SunShot
U.S. Department of Energy

SunShot Vision Study

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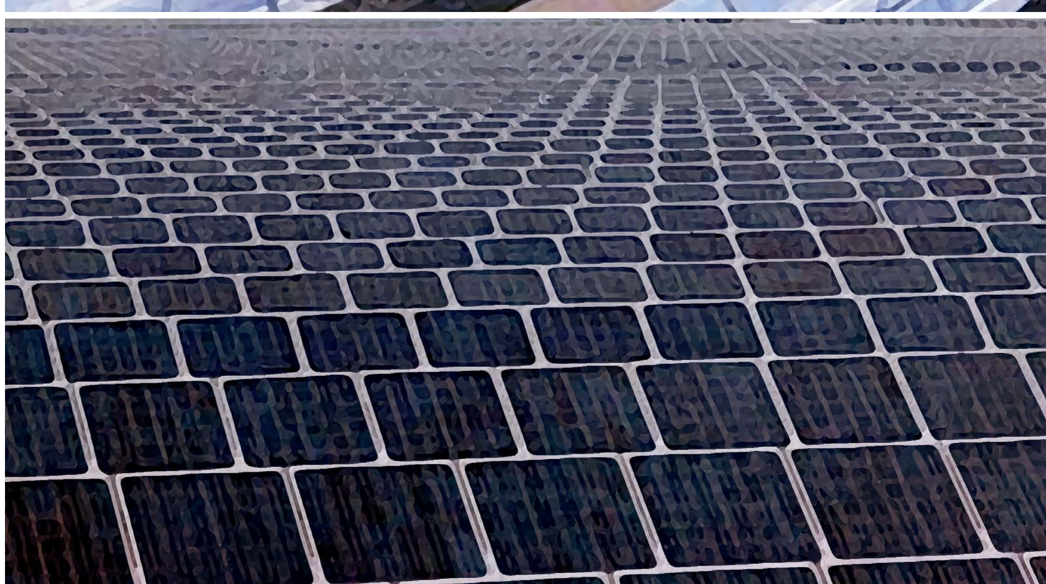

3. Analysis of PV and CSP Growth in the SunShot Scenario

3.1 Introduction

The *SunShot Vision Study* explores the potential impact of achieving the U.S. Department of Energy's (DOE's) SunShot Initiative price targets on photovoltaics (PV) and concentrating solar power (CSP) deployment in the United States through 2050. The modeling scenarios are not predictions of the future; rather, they represent internally consistent model results based on a specific set of assumptions. The model scenarios are used to explore and quantify the costs, challenges, and benefits of reaching high levels of solar penetration. The analysis provides insights that could assist research, development, and demonstration (RD&D) portfolio managers and policy makers in designing programs aimed at achieving the SunShot targets and increasing opportunities for the United States to reap economic benefits from PV and CSP technology advancement.

In this chapter, Section 3.2 describes the SunShot scenario and the reference scenario against which it is compared, including the analysis models used, major assumptions, projected deployment of PV and CSP resources, evolution of the U.S. electric sector, transmission requirements and electrical energy flows, and operational feasibility. Section 3.3 evaluates the impact of the SunShot scenario's projected solar deployment, including electric-sector costs, carbon emissions, and solar sector employment.

3.2 SunShot Growth Scenario

Section 3.2.1 describes the models used to analyze the SunShot growth scenario. Section 3.2.2 describes the SunShot scenario assumptions and total solar deployment results. Sections 3.2.3–3.2.6 present the results of the analysis in terms of generation and capacity mix, regional deployment, transmission requirements, and operational impacts.

3.2.1 Analysis Models

Several modeling tools were used for the analysis. The Regional Energy Deployment System (ReEDS) model (Short et al. 2011), developed at the National Renewable Energy Laboratory (NREL), is a linear-optimization, capacity-expansion model that simulates the least-cost deployment and dispatch of generation resources. ReEDS was used to explore the evolution of the U.S. electric sector in meeting the

SunShot targets, and to calculate the additional transmission capacity and reserve capacity required to meet customer demand and maintain grid reliability. ReEDS determines the geographical deployment of PV, CSP, and other generation technologies based on a number of factors: regional solar resource quality, future technology and fuel price projections, future U.S. electricity demand projections, impacts of variability in renewable generation, transmission requirements, and reserve requirements. ReEDS does not take into account potential distribution side impacts and issues. Model methodology and assumptions are described in detail in Appendix A.

The Solar Deployment System (SolarDS) model (Denholm et al. 2009)—also developed at NREL—was used to simulate PV adoption in residential and commercial rooftop PV markets based on regional solar insolation, retail electricity rates, and market diffusion characteristics. SolarDS simulates regional PV economics at high spatial resolution using hourly PV generation profiles from hundreds of solar resource regions, combined with state-based retail electricity rate distributions compiled from more than 1,000 utilities. PV economics are used to project PV adoption rates using market adoption and diffusion characteristics, and the resulting adoption rates are combined with a residential and commercial building stock database to calculate market size. Utility concerns such as voltage regulation, unintentional islanding, coordinated protection, and so on, are not considered as part of the SolarDS model.

Lastly, GridView—a production-cost model frequently used by electric service providers to schedule and dispatch generation resources—was used to verify the real-world operability of the SunShot scenario.

3.2.2 SunShot Scenario Assumptions and Total Solar Deployment Projections

Table 3-1 shows price and performance characteristics used to model the SunShot and reference scenarios. The SunShot price targets were set so that PV- and CSP-generated electricity would become competitive with conventionally generated electricity without subsidies by 2020. In the SunShot scenario, utility-scale PV is assumed to achieve $1.00/watt (W) installed system prices by 2020, and prices are assumed to follow close to a linear trajectory from today's price to $1.00/W.[15] Rooftop PV is assumed to reach $1.25/W (commercial) and $1.50/W (residential) installed system prices. This is also consistent with the higher supply chain and installation costs and margins for smaller distributed PV systems. CSP is assumed to reach $3.60/W installed prices for systems with 14 hours of thermal energy storage and a 67% capacity factor (CF). The reference PV and CSP prices listed in Table 3-1 were developed by Black & Veatch (forthcoming) to support various DOE electricity generation capacity expansion studies, except for the 2010 reference PV prices, which are the approximate benchmark PV prices established in Chapter 4. The reference CSP prices refer to systems with 6 hours of thermal energy storage. However, the ReEDS model optimally deploys CSP thermal storage resources based on system economics; see Appendix A for details.

[15] Note that throughout this report all "$/W" units refer to 2010 U.S. dollars per peak watt-direct current (DC) for PV and 2010 U.S. dollars per watt-alternating current (AC) for CSP, unless specified otherwise.

Table 3-1. Projected PV and CSP Installed System Prices and Performance (2010 U.S. Dollars/W)[a]

	Utility PV		Residential Rooftop PV		Commercial Rooftop PV		CSP					
	SunShot	Ref.	SunShot	Ref.	SunShot	Ref.	SunShot			Ref.		
	$/W_{DC}$	$/W_{DC}$	$/W_{DC}$	$/W_{DC}$	$/W_{DC}$	$/W_{DC}$	$/W_{AC}$	hours storage[b]	CF (%)	$/W_{AC}$	hours storage[b]	CF (%)
2010	4.00	4.00	6.00	6.00	5.00	5.00	7.20	6	43	7.20	6	43
2020	1.00	2.51	1.50	3.78	1.25	3.36	3.60	14	67	6.64	6	43
2030	1.00	2.31	1.50	3.32	1.25	2.98	3.60	14	67	5.40	6	43
2040	1.00	2.16	1.50	3.13	1.25	2.79	3.60	14	67	4.78	6	43
2050	1.00	2.03	1.50	2.96	1.25	2.64	3.60	14	67	4.78	6	43

[a] All reference (Ref.) prices in this table are from Black & Veatch (forthcoming) except for the 2010 PV prices, which are the approximate benchmark PV prices established in Chapter 4. The SunShot prices are the benchmarks and SunShot Initiative targets discussed in Chapters 4 and 5 except for the 2010 CSP SunShot price, which is from Black & Veatch (Chapter 5 does not establish a 2010 benchmark price for CSP with 6 hours of storage). The CSP prices are based on a project's "overnight installed cost," which is the total direct and indirect costs that would be incurred if the project was built in an instant, void of any additional costs for financing the construction period.
[b] The number of hours of thermal energy storage for CSP is optimized in the ReEDS model, and is slightly different than the numbers in this table due to restrictions on the solar multiple within ReEDS (see Appendix A).

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Table 3-2 summarizes the results of the SunShot scenario analysis, including the cumulative installed capacity, energy generation, and fraction of electricity demand[16] met by solar generation in 2030 and 2050. In the SunShot scenario, solar generation meets about 14% of U.S. electricity demand by 2030 (11% PV, 3% CSP) and 27% of demand by 2050 (19% PV, 8% CSP). About two-thirds of PV generation is from utility-scale ground-mounted systems,[17] and the remainder is from rooftop PV systems. These results are sensitive to technology prices and other assumptions. Appendix C discusses the sensitivity of the SunShot scenario results to the projected cost of solar technologies and the projected cost of non-solar renewable technologies. Additional sensitivity analysis will be published in supplementary technical reports.

Note that all results in this report refer to the contiguous United States (excluding Alaska and Hawaii) unless otherwise noted. For example, solar technologies are projected to meet about 14% of contiguous U.S. electricity demand by 2030 and 27% by 2050.

These SunShot scenario results are not a prediction of the future. Rather, they represent a possible growth trajectory for the U.S. electric sector if the envisioned price and performance improvements are achieved. Modeled deployment is highly dependent on several assumptions, including projections of future technology and fuel prices, electricity demand, retirement schedules for existing generation resources, transmission expansion costs, and several others, all characterized within

[16] The scenarios represent end-use electricity demand generated by the electric power sector; they do not include onsite industrial generation or onsite co-generation of heat and electricity.
[17] Utility-scale PV systems are represented in ReEDS by both central and distributed systems. See Appendix A for descriptions of these types of utility-scale systems. Distributed systems represent ~1–20 MW plants located within distribution networks, while central systems represent ~100-MW plants located outside of distribution networks. Both systems assume 1-axis tracking.

Additional Key Model Assumptions Used in the SunShot and Reference Scenarios[a]

- Electricity demand projections are based on the EIA (2010) reference scenario through 2035 and extrapolated through 2050. Electricity demand increases about 20% by 2030 and 40% by 2050.
- Capital cost projections for all energy technologies other than PV and CSP are based on an engineering analysis by Black & Veatch (forthcoming).
  - Capital costs for coal, gas, or nuclear generation technologies are assumed to stay fixed through 2050, but coal and gas achieve 10%–20% performance improvements by 2030.
  - Non-solar renewable technologies are assumed to achieve moderate price and performance improvements.
  - Geothermal is projected to achieve a 17% price reduction by 2050.
  - Onshore wind has fixed prices through 2050 but about a 10% increase in performance by shifting to taller towers.
  - Offshore wind is projected to achieve a 20% price reduction by 2050 in addition to a performance improvement similar to onshore wind.
  - Biopower is projected to achieve a small price reduction on the order of a few percent and performance improvements of about 25% by 2050.
- Future coal and natural gas fuel prices and price elasticities are based on EIA (2010) through 2035 and extrapolated based on electric sector fuel use through 2050. Coal prices stay fixed through 2030 and then increase by about 5% from 2030 to 2050. Natural gas prices increase by about 50% by 2030, and 95% by 2050.
- Retail electricity rate projections (used to model rooftop PV) are based on the EIA (2010) reference scenario and extrapolated through 2050. Residential rates are assumed to increase by 0%–1.5% annually, depending on region. Commercial rates are assumed to increase by 0%–1% annually, depending on region.
- No carbon tax or emissions prices are assumed. However, a 6% investment risk was added to the required rate of return for new coal investments to characterize uncertainty over future carbon policy[b] (Barbose et al. 2008).

[a] Modeling assumptions are described in further detail in Appendix A.

[b] The 6% investment risk is higher than the base case assumption used by many electric utilities for capacity expansion planning, but is representative of the middle to lower range of carbon sensitivities used by many utilities to develop capacity expansion plans (Barbose et al. 2008). Carbon prices were used to estimate equivalent investment risk adders based on system financing assumptions in Chapter 8.

Table 3-2. Solar Deployment in the SunShot Scenario[18]

	2030			2050		
	Capacity [gigawatts (GW)]	Energy [terawatt-hours (TWh)][a]	Fraction of Electric-Sector Demand (%)	Capacity (GW)	Energy (TWh)[a]	Fraction of Electric-Sector Demand (%)
Total Solar	**329**	**642**	**13.8**	**714**	**1,448**	**26.9**
Total PV	**302**	**505**	**10.8**	**632**	**1,036**	**19.3**
Rooftop PV	121	164	3.5	240	318	5.9
Utility PV[b]	181	341	7.3	391	718	13.4
Total CSP	**28**	**137**	**3.0**	**83**	**412**	**7.7**
Electricity Demand[c]	-	**4,421**	-	-	**5,103**	-

Components do not always add up to totals because of rounding.

[a] The capacity-expansion models (ReEDS and SolarDS) place solar technologies in locations where they are most economic, leading to capacity factors of about 15% for rooftop PV, 23% for utility-scale PV (1-axis tracking systems), 60% for CSP (ReEDS primarily builds CSP systems with several hours of storage), and 41% for wind.

[b] Utility PV includes central and distributed utility-scale PV systems. See Appendix A for descriptions of these types of utility-scale systems.

[c] Electricity demand is based on projections of electricity sales through 2035 from *Annual Energy Outlook 2010* (EIA 2010); extrapolated through 2050.

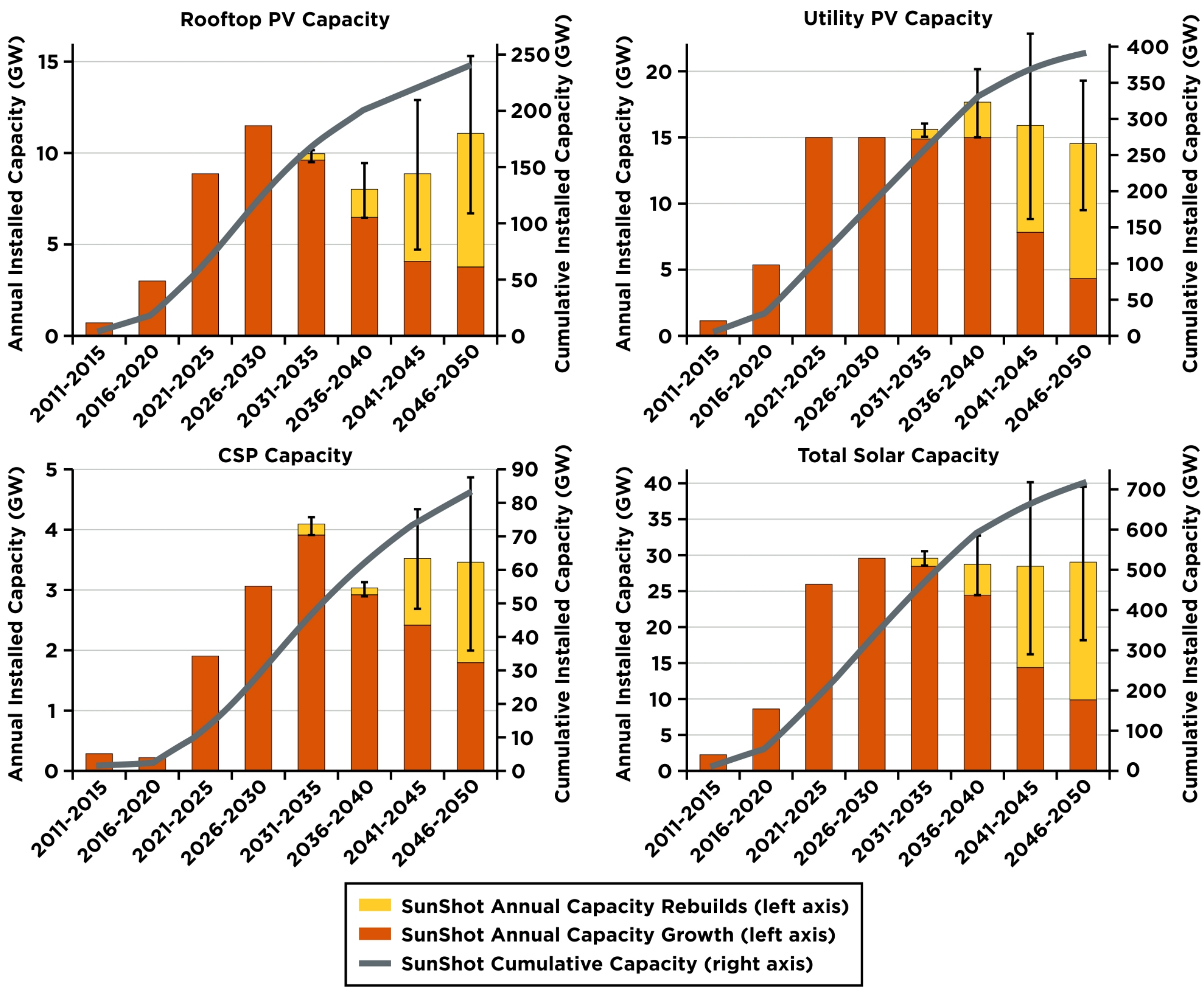
the modeling framework. Key model assumptions are listed in the sidebar, and a detailed description of the modeling methodology and assumptions is included in Appendix A.

Figure 3-1 shows annual and cumulative installed solar capacity for the SunShot scenario, and a range of annual installed capacities required to meet both the solar market growth and end-of-life replacements or retrofits. Market evolution for utility-scale PV and CSP is based on the economic optimization determined by the ReEDS model, with constraints to limit growth in annual installed capacity to no more than double in each 2-year model period, and to limit U.S. demand so it does not exceed 15 GW per year of annual installations. These constraints were added to avoid boom-bust cycles in supply-demand, i.e., where demand rises to a very high level for a few model periods and then collapses. The constraints could also be interpreted as representing the fact that manufacturers would consider longer-term market sustainability before developing manufacturing capacity and that market distribution and installation infrastructure takes time to develop.[19] Figure 3-1 shows that the utility-scale PV market is constrained by these growth rates before 2030, but that this constraint does not significantly decrease total market size in later study years. Rooftop PV markets were simulated using the SolarDS model, and these capacity additions were added into the ReEDS model.

[18] Totals may differ from components due to rounding.

[19] Unconstrained growth in electric-sector demand models frequently produces shorter-term growth peaks for individual technologies like PV, followed by several years of decreased demand. Constraints were added on annual growth rates to decrease these oscillations in PV manufacturing and labor markets to better represent the fact that market participants will temper growth based on market foresight.

Figure 3-1. Annual and Cumulative Installed Capacity for Rooftop PV, Utility-Scale PV, CSP, and All Solar Technologies



End-of-life PV and CSP system and component replacements (rebuilds) are included in Figure 3-1 to show the potential size of future solar markets. Annual solar rebuilds are approximated by the gray bars, which represent the average of rebuilds calculated using a range of system lifetimes from 20 to 30 years (the range is represented by the black error bars).

PV markets show peak growth trends during 2020–2040. CSP markets show peak growth trends during 2025–2040. The distribution of annual installations combine to form an S-shaped diffusion curve in cumulative installed capacity, for all solar technologies. Including rebuilds, the modeled U.S. PV market stabilizes at about 25–30 GW/year (yr), and the U.S. CSP market stabilizes at about 3–4 GW/yr of new capacity additions and plant retrofits.

3.2.3 GENERATION AND CAPACITY MIX

Figure 3-2 shows the mix of electricity generated by each technology in the SunShot and reference scenarios.[20] In the SunShot scenario, solar generation primarily displaces natural gas and coal generation relative to the reference scenario. Before 2030, solar generation primarily offsets natural gas generation. This is because midday solar generation corresponds well with times of peak midday electricity demand, and solar electricity frequently offsets more expensive peaking generation resources, such as natural gas generators. However, once a large amount of solar generation has been added to the system (14% of demand by 2030), the "net load" of the system, defined as electricity demand minus solar and wind generation, shifts from midday to evening. Once this happens, solar generation offsets the new buildout of coal capacity seen in the reference scenario, and solar significantly offsets coal use after 2030. Additional natural gas is built to satisfy the evening peak in net load, and CSP resources are deployed with several hours of storage representing a dispatchable solar generation resource.

Figure 3-2. Evolution of Electricity Generation in the SunShot and Reference Scenarios ("Other" Includes Biomass and Geothermal Technologies)

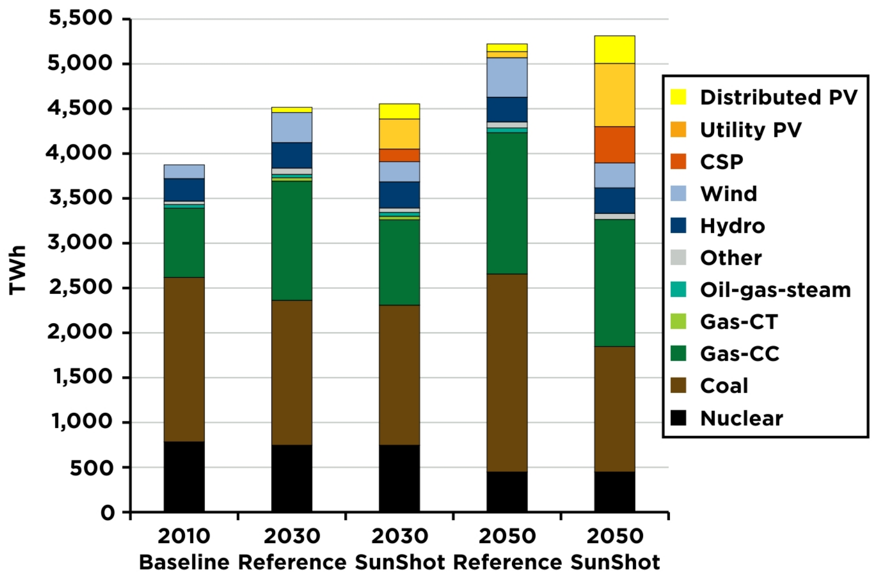


Figure 3-3 shows the avoided use of coal and natural gas fuel in the SunShot scenario relative to the reference scenario. Solar generation displaces about 2.6 quadrillion British thermal units (Quads) of natural gas and 0.4 Quads of coal per year by 2030. In 2050, solar generation displaces the use of 1.5 Quads of natural gas and 7.3 Quads of coal per year. This corresponds to a fuel savings of about $34 billion per year by 2030 and $41 billion per year by 2050.

Figure 3-4 shows the evolution of electricity generation capacity in the SunShot and reference scenarios. The electricity generation capacity deployed in ReEDS ensures

[20] The projected mix of generating technologies is sensitive to technology prices and various other assumptions. See Appendix C for additional information about sensitivities.

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

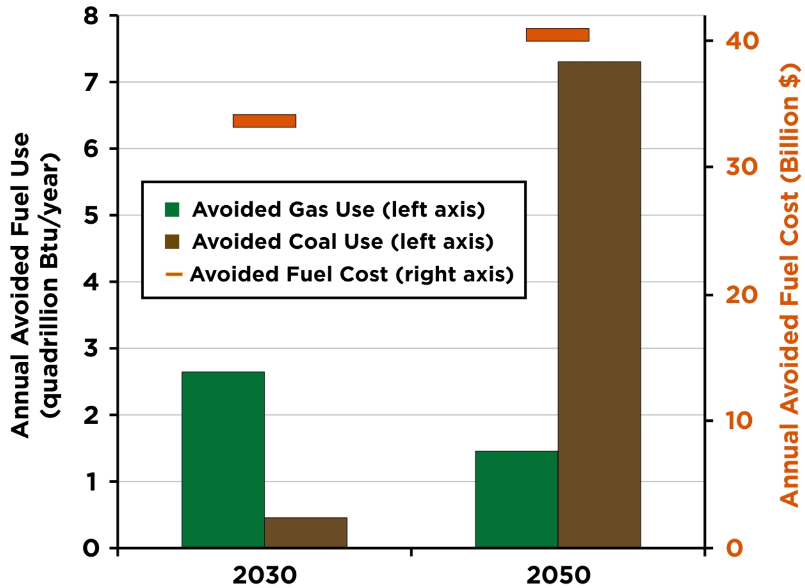
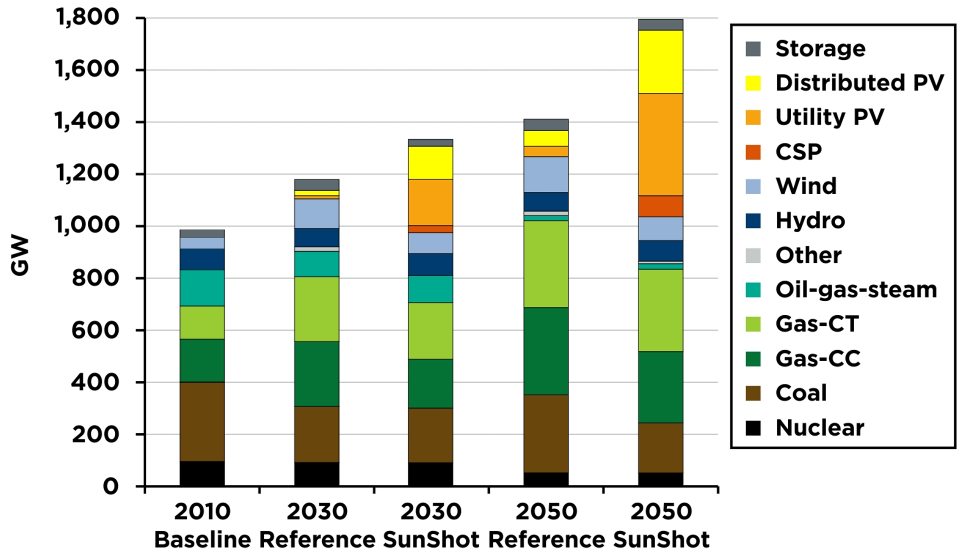


Figure 3-4. Evolution of Electricity-Generation Capacity in the SunShot and Reference Scenarios ("Other" Includes Biomass and Geothermal Technologies)



that peak electricity demands are met, and that additional resources provide operating and planning reserves to cover unexpected plant outages, load fluctuations, and variability in wind and PV generation. Both electricity demand and reserve requirements are time-dependent and specific to each region depending on the historical development of generation capacity.[21]

[21] Additional detail on reserve requirements can be found in Appendix A, along with specific reserve requirements of the SunShot scenario. Note that, in addition to generating capacity, ReEDS also includes interruptible load resources as operating reserves.

The SunShot scenario shows significantly more generation capacity than the reference scenario, reflecting the lower solar capacity factors relative to conventional technologies, and the additional need for reserve capacity. Although more generation capacity is built, the overall system costs are less (see Section 3.3.1) because of the annual fuel savings (Figure 3-3). The increased capacity is particularly pronounced in 2050 relative to 2030 because coal units are typically built to provide baseload with high capacity factors. The SunShot scenario shows a similar buildout of gas-combustion turbine (gas-CT) and gas-combined cycle (gas-CC) capacity as the reference scenario, suggesting that the increase in reserve requirements from the wide-scale deployment of solar resources is roughly offset by the reduction in midday peak demand from the coincidence of solar generation and peak load.

Storage technologies see modest growth in the SunShot scenario. Storage capacity starts at about 20 gigawatts (GW) in 2010, and grows to 29 GW by 2030 and 38 GW by 2050. Storage technologies[22] provide several benefits to the system, including shifting demand, reducing curtailment,[23] and providing capacity resources for operational reserves and regulation. These benefits result in a 50% increase in storage resources by 2030, and a doubling in storage resources by 2050, but not wide-scale deployment in the SunShot scenario. Additionally, interruptible load resources[24] can be developed in the ReEDS model to provide operating reserves, and these resources grow from 13 GW in 2010 to 48 GW by 2050 in the reference scenario and 93 GW by 2050 in the SunShot scenario.

Essentially, the flexibility needed to integrate the levels of PV electricity envisioned in the SunShot scenario is derived largely from fast-ramping generation resources (including existing generators) and the development of demand response resources, as opposed to a large amount of dedicated storage capacity. This is in part due to the fact that CSP is projected to be built with significant amounts of thermal storage, which can be used to provide fast ramping and load shifting. In the SunShot scenario, ReEDS primarily deploys CSP systems with more than 10 hours of storage, and this is a relatively inexpensive method for energy storage relative to other electricity storage options. However, ReEDS does not identify the potential value and opportunities of many storage devices. In particular, it does not evaluate opportunities to relieve local transmission or distribution (T&D) congestion, the value of T&D deferral, or benefits of decreased distribution losses. ReEDS also does not explicitly model storage technologies designed to provide short-term ancillary services such as flywheels. Thus, the modeling assumptions inherently undervalue certain storage devices, and deployment of these technologies is likely underestimated in the SunShot scenario.

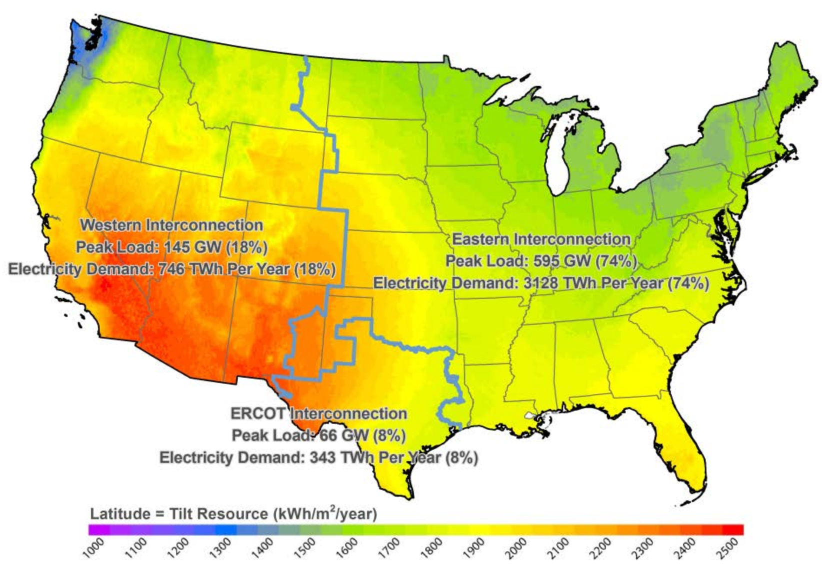
[22] Storage technologies in ReEDS include pumped-hydropower, compressed-air energy storage (CAES), and batteries. Storage technologies in ReEDS are discussed in Appendix A, along with cost and performance assumptions.
[23] Curtailments of variable renewable generation are calculated statistically in ReEDS. See Appendix A for a more detailed description.
[24] Interruptible load represents demand entities that utilities can partially control under contract; its treatment in ReEDS is described in Appendix A.

3.2.4 Regional Deployment

Solar energy contains a direct component (light from the solar disk that has not been scattered by the atmosphere) and a diffuse component (light that has been scattered by the atmosphere). The direct solar component is commonly referred to as direct-normal irradiance (DNI) and is important for concentrating solar applications because only the DNI component of solar radiation can be focused effectively by mirrors or lenses. DNI typically accounts for 60%–80% of surface solar insolation[25] in clear-sky conditions and decreases with increasing relative humidity, cloud cover, and atmospheric aerosols (e.g., dust, and urban pollution). Solar technologies that do not concentrate sunlight, such as most PV applications, can use both the direct and diffuse components of solar radiation and can be economically deployed over a wider range of locations and conditions than concentrating technologies that depend on high DNI.

The U.S. solar resource has significant geographic variation, as shown in Figure 3-5. The southwestern United States has both a high DNI fraction and generally high total solar radiation, leading to higher PV capacity factors than elsewhere in the country. For example, a 1-axis tracking PV module installed near Los Angeles will generate about 23% more electricity than the same module installed near New York City.[26]

Figure 3-5. Global Horizontal Solar Resource (South Facing, Tilted at Latitude) with Electricity Use Statistics by Interconnection



Source: NREL

[25] Insolation is a measure of solar radiation energy received on a given surface area in a given time.
[26] PV generation profiles were calculated using version 2011.8.30 of the System Advisor Model (SAM). www.nrel.gov/analysis/sam. Accessed September 2011.

Electricity demand and wholesale electricity prices also have significant geographic variation. Figure 3-5 shows the peak electricity demand (power) and the annual electricity demand (energy) for the three U.S. electric interconnections.[27] The Western Interconnection represents about 18% of peak and annual demand, the Electric Reliability Council of Texas (ERCOT) Interconnection represents 8% of demand, and the Eastern Interconnection represents 74% of demand. Solar deployment can be more economic in regions with access to better solar resources, and the SunShot scenario leads to higher relative solar generation fractions in the Western and ERCOT Interconnections than in the Eastern Interconnection, particularly for CSP resources. However, since total electricity demand is higher in the Eastern Interconnection, the total amount of PV installed there is higher than in the other interconnections.

Figure 3-6 shows the distribution of PV and CSP deployed in the SunShot scenario. PV is widely deployed in all U.S. states. Rooftop PV markets in particular develop in all U.S. states, while utility-scale PV is predominantly deployed in southern states, reflecting the combination of good solar resources and the general correspondence of PV output with peak afternoon summer air-conditioning load. On a capacity basis, the largest PV markets are in California, Texas, and Florida, reflecting the relatively good solar resource, and relatively high electricity demand. CSP is primarily deployed in the arid southwestern United States, where DNI is highest. The primary CSP markets are in California, Arizona, and Texas, reflecting the high DNI resource and access to load centers in southern California and eastern Texas.

Figure 3-7 shows the fraction of end-use electricity demand satisfied by solar and wind resources within each interconnection in 2030 and 2050. In 2030, solar is preferentially deployed in the Western Interconnection (meeting 31% of annual electricity demand) and the ERCOT Interconnection (14% of demand). PV satisfies about 9% of electricity demand in the Eastern Interconnection, and CSP supplies a small fraction of demand. There are good wind resources in each interconnection, and about 6% of electricity demand is met with wind in each interconnection. However, since CSP is built with several hours of storage, making it a dispatchable resource, the variable renewable energy (PV and wind) fraction is less stratified between interconnections, represented by 22% of electricity demand in the Western Interconnection, and 20% and 13% of electricity demand in the Eastern and ERCOT Interconnections, respectively.

By 2050, solar generation reaches 56% of demand in the Western Interconnection, 28% in the ERCOT Interconnection, and 18% in the Eastern Interconnection. CSP provides the largest share of solar generation in the Western Interconnection, and the resulting variable renewable generation (PV and wind) is similarly less stratified across interconnections (29%, 27%, and 23% in the Western, ERCOT, and Eastern Interconnections). At these levels of regional market penetration, system operation is

[27] The electric system for the continental United States comprises three largely independent grids or "interconnections": the Western, Eastern, and ERCOT (sometimes referred to as Texas) Interconnections. Although the Western and Eastern Interconnections technically reach north of the U.S. border into Canada, only the U.S. regions of those interconnections are accounted for in the analysis for this report.

Figure 3-6. Cumulative Installed PV and CSP Capacity in the SunShot Scenario in 2030 and 2050

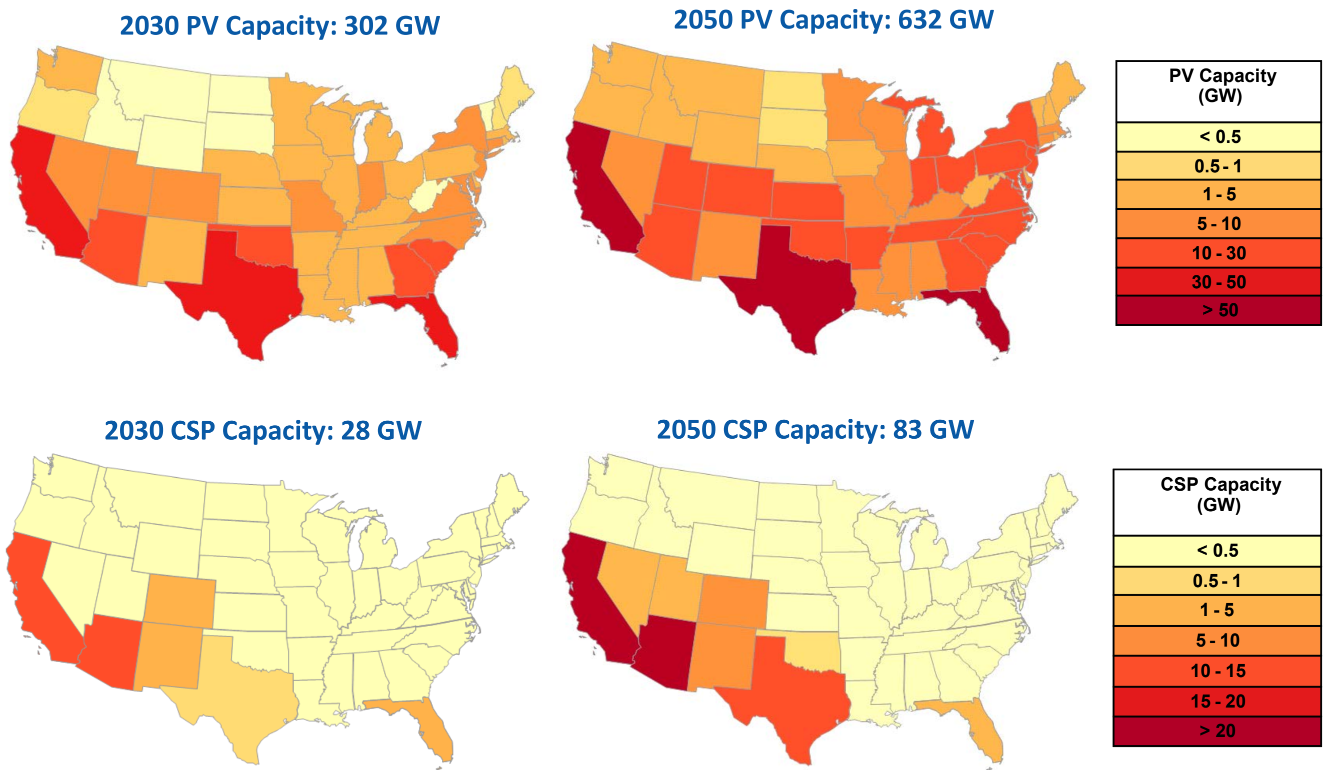
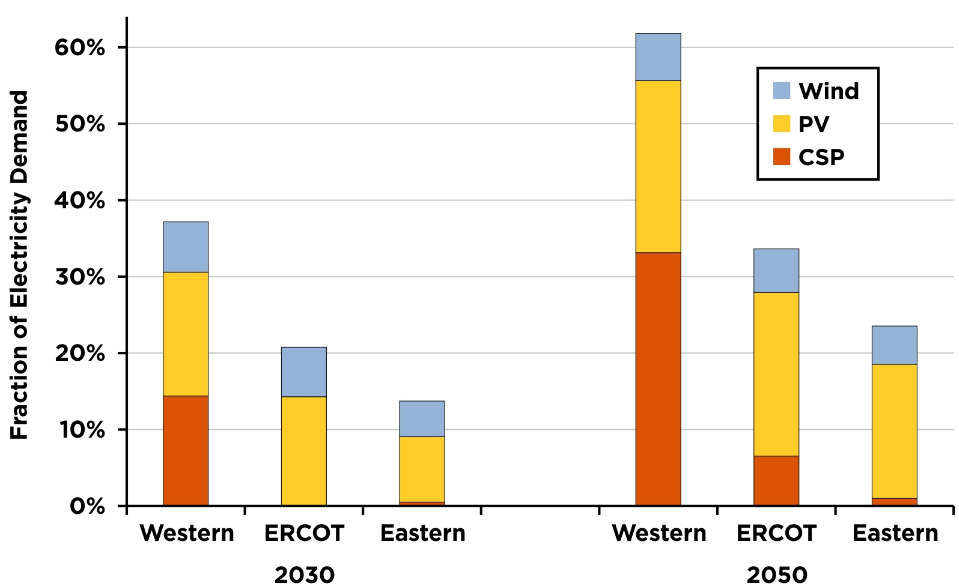


Figure 3-7. Fractions of Electricity Demand Met by CSP, PV, and Wind in Each Interconnection for the SunShot Scenario



clearly a concern. However, CSP with storage can be operated as a dispatchable resource to help integrate variable renewable resources. Grid operability is discussed in Section 3.2.6.

Although solar resources are preferentially deployed in the Western and ERCOT Interconnections, seen by the higher fraction of electricity demand met by solar resources, the larger population and electricity demand in the Eastern Interconnection leads to significantly higher PV capacity additions there than in the Western and ERCOT Interconnections combined. Table 3-3 summarizes the PV and CSP capacity built by interconnection in the SunShot scenario for 2030 and 2050. The majority of PV capacity is installed in the Eastern Interconnection (63% by 2030, 70% by 2050), and the majority of CSP capacity is installed in the Western Interconnection (87% by 2030, 81% by 2050).

Table 3-3. Solar Deployment by Interconnection in the SunShot Scenario

Interconnection	2030		2050	
	PV	CSP	PV	CSP
Eastern	190 GW (63%)	3 GW (12%)	442 GW (70%)	9 GW (11%)
ERCOT	32 GW (11%)	<1 GW (1%)	59 GW (9%)	7 GW (9%)
Western	79 GW (26%)	24 GW (87%)	130 GW (21%)	67 GW (81%)
Total	302 GW	28 GW	632 GW	83 GW

3.2.5 Transmission Requirements

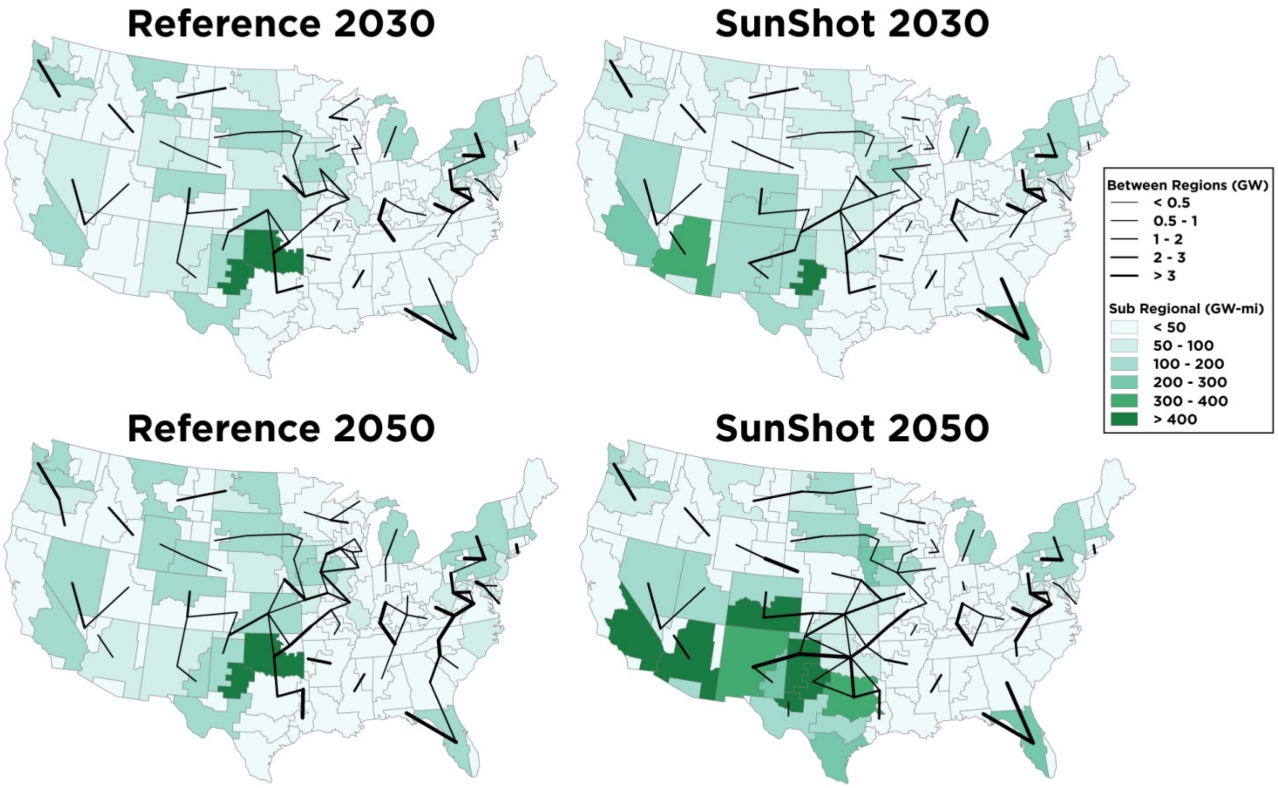
U.S. transmission resources are projected to increase in both the reference and SunShot scenarios. In the reference scenario, growing electricity demand met primarily by new conventional and wind resources necessitates expanded transmission. In the SunShot scenario, transmission is similarly expanded to serve growing demand, but is built out differently in order to develop solar resources.

Figure 3-8 shows the transmission expansion for the SunShot and reference scenarios by 2030 and 2050 as modeled using ReEDS. Transmission expansion includes capacity additions within each region to connect CSP and wind resources to the existing transmission network, and capacity built between regions to enhance the existing transmission network. The transmission infrastructure and cost required to connect utility-scale PV to the grid is assumed to be similar to that for conventional generation since PV resources can frequently be sited near load centers or existing transmission lines. Interregional transmission is expanded in ReEDS to connect different power control areas (PCAs)[28] and is primarily built to connect remote solar and wind resources to load centers. Existing interregional transmission is characterized using the historical transmission development in the United States. A detailed description of the transmission assumptions and model characterization is included in Appendix A.

Transmission expansion is highest in the southwest United States in the SunShot scenario, to connect CSP resources to load centers. Similar cross-interconnection lines are built to connect the Western and Eastern Interconnections in the western plains states in both the reference and SunShot scenarios. These are likely built to

[28] Though existing Balancing Authority (BA) area boundaries 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. In ReEDS, PCAs are the regional level at which demand requirements are satisfied. See Chapter 6 and Appendix A for a more detailed description of BA areas.

Figure 3-8. Transmission Capacity Additions (Intraregional Capacity Expansion Shown by Color, Interregional Expansion Shown by Lines)



support wind development in both scenarios, and to increase power flow between interconnections. The reference scenario shows more transmission buildout in several midwest and plains states to accommodate increased wind development. Modeled transmission expansion is somewhat limited in parts of the Eastern Interconnection since transmission expansion is assumed to cost more (up to four times) than in other regions because of siting and regulatory challenges. Florida is an exception, and sees significant transmission expansion to meet growing demand and integrate some CSP capacity.

In the reference scenario, transmission capacity is expanded 15% from 2010 to 2030, growing from about 88,000 gigawatt-miles (GW-mi)[29] to 102,000 GW-mi in the model representation. This 15% growth supports a 21% assumed increase in U.S. electricity demand, and provides transmission for developing wind resources in the reference scenario. The SunShot scenario shows 13% transmission capacity expansion during this same period, growing to about 100,000 GW-mi. Less transmission expansion is projected in the SunShot scenario than in the reference scenario because a significant amount of utility-scale PV capacity is developed near

[29] Modeled transmission infrastructure is summarized here using the unit gigawatt-mile (GW-mi), which represents a transmission line that is rated to carry 1 GW of power over a distance of 1 mile. Model representation of transmission resources is more detailed than this summary metric, as described in Appendix A, and this simplifying measure is primarily used for reporting existing transmission resources, and the expansion of these resources within the modeling framework.

load centers and near existing underutilized[30] transmission infrastructure. By 2050, the reference scenario shows a 25% increase in transmission capacity relative to 2010 levels, reaching about 110,000 GW-mi, to meet the 40% increase in U.S. electricity demand. The SunShot scenario shows a 32% increase in transmission capacity by 2050, reaching about 117,000 GW-mi. Additional transmission is built in the SunShot scenario by 2050 primarily to connect remote CSP resources to load centers. The growth in transmission capacity is projected to be less than the increase in U.S. electricity demand in all scenarios.[31]

The projected cost of expanding transmission in the SunShot and reference scenarios is low compared to the overall cost of generating electricity. The discounted cost of expanding transmission capacity from 2010 to 2050 is about $60 billion (2010 dollars) in both scenarios. The discounted cost[32] for the SunShot scenario is approximately the same as for the reference scenario, even though more transmission capacity is built, because this additional capacity is developed later in the study period whereas the reference scenario develops more transmission capacity earlier in the period. The $60 billion transmission investment required in both scenarios is spread out over 40 years, representing about 2% of the total electric-sector costs (see Section 3.3.1). This level of investment is within the historical range of U.S. transmission expenditures by investor-owned utilities, which was $2–$9 billion per year between 1995 and 2008 (Pfeifenberger et al. 2009).

Figure 3-9 shows the mean regional energy imports, exports, and interregional energy transmission for the SunShot and reference scenarios. Regions that generate more electricity from all sources than local demand are shown in red, and importing regions are shown in blue. The mean geographic structure of electricity exporting and importing regions is similar in the reference and SunShot scenarios. The main difference is that in the SunShot scenario, the southwestern United States becomes a significant electricity exporting region by 2050 because of CSP deployment. CSP electricity is primarily exported into West Coast electricity markets. Florida also generates significantly more electricity in the SunShot scenario relative to the reference scenario, primarily because of regional PV deployment. While there are several regional differences in electricity generation and interregional transport between the reference and SunShot scenarios, these are generally small or localized. This suggests that, while there are a few regional differences, the SunShot scenario does not fundamentally change where electricity is generated and transported, which is consistent with the relatively low amount of transmission expansion required in the SunShot scenario relative to the reference scenario (Figure 3-8).

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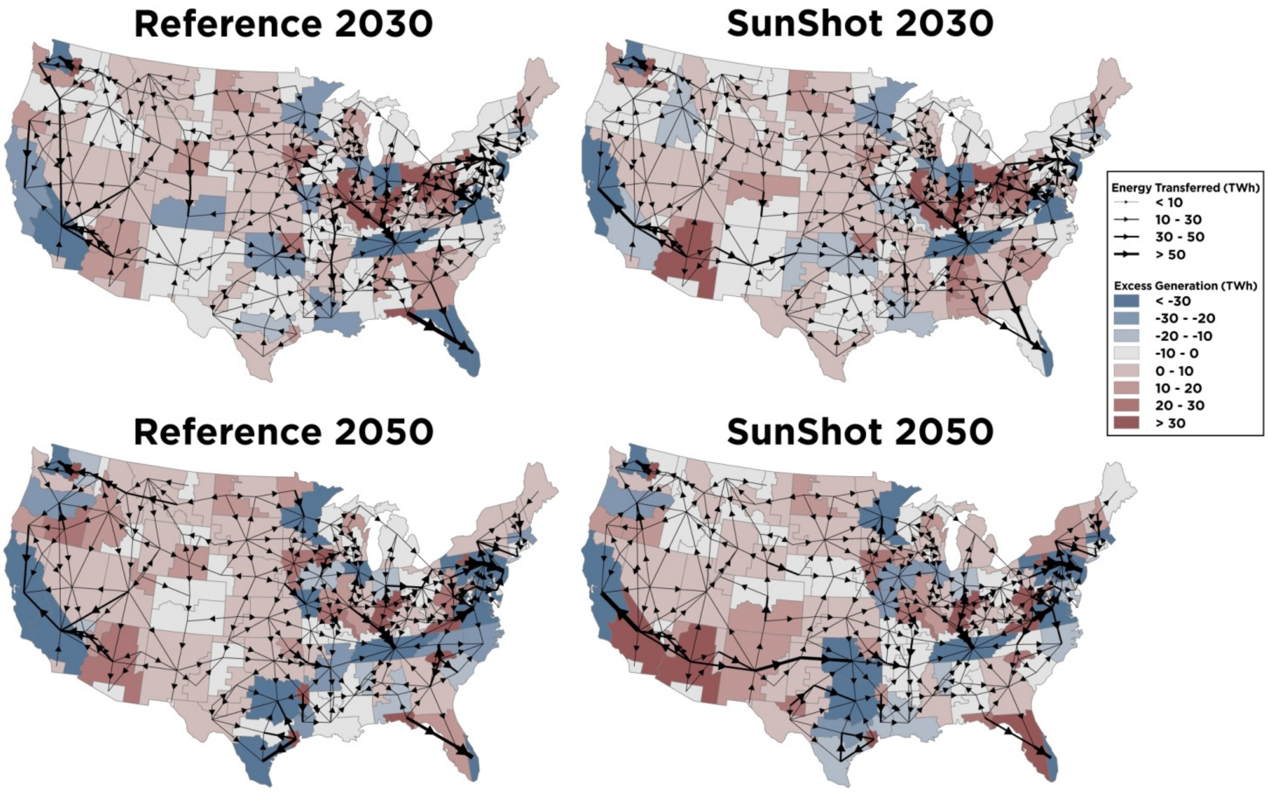
[30] As existing electricity generation capacity is retired during the study period, some transmission capacity resources become underutilized, representing an opportunity for developing solar resources to take advantage of excess transmission capacity.

[31] The ReEDS model likely underestimates transmission requirements for several reasons, including: 1) the model does not characterize the potential need for developing new intraregional transmission capacity beyond what is required to connect generation resources to the existing grid, 2) the modeling framework assumes generation resources can be developed incrementally, at any size, relieving the need for transmission to multiple destinations from a large new power plant, 3) the model does not include a detailed treatment of siting restrictions for conventional and renewable generation resources. Model transmission assumptions are described in more detail in Appendix A.

[32] Transmission costs include grid-interconnection fees (for conventional and renewable resources) in addition to building and maintaining transmission lines.

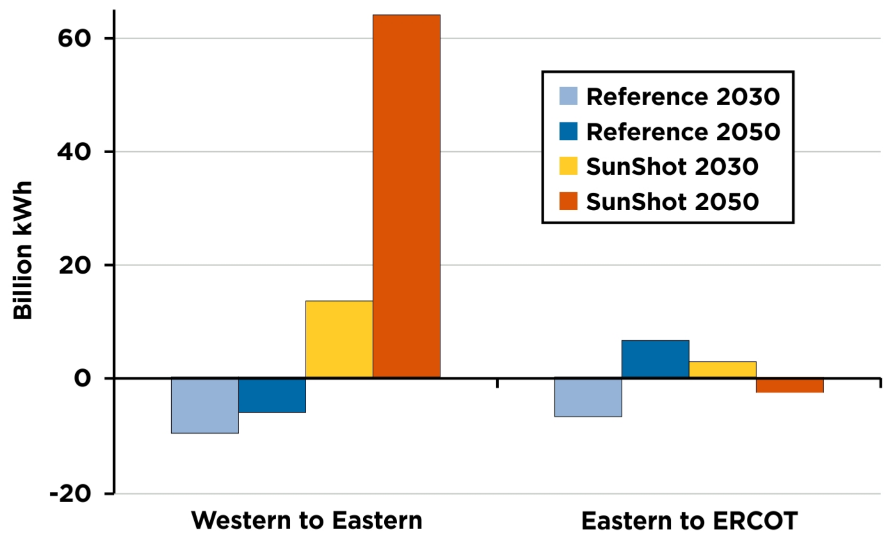
Figure 3-9. Mean Transmitted Energy Showing Net Exporting (Red) and Net Importing (Blue) Regions and Interregional Energy Transmission (Arrows)



Most regions in the Western Interconnection are net exporters in the SunShot scenario, with surplus electricity transmitted to the Eastern Interconnection (Figure 3-10). Net annual exports from the Western to the Eastern Interconnection reach about 14 terawatt-hours (TWh) per year by 2030, or about 2% of the electricity demand in the Western Interconnection. By 2050, the net energy exported from the Western to the Eastern Interconnection increases to about 64 TWh each year, or about 7% of the Western Interconnection's annual electricity demand. In the reference scenario, the Western Interconnection is a small net importer of electricity from the Eastern Interconnection, primarily wind electricity sited in the plains states. All other energy transfers between interconnections are small in comparison to exports out of the Western Interconnection in the SunShot scenario.

To facilitate energy transfer between interconnections, the transmission capacity crossing interconnection boundaries is expanded. In 2010, only a few gigawatts of transmission capacity link the Eastern Interconnection with the Western and ERCOT Interconnections. In the SunShot scenario, the Eastern and Western Interconnections are linked by 7 GW of transmission capacity by 2030 and 18 GW by 2050. The Eastern and ERCOT Interconnections are linked by 4 GW of transmission capacity by 2030 and 5 GW by 2050. The Western and ERCOT Interconnections currently do not have transmission capacity linking each other, and building of this transfer capacity was not simulated because of the small geographic boundary shared by these interconnections, in a location that is far from load centers.

Figure 3-10. Net Energy Transmitted Between Interconnections (Negative Values Represent Imported Energy, Positive Values Represent Exported Energy)



While the increase in transmission capacity and net energy exports between interconnections represents a significant expansion of existing resources and energy transfer, the required growth represents more of an economic and policy challenge in developing new direct current (DC) interconnection capacity than a technical barrier to increasing the amount of electricity transferred between interconnections. This is discussed in detail in Chapter 6.

3.2.6 Operational Impacts

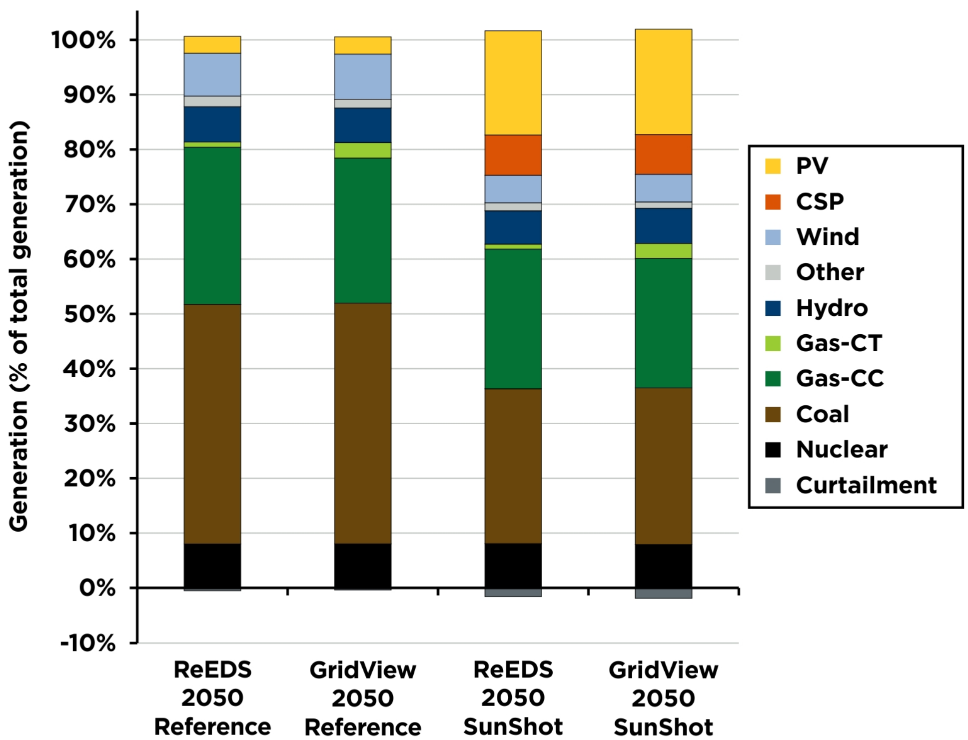
The ReEDS model, used to develop and evaluate the SunShot scenario, uses a reduced-form dispatch and transmission model that cannot completely capture many of the integration and transmission challenges explored in the SunShot scenario. GridView[33] was used to check the basic operability of the SunShot scenario in 2050, including analysis of transmission-flow constraints. In particular, ReEDS and GridView were compared with regard to how they dispatch generation resources, transmit and curtail electricity, and analyze electric-sector fuel use and emissions. In general, the GridView analysis helped confirm that the ReEDS dispatch method produces comparable results to a more detailed dispatch model.

The ReEDS-based SunShot and reference scenarios were imported into GridView, including the generator fleet, transmission network, and DC ties between the three interconnections. The transmission capacity built in ReEDS was augmented across some interfaces because GridView models more congestion compared to ReEDS due to parallel-flow constraints not considered in ReEDS. This led to additional transmission capacity equivalent to 12% of 2010 interzonal transmission capacity in the SunShot scenario, compared to an 11% addition in the reference scenario.

[33] GridView is one of several commercially available utility simulation tools that combines security-constrained unit commitment, economic dispatch, and optimal power flow to optimally dispatch a power plant fleet and provide reliable electricity at the lowest cost. GridView is described in further detail in Appendix A.

The GridView simulations confirm the basic hourly operational feasibility of the SunShot scenario developed in ReEDS. Electricity demand and operating reserves are completely served in all areas during every hour of the year. Also, electric-sector operating parameters—primarily fuel use and generation mix—are very similar in ReEDS and GridView (Figure 3-11). In the GridView simulation, coal provides 44% of generation in the reference scenario and 28% of generation in the SunShot scenario—compared with 43% and 28% in ReEDS. GridView dispatches natural gas units to generate 29% of electricity demand in the reference scenario and 26% in the SunShot scenario—compared to 30% and 26% in ReEDS. GridView projects that each megawatt-hour (MWh) of solar energy produced would displace a mix of 0.64 MWh from coal units and 0.16 MWh from gas units based on the available gas and coal generators projected by ReEDS. The remaining 0.20 MWh would be displaced wind generation or curtailment.

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

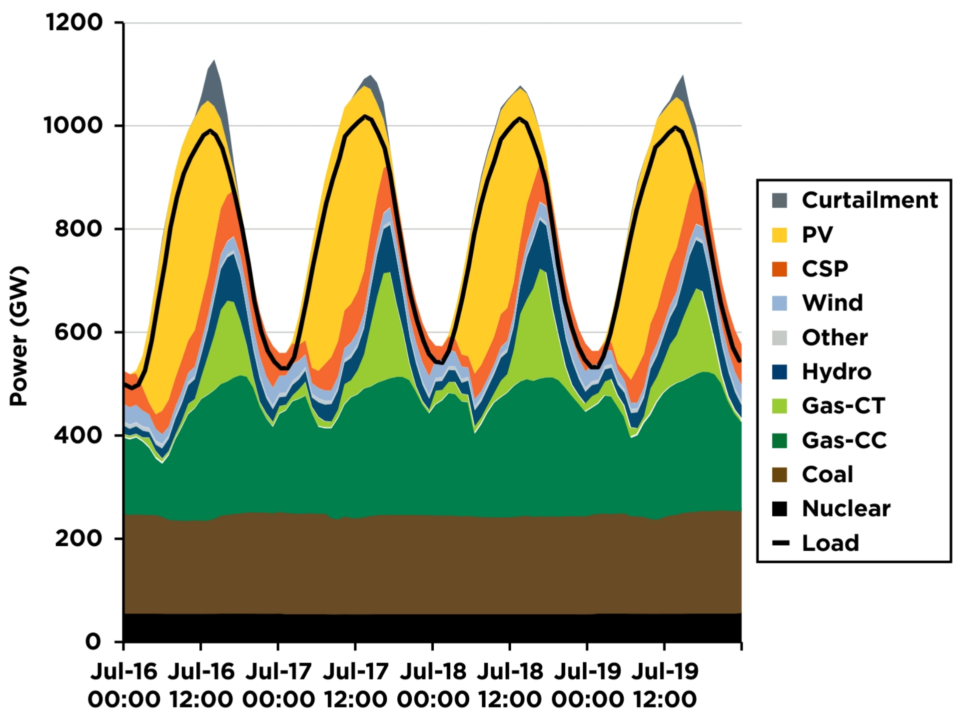


The hourly GridView modeling shows that the SunShot scenario introduces operational challenges and that some solar energy is curtailed, particularly during periods of peak solar output and low demand. The GridView simulation of the SunShot scenario shows 90 TWh of curtailment in 2050, representing 1.8% of the demand and 5.3% of wind and solar generation; ReEDS simulates 80 TWh, representing 1.6% of demand and 4.6% of wind and solar generation. In the reference scenario, GridView curtails 1 TWh of wind and solar energy, while ReEDS curtails 17 TWh of wind energy. The differences in simulated curtailment are primarily caused by the different treatment of transmission in each model (see Appendix A).

Although the annual curtailment estimates are relatively modest, curtailment can be significant during some periods. Fifty-five percent of curtailment occurs between April and June, mostly during mid-day. During this spring period, solar, wind, and hydroelectric generation are all at or near their peak output, while demand is still low compared with the overall summer peak. Curtailment could be reduced by adding transmission capacity, to send excess electricity to areas with unmet demand, or by utilizing energy storage. However, the ReEDS model does not build large amounts of storage capacity or additional transmission capacity because the added cost of investing in these resources is higher than the benefit of reducing curtailment during a relatively small number of hours. Eighty-two percent of the curtailment occurs in the Western Interconnection, which is due to limited transmission capacity to the major load centers in the eastern United States.

Figure 3-12 shows the hourly dispatch from GridView for the entire United States during a typical 4-day summer period in the SunShot scenario in 2050. Electricity load is shown by a black line—the difference between generation and load is due to transmission losses—and curtailment is shown by the grey above the load line. Although most summer days show little or no curtailment, some days, such as July 16, representing a Sunday, show significant curtailment during midday because of the combination of higher solar output and lower demand. CSP units with thermal storage generate at more than half capacity during all hours and generate near peak capacity during the evening after PV generation has decreased but load is still high. The peak net load (load minus wind and PV) shifts from approximately 3 or 4 p.m. local time for a given electric power system with insignificant PV penetration to approximately sunset in the SunShot scenario. This is true during all seasons in most

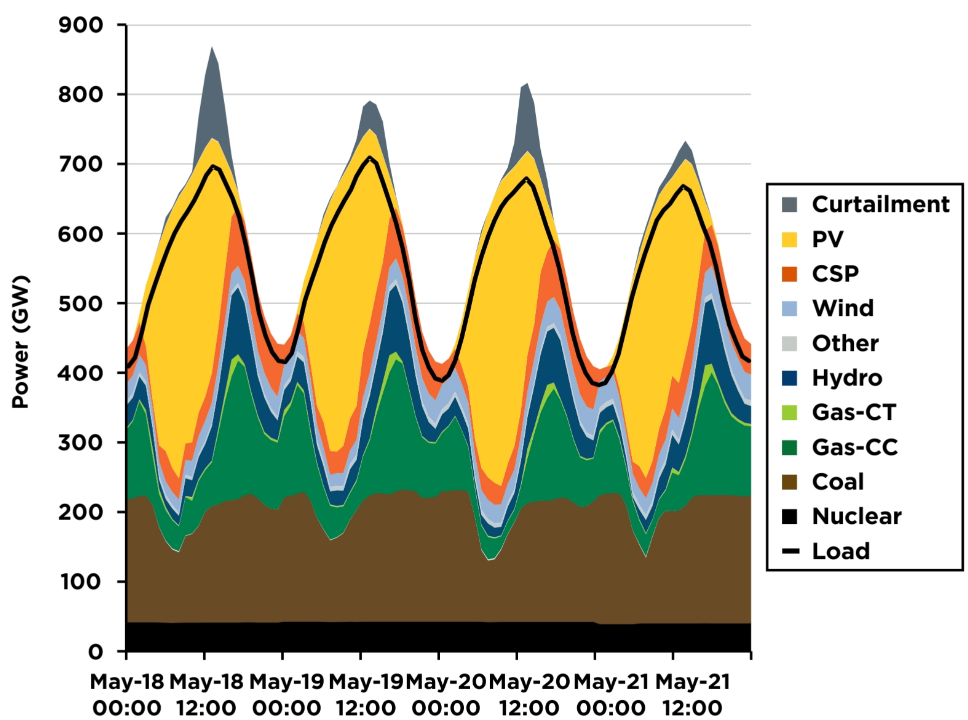
Figure 3-12. GridView-Simulated National Mean Dispatch Stack During 4 Days in Summer for the SunShot Scenario in 2050



areas in the SunShot scenario. During these evening hours, the remaining thermal generators ramp to provide additional energy. The flexibility of CSP generators allows them to produce electricity at maximum capacity during the evening peak in net load.

Figure 3-13 shows the hourly dispatch for a typical 4-day period during May for the SunShot scenario in 2050. During spring, peak electricity demand is up to 40% lower than the summer peak, and renewable generation is high. Any generation resource with no marginal production cost, such as wind, PV, CSP, hydropower, and geothermal, could be curtailed without changing the overall production cost. This curtailment is dominated by curtailment in the Western Interconnection, and is primarily attributed to CSP in GridView. The CSP capacities described in the SunShot growth trajectories represent systems with up to 12 hours of storage and an average solar multiple of 2.6.[34] For the SunShot scenario in 2050, the 81 GW of installed CSP capacity with storage represents approximately 210 GW of instantaneous power from the solar field. The curtailment of more than 100 GW on May 20 represents times when CSP thermal storage capacity is "full," and excess power from the solar field is curtailed. Although curtailment in the Western Interconnection is significant, the amount of curtailment in the ERCOT and Eastern Interconnections during this period is small.

Figure 3-13. GridView-Simulated National Mean Dispatch Stack During 4 Days in Spring for the SunShot Scenario in 2050



[34] The solar multiple is the ratio of the peak thermal power generated by the solar field to the power required to operate the thermal generator at peak capacity. A solar multiple greater than one represents a system with increased solar collector area, and the additional thermal energy can be used to increase system capacity factors by running the generator at peak load for more hours each year.

Several modeling assumptions affect the amount of curtailed solar and wind energy. For example, GridView uses a conservative estimate of the ability to redispatch hydropower. Although there are significant limitations related to real-world dispatch of hydro resources, there may be additional flexibility to reschedule these resources to reduce curtailment.

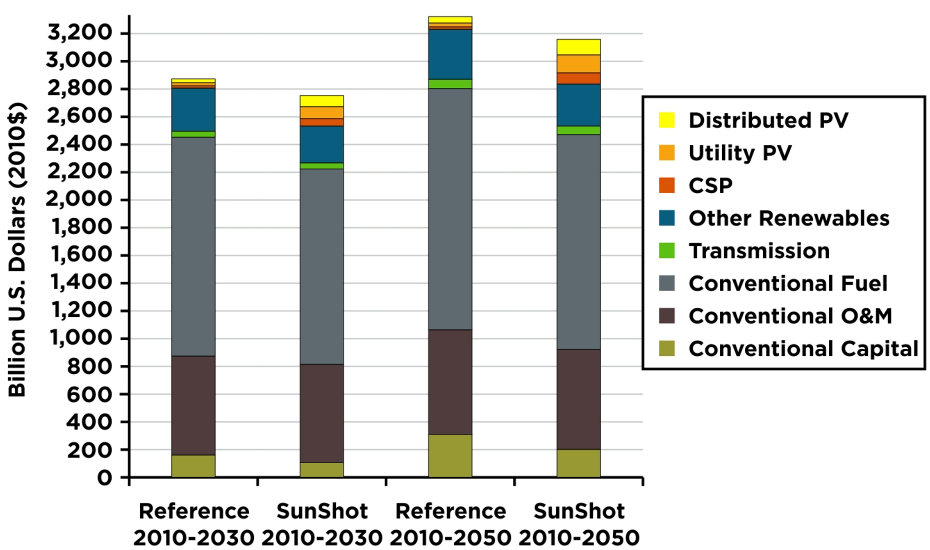
3.3 COSTS AND BENEFITS

Achieving the SunShot price targets has the potential to reduce electric-sector costs and retail electricity prices, reduce greenhouse gas (GHG) emissions, and create a robust solar sector based on increasing solar employment. These impacts are discussed below. Additional environmental and financial impacts are discussed in Chapters 7 and 8, respectively.

3.3.1 COSTS

Direct electric-sector costs include the cost of investing in renewable and conventional generation capacity as well as costs for operation and maintenance (O&M), fuel, and expanding transmission capacity. Figure 3-14 shows the electric-sector costs for the reference and SunShot scenarios, calculated using 2010 U.S. dollars adjusted with a 7% real discount rate.[35] The PV and CSP installed prices are based on SunShot price targets and the financing assumptions outlined in Table 8-1 of Chapter 8. The costs shown in Figure 3-14 represent the cost of expanding generation and transmission capacity for the years shown plus operating the systems (incurring fuel and O&M costs) for an additional 20 years. Thus, the “2010-2030” costs include the cost of building and operating the generation capacity/transmission during 2010-2030 plus operating it during 2030-2050. The “2010-2050” costs

Figure 3-14. Direct Electric-Sector Costs for the Reference and SunShot Scenarios



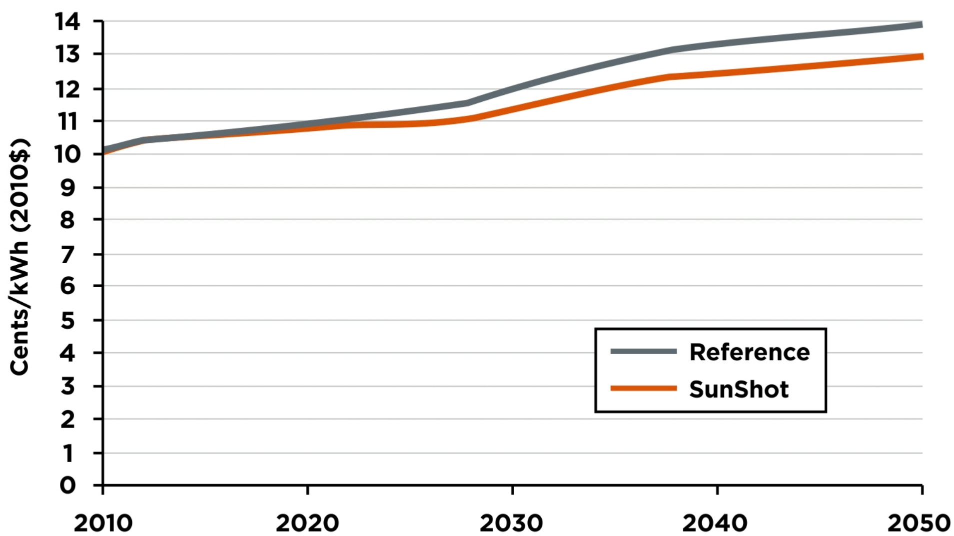
[35] See Chapter 8 for a detailed discussion of electric-sector costs and discounting.

include the cost of building and operating the generation capacity/transmission during 2010-2050 plus operating it during 2050-2070. The costs in Figure 3-14 do not account for incentives, such as the federal investment tax credit (ITC), but they do include rooftop PV installations that will be financed by end users. Because of this, the direct costs incurred by electric service providers for the solar technologies in the SunShot scenario are less than those shown in Figure 3-14. However, electric-sector costs do not include the cost of upgrading and maintaining the distribution system, which could add significant cost to the reference and SunShot scenarios (see Chapter 6).

In the SunShot scenario, the cost of developing solar resources is more than offset by annual fuel savings and reduced capital and O&M expenditures from other technologies. Based on *AEO 2010* (EIA 2010), projected fuel prices that are adjusted for higher or lower fuel demand within each scenario, annual fuel savings in the SunShot scenario reach $34 billion by 2030 and $41 billion by 2050, relative to the reference scenario. For both scenarios, transmission costs are significantly less than the costs of investing in new generation capacity, O&M, and fuel.

Figure 3-15 shows mean retail electricity rates (2010 dollars) charged to end users through 2050. Mean U.S. retail rates are about 5% lower in the SunShot scenario by 2030 and 7% lower by 2050 relative to the reference scenario. This corresponds to a 0.6 cents/kilowatt-hour (kWh) reduction in retail rates by 2030 in the SunShot scenario and 0.9 cents/kWh reduction by 2050 relative to the reference scenario. The lower costs in the SunShot scenario result in about a $6 savings per household, per month by 2030, and about a $9 savings per household, per month by 2050.[36] Real electricity rates increase by about 40% in the reference scenario based on the assumed increase in real natural gas and coal prices in *AEO 2010*. Across all market sectors, the lower electricity prices in the SunShot scenario translate into about $30 billion in annual cost savings by 2030 and $50 billion in annual savings by 2050.

Figure 3-15. Average U.S. Retail Electricity Rates in the SunShot and Reference Scenarios



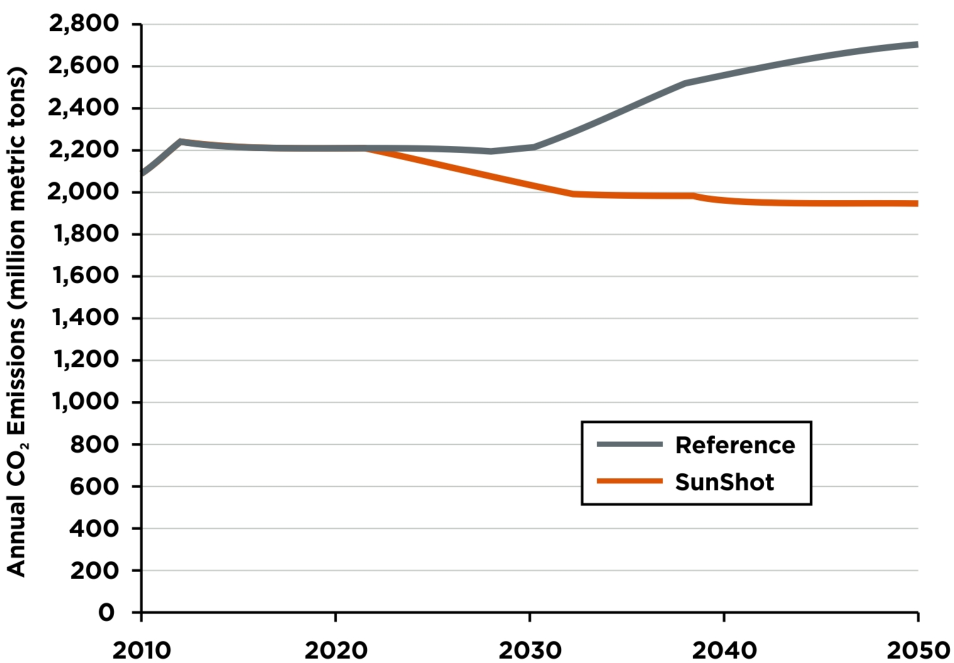
[36] Assuming average household electricity use of about 12,000 kilowatt-hours (kWh) per year, calculated using energy use and household growth statistics from *AEO 2010* (EIA 2010).

Retail electricity rates include the cost of generation, transmission, and distribution. The costs of generation and transmission are captured in the ReEDS model. Distribution costs are based on average historical costs for the entire U.S. electric-power sector, which is assumed to remain regulated. End-use rooftop PV investments do not significantly impact wholesale electricity rates.[37]

3.3.2 Carbon Emissions

Achieving the SunShot price targets could significantly reduce U.S. electric-sector carbon emissions. Figure 3-16 shows electric-sector carbon dioxide (CO_2) emissions for the reference and SunShot scenarios. In the reference scenario, electric-sector emissions increase by 6% from 2010 to 2030, caused by the 21% increase in electricity demand that is partially offset by increasing wind generation and a higher fraction of natural gas generation. Emissions in the SunShot scenario decrease by 3% from 2010 to 2030, where solar generation more than offsets emissions from demand growth. In 2030, emissions in the SunShot scenario are 8% lower than the reference scenario. Emissions in the reference and SunShot scenarios increase briefly after 2010, reflecting increased demand and higher natural gas fuel prices during the recovery from the current economic downturn.

Figure 3-16. Annual Electric-Sector CO_2 Emissions in the SunShot and Reference Scenarios



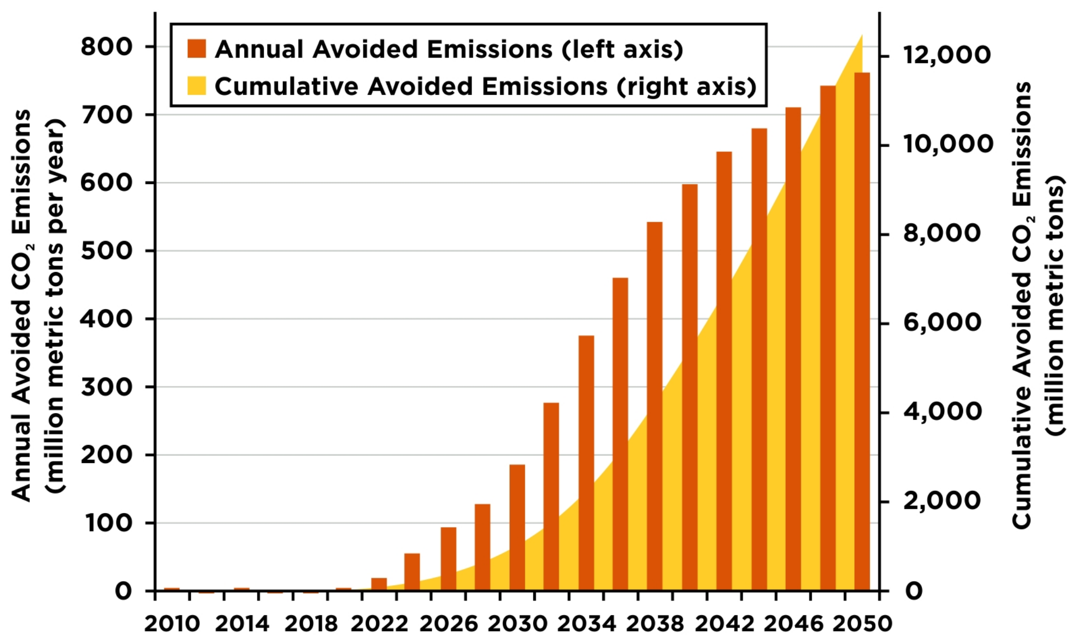
By 2050, CO_2 emissions in the reference scenario increase 29% beyond 2010 levels, due in large part to the expansion of new coal capacity and generation between 2030

[37] End-use distributed photovoltaic (PV) investments are similar to energy-efficiency investments in that customers spend money to reduce the amount of electricity they purchase from the utility. While the customer, not the utility, pays for this investment, it can affect utility rates by reducing daytime demand in load centers. This impact of rooftop PV on mean wholesale electricity rates is characterized in the modeling framework; however, the costs and benefits of integrating PV on distribution networks are not characterized.

and 2050. By offsetting this expansion of new coal capacity, the SunShot scenario achieves a significant reduction in CO_2 emissions. Emissions in the SunShot scenario decrease by 7% from 2010 to 2050, and 2050 emissions in the SunShot scenario are 28% below 2050 emissions in the reference scenario.

Figure 3-17 shows annual and cumulative CO_2 emissions reductions from the SunShot scenario relative to the reference scenario. The cumulative avoided emissions by 2030 and by 2050 would total about 900 and 12,500 million metric tons (MMT) of CO_2, respectively. However, the PV and CSP systems deployed in the SunShot scenario will continue to operate beyond 2050, leading to even greater emissions reductions. If the electric-power sector developed in the SunShot scenario was operated through 2070, the cumulative avoided emissions would be about 27,700 MMT of CO_2.

Figure 3-17. Annual and Cumulative Electric-Sector Emissions Reductions in the SunShot Scenario Relative to the Reference Scenario



3.3.3 EMPLOYMENT

As the U.S. solar industry expands under the SunShot scenario, additional skilled workers will be needed to design, manufacture, distribute, install, and maintain solar systems. Estimating SunShot employment impacts requires accounting for two classes of jobs: 1) manufacturing/distribution and installation jobs for PV and CSP, based on annual production and installation demand and, 2) operations and maintenance jobs for PV and CSP, based on the cumulative deployed solar capacity. SunShot employment estimates are based on gross job creation.[38] Several assumptions are necessary to estimate job growth, including the increase in domestic manufacturing capacity to meet solar market demand, the impact of automation on

[38] Gross job estimates represent jobs that are directly tied to solar markets, whereas a net jobs estimate would account for the potential displacement of jobs in other sectors, such as coal or natural gas industries.

manufacturing labor intensities, and the increase in labor productivity due to streamlining solar manufacturing and installation methods.[39] SunShot job estimates were developed by establishing the current job intensity for PV and CSP, and then accounting for improved labor productivity as solar price and performance improvements are achieved. For this analysis, a full-time equivalent (FTE) job is defined as 2,000 hours per year of employment, which could represent a single full-time employee or several part-time employees.

PV job intensities for 2010 were estimated based on the Solar Foundation's National Solar Jobs Census, which included about 2,500 interviews with employers in each major sector of the solar value chain across solar technologies (Solar Foundation 2010). The study estimated 93,500 direct and indirect U.S. workers with greater than 50% focus on solar in four major market industry sectors: installation, wholesale trade, manufacturing, and utilities. Accounting for the fact that not all of these employees work full time on solar, this level of employment translates into roughly 60,000–70,000 FTE jobs. These FTEs include both direct and indirect jobs; however, induced impacts were not part of the study. Based on the data gathered in this study, PV workers outnumber those focused on solar thermal technologies by about 2.5 to 1 (with many companies engaged in both PV and solar thermal). Thus, of the total estimated FTE jobs, the PV workforce was approximately 40,000–50,000 FTEs, as of the July/August 2010 time frame during which the data were gathered. These were split almost equally between PV manufacturing/distribution and installation. Table 3-4 uses the mid-point of this range (45,000 FTEs) as the 2010 benchmark for estimating jobs per megawatt (MW) in PV manufacturing, distribution, and installation.

Based on an estimated 0.9 GW of U.S. PV installations in 2010, the resulting job intensities were roughly 25 jobs per megawatt in manufacturing/distribution and 25 jobs per megawatt in installation. The operation and maintenance job intensity for PV in 2010 was estimated at 0.5 jobs per MW. These 2010 U.S. PV job intensity estimates are considerably higher than one would expect in an efficient manufacturing/distribution supply chain and installation infrastructure. The fact that they are relatively high is not surprising given that the U.S. PV industry in 2010 was in a scale-up phase, where a significant fraction of FTE jobs were likely focused on business development, research and development (R&D), regulatory issues, and production scale-up.

[39] A number of other factors can create variability in published job estimates, including the following: data collection and analysis methods, types of jobs being considered, types of occupations being considered, variation in estimates of capacity being installed, types of industry subsectors included, variation in metrics or units being used, and variation in the time periods being considered.

3

Table 3-4. Solar Industry Jobs Supported in the SunShot Scenario

	2010	2030	2050
PV Employment			
Jobs index[a]	1	0.2	0.2
Annual installed PV capacity (GW)	0.9	25	30
Cumulative installed PV capacity (GW)	2.5	302	631
PV manufacturing and distribution jobs/MW	25	5	5
PV installation jobs/MW	25	5	5
PV O&M jobs per MW	0.5	0.1	0.1
PV manufacturing and distribution jobs[b]	22,500	125,000	150,000
PV installation jobs[b]	22,500	125,000	150,000
PV O&M jobs[c]	1,250	30,100	63,100
Total PV industry jobs[e]	46,000	280,000	363,000
CSP Employment			
Jobs index[d]	1	0.33	0.33
Annual installed CSP capacity (GW)	0.1	4	4
Cumulative installed CSP capacity (GW)	0.5	28	83
CSP manufacturing and distribution jobs/MW	25	8.3	8.3
CSP installation jobs/MW	15	5	5
CSP O&M jobs per MW	1	0.33	0.33
CSP manufacturing and distribution jobs[b]	2,500	33,300	33,300
CSP installation jobs[b]	1,500	20,000	20,000
CSP O&M jobs[c]	500	9,300	27,700
Total CSP industry jobs[e]	4,500	63,000	81,000
Total Solar Industry Employment[e]	**51,000**	**343,000**	**444,000**

[a] The PV jobs index is based on the decline in PV prices in residential, commercial, and utility-scale markets (Chapter 4) and improved labor productivity as PV markets mature.
[b] The manufacturing and installation jobs are proportional to the annual installed capacity (i.e., equal to the annual installed capacity × manufacturing/installation jobs per MW).
[c] The O&M jobs are proportional to the cumulative installed capacity (i.e., equal to the cumulative installed capacity × O&M jobs per MW).
[d] The CSP jobs index is based on the declining cost of CSP-generated electricity (Chapter 5). The move to increasing levels of thermal storage means that CSP costs—and employment intensities—are not expected to decline as rapidly as PV costs.
[e] These include direct and indirect (e.g., supply chain) jobs supported as a result of increased solar-industry activity. These do not include induced jobs. Some categories may not add exactly due to rounding errors, and jobs numbers should be interpreted as rough estimates.

CSP job intensities for 2010 were based roughly on McCrone et al. (2009), with job intensities adjusted slightly upward to account for labor inefficiencies during industry scale-up. As with PV, a significant fraction of U.S. CSP full-time equivalent jobs in 2010 were likely focused on business development, R&D, regulatory issues, and production scale-up. CSP job intensities were estimated at 25 jobs per MW in manufacturing/distribution and 15 jobs per MW in installation. The operation and maintenance job intensity for CSP in 2010 was estimated at one job per MW. This represented about 4,500 FTE CSP jobs in the United States in 2010.

The 2010 labor intensities represent market dynamics for current PV and CSP prices. These labor intensities will need to decrease significantly as solar markets mature and prices decrease in the SunShot scenario. The PV job intensities are assumed to decrease by a factor of five by 2020, corresponding to both a decrease in PV prices and an increase in PV supply chain and installation efficiencies as PV markets mature. The CSP job intensities are assumed to decrease by a factor of three by 2020, based on the combination of CSP price reductions and the transition from plants that have historically been built with little or no thermal storage to building plants with several hours of storage.[40]

Through 2010, U.S. solar technology production has been more than sufficient to meet U.S. demand. Given that an important component of the SunShot Initiative is enabling and encouraging the scale-up of the U.S. solar industry, it is assumed here that U.S. solar demand will continue to be met largely by domestic solar manufacturing, distribution, and installation.

Table 3-4 summarizes SunShot solar employment projections for 2030 and 2050. Under the SunShot scenario, gross solar jobs could increase from roughly 51,000 FTE jobs in 2010 to 340,000 FTE jobs in 2030 and to 440,000 FTE jobs in 2050. This could support about 290,000 new jobs by 2030, and 390,000 new jobs by 2050. About 80% of solar jobs are estimated to be produced by PV market growth, and about 20% from CSP market growth.

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[40] The factor of three intensity reduction is based on decreasing CSP levelized cost of energy (LCOE) from about 18 cents/kilowatt-hour (kWh) currently to around 6 cents/kWh in the SunShot scenario. The price of energy is a better proxy for basing job intensity than capacity costs for CSP because there is a large range in the amount of thermal storage capacity both in the historical labor data and in model projections.

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