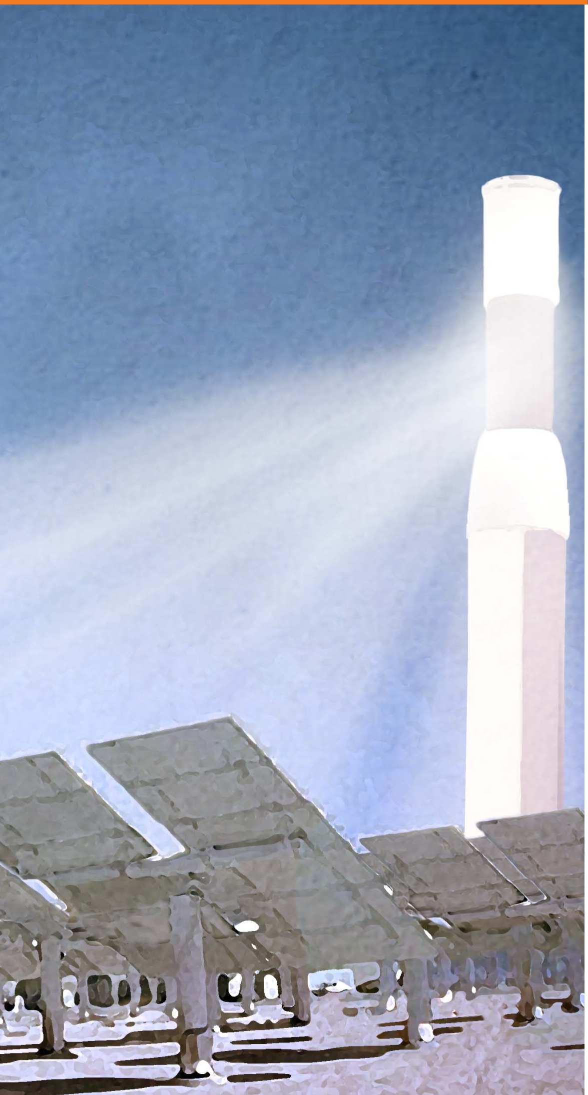
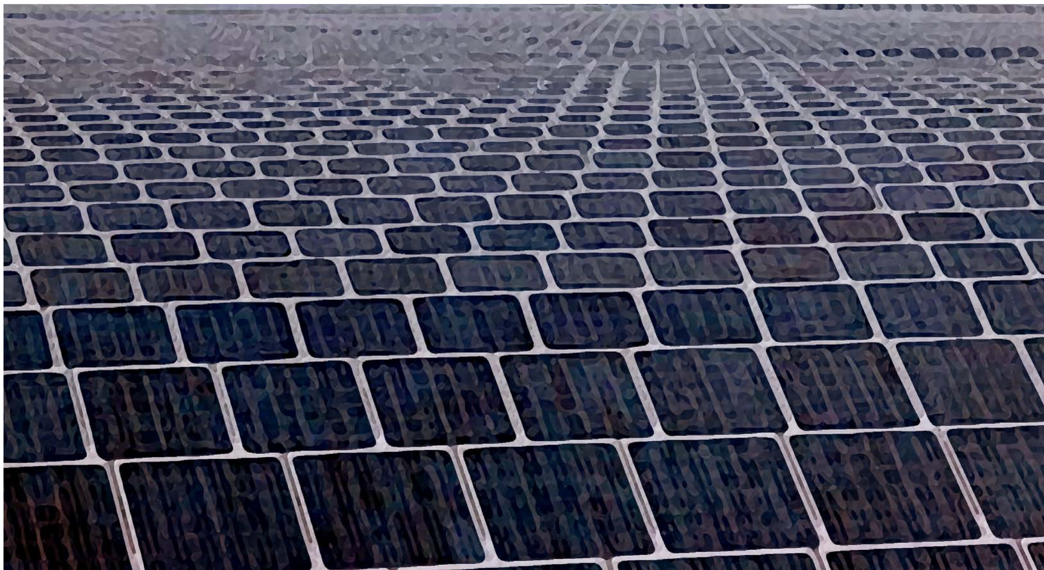
SunShot
U.S. Department of Energy

SunShot Vision Study

February 2012





7. Solar Power Environmental Impacts and Siting Challenges

7.1 Introduction

All energy-generating technologies, including solar technologies, affect the environment in many ways. However, the potential of solar technologies to reduce greenhouse gas (GHG) emissions and other environmental impacts of energy generation compared with other generating technologies is among the most important reasons for widespread solar use. This chapter discusses the potential environmental impacts of achieving the SunShot scenario (Section 7.2), with comparisons to other generating technologies and land uses whenever possible, as well as the challenges associated with siting utility-scale (Section 7.3) and distributed (Section 7.4) solar technologies.

Environmental Benefits and Impacts

Solar energy reduces GHG emissions compared with most other sources of energy. Compared with the reference scenario, the SunShot scenario is estimated to reduce electric-sector operational carbon dioxide (CO_2) emissions by 181 million metric tons (MMT) per year by 2030 (an 8% reduction), and the estimated reduction by 2050 is 760 MMT per year for the SunShot scenario (a 28% reduction). Life-cycle GHG emissions from photovoltaics (PV) and concentrating solar power (CSP) are one to two orders of magnitude lower than from natural gas and coal power plants. Replacing fossil-fuel plants with solar also can reduce emissions of mercury, nitrogen oxides (NO_x), sulfur oxides (SO_x), and particulate matter (PM).

The SunShot scenario deployment of utility-scale solar technologies will require a substantial amount of land: an estimated 370,000–1,100,000 hectares[56] (ha) in 2030 and 860,000–2,500,000 ha in 2050, concentrated in the southern United States. This is equivalent to about 0.05%–0.14% of the contiguous U.S. land area in 2030 and about 0.11%–0.33% in 2050.[57] However, solar technologies can require less land per unit of electricity produced than other energy technologies on a life-cycle basis. In addition, distributed rooftop PV requires little or no land, i.e., by utilizing rooftop space for residential and commercial installations.

[56] One hectare equals approximately 2.471 acres.
[57] All results in this report refer to the contiguous United States (excluding Alaska and Hawaii) unless otherwise noted.

Although some solar technologies consume significant amounts of water during operation, many solar configurations may reduce water consumption dramatically compared with conventional energy technologies. The largest water consumption associated with solar electricity production is for CSP wet cooling. Dry and hybrid cooling can reduce CSP water consumption substantially, although these systems can increase cost and reduce efficiency compared with wet cooling. Solar development could actually reduce water consumption if it replaces activities that have more intensive water consumption, such as irrigation-intensive agriculture.

Like all other technologies, solar technologies require proper waste management and recycling. PV is associated with a few particular waste management and recycling issues, whereas CSP shares issues with other technologies that use common materials such as concrete, glass, and steel. The technical and economic feasibility of recycling PV materials has been established, and existing recycling programs could provide models for the large-scale management of PV materials that will be required under the SunShot scenario.

The primary ecological and other land-use impacts of solar development relate to utility-scale PV and CSP sites. A wide range of habitats, plant and animal species, and cultural and economic activities could be affected by widespread solar development, particularly in the southern United States. Consultation among government and tribal agencies, property owners, and other stakeholders early in the development-planning process can help identify potential land-use conflicts, applicable regulations, and strategies for reducing the impacts of solar projects.

Siting Challenges

Siting and construction of utility-scale solar projects and associated transmission infrastructure requires extensive government and stakeholder review and approval. Potential improvements to siting processes for utility-scale projects and transmission are discussed in detail in Section 7.3. A number of initiatives have identified a large potential resource for utility-scale solar that can avoid developing the most environmentally sensitive areas while expediting development on less-sensitive areas.

Although distributed solar technologies (rooftop PV) do not face the same land-use issues as utility-scale technologies, they do face siting challenges related to their use on residential and commercial buildings, including codes and permits, zoning ordinances, and restrictive covenants. Achieving the SunShot targets will require additional streamlining of distributed solar siting requirements and processes. In particular, a unified permitting process across different regions would facilitate expansion of the distributed solar market. Establishing strong solar access and rights laws would protect the rights of consumers to install solar energy systems.

7.2 ENVIRONMENTAL BENEFITS AND IMPACTS

Solar energy provides environmental benefits compared with most other energy technologies and many other land uses. The adverse impacts of solar energy are mainly local, whereas the benefits of solar are local, regional, and global. The following environmental topics are covered in this section: GHG emissions and global climate change, air pollutant emissions, land use, water consumption, waste management and recycling, and ecological[58] and other land-use impacts.

7.2.1 Greenhouse Gas Emissions and Global Climate Change

Global climate change, largely caused by anthropogenic GHG emissions, threatens public health, welfare, and the environment around the world (IPCC 2007). In 2009, the U.S. Environmental Protection Agency (EPA) officially recognized GHGs as a threat to the health and welfare of the American people. Increased temperatures will likely increase heat-related morbidity and mortality and the prevalence of diseases and other health threats that depend largely on local climate (EPA 2007a, USCCSP 2008). Warmer temperatures can also increase air and water pollution, which in turn can harm human health (EPA 2007a, CDC 2010, USCCSP 2008). Global warming exacerbates the problem of ground-level ozone (smog), intensifying the public health dangers associated with air-quality violations (EPA 2007b). Increased surface water evaporation could lead to more wildfires and increased dust from dry soil, both of which generate harmful PM emissions.

In 2007, all sectors of the United States emitted approximately 6,000 MMT of CO_2, the most important GHG. The electric power sector was responsible for about 40% of these emissions (EIA 2010a). The entire world emitted about 29,700 MMT of CO_2 in 2007 (EIA 2010b). The Energy Information Administration (EIA) (2010a) projects U.S. CO_2 emissions to grow to about 6,200 MMT in 2030, with the electric power sector contributing 41%. World CO_2 emissions are projected to reach 39,300 MMT in 2030 (EIA 2010b).

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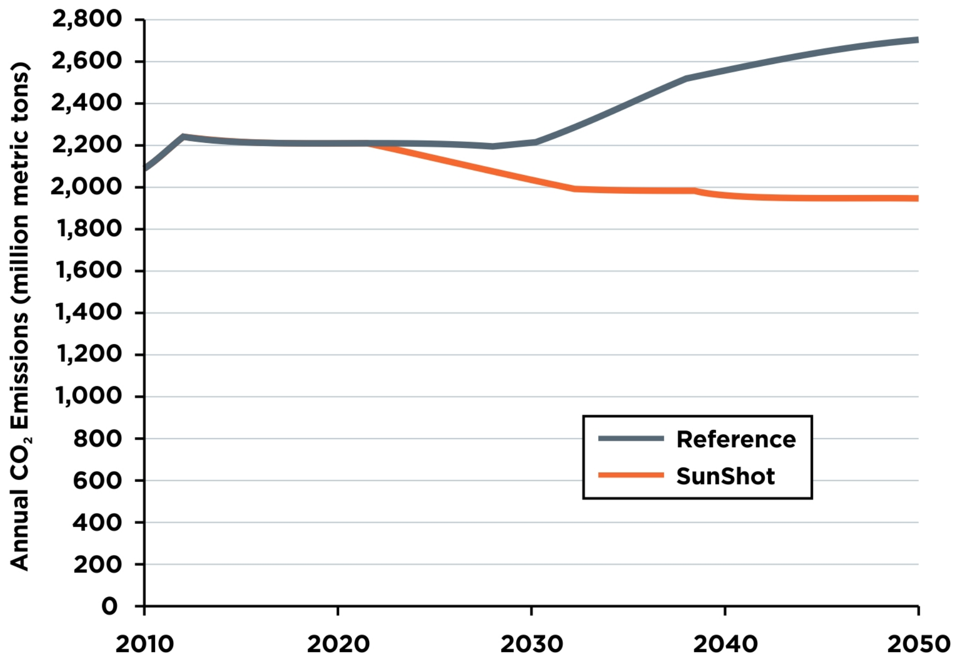
Significant reductions in U.S. GHG emissions are projected under the SunShot scenario. Combined with other efforts worldwide, these reductions have the potential to contribute significantly to the deceleration of global climate change. Figure 7-1 compares the CO_2 emissions projections, for the period 2010–2050, under the SunShot and reference scenarios. Chapter 3 describes the SunShot and reference scenarios, including descriptions of the modeled electricity capacity and generation mixes and discussion of peak and baseload power resources. Note that the CO_2 emissions shown in Figure 7-1 are operational emissions (i.e., emissions resulting directly from electricity generation); lifecycle GHG emissions are discussed later in this section.

In the reference scenario, annual electric-sector operational CO_2 emissions are estimated to increase by 123 MMT by 2030. In the SunShot scenario, annual emissions are estimated to decrease by 59 MMT by 2030—an 8% reduction compared with the reference scenario.

In the reference scenario, annual electric-sector operational CO_2 emissions are estimated to increase by 613 MMT by 2050. In the SunShot scenario, annual emissions are estimated to decrease by 146 MMT by 2050—a 28% reduction compared with the reference scenario.

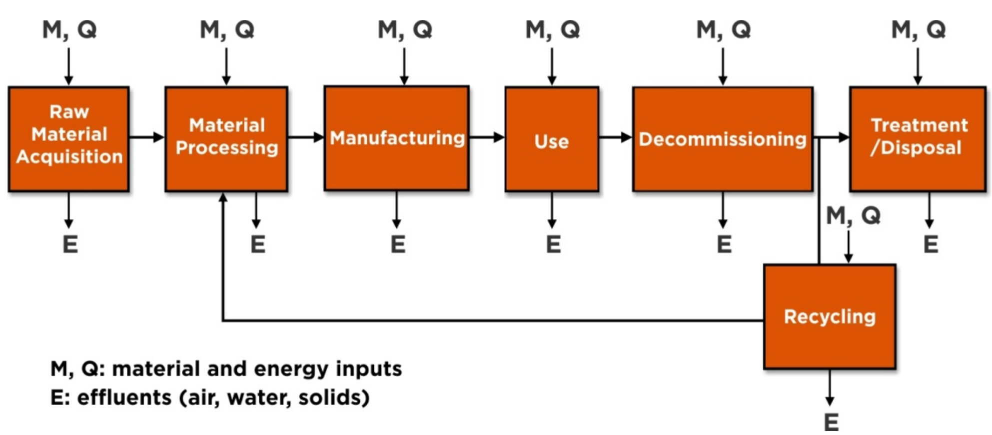
[58] Ecological impacts are defined here as "the effect that a man-caused or natural activity has on living organisms and their non-living (abiotic) environment" (EPA 2006).

Figure 7-1. Annual Electric-Sector Operational CO_2 Emissions under the SunShot and Reference Scenarios



These results are based on CO_2 emissions resulting from electricity generation only. However, electricity-generating technologies produce CO_2 and other GHG emissions during additional stages in their life cycles, such as, from raw materials extraction through end-of-life disposal and recycling (Figure 7-2). For example, the fuel for solar technologies—sunlight—generates no GHG emissions, but GHGs are generated throughout the solar technology life cycle. Similarly, GHG emissions are produced during coal mining, natural gas drilling, wind-turbine manufacturing, and so forth.

Figure 7-2. Energy, Material, and Waste Flows Across Stages of Energy Technology Life Cycles



Source: Fthenakis and Kim (2007)

Because PV and CSP life-cycle GHG emissions are generated primarily during manufacturing processes, the rapid growth of solar technologies could lead to a small net increase in short-term U.S. GHG emissions. However, this increase has been shown to be less than a fraction of one percent, and the lifetime GHG reductions from PV and CSP far outweigh the up-front manufacturing emissions (Drury et al. 2009).

A related concept is energy payback time, which is the time required for an energy technology to generate the amount of energy used to manufacture it. The energy payback time for PV systems is about 0.8–1.8 years at the average insolation found in the United States and southern Europe [1,700 kilowatt-hours (kWh)/square meter (m^2)/year] (Fthenakis et al. 2009a). During an expected lifetime of 30 years, PV systems produce 10–30 times the energy required for their manufacture (Fthenakis and Alsema 2006). The energy payback time for CSP systems is about 12–13 months for a plant in Daggett, California, with a direct-normal irradiance (DNI) of 2,700 kWh/m^2/year (yr) (Burkhardt et al. 2010). During an assumed lifetime of 30 years, such a CSP system would produce about 20 times the energy required for its manufacture. Solar energy payback time depends, in part, on the energy requirements associated with manufacturing specific to PV or CSP technologies and where the technologies are installed (i.e., what solar resource is available). The energy payback times of PV and CSP installations in the U.S. Southwest will be shorter than the U.S. average.

When entire technology life cycles are taken into account, the full GHG-reduction benefits of solar technologies become apparent. Figure 7-3 presents approximate

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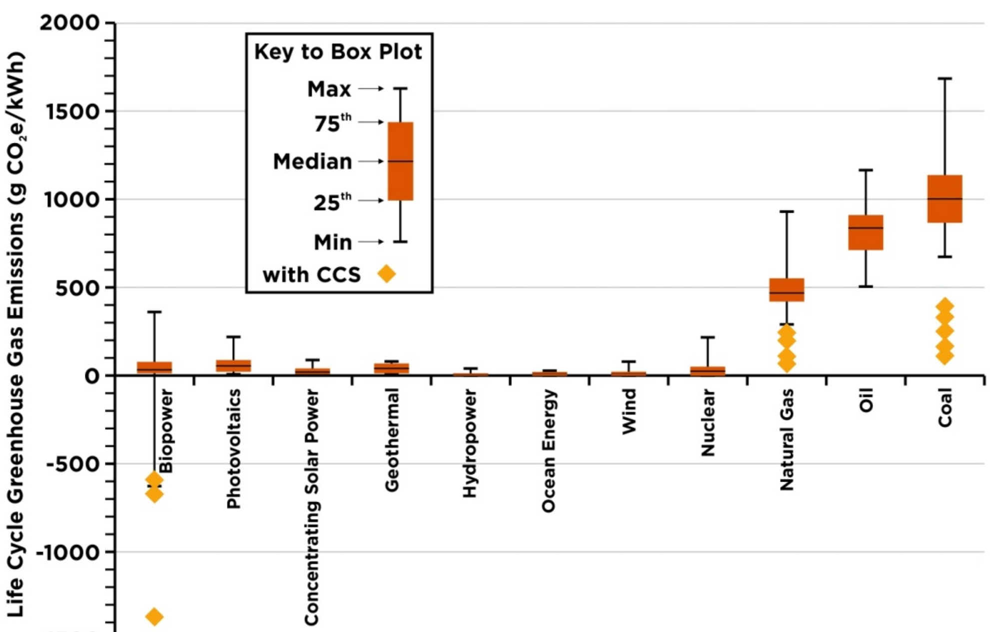
Figure 7-3. Life-Cycle GHG Emissions for Various Electricity-Producing Technologies



These estimates are based on a comprehensive review of English-language life-cycle analysis literature screened for relevance and quality. They are not directly comparable because they use different assumptions for key performance parameters, life-cycle analysis boundaries, and other methodological issues. For example, different insolation/irradiation levels are assumed in the PV and CSP analyses. However, this comparative plot clearly displays major trends based on the best available literature.

Source: Adapted from Edenhofer et al. (2011)

ranges of life-cycle GHG emissions estimates for many electricity-generating technologies. The figure is useful for comparing major trends in life-cycle GHG emissions among technologies. Importantly, there are large differences between renewable technologies and conventional fossil-fuel generation and relatively small differences among renewable technologies. The diamonds show life-cycle GHG emissions estimates for biopower, natural gas, and coal generation with carbon capture and storage (CCS). Ongoing research aims to provide more robust and consistently derived estimates of life-cycle GHG emissions for these and other electricity-generating technologies.

Solar GHG emissions depend, in part, on the specific PV or CSP technology type and where it is installed. According to Fthenakis et al. (2009a), life-cycle GHG emissions for typical PV technologies installed in the southwestern United States are approximately 13–22 grams (g) of CO_2-equivalent per kilowatt-hour (g CO_2e/kWh). For CSP, Burkhardt et al. (2010) modeled a parabolic trough plant with molten salt thermal energy storage in southern California, based on an engineering design study (Turchi 2010). They estimated life-cycle GHG emissions at 24–28 g CO_2e/kWh depending on cooling technology (wet or dry cooling) and thermal storage design (two-tank or thermocline). In contrast to PV and CSP, coal power plants emit about 700–1,700 g CO_2e/kWh, and natural gas power plants emit about 300–900 g CO_2e/kWh (Figure 7-3).

Integration of variable-generation renewable technologies can introduce inefficiencies in the electricity system because conventional-generation sources must operate at suboptimal efficiency under some conditions to maintain the system's supply-demand balance. These system inefficiencies can partially offset the GHG benefits provided by the renewable technologies, although one study suggested the efficiency penalty is relatively small for renewable penetration levels less than 35% of electricity production (GE Energy 2010). Strategies such as drawing from PV installed over a wide area (Fthenakis et al. 2009b) and using thermal storage with CSP should reduce the efficiency penalties. Additional research is needed to quantify the effects on the electricity system of integrating a high proportion of solar generation. See Chapter 6 for additional information about integrating variable-generation technologies.

7.2.2 Air Pollutant Emissions

All electricity-generating and thermal energy technologies emit pollutants during their life cycles, but solar energy technologies emit few or no pollutants during operation (Figure 7-2). Among the emissions of greatest concern for electricity generation are mercury, NO_x, SO_x, and PM.

Mercury can harm the nervous system of unborn babies and young children (EPA 2010a). Coal-burning power plants account for more than 40% of U.S. mercury emissions. Displacing coal-derived electricity using technologies such as PV and CSP would reduce mercury emissions.

NO_x contribute to health and environmental problems such as respiratory ailments, acid rain, climate change, deterioration of water quality, ground-level ozone (smog), air toxics, and PM. SO_x can aggravate respiratory illness and heart and lung disease, form PM, and cause acid rain. In the United States, electricity generation is a major source of NO_x (motor vehicles are the largest source) and the largest source of SO_x (EPA 2010b). For technologies such as PV that produce no emissions during operation, NO_x and SO_x emission estimates depend largely on assumptions about which power sources are used to manufacture PV equipment. For CSP, sources of electric or thermal heat used to warm transfer and storage media and heat boilers at the beginning or end of the day are also factors; the amount of energy required for these purposes is highly technology dependent. For coal-burning power plants, the most important assumptions are which combustion technologies are used and which technologies are installed to reduce NO_x and SO_x emissions during operation. In general, life-cycle NO_x and SO_x emissions from PV and CSP are very small in comparison to emissions from natural gas and coal-burning power plants (National Academy of Sciences 2010a, Fthenakis et al. 2008, Viebahn et al. 2008, Pehnt 2006).

PM, particularly particles less than 2.5 microns in size ($PM_{2.5}$), causes health problems including premature death, reduced lung function, asthma, bronchitis, and cardiovascular diseases. PM also alters soil and water chemistry and upsets nutrient balances. In addition, impacts of PM emissions can occur far from their source (EPA 2008). Displacing fossil-fuel combustion with solar technologies would reduce $PM_{2.5}$ emissions drastically. The National Academy of Sciences (2010b) discusses in more detail the health and environmental impacts of emissions from coal and natural gas power plants, including emissions of mercury, NO_x, SO_x, and PM.

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7.2.3 Land Use

Under the SunShot scenario, a substantial amount of PV is expected to be installed on buildings and other low-opportunity-cost areas such as parking structures, awnings, and airports. However, much of the solar deployment under the SunShot scenario would require use of land that was previously used for other applications (e.g., abandoned industrial, fallow agricultural, or former mining sites) or was previously undeveloped. The way in which solar technologies are deployed can change the nature of their impacts on the land (see Section 7.2.6).

Table 7-1 shows estimates of current direct land requirements for utility-scale solar technologies.[59] The values for land use by capacity [ha/megawatt (MW)] are based on previous estimates as well as a survey of existing or proposed utility-scale PV and CSP installations in the United States. The range in values is a function of several factors. For PV, land use is a function of module efficiency and spacing. For CSP, there is a particularly wide range of values—this is in part due to the variation in the size of the solar field (solar multiple) for a given unit of capacity enabled by the use of thermal storage. For a better comparison, the values for land use by annual electricity production [ha/terawatt-hour (TWh)] are also provided. These are based on the land-use-by-capacity values normalized to a single insolation level in the southwestern United States. Therefore, regardless of where the projects are actually located, their electricity production was calculated using this single insolation value. This single insolation value is approximately equal to the average insolation value for utility-scale PV and CSP deployments in the SunShot scenario, about 2,500 $kWh/m^2/yr$ of DNI or global horizontal insolation of about 2,100 $kWh/m^2/yr$.

[59] Here, direct land requirements are defined as the land "footprint" occupied by the solar power plant. Indirect land requirements, such as land transformation associated with the energy and materials required to construct a solar technology, are not included.

Table 7-1. Estimates of Current Direct Land Requirements for Utility-Scale Solar Technologies

	Number of Installations Evaluated	Direct Land Use by Capacity (ha/MW)[a]	Direct Land Use by Annual Electricity Production (ha/TWh)[b]
PV, fixed tilt	26	1.4–4.3	800–2,500
PV, 1-axis tracking	25	1.8–4.1	900–1,900
CSP, dish/engine	3	3.5–4.1	1,600–1,800
CSP, tower	5	1.6–6.2	700–1,800
CSP, trough	10	2.2–3.6	800–1,200

[a] Based on data from 69 existing, under-construction, and proposed U.S. utility-scale PV and CSP installations as of August 2010. The values for land use by capacity (ha/MW) are based on estimates from the actual installations. The information was collected from project developers and project websites to construct this table for the *SunShot Vision Study*.
[b] The values for land use by annual electricity production (ha/TWh) were calculated using the National Renewable Energy Laboratory's (NREL's) System Advisor Model (SAM) www.nrel.gov/analysis/sam. They are based on the average insolation value for utility-scale PV and CSP deployments in the SunShot scenario, equal to about 2,500 kWh/m^2/yr of DNI or global horizontal insolation of about 2,100 kWh/m^2/yr.

Source: Ong et al. (forthcoming)

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Table 7-2 shows estimates of solar land use in 2030 and 2050 under the SunShot scenario, derived from the utility-scale solar ranges shown in Table 7-1. These ranges are wide for a variety of reasons, including those discussed above. The exact mix of solar technologies and land-use practices that will evolve through 2050 is unknown. If minimizing land use is given priority, it is likely that values at the low end of the range, or lower, would be achieved. In any case, these estimates are based on current solar technology; it is likely that land requirements per unit of capacity installed and electricity generated will generally be lower through 2050 as the efficiency and maturity of solar systems improve across technologies. See Chapters 4 and 5 for details about expected technology improvements.

Table 7-2. Estimates of Direct Solar Land Requirements in 2030 and 2050 under the SunShot Scenario

	Direct Land Use by Annual Electricity Production (ha/TWh)[a]	Solar Generation in 2030 (TWh)	Direct Solar Land Use in 2030 (ha)	Solar Generation in 2050 (TWh)	Direct Solar Land Use in 2050 (ha)
PV, Rooftop[b]	0	164	0	318	0
PV, Utility-Scale	800–2,500	341	270,000–850,000	718	570,000–1,800,000
CSP	700–1,800	137	96,000–250,000	412	290,000–740,000
Total		**642**	**370,000–1,100,000**	**1,448**	**860,000–2,500,000**

[a] These land-use ranges are from Table 7-1.
[b] Indirect land uses are not considered in these calculations. Also not considered is potential land required for another use due to rooftop PV occupying space on a structure that might otherwise accommodate that use. Rooftop PV is assumed to account for a negligible amount of direct land use.

Chapter 3 shows the regional deployment of solar technologies under the SunShot scenario, with the CSP and much of the utility-scale PV deployed in the southern United States. The highest estimate of land use for 2050 (2.5 million ha) in Table 7-2 is equivalent to less than 10% of the land area of Arizona, which covers about 30 million ha, and is similar in magnitude to the land area dedicated to golf courses (about 1 million ha) in the United States (Denholm and Margolis 2008).

These land-use estimates can also be compared with other energy-production land uses. For example, a study by Fthenakis and Kim (2009) found that, on a life-cycle electricity-output basis—including direct and indirect land transformation—utility-scale PV in the U.S. Southwest requires less land than the average U.S. power plant using surface-mined coal.

7.2.4 WATER CONSUMPTION

Water consumption for solar generation varies by technology and location.[60] Table 7-3 gives estimates for solar-, wind-, fossil-fuel, and nuclear-generating technologies. Biomass and co-fired biomass power plants will have cooling/generating water consumption similar to that of comparable coal plants, but water consumption related to growing biomass fuel is highly variable (Gerbens-Leenes et al. 2009, Macknick et al. 2011). Table 7-4 shows estimated water-consumption ranges for solar deployment in 2030 and 2050 under the SunShot scenario; these values represent estimates of gross water consumption from deployed solar technologies only (i.e., they do not consider the amount of water consumption avoided owing to replacement of other electricity-generating technologies by solar). As Table 7-3 shows, many solar configurations can reduce water consumption dramatically compared with conventional technologies that use evaporative cooling systems (i.e., cooling towers). Other cooling types (e.g., once-through and pond systems) may have different water consumption and withdrawal rates, but these technologies are generally not feasible in arid regions owing to their higher withdrawal rates.

PV consumes little, if any, water during operation; some PV operators wash panels to maintain optimal performance, whereas others do not. Concentrating solar technologies, including concentrating photovoltaics (CPV) and CSP, require water for rinsing panels, mirrors, and reflectors to ensure maximum energy production. Manufacturing solar technologies also consumes water. For a trough-based CSP facility with 6 hours of two-tank indirect thermal energy storage

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[60] Water consumption is defined as the amount of water that is "evaporated, transpired, incorporated into products or crops, consumed by humans or livestock, or otherwise removed from the immediate water environment" (Kenny et al. 2009). Water consumption is distinct from water withdrawal. Water withdrawal is the total amount of "water removed from the ground or diverted from a surface-water source for use" (Kenny et al. 2009), but which may be returned to the source. Both water withdrawal and consumption are important metrics, but consumption is a very useful metric for water-scarce regions, especially in the context of future resource development, because consumption effectively removes water from the system so it is not available for other uses (e.g., agriculture or drinking).

Table 7-3. Water Intensity of Electricity Generation by Fuel Source and Technology[a]

Generation Technology	Cooling System	Water Consumed for Cooling (gal/MWh)	Other Water Consumed in Generation (gal/MWh)	Water Consumed in Producing Fuel (gal/MWh)
CSP trough or tower (wet-cooled)[b]	Closed-loop cooling tower	710–960	40–60	0
CSP trough or tower (dry-cooled)[c]	Dry air cooling	0	30–80	0
CSP dish/engine[d]	Dry air cooling	0	4–6	0
PV[e]	None	0	0–5	0
Wind[f]	None	0	0	0
Pulverized coal[f,g]	Closed-loop cooling tower	360–590	60–120	5–74
Pulverized coal with CO_2 capture[f,h]	Closed-loop cooling tower	700–770	150–180	5–74
Integrated gasification combined cycle (IGCC)[f,i]	Closed-loop cooling tower	250–370	40–70	5–74
IGCC with CO_2 capture[f,j]	Closed-loop cooling tower	390–410	130–150	5–74
Natural gas combined cycle (CC)[f,k]	Closed-loop cooling tower	180–280	2	11
Nuclear[f,l]	Closed-loop cooling tower	580–850	30	45–150

[a] The table does not account for water consumption in system manufacturing or construction of any of the technologies. Water consumption for fuel extraction is considered for fossil and nuclear. All wet-cooled Rankine power cycles are assumed to use closed-loop cooling towers with four cycles of concentration and blowdown water discharge to an on-site evaporation pond. Water consumption values for wet-cooled Rankine power cycles using once-through cooling systems are not shown because their large water withdrawal requirements make them infeasible for the Southwest. Dry cooling is possible with all Rankine cycles, although it is explicitly shown for CSP only.

[b] From Cohen et al. (1999) and Viebahn et al. (2008). Other water consumed for trough and tower technologies includes water for washing mirrors and steam cycle blowdown and makeup. Mirror soiling rates/washing rates are site- and developer-specific. Towers will be at the lower end of the cooling-water range and troughs at the higher end owing to thermal efficiency differences.

[c] From Brightsource Energy (2007) and Kelly (2006). Other water consumed for trough and tower technologies includes water for washing mirrors and steam cycle blowdown and makeup. Mirror soiling rates/washing rates are site- and developer-specific. There is more uncertainty in other water consumed for dry-cooled trough/tower technologies than for wet-cooled technologies because fewer dry-cooled plants have been built.

[d] Dish/engine washing rates and other water use are not well documented and vary by site/developer. The estimate of 4–6 gal/MWh is based on Leitner (2002) and CEC (2010) as well as industry knowledge.

[e] Utility-scale PV washing rates and other water use are not well documented and vary by site/developer. The estimate of 0–5 gal/MWh is based on Aspen Environmental Group (2011a and 2011b) as well as industry knowledge.

[f] From DOE (2006).

[g] From NETL (2010) and NETL (2007). Cooling and other-generation values are for new subcritical and supercritical coal plants.

[h] From NETL (2010). Cooling and other-generation values are for new subcritical and supercritical coal plants.

[i] From NETL (2010) and NETL (2007).

[j] From NETL (2010).

[k] From EPRI (2002) and NETL (2007).

[l] From Gleick (1993) and Gerdes and Nichols (2009).

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Table 7-4. U.S. Solar-Related Water Consumption for Solar Technology Deployment in 2030 and 2050 under the SunShot Scenario

	Solar Generation in 2030 (TWh)	Solar-Related Water Consumption in 2030 (billion gal)	Solar Generation in 2050 (TWh)	Solar-Related Water Consumption in 2050 (billion gal)
Rooftop PV	164	0–0.8	318	0–1.6
Utility-scale PV	341	0–1.7	718	0–3.6
CSP[a]	137	14–75	412	42–227
Total	**642**	**14–78**	**1,448**	**42–232**

[a] The CSP water-use ranges reflect the range of trough/tower water-use estimates from Table 7-3. The low number reflects trough/tower technology with 90% use of dry cooling and 10% use of wet cooling, with per-megawatt-hour consumption at the low end of the trough/tower ranges. The high number reflects trough/tower technology with 50% use of wet cooling and 50% use of dry cooling, with per-megawatt-hour consumption at the high end of the trough/tower ranges. The SunShot scenario assumes 100% dry cooling as a conservative estimate of costs, but it is likely that the mix would consist of various technologies. Thus, the values given in this table are meant to illustrate a range of possible scenarios of CSP deployment. As Table 7-3 shows, dish/engine CSP technologies use even less water than dry-cooled trough/tower technologies. Trough/tower technologies were used in these calculations because substantially more data are available for them, but, assuming dish/engine technologies meet the price and performance characteristics envisioned in the SunShot scenario, widespread deployment of these technologies could help reduce CSP-related water use.

(TES), Burkhardt et al. (2010) estimate about 120 gallons (gal)/megawatt-hour (MWh), mainly consumed in the production of solar collector assemblies, nitrate salts, and heat-transfer fluid (HTF). While water-consumption values for PV manufacturing have not been established, Fthenakis and Kim (2010) provide some information about water withdrawals related to PV manufacturing (i.e., water used in the PV manufacturing process but not entirely consumed, with some of the water processed and returned to the immediate water environment). Water consumed to extract, process, and transport fuels can be significant for fossil-fuel and nuclear technologies, but is not required for solar and wind technologies (Table 7-3).

The largest water consumption associated with solar-electricity production is for cooling CSP trough and tower plants. The amount of water a CSP system consumes for cooling depends on the technology, cooling system, location, climate, and water availability. Three types of CSP cooling systems can be deployed: wet, dry, and hybrid (combination wet/dry). Wet cooling (using cooling towers) currently offers the highest performance at the lowest overall cost (Turchi et al. 2010), but it also consumes the largest amount of water. Dry cooling cuts operational water consumption by as much as 97% compared with wet cooling, but it increases capital costs and reduces efficiency on hot days (Turchi 2010). The cost of electricity from a dry-cooled parabolic-trough plant in the Mojave Desert is about 7% higher than from a similar wet-cooled plant (DOE 2009a, Turchi 2010). Dish/engine CSP plants are dry cooled.

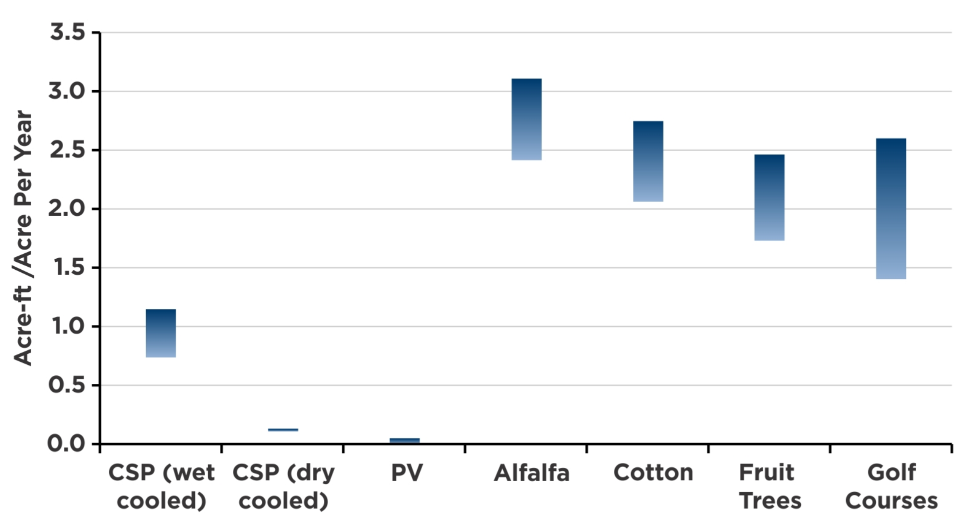
To overcome the cost and performance penalty associated with dry cooling, some developers are considering hybrid systems that employ dry cooling when temperatures are below 38°C (100°F) and wet cooling for hotter periods. Hybrid systems can consume 40%–90% less water than a wet-cooled system while maintaining 97%–99% of the performance (DOE 2009). However, hybrid systems currently have a higher life-cycle cost than wet-cooled systems (Turchi et al. 2010).

See Chapter 5 for information about CSP cooling system research and development (R&D).

In addition to consuming water for cooling, trough and tower CSP systems consume a relatively small amount of water to produce steam for electricity generation. In a typical Rankine-cycle steam turbine, water in a closed loop is heated to produce steam and spin a turbine, then cooled, re-condensed, and used again. A relatively small amount of water—compared with the water consumed in an evaporative cooling system—is drained to remove particulates and salts (a process called "blowdown") in the boiler and cooling systems. The amount of blowdown water depends on the quality of the source water; more is required when using degraded water sources. Dish/engine CSP plants with Stirling engines do not use a water-steam cycle; the movement of a gas is used to produce electricity in these systems.

The distribution of solar water consumption will not be uniform across the United States; it will be highest in the arid Southwest, where CSP deployment will be concentrated. Dry cooling is assumed for all CSP deployment in the SunShot scenario. Unless dry cooling is used, siting CSP in arid areas presents a potentially insurmountable deployment challenge because of water constraints in these areas (Carter and Campbell 2009). The West accounted for half of all U.S. population growth from 1990 to 2000, creating additional demand for water (Anderson and Woosley 2005). Water resources in arid regions may also decline with climate change, and the Southwest has experienced the most rapid warming in the United States (U.S. Global Change Research Program 2009). As shown in Figure 7-4, water consumption per unit of area for PV and CSP is less intensive than for a number of other activities. Thus, although water consumption is likely to be a contentious issue in the Southwest going forward, it is possible that solar developers will be able to obtain water rights from existing water-rights holders, sometimes resulting in less-intensive water consumption.

Figure 7-4. Water Consumption per Acre for Different Applications in the Southwest



7.2.5 WASTE MANAGEMENT AND RECYCLING

Like all other technologies, solar technologies require proper waste management and recycling. PV is associated with a few particular waste management and recycling issues, whereas CSP shares issues with other technologies that use common materials such as concrete, glass, and steel. Waste management and recycling issues for each technology are discussed below, with a focus on the issues surrounding PV.

PV modules contain hazardous materials [e.g., compounds of cadmium (Cd), selenium (Se), and lead (Pb)], and there are concerns about potential emissions at the end of a module's useful life. Managing the disposal and/or recycling of these materials to avoid groundwater contamination (via landfills) and air pollution (via incinerators) is an important environmental consideration.

In addition to materials contained within the completed module, a number of chemicals may be used during PV manufacturing. For crystalline silicon modules, feedstock materials are made through a purification process, the by-products of which typically include silicon tetrachloride ($SiCl_4$). To reduce costs and protect the environment, most of today's manufacturing plants use a closed-loop process that greatly minimizes waste products by converting, separating, and reusing trichlorosilane from the $SiCl_4$ by-product. Silicon nitride (SiN_4) is used as an antireflective-coating material and is generally deposited via chemical vapor deposition. This process requires the safe handling and management of pyrophoric silane gas—i.e., gas that can ignite spontaneously when exposed to air. Silane is also the major feedstock in thin-film amorphous silicon (a-Si) PV. The a-Si/thin-film tandem segment of the PV industry also uses nitrogen trifluoride (NF_3) for reactor cleaning, which has a global warming potential 17,000 times greater than CO_2. The controlled use and production of NF_3 has been proven for specific production and end-use systems (for example, in the liquid crystal display industry), and its use in the a-Si/microcrystalline silicon PV industry will not alter the environmental benefits of PV replacing fossil fuels if best practices are adopted globally (Fthenakis et al. 2010).

The greatest concern surrounding thin-film cadmium telluride (CdTe) and copper indium gallium selenide (CIGS) PV is potential exposure to Cd, which the EPA defines as a Class B1 carcinogen (EPA 2000). Typical CdTe PV material contains 5 g of Cd per m^2 of module, whereas typical CIGS material (which can contain cadmium sulfide) contains less than 1 g of Cd per m^2 of module (Fthenakis and Zweibel 2003). Although Cd is not emitted during normal module operation, small emissions could occur during manufacturing or accidental fires. However, the life-cycle Cd emissions of CdTe and CIGS PV are orders of magnitude lower than Cd emissions from the operation of fossil-fuel power plants (Fthenakis 2004, Fthenakis et al. 2005, Fthenakis et al. 2008).

Recycling helps resolve end-of-life PV module issues, and the PV industry is proactively engaged in building recycling infrastructure. The technical and economic feasibility of recycling the semiconductor materials, metals, and glass from manufacturing scrap and spent PV modules has been established (Fthenakis 2000). Furthermore, recycling can provide a significant secondary source of materials that may be used in the production of future PV technologies, such as, tellurium, indium, and germanium (Fthenakis 2009). First Solar, which manufactures thin-film CdTe PV, established the industry's first comprehensive, pre-funded module collection and recycling program, which the company claims will result in recycling 90% of the weight of each recovered First Solar PV module (First Solar 2010). In Europe, the PV industry has established PV Cycle, a voluntary program to recycle PV modules (PV Cycle 2010). The United States could adopt this type of industry-wide approach to manage the large-scale recycling and management of PV materials that will be required under the SunShot scenario.

The major constituents of CSP plants include glass, steel, and concrete. In addition, some CSP plants will contain a significant quantity of nitrate salt and organic heat transfer oil. All these materials are recyclable. For more detail on the material requirements for CSP plants, see Chapter 5.

7.2.6 Ecological and Other Land-Use Impacts

All development creates ecological and other land-use impacts. The primary impacts of solar development relate to land used for utility-scale PV and CSP (rooftop PV installations have negligible direct land-use impacts). As described in Section 7.2.3, under the SunShot scenario, these utility-scale installations are projected to require 370,000–1,100,000 ha of land by 2030 and 860,000–2,500,000 ha of land by 2050, mostly in the southern United States. However, as this chapter discusses, solar technologies can affect less land, emit lower levels of GHGs and other pollutants, and consume less water than some other electricity-generating technologies on a life-cycle basis. A thorough consideration of solar development weighs both positive and negative impacts.

Even with the most careful land selection, the projected utility-scale solar development may have significant local land-use impacts, especially on portions of the southern United States. Solar development should be consistent with national and local land-use priorities. This section discusses the potential impacts of solar development and strategies to reduce those impacts. Because the discussion is drawn largely from the draft *Solar Programmatic Environmental Impact Statement (Solar PEIS) on Solar Energy Development on BLM-Administered Lands in the Southwestern United States* (DOE and DOI 2010), it focuses on Southwestern impacts. However, each area in which solar development occurs is subject to a unique set of impacts. See Chapter 3 for the regional deployment of solar technologies under the SunShot scenario.

Impacts

The impacts of solar development include direct impacts, such as soil disturbance, habitat fragmentation, and noise, and indirect impacts, such as changes in surface water quality because of soil erosion at the construction site. The specific impacts of utility-scale solar development will depend on project location, solar technology employed, size of the development, and proximity to existing roads and transmission lines.

The potential ecological impacts in the southwestern United States are particularly important because of the large scale of solar development envisioned for this area. The Southwest supports a wide variety of plant communities and habitats, including arid and semiarid desert-scrub and shrub land, grasslands, woodlands, and savannas.

The wildlife in these areas includes diverse species of amphibians, reptiles, birds, and small and large mammals. Government agencies and conservation groups have identified a significant list of species that may be affected by solar development (DOE and DOI 2010).

Altering plant communities with development can strain wildlife living in or near these communities, making it more difficult to find shelter, hunt, forage, and reproduce. Fenced-in power plants can add further strain by affecting terrestrial and avian migration patterns. Aquatic species also can be affected—as can terrestrial and avian species that rely on aquatic habitats—if the water requirements of solar development result in substantial diversion of local water sources. Large areas covered by solar collectors also may affect plants and animals by interfering with natural sunlight, rainfall, and drainage. Solar equipment may provide perches for birds of prey that could affect bird and prey populations.

The potential impacts of solar development are not limited to ecological impacts. Solar development could affect a variety of activities that take place on public and private land. For example, conflicts may arise if development impacts cultural sites or interferes with U.S. Department of Defense (DOD) activities. In addition, loss of forage base could result in reduced grazing, which would disrupt the longstanding economic and cultural characteristics of ranching operations. Potential indirect impacts include conversion of land to provide support services and housing for people who move to the region to support the solar development, with associated increases in roads, traffic, and penetration into previously remote areas. The additional transmission infrastructure associated with solar development could create various impacts as well.

These are merely examples of the types of impacts that may be associated with solar development. For an exhaustive discussion, see DOE and DOI (2010) and other detailed environmental-impact studies. Less well-studied impacts are also important and must be evaluated as solar development progresses. For example, the local and global climate effects of changes in albedo—which determines the amount of incoming solar radiation that is reflected back into space—due to widespread PV and CSP deployment are not well studied. One study evaluated the net balance between GHG emissions reduction resulting from PV replacing fossil-fuel-based power generation (with PV growing to meet 50% of world energy demand in 2100) and a decrease in desert albedo due to PV module covering, concluding that the PV albedo effect would have little impact on global warming (Nemet 2009).

Impact Reduction

Consultation among government and tribal agencies, property owners, and other stakeholders early in the development-planning process can help identify potential land-use conflicts, applicable regulations, and strategies for reducing impacts. Site assessments by biologists and other experts can help identify specific ecological issues and strategies for addressing them. Thorough planning, employee education, and monitoring throughout a solar project's life cycle also can help reduce negative impacts. Management strategies and monitoring might even offer opportunities for improving the land within solar development areas, for example, by enhancing associated wildlife habitat (Fthenakis et al. 2011, Turney and Fthenakis 2011).

Strategies for avoiding or mitigating impacts may include avoiding development in sensitive areas, choosing sites and grouping development to minimize fragmentation, avoiding wildlife disturbance during vulnerable seasons, designing appropriate lighting, and designing projects to minimize contaminant release. Most of these examples are accepted, effective practices, but their implementation must be tailored to each specific project. See DOE and DOI (2010) and other detailed environmental-impact studies for greater detail. Also, see Section 7.3.1 for information about how various stakeholders are considering the impacts of solar development when choosing solar sites.

7.3 Siting Challenges for Utility-Scale Solar Projects

A close examination of specific areas will be necessary for siting utility-scale solar projects. This section discusses the issues surrounding siting to avoid environmentally sensitive areas; the federal, state, and local regulatory frameworks for utility-scale solar projects; and the issues involved with transmission siting. Distributed solar technologies—such as rooftop PV—do not cause the same concerns because their direct land requirements are minimal. Section 7.4 describes the unique siting challenges these technologies face.

7.3.1 Siting to Avoid Environmentally Sensitive Areas

As with any land development, the impacts of solar development on environmentally sensitive areas must be minimized. Various government-led initiatives have sought to identify areas with high solar-energy potential and relatively low environmental sensitivity as starting points for large-scale solar development. This section discusses the major initiatives: the U.S. Bureau of Land Management (BLM) Solar Energy Study Areas, California Renewable Energy Transmission Initiative (RETI), Western Governors' Association (WGA) Western Renewable Energy Zones (WREZ) initiative, and EPA RE-Powering America's Land project.

Lands that are part of the BLM National Landscape Conservation System (NLCS) are already excluded from solar development, including the following:

- Wilderness areas
- Wilderness study areas
- National monuments
- National conservation areas
- National wild and scenic rivers
- National scenic and historic trails
- Conservation lands of the California desert.

In a response to the Solar PEIS proposed by the BLM and U.S. Department of Energy (DOE), The Wilderness Society, Natural Resources Defense Council

(NRDC), and other contributors recommended expanding the areas excluded from solar development to include the following (ANL 2009):

- National recreational rivers, study rivers and segments, and eligible rivers and segments
- Areas of critical environmental concern
- Threatened, endangered, and sensitive-species habitat
- Critical cores and linkages for wildlife habitat
- Citizen-proposed wilderness areas
- Other lands with wilderness characteristics.

In June 2009, the BLM proposed a set of Solar Energy Study Areas, an initial set of suitable lands meant to accommodate solar development with minimal environmental conflicts (ANL 2011). The total area of these lands is about 273,000 ha. If all of these lands were allocated to solar development, they could produce about 110–390 TWh per year (based on the calculations in Table 7-1), or about 23%–82% of the SunShot scenario's total utility-scale solar-generation target in 2030.[61] Note that this initial set of lands was identified to expedite solar development; it should not be viewed as a limit on total potential solar development in the areas considered.

In California, RETI is seeking to identify competitive renewable energy zones (CREZs) that could be developed in the most cost-effective and least environmentally harmful manner (CEC 2009). RETI is an open and transparent collaborative process in which all interested parties are encouraged to participate. As of summer 2009, California CREZs identified by RETI included 21 sites potentially available for utility-scale solar projects with an estimated capacity of more than 61 gigawatts (GW) and energy production of 150 TWh per year (RETI 2009). The CREZ designations and sizes are subject to change. In 2009, California and the federal government initiated preparation of the Desert Renewable Energy Conservation Plan (DRECP), which is scheduled for completion in 2013 (DRECP 2011). This plan will identify areas appropriate for renewable energy development, identify protected areas, and establish a comprehensive environmental impact mitigation strategy for the Colorado and Mojave deserts.

The WGA, in collaboration with DOE, has undertaken a similar process to identify potential renewable energy zones (REZs) in the regions of the Western Interconnection (WGA 2009). The WREZ initiative was launched in May 2008, engaging stakeholders to identify areas with significant renewable energy resources with the goal of expediting appropriate renewable energy development and delivery. In June 2009, the WGA released the WREZ Phase 1 assessment of high-quality, developable renewable resource areas, which have a cumulative technical capacity of approximately 87 GW, or about 200 TWh per year, of utility-scale solar power. Following on this work, the WGA has expanded resource assessments and transmission planning within the Western Interconnection.

[61] Full realization of the solar potential in these areas is only a theoretical possibility because of development and other constraints.

The EPA, with assistance from DOE and NREL, developed the RE-Powering America's Land project to promote the use of current and formerly contaminated land and mining sites for renewable energy projects (EPA 2009). Maps and datasheets provide information about more than 2 million ha of land with potential for utility-scale CSP or PV installations in the western United States, although much of this land may not be suitable owing to slope or existing use. More than 9,000 additional sites for distributed PV are identified throughout the United States, ranging from 0.5–80 ha. Although state and federal laws and policies are intended to clarify—and sometimes provide protection against—liability risks related to developing contaminated land, the applicability of these laws and policies depends on the specifics of each potential project (EPA 2011). Renewable energy developers should thoroughly evaluate the potential for liability and additional costs before developing contaminated land (EPA 2011).

As these studies show, the potential resource for utility-scale solar deployment is enormous, indicating that careful selection can be made to reduce conflicts with environmental, cultural, and aesthetic interests—particularly with respect to public lands. Examination of these areas should yield lands suitable for hosting a large proportion of the utility-scale solar installations projected under the SunShot scenario.

7.3.2 Siting Regulatory Framework

Construction of utility-scale solar projects and their associated transmission infrastructure will require government review and approval at various levels. This section provides background on the National Environmental Policy Act of 1969 (NEPA) and Endangered Species Act of 1973 (ESA), the public's involvement in NEPA, and state and local regulation with a particular focus on California's experience. It also examines potential options for modifying the siting regulatory framework to support solar energy. Distributed solar technologies are subject to different processes (described in Section 7.4).

NEPA and ESA

Federal land management and permitting agencies will have to comply with applicable laws and regulations, including NEPA and ESA, in managing solar resources on federal lands. NEPA and its implementing regulations require the federal government to evaluate the effects of its actions on the environment and to consider alternative courses of action. The statute requires that an environmental impact statement (EIS) be prepared for major federal actions with the potential for significant impact on the quality of the human environment.

The ESA, in contrast, provides for the identification, or "listing," of wildlife and plant species as "endangered" or "threatened" if they meet specific criteria as well as for the designation of "critical habitat" for listed species. Once a species has been listed, federal agencies must consult with the U.S. Fish and Wildlife Service (USFWS) before taking any action that may affect listed species. Private landowners are also subject to ESA requirements.

Because DOE and the U.S. Department of the Interior (DOI) have determined that establishing agency-wide solar energy programs constitutes major federal actions as defined by NEPA, they have decided to jointly prepare a programmatic environmental impact statement (PEIS) (ANL 2011). A PEIS evaluates the environmental impacts of broad agency actions, such as the development of programs or the setting of national policies. For DOI (specifically BLM), the PEIS will involve the adoption of additional policy and mitigation strategies to use when evaluating utility-scale solar energy development on BLM lands. For DOE, the PEIS is aimed at establishing environmental policies and mitigation strategies to be considered in evaluating whether to support solar projects that will be located on BLM or other federal, state, tribal, or private lands. DOE and DOI will consult with USFWS pursuant to the ESA in connection with this PEIS.

Public Involvement in NEPA

The public, other federal agencies, and outside parties may provide input into the preparation of an EIS and then comment on the draft EIS when it is completed. After a final EIS is prepared and a decision about the proposed action is made, the relevant federal agency prepares a public record of the decision that addresses how the findings of the EIS—including consideration of alternatives—were incorporated into the agency's decision-making process. Figure 7-5 shows the basic structure for the Solar PEIS process and how it incorporates public involvement. The draft Solar PEIS was released for public comment in December 2010, and the public comment period ended in May 2011.

7

Figure 7-5. Public Involvement in the Solar PEIS Process

Public Scoping	Draft Programmatic EIS	Final Programmatic EIS	Record of Decision
What Happens: Gather Public Issues and Comments on Scope	***What Happens:*** Publish Draft Programmatic EIS	***What Happens:*** Revise Draft Programmatic EIS	***What Happens:*** Write and Publish Record of Decision
Consider Public Comments	Public Examination and Comment Period	Publish Final Programmatic EIS	
	Consider Public Comments		
May 2008-July 2008 July 2009-September 2009	Draft PEIS published December 2010. Public comment period closed on May 2, 2011.	To be determined	To be determined
Public Involvement Activities: Public Scoping Meetings	***Public Involvement Activities:*** Public Meetings	***Public Involvement Activities:*** Public Distribution of Final EIS	***Public Involvement Activities:*** Public Distribution of Record of Decision
Submit Public Comments via Mail, Web, or in Person at Meetings	Submit Public Comments via Mail, Web, or in Person at Meetings		

Source: ANL (2011)

State, Local, and California Regulation

In addition to the federal process described above, solar projects are subject to a diverse set of regulatory requirements—including different standards, information requirements, decision-making processes, and public-participation requirements—some of the variability and complexity of state regulations; it is not an exhaustive list of states with regulations or an exhaustive list of regulations within the listed depending on the state in which they are located and, in some states, on their size and technology. Depending on the state, they may be regulated at the state level, local level, or both.

Table 7-5 shows a few examples of state regulatory considerations related to water use, project review and approval, and the environment. It is meant only to illustrate states. Regulations and interpretations of regulations change frequently. Examples of additional regulatory areas include historical/cultural preservation, public-participation processes, and incentives. California—where significant utility-scale solar development is projected—has one of the nation's strongest regulatory programs for both generation and transmission projects and is discussed in more detail below.

In California, all thermal-generating projects larger than 50 MW must be certified by the California Energy Commission (CEC), and this includes CSP projects. Large PV projects, because they are not thermal, do not come under the jurisdiction of the CEC. Smaller CSP and PV projects are primarily permitted at the county level.

Transmission lines that serve those projects are permitted by the California Public Utilities Commission (CPUC) or by municipal power authorities, while interconnections to the grid and assurance that projects maintain grid reliability are governed by the California Independent System Operator Corporation (CAISO) or municipal power authorities.

Except on federal lands, the CEC has essentially exclusive jurisdiction over large CSP plants. When projects 50 MW or larger are proposed for federal lands in California, the federal government works with the CEC to review the projects pursuant to a series of federal-state memoranda of understanding (MOUs).[62] The CEC's permitting process is designed to ensure compliance with all applicable state laws, ordinances, and regulations, including the California Environmental Quality Act (CEQA)[63] and the California Endangered Species Act (CESA).[64] The process incorporates project review by relevant state and local agencies as well as extensive public participation. In contrast, all utility-scale PV and smaller-scale solar thermal project proponents must independently obtain all required federal and state permits, including construction permits from the county in which the project is located, and it

[62] For example, see http://energy.ca.gov/siting/solar/BLM_CEC_MOU.PDF.
[63] See generally, California Energy Commission, Energy Facilities Licensing Process – Guide to Public Participation. http://www.energy.ca.gov/siting/guide_license_process.html. Extensive information about the CEC process is available at its website: http://www.energy.ca.gov/sitingcases/index.html including information for developers and the public.
[64] Although similar to their federal analogues, both CEQA and CESA have requirements that are different, thus adding to the complexity of the permitting process for projects located on federal lands in California.

Table 7-5. Examples of State Regulatory Considerations[a]

State	Water	Project	Environment
Arizona	Requirements based on location and water source; “Aquifer Protection Permit” required for discharges.	Application, review, and public hearing required for transmission lines ≥115 kilovolt (kV); power plants ≥100 MW must obtain Certificate of Environmental Compatibility.	Reviews based on animals and plants, noise, recreation, and environment.
California	Dry cooling default for regulated projects; wet cooling only with non-potable water or if dry cooling is deemed “uneconomic.”	California Public Utilities Commission (CPUC) regulates investor-owned utility (IOU) transmission >50 kV; municipal utilities self-regulate; California Energy Commission (CEC) permits transmission for projects it regulates; CEC permits CSP >50 MW; smaller projects and PV permitted by counties.	California Endangered Species Act (CESA) protects species; usually 2 years of surveys for sensitive areas.
Florida	Water use and discharge permits issued through the Florida Electrical Power Plant Siting Act (PPSA) certification process.	PPSA is a one-stop certification procedure for construction/expansion of plants and transmission; PPSA applies to solar generators ≥75 MW, transmission associated with new power plants, and lines that are ≥230 kV, cross a county line, and are >15 miles in length.	Avoiding and/or mitigating impacts on state and federally listed animal and plant species may be required.
Nevada	New water rights or changes in existing rights regulated by State Engineer, usually involving public process; groundwater discharge permitting similar to Arizona’s.	Public Utility Commission of Nevada (PUCN) permits construction; municipalities and certain trusts exempt from requirement to obtain a Certificate of Public Convenience and Necessity; PUCN regulates transmission >200 kV, power plants >150 MW; land- and air-quality permits also required.	Endangered species law covers plants and animals, but recovery plans, consultation, and critical habitat designation not required; harmful stream modification prohibited.
New Mexico	Regulations ensure that other water users not impaired and no additional depletions occur on fully appropriated streams or streams needed to fulfill interstate compact obligations.	Transmission ≥230 kV approved by New Mexico Public Regulation Commission (NMPRC); Renewable Energy Transmission Authority (RETA) implements state renewable energy law; approval needed from NMPRC for solar.	New Mexico Fish and Game Department guidelines on wildlife impacts applied to renewable energy projects.
Texas	Groundwater regulated through Groundwater Management Areas and local districts; no regulations specific to renewable energy.	Public Utility Commission of Texas (PUCT) regulates construction plants ≥10 MW if constructed, owned, or operated by a bundled electric utility; PUCT regulates CREZs established for wind power; no solar CREZ established to date.	Texas Parks and Wildlife Department recommends CREZ wildlife impact mitigation measures.
Utah	No specific limitations on water use for energy generation.	No single state agency has primary responsibility for plant siting; Certificate of Public Convenience and Necessity from Utah Public Service Commission required; various additional agencies establish requirements for specific projects.	State-listed species not protected by special regulations.

[a] This table illustrates generalized examples only. It does not represent an exhaustive list of states with regulations or an exhaustive list of regulations within the listed states and should not be relied upon to make decisions. Regulations and interpretations of regulations change frequently. The relevant government agencies are the best source of official, updated information.

Sources: Relevant state and utility websites accessed in 2010 is the county that is responsible for CEQA analysis and for ensuring that all significant adverse impacts are mitigated.[65]

Although the CEC's permitting process is required to be completed within 12 months, it has taken longer for CSP plants because of the CEC's lack of familiarity with CSP, the newness of some of the technologies, and the scale of the projects. The CEC and its staff are making significant progress to develop expertise and experience with these projects. The same is true of the staff at DOI and its agencies, with whom the CEC now prepares coordinated NEPA/CEQA reviews and joint environmental documents for most projects currently proposed on federal land.[66] Ultimately, it is expected that the integration of these two decision-making processes and environmental reviews will save time and effort for all concerned, including developers.

The CPUC regulates planning and construction of network transmission facilities [above 50 kilovolts (kV)] if they are owned by an investor-owned utility (IOU). CPUC prepares joint environmental documents with federal land management agencies (CPUC and BLM 2008). Municipal power authorities regulate the construction of lines that feed their own systems (either individually or through consortiums, such as the Transmission Agency of Northern California). Transmission facilities are subject to CEQA and its public participation opportunities and may also be required to comply with requirements of other state and federal agencies.

Siting and Permitting Improvements to Support Utility-Scale Solar Energy

To meet the SunShot scenario deployment levels, there are a number of options that could help improve the siting and permitting process. Most of these options could be pursued at the state, regional, or federal level. These options include:

- Developing clear and consistent criteria for environmental screening to aid in selecting optimal solar-generation sites. The California RETI process serves as a good example for other states or regions to follow.
- Developing a comprehensive and consistent strategy for environmental mitigation. Any funds set aside for mitigation purposes would ideally last for the duration of a project, and can be managed independently.
- Fostering cooperation between federal and state agencies responsible for permitting and streamlining the process among agencies. Although several states have undertaken efforts to streamline the permitting processes with the federal government, there has not been a region-wide effort to achieve this goal on a broader scale.[67]

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[65] CEQA requires mitigation to the extent feasible. Where mitigation is not feasible, the permitting authority can deny the application or issue a Statement of Overriding Considerations that allows permitting despite the remaining impacts.

[66] See, e.g., CPUC and BLM (2008). Note that approval of projects on lands managed by the U.S. Department of Defense (DOD), DOE, or other federal agencies such as the U.S. Forest Service (USFS) would involve federal wildlife agencies, but not the U.S. Department of the Interior's (DOI) BLM.

[67] The Renewable Energy Policy Group is one example of a state's, specifically California (CA), efforts to streamline the permitting process with the federal government. A memorandum of understanding (MOU) was signed in fall 2009 between CA Governor Arnold Schwarzenegger and DOI Secretary Ken Salazar to merge the efforts and responsibilities of the CA Governor's office, CA Natural Resources Agency, and DOI in addressing issues surrounding the permitting of large-scale solar thermal plants (CA 2010).

- Staffing state and federal permitting agencies adequately to enable processing of renewable energy applications in a timely manner. This could include use of outside contractors and could be funded from reasonable application-processing fees. Educating staff on solar and other renewable technologies would also contribute to improving the efficiency of processing applications.

7.3.3 TRANSMISSION SITING

Establishing solar-energy transmission infrastructure presents unique challenges. The sections below discuss the transmission siting process, transmission regulations, and improving the regulatory framework to support solar energy.

Transmission Siting Process

The remote location of much of the envisioned utility-scale solar capacity will require the construction of new high-voltage transmission lines to transport electricity to population centers. Because transmission lines can cross private, public (state and federal), and tribal lands, the process of planning, permitting, and building new lines is highly visible and implicates many diverse interests—and it can be costly, time consuming, and controversial.

Before approval for new transmission is granted, the regulatory authority must determine that the project is necessary. Non-transmission alternatives must often be considered, including energy conservation, energy efficiency, distributed generation, and fully using unused capacity on existing transmission lines. When new transmission lines are deemed necessary, developers[68] and utilities must find the best routes to the greatest concentrations of renewable energy and build with the least possible impact to the environment. Transmission lines can fragment and interfere with wildlife habitats and corridors and can increase wildlife mortality due to collisions, electrocution, and by serving as perches for predators (WGA 2008). There are also concerns about the visual impacts and potential health impacts of transmission lines. Burying transmission lines can help avoid many of the environmental and aesthetic issues. However, burying lines may also have negative impacts on soil, vegetation, and other resources (Molburg et al. 2007), and underground lines are typically four times as expensive as overhead lines (Brown and Sedano 2004). Also, although high-voltage direct-current (DC) lines can be buried, there is a limit on the maximum voltage and length of alternating-current (AC) lines that can be buried.

In all, constructing major new transmission can require 7–10 years from planning to operation: 1 year for final engineering, 1–2 years for construction, and the rest of the time for planning and permitting. Substantial time and controversy are added to the process when environmental and related concerns are addressed at the end instead of the beginning. It is expected that the designation of REZs (see Section 7.3.1) will accelerate the development of renewable energy and associated transmission infrastructure. For example, the Texas CREZ program has resulted in significant new transmission for wind power projects.

[68] Transmission developers include IOUs, Federal Power Marketing Authorities [such as the Western Area Power Administration (WAPA)], publicly-owned utilities (such as Los Angeles Department of Water and Power), and, sometimes, independent merchant transmission developers.

Transmission Regulations

The existing regulatory framework for planning, siting, and allocating costs for transmission presents challenges to achieving the SunShot scenario's utility-scale solar deployment. Originally designed for vertically-integrated utilities that build their own, largely fossil-fueled generation, this framework would need to be modified to accommodate a more diverse generation portfolio that includes larger numbers of smaller, location-constrained renewable resources, distributed generation, aggressive conservation and demand response programs, and "smart grid" technologies.

Transmission planning in much of the western United States is done at the sub-regional level by IOUs on an ad hoc basis. In areas served by a Regional Transmission Organization (RTO) or independent system operator (ISO)—such as CAISO, the Electric Reliability Council of Texas (ERCOT), and various ISOs and RTOs in the Midwest and Northeast—planning is done for a larger region. RTOs and ISOs coordinate generation and transmission within their respective regions—including within or across state lines—to ensure balanced electricity supply and demand and to provide non-discriminatory transmission access. However, there is little coordination between RTOs or ISOs and little, if any, correlation to regions rich in renewable energy resources. In 2009, DOE initiated multi-stakeholder, interconnection-wide transmission planning in the Eastern and Western Interconnections, but it is too early to tell if these efforts will result in tangible regional transmission plans that support renewable energy development.

Transmission plans are reviewed by regional reliability councils to ensure they meet reliability and security requirements, but these councils have no enforcement authority to ensure projects are built. Actual siting decisions are made by state utility commissions or, in some cases, local siting authorities or federal land management agencies. The authorized state or local authority is responsible for approving the tariff for any retail sales associated with the new or expanded transmission facilities. If the transmission line supports interstate commerce, the Federal Energy Regulatory Commission (FERC) has jurisdiction for setting the wholesale transaction tariffs. FERC is also responsible for ensuring open access to all interstate transmission lines but lacks the authority to require states to plan or build transmission to serve renewable generators.

Cost allocation (i.e., who pays for transmission) is one of the most significant barriers to renewable energy development in the United States. This topic is discussed in Chapter 8.

Closely related to cost allocation is cost recovery. In areas outside an RTO or ISO, rates are typically set to recover the cost of transmission within a utility's footprint, which are known as "license plate rates." More common within an RTO or ISO service area are "postage stamp rates," which are uniform rates charged for all transmission service within a specified area. In either instance, FERC must approve the wholesale transmission tariff.

Merchant transmission developers have the option to either accept the FERC-approved postage stamp or license plate rates or hold an "open season" and try to get subscriptions for capacity on the proposed line, often with a large anchor tenant.

They may enter into bilateral agreements and charge fees to recover their costs that are outside the RTO- or ISO-approved tariffs, but which must still be approved by FERC.

Regardless of the method of cost recovery, there currently exists the phenomenon known as “rate pancaking.” Energy transmitted across the service areas of multiple transmission owners is charged a separate transmission rate across each. Thus, the total amount charged is the sum of all transmission charges for each area. This can make the cost for transmitting renewable energy across multiple utility or RTO/ISO service areas prohibitively expensive.

Another issue is “right-sizing,” i.e., sizing the transmission infrastructure to meet expected renewable energy development to minimize costs and environmental impact. For example, rather than building a single 500-kV line, two 500-kV lines could be built along the same right-of-way from the start, assuming sufficient renewable resources are available to ultimately use this infrastructure. PacifiCorp’s Gateway transmission project is an attempt to right-size transmission to tap wind resources in Wyoming. The original plans called for two 500-kV lines along the same right-of-way (each capable of carrying about 1,500 MW), but PacifiCorp has been unable to obtain subscriptions to fill even one of the lines (Radford 2010). A core issue in right-sizing is cost recovery: should consumers pay up front for transmission capacity that will go unused for an undetermined period?

Transmission Improvements to Support Solar Energy

To achieve the SunShot scenario, there are a number of options that could help facilitate transmission improvements to support increased amounts of solar energy on the grid. Most of these options could be pursued at the regional or federal level. These options include:

- Planning transmission on a regional level.
- Conducting regional planning with involvement of multiple stakeholders from the beginning.
- Giving regional plans enforcement provisions that authorize or require states to site and permit their respective portions of the plan.
- Addressing cost-allocation and cost-recovery issues adequately.

In 2010, FERC issued a Notice of Proposed Rulemaking (NOPR) that addresses regional transmission planning and cost allocation. Should FERC’s proposed rule become final, it could significantly improve the chances for building regional transmission to bring renewable energy to market. However, the NOPR contains many controversial provisions that are sure to delay its implementation or that could be significantly altered in the final rulemaking. Although it is encouraging that FERC is attempting to address regional cost allocation and planning, it is too early to tell how effective the rulemaking will be.

7.4 Siting Challenges for Distributed Solar Projects

Although distributed solar technologies do not face the same land-use issues as utility-scale technologies (discussed in Section 7.3), they do face siting challenges related to their use on residential and commercial buildings. Currently, inconsistency of codes and standards between jurisdictions and a lack of familiarity of states and municipalities with solar technologies present obstacles to the efficient deployment of solar systems. This section discusses current codes and permits, zoning ordinances and restrictive covenants, and ways to improve the acceptance of distributed solar technologies at the state and local levels.

7.4.1 Codes, Permitting, and Standards for Distributed Solar

This section discusses current codes and permits related to distributed solar, as well as the current and potential improvements that are being made to these processes through standardization.

Current Codes and Permits

Distributed solar technologies are subject to numerous government regulations and codes. These often vary from community to community and from state to state based on the opinion of the "authority having jurisdiction," which is usually the local building inspection authority (Nelson 2009). Even in the case of national codes, states and/or local authorities often impose additional requirements on the design, permitting, installation, or operation of a distributed solar system. The most common requirements for distributed PV involve building and electrical codes.

Building codes govern the safe construction of structures. For PV, the primary concerns are ensuring that the systems are secured to the roof, that they are not prone to wind damage and/or roof leakage, and that the roof can withstand the additional weight (Pitt 2008). Fire codes address fire prevention and safety in a structure's design, construction, and maintenance, as well as allowing for sufficient roof access for emergency personnel and/or building evacuation in the case of a fire. Similar to building codes, model fire codes are established at the national level, but some states and many local fire departments modify these codes. Each city has building inspectors responsible for enforcing building and fire codes.

Installing a distributed PV system generally requires meeting electrical codes set by the local building department and interconnection codes made by or with the local utility. Permits for these codes are designed to prevent safety hazards such as fires, electrocution, and power surges (Pitt 2008). Most jurisdictions' electrical codes are based on Article 690 of the National Electrical Code (NEC), which outlines the requirements for installing safe and reliable PV systems (DOE 2004). Some jurisdictions, such as the State of California, establish their own codes that go beyond the NEC. In addition to, and often in coordination with, the NEC, utilities require interconnection agreements before connecting any electricity generator to the distribution network. These rules are typically approved by the state utilities commission or municipal utility authorities and, occasionally, by the state government. Interconnection rules are discussed in greater detail in the previous section.

Codes and regulations placed on distributed PV systems have resulted in processes that increase system cost and installation time. Each jurisdiction sets permitting fees, which can vary tremendously from one city to the next. In addition, installers may be challenged with the intricacies of requirements across different jurisdictions, and/or permitting officials may not understand system design. These inefficiencies have prevented projects from moving forward and/or have caused areas to avoid even having a permitting process (DOE 2009b).

Improvements through Standardization

Several entities facilitate the permitting and standardization of PV systems and their respective components, with the goal of increasing acceptance of distributed solar technologies. DOE has taken a lead role in this area through the establishment of the Solar America Board for Codes and Standards (Solar ABCs), a collaborative effort among stakeholders to develop coordinated recommendations to codes- and standards-making bodies for existing and new solar technologies. Solar ABCs develops model codes, standards, rules, and ordinances to remove barriers to the adoption of PV. In October 2009, Solar ABCs released a model expedited permitting process to support jurisdictions with implementing PV installations.

In addition, DOE has asked states to show what measures they are taking to encourage efficient and renewable energy as part of federal stimulus packages that provide assistance with a green focus. This effort, as well as the funds available for energy-efficiency projects and new solar construction, have assisted or motivated a number of states to examine their codes, and where prior standards did not exist, to develop them, often along the lines that other states had implemented. This standardization set a solid foundation for further federal standards. Industry-wide standards are also emerging, such as the 2009 adoption of a set of solar standards by the American National Standards Institute (ANSI).[69]

Achieving the SunShot targets will require additional streamlining and standardization of distributed solar siting requirements and processes. In particular, a unified permitting process across different regions would facilitate expansion of the distributed solar market. Another policy option to facilitate solar deployment is to require that certain new buildings be constructed in such a way that they may be easily retrofitted with PV technologies; this is often termed “solar-ready” construction.

7.4.2 Solar Rights and Solar Access Protection

Despite the growing support for renewable energy development at the state and local level, many consumers still face local ordinances or homeowner association rules that prohibit, restrict, or drastically increase the cost of installing a solar energy system. In general, zoning laws are established by local government ordinances,

[69] The American National Standards Institute approved the 2009 Uniform Solar Energy Code (USEC), a consensus-based model code for the installation, inspection, and maintenance of solar energy systems and component products, for accreditation as an American National Standard.

whereas restrictive covenants may be the product of planned community or homeowner association rules. Examples of potential zoning issues for distributed solar include obstructing side yards, erecting unlawful protrusions on roofs, and siting the system too close to streets or lot boundaries (DOE 2010a). Restrictive covenants may be even more particular and restrictive with regard to community aesthetics and visual requirements.

Distributed solar technologies need protection from local ordinances and covenants to achieve the SunShot targets. A solar rights law provides protection for residential and commercial entities by limiting or prohibiting private restrictions (e.g., neighborhood covenants and bylaws, local government ordinances, and building codes) on the installation of solar energy systems. Solar rights laws have been proven to support solar market expansion. California's Solar Rights Act, established in 1978 and updated several times since, places the financial burden of restricting solar installations on the restricting entity (DSIRE 2010). Vague or absent provisions in solar rights laws have led to lawsuits and delays in a number of states.

Meanwhile, owners of existing systems face potential challenges when growing trees or new structures on neighboring property shade their solar collectors. Given that there is no common-law right to sunlight in the United States, these issues present serious barriers to the adoption of solar energy. Solar access laws protect landowners' rights to present and future unobstructed direct sunlight (DOE 2010b). As of April 2011, 38 states have solar access laws, and local governments also have this authority (DSIRE 2011).

The most common approach to addressing the post-installation issues at the state level is the solar easement. The solar easement allows the owner of a solar energy system to secure rights to continued access to sunlight on a voluntary basis from a neighboring party whose property could be developed in such a way (e.g., building or foliage) as to impede the system's access to sunlight. As of September 2010, more than half of the states in the United States have solar easement provisions (DSIRE 2011). Some jurisdictions have incorporated solar easements into the solar permit process such that when a customer receives a permit, an easement is automatically recorded.

Ensuring that homeowners and businesses have the right to install solar equipment on their property, and have a mechanism to protect their access to sunlight, will be essential to achieving the SunShot scenario. Without these provisions, a significant portion of the distributed rooftop potential could be made unviable.

7.5 References

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