financial operation of the electric power system with a constrained transmission grid based on a DC power flow (ABB 2008). GridView commits and dispatches electric generating units in order to minimize the production cost of the system as a whole while meeting electricity demand and reliability reserve requirements. GridView models the same generation technologies that are represented in ReEDS, including thermal generators,[99] hydroelectric generators and pumped storage, variable generators such as wind and PV, CSP with thermal storage, and CAES. GridView also represents interruptible load, as does ReEDS.

[99] The thermal generators modeled in GridView include generators that utilize conventional fuels (e.g., natural gas, coal, and uranium) and renewable fuels (e.g., biomass and geothermal).

GridView minimizes the total system production cost—including generator dispatch, transmission violation penalty, and unserved load penalty costs—via the following objective function:

$$Total\_Cost = \min\left[\sum_t \left\{\sum_i \left(C_i\left(q_{i,t}\right) + N_i u_{i,t} + SU_i s_{i,t}\right) + penalties\right\}\right]$$

Where the decision variable $q_{i,t}$ represents the generation provided by generator $i$ in hour $t$ and $u_{i,t}$ and $s_{i,t}$ are binary variables that indicate whether unit $i$ is up and has been started up (respectively) during hour $t$. Parameters $C_i(q_{i,t})$, $N_i$, and $SU_i$ represent the piecewise linear generating cost function, no-load cost, and startup cost for generator $i$. The optimization is subject to a number of constraints, which are simplified in the equations below. One of the constraints is system energy balance:

$$D_t = \sum_i q_{i,t}$$

Where $D_t$ is the system demand at time $t$. Spinning reserves are another constraint:

$$\sum_i sp_{i,t} \geq SR \quad ; \qquad sp_{i,t} + q_{i,t} \leq Cap_i$$

Where $sp_{i,t}$ is the spinning reserves provided by generator $i$ at time $t$. $SR$ is the spinning reserve requirement for the system, which depends on solar and wind penetrations. $Cap_i$ is the maximum capacity at generator $i$. Constraints also bound generator operating limits, startup costs, ramping constraints, and transmission line ratings.

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In the present study, GridView is used to supplement the ReEDS analysis by modeling the detailed operation of the system in 2050 for the SunShot scenario. GridView helps to demonstrate the operational feasibility of a system with high solar and wind penetration by using an hourly time step, a more accurate representation of thermal generation ramp-rate limits, and a more realistic representation of transmission power flows as compared to ReEDS. As a result of these capabilities, GridView can analyze how the system responds to uncertain ramps in the output of variable generation and provides a more complete understanding of the need for curtailment in times when generation supply exceeds demand.

The inputs for the GridView analysis are based on the ReEDS results from the SunShot scenario in 2050. Transmission capacity and generator fleet expansion results from ReEDS are input into GridView as individual units and lines. The database of existing electric system infrastructure comes from the WECC Transmission Expansion Planning Policy Committee, ERCOT, and the NERC Multiregional Modeling Working Group. The electric power systems represented in these three datasets were merged into a single database, connected with high-voltage direct current (HVDC) lines (as modeled by ReEDS), and centrally dispatched to minimize production cost. The assumption of nationwide dispatch represents either a single system operator that manages the entirety of the U.S. electric system or frictionless markets between separate system operators. The transmission system in GridView is capable of operating in a detailed nodal format, where every major substation and transmission line is modeled individually. However, computational constraints and the spatial resolution of the ReEDS output limited the GridView analysis conducted in the present study to an aggregated zonal format, where transmission constraints are modeled only across the interfaces between the 134 assumed PCAs as defined by ReEDS.

## A.5 References


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# Appendix B. Tables Supporting Chapter 3 Figures

This appendix provides the raw data results from the Regional Energy Deployment System (ReEDS) associated with figures in *Chapter 3: Analysis of PV and CSP Growth in the SunShot Scenario*.

**Table B-1. Figure 3-1. Cumulative Installed Capacity for Rooftop Photovoltaics (PV), Utility-Scale PV, Concentrating Solar Power (CSP), and All Solar Technologies [gigawatts (GW)]**

| | Rooftop PV | Utility PV | CSP | Total Solar |
|---|---|---|---|---|
| 2010 | 1 | 0 | 0 | 2 |
| 2015 | 4 | 5 | 2 | 11 |
| 2020 | 19 | 31 | 3 | 53 |
| 2025 | 63 | 106 | 12 | 182 |
| 2030 | 121 | 181 | 28 | 329 |
| 2035 | 169 | 256 | 47 | 472 |
| 2040 | 201 | 331 | 62 | 594 |
| 2045 | 221 | 370 | 74 | 666 |
| 2050 | 240 | 391 | 83 | 714 |

**Table B-2. Figure 3-2. Evolution of Electricity Generation in SunShot and Reference Scenarios (“Other” Includes Biomass and Geothermal Technologies) [terawatt-hours (TWh)]**

| | 2010 Gen | 2030 Reference | 2030 SunShot | 2050 Reference | 2050 SunShot |
|---|---|---|---|---|---|
| Nuclear | 790 | 757 | 757 | 448 | 448 |
| Coal | 1,849 | 1,600 | 1,561 | 2,215 | 1,411 |
| Gas-CC | 762 | 1,333 | 966 | 1,603 | 1,406 |
| Gas-CT | 11 | 34 | 25 | 37 | 27 |
| Oil-gas-steam | 31 | 51 | 49 | 0 | 0 |
| Hydro | 277 | 280 | 278 | 280 | 279 |
| Other | 27 | 65 | 49 | 65 | 48 |
| Wind | 115 | 342 | 236 | 435 | 283 |
| CSP | 1 | 4 | 137 | 9 | 412 |
| Utility PV | 0 | 17 | 335 | 68 | 710 |
| Distributed PV | 2 | 34 | 155 | 81 | 302 |
| Storage | 0 | 0 | 0 | 0 | 0 |

Gas-CC = combined cycle natural gas plant; Gas-CT = gas combustion turbine

**Table B-3. Figure 3-3. Annual Avoided Fuel Use in the SunShot Scenario**

| | 2030 | 2050 |
|---|---|---|
| Gas Use (Quad/yr) | 2.6 | 1.5 |
| Coal Use (Quad/yr) | 0.4 | 7.3 |
| Fuel Cost (Bil$/yr) | 34 | 41 |

Quad: quadrillion British thermal units

**Table B-4. Figure 3-4. Evolution of Electricity-Generation Capacity in SunShot and Reference Scenarios ("Other" Includes Biomass and Geothermal Technologies) (GW)**

| | 2010 Capacity | 2030 Reference | 2030 SunShot | 2050 Reference | 2050 SunShot |
|---|---|---|---|---|---|
| Nuclear | 100 | 96 | 96 | 57 | 57 |
| Coal | 309 | 218 | 213 | 300 | 192 |
| Gas-combined cycle (CC) | 164 | 249 | 181 | 333 | 275 |
| Gas-combustion turbine (CT) | 125 | 248 | 223 | 335 | 314 |
| Oil-gas-steam | 135 | 98 | 98 | 24 | 24 |
| Hydro | 78 | 79 | 79 | 79 | 79 |
| Other | 4 | 9 | 7 | 9 | 7 |
| Wind | 44 | 107 | 79 | 132 | 91 |
| CSP | 0 | 2 | 28 | 3 | 83 |
| Utility PV | 0 | 9 | 181 | 32 | 391 |
| Distributed PV | 1 | 25 | 121 | 62 | 240 |
| Storage | 20 | 38 | 29 | 43 | 38 |

**Table B-5. Figure 3-6. Cumulative Installed PV and CSP Capacity in the SunShot Scenario in 2030 and 2050 (GW)**

| | 2030 PV | 2030 CSP | 2050 PV | 2050 CSP |
|---|---|---|---|---|
| Alabama | 2.3 | 0 | 6.6 | 0 |
| Arizona | 14.2 | 10.1 | 23.5 | 22.6 |
| Arkansas | 1.6 | 0 | 10.2 | 0 |
| California | 38.4 | 10.1 | 53.4 | 24.2 |
| Colorado | 6.3 | 2.1 | 11.7 | 8.2 |
| Connecticut | 5.3 | 0 | 8.1 | 0 |
| Delaware | 1.6 | 0 | 4.5 | 0 |
| Florida | 39.1 | 1.9 | 74.7 | 1.9 |
| Georgia | 13.1 | 0 | 25.5 | 0 |
| Idaho | 0.5 | 0 | 1.7 | 0 |
| Illinois | 2.6 | 0 | 6.1 | 0 |
| Indiana | 6 | 0 | 26.4 | 0 |
| Iowa | 1.6 | 0 | 2.7 | 0 |
| Kansas | 4 | 0 | 10.2 | 0 |
| Kentucky | 2.5 | 0 | 5.9 | 0 |
| Louisiana | 3.6 | 0 | 5.4 | 0 |
| Maine | 0.8 | 0 | 1.4 | 0 |
| Maryland | 7.5 | 0 | 13.3 | 0 |
| Massachusetts | 2.7 | 0 | 5 | 0 |
| Michigan | 2.8 | 0 | 18.8 | 0 |
| Minnesota | 2 | 0 | 7.4 | 0 |
| Mississippi | 1.2 | 0 | 7 | 0 |
| Missouri | 5.6 | 0 | 9.8 | 0 |
| Montana | 0.4 | 0 | 1.4 | 0 |
| Nebraska | 1.3 | 0 | 2.2 | 0 |
| Nevada | 5.4 | 0.5 | 8.7 | 2.3 |
| New Hampshire | 0.6 | 0 | 1 | 0 |
| New Jersey | 7.2 | 0 | 14.2 | 0 |
| New Mexico | 3.4 | 2.1 | 6.9 | 9.6 |
| New York | 7.7 | 0 | 19.2 | 0 |
| North Carolina | 8.2 | 0 | 21.7 | 0 |
| North Dakota | 0.2 | 0 | 0.8 | 0 |
| Ohio | 3.8 | 0 | 13.3 | 0 |
| Oklahoma | 11.1 | 0.2 | 15.7 | 0.5 |
| Oregon | 0.6 | 0 | 3.6 | 0 |
| Pennsylvania | 4.8 | 0 | 14.7 | 0 |
| Rhode Island | 2.6 | 0 | 4.4 | 0 |
| South Carolina | 14.5 | 0 | 18.8 | 0 |
| South Dakota | 0.3 | 0 | 0.6 | 0 |
| Tennessee | 3.9 | 0 | 19.4 | 0 |
| Texas | 41 | 0.6 | 78.4 | 12.6 |
| Utah | 6.3 | 0.1 | 12.8 | 1.1 |
| Vermont | 0.3 | 0 | 2.3 | 0 |
| Virginia | 8.7 | 0 | 21.2 | 0 |
| Washington | 1.9 | 0 | 2.3 | 0 |
| West Virginia | 0.2 | 0 | 1.5 | 0 |
| Wisconsin | 1.4 | 0 | 5 | 0 |
| Wyoming | 0.2 | 0 | 1.7 | 0 |

**Table B-6. Figure 3-7. Fractions of CSP, PV, and Wind Electricity Generation in Each Interconnection for the SunShot Scenario**

| | Wind | PV | CSP |
|---|---|---|---|
| 2030 Western | 6% | 16% | 14% |
| 2030 Electric Reliability Council of Texas (ERCOT) | 6% | 14% | 0% |
| 2030 Eastern | 5% | 9% | 0% |
| 2050 Western | 6% | 23% | 33% |
| 2050 ERCOT | 6% | 21% | 7% |
| 2050 Eastern | 5% | 18% | 1% |

**Table B-7. Figure 3-10. Net Energy Transmitted Between Interconnections (Negative Values Represent Imported Energy, Positive Values Represent Exported Energy) (TWh)**

| | Western to Eastern | Eastern to ERCOT |
|---|---|---|
| Reference 2030 | -9 | -7 |
| SunShot 2030 | 14 | 3 |
| Reference 2050 | -6 | 7 |
| SunShot 2050 | 64 | -2 |

**Table B-8. Figure 3-11. Comparison of the National Generation Mix Simulated in GridView and ReEDS for the Reference and SunShot Scenarios, 2050**

| | ReEDS 2050 Reference | GridView 2050 Reference | ReEDS 2050 SunShot | GridView 2050 SunShot |
|---|---|---|---|---|
| PV | 2.8% | 2.8% | 18.8% | 19.2% |
| CSP | 0.2% | 0.2% | 7.5% | 7.1% |
| Wind | 7.9% | 8.0% | 5.1% | 5.3% |
| Other | 1.6% | 1.4% | 1.3% | 1.1% |
| Hydropower | 6.5% | 6.3% | 6.4% | 6.4% |
| Gas-CT | 0.7% | 3.1% | 0.5% | 2.7% |
| Gas-CC | 29.2% | 26.3% | 25.5% | 23.7% |
| Coal | 43.4% | 44.0% | 28.2% | 28.5% |
| Nuclear | 8.2% | 7.9% | 8.1% | 7.9% |
| Curtailment | -0.3% | 0.0% | -1.4% | -1.7% |

**Table B-9. Figure 3-14. Direct Electric-Sector Costs for the Reference and SunShot Scenarios (Billion $)**

| | Reference 2010–2030 | SunShot 2010–2030 | Reference 2010–2050 | SunShot 2010–2050 |
|---|---|---|---|---|
| Conventional Capital | 165 | 114 | 315 | 203 |
| Conventional O&M | 717 | 703 | 748 | 723 |
| Fuel | 1,566 | 1,407 | 1,739 | 1,544 |
| Transmission | 45 | 41 | 61 | 60 |
| Other Renewables | 317 | 269 | 368 | 303 |
| CSP | 8 | 45 | 10 | 83 |
| Utility PV | 20 | 92 | 28 | 133 |
| Distributed PV | 29 | 74 | 40 | 101 |

O&M: operation and maintenance

**Table B-10. Figure 3-15. Average U.S. Retail Electricity Rates in the SunShot and Reference Scenarios [2010 cents/kilowatt-hour (kWh)]**

| | Reference | SunShot |
|---|---|---|
| 2010 | 10.1 | 10.1 |
| 2012 | 10.4 | 10.4 |
| 2014 | 10.5 | 10.5 |
| 2016 | 10.6 | 10.6 |
| 2018 | 10.7 | 10.7 |
| 2020 | 10.9 | 10.8 |
| 2022 | 11.1 | 10.9 |
| 2024 | 11.2 | 10.9 |
| 2026 | 11.4 | 10.9 |
| 2028 | 11.6 | 11.1 |
| 2030 | 12 | 11.4 |
| 2032 | 12.3 | 11.6 |
| 2034 | 12.7 | 11.9 |
| 2036 | 12.9 | 12.1 |
| 2038 | 13.2 | 12.3 |
| 2040 | 13.3 | 12.4 |
| 2042 | 13.4 | 12.5 |
| 2044 | 13.5 | 12.6 |
| 2046 | 13.6 | 12.7 |
| 2048 | 13.8 | 12.8 |
| 2050 | 13.9 | 13 |

**Table B-11. Figure 3-16. Annual Electric-Sector Carbon Dioxide ($CO_2$) Emissions in the SunShot and Reference Scenarios [million metric tons (MMT) $CO_2$]**

| | Reference | SunShot |
|---|---|---|
| 2010 | 2,090 | 2,090 |
| 2012 | 2,240 | 2,240 |
| 2014 | 2,220 | 2,220 |
| 2016 | 2,210 | 2,210 |
| 2018 | 2,210 | 2,210 |
| 2020 | 2,210 | 2,210 |
| 2022 | 2,210 | 2,200 |
| 2024 | 2,220 | 2,170 |
| 2026 | 2,220 | 2,120 |
| 2028 | 2,200 | 2,070 |
| 2030 | 2,210 | 2,030 |
| 2032 | 2,270 | 2,000 |
| 2034 | 2,360 | 1,980 |
| 2036 | 2,440 | 1,980 |
| 2038 | 2,530 | 1,990 |
| 2040 | 2,560 | 1,960 |
| 2042 | 2,590 | 1,950 |
| 2044 | 2,630 | 1,950 |
| 2046 | 2,660 | 1,950 |
| 2048 | 2,690 | 1,950 |
| 2050 | 2,710 | 1,950 |

**Table B-12. Figure 3-17. Cumulative Electric-Sector Emissions Reductions in the SunShot Scenario Relative to the Reference Scenario (MMT $CO_2$)**

| | |
|---|---|
| 2010 | 0 |
| 2012 | 0 |
| 2014 | 0 |
| 2016 | 0 |
| 2018 | 0 |
| 2020 | 0 |
| 2022 | 30 |
| 2024 | 140 |
| 2026 | 320 |
| 2028 | 570 |
| 2030 | 940 |
| 2032 | 1,490 |
| 2034 | 2,230 |
| 2036 | 3,150 |
| 2038 | 4,230 |
| 2040 | 5,420 |
| 2042 | 6,710 |
| 2044 | 8,070 |
| 2046 | 9,490 |
| 2048 | 10,970 |
| 2050 | 12,490 |

# Appendix C. Sensitivity of Renewable Electricity Technology Deployment Projections to Technology Price Assumptions

## C.1 Introduction

This appendix examines the sensitivity of renewable electricity technology deployment projections to technology price assumptions. The *SunShot Vision Study* models the effects of reducing the price of solar energy systems by about 75% between 2010 and 2020. In comparison, the prices of conventional and other renewable electricity technologies are assumed to change relatively little during the study period. Because the models used in the analysis project the mix of electricity-generating technologies based on least-cost deployment, solar deployment is dependent on the assumed solar price reductions. Similarly, if the prices of other renewable electricity technologies were varied along with the price of solar technologies, the projected mix of electricity-generating technologies would depend on those price assumptions as well. Scenarios[100] exploring the effects of various solar price reductions and various non-solar renewable price reductions are described below.

## C.2 Sensitivity of Solar Deployment to Solar Prices

To explore the sensitivity of solar deployment to solar technology prices, solar deployment was modeled using two price scenarios, in addition to the SunShot and reference scenarios. These two scenarios included cost reductions that were less aggressive than the SunShot targets: 1) Photovoltaic (PV) prices decline by 50% between 2010 and 2020, and 2) PV prices decline 62.5% between 2010 and 2020. Table C-1 shows the SunShot and sensitivity scenario prices for all solar technologies and applications. The SunShot scenario's 2010 utility-scale PV benchmarked price is \$4/watt (W); thus, the sensitivity scenarios' 2020 utility-scale

[100] Note that these sensitivity scenarios do not assume any potential costs for mercury and air toxins, carbon emissions, or other environmental externalities.

**Table C-1. Price Inputs for SunShot and Sensitivity Scenarios**

| Technology/Application | SunShot Scenario 2020 -75% Price | Sensitivity Scenario 2020 -62.5% Price | Sensitivity Scenario 2020 -50% Price | Reference Scenario 2020 |
|---|---|---|---|---|
| **PV – Residential [$/watt $(W)_{DC}$]** | 1.50 | 2.25 | 3.00 | 3.78 |
| **PV – Commercial ($/$W_{DC}$)** | 1.25 | 1.88 | 2.50 | 3.36 |
| **PV – Utility Scale ($/$W_{DC}$)** | 1.00 | 1.50 | 2.00 | 2.51 |
| **CSP, 6/14 hour Storage ($/$W_{AC}$)[a]** | 3.60 | 4.87 | 6.14 | 6.64 |

[a] All values are for CSP systems with 14 hours of thermal storage except for the reference scenario value, which is for 6 hours of thermal storage.

PV prices are $2/W and $1.50/W, respectively. Similarly, the sensitivity scenarios' 2020 distributed PV (residential and commercial) prices are 50% and 62.5% lower in relation to their 2010 benchmarked prices. For concentrating solar power (CSP), the decline in installed capital cost was set to yield a similar level of relative cost reduction on an LCOE basis, including a shift to increased storage. The increased levels of storage assumed for CSP are reflected in Table C-1 with higher values for capacity factors. All conventional and non-solar renewable technology prices are the same for the SunShot and sensitivity scenarios. In all other parameters, the sensitivity analysis matches the SunShot analysis.

Figure C-1 and Figure C-2 show the results of the sensitivity analysis. In the SunShot scenario, installed solar capacity reaches 330 gigawatts (GW) in 2030 and 715 GW in 2050 (Figure C-1). In the 62.5% price decline scenario, solar capacity reaches 270 GW in 2030 (18% lower than in the SunShot scenario) and 470 GW in 2050 (35% lower). In the 50% price decline scenario, solar deployment drops dramatically: 130 GW in 2030 (59% lower than in the SunShot scenario) and 200 GW in 2050 (73% lower). In the reference scenario, solar capacity reaches 40 GW in 2030 (89% lower than in the SunShot scenario) and 100 GW in 2050 (86% lower). Figure C-2 shows similar results for solar generation fraction. Clearly, solar market penetration is sensitive to the projected level of PV and CSP price reductions. These results indicate that there is a threshold at which solar deployment increases non-linearly as price decreases. This threshold is below $2/W for utility-scale PV (and an equivalent level of price reduction for distributed PV and CSP).



## C.3 Sensitivity of Electricity-Generating Mix to Non-Solar Renewable Energy Prices

To explore the sensitivity of the electricity-generating mix to non-solar renewable technology prices, modeling was performed with non-solar renewable price reductions/performance improvements that are more aggressive than those in the SunShot scenario. These more aggressive assumptions are shown in Table C-2 and are included in the SunShot renewable electricity-evolutionary technology improvement (SSRE-ETI) scenario. SunShot solar price reductions were used both for the SunShot scenario and the SSRE-ETI scenario. In all other parameters, the analysis matched the SunShot analysis.

**Figure C-1. Total Solar Capacity Under a Range of Solar Price-Reduction Scenarios**

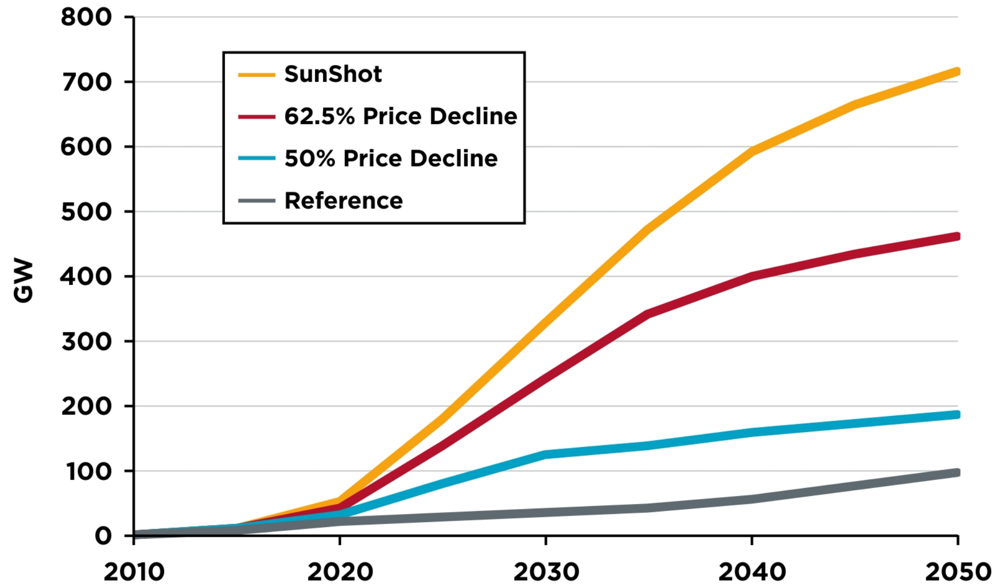


**Figure C-2. Total Solar Generation Fraction Under a Range of Solar Price-Reduction Scenarios**

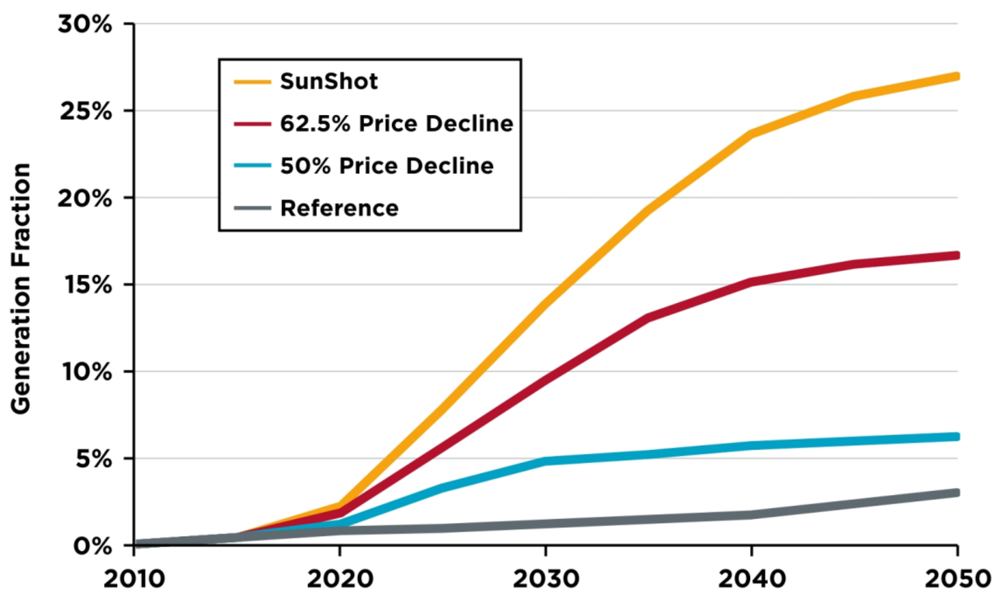


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**Table C-2. Price and Performance Inputs for SunShot and SSRE-ETI Scenarios**

| Technology | Price and Performance | |
|---|---|---|
| | SunShot Scenario | SSRE-ETI Scenario |
| **Solar** | SunShot targets | SunShot targets |
| **Onshore wind** | Reference | Capital cost decreases from about $2,000/kilowatt (kW) to $1,775/kW during 2010–2035. Performance ~10% above reference level in 2010, additional ~10% performance improvement by 2030. Capacity factors substantially higher than in reference. Wind levelized cost of energy (LCOEs) approach solar LCOEs by 2035. |
| **Offshore wind** | Reference | Capital cost decreases from about $3,650/kW to $2,700/kW during 2010–2035. Performance improvements similar to onshore wind. Capacity factors substantially higher than in Reference. |
| **Biopower** | Reference | Capital cost slightly lower, operation and maintenance (O&M) 30%–50% lower than reference. Heat rate starts at lower value than in reference and improves by ~30% during 2010–2050. |
| **Geothermal** | Reference | Capital cost decreases ~10% by 2030 and ~20% by 2050. Includes about 25 GW of additional "undiscovered" resource. |
| **Hydropower** | Reference | O&M ~40% lower than reference. |
| **Non-renewable technologies** | Reference | Reference |

Reference prices and performance are from Black & Veatch (forthcoming). See Appendix A for details.

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Figure C-3 shows the installed capacity results of the sensitivity analysis. Wind capacity increases significantly in the SSRE-ETI scenario. In 2030, wind capacity is 119 GW in the SSRE-ETI scenario, 51% higher than in the SunShot scenario (79 GW). In 2050, wind capacity is 240 GW, 164% higher than in the SunShot scenario (91 GW). At the same time, solar capacity (PV plus CSP) decreases slightly in the SSRE-ETI scenario. In 2030, solar capacity is 317 GW, 4% lower than in the SunShot scenario (330 GW). In 2050, solar capacity is 655 GW, 8% lower than in the SunShot scenario (715 GW). To accommodate the additional variable renewable energy capacity in the SSRE-ETI scenario, gas-combustion turbine (gas-CT) capacity increases while gas-combined cycle (Gas-CC) capacity decreases. Coal capacity increases by 11 GW (5%) in the SSRE-ETI scenario compared with the SunShot scenario in 2030, but it decreases by 27 GW (14%) in 2050. This result highlights the complementarity of the solar and wind resources. Even with a substantial build-out of wind generation capacity, there is only a small reduction in solar capacity. Together, these two renewable resources largely complement rather than compete with each other, enabling a much higher penetration of renewable generation on the grid.

**Figure C-3. Electricity Capacity by Source, SunShot and Sensitivity Scenarios**

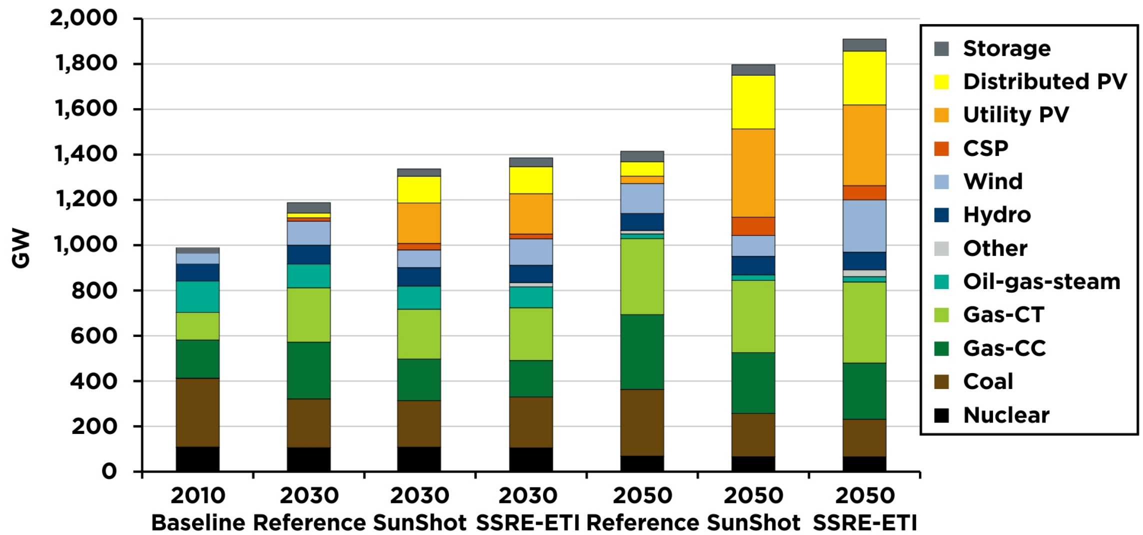
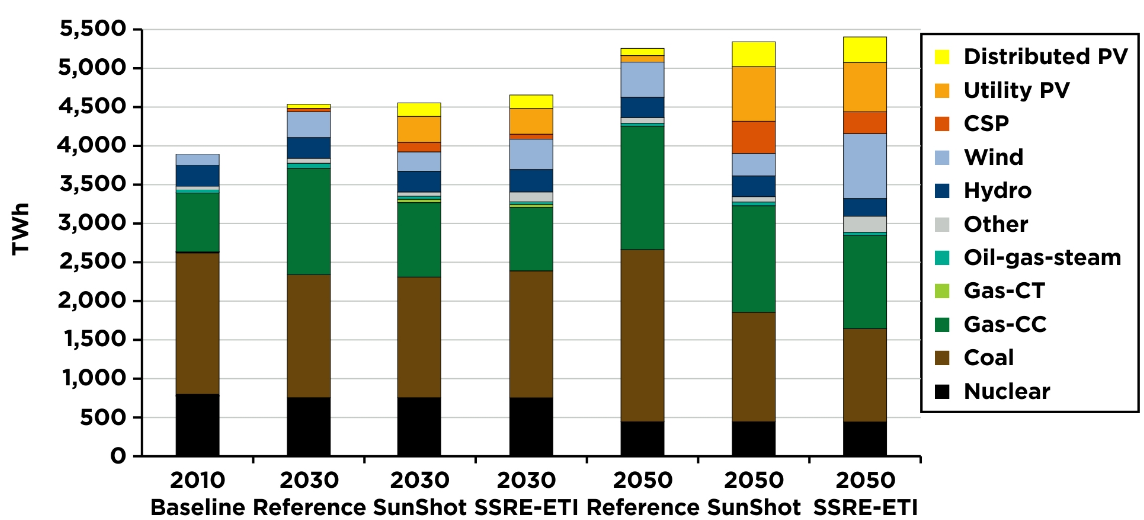



Figure C-4 shows the electricity generation results of the sensitivity analysis. In 2030, wind contributes 8% of generation in the SSRE-ETI scenario, compared with 5% in the SunShot scenario with low technology costs for solar alone. In 2050, wind contributes 16% of generation in the SSRE-ETI scenario, compared with 6% in the SunShot scenario. The share of electricity from "Other" sources—which include geothermal and biopower—increases in the SSRE-ETI scenario (3% in 2030, 4% in 2050) compared with the SunShot scenario (1% in 2030 and 2050). At the same time, the contribution of solar decreases in the SSRE-ETI scenario (12% in 2030, 23% in 2050) compared with the SunShot scenario (14% in 2030, 27% in 2050). By 2050, the combined contribution of coal and natural gas also decreases in the SSRE-ETI scenario compared with the SunShot scenario (from 53% to 45%).

**Figure C-4. Electricity Generation by Source, SunShot and Sensitivity Scenarios**

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Clearly, the increased penetration of non-solar renewable technologies in the SSRE-ETI scenario, due to reduced prices and/or improved performance, reduces solar capacity and electricity generation. However, the contribution of fossil fuels is reduced even more substantially by 2050 because of the increased renewable penetration.

## C.4 Sensitivity of Solar Deployment to Natural Gas Prices

An additional sensitivity on the Sunshot scenario was run with lower natural gas prices because natural gas fuel supply assumptions in the U.S. Energy Information Administration's (EIA's) *Annual Energy Outlook* 2011 (*AEO 2011*) were significantly more optimistic than those of *AEO 2010*. The same methodology for constructing a new natural gas supply curve in ReEDS was used for *AEO 2011* as was used for *AEO 2010* (see Appendix A). This resulted in natural gas prices that were \$1.50 /$10^6$ British thermal units (Btu) to \$2.00 /$10^6$ Btu lower in the *AEO 2011* natural gas fuel price sensitivity than in the SunShot scenario, assuming the same amounts of gas usage. This sensitivity produced 400 terawatt-hours (TWh) more electricity generation from natural gas combined cycle plants than SunShot in 2050, or 7% of total electricity generation. However, 350 TWh of this additional gas generation merely replaced coal generation, mostly from new coal plants that were built in the SunShot scenario after 2034. The solar generation fraction for this sensitivity was 25.5%, as compared to 26.9% in the SunShot scenario. These results suggest that if solar costs reach SunShot targets, solar will be able to compete with natural gas generation at a range of natural gas fuel prices, and that natural gas does not compete directly with solar at high-solar penetrations because the load shape has shifted.

## C.5 References

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EIA. (2011). *Annual Energy Outlook 2011*. Report No. DOE/EIA-0383 (2011). Washington, DC: U.S. EIA.

# Appendix D. Authors, Reviewers, and Other Contributors

## D.1 Overview

The U.S. Department of Energy (DOE) would like to acknowledge the *SunShot Vision Study's* authors, reviewers, and other contributors listed below. This report draws heavily on research, analysis, and material created for DOE's draft *Solar Vision Study*, which was in development from June 2009 through December 2010. When DOE's SunShot Initiative was launched in February 2011, the *Solar Vision Study* was redeveloped to fit the SunShot framework, resulting in this *SunShot Vision Study*. The following acknowledgments represent the full spectrum of participation during the evolution of this project, including coordinators and production support; the *SunShot Vision Study* authors, editors, and reviewers; and the draft *Solar Vision Study* steering committee, authors, external reviewers, and other contributors.

The final version of the *SunShot Vision Study* is the sole responsibility of DOE. The participation of external reviewers of the *SunShot Vision Study* and authors and external reviewers of the draft *Solar Vision Study* does not imply that they or their respective organizations either agree or disagree with the findings of this report.

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The following individuals were responsible for leading the drafting, review, and editing processes for the *SunShot Vision Study* and draft *Solar Vision Study* in support of, and in collaboration with, staff from the DOE Solar Energy Technologies Program (SETP).

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## D.3 *SunShot Vision Study* Authors, Editors, and Reviewers

The *SunShot Vision Study* used the post-external review version of the draft *Solar Vision Study* as a starting point. Much of the *SunShot Vision Study* effort was internal, utilizing expertise from DOE staff, contractors, and national laboratories. The public was engaged, however, through an open external review process in which input was provided by more than 30 individuals representing key sectors of the solar industry.

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### D.3.1 Authors and Editors

The following individuals were responsible for key elements of the analysis, writing, and revision process that took place from March through October, 2011. Examples of activities during this process include developing and modeling the SunShot and reference scenarios; drafting and editing each chapter's content; and addressing comments made by external reviewers.

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The following individuals provided comments on the *SunShot Vision Study* during various stages of the report's development and were internal to the process.

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### D.3.3 External Reviewers

The draft chapters of the *SunShot Vision Study* were made public for external review and comment from July 25 through August 15, 2011. All contributors (authors and reviewers) to the draft *Solar Vision Study* were invited to review the draft *SunShot*

*Vision Study*. An additional 16 individuals were invited to review the draft *SunShot Vision Study* by the Program Manager of DOE's Solar Energy Technologies Program, Ramamoorthy Ramesh. Finally, the review process was open to the general public via a publically accessible website. Note that colleagues of some individuals listed below also provided input, as well as staff from the Solar Energy Industries Association (SEIA).

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# D.4 *Solar Vision Study* Steering Committee, Authors, External Reviewers, and Other Contributors

The draft *Solar Vision Study* was launched in June 2009 and drew on a steering committee and working groups with more than 140 representatives from solar companies, utilities, financial firms, universities, national laboratories, non-profits, industry associations, and other organizations. A draft of the *Solar Vision Study* was circulated for external review during June 2010. Comments were received from more than 50 individuals representing stakeholders across the solar industry. The contributions made by authors and reviewers of the draft *Solar Vision Study* provided a starting point for the *SunShot Vision Study*, with the exception of material focused on solar heating and cooling technologies, which was not included in the *SunShot Vision Study*.

## D.4.1 Steering Committee and Chapter Working Group Authors and Contributors

The following list includes the draft *Solar Vision Study* steering committee, working group authors, and other contributors such as those involved in the analysis development and modeling process.

A steering committee was formed during the second quarter of 2009 to provide strategic guidance and feedback throughout the development of the draft *Solar Vision Study*. The Solar Energy Industries Association and the Solar Electric Power Association aided in identifying the individuals for this role. The committee representatives are in italics below. An asterisk (*) denotes individuals who were 'observers' of the steering committee.

Each chapter had a working group consisting of chapter leaders and members with varying types of responsibility. The objective of each group was to draft its respective chapter to be technically sound and consistent with the analyses used for the draft *Solar Vision Study*. The working groups were developed through recommendations by the draft *Solar Vision Study* steering committee as well as input from DOE.

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### D.4.2 External Reviewers

The following list consists of individuals who provided comments during the draft *Solar Vision Study* external review period from May 28 through June 25, 2010. Recommendations by the chapter working groups and input from DOE provided the basis for selecting specific individuals to be invited to the review process. In addition, the draft chapters were posted on a publically accessible website and available for comment from the general public. Over 50 individuals external to the draft *Solar Vision Study* process provided comments on one or more draft chapters. This total and the list below do not include individuals internal to the draft *Solar Vision Study* development process (e.g., active working group members) who provided comments during the review process.

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| Larry Sherwood | Interstate Renewable Energy Council |
| Greg Smestad | Solar Energy Materials and Solar Cells |
| J Charles Smith | Utility Wind Integration Group |
| Marty Smith | Xcel Energy |
| Phil Smithers | Arizona Public Service |
| Kathleen Sullivan | Abengoa Solar |
| Ted Sullivan | Lux Research |
| Cecilia Tam | International Energy Agency |
| Craig Tyner | eSolar, Inc. |
| Joe Tyrrell | 3M |
| Harin Ullal | National Renewable Energy Laboratory |
| Bolko vonRoedern | National Renewable Energy Laboratory |
| Thomas Wells | Southern Company |
| Sahm White | FIT Coalition |
| Cherif Youssef | Sempra Energy |

### D.4.3 Solar Vision Workshop, October 26, 2009

The Solar Vision Workshop was held on October 26, 2009, in Anaheim, California, adjacent to the Solar Power International Conference. The purpose of the workshop was to review the status and direction of the draft *Solar Vision Study*, by providing a venue for each chapter working group to present its respective chapter's progress, as well as address questions and concerns from the steering committee, other working group members, and the general public. The following list includes all participants (more than 100 individuals) in attendance at the workshop. An asterisk (*) is used to identify individuals who were external to the draft *Solar Vision Study* process.

| | |
|---|---|
| Rajiv Advani* | Advantage for Analysts |
| Savina Angel* | SEMI PV Group |
| David Arfin | SolarCity |
| Jim Baak | The Vote Solar Initiative |
| Justin Baca | Solar Energy Industries Association |
| Jessica Ballard | Infinia Corporation |
| Galen Barbose | Lawrence Berkeley National Laboratory |
| John Bartlett | New West Technologies, LLC (formerly) |
| Kelly Beninga | WorleyParsons |
| Gordon Bigler* | MicroGrid Energy Corporation |
| Walter Block* | Building Industries |
| Julie Blunden | SunPower Corporation |
| Molly Borchers | Sentech, Inc. |
| Lynnae Boyd* | National Renewable Energy Laboratory |
| Peter Brehm | Infinia Corporation |
| Adam Browning | The Vote Solar Initiative |
| Marni Carroll | Iberdrola Renewables |
| Bob Cart | GreenVolts, Inc. (formerly) |
| Bob Charles | Sargent & Lundy |
| Mark Chen* | Abound Solar |
| Charlie Coggeshall | New West Technologies, LLC |
| Kevin Collins | First Solar, Inc. |
| Craig Cornelius* | Hudson Clean Energy Partners |
| Karlynn Cory | National Renewable Energy Laboratory |
| Carrie Cullen Hitt | The Solar Alliance |
| Ken Davis | Sargent & Lundy |
| Jennifer DeCesaro | U.S. Department of Energy |
| Paul Denholm | National Renewable Energy Laboratory |
| Thomas Dinwoodie | SunPower Corporation |
| Martha Duggan | United Solar |
| Ed Etzkorn | U.S. Department of Energy |
| Barry Friedman | National Renewable Energy Laboratory |
| Sean Gallagher | Tessera Solar |
| Charlie Gay | Applied Materials |
| Katherine Gensler | Solar Energy Industries Association |
| Rick Gilliam | SunEdison (an MEMC company) |

| | |
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| Susan Gouchoe | North Carolina Solar Center |
| Bill Gould | SolarReserve |
| Richard Gruber* | First Solar, Inc. |
| Micah Haman* | Puget Sound Energy |
| Charles Hanley | Sandia National Laboratories |
| Dennis Harper | First Solar, Inc. |
| Bob Hassett | U.S. Department of Energy |
| Arthur Haubenstock | BrightSource Energy, Inc. |
| Jim Haugen* | Clean Power Research |
| Tom Hoff | Clean Power Research |
| Roland Hulstrom* | National Renewable Energy Lab |
| Eric John | SkyFuel, Inc. |
| Izumi Kaizuka* | RTS Corporation |
| Juris Kalejs* | American Capital Energy |
| Bill Kammerer* | FIT Coalition |
| David Kearney | Kearney & Associates |
| Tom Kimbis | The Solar Foundation |
| Ben Kroposki | National Renewable Energy Laboratory |
| Hal LaFlash | Pacific Gas and Electric Company |
| Mark Lausten | Sentech, Inc. |
| Craig Lewis | RightCycle |
| Joshua Linn | Massachusetts Institute of Technology |
| Craig Lund* | 1366 Technologies |
| John Lushetsky | U.S. Department of Energy |
| Jeffrey Luth* | Az4Solar.org |
| Robert Margolis | National Renewable Energy Laboratory |
| Alex Marker | SCHOTT Solar, Inc. |
| Joseph McCabe* | Ascent Solar |
| Jan McFarland | California Alternative Energy & Advanced Transportation Financing Authority |
| Jim McVeigh | Sentech, Inc. |
| Mark Mehos | National Renewable Energy Laboratory |
| Tim Merrigan | National Renewable Energy Laboratory |
| Paula Mints | Navigant Consulting |
| Ray Morgan* | SEMI PV Group |
| Fred Morse | Morse Associates, Inc. |
| Matt Mowers | National Renewable Energy Laboratory |
| Terry Murphy | SolarReserve |
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| James Nelson* | University of California, Berkeley |
| Sam Newman* | Rocky Mountain Institute |
| Patricia Nugent* | Dow Chemical |
| Bob O'Hara | Sargent & Lundy |
| Steve O'Rourke | Deutsche Bank |
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| Terry Peterson | Terry M. Peterson, Ph.D. |
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| Hank Price | Abengoa Solar Inc. |
| Richard Raushenbush | GreenVolts |
| Rick Reed | SunEarth Inc. |
| Sally Rosauer | FAFCO |
| Vishal Shah | Barclays Capital |
| Gianluca Signorelli | MMA Renewable Ventures (formerly) |
| Eric Silagy | Florida Power & Light Company |
| Chrissy Skudera | New West Technologies |
| Cai Steger | Natural Resources Defense Council |
| Joshua Stein | Sandia National Laboratories |
| Mark Storch* | Plextronics |
| Samir Succar | Natural Resources Defense Council |
| Dick Swanson | SunPower Corporation |
| Blair Swezey | SunPower Corporation |
| Mike Taylor | Solar Electric Power Association |
| Andy Taylor | BrightSource Energy |
| Cindy Tindell | Florida Power & Light |
| Craig Turchi | National Renewable Energy Laboratory |
| Cyrus Wadia | U.S. Executive Office of the President |
| Johanna Wald | Natural Resources Defense Council |
| Peter Weiner | Paul Hastings |
| Carl Zichella | Sierra Club (formerly) |
| Ken Zweibel | George Washington University Solar Institute |

# Appendix E. Glossary

**Acre-foot**: The volume of water that will cover an area of 1 acre to a depth of 1 foot.

**Alternating current (AC)**: A type of electrical current, the direction of which is reversed at regular intervals or cycles. In the United States, the standard is 120 reversals or 60 cycles per second. Electricity transmission networks use AC because voltage can be controlled with relative ease.

**Amorphous silicon (a-Si)**: A thin-film, silicon photovoltaic (PV) cell having no crystalline structure. Manufactured by depositing layers of doped silicon on a substrate. See also single-crystal silicon and polycrystalline silicon.

**Authority having jurisdiction**: A federal, state, or local entity having statutory authority for approving equipment, an installation, or a procedure.

**Balance-of-systems (BOS)**: Represents all components and costs other than the photovoltaic modules/array. It includes design costs, land, site preparation, system installation, support structures, power conditioning, operation and maintenance costs, indirect storage, and related costs.

**Balancing Authority (BA)**: The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real time.

**Balancing Authority Area**: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

**Base load**: The average amount of electric power that a utility must supply in any period.

**Behind the meter (customer side of the meter)**: The location where a generating technology (such as a PV system) is connected to the electricity grid. A behind-the-meter PV system is connected between the utility meter and the facility using the electricity, so all electricity generated by the PV systems that is not being used by the facility flows through the utility meter to the grid.

**Brayton cycle**: A thermodynamic cycle using constant pressure, heat addition and rejection, representing the idealized behavior of the working fluid in a gas turbine type heat engine.

**British thermal unit (Btu)**: The amount of heat required to raise the temperature of 1 pound of water 1 degree Fahrenheit; equal to 252 calories.

**Building-integrated photovoltaics (BIPV)**: A term for the design and integration of photovoltaic (PV) technology into the building envelope, typically replacing conventional building materials. This integration may be in vertical facades, replacing view glass, spandrel glass, or other facade material; into semitransparent skylight systems; into roofing systems, replacing traditional roofing materials; into shading “eyebrows” over windows; or other building envelope systems.

**Cadmium telluride (CdTe)**: A polycrystalline thin-film photovoltaic material.

**Cap and trade**: An established policy tool that creates a marketplace for emissions. Under a cap and trade program, the government regulates the aggregate amount of a type of emissions by setting a ceiling or cap. Participants in the program receive allocated allowances that represent a certain amount of pollutant and must purchase allowances from other businesses to emit more than their given allotment.

**Capacity**: The load that a power generation unit or other electrical apparatus or heating unit is rated by the manufacture to be able to meet or supply.

**Capacity factor (CF)**: The ratio of the average load on (or power output of) an electricity-generating unit or system to the capacity rating of the unit or system over a specified period of time. For a solar plant, it is equivalent to: [Annual kilowatt-hours (kWh) generated for each kilowatt (kW) alternating current (AC) of peak capacity {[in kWh per peak kilowatt ($kW_p$)]}/8,760 hours per year.

**Capital costs**: The cost of field development and plant construction and the equipment required for industry operations.

**Central receiver (power plants)**: Also known as "power towers," central receivers use fields of two-axis tracking mirrors known as heliostats. Each heliostat is individually positioned by a computer control system to reflect the sun's rays to a tower-mounted thermal receiver. The effect of many heliostats reflecting to a common point creates the combined energy of thousands of suns, which produces high-temperature thermal energy. In the receiver, molten nitrate salts absorb the heat energy. The hot salt is then used to boil water to steam, which is sent to a conventional steam turbine-generator to produce electricity.

**Climate change**: A term used to describe short and long-term effects on the Earth's climate as a result of human activities such as fossil-fuel combustion and vegetation clearing and burning.

**Cogeneration**: The generation of electricity or shaft power by an energy conversion system and the concurrent use of rejected thermal energy from the conversion system as an auxiliary energy source.

**Combined cycle (CC)**: An electric-generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric-generating unit.

**Combined heat and power plant (CHP)**: A plant designed to produce both heat and electricity from a single heat source.

**Combustion**: The process of burning; the oxidation of a material by applying heat, which unites oxygen with a material or fuel.

**Commercial sector**: An energy-consuming sector that consists of service-providing facilities and equipment of businesses; federal, state, and local governments; and other private and public organizations, such as religious, social, or fraternal groups.

**Concentrating solar power (solar thermal power system) (CSP)**: Solar energy conversion technologies that convert solar energy to electricity, by heating a working fluid to power a turbine that drives a generator. Examples of these systems include central receiver systems, parabolic dish, and solar trough.

**Concentrator (PV)**: A photovoltaic module, which includes optical components such as lenses (Fresnel lens) to direct and concentrate sunlight onto a solar cell or smaller area. Most concentrator arrays must directly face or track the sun. They can increase the power flux of sunlight hundreds of times.

**Conventional fuel**: The fossil fuels: coal, oil, and natural gas.

**Copper indium (gallium) diselenide (CIGS)**: A polycrystalline thin-film photovoltaic material (sometimes incorporating gallium (CIGS) and/or sulfur).

**Crystalline silicon (c-Si)**: A type of photovoltaic cell made from a slice of single-crystal silicon or polycrystalline silicon.

**Curtailment**: A reduction in the scheduled capacity or energy delivery of an agreement to transfer energy.

**Customer side of the meter**: See "Behind the meter".

**Demand**: The rate at which electricity is delivered to or by a system, part of a system, or piece of equipment expressed in kilowatts, kilovolt amperes, or other suitable unit, at a given instant or averaged over a specified period of time.

**Demand-side management (DSM)**: The process of managing the consumption of energy, generally to optimize available and planned generation resources.

**Diffuse insolation**: Sunlight received indirectly as a result of scattering due to clouds, fog, haze, dust, or other obstructions in the atmosphere.

**Direct current (DC)**: A type of electricity transmission and distribution by which electricity flows in one direction through the conductor, usually relatively low voltage and high current. To be used for typical 120 volt or 220 volt household appliances, DC must be converted to alternating current (AC), its opposite.

**Direct incentive**: Cash given back to consumers for a qualified solar installation. Direct incentives include up-front rebates and grants and production-based incentives that are typically distributed over several years.

**Direct-normal irradiance (DNI)**: The amount of solar radiation from the direction of the sun.

**Discount rate**: The interest rate at which the Federal Reserve System stands ready to lend reserves to commercial banks. The rate is proposed by the 12 Federal Reserve banks and determined with the approval of the Board of Governors.

**Dish**: See "Solar thermal parabolic dishes".

**Dispatchability**: The ability to schedule and control the generation and delivery of electric power.

**Distributed generation (DG)**: A term used by the power industry to describe localized or on-site power generation.

**Distributed utility-scale generation**: For the purposes of this report, distributed utility-scale includes PV systems with a representative size of 1–20 megawatts (MW) located within and directly connected to distribution networks.

**DOE**: In this context, always refers to the U. S. Department of Energy, although other departments may have the same acronym.

**Ecological impact**: The effect that a man-caused or natural activity has on living organisms and their non-living (abiotic) environment.

**Electricity generation**: The process of producing electricity by transforming other forms or sources of energy into electrical energy; commonly expressed in kilowatt-hours.

**Energy**: The capability of doing work; different forms of energy can be converted into other forms, but the total amount of energy remains the same.

**Energy demand**: The requirement for energy as an input to provide products and/or services.

**Energy efficiency**: A ratio of service provided to energy input. Services provided can include buildings-sector end uses such as lighting, refrigeration, and heating: industrial processes; or vehicle transportation. Unlike conservation, which involves some reduction of service, energy efficiency provides energy reductions without sacrifice of service.

**Energy Information Administration (EIA)**: An independent agency within the U.S. Department of Energy that develops surveys, collects energy data, and does analytical and modeling analyses of energy issues.

**Feed-in tariff (FIT)**: A renewable energy policy that typically offers renewable energy project developers a guaranteed payment for electricity produced by their renewable energy system over a fixed period, usually 15 to 20 years.

**Fixed-tilt array**: A photovoltaic array set in at a fixed angle with respect to horizontal.

**Fresnel lens**: An optical device that focuses light like a magnifying glass; concentric rings are faced at slightly different angles so that light falling on any ring is focused to the same point.

**Fuel**: Any material substance that can be consumed to supply heat or power. Included are petroleum, coal, and natural gas (the fossil fuels), and other consumable materials, such as uranium, biomass, and hydrogen.

**Gigawatt (GW)**: A unit of power that has an instantaneous capability equal to 1 billion watts, 1 million kilowatts, or 1,000 megawatts.

**Gigawatt-hour (GWh)**: One billion watt hours.

**Grid-connected system**: Independent power systems that are connected to an electricity transmission and distribution system (referred to as the electricity grid) such that the systems can draw on the grid's reserve capacity in times of need, and feed electricity back into the grid during times of excess production.

**Heat-transfer fluid (HTF)**: A gas or liquid used to move heat energy from one place to another; a refrigerant.

**Heliostat**: A device that tracks the movement of the sun; used to orient solar concentrating systems.

**Independent power producer (IPP)**: A company or individual that is not directly regulated as a power provider. These entities produce power for their own use and/or sell it to regulated power providers.

**Independent system operator (ISO)**: An independent, federally regulated entity established to coordinate regional transmission in a non-discriminatory manner and ensure the safety and reliability of the electric system.

**Insolation**: The solar power density incident on a surface of stated area and orientation, usually expressed as watts per square meter or British thermal units per square foot per hour. See diffuse insolation and direct insolation.

**Installed capacity**: The total capacity of electrical generation devices in a power station or system.

**Interconnection**: A connection or link between power systems that enables the systems to draw on each other's reserve capacity in times of need. This includes any one of the three major electric system networks in North America: Eastern Interconnection, Western Interconnection, and the Electric Reliability Council of Texas (ERCOT).

**Inverter**: A device that converts direct current electricity (from, for example, a solar photovoltaic module or array) to alternating current for use directly to operate appliances or to supply power to a electricity grid.

**Investor owned utility (IOU)**: A power provider owned by stockholders or other investors; sometimes referred to as a private power provider, in contrast to a public power provider that is owned by a government agency or cooperative.

**Irradiance**: The direct, diffuse, and reflected solar radiation that strikes a surface. Usually expressed in kilowatts per square meter. Irradiance multiplied by time equals insolation.

**Junction**: A region of transition between semiconductor layers, such as a p/n junction, which goes from a region that has a high concentration of acceptors (p-type) to one that has a high concentration of donors (n-type).

**Kilowatt (kW)**: A standard unit of electrical power equal to 1,000 watts, or to the energy consumption at a rate of 1,000 joules per second.

**Kilowatt-hour (kWh)**: A unit or measure of electricity supply or consumption of 1,000 watts over the period of one hour; equivalent to 3,412 British thermal units.

**Levelized cost of energy (or electricity) (LCOE)**: A means of calculating the cost of generating energy (usually electricity) from a particular system that allows one to compare the cost of energy across technologies. LCOE takes into consideration the installed solar energy system price and associated costs such as the cost of financing, land, insurance, operation and maintenance, and other expenses.

**Load**: The demand on an energy producing system; the energy consumption or requirement of a piece or group of equipment. Usually expressed in terms of amperes or watts in reference to electricity.

**Load-serving entity (LSE)**: Secures energy and transmission service (and related interconnected operations services) to serve the electrical demand and energy requirements of its end-use customers.

**Megawatt (MW)**: 1,000 kilowatts, or 1 million watts; standard measure of electric-power plant-generating capacity.

**Megawatt-hour (MWh)**: One thousand kilowatt-hours or 1 million watt-hours.

**Metric ton (tonne) (MT)**: A unit of mass equal to 1,000 kilograms or 2,204.6 pounds.

**Multicrystalline (mc)**: A semiconductor (photovoltaic) material composed of variously oriented, small, individual crystals. Sometimes referred to as polycrystalline or semicrystalline.

**Multijunction device**: A high-efficiency photovoltaic device containing two or more cell junctions, each of which is optimized for a particular part of the solar spectrum.

**National Electric Code (NEC)**: Contains guidelines for all types of electrical installations. The 1984 and later editions of the NEC contain Article 690, "Solar Photovoltaic Systems" which should be followed when installing a PV system.

**Net metering**: The practice of using a single meter to measure consumption and generation of electricity by a small generation facility (such as a house with a wind or solar photovoltaic system). The net energy produced or consumed is purchased from or sold to the power provider, respectively.

**Nitrogen oxides ($NO_x$)**: The products of all combustion processes formed by the combination of nitrogen and oxygen.

**Nominal price**: The price paid for goods or services at the time of a transaction; a price that has not been adjusted to account for inflation.

**Parabolic dish (solar)**: A solar energy conversion device that has a bowl shaped dish covered with a highly reflective surface that tracks the sun and concentrates sunlight on a fixed absorber, thereby achieving high temperatures, for process heating or to operate a heat (Stirling) engine to produce power or electricity.

**Parabolic trough (solar)**: A solar energy conversion device that uses a trough covered with a highly reflective surface to focus sunlight onto a linear absorber containing a working fluid that can be used for medium temperature space or process heat or to operate a steam turbine for power or electricity generation.

**Peak demand/load**: The maximum energy demand or load in a specified time period.

**Peak power**: Power generated that operates at a very low capacity factor; generally used to meet short-lived and variable high-demand periods.

**Peak watt**: A unit used to rate the performance of solar cells, modules, or arrays; the maximum nominal output of a photovoltaic device, in peak watts ($W_p$) under standardized test conditions, usually 1,000 watts per square meter of sunlight with other conditions, such as temperature specified.

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**Peaking capacity**: Power generation equipment or system capacity to meet peak power demands.

**Photovoltaic (conversion) efficiency**: The ratio of the electric power produced by a photovoltaic device to the power of the sunlight incident on the device.

**Photovoltaic array**: An interconnected system of photovoltaic modules that function as a single electricity-producing unit. The modules are assembled as a discrete structure, with common support or mounting. In smaller systems, an array can consist of a single module.

**Photovoltaic cell**: The smallest semiconductor element within a photovoltaic module to perform the immediate conversion of light into electrical energy (direct current voltage and current). Also called a solar cell.

**Photovoltaic module**: The smallest environmentally protected, essentially planar assembly of solar cells and ancillary parts, such as interconnections, terminals, (and protective devices such as diodes) intended to generate direct current power under unconcentrated sunlight. The structural (load carrying) member of a module can either be the top layer (superstrate) or the back layer (substrate).

**Photovoltaic system**: A complete set of components for converting sunlight into electricity by the photovoltaic process, including the array and balance of system components.

**Polycrystalline silicon**: A material used to make photovoltaic cells, which consist of many crystals unlike single-crystal silicon.

**Power**: Energy that is capable or available for doing work; the time rate at which work is performed, measured in horsepower, watts, or British thermal units per hour. Electric power is the product of electric current and electromotive force.

**Power (solar) tower**: A term used to describe solar thermal, central receiver, power systems, where an array of reflectors focus sunlight onto a central receiver and absorber mounted on a tower.

**Power purchase agreement (PPA)**: A legal contract between an electricity generator and electricity purchaser. Solar power purchase agreements typically provide a long-term contract to purchase electricity generated from a solar installation on public or private property; a type of third-party ownership model.

**Public utility (or services) commission (PUC or PSC)**: These are state government agencies responsible for the regulation of public utilities within a state or region. A state legislature oversees the PUC by reviewing changes to power generator laws and rules and regulations and approving the PUC's budget. The commission usually has five commissioners appointed by the governor or legislature. PUCs typically regulate electric, natural gas, water, sewer, telephone services, trucks, buses, and taxicabs within the commission's operating region. The PUC tries to balance the interests of consumers, environmentalists, utilities, and stockholders. The PUC makes sure a region's citizens are supplied with adequate, safe power provider service at reasonable rates.

**Ramp rate**: The rate at which load on a power plant is increased or decreased. The rate of change in output from a power plant.

**Rankine cycle**: The thermodynamic cycle that is an ideal standard for comparing performance of heat engines, steam power plants, steam turbines, and heat pump systems that use a condensable vapor as the working fluid. Efficiency is measured as work done divided by sensible heat supplied.

**Real dollars**: These are dollars that have been adjusted for inflation.

**Receiver**: The component of a central receiver solar thermal system where reflected solar energy is absorbed and converted to thermal energy.

**Renewable energy**: Energy from resources that naturally replenish themselves and are virtually inexhaustible. Renewable energy resources include biomass, hydropower, geothermal, solar, wind, ocean thermal, wave action, and tidal action.

**Renewable energy certificate or credit (REC)**: A REC represents the property rights to the environmental, social, and other non-power qualities of renewable electricity generation. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source.

**Renewable portfolio standard (RPS)**: A mandate requiring that renewable energy provides a certain percentage of total energy generation. The mandate is sometimes referred to as a renewable electricity standard or RES.

**Reserve capacity**: The amount of generating capacity a central power system must maintain to meet peak loads.

**Residential sector**: An energy-consuming sector that consists of living quarters for private households. Common uses of energy associated with this sector include space heating, water heating, air conditioning, lighting, refrigeration, cooking, and running a variety of other appliances.

**Retail (electricity market)**: Sales covering electrical energy supplied for residential, commercial, and industrial end-use purposes. Other small classes, such as agriculture and street lighting, are also included in this category.

**Semiconductor**: Any material that has a limited capacity for conducting an electric current. Certain semiconductors, including silicon, gallium arsenide, copper indium diselenide, and cadmium telluride, are uniquely suited to the photovoltaic conversion process.

**Set aside**: A mandate or goal for some fraction of a renewable portfolio standard to be met with designated technologies such as photovoltaics.

**Silicon (Si)**: A semi-metallic chemical element that makes an excellent semiconductor material for photovoltaic devices. It crystallizes in face-centered cubic lattice like a diamond and is commonly found in sand and quartz (as the oxide).

**Solar access**: The ability of one property or area to continue to receive sunlight without obstruction from a nearby home or building, landscaping, or other impediment.

**Solar field**: Solar field is a term used to describe the geographic area of solar collectors used for concentrating solar power systems.

**Solar resource**: The amount of solar insolation a site receives, usually measured in kilowatt-hours per square meter per day, which is equivalent to the number of peak sun hours.

**Solar right law**: A law or ordinance that furnishes protection for homes and businesses by limiting or prohibiting restrictions (for example, neighborhood covenants and bylaws, local government ordinances, and building codes) on the installation of solar energy systems.

**Solar thermal electric system**: See “concentrating solar power”.

**Steam turbine**: A device that converts high-pressure steam, produced in a boiler, into mechanical energy that can then be used to produce electricity by forcing blades in a cylinder to rotate and turn a generator shaft.

**Stirling engine**: A heat engine of the reciprocating (piston) where the working gas and a heat source are independent. The working gas is compressed in one region of the engine and transferred to another region where it is expanded. The expanded gas is then returned to the first region for recompression. The working gas thus moves back and forth in a closed cycle.

**Storage capacity**: The amount of energy an energy storage device or system can store.

**Therm**: A unit of heat containing 100,000 British thermal units (Btu).

**Thermal energy**: The energy developed through the use of heat energy.

**Thermal energy storage**: The storage of heat energy during power provider off-peak times at night, for use during the next day without incurring daytime peak electric rates.

**Thin film**: A layer of semiconductor material, such as copper indium diselenide or gallium arsenide, a few microns or less in thickness, used to make photovoltaic cells.

**Tracking solar array**: A solar energy array that follows the path of the sun to maximize the solar radiation incident on the photovoltaic surface. The two most common orientations are (1) 1-axis, where the array tracks the sun east to west and (2) two-axis, where the array points directly at the sun at all times. Tracking arrays use both the direct and diffuse sunlight. Two-axis tracking arrays capture the maximum possible daily energy.

**Transmission**: The process of sending or moving electricity from one point to another. This usually defines that part of an electric power provider's electric power lines from the power plant buss to the last transformer before the customer's connection.

**Turbine**: A device for converting the flow of a fluid (such as air, steam, water, or hot gases) into mechanical motion.

**Utility-scale**: For the purposes of this report, larger systems installed on the ground are called "utility-scale PV." These systems can range from a few megawatts to hundreds of megawatts. Large utility-scale systems greater than 20 megawatts are typically connected to the electricity-transmission system which transmits electricity from generating plants to electrical substations.

**Utility**: A regulated entity which exhibits the characteristics of a natural monopoly (also referred to as a power provider). For the purposes of electric industry restructuring, "utility" refers to the regulated, vertically-integrated electric company. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system which serves retail customers.



**Voltage**: The amount of electromotive force, measured in volts, that exists between two points.

**Wafer**: A thin sheet of semiconductor (photovoltaic material) made by cutting it from a single crystal or ingot.

**Watt (W)**: The rate of energy transfer equivalent to one ampere under an electrical pressure of one volt. One watt equals 1/746 horsepower, or 1 joule per second. It is the product of voltage and current (amperage).

**Watt-hour (Wh)**: The electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour.

**Wholesale (electric market)**: The purchase and sale of electricity from generators to resellers (retailers), along with the ancillary services needed to maintain reliability and power quality at the transmission level.

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