SunShot
U.S. Department of Energy

SunShot Vision Study

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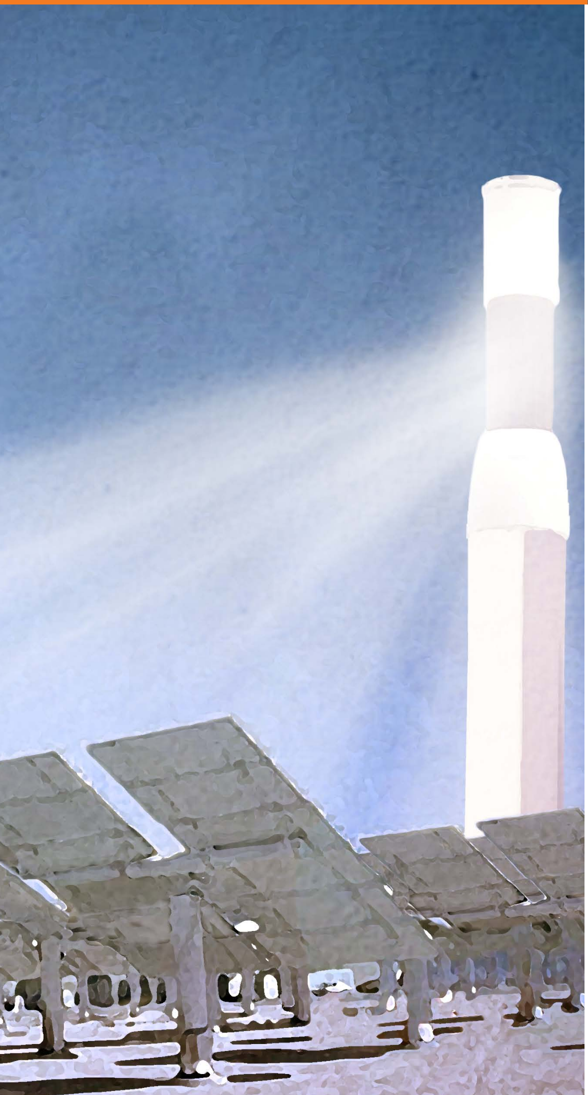

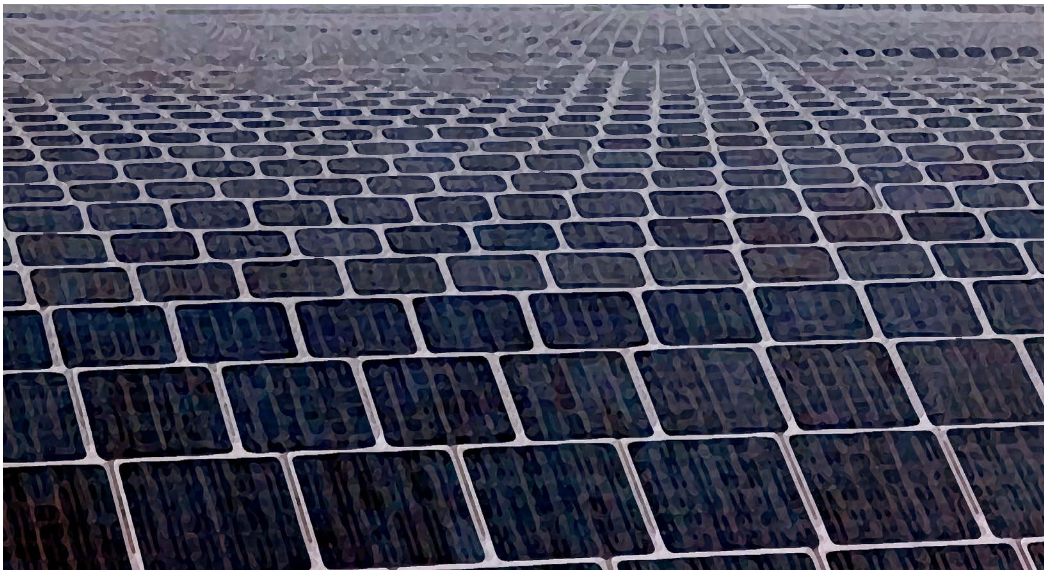

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MESSAGE FROM THE DIRECTOR OF THE SUNSHOT INITIATIVE

The SunShot Initiative was launched in February 2011 with the goal of making solar energy cost-competitive with conventional electricity generating technologies within the decade. Achieving this goal will require dramatic decreases in the cost structure of solar technologies—on the order of a 75% reduction—across all markets including residential, commercial, and utility-scale deployments of solar. To do this most effectively, the SunShot Initiative spans the full spectrum from basic science to applied research and development. It also spans across multiple U.S. Department of Energy (DOE) offices, including Energy Efficiency and Renewable Energy (EERE), Advanced Research Projects Agency-Energy (ARPA-E) and the Office of Science (SC).

The *SunShot Vision Study* explores the implications of achieving the SunShot Initiative's targets both in terms of potential benefits as well as potential challenges. The potential benefits include solar contributing an increasingly significant share of electricity generation over the next 20 to 40 years, creating thousands of new jobs, and saving consumers money by placing downward pressure on electricity prices. The potential challenges include scaling-up manufacturing capacity, integrating large amounts of solar energy into the grid, and improving access to financing. The benefits and challenges of achieving the SunShot vision are discussed in detail in the study.

By design, this study focuses on solar technologies and presents a "best case" solar scenario. It was specifically designed this way to highlight the potential for solar electricity to significantly impact the electricity generation portfolio and to explore the challenges likely to be encountered as the industry grows. The basic elements of this study include an analysis of the share of the total electricity market under the SunShot targets, while keeping other competing technologies (such as wind, geothermal, natural gas, etc.) on nominal cost-reduction curves. The reason to explore such an aggressive hypothesis was to ask the fundamental question: what is the upper bound of the electricity market share that can be captured by solar electricity, given the envisioned SunShot cost structures?

This study is not intended to be viewed as a prediction that solar will beat out other competing technologies, but rather an exploration of how far solar could go under a specific set of assumptions. The study indicates that under these assumptions, solar electricity could contribute up to 14% and 27% of the total electricity demand by 2030 and 2050, respectively. While there are many challenges along the way, achieving this vision would represent a transformation in the way we generate, store, and utilize solar energy.

Ramamoorthy Ramesh
Director, SunShot Initiative

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Abbreviations and Acronyms

AC	alternating current
AEO	Annual Energy Outlook
Ag	silver
ANSI	American National Standards Institute
APS	Arizona Public Service
AR	anti-reflection
ARRA	American Recovery and Reinvestment Act
a-Si	amorphous silicon
ATC	available transfer capacity
BA	Balancing Authority
BIPV	Building-integrated photovoltaics
BLM	Bureau of Land Management
BOS	balance-of-systems
Btu	British thermal unit
c-Si	crystalline silicon
CA	California
CAES	compressed air energy storage
CAGR	compound annual growth rate
CAISO	California Independent System Operator Corporation
CapEx	capital expenditure
CC	combined cycle
CCS	carbon capture and storage
Cd	cadmium
CDC	Center for Disease Control
CdTe	cadmium telluride
CEC	California Energy Commission
CEDA	Clean Energy Deployment Administration
CEQA	California Environmental Quality Act
CES	clean energy standard
CESA	California Endangered Species Act
CF	capacity factor
CIGS	copper indium gallium diselenide
CIS	copper indium diselenide
CLFR	compact linear Fresnel reflector
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CPUC	California Public Utilities Commission
CPV	concentrating photovoltaics

CREB	clean renewable energy bond
CREZ	competitive renewable energy zone
CSI	California Solar Initiative
CSP	concentrating solar power
CT	combustion turbine
Cu	copper
DC	direct current
DER	distributed energy resource
DG	distributed generation
DNI	direct-normal irradiance
DOD	U.S. Department of Defense
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DRECP	Desert Renewable Energy Conservation Plan
DSM	demand side management
EESA	Emergency Economic Stabilization Act
EIA	Energy Information Administration
EIS	environmental impact statement
EISA	Energy Independence and Security Act
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ESA	Endangered Species Act
EVA	ethylene vinyl acetate
FERC	Federal Energy Regulatory Commission
FHFA	Federal Housing Finance Agency
FIT	feed-in tariff
FPA	Federal Power Act
FPL	Florida Power & Light Company
ft^2	square foot
FRCC	Florida Reliability Coordinating Council
FTE	full-time equivalent
g	gram
GA	gallium
gal	gallon
gas-CC	combined cycle natural gas plant
gas-CT	gas combustion turbine
GDP	U.S. Gross Domestic Product
GE	General Electric
GHG	greenhouse gas
GIS	geographic information system

GW	gigawatt
GWh	gigawatt-hour
GW-mi	gigawatt-mile
GW_{th}	gigawatt thermal
Hz	hertz
ha	hectare
HTF	heat-transfer fluid
HVDC	high-voltage direct current
ID	Idaho
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IGCC	integrated gasification combined cycle
In	indium
IOU	investor-owned utility
IPCC	Intergovernmental Panel on Climate Change
IPP	independent power producer
IRS	Internal Revenue Service
ISO	independent system operator
ISO-NE	Independent System Operator - New England
ITC	investment tax credit
kg	kilogram
km	kilometer
km^2	square kilometer
kV	kilovolt
kW	kilowatt
kWh	kilowatt-hour
LaaR	Loads acting as a Resource
LBNL	Lawrence Berkeley National Laboratory
LCOE	levelized cost of energy
LFR	linear Fresnel reflector
LMP	location marginal pricing
LVRT	low voltage ride-through
m	meter
m^2	square meter
m^3	cubic meter
mc	multicrystalline
mm	millimeter
MACRS	modified accelerated cost recovery system
MISO	Midwest Independent Transmission System Operator
MJ	multijunction
MMT	million metric tons

MN	Minnesota
Mo	molybdenum
MOU	memorandum of understanding
MPR	Market Price Referent
MRO	Midwest Reliability Organization
MT	metric ton
MVA	mega-volt amperes
MW	megawatt
MW_e	megawatt electric
MWh	megawatt-hour
MW_t	megawatt thermal
NARUC	National Association of Regulatory Utility Commissioners
NCAR	National Center for Atmospheric Research
NCEP	National Commission on Energy Policy
NEC	National Electrical Code
NEF	New Energy Finance
NEMS	National Energy Modeling System
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NF_3	trifluoride
NLCS	National Landscape Conservation System
NMPRC	New Mexico Public Regulation Commission
NOPR	Notice of Proposed Rulemaking
NO_x	nitrogen oxides
NPCC	Northeast Power Coordinating Council
NRDC	National Resources Defense Council
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
NV	Nevada
NW	Northwest
NYISO	New York Independent System Operator
O&M	operation and maintenance
OGS	oil/gas/steam
OMB	U.S. Office of Management and Budget
OPV	organic photovoltaics
OR	Oregon
PACE	property-assessed clean energy (financing)
Pb	lead
PCA	power control area
PCC	point of common coupling
PCM	phase-change material
PE	private equity
PEIS	programmatic environmental impact statement

PHS	pumped hydropower storage
PJM	PJM Interconnection LLC
PM	particulate matter
$PM_{2.5}$	particulate matter less than 2.5 microns in size
PPA	power purchase agreement
PPSA	Florida Electrical Power Plant Siting Act
PR	progress ratio
PTC	production tax credit
PUC	public utility commission
PUCN	Public Utility Commission of Nevada
PUCT	Public Utility Commission of Texas
PUHCA 2005	Public Utility Holding Company Act of 2005
PURPA	Public Utilities Regulatory Policy Act
PV	photovoltaics
PV/T	combined photovoltaic/thermal
Quad	quadrillion British thermal units
RAM	Renewable Auction Mechanism
R&D	research and development
RC	reliability coordinator
RD&D	research, development, and demonstration
REC	renewable energy certificate
ReEDS	Regional Energy Deployment System
RES	renewable electricity standard
RETA	Renewable Energy Transmission Authority
RETI	Renewable Energy Transmission Initiative
REZ	renewable energy zone
RFC	Reliability First Corporation
ROW	rest of world
RPS	renewable portfolio standard
RROE	rate of return on equity
RSI	Renewable Systems Integration
RTO	Regional Transmission Organization
SAM	System Advisor Model
Sandia	Sandia National Laboratories
SCADA	supervisory control and data acquisition
Se	selenium
SEGS	Solar Energy Generating Systems
SEIA	Solar Energy Industries Association
SERC	Southeastern Electric Reliability Council
SES	Stirling Energy Systems
SETP	Solar Energy Technologies Program
SGIP	Small Generator Interconnection Procedure
$SiCl_4$	silicon tetrachloride

SiN_4	silicon nitride
Sn	tin
Solar ABCs	Solar America Board for Codes and Standards
SolarDS	Solar Deployment System
Solar PEIS	Solar Programmatic Environmental Impact Statement
SO_x	sulfur oxides
SO_2	sulfur dioxide
SPP	Southwest Power Pool
SRCC	Solar Rating and Certification Corporation
SREC	solar renewable energy certificate
T&D	transmission and distribution
TDY	typical DNI year
Te	tellurium
TES	thermal energy storage
TIO	technology improvement opportunities
TOU	time of use
TRE	Texas Reliability Entity
TW	terawatt
TWh	terawatt-hour
USEC	Uniform Solar Energy Code
USFS	U.S. Forest Service
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
VC	venture capital
VER	variable energy resources
W	watt
WA	Washington
WACC	weighted average cost of capital
WAPA	Western Area Power Administration
WDG	wholesale distributed generation
WECC	Western Electricity Coordinating Council
WGA	Western Governors' Association
Wp	peak watt
WREZ	Western Renewable Energy Zones
yr	Year

Executive Summary

The objective of the *SunShot Vision Study* is to provide an in-depth assessment of the potential for solar technologies to meet a significant share of electricity demand in the United States during the next several decades. Specifically, it explores a future in which the price of solar technologies declines by about 75% between 2010 and 2020—in line with the U.S. Department of Energy (DOE) SunShot Initiative's targets. As a result of this price reduction, solar technologies are projected to play an increasingly important role in meeting electricity demand over the next 20–40 years, satisfying roughly 14% of U.S. electricity demand by 2030 and 27% by 2050.[1] In terms of technology, the SunShot Initiative and this report both focus on photovoltaics (PV) and concentrating solar power (CSP). Details about how the SunShot Initiative is organized to achieve its targets and increase American competitiveness in solar energy can be found on the initiative's website (www.eere.energy.gov/solar/sunshot/).

The *SunShot Vision Study* uses the National Renewable Energy Laboratory's (NREL) Regional Energy Deployment System (ReEDS) and Solar Deployment System (SolarDS) models to develop and evaluate a SunShot scenario and a reference scenario. In both scenarios, the models are used to develop a least-cost geographical deployment of solar technologies and other generating technologies (conventional and other renewable). The scenarios assume the federal investment tax credit (ITC) and production tax credit (PTC) run through their currently established expiration dates—end of 2016 and 2012, respectively—but that existing supports for conventional technologies that are embedded in the tax code or through other provisions continue indefinitely. Further, the scenarios do not incorporate any additional costs for mercury and air toxins, carbon emissions, or other environmental externalities associated most strongly with conventional generation technologies. Key variables evaluated by the models include solar resource quality, cost of electricity, transmission requirements, reserve requirements, variability impacts, and projected fuel prices. For the SunShot scenario, solar technology installed system prices are assumed to reach the SunShot Initiative's targets by 2020: \$1/watt (W) for utility-scale PV systems, \$1.25/W for commercial rooftop PV, \$1.50/W for residential rooftop PV, and \$3.60/W for CSP systems with up to 14 hours of thermal energy storage capacity.[2] The reference scenario is modeled with moderate solar energy price reductions to enable comparison of the costs, benefits, and challenges relative to the reference case of achieving the SunShot price targets.

The *SunShot Vision Study* examines the potential pathways, barriers, and implications of achieving the SunShot Initiative's price-reduction targets and resulting market-penetration levels. Key factors examined include current and

[1] All results in this report refer to the *contiguous* United States (excluding Alaska and Hawaii), unless otherwise noted, e.g., solar technologies are projected to satisfy roughly 14% of contiguous U.S. electricity demand by 2030 and 27% by 2050.
[2] 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 otherwise specified.

projected costs, raw material and labor availability, manufacturing scale-up, grid integration, financing, and siting and environmental issues.

The *SunShot Vision Study* does not prescribe a set of policy recommendations for solar energy in the United States, nor does it present a vision of what the total mix of energy sources should look like in the future. The *SunShot Vision Study* does, however, provide analysis and insights that could help policymakers design and implement measures aimed at optimizing solar energy's potential within an integrated national energy policy framework. The study's focus on both a 20- and 40-year time horizon allows sufficient time to implement and realize the benefits of policy changes. It also provides a framework for analyzing both the short- and long-term evolution of the U.S. electricity-generation system, and is long enough to envision substantial change to the system as a whole. Thus, this study provides insights about both the near- and long-term technology investments and policy changes that may be required to achieve the envisioned levels of market penetration.

The *SunShot Vision Study* is meant to be the most comprehensive review of the potential for U.S. solar electricity generation to date. The study was initiated by the DOE Solar Energy Technologies Program (SETP) and managed by NREL.[3] Key findings of the *SunShot Vision Study* include the following:

- *Achieving the level of price reductions envisioned in the SunShot Initiative could result in solar meeting 14% of U.S. electricity needs by 2030 and 27% by 2050. However, realizing these price and installation targets will require a combination of evolutionary and revolutionary technological changes.* The SunShot Initiative aims to reduce the price of solar energy systems by about 75% between 2010 and 2020. Achieving this target is expected to make the cost of solar energy competitive with the cost of other energy sources, paving the way for rapid, large-scale adoption of solar electricity across the United States. Existing challenges can be addressed through technological advances—e.g., efficiency improvements, materials substitutions, and expanded material supplies—and planning. Significant manufacturing scale-up is required under the SunShot scenario, but solar manufacturers have demonstrated the ability to scale up rapidly over the past decade. The continued expansion and price reductions anticipated over the next decade should enable the required high-volume, low-cost production.
- *Achieving the SunShot price targets is projected to result in the cumulative installation of approximately 302 gigawatts (GW) of PV and 28 GW of CSP by 2030, and 632 GW of PV and 83 GW of CSP by 2050*. To achieve these cumulative installed capacities, annual installations must reach 25–30 GW of PV and 3–4 GW of CSP in the SunShot scenario between 2030 and 2050. By 2030, this translates into PV generating 505 terawatt-hours (TWh) per year of electricity or 11% of total U.S. electricity demand, and CSP generating 137 TWh per year or 3% of total demand. By 2050, this

[3] This study draws heavily on research, analysis, and material developed for DOE's draft *Solar Vision Study*. The *Solar Vision Study* was launched in June 2009 and drew on a steering committee and working groups with more than 140 representatives from solar companies, utilities, financial firms, universities, national laboratories, non-profit organizations, industry associations, and other organizations. A draft of the *Solar Vision Study* was circulated for external review during June 2010. The post-review version of the *Solar Vision Study* was used as the starting point for the *SunShot Vision Study*.

translates into PV generating 1,036 TWh per year or 19% of total demand, and CSP generating 412 TWh per year or 8% of total demand.

- *Annual U.S. electricity-sector carbon dioxide (CO_2) emissions are projected to be significantly lower in the SunShot scenario than in the reference scenario: 8%, or 181 million metric tons (MMT), lower in 2030, and 28%, or 760 MMT, lower in 2050.* This would provide carbon emissions reductions that are equivalent to taking 30 and 130 million cars off the road by 2030 and 2050, respectively. The emissions reductions are primarily a result of the displacement of natural gas and coal generation. Before 2030, solar primarily offsets natural gas generation, while post-2030, solar begins to significantly offset coal generation.
- *Both the SunShot and reference scenarios require significant transmission expansion. In the reference scenario, transmission is expanded primarily to meet growing electricity demand by developing new conventional and wind resources. In the SunShot scenario, transmission is expanded at a similar level, but in different locations in order to develop solar resources.* In the reference scenario, transmission capacity is projected to increase from about 88,000 gigawatt-miles (GW-mi) in 2010 to 102,000 GW-mi in 2030, and 110,000 GW-mi in 2050—a 15% and 25% increase, respectively. In the SunShot scenario, transmission capacity is expected to increase to 100,000 GW-mi in 2030 and 117,000 GW-mi in 2050, a 13% and 32% increase, respectively. Expanding transmission at these rates would require a level of investment well within the historical range of transmission investments during the past few decades.
- *The level of solar deployment envisioned in the SunShot scenario poses significant but not insurmountable technical challenges with respect to grid integration and could require substantial changes to system planning and operation practices.* The main grid integration challenges at the bulk system levels are expanding access to transmission capacity and dealing with the additional variability and uncertainty of solar generation. The impact and cost of variability and uncertainty can be reduced by improving access to flexible resources in the system (both generation and load) and optimizing their deployment. Improved solar production forecasts and better access to well-functioning electricity markets are two key enabling factors. At the distribution system level, the main technical challenges are related to control of voltage and system protection with high-penetration PV. In addition to technological advances, existing codes and standards must be revised, and better models and analysis techniques are needed.
- *The land area that is potentially suitable for solar deployment is enormous and thus land, per se, is not a constraint on meeting the SunShot scenario level of deployment. However, it is important to make careful selection of sites in order to provide access to available or planned transmission, and to minimize conflicts with environmental, cultural, and aesthetic interests.* The land area required to supply all end-use electricity in the United States using PV is only about 0.6% of the country's total land area.[4] Similarly, the technical potential for CSP is enormous: about 17,500 TWh of annual CSP

[4] This calculation is based on deployment/land in the entire United States (including Alaska and Hawaii).

electricity generation, which is more than four times the 2010 U.S. annual demand, could be sited in seven southwestern states on land that has been pre-screened to avoid prominent land-use issues and to meet technical requirements such as insolation and slope. About 370,000–1,100,000 hectares (ha) (900,000–2,700,000 acres) are required for utility-scale solar installations in 2030 under the SunShot scenario, and about 860,000–2,500,000 ha (2,100,000–6,300,000 acres) are required in 2050. The required land area 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. Solar development in the SunShot scenario is greatest in the South and Southwest. Often the highest-quality solar resource areas are dry environments that are typically not well suited for cropland or offer little value for forestry and rangeland.

- *Siting poses significant, but not insurmountable, regulatory challenges to achieving the level of solar market penetration envisioned in the SunShot scenario.* The regulatory framework for siting utility-scale solar projects and associated transmission infrastructure is complex, costly, and time consuming. Similarly, distributed PV installers, both in the residential and commercial sectors, face the challenges and expense associated with complex and variable codes and permits, zoning ordinances, and restrictive covenants. Streamlining of siting and regulatory requirements for utility-scale and distributed solar projects, as well as electricity-transmission projects, would help to enable the rapid solar development envisioned under the SunShot scenario.
- *Water-use constraints will require CSP technologies to transition away from wet cooling toward dry and hybrid cooling.* Although PV requires very little water (for occasional panel washing), CSP with traditional wet cooling uses similar amounts of water as used by some conventional electricity-generation technologies. However, dry or hybrid CSP cooling technologies can reduce water use by 40%–97% compared with wet cooling. Because most land suitable for CSP is in the Southwest, where water availability is constrained, it is very likely that in order to achieve the level of deployment projected in the SunShot scenario, most CSP plants will need to use dry or hybrid cooling.
- *Financing the scale of expansion in the SunShot scenario will require significant new investments in the solar manufacturing supply chain and in solar energy projects.* Building out U.S. PV and CSP manufacturing capacity to meet the level of installations envisioned in the SunShot scenario would require cumulative investments of roughly $25 billion through 2030 and $44 billion through 2050. On an annual basis, the required level of investments would be on the order of $1–$3 billion, well below private sector investments in solar in the United States during the past couple of years. Investments in the solar supply chain have historically been financed by a mix of venture capital, private equity, public equity, and corporate debt. Financing solar project deployment under the SunShot scenario, however, will cost much more than financing the supply chain—on the order of $40–$50 billion per year between 2030 and 2050. On a cumulative basis, this translates into roughly $250 billion through 2030 and $375 billion through 2050. The primary financing challenge will be managing the transition from the pre-2020 period, when solar electricity is less cost competitive with

other electricity sources, to the post-2020 period, when the availability of cost-competitive solar energy should stimulate private solar investment and facilitate use of mainstream financial instruments.

- *Achieving the SunShot scenario level of solar deployment would result in significant downward pressure on retail electricity prices.* By 2030, the average retail price for electricity in the SunShot scenario is projected to be 0.6 cents/kilowatt-hour (kWh) less than in the reference scenario, which translates into a cost savings of about $6 per month, per household. By 2050, the average retail price of electricity is projected to be 0.9 cents/kWh less, which translates into a cost savings of about $9 per month, per household. 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, compared to the reference scenario.
- *Achieving the SunShot scenario level of solar deployment could support 290,000 new solar jobs by 2030, and 390,000 new solar jobs by 2050*. These figures include direct and indirect jobs for the PV and CSP supply chains. The U.S. PV workforce is expected to grow from about 46,000 in 2010 to 280,000 in 2030 and to 363,000 in 2050. The U.S. CSP workforce is expected to grow from about 4,500 in 2010 to 63,000 in 2030 and to 81,000 in 2050. Labor requirements for manufacturing of PV and CSP components are readily transferable from other industries. Similarly, CSP power plant development can tap into the same skilled engineering and construction labor pool used for conventional fossil-fuel power plant development. The workforce to support distributed PV installations will require additional training and certification within the existing residential and commercial construction industries.
- *Sensitivity analyses indicate that a number of factors could influence the level of solar deployment envisioned in the SunShot scenario, including more aggressive cost reductions in other renewable and conventional electricity-generation technologies, fossil fuel prices, electricity demand growth, and other assumptions.* For example, sensitivity analyses indicate that there is a solar price threshold at which solar deployment increases non-linearly as price decreases. Similarly, sensitivity analyses show that assuming larger price reductions for non-solar renewable technologies in the SunShot scenario would result in higher penetration of those technologies, particularly wind. Some sensitivity analyses are presented in Appendix C. Additional sensitivity analyses will be published in supplementary technical reports. The *SunShot Vision Study* looks primarily at the implications of and challenges associated with a very low-cost solar future, and generally assumes much less aggressive improvements in other renewable technologies. There are, however, significant opportunities to reduce the cost of other renewable technologies and thus see additional benefits from their market penetration as well.

1. Introduction

1.1 The SunShot Vision: Deep Price Reductions Spur Rapid, Large-Scale Solar Deployment

Achieving the level of price reductions envisioned in the SunShot Initiative could result in solar meeting 14% of U.S. electricity needs by 2030 and 27% by 2050. However, realizing these price and installation targets will require a combination of evolutionary and revolutionary technological changes.

Solar energy offers a number of strategic benefits to the United States. Replacing fossil-fuel combustion with solar energy reduces emissions of human-induced greenhouse gases (GHGs) and air pollutants. Sunlight is a free resource. Thus, once solar technologies are installed, they have very low operating costs and require minimal non-solar inputs—this provides insurance against conventional fuel supply disruptions and price volatility. In addition, growing the domestic solar energy industry could establish the United States as a global leader in solar technology innovation, and support a growing number of solar-related jobs.

Despite these benefits, solar energy currently supplies only a small fraction of U.S. energy needs, largely because it historically has cost more than conventional energy sources. However, solar manufacturing costs and sales prices have dropped dramatically over the past few decades, and solar technologies are approaching energy-price parity with conventional generating sources in some regions of the United States and abroad. Further, experience accumulated by solar manufacturers and developers, utilities, and regulatory bodies has shortened the time and expense required to install a fully operating solar system. These gains have come partly through research and development (R&D) and partly through U.S. and global solar market stimulation. An additional strong, coordinated effort could enable solar energy technologies to become increasingly cost competitive with conventional electricity-generation technologies in the United States. over the next decade.

The U.S. Department of Energy (DOE) is providing this type of strong, coordinated effort through its SunShot Initiative. Launched in 2011, the SunShot Initiative aims to reduce the price of solar energy systems by about 75% between 2010 and 2020. Achieving this target is expected to make the unsubsidized cost of solar energy competitive with the cost of other currently operating energy sources, paving the way for rapid, large-scale adoption of solar electricity across the United States.

To assess the potential benefits and impacts of achieving the SunShot Initiative targets, DOE's Solar Energy Technologies Program (SETP) produced this *SunShot Vision Study*. This study assumes that the SunShot price targets are achieved by

2020 and models the resulting penetration of solar technologies in the United States. Solar growth based on non-cost factors (e.g., GHG-reduction and energy security benefits) is not considered in this analysis, but could result in additional solar market penetration. The results suggest that solar energy could satisfy roughly 14% of U.S. electricity demand by 2030 and 27% by 2050.[5]

These levels of solar penetration represent a dramatic transformation of the U.S. electricity system. Based on the scenario assumptions discussed in Section 1.4, the projected benefits of achieving the SunShot targets versus a reference case projection could include the following:

- Displacing the use of about 2.6 quadrillion British thermal units (Quads) of natural gas and 0.4 Quads of coal per year by 2030, and about 1.5 Quads of natural gas and 7.3 Quads of coal per year by 2050. This corresponds to a fuel savings of about $34 billion per year by 2030 and $41 billion per year by 2050.
- Reducing annual electric-sector carbon-dioxide (CO_2) emissions 8% below projected reference case levels in 2030 and 28% below projected reference case levels in 2050, equivalent to taking 30 and 130 million cars off the road.
- Reducing emissions of other pollutants including mercury, nitrogen oxides, sulfur oxides, and particulate matter.
- Supporting roughly 290,000 new solar-related jobs by 2030 and 390,000 new solar-related jobs by 2050.
- Reducing retail electricity rates by 0.6 cents/kilowatt-hour (kWh) in 2030 and 0.9 cents/kWh in 2050 compared to the reference scenario.
- Saving electricity consumers across all market sectors about $30 billion per year by 2030 and $50 billion per year by 2050.

This chapter begins by providing basic information about solar energy technologies and the status and potential of solar energy in the United States. Next, the SunShot scenario and analysis methodology are summarized, and several electric-sector impacts of achieving the SunShot targets are discussed. Finally, potential barriers to realizing the level of solar market penetration envisioned in the SunShot scenario—and strategies for overcoming them—are discussed. The body of the report contains all supporting details and references.

1.2 Solar Energy Basics

There are two major categories of solar energy technologies included in this study, which are distinguished by the way they convert sunlight into electricity: photovoltaics (PV) and concentrating solar power (CSP).

PV employs a semiconductor material—traditionally silicon but, increasingly, other materials as well—to convert sunlight directly into electricity. Sunlight enters a PV

[5] All results in this report refer to the contiguous United States (excluding Alaska and Hawaii) unless otherwise noted, e.g., solar technologies are projected to satisfy roughly 14% of *contiguous* U.S. electricity demand by 2030 and 27% by 2050.

module and is converted into direct-current (DC) electricity. For applications that are connected to the electrical grid, an inverter transforms this DC electricity into the alternating-current (AC) electricity that the grid carries. In this report, relatively small PV systems installed on structures such as rooftops, parking garages, and awnings, are called distributed or rooftop PV systems. Rooftop PV systems range in size from a few kilowatts (kW) for residential systems to hundreds of kilowatts or a few megawatts (MW) on large commercial roofs. Larger systems installed on the ground are called utility-scale PV. These systems can range from a few megawatts to hundreds of megawatts. Large utility-scale systems greater than 20 MW are typically connected to the electricity-transmission system which transmits electricity from generating plants to electrical substations. Smaller utility-scale systems can be located near areas of high-electricity demand and be connected to the electricity-distribution system which distributes electricity from electrical substations to end users.

CSP uses mirrors or lenses to concentrate sunlight and produce intense heat, which is used to produce electricity via a thermal energy conversion process similar to those used in conventional power plants. Several CSP technologies accomplish this by using concentrated sunlight to heat a fluid, boil water with the heated fluid, and channel the resulting steam through a steam turbine to produce electricity. An alternate approach uses gases heated with concentrated sunlight to drive a closed cycle heat engine that produces electricity. Most CSP systems can incorporate thermal energy storage or natural gas back-up, which can be used to smooth out short-term transients (e.g., collector shading from passing clouds) and enable CSP systems to continue producing electricity during the late afternoon and evening hours. Adding multiple hours of storage to CSP systems is critical because it is an enabler for the integration of substantial solar and wind generation in the SunShot scenario. Although some CSP technologies are capable of being deployed at the distributed level, most are designed for utility-scale operation and connected to the electricity-transmission system.

1.3 Solar Energy History, Status, and Potential

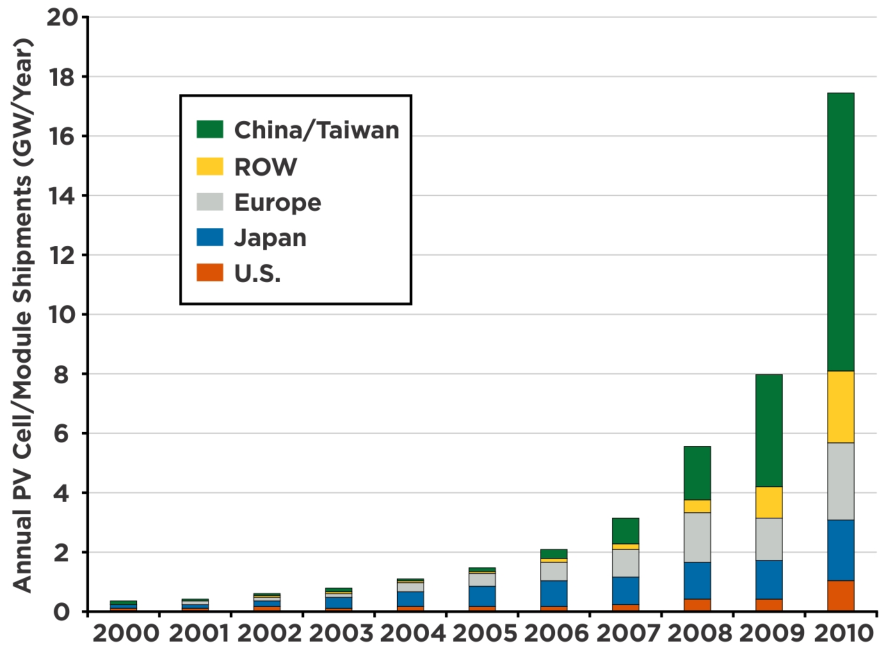
The global PV market has achieved a 53% annual growth rate, on average, over the past decade.

In 2010, solar energy provided less than 0.1% of U.S. electricity demand. This is comparable to the amount supplied by nuclear energy in 1960, which subsequently grew to 11% by 1980 and to 19% by 1990 (EIA 2010a). Over the past decade, U.S. solar deployment has lagged behind deployment in European and Asian countries, primarily because these countries instituted strong solar-promoting policies, while solar policies in the United States were limited and inconsistent. In considering the potential for future growth, it is useful to examine historical growth rates in global markets.

Figure 1-1 shows the regional PV cell and module shipments from the United States, Japan, Europe, China/Taiwan, and the rest of the world (ROW) over the past decade.

Between 2000 and 2010, PV module shipments achieved a compound annual growth rate of 53%, reaching 17 gigawatts (GW) of annual module shipments in 2010, and

Figure 1-1. Regional PV Cell and Module Shipments, 2000–2010



Source: Mints (2011a)

bringing the cumulative global PV shipments to about 40 GW. Although the United States accounted for 30% of global shipments in 2000, the U.S. market share declined significantly during the past decade. In 2010, the United States accounted for only 6% (about 1,000 MW) of PV module supply and only 8% (or about 1,400 MW) of demand (Mints 2011a, Mints 2011b). As of mid-2011, continued R&D and market forces have helped reduce PV prices sharply and, together with a mix of state and federal policies, have positioned the U.S. PV market for rapid future growth.

Almost 10 GW of CSP projects were under development in the United States at the end of 2010.

Historically, CSP market growth has been sporadic. After a number of CSP plants were built in California in the late 1980s, almost 15 years passed before the next commercial CSP plant was built, followed by a number of new plants in the United States and Spain during 2007–2010. By the end of 2010, global CSP capacity was about 1,300 MW, with 512 MW in the United States and most of the rest in Spain. In the United States, almost 10 GW of CSP projects were under various stages of development at the end of 2010. Even if only a small fraction of these projects are built, the industry will experience very rapid growth in the near future.

Although solar energy's contribution to U.S. energy supply has been small to date, its technical potential is enormous. For example, one estimate suggested that the area required to supply an amount of electricity equivalent to all end-use electricity in the United States using PV is only about 0.6% of the country's total land area (Denholm and Margolis 2008).[6] PV can also be installed on rooftops with essentially

[6] This calculation is based on deployment/land in the entire United States (including Alaska and Hawaii).

no land-use impacts. About 17,500 terawatt-hours (TWh) of annual CSP electricity generation—more than four times the current U.S. annual demand—could be sited in seven southwestern states on land that was screened for use restrictions and technical requirements such as solar insolation and land slope.

1.4 Modeling the SunShot Scenario

The *SunShot Vision Study* models the potential impact of achieving the SunShot price reduction targets by 2020 in the U.S. electric sector through 2050. To understand how this scenario evolves, the effects in 2030 (10 years after the price targets are achieved) and 2050 (30 years after the price targets are achieved) are highlighted here.

1.4.1 Defining the SunShot and Reference Scenarios

For the SunShot scenario, solar technology installed system prices were assumed to reach the SunShot Initiative's targets by 2020: $1/watt (W) for utility-scale PV systems, $1.25/W for commercial rooftop PV, $1.50/W for residential rooftop PV, and $3.60/W for CSP systems with 14 hours of thermal storage capacity.[7] These installed system prices represent a set of very aggressive, but technically possible targets that would translate into solar technology having a similar levelized cost of energy (LCOE) as competing electricity sources in each market segment. In other words, $1/W for PV and $3.60/W for CSP is expected to enable these solar technologies to be competitive in the wholesale electricity market, while $1.25/W is expected to enable PV to be competitive in the commercial retail market, and $1.50/W is expected to enable PV to be competitive in the residential retail market.

For the purposes of modeling the SunShot scenario, these installed system prices are assumed to remain constant through the 2020–2050 time frame, i.e., no further price reductions are modeled for solar technologies beyond 2020. Installed system price estimates for the development of all conventional and other renewable (including wind) electricity-generating technologies are based on Black & Veatch (forthcoming). Fuel prices and price elasticities are based on the Energy Information Administration's (EIA's) *Annual Energy Outlook 2010* (*AEO 2010*) (EIA 2010b) and are extrapolated through 2050 based on modeled fuel demand. Unless otherwise noted, all prices and values in the *SunShot Vision Study* are given in 2010 U.S. dollars. Future costs are discounted using a 7% real discount rate, per guidance from the U.S. Office of Management and Budget (OMB 2003).

A reference scenario with moderate solar energy price reductions was also modeled to enable comparison of the costs, benefits, and challenges of achieving the SunShot price targets. Future installed system price estimates for all technologies, including solar, are based on Black & Veatch (forthcoming) in the reference scenario. In both the SunShot and reference scenarios, electricity demand is assumed to increase by about 1% per year through 2050. This assumption is consistent with projections through 2035 provided by EIA (2010b), and an extension of EIA's projected trend through 2050. At this rate, demand reaches about 4,400 TWh by 2030 and 5,100

[7] 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.

TWh by 2050. Table 1-1provides a breakdown of PV and CSP prices including benchmarked prices in 2010 and projected prices in 2020 for both the SunShot and reference scenarios.

Table 1-1. Benchmarked 2010 Solar Prices and Projected 2020 Solar Prices (2010$/W)

Technology/Market	Benchmark 2010 Price	Reference 2020 Price	SunShot 2020 Price
Utility-Scale PV ($/W$_{DC}$)	4.00	2.51	1.00
Commercial Rooftop PV ($/W$_{DC}$)	5.00	3.36	1.25
Residential Rooftop PV ($/W$_{DC}$)	6.00	3.78	1.50
CSP ($/W$_{AC}$)	7.20[a]	6.64[a]	3.60[b]

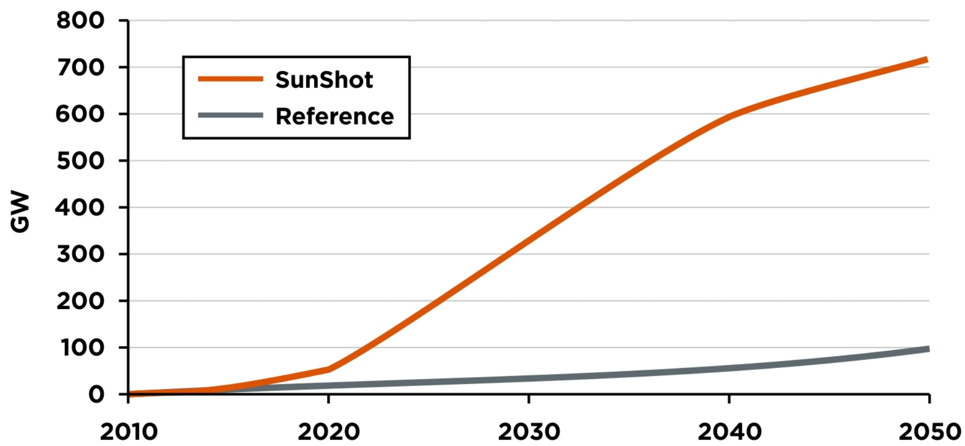
[a] CSP system with 6 hours of thermal storage
[b] CSP system with 14 hours of thermal storage

Several modeling tools were used to develop and evaluate the SunShot and reference scenarios. The Regional Energy Deployment System (ReEDS) capacity-expansion model, developed at the National Renewable Energy Laboratory (NREL), simulated the least-cost deployment and operation of utility-scale electricity-generating resources in the reference and SunShot scenarios. The Solar Deployment System (SolarDS) model, also developed at NREL, simulated the evolution of the residential and commercial rooftop PV markets. These models evaluated the trade-offs between solar resource quality, cost of electricity, transmission requirements, and other factors to determine a least-cost geographical deployment of the various solar technologies and configurations. Similarly, the remaining mix of electricity-generating technologies (conventional and other renewable) were determined on a least-cost basis, with considerations including the impacts of variability, reserve requirements, and projected fuel prices. The scenarios assume the federal investment tax credit (ITC) and production tax credit (PTC) run through their currently established expiration dates—end of 2016 and 2012, respectively—but that existing supports for conventional technologies that are embedded in the tax code or through other provisions continue indefinitely. Further, the scenarios do not incorporate any additional costs for mercury and air toxins, carbon emissions, or other environmental externalities associated most strongly with conventional generation technologies. In addition, 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.

1.4.2 Solar Growth Results

Achieving the SunShot targets is projected to result in the cumulative installation of approximately 302 GW of PV and 28 GW of CSP by 2030. By 2050, the cumulative installed capacities are projected to increase to 632 GW of PV and 83 GW of CSP. To achieve this level of cumulative installed capacity, annual installations would need to reach about 25–30 GW for PV and about 3–4 GW for CSP. Solar grows much more slowly in the reference scenario (Figure 1-2).

Figure 1-2. Total Solar Capacity under the SunShot and Reference Scenarios



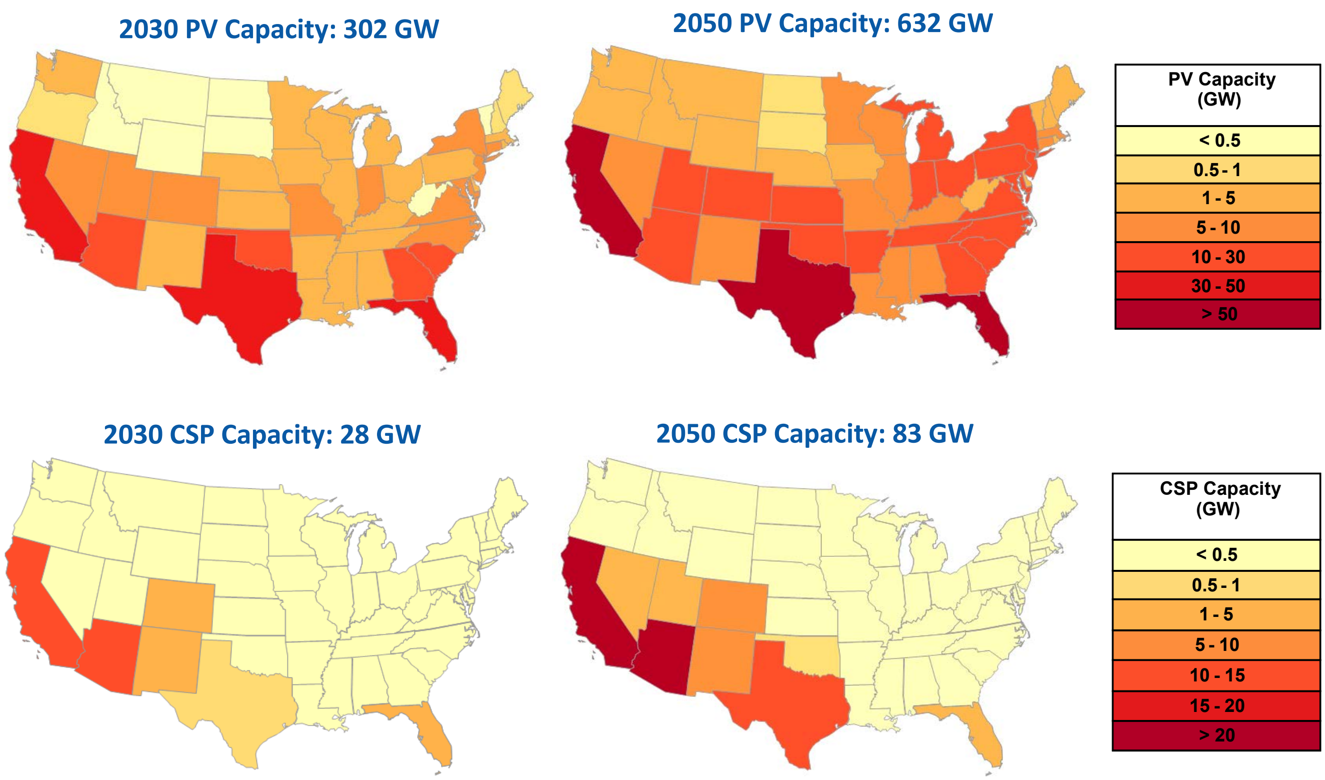
By 2030, the SunShot scenario levels of installations translate into PV generating 505 TWh of electricity, or 11% of total electricity demand, and CSP generating 137 TWh, or 3% of total demand. By 2050, PV is projected to generate 1,036 TWh, or 19% of total demand, and CSP is projected to generate 412 TWh, or 8% of total demand. Table 1-2 summarizes the electricity generation and installed capacity of PV and CSP in 2030 and 2050.

Table 1-2. Overview of SunShot Scenario Results

Year	Technology	Electricity Generation (TWh)	Installed Capacity (GW)
2030	PV	505	302
	CSP	137	28
2050	PV	1,036	632
	CSP	412	83

Figure 1-3 shows the geographical deployment of PV and CSP under the SunShot scenario in 2030 and 2050. Strong PV markets develop in all U.S. states, while CSP is primarily deployed in the arid Southwest, where direct-normal irradiance (DNI)—the intense sunlight needed for CSP—is highest. The SunShot scenario results shown in Figure 1-2 and Figure 1-3 present a case in which solar plays an increasingly important role in the U.S. electricity-generation system. Some sensitivity analyses are also discussed in the accompanying text box and Appendix C. Additional sensitivity analysis will be published in supplementary technical reports.

Figure 1-3. Cumulative Installed PV and CSP Capacity in the SunShot Scenario in 2030 and 2050



1.4.3 Differences between PV and CSP Deployment and Electricity Production

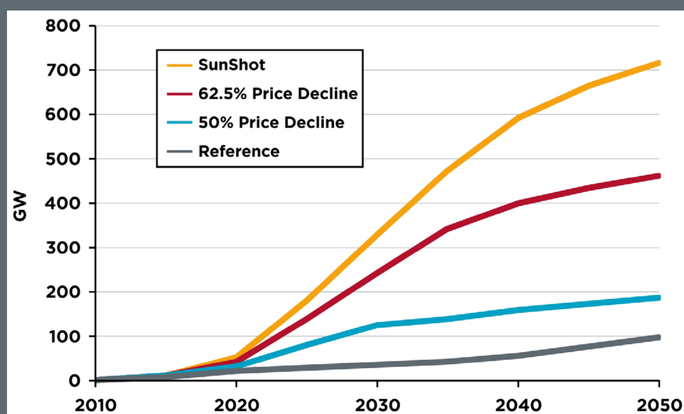
In the SunShot scenario, approximately 11 times more PV capacity than CSP capacity would be installed by 2030, and 8 times more by 2050. However, the amount of electricity produced by PV is only 4 times greater than the amount of electricity produced by CSP in 2030 and only 3 times greater in 2050. CSP produces more electrical energy per unit of capacity because, on average, CSP is deployed where solar resources are higher, CSP systems always use solar tracking, and CSP resources are deployed with several hours of thermal storage capacity which significantly increases the capacity factor of a CSP plant. The collector area for a CSP system can be expanded significantly to collect solar energy in excess of the peak load requirements of the power generator (also called the power block) and storing it as thermal energy, which can be used to generate electricity during non-sunny times of the day or into the evening and nighttime. In contrast, the peak power for PV is determined by the size, efficiency, and location of the collector area, and the capacity factor is determined by the local solar resource and the ability to track the sun.

The higher deployment of PV compared with CSP occurs for several reasons that are related to the cost and value of electricity produced by each of the technologies. First, the price per unit of capacity is lower for PV ($1.00–$1.50/W) than for CSP ($3.60/W); thus, much more PV capacity than CSP capacity can be installed for a given amount of investment. This factor is particularly important through 2030,

Sensitivity of SunShot Scenario Results to Renewable Target and Price Assumptions

Sensitivity analyses indicate that there is a solar price threshold at which solar deployment increases non-linearly as price decreases. As shown in Figure A, in order to explore the sensitivity of solar deployment to solar technology prices, solar deployment was modeled using two price scenarios, in addition to the SunShot and reference scenarios. These two scenarios included cost reductions that were less aggressive than the SunShot targets: 1) Photovoltaic (PV) prices decline by 50% between 2010 and 2020, and 2) PV prices decline 62.5% between 2010 and 2020. Both sensitivity cases included comparable price declines for CSP. Additional sensitivity analyses indicate that assuming larger price reductions for non-solar renewable technologies in the SunShot scenario would result in higher penetration of those technologies, particularly wind. For details see Appendix C.

Figure A. Solar Capacity under a Range of SunShot Solar Price-Reduction Scenarios



when solar is at relatively low levels of market penetration. Under these conditions, peak PV electricity generation coincides with the hours of peak electricity demand, and peak electricity prices, corresponding to a relatively high PV capacity value. However, after 2030, PV generation begins to saturate the peak electricity-demand window, CSP with energy storage becomes increasingly more valuable to the system, and CSP markets begin to grow more rapidly.

Second, residential and commercial rooftop PV systems generate electricity at the customer's facility, and thus PV competes largely against retail rather than wholesale electricity prices. This enables PV to compete in a broader set of markets with higher electricity prices than CSP.

Third, because CSP must be built in areas with good DNI, CSP deployment is constrained primarily to the Southwest. This constraint also means that new transmission lines may need to be built to carry CSP-generated electricity to demand centers, which slows deployment and adds cost. In contrast, PV can be deployed economically in a wider geographic area, including in close proximity to demand centers, which reduces the expense and time required to develop new transmission infrastructure.

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1.5 SunShot Impacts

Achieving the level of solar deployment envisioned in the SunShot scenario could affect the U.S. electricity system in a number of areas: the mix of electricity-generating resources, fossil-fuel use, electricity distribution and transmission, electricity costs, environmental impacts, and employment. These areas are discussed briefly below and in detail in the body of this report.

1.5.1 Electricity Generation and Fossil-Fuel Use

The SunShot scenario results in a reduction in the need for new conventional generation capacity and the use of fossil fuels—primarily natural gas and coal. Figure 1-4 shows the evolution of the electric sector in the SunShot and reference scenarios. Before 2030, solar generation primarily offsets natural gas generation in the SunShot scenario. 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, like natural gas combustion turbines (CTs). 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 begins to significantly offset coal use after 2030. Additional natural gas resources are developed after 2030 to satisfy the evening peak in net load, and CSP resources are deployed with several hours of storage providing a dispatchable solar generation resource.

Figure 1-4. Evolution of Electricity Generation in the Reference and SunShot Scenarios

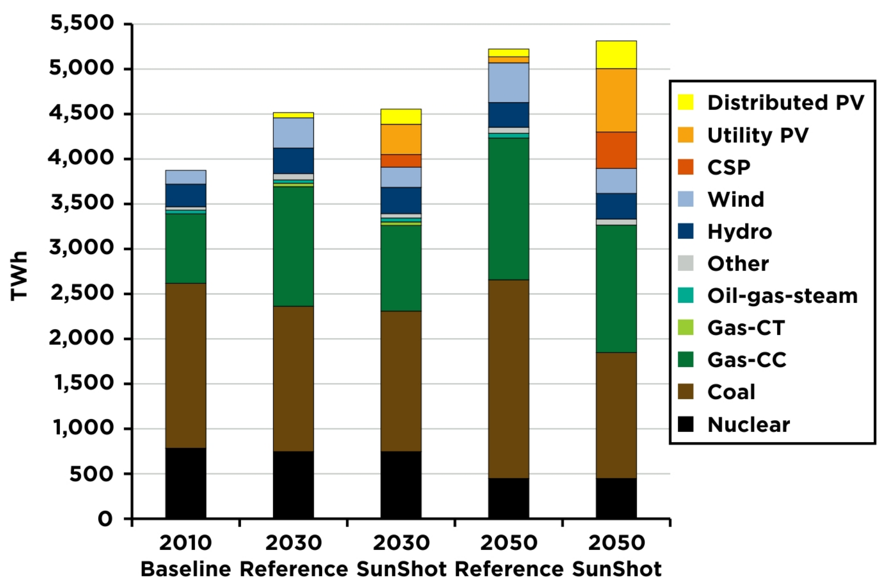
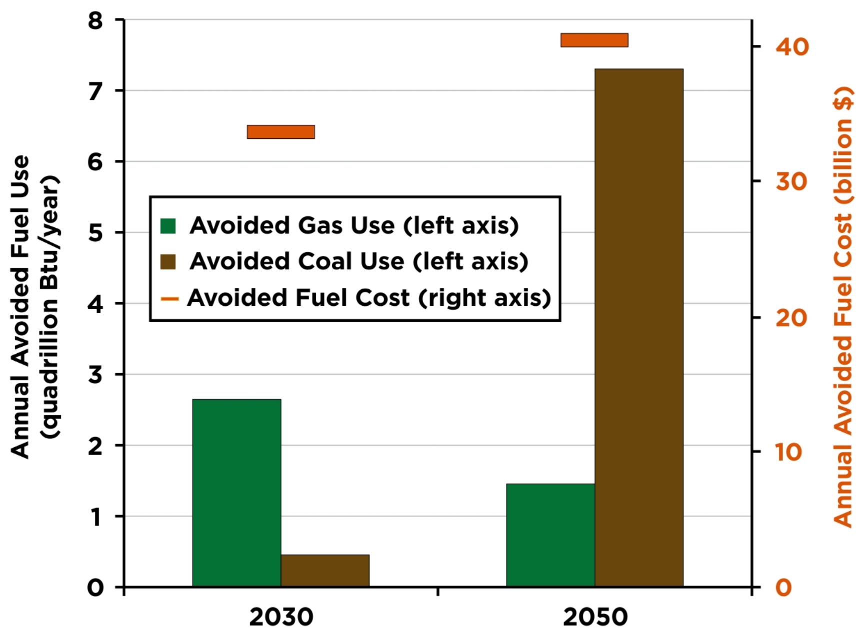


Figure 1-5 shows the avoided fuel use in the SunShot scenario relative to the reference scenario. In the SunShot scenario, solar displaces about 2.6 Quads of natural gas and 0.4 Quads of coal per year by 2030. Based on projected fuel prices from *AEO 2010*, as adjusted in ReEDS based on demand fluctuations, this represents

Figure 1-5. Avoided Fuel Use in the SunShot Scenarios



projected annual fuel-cost savings of about $34 billion per year by 2030. In 2050, the projected annual savings are 1.5 Quads of natural gas and 7.3 Quads of coal, which results in about $41 billion in fuel-cost savings per year.

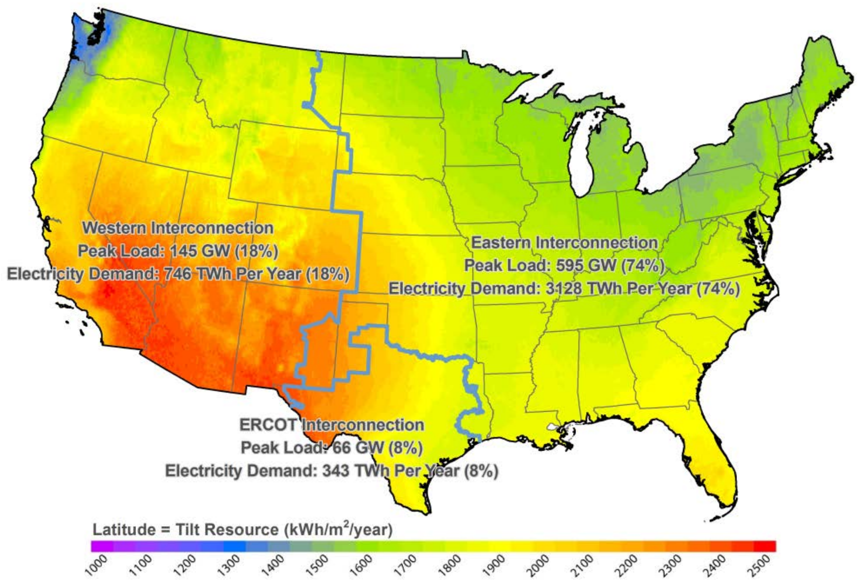
1.5.2 Electricity Transmission

Solar resources are not distributed evenly across the United States. 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.[8] Although there is significant generation potential at the distributed level, in many cases, the best solar resources are located far from regions with high-electricity demand. The same is true for wind resources. In the reference scenario, transmission is expanded primarily to meet growing electricity demand by developing new conventional and wind resources. In the SunShot scenario, transmission is expanded at a similar level, but in different locations, in order to develop solar resources.

The electricity grid in the continental United States is comprised of three interconnections: the Western Interconnection; the Eastern Interconnection; and the Electric Reliability Council of Texas (ERCOT) Interconnection, sometimes also referred to as the Texas Interconnection. Figure 1-6 shows the U.S. solar energy resource for a south-facing PV system tilted at latitude, along with peak and annual electricity demand for each interconnection. In the United States, the Western Interconnection represents about 18% of peak load, the ERCOT Interconnection represents 8%, and the Eastern Interconnection represents 74%. Achieving the SunShot scenario leads to higher relative solar deployment levels in the Western and ERCOT Interconnections than in the Eastern Interconnection, particularly for CSP.

[8] PV generation profiles were calculated using version 2001.8.30 of the System Advisor Model (SAM) www.nrel.gov/analysis/sam. Accessed September 2011.

Figure 1-6. Global Horizontal Solar Resource (South Facing, Tilted at Latitude with Electricity Use Statistics by Interconnection

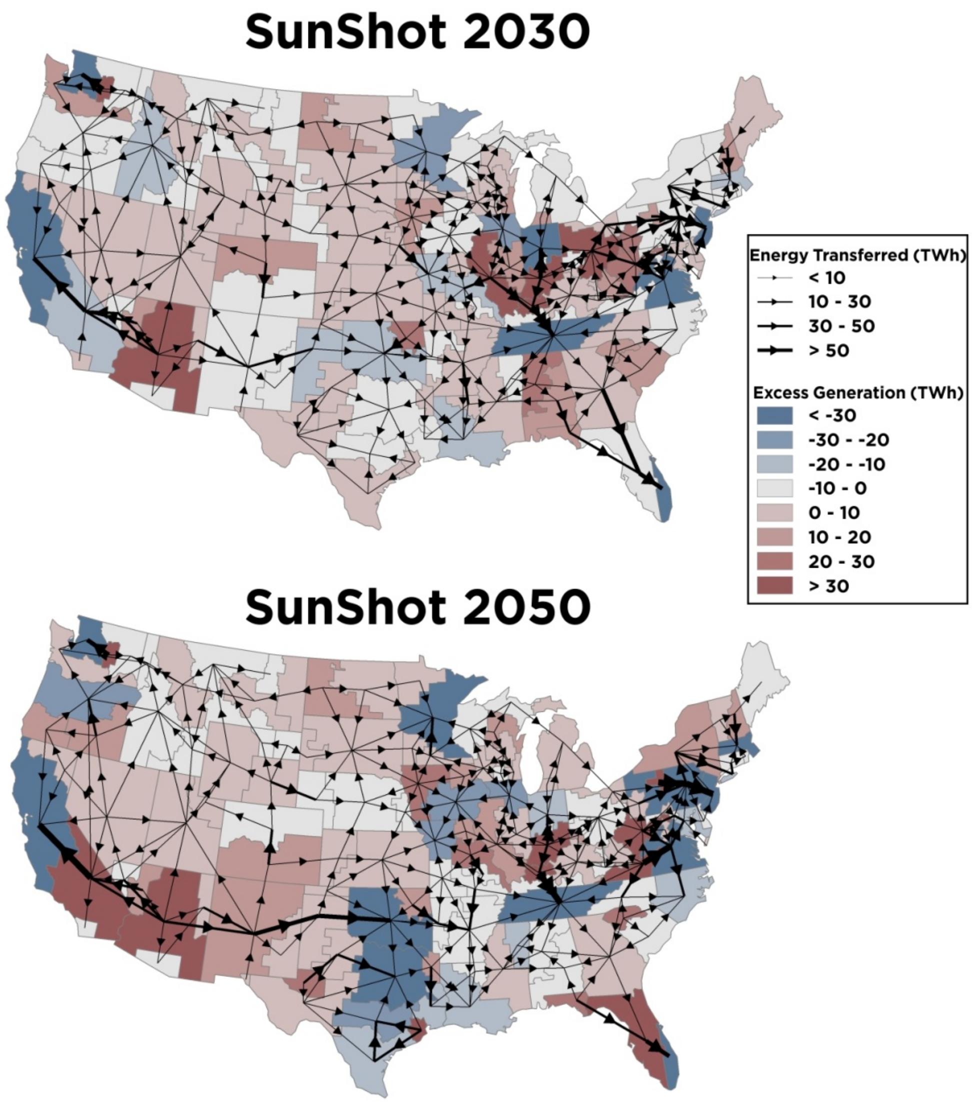


Source: NREL

Modeled transmission capacity is summarized using units measured in gigawatt-miles (GW-mi), i.e., miles of transmission lines multiplied by the capacity of the lines in gigawatts. In the reference scenario, transmission capacity is projected to increase from about 88,000 GW-mi in 2010 to 102,000 GW-mi in 2030 and 110,000 GW-mi in 2050, a 15% and 25% increase, respectively. In the SunShot scenario, transmission capacity is expected to increase to 100,000 GW-mi in 2030 and 117,000 GW-mi in 2050, a 13% and 32% increase, respectively. In other words, the SunShot scenario requires slightly less additional transmission capacity than the reference scenario through 2030, because a significant amount of utility-scale PV capacity is developed near load centers and near existing underutilized transmission lines. However, the SunShot scenario requires more additional transmission capacity than the reference scenario by 2050, primarily to connect remote CSP resources to load centers. The projected cost of expanding transmission in both the SunShot and reference scenarios through 2050 is about the same, roughly $60 billion dollars. This level of investment, which would be spread out over 40 years, represents about 2% of the total electric-sector costs under the SunShot scenario, and is well within the historical range of annual transmission investments by investor-owned utilities during the past few decades.

Figure 1-7 illustrates the patterns of electricity supply and demand in 2050 by showing the different regions in terms of excess generation—power generated that cannot be used locally and needs to be exported to other regions. Regions that generate more electricity (from all sources) than local demand are shown in shades of red, and importing regions are shown in shades of blue. Regions with significant CSP and wind deployment are frequently export regions. This trend is particularly strong in the Southwest for CSP and the Northern Plains for wind.

Figure 1-7. Mean Transmitted Energy for the SunShot Scenario, with Net Exporting (Red) and Importing (Blue) Regions and Interregional Energy Transmission (Arrows)



1.5.3 Cost

The cost of achieving the SunShot scenario presents a trade-off between investments in up-front capital for solar generation capacity and reduced annual expenditures on fossil fuels and operations costs for thermal generation capacity. Figure 1-8 shows the present value of the total direct electric-sector investment for the SunShot and reference scenarios. These costs include the capital investment in renewable and conventional capacity additions, transmission expansion, fuel, and operation and maintenance (O&M). The costs from expanding generation and transmission capacity are accounted for through the estimate year, i.e., 2030 or 2050; however, to capture the value of adding renewable generation capacity through a given year, the value of the

Achieving the SunShot targets could result in a significant reduction in the cost of electricity, enabling consumers across all market sectors to save about $30 billion annually by 2030 and $50 billion annually by 2050.

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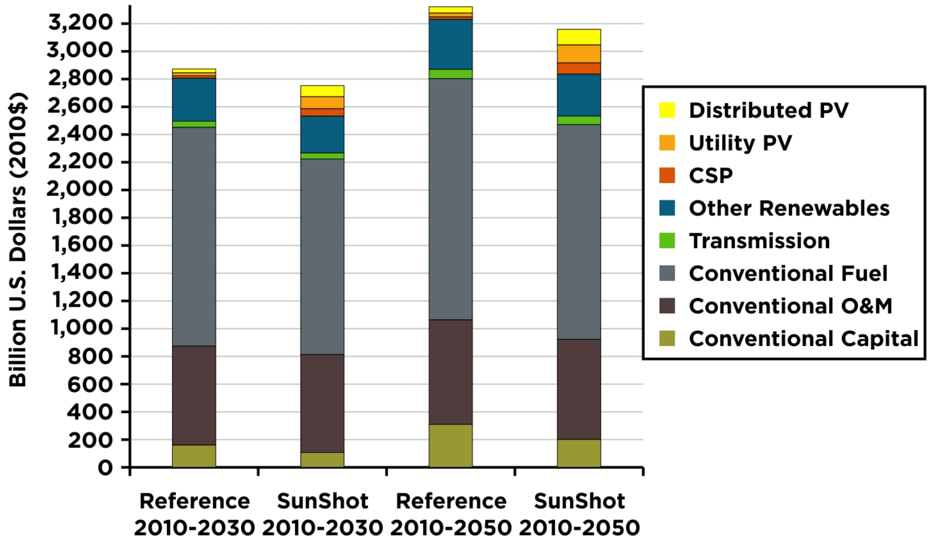
Figure 1-8. Direct Electric-Sector Costs for the Reference and SunShot Scenarios



installed capacity's output, plus fuel and O&M costs for running the system for an additional 20 years, are also included in the cost calculation. The capacity-addition costs include the cost of distributed rooftop PV installations, but do not include potential impacts on electricity-distribution costs.

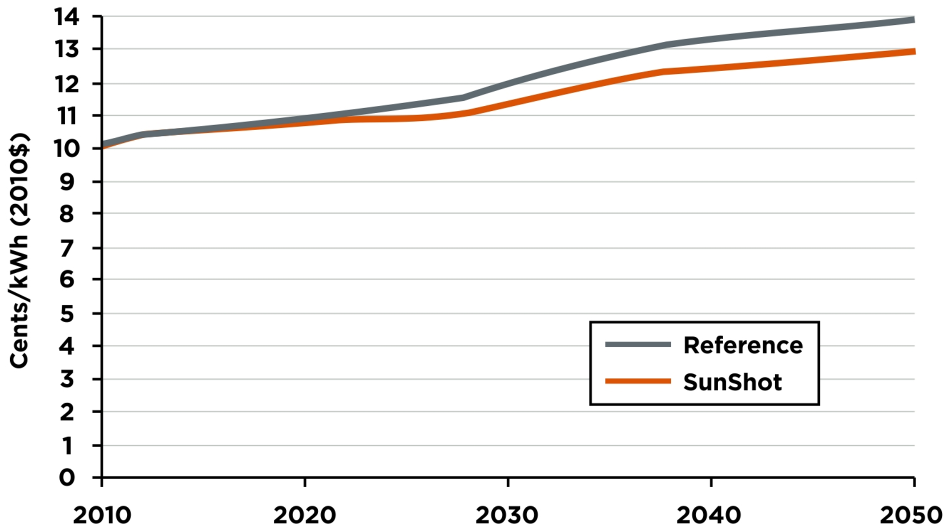
Figure 1-8 shows that the discounted cost of the SunShot scenario is projected to be about 4% below the cost of the reference scenario in 2030 and about 5% below the cost of the reference scenario in 2050. Transmission costs are similar in the SunShot and reference scenarios and are significantly less than generation capacity investments.

The impact of achieving the SunShot scenario on the cost of retail electricity is projected to be significant (Figure 1-9). By 2030, the average retail electricity price is about 0.6 cents/kWh less than the price in the reference scenario, saving an average household about $6 per month. By 2050, the electricity price is about 0.9 cents/kWh less than in the reference scenario, or about $9 lower per month, per household. 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.

1.5.4 Environment

All energy-generating technologies, including solar technologies, affect the environment in many ways. However, the potential for solar technologies to reduce the environmental impacts of energy generation compared with other generating technologies is among the most important reasons for widespread solar use. Significant reductions in U.S. GHG emissions are calculated under the SunShot scenario. As shown in Figure 1-10, total annual electric-sector CO_2 emissions in 2030 are 8% lower in the SunShot scenario than in the reference scenario. Annual electric-sector emissions in 2050 are 28% lower in the SunShot scenario than in the reference scenario. Relative to the reference scenario, the SunShot scenario results in

Figure 1-9. Average U.S. Retail Electricity Rates under the SunShot and Reference Scenarios



annual reductions of 181 and 760 million metric tons (MMT) of CO_2 by 2030 and 2050, respectively. This is equivalent to the annual emissions from 30 and 130 million cars. The SunShot scenario also results in emissions reductions of other potentially harmful pollutants such as mercury, nitrogen oxides, sulfur oxides, and particulate matter.

The water impacts of the SunShot scenario depend largely on the type of CSP technology deployed. PV requires very little water for washing panels occasionally depending on local climate conditions, and thus, by displacing fossil-fuel generation, it reduces water consumption from electricity generation significantly. In contrast, if CSP is deployed with wet cooling, its water consumption can be comparable to the water consumption of several conventional generation technologies that use evaporative cooling systems (i.e., cooling towers). Wet-cooled tower and trough CSP plants consume about 750–1,020 gallons/Megawatt-hour (MWh), which is slightly more than the levels of water consumed in pulverized coal plants (425–784 gallons/MWh), and similar to the levels consumed in pulverized coal plants with CO_2 capture (855–1,024 gallons/MWh) and nuclear plants (655–1,030 gallons/MWh).[9] Given the limits of water availability in the Southwest, however, it is likely that CSP will be deployed with significant amounts of dry or hybrid cooling, which can reduce water use by 40%–97%, compared with wet cooling, and have a relatively small impact on overall system performance. For the purposes of modeling CSP in the SunShot scenario, CSP cost and performance characteristics assumed dry cooling.

The primary potential ecological impacts of solar energy technologies relate to land used for utility-scale PV and CSP. In 2030, about 370,000–1,100,000 hectares (ha)

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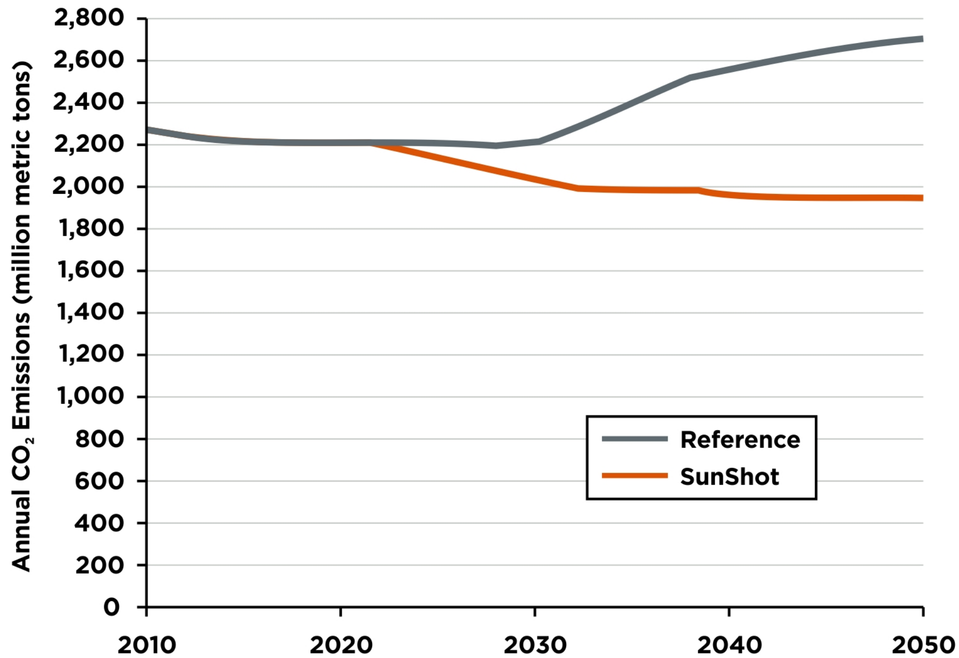
[9] Details on this data are provided in Table 7-3. Citations are provided below:
CSP: Cohen et al. (1999) and Viebahn et al. (2008);
Pulverized coal: DOE (2006), NETL (2010), and NETL (2007);
Pulverized coal with CO_2 capture: DOE (2006) and NETL (2010);
Nuclear: DOE (2006), NETL (2010), and NETL (2007).

Figure 1-10. Annual Electric-Sector CO_2 Emissions under the SunShot and Reference Scenarios



of land—equivalent to 900,000–2,700,000 acres or 0.05%–0.14% of the contiguous U.S. land area—could be required under the SunShot scenario. In 2050, about 860,000–2,500,000 ha—equivalent to 2,100,000–6,300,000 acres or 0.11%–0.33% of the contiguous U.S. land area could be required. Most of this would be in the South and Southwest. The specific ecological and other land-use impacts of solar energy technologies, for example, on local wildlife, will vary from region to region and will depend on policies implemented and approaches adopted to reduce the impacts.

Proper waste management and recycling are important parts of achieving the environmental benefits of the SunShot scenario. Current production, recycling, and disposal techniques have demonstrated the ability to minimize the introduction of hazardous materials into waste streams and avoid unintended consequences that would reduce the environmental benefits of large-scale solar deployment.

1.5.5 Employment

The overall U.S. solar workforce is expected to increase from about 51,000 in 2010 to about 340,000 in 2030 and 440,000 in 2050.

In estimating the potential workforce needed for meeting the SunShot scenario solar deployment levels, 2010 solar labor intensities were estimated using recent market analyses (McCrone et al. 2009, Solar Foundation 2010). The 2010 labor intensities represent current solar market dynamics, and labor intensities are likely to decrease with decreasing solar prices in the SunShot scenario, and as solar markets mature and become more efficient. The projected reductions in PV and CSP labor intensities in the SunShot scenario reflect that as costs per megawatt decline, the number of jobs per megawatt will also decline, i.e., labor productivity is assumed to increase in proportion to overall system-cost reductions. However, total solar jobs at any point in time are a product of labor intensity and installations. Using this approach, the overall U.S. solar (PV and CSP) workforce is expected to increase from about 51,000 in 2010 to about 340,000 in 2030 and to about 440,000 in 2050. This could support about 290,000 new solar jobs by 2030, and 390,000 new solar jobs by 2050.

In the PV-manufacturing environment, labor is readily transferable from other manufacturing industries. Similarly, PV power plant and utility-scale distributed development is likely to draw from the same skilled engineering and construction labor pool as traditional fossil-fuel power plant development. Distributed PV for rooftop projects can use much of the same labor pool as the residential and commercial construction industries, although additional training and certification is required. Additional jobs supported in the PV industry will include accountants, salespeople, engineers, computer analysts, factory workers, truck drivers, mechanics, and so forth. The U.S. PV workforce is expected to grow, in terms of gross jobs, from about 46,000 in 2010 to 280,000 in 2030 and to 363,000 in 2050. These estimates include direct and indirect jobs throughout the PV supply chain, with about 89% and 83% designated under manufacturing and installation in 2030 and 2050, and the remainder in O&M.

CSP power plant development is also likely to draw from the same skilled engineering and construction labor pool as traditional fossil-fuel power plant development. The workforce will include laborers, craftsmen, supervisory personnel, support personnel, and construction management personnel. The U.S. CSP workforce is expected to grow, in gross jobs, from about 4,500 in 2010 to 63,000 in 2030 and to 81,000 in 2050. These estimates include direct and indirect jobs throughout the CSP supply chain, with about 85% and 66% designated under manufacturing and installation in 2030 and 2050, and the remainder in O&M.

1.6 REALIZING THE SUNSHOT VISION

Several conditions would need to be met to achieve the SunShot Initiative's price reduction targets and to enable the projected large-scale deployment of solar technologies envisioned in the SunShot scenario. The performance of solar technologies would need to be improved significantly, with a corresponding decrease in the cost of solar energy. An adequate supply of raw materials and manufacturing capabilities would need to be available. Numerous solar installations would need to be sited and integrated with the electricity grid. New financing vehicles that encourage solar growth would need to be implemented, especially in the 2010–2020 time frame before solar prices reach the SunShot targets.

Meeting these conditions poses many challenges. However, vast new raw materials supplies, unprecedented manufacturing scale-up, or radical financing and policy approaches will not be required. The challenges to meeting the SunShot Initiative's price reduction targets and the level of solar deployment envisioned in the SunShot scenario, and potential strategies for addressing these challenges, are discussed briefly below and in detail throughout the body of this report.

1.6.1 TECHNOLOGY IMPROVEMENTS AND COST REDUCTIONS

To realize the SunShot targets, continued solar cost reductions and performance improvements are required. Many solar technologies have been demonstrated commercially since the 1970s or 1980s and have a strong record of cost reductions and performance improvements resulting from R&D investments, manufacturing scale-up, and accumulated experience. The technological progress envisioned in this study is significant, requiring a combination of evolutionary and revolutionary technology improvements.

Chapter 4 provides a detailed bottom-up engineering analysis of the opportunities for continued PV cost reductions and compares these cost reductions with historical trends. Key challenges to achieving the levels of PV penetration in the SunShot scenario are evaluated, including manufacturing scale-up and the supply of feedstock materials. To meet the SunShot targets, the total price of PV (and the corresponding LCOE) would need to be reduced by roughly 75% by 2020. This would make residential PV broadly competitive with retail electricity rates, commercial PV broadly competitive with commercial retail electricity rates, and utility-scale PV broadly competitive with utility wholesale electricity rates by 2020. These price reductions would result from a combination of R&D advances, more efficient manufacturing methods, reduced supply chain inefficiencies, and benefits from economies of scale as markets continue to grow and mature.

Chapter 5 provides a similar analysis for CSP technologies, including parabolic trough, linear Fresnel, power tower, and dish/engine technologies. Costs are discussed for all of these technologies; however, the analysis focuses primarily on trough and tower technologies. The potential role of integrating thermal energy storage and/or fossil-fuel hybridization into CSP plant designs as well as a range of component-specific advances are also examined. To meet the SunShot targets, continued R&D and learning-associated improvements would need to reduce the total price of CSP (and the corresponding LCOE) by roughly 70% by 2020. This would make utility-scale CSP broadly competitive with utility wholesale electricity rates by 2020. In particular, adding thermal energy storage or hybridization to CSP plants enables them to serve as dispatchable resources and thus to be more easily integrated into the electricity grid. The dispatchability of CSP also enables it to play a key role in helping to integrate other variable renewable energy technologies—e.g., PV and wind—as discussed in Chapter 6.

1.6.2 RAW MATERIALS

PV technologies use a number of materials that could be subject to shortages at the increased production levels required by the SunShot scenario, including tellurium, indium, selenium, gallium, germanium, ruthenium, copper, silver, and molybdenum. The biggest concerns are tellurium and indium for use in PV. As discussed in Chapter 4, to avoid potential material shortages for any of the PV technologies, one or more of the following strategies could be pursued:

- Increase efficiency (less material per delivered watt)
- Reduce material use through thinner layers
- Improve process utilization and in-process recycling

- Increase ore extraction and refining
- Shift to using materials that are more abundant.

The most important raw materials for CSP, as discussed in Chapter 5, are aluminum, steel, glass, heat-transfer fluid, and molten salt. In general, these materials are not subject to rigid supply limits, but they are affected by changes in commodity prices.

1.6.3 Manufacturing Scale-Up

Substantial increases in the manufacturing capacity of PV and CSP components and systems will be required to achieve the SunShot scenario, especially because the rest of the world will likely be scaling up its solar capacity at the same time. However, domestically and globally, these solar industries have demonstrated an ability to scale-up production volumes rapidly and realize associated cost reductions, particularly over the past decade.

The PV industry is expanding its manufacturing capacity, helped by new market entrants bringing capital as well as technology, manufacturing, and supply chain management experience, often from other successful industries—e.g., computer semiconductor, liquid crystal display, and specialized material industries. Manufacturing scale-up should not limit the PV deployment envisioned in the SunShot scenario.

Manufacturing of many CSP components can draw on the existing capabilities of other industries, such as fossil-fuel boiler manufacturers to produce steam or molten salt receivers and the automotive industry to produce CSP engines. Components unique to CSP systems are made of common materials and are relatively simple in design. Manufacturing scale-up should not present a barrier to achieving the SunShot scenario.

1.6.4 Grid Integration

The variability and uncertainty associated with PV and, to a lesser extent CSP, adds challenges to the operation of the U.S. electricity transmission and distribution systems. To verify that the electricity system can be operated under the SunShot scenario, GridView, a production cost/power flow model made by engineering company ABB, was used to evaluate the ReEDS model's projected capacity mix and identify operational challenges. 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.

A number of conclusions can be drawn from this analysis and from previous wind and solar integration studies. Although the GridView modeling confirmed the basic operational feasibility of the SunShot scenario, meeting both load and reserve requirements during all hours of the year, it also demonstrated the same challenges shown in previous studies of large-scale wind deployment. These include greatly increased rates and ranges over which the generation fleet must ramp, uncertainty in net load, and potential curtailment of variable generation during low-load periods in the spring. As discussed in Chapter 6, a number of strategies can be pursued to increase the ability to integrate variable and uncertain energy resources:

- Increasing the flexibility from conventional generation
- Sharing of energy supply, demand, and reserves over larger areas
- Incorporating thermal storage or hybridization into CSP systems
- Increasing operating reserves
- Incorporating forecasting into operations (including operation of distributed PV) and scheduling conventional units over short periods
- Employing load/demand-side management or storage technologies to increase system flexibility.

Many of these strategies may guide energy market development to integrate solar in the most cost-effective manner. In general, lower cost and easier integration will result from markets that are more flexible, larger, and more diverse.

Increased reliance on load-sited and distributed resources can present both additional challenges and potential benefits to managing the electricity-distribution system. New standards are needed to maintain system reliability and safety, and modifications to PV inverter and distribution equipment may be needed. In addressing many of these challenges, there may also be ways to leverage emerging “smart grid” technologies to enable market participation of customer-sited generation and loads to maximize grid efficiency.

1.6.5 Siting

As discussed in Chapter 7, there would be challenges to siting the SunShot scenario’s large and numerous solar installations. One set of challenges applies to utility-scale solar technologies and another to distributed solar technologies.

More than enough suitable land is available to enable the SunShot scenario’s utility-scale solar deployment and required transmission expansion. However, it will be important to make careful selection of sites to minimize conflicts with environmental, cultural, and aesthetic interests—particularly with respect to public lands. Even with the most careful land selection, the utility-scale solar development and related transmission expansion will have environmental impacts, especially on portions of the southern United States. These potential impacts—and ways to reduce them—are being studied by various stakeholders. Approaches include identifying solar energy study areas and renewable energy zones that can accommodate solar development with minimal environmental conflicts as well as promoting the use of land already damaged by contamination, mining, and other uses. The regulatory framework for siting utility-scale solar projects and associated transmission infrastructure is complex, costly, and time consuming. Streamlining this process, such as, with clear and consistent criteria that leverage the cooperation of federal, state, and regional authorities, would help to enable the rapid levels of development envisioned in the SunShot scenario.

Distributed rooftop solar technologies do not require the use of undeveloped land, but have a unique set of siting challenges. More than enough potential distributed sites are available to achieve the SunShot scenario deployment. Even after accounting for limiting factors such as shading, and orientation, U.S. rooftops alone could accommodate more than 600 GW of PV capacity, and additional opportunities exist on sites such as parking structures, awnings, and airports (Denholm and Margolis 2008). Most of the siting challenges distributed PV faces relate to its installation on structures, including complex and variable codes and permits, zoning ordinances, and restrictive covenants. Again, to enable rapid levels of deployment in the SunShot scenario, it would help to streamline and unify distributed solar siting requirements and processes and establish strong solar access and rights laws to protect the rights of consumers to install solar energy systems.

1.6.6 Financing

Financing the scale of expansion in the SunShot scenario would require significant new investments in the solar manufacturing supply chain and in solar energy projects. Attracting adequate investment to the solar supply chain—such as manufacturing facilities for PV modules and CSP mirrors—should be relatively straightforward because many of the mechanisms for doing so are already well developed and liquid. Financing SunShot scenario-scale solar project deployment—the widespread construction of distributed and central solar electricity-generating plants—is a greater challenge, with different considerations in the pre-2020 and post-2020 periods.

As discussed in Chapter 8, building out U.S. PV and CSP manufacturing capacity to meet the level of installations envisioned in the SunShot scenario would require cumulative investments of roughly $25 billion through 2030 and $44 billion through 2050. Although these levels of cumulative investments are not trivial, on an annual basis the required investments would be on the order of $1–$3 billion, well below private sector investments in solar in the United States during the past couple of years. Moreover, the necessary financing instruments and structures are well developed and well understood in the capital markets.

Financing solar project deployment under the SunShot scenario, however, will cost much more than financing the supply chain—on the order of $40–$50 billion per year between 2030 and 2050. On a cumulative basis, this translates into roughly $250 billion through 2030 and $375 billion through 2050. To put these numbers into context, it is important to compare them to the total capital required to build all types of electric-generating equipment—conventional and renewable. The difference in total capital required between the SunShot and reference scenarios through 2050 is less than 1%. Thus, it is not so much the total level of investment in electricity generation that needs to change in the SunShot scenario, but the pattern of investment.

Securing adequate financing for solar project deployment will be particularly challenging during the pre-2020 period, before solar electricity is cost competitive with other electricity sources. In 2020 and beyond, the availability of cost-competitive solar energy should stimulate private solar investment and facilitate use of mainstream financial instruments.

1

1.7 Conclusion

Achieving the SunShot Initiative's price reduction targets could enable solar energy to become competitive with other electricity-generation technologies by 2020 and could result in large-scale solar energy deployment through 2030–2050. Private capital would need to be invested to scale up the manufacturing and installation of solar energy technologies. Public investment in R&D and market transformation would be required to enable low-cost, rapid solar growth. The U.S. electrical transmission and distribution systems would need to be optimized to enable rapid solar growth. With these challenges addressed, the potential benefits of the SunShot Initiative—reduced fossil fuel use, lower GHG and other pollutant emissions, and solar job growth—could be realized along with a significant reduction in the projected average retail price of electricity. In short, realizing the price reduction targets of the SunShot Initiative would enable the nation to accelerate its evolution towards a cleaner, more cost-effective, and more secure energy system.

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2. Solar Energy Market Evolution and Technical Potential

This chapter provides context for the SunShot scenario by reviewing the evolution of global and U.S. markets for photovoltaics (PV) and concentrating solar power (CSP). It also examines the maximum potential of U.S. solar markets as determined by the potential of solar technologies to convert available sunlight into electricity and thermal energy.

The global PV market has accelerated over the past decade, with PV shipments averaging 53% annual growth and reaching 17 gigawatts (GW) in 2010, bringing cumulative shipments to about 40 GW. In 2010, the United States accounted for 8% or about 1,400 megawatts (MW) of PV market demand and 6% or about 1,000 MW of supply. The technical potential of the U.S. PV market is large. In fact, one estimate of the land area required to supply all end-use electricity in the United States using PV is only about 0.6% of the country's total land area or about 22% of the "urban area" footprint (Denholm and Margolis 2008a).[10]

The technical potential for CSP is also large. After implementing filters that account for insolation, slope, and land-use restrictions, the technical potential of the U.S. CSP market is about 7,500 GW of potential generating capacity—several times higher than the entire U.S. electric grid's capacity—in seven southwestern states (Turchi 2009). However, CSP market growth has been historically sporadic. After CSP plants were built in California in the late 1980s, almost 15 years passed before the next commercial CSP plant was built, followed by a surge of new plants in the United States and Spain during 2007–2010. At the end of 2010, global CSP capacity was about 1,300 MW, with about 39% in the United States and 57% in Spain; parabolic trough technology accounted for about 96% of the global total and tower technology for 3%.

2.1 Evolution of U.S. Solar Markets

This section discusses market evolution for PV and CSP, including changes in global and U.S. supply and demand and the current status of U.S. solar technology manufacturing. Also discussed are the factors affecting solar market evolution and recent solar industry employment statistics. Putting all the information together, a picture emerges of a solar industry that has come a long way over the past few decades, setting the stage for SunShot-scale deployment during the next several decades.

[10] This calculation is based on deployment/land in all 50 states.

2.1.1 PHOTOVOLTAICS

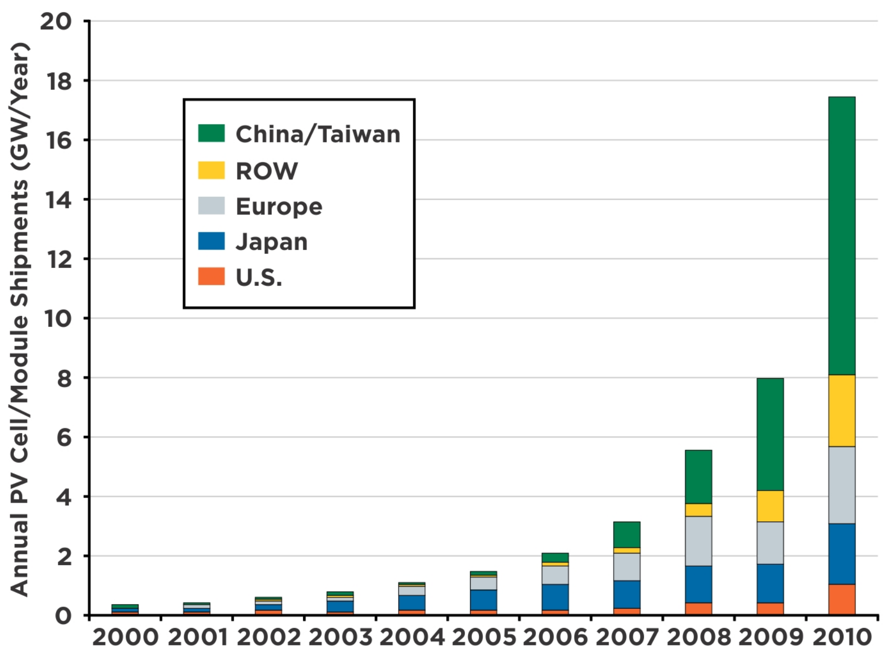
While the global PV market grew rapidly during the past decade, the U.S. market position declined based on more rapid growth in Asia and Europe. During the past couple of years, federal and state policies have helped to drive PV market demand growth and a renewed interest in PV manufacturing in the United States.

Global PV Supply and Demand

Shipments of PV cells and modules by region are a key indicator of market evolution. Shipments attributed to a given region represent PV supplied by that region, as measured at the first point of sale. However, not all shipped cells and modules end up in the market the year they are produced or in the country in which they were first sold.

Figure 2-1 shows the dramatic growth in PV shipments during the past decade: a 53% compound annual growth rate from 2000 through 2010, reaching 17.4 GW in annual shipments in 2010. The United States accounted for 30% of global PV shipments in 2000, but then lost market share over the next decade, first to Japan, then to Germany, and finally to China and Taiwan. In 2010, China and Taiwan accounted for 53% of global PV shipments. The Japanese market surge resulted largely from its residential subsidy program, which began during the mid-1990s. The European surge resulted largely from the German feed-in tariff, which was implemented in 2000, streamlined over the next couple of years, and adopted by a number of other European countries during the past 5 years. During 2006–2010, China and Taiwan invested heavily in PV manufacturing and demonstrated an ability to scale-up production rapidly while reducing manufacturing cost substantially.

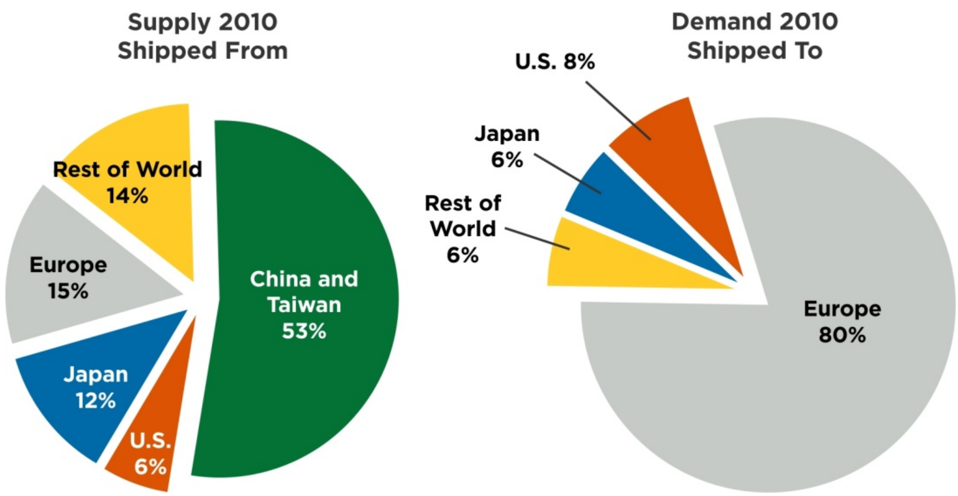
Figure 2-1. Regional PV Cell and Module Shipments, 2000–2010



Source: Mints (2011a)

Figure 2-2, which depicts global PV supply and demand in 2010, clearly shows the dominance of manufacturers in China and Taiwan. The rest of world (ROW) region includes Australia, India, the Philippines, and Malaysia.

Figure 2-2. 2010 Global PV Supply and Demand



Source: Mints (2011a) and Mints (2011b)

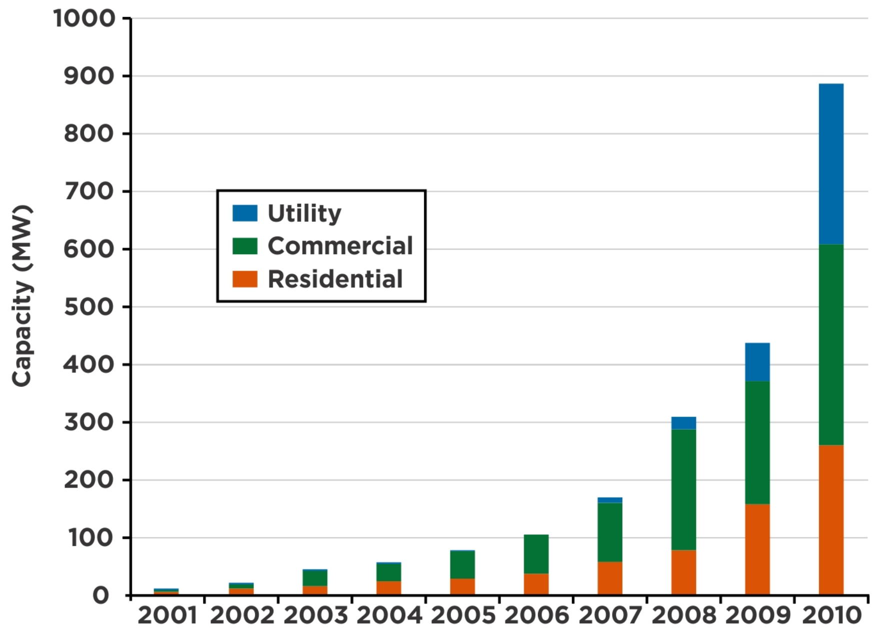
Historically, PV shipments have been dominated by crystalline-silicon technology. In 2003, the market share for crystalline-silicon PV was 95%, compared with 5% for thin-film PV. However, thin-film shipments have grown rapidly in recent years, particularly shipments of cadmium telluride (CdTe) and amorphous silicon (a-Si) technologies. At the same time, newer PV technologies—such as copper indium gallium diselenide (CIGS) and concentrating photovoltaics (CPV)—have been preparing to enter full-scale production. By the end of 2010, thin-film technology accounted for 13% of global PV shipments (3% a-Si, 8% CdTe, and 2% CIGS). The United States was responsible for 18% of global CdTe and 20% of global a-Si shipments in 2010 (Mints 2011a).

U.S. PV Demand

Despite a long history of public and private investments in PV technology, the United States remains a relatively immature PV market. In the 1980s, the U.S. and global PV demand was dominated by off-grid applications, typically very small systems with installed capacities measured in hundreds of watts. During the late 1990s, grid-connected systems—with installed capacities measured initially in kilowatts and later in megawatts—began dominating global demand. As this transition occurred, system cost declined significantly owing to a combination of research and development (R&D) advances as well as economies of scale on the production and installation sides. In the United States, the transition to a market dominated by grid-connected systems occurred slightly later, driven by state and federal incentives.

Figure 2-3 illustrates the annual growth in U.S.-installed grid-connected PV from 2001 to 2010 for residential, commercial, and utility-owned applications.[11] The entire installed PV market has grown substantially over the past decade. The utility market segment made a notable market share increase from 2009–2010, primarily the result of only 34 large (over 1 MW) installations. Off-grid PV installations—not depicted in this figure—accounted for approximately 40–60 MW in 2010 (IREC

Figure 2-3. U.S. Annual Installed Grid-Connected PV Capacity by Market, 2001–2010



Source: IREC (2011)

2011).

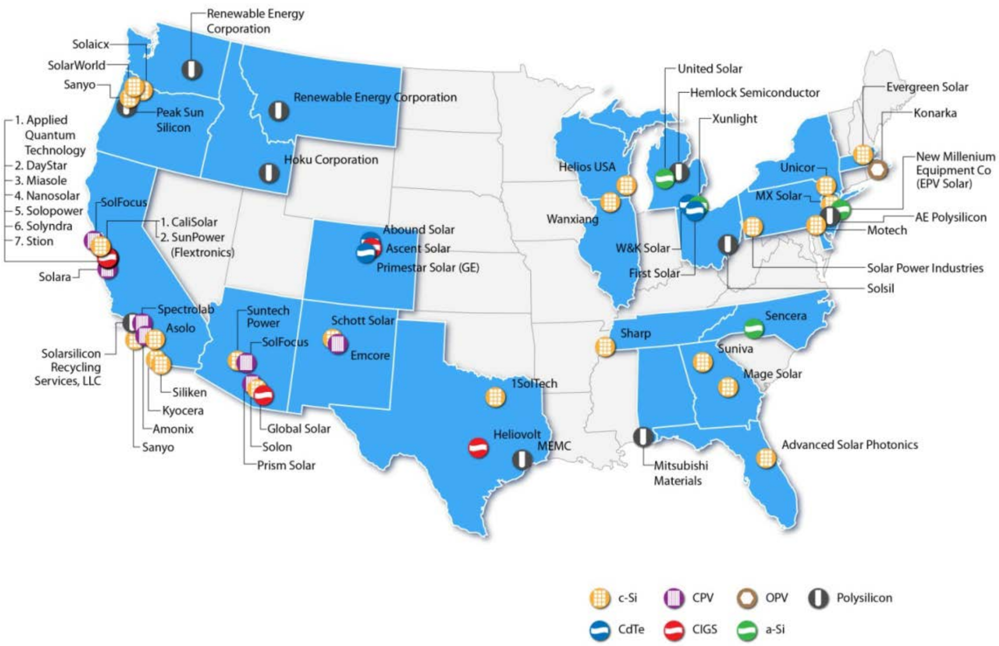
As of 2010, California was by far the strongest U.S. PV market. The California Solar Initiative, enacted in December 2005, provided the long-term market stability critical for encouraging new entrants on the production and installation sides. California continues to encourage solar and other renewable energy technologies through innovative policies, including a strong renewable portfolio standard (RPS), a diverse portfolio of incentives, and utility involvement. Other U.S. markets that have grown significantly during the past few years are Arizona, Colorado, New Mexico, New Jersey, New York, and Nevada.

U.S. PV Manufacturing

Recent federal and state incentives have encouraged manufacturers to expand PV production in the United States. Figure 2-4 shows the location and technology of

[11] The residential and commercial data generally represent installations where electricity is used on-site, whereas the utility data represent installations that generate electricity sent to the bulk grid. Commercial data capture government, non-profit, and other non-residential installations. The owner of the installation for any of the three market segments could be either the site owner or a third party.

Figure 2-4. U.S. PV Cell, Module, Wafer, and Polysilicon Manufacturing Facilities, July 2011



Sources: SEIA and GTM Research (2011a), Mehta (2009), Bradford (2008), BNEF (2009)

U.S. PV manufacturing facilities as of July 2011.[12] The figure shows that 59 PV facilities in 22 states were in operation in mid-2011.

These facilities produce crystalline-silicon, CPV, and thin-film technologies such as a-Si, CdTe, CIGS, and organic photovoltaics (OPV), as well as polysilicon and wafers for use in crystalline-silicon PV. In 2010, U.S. cell production was about 1,100 MW or 5% of global production, and module production was about 1,200 MW or 6% of global production (SEIA and GTM Research 2011b). The United States produced 42,561 metric tons (MT) of polysilicon in 2010, approximately 30% of global supply. The median estimate of total polysilicon produced in 2010 was 148,750 MT, of which about 81% (or 120,400 MT) was produced for the solar industry. In addition to these numbers, scrap polysilicon from the electronics industry has always supplied the solar industry with varying amounts of the material. The total 2010 production of polysilicon represented an estimated 60% increase over 2009 production.

The discrepancy between U.S. polysilicon production versus module production is due in part to polysilicon production being very capital intensive and complex, requiring technological sophistication, whereas module production is labor intensive, benefiting countries with low-cost labor. In addition, shipping costs of

[12] An attempt was made to only include all manufacturing plant locations with at least 5 MW of production capacity as of July 2011. However, the constantly changing landscape for PV component manufacturing and diversity of players in the solar manufacturing industry make it difficult to have a comprehensive list at any point in time. This list is not an exception, and should not be viewed as absolute.

polysilicon are minimal, so plant location near the end customer is not a key factor, whereas modules are more expensive to ship, benefitting countries in Europe where the largest end markets are located.

2.1.2 Concentrating Solar Power

The market for CSP has surged in recent years, especially in Spain and the United States. Trough systems dominate global CSP installations, but other technologies are gaining market share.

Global CSP Installations

Luz, a California-based company, first commercialized CSP in the 1980s with the Solar Energy Generating Systems (SEGS), 354 MW of parabolic trough plants in the Mojave Desert of southern California. The next CSP plant to come online in the United States was the Arizona Public Service (APS) Saguaro 1-MW parabolic trough plant, installed in Red Rock, Arizona, in 2005. Another 64 MW of CSP capacity were added in 2007 when the Nevada Solar One parabolic trough plant was installed in Boulder City, Nevada. At the end of 2008, 430 MW of grid-tied CSP capacity were in commercial operation worldwide, more than 95% of which was in the southwestern United States.

By December 2010, global CSP capacity increased to about 1,300 MW. Most of the capacity additions during 2009–2010 were in Spain, and at the end of 2010, Spain accounted for about 57% of all global CSP capacity. Parabolic trough technology accounted for about 96% of global CSP capacity at the end of 2010; tower technology accounted for 3%. Table 2-1 lists commercial and grid-tied demonstration CSP plants (with capacities of 1 MW or greater) installed worldwide as of December 2010. The Andasol 1 and Andasol 2 plants shown in the table are the first commercial CSP plants to feature thermal storage, using a two-tank molten salt system to store up to 7.5 hours of peak-load energy (Solar Millennium 2010).

Table 2-1. Commercial and Grid-Tied Demonstration CSP Plants ($\geq$ 1 MW_{AC} capacity) Installed Worldwide as of December 2010

Plant Name	Location	Technology Type	Year Installed	Capacity (MW_{AC})
SEGS I – IX	California, U.S.	Trough	1985–1990	354
Inditep	Spain	Trough	2005	1.2*
APS Saguaro	Arizona, U.S.	Trough	2006	1
Nevada Solar One	Nevada, U.S.	Trough	2007	64
PS10	Spain	Tower	2007	11
Kimberlina	California, U.S.	Compact linear Fresnel reflector (CLFR)	2008	7*
Andasol 1	Spain	Trough w/thermal storage	2008	50
Liddell	Australia	CLFR	2008	3
Sierra Sun Tower	California, U.S.	Tower	2009	5*
Holaniku	Hawaii, U.S.	Trough	2009	2*
Stadtwerke Julich	Germany	Tower	2009	1.5*

Plant Name	Location	Technology Type	Year Installed	Capacity (MW_{AC})
Puerto Errado 1	Spain	Linear Fresnel	2009	1.4*
Puertollano Ibersol	Spain	Trough	2009	50
La Risca	Spain	Trough	2009	50
PS20	Spain	Tower	2009	20
Holaniku	Hawaii, U.S.	Trough	2009	2
Maricopa Solar	Arizona, U.S.	Dish	2010	1.5*
IEECAS Badaling	China	Tower	2010	1.5*
Cameo	Colorado, U.S.	Trough	2010	1*
Casa del Ángel Termosolar	Spain	Stirling	2010	1*
Himin Yanqing	China	Tower	2010	1*
Martin	Florida, U.S.	Trough	2010	75
Andasol 2	Spain	Trough w/thermal storage	2010	50
Extresol 1	Spain	Trough w/thermal storage	2010	50
Solnova 1	Spain	Trough	2010	50
Solnova 3	Spain	Trough	2010	50
Solnova 4	Spain	Trough	2010	50
La Florida	Spain	Trough	2010	50
Majadas	Spain	Trough	2010	50
La Dehesa	Spain	Trough w/thermal storage	2010	50
Palma Del Rio II	Spain	Trough	2010	50
Extresol-2	Spain	Trough w/thermal storage	2010	50
Manchasol-1	Spain	Trough w/thermal storage	2010	50
Ain Beni Mathar	Morocco	Trough	2010	20
Al Kuraymat	Egypt	Trough	2010	20
Archimede	Italy	Trough	2010	5

*Denotes grid-tied demonstration plant

Sources: Abengoa Solar (2011), Acciona Energy (2008), Ausra (2009), BrightSource Energy (2008), Emerson Process Management (2009), eSolar (2009), Grama et al. (2008), Solar Millennium (2010), Sopogy (2009), Tessera Solar (2010), Protermosolar (2011), NREL (2011a), Renovalia Energy (2010), EIA (2010a), SEIA-GTM (2011b), BNEF (2011), NextEra Energy (2011), Areva Solar (2010)

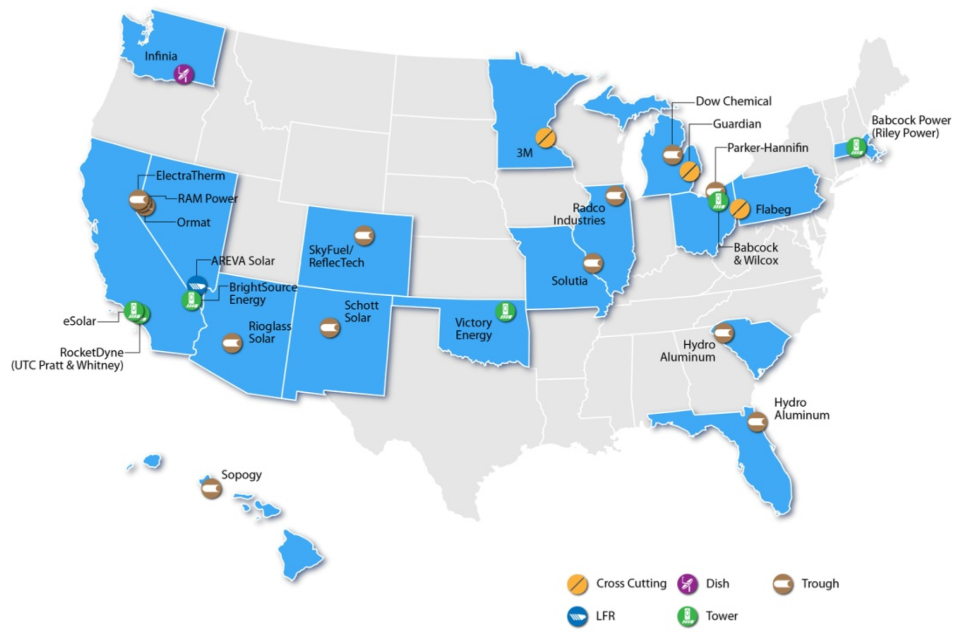
U.S. CSP Manufacturing

Figure 2-5 shows U.S. component manufacturing facilities for CSP technologies including parabolic troughs, power towers, linear Fresnel reflectors, and dish/engine systems. A total of 24 manufacturing facilities that produce CSP components—possibly among other products—were in operation by mid-2011.[13] CSP

[13] An attempt was made to only include all manufacturing plant locations with at least 5 MW of production capacity as of July 2011. However, the constantly changing landscape for CSP component manufacturing and diversity of players in the solar manufacturing industry make it difficult to have a comprehensive list at any point in time. This list is not an exception, and should not be viewed as absolute.

2

Figure 2-5. U.S. CSP Component Manufacturing Facilities, July 2011



Sources: SEIA and GTM Research (2011a), BNEF (2009), DOE (2010)

components—many of which cut across technologies—include mirrors, reflectors, collector structures, heat-transfer fluids and salts, turbines, and controls. The expectation of strong CSP installation growth has resulted in CSP component production facilities being established by specialized manufacturers and large industrial conglomerates.

2.1.3 Solar Industry Employment

This section discusses the existing types and levels of employment in the solar industry for PV and CSP.

The PV and CSP industries include a variety of jobs across their supply chains and in support roles. In measuring economic impact, jobs can be divided among three categories: direct, indirect, and induced jobs. Direct jobs accomplish final production along the solar industry supply chains, e.g., manufacturing, installation, and R&D. Indirect jobs are in industries that support the solar industry, e.g., glass, steel, and office-equipment industries. Induced jobs result from the economic activity stimulated by the solar industry, e.g., jobs related to people buying more goods and services in a region that hosts a manufacturing plant or project under construction.

It is most feasible to quantify direct and indirect jobs resulting from solar industry growth. The range of direct and indirect solar jobs includes the following:

- *Manufacturing:* Technology research, engineering, raw materials production, assembly line, quality control, shipping, and marketing
- *Project planning:* Mechanical, electrical, and structural engineers, energy transmission engineers, architects, project developers, land brokers, contract personnel, environmental consultants, utility procurement staff, local permitting officials, lenders, and investors
- *Installation:* Construction managers, installers, pipefitters, electricians, plumbers, laborers, and truck drivers
- *Operations, maintenance, and ownership:* System monitors, field technicians, warranty servicing, and accounting
- *Decommissioning and disposal:* Demolition, transportation, and recycling
- *Education and training:* Professors, instructors, and administrators
- *Policy, program administration, research, and advocacy:* Energy officials, utility program administrators, government-relations staff, trade associations, market analysts, non-profits, and media.

There were an estimated 51,000 full-time-equivalent PV- and CSP-related jobs in 2010, about 90% of which were related to PV and 10% to CSP. See Chapter 3 for employment details and projections through 2050.

The distributed energy model afforded by solar technologies is a key factor influencing solar employment characteristics. The multiplicity of small- and mid-sized solar energy systems yields more installation and operations jobs compared to common central station energy technologies, per energy unit [e.g., megawatt-hours (MWh)] produced. These jobs are more widely distributed in communities across the nation, including rural locations. This enables communities to "in-source" energy production, expanding local economies and providing jobs that cannot be moved offshore (Wei et al. 2010).

2.1.4 Hedging Against Energy Price Increases

Solar energy technologies enable users to reduce their exposure to future increases in the cost of energy because these systems do not face variable fuel costs. This is an attractive attribute of solar energy technologies. In particular, the potential impact of increased solar market penetration on natural gas use and pricing is important (this is discussed in more detail in Chapter 3). Natural gas is currently a key determinant of electricity, heating, and cooling costs in the United States. Natural gas accounts for roughly 20% of U.S. electricity generation; however, because natural-gas generation plants are usually the last power source to be activated to meet a given load, it is a key determinant in setting the wholesale market price of electricity throughout much of the country. Solar energy technologies provide potential price-hedging benefits to individual consumers, by substituting a fixed cost in place of a potentially volatile fuel cost, and the broader public, by displacing demand for natural gas.

2.2 Solar Resource Availability and Technical Potential

The U.S. solar resource is enormous. In fact, the amount of solar energy falling on the United States in 1 hour of noontime summer sun is about equal to the annual U.S. electricity demand. Moreover, as shown in Figure 2-6 and discussed below, every region of the contiguous United States has a good solar resource.

The ability to exploit the available solar resource varies by technology. Solar energy contains a direct component, i.e., light from the solar disk that has not been scattered by the atmosphere, and an indirect or diffuse component, i.e., light that has been scattered by the atmosphere. Only the direct solar component can be focused effectively by mirrors or lenses such as those used by CPV and CSP systems. The direct component typically accounts for 60%–80% of surface solar insolation in clear-sky conditions and decreases with increasing relative humidity, cloud cover, and atmospheric aerosols, e.g., due to dust and urban pollution. This section describes the technical potential for PV and CSP market growth in the context of the exploitable U.S. solar resource.

2.2.1 Photovoltaics

Flat-plate PV can take advantage of direct and indirect insolation, so PV modules need not directly face and track incident radiation. This gives PV systems a broad geographical application.

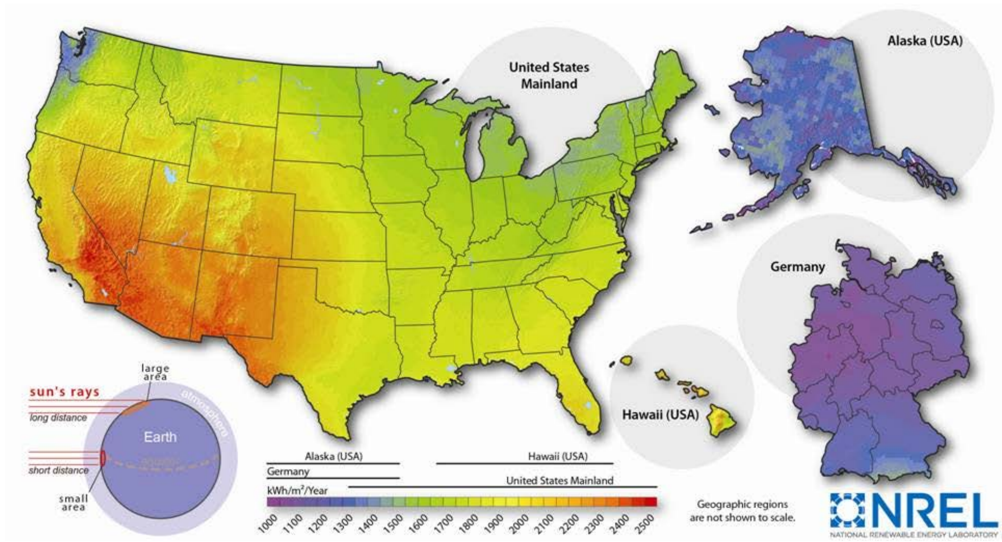
Figure 2-6 illustrates the solar resource in the United States and Germany for a flat-plate PV collector tilted south at latitude. Solar resources across the United States are mostly good to excellent at about 1,000–2,500 kilowatt-hours (kWh)/square meter (m^2)/year. The Southwest is at the top of this range, while only Alaska and part of Washington are at the low end. The range for the 48 contiguous states is about 1,350–2,500 kWh/m^2/year. Nationwide, solar resource levels vary by about a factor of two, which is considered relatively homogeneous compared with other renewable energy resources.

The U.S. solar resource is much higher than Germany's, and the southwestern United States has a better resource than southern Spain. Germany's solar resource has about the same range as Alaska's (1,000–1,500 kWh/m^2/year), but more of Germany's resource is at the lower end of the range. Spain's solar resource ranges from about 1,300–2,000 kWh/m^2/year, among the best in Europe.

The total U.S. land area suitable for PV is significant and will not limit PV deployment. For example, one estimate suggested that the land area required to supply all end-use electricity in the United States using PV is about 5,500,000 hectares (ha) (13,600,000 acres), which is equivalent to 0.6% of the country's land area or about 22% of the "urban area" footprint (Denholm and Margolis 2008a).[14] See Chapter 7 for calculations of PV land use and electricity generation under the SunShot scenario. In addition to siting PV on greenfields, there are many opportunities for installing PV on underused real estate such as parking structures,

[14] This calculation is based on deployment/land in all 50 states.

Figure 2-6. PV Solar Resource: United States and Germany



Source: NREL (2011b)

awnings, airports, freeway margins, and farmland set-asides. PV can also be located on rooftops, where it will have essentially no land-use impacts. A recent estimate of the total roof area suitable for PV in the United States is about 6 billion m^2, even after eliminating 35%–80% of roof space to account for panel shading (e.g., by trees) and suboptimal roof orientations; with current PV performance, this area has the potential for more than 600 GW of capacity (Denholm and Margolis 2008b).

2.2.2 CONCENTRATING SOLAR POWER

The geographic area most suitable for CSP is smaller than that for PV because CSP can exploit only direct-normal irradiance (DNI), i.e., light that can be focused effectively by mirrors or lenses. Globally, the most suitable sites for CSP plants are arid lands within 35° north and south of the equator. In the United States, the best location for CSP is the Southwest, which has some of the best solar resources in the world. Figure 2-7 shows the DNI resource in the Southwest; red indicates the most intense solar resource, and green indicates the least intense.

A strong solar resource is only one criterion for the effective deployment of large solar power stations. The land must also be relatively flat, unoccupied, and suitable for development. NREL has performed various assessments of the Southwest to estimate the quantity of land suitable for solar power stations and the amount of energy that might be produced. Figure 2-8 shows locations in the Southwest with characteristics ideal for CSP systems, including DNI greater than 6.0 kWh/m^2/day (2,200 kWh/m^2/year) and a land slope of less than 1°. In addition, land-use filters exclude bodies of water, urban areas, national parks and preserves, wilderness areas, and wildlife refuges. Because the economics of utility-scale solar facilities favor large size, land areas smaller than 1 square kilometer (km^2) are also excluded (Mehos et al. 2009).

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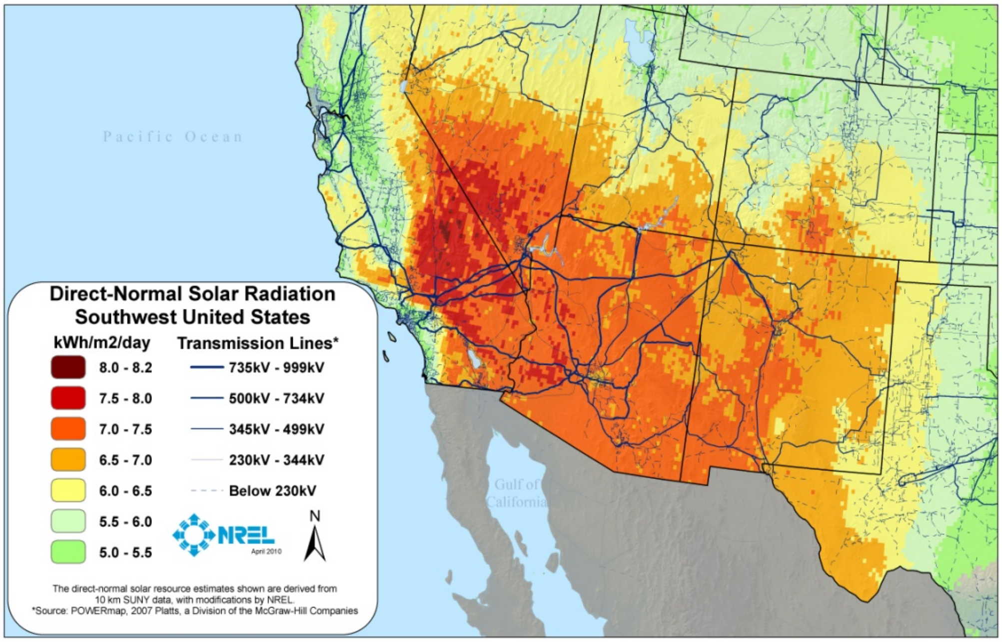
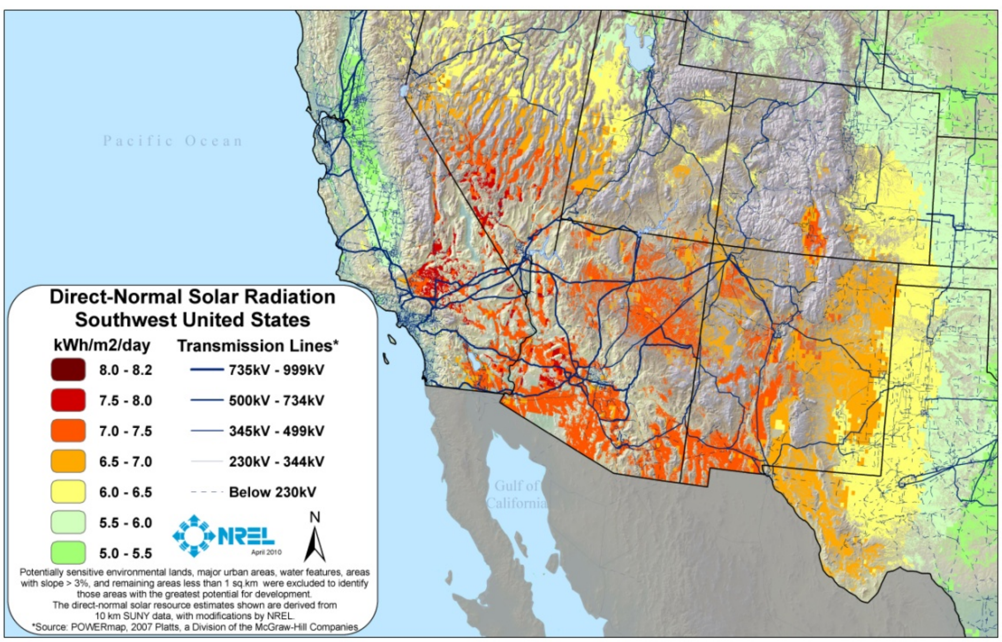
Figure 2-7. DNI Resource in the U.S. Southwest



kV: kilovolts
Source: Mehos and Kearney (2007)

Figure 2-8. DNI Resource in the U.S. Southwest, Filtered by Resource, Topography, and Land Use



Sources: Mehos et al. (2009), Turchi (2009)

After implementing the appropriate insolation, slope, and land-use filters, 22,593,000 ha (55,800,000 acres) are available in the seven states considered to be most CSP compatible: Arizona, California, Colorado, Nevada, New Mexico, Texas, and Utah (Table 2-2). This relatively small land area amounts to nearly 7,500 GW of resource potential and more than 17.5 million gigawatt-hours (GWh) of annual generating capacity, assuming a capacity factor of 27% (Mehos et al. 2009, Turchi 2009). The potential generating capacity exceeds the total U.S. electric grid capacity by a factor of more than six, while the potential energy production exceeds U.S. demand by a factor of more than four (EIA 2010b, EIA 2010c).

Table 2-2. Ideal CSP Resource Potential and Land Area in Seven Southwestern States

State	Available Area (ha)	Capacity (GW)	Annual Electricity[a] (GWh)
Arizona	3,525,700	1,162	2,748,000
California	1,626,000	536	1,267,000
Colorado	1,614,100	532	1,258,000
Nevada	2,872,300	946	2,238,000
New Mexico	5,272,200	1,737	4,108,000
Texas	1,650,800	544	1,286,000
Utah	6,031,600	1,987	4,700,000
Total CSP Resource	**22,593,000**	**7,444**	**17,605,000**

[a] Annual electricity production was estimated using an average capacity factor of 27%, although actual values would depend on technology and level of thermal energy storage deployed.

Sources: Mehos et al. (2009), Turchi (2009)

A value of 3 ha/MW (7.5 acres/MW) was used to determine capacity per unit of land area. This value represents an estimated average for different CSP technologies, and actual values will depend on the specific technology used, location, and system efficiency. CSP systems with thermal storage will have a higher land use per unit of capacity due to a larger collector area needed for generating excess thermal energy. However, because the storage also results in a higher capacity factor, these effects offset each other in the calculation of annual energy production. See Chapter 7 for calculations of CSP land use and electricity generation under the SunShot scenario.

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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).

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.

3

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.

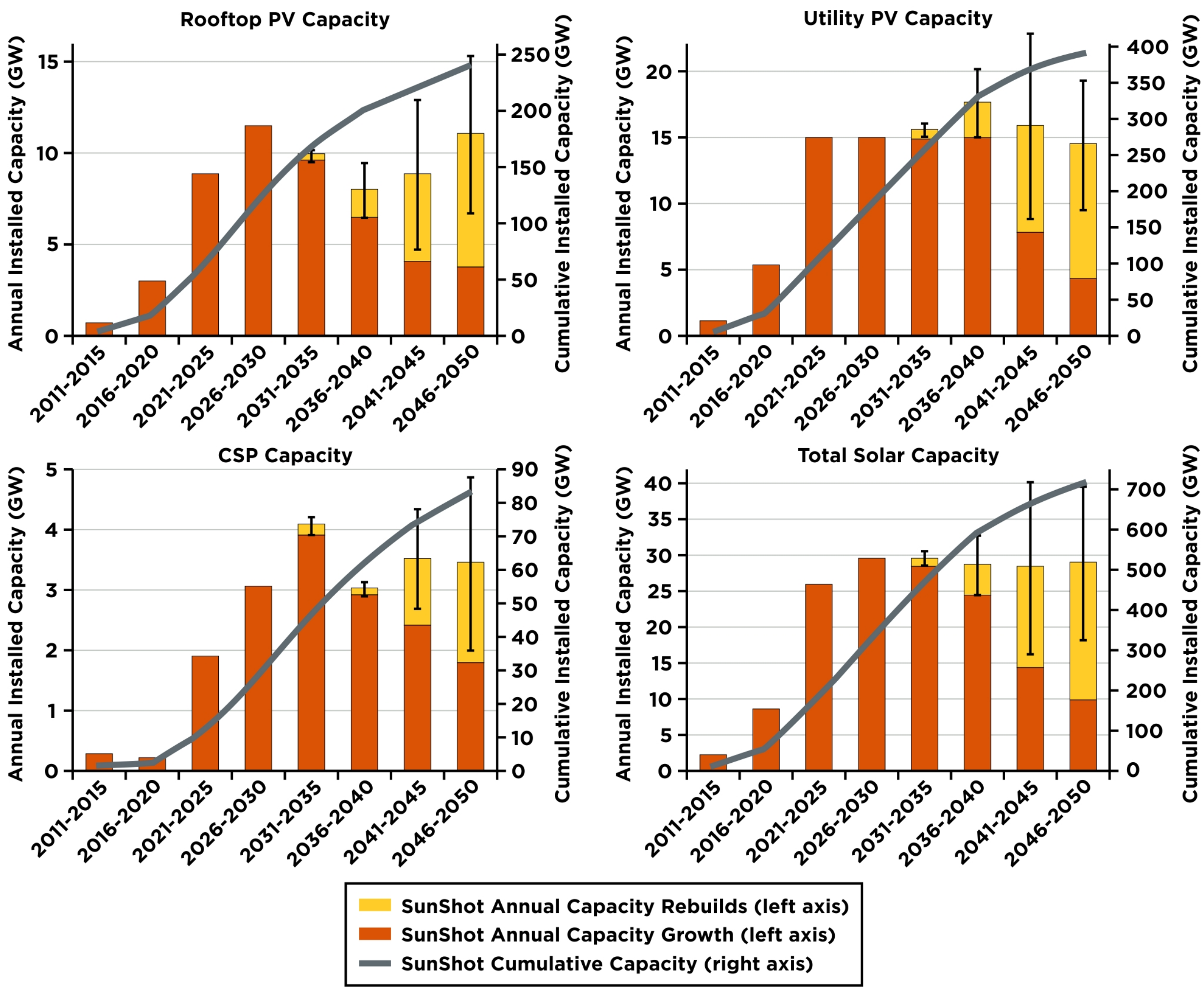
the modeling framework. Key model assumptions are listed in the sidebar, and a detailed description of the modeling methodology and assumptions is included in Appendix A.

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)

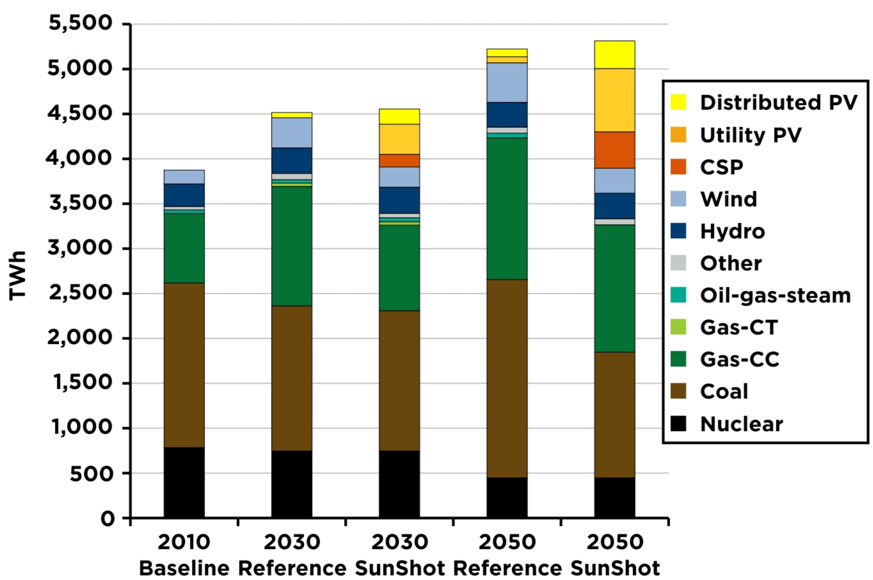


Figure 3-3 shows the avoided use of coal and natural gas fuel in the SunShot scenario relative to the reference scenario. Solar generation displaces about 2.6 quadrillion British thermal units (Quads) of natural gas and 0.4 Quads of coal per year by 2030. In 2050, solar generation displaces the use of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

3

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

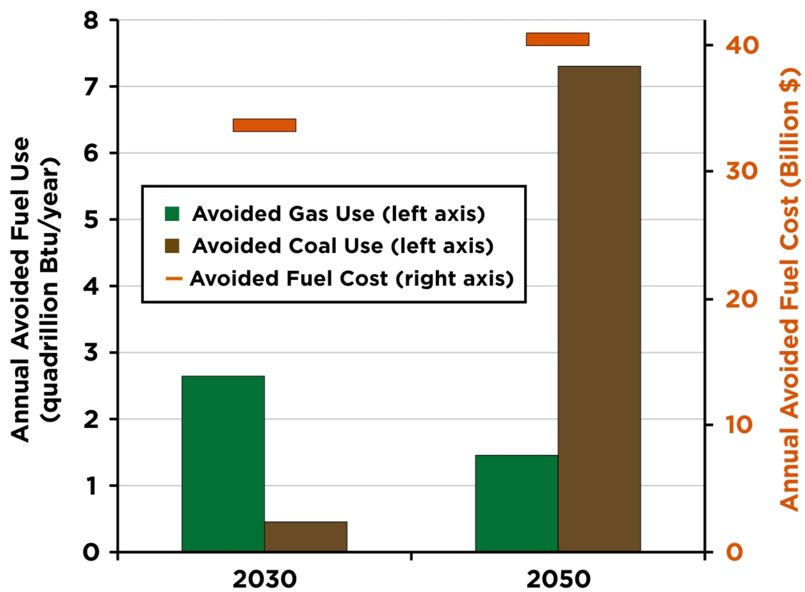
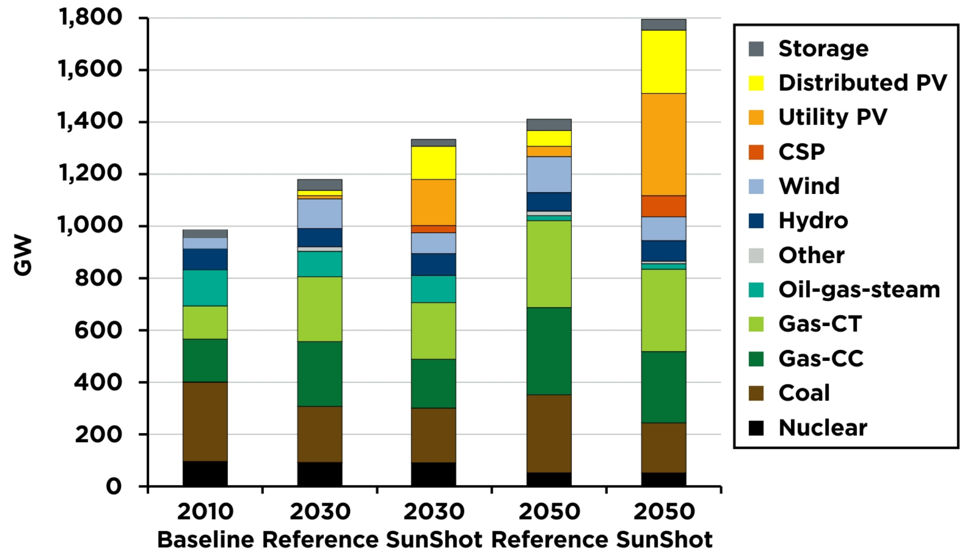


Figure 3-4. Evolution of Electricity-Generation Capacity in the SunShot and Reference Scenarios ("Other" Includes Biomass and Geothermal Technologies)



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.

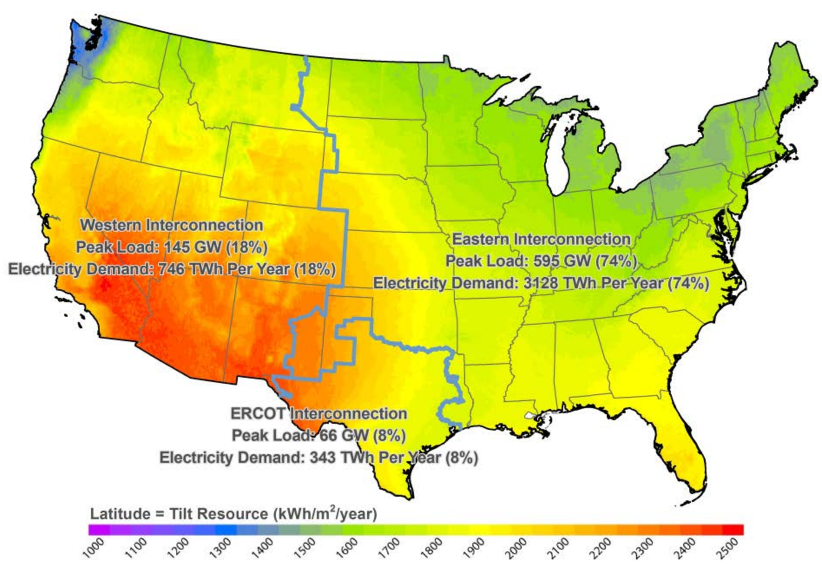
[22] Storage technologies in ReEDS include pumped-hydropower, compressed-air energy storage (CAES), and batteries. Storage technologies in ReEDS are discussed in Appendix A, along with cost and performance assumptions.
[23] Curtailments of variable renewable generation are calculated statistically in 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

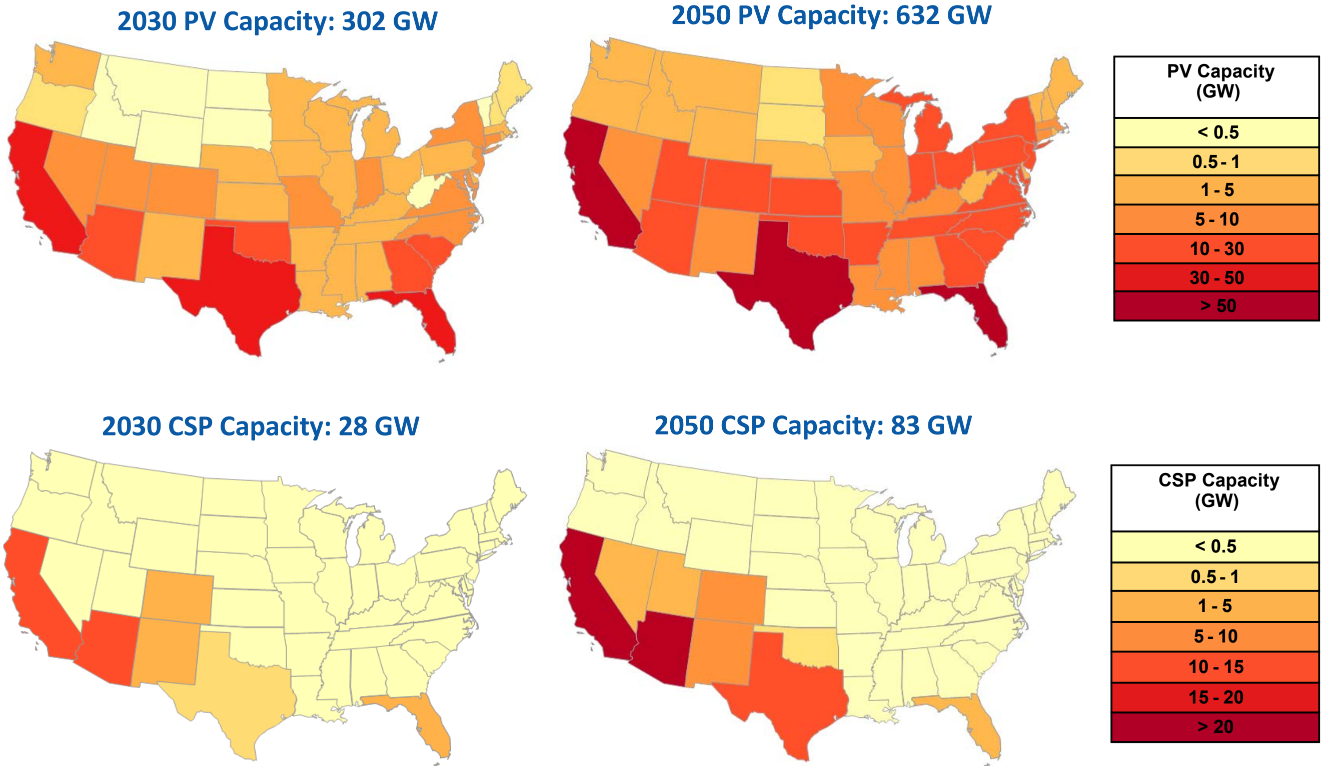
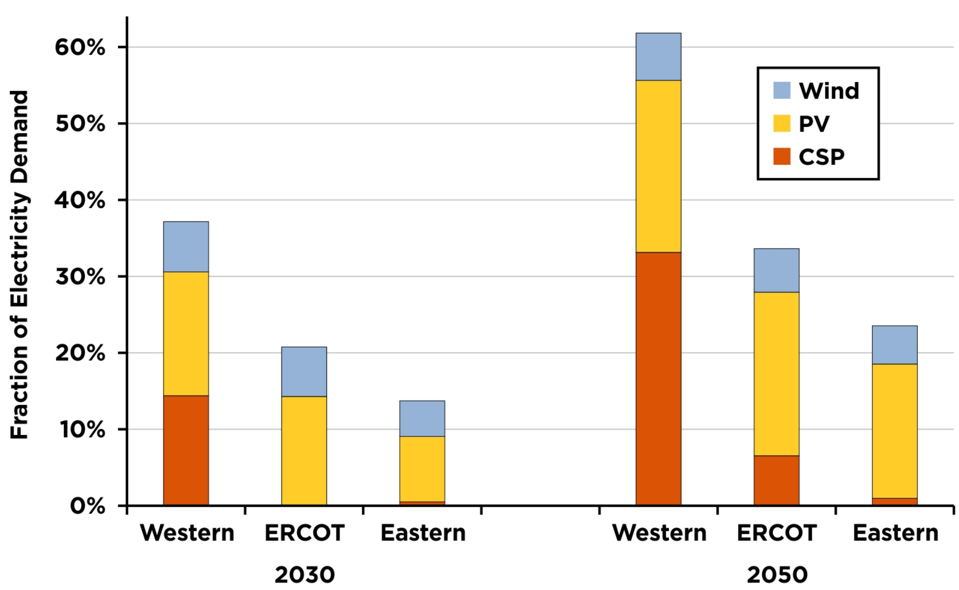


Figure 3-7. Fractions of Electricity Demand Met by CSP, PV, and Wind in Each Interconnection for the SunShot Scenario



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

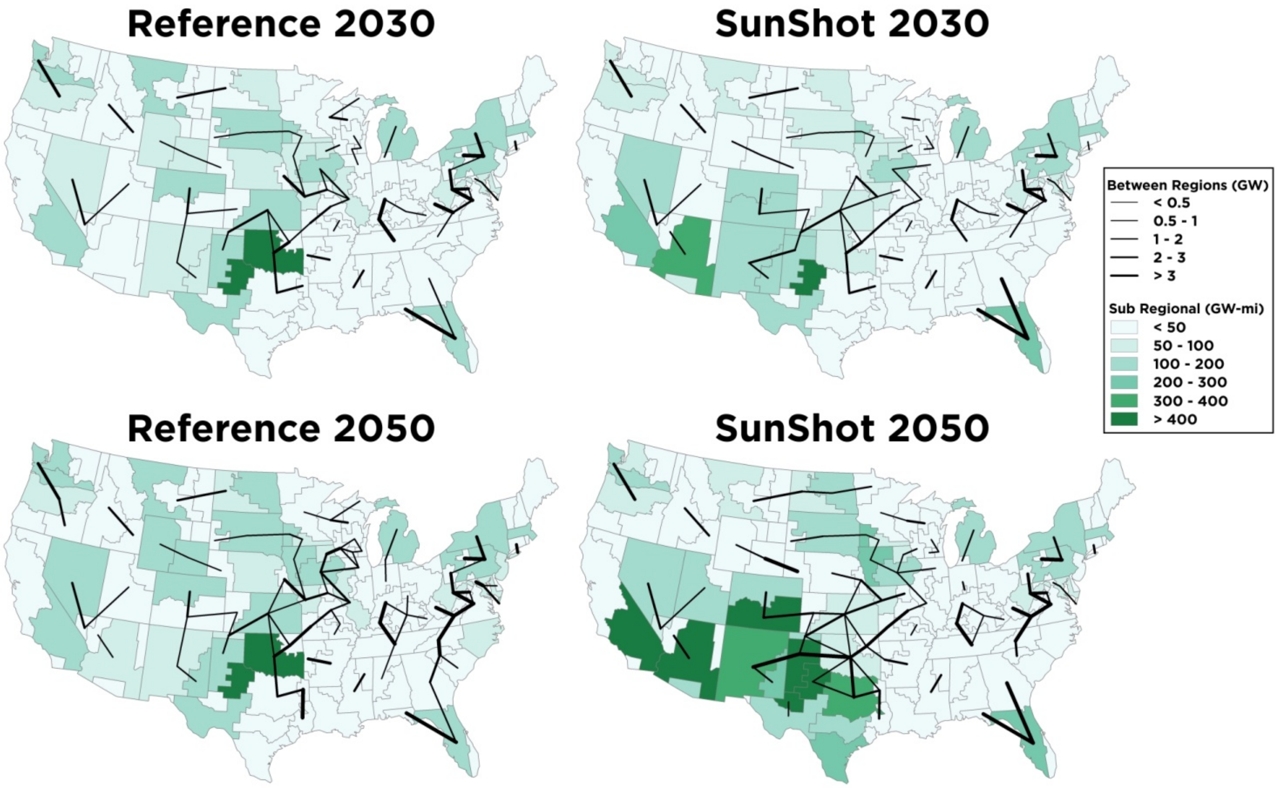
U.S. transmission resources are projected to increase in both the reference and SunShot scenarios. In the reference scenario, growing electricity demand met primarily by new conventional and wind resources necessitates expanded transmission. In the SunShot scenario, transmission is similarly expanded 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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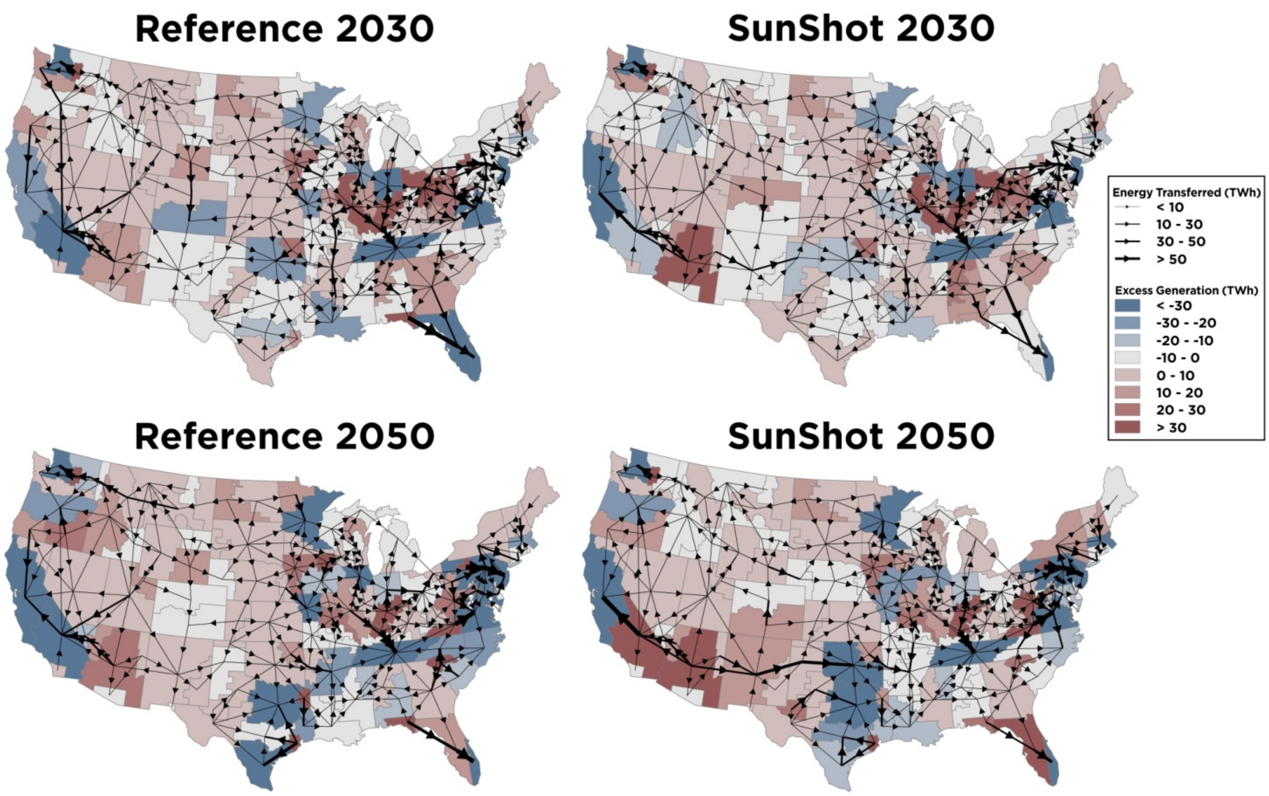
[30] As existing electricity generation capacity is retired during the study period, some transmission capacity resources become underutilized, representing an opportunity for developing solar resources to take advantage of excess transmission capacity.

[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.

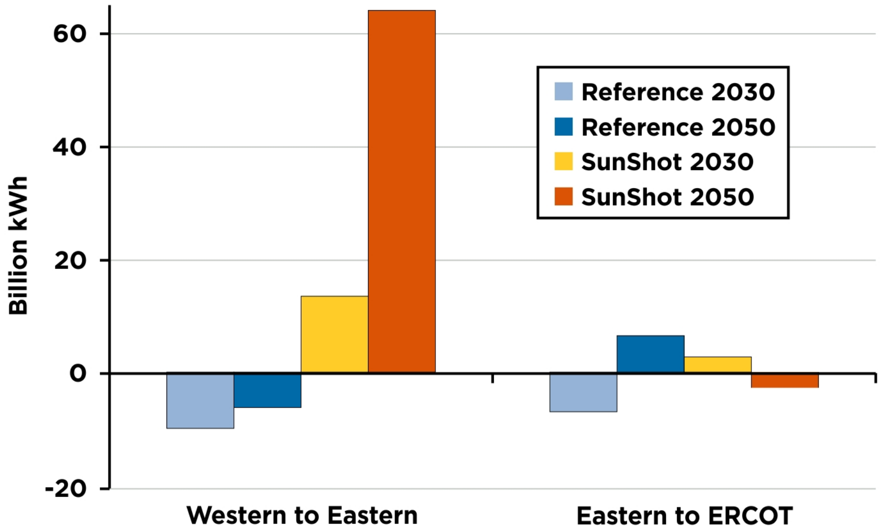
Figure 3-9. Mean Transmitted Energy Showing Net Exporting (Red) and Net Importing (Blue) Regions and Interregional Energy Transmission (Arrows)



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

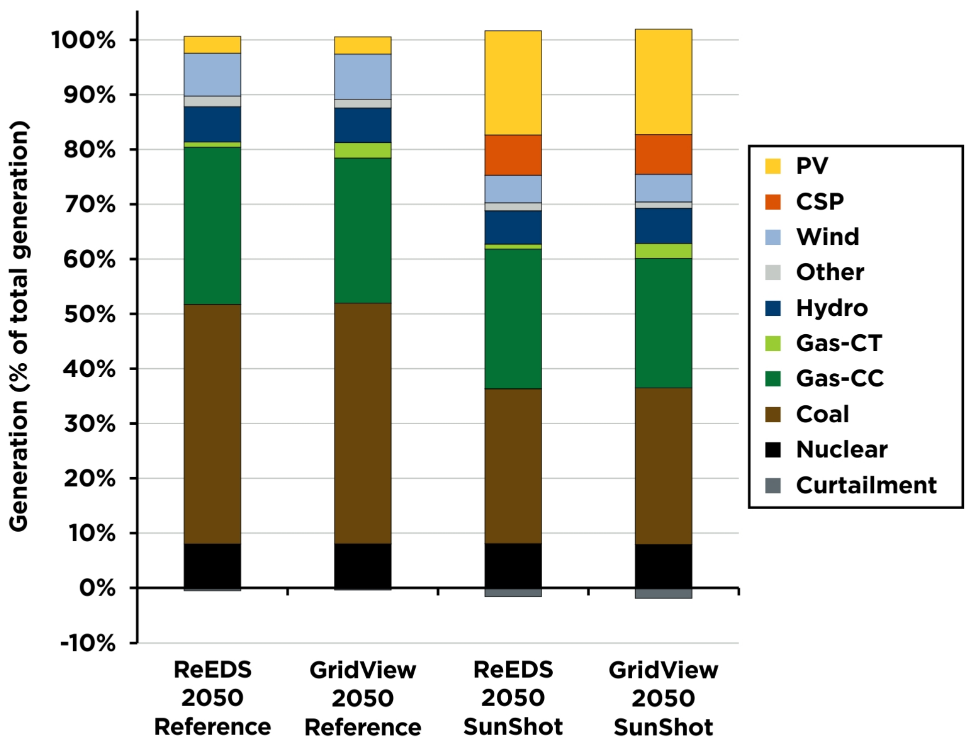
The ReEDS model, used to develop and evaluate the SunShot scenario, uses a reduced-form dispatch and transmission model that cannot completely capture many of the integration and transmission challenges explored in the SunShot scenario. GridView[33] was used to check the basic operability of the SunShot 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

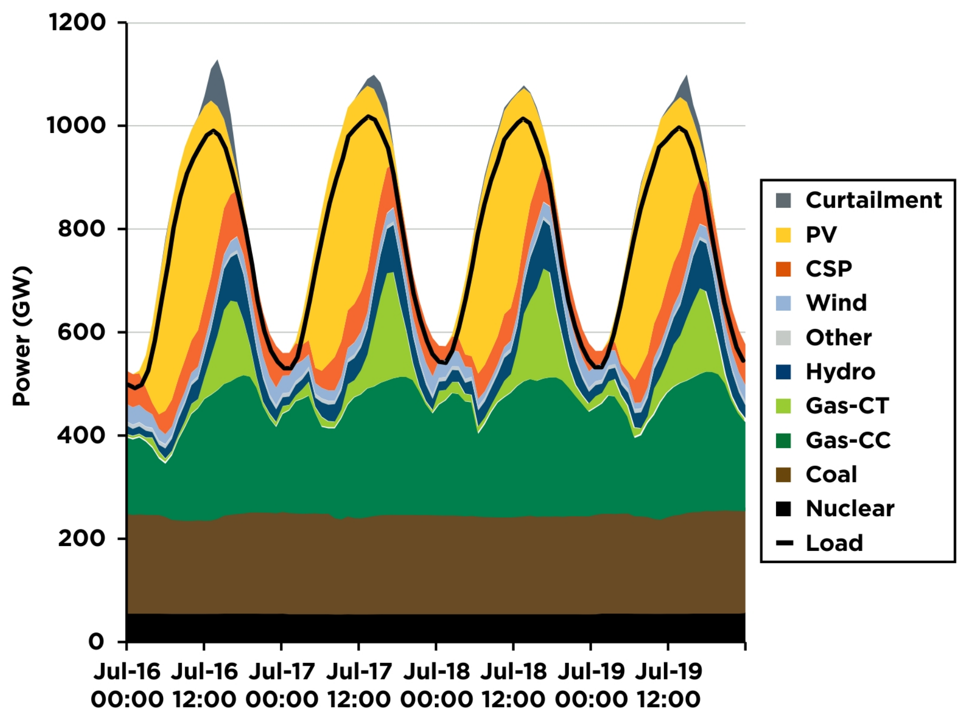


The hourly GridView modeling shows that the SunShot scenario introduces operational challenges and that some solar energy is curtailed, particularly during periods of peak solar output and low demand. The GridView simulation of the SunShot scenario shows 90 TWh of curtailment in 2050, representing 1.8% 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

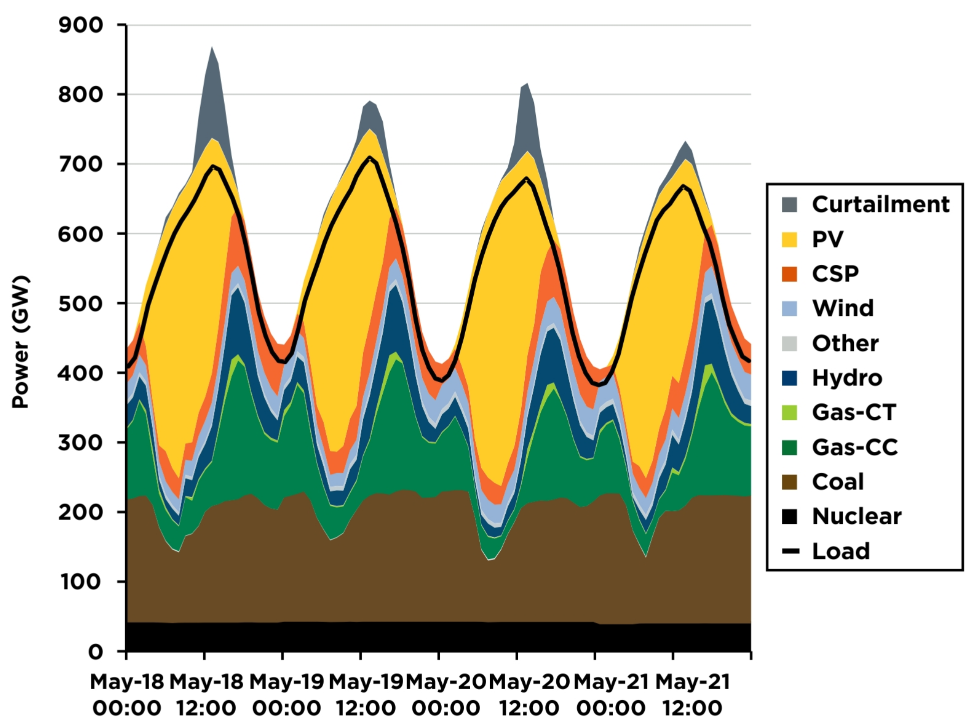
Figure 3-12. GridView-Simulated National Mean Dispatch Stack During 4 Days in Summer for the SunShot Scenario in 2050



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.

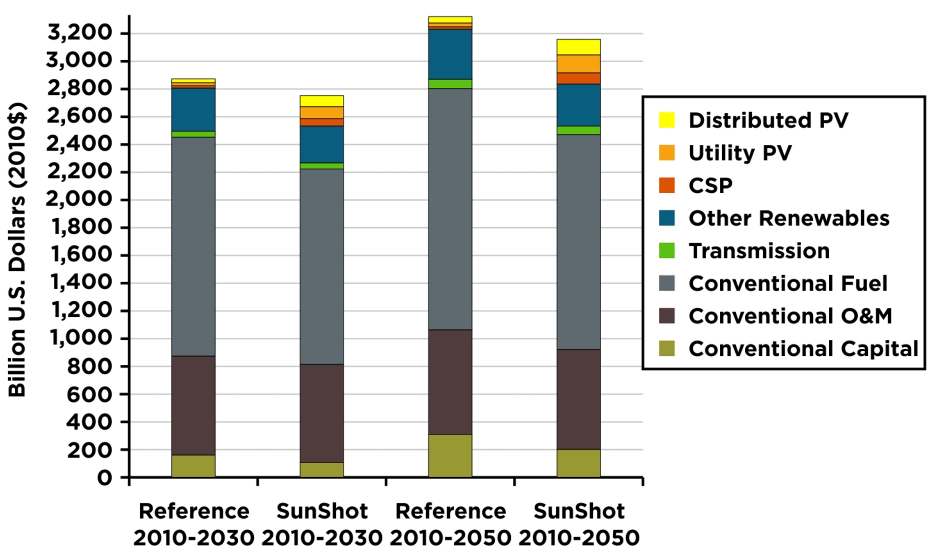
3.3 COSTS AND BENEFITS

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



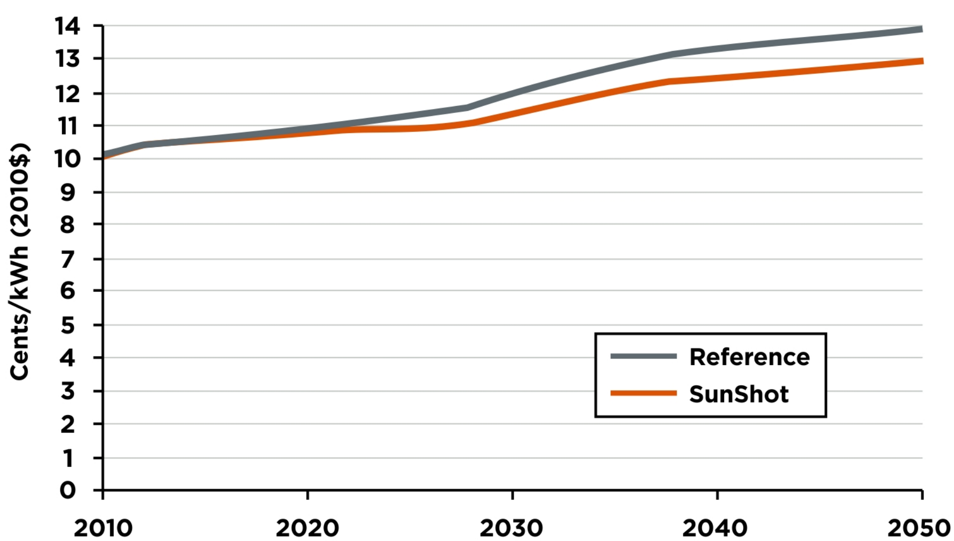
[35] See Chapter 8 for a detailed discussion of electric-sector costs and discounting.

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



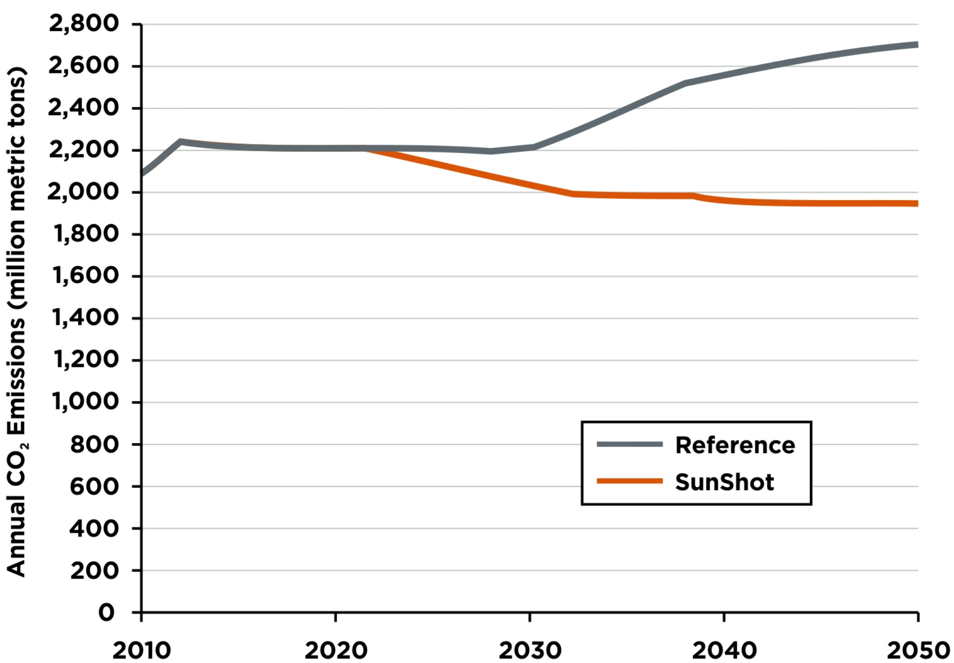
[36] Assuming average household electricity use of about 12,000 kilowatt-hours (kWh) per year, calculated using energy use and household growth statistics from *AEO 2010* (EIA 2010).

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



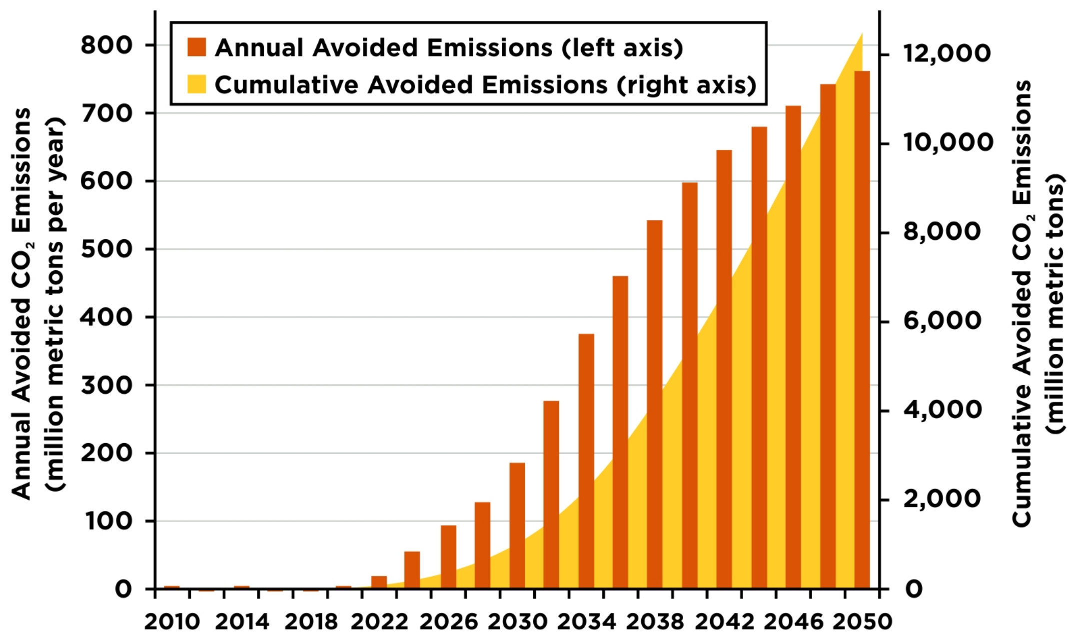
By 2050, CO_2 emissions in the reference scenario increase 29% beyond 2010 levels, due in large part to the expansion of new coal capacity and generation between 2030

[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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4. Photovoltaics: Technologies, Cost, and Performance

4.1 Introduction

Photovoltaic (PV) technologies currently supply only a small fraction of U.S. energy needs, largely because PV-generated electricity historically has cost more than electricity from conventional sources. Achieving the SunShot Initiative's PV cost-reduction targets—reducing the price of PV systems by about 75% by 2020—is projected to make PV competitive with conventional sources on a levelized cost of energy (LCOE) basis. Achieving this electricity price parity is projected to result in large-scale U.S. deployment of PV technologies, which would meet 11% of contiguous U.S. electricity demand in 2030 and 19% in 2050 (see Chapter 3 for detailed analysis of the SunShot scenario).

Over the past several decades, PV manufacturing costs and sales prices have dropped dramatically while experience accumulated by solar manufacturers and developers, utilities, and regulatory bodies has shortened the time and expense required to install a fully operating PV system. These gains have come partly through research, development, and demonstration (RD&D) and partly through market stimulation. Best-in-class installed PV prices in late 2010 were about $3/watt (W)[41] for utility-scale systems, with an average of about $3.80/W (Goodrich et al. 2010), and prices continue to decline following the global trend of continuous price and performance improvements.

Bringing PV prices down even further and more rapidly, to the SunShot levels, will require a combination of evolutionary and revolutionary technological improvements, in conjunction with, and in support of, substantial market and manufacturing scale-up. Concerted RD&D efforts are needed to create breakthrough technologies and processes that drastically reduce PV module, power electronics, and balance-of-systems (BOS) costs. This will also include a close collaboration with the private sector to ensure that new PV technologies are deployed commercially and installed in a cost-effective manner.

This chapter evaluates the current price and performance of PV technologies. Price projections representing incremental/evolutionary technological improvements are compared with the SunShot price projections. This analysis indicates that achieving the SunShot price-reduction targets will require going beyond evolutionary changes

[41] Note: all "$/W" units refer to 2010 U.S. dollars per peak watt-direct current (DC), unless specified.

to PV technologies; revolutionary steps forward are needed to achieve the SunShot targets.

The availability of key PV materials and the required scale-up of PV manufacturing capacity are also evaluated. Increased production and improved utilization of PV materials should enable the PV growth projected under the SunShot scenario. Rapid PV manufacturing capacity scale-up is possible and should not constrain SunShot levels of PV growth.

4.2 Today's PV Technology

Current PV technology is the result of decades of performance and price improvements. This section describes the components that make up a PV system, the types of PV module technologies, and the history and current status of PV prices and performance.

4.2.1 Components of a PV System

For the purpose of characterizing costs, PV systems can be classified into three subsystems: PV modules, power electronics, and BOS.

PV modules are made up of interconnected PV cells that convert sunlight directly into electricity. PV cells are fabricated from semiconductor materials that enable photons from sunlight to "knock" electrons out of a molecular lattice, leaving a freed electron and "hole" pair that diffuse in an electric field to separate contacts, generating direct-current (DC) electricity. This "photoelectric effect" has most commonly been generated with materials such as crystalline silicon (c-Si) and a range of thin-film semiconductors, which are described in the next subsection (Luque and Hegedus 2003).

The great majority of electrical applications require alternating-current (AC) electricity. For these applications, power electronics are required to convert and condition the DC electricity generated by the PV module into AC electricity suitable for customer use or transmission; most importantly, an inverter converts DC to AC, and a transformer steps the electricity up to the appropriate voltage. BOS comprises the remaining components and procedures required to produce a complete PV system, including mounting and wiring hardware, land, installation, and permitting fees.

4.2.2 PV Module Technologies

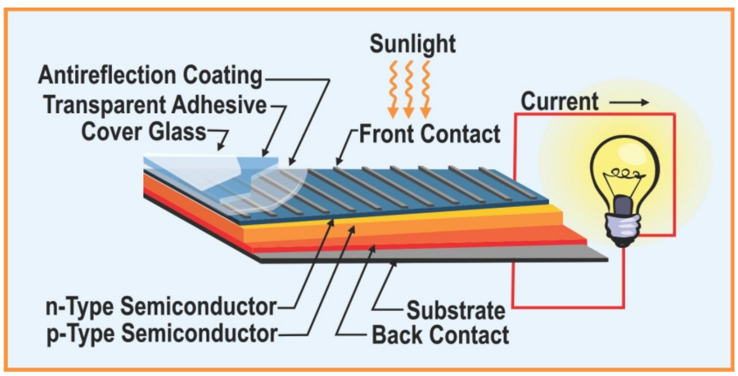
Several c-Si and thin-film PV technologies have been demonstrated commercially on a large scale. In addition, several emerging PV technologies may be technically and economically competitive in the future. This subsection briefly describes these types of PV module technologies. Efficiency is one important characteristic described in this subsection. The efficiency of a solar cell or module is the percentage of the sun's energy striking the cell or module that is converted into electricity.

Crystalline Silicon

Crystalline silicon technologies constitute about 85% of the current PV market (Mints 2011). This technology has a long history of reliable performance; c-Si modules have demonstrated operational lifetimes of more than 25 years (Jordan and Kurtz 2011).

There are two general types of crystalline, or wafer-based, silicon PV: monocrystalline and multicrystalline. Monocrystalline semiconductor wafers are cut from single-crystal silicon ingots. Multicrystalline semiconductor wafers are cut from directionally solidified blocks or grown in thin sheets. Monocrystalline ingots are more difficult, energy intensive, and expensive to grow than simple blocks of multicrystalline silicon. However, monocrystalline silicon produces higher-efficiency cells. For both types, the silicon is processed to create an internal electric field, and positive and negative electrical connections are added to wafers to form a cell (Figure 4-1). Standard cell processes are used to complete the circuit for both mono- and multicrystalline cells, and multiple cells are linked and encapsulated to form modules.

Figure 4-1. Basic Components of a c-Si PV Cell



Source: NREL

The rated DC efficiencies of standard c-Si PV modules are about 14%–16%. A number of new or non-standard cell architectures—such as back-contact cells—are growing in importance because they offer the potential for significantly higher efficiency. Non-standard cell architectures tend to use high-quality monocrystalline wafers and more sophisticated processing to achieve module efficiencies of about 17%–21%.

Thin Film

Thin-film PV cells consist of a semiconductor layer a few microns (µm) thick, which is about 100 times thinner than current c-Si cells. Most thin films are direct bandgap semiconductors, which means they are able to absorb the energy contained in sunlight with a much thinner layer than indirect bandgap semiconductors such as traditional c-Si PV. The most common thin-film semiconductor materials are cadmium telluride (CdTe), amorphous silicon (a-Si), and alloys of copper indium gallium diselenide (CIGS). The semiconductor layer is typically deposited on a substrate or superstrate inside a vacuum chamber. A number of companies are pursuing lower-cost, non-vacuum approaches for manufacturing thin-film technologies. Glass is a common substrate/superstrate, but thin films can also be deposited on flexible substrates/superstrates such as metal, which allows for the potential for flexible lightweight solar modules. Thin films are very sensitive to water vapor and thus have traditionally been encapsulated behind glass to maintain performance. Eliminating the need for glass through the use of "ultra barrier" flexible glass replacement materials is an important next step in thin film development.

Thin-film modules have lower DC efficiencies than c-Si modules: about 9%–12% for CdTe, 6%–9% for a-Si, and 8%–14% for CIGS. CdTe-based PV has experienced significantly higher market growth during the last decade than the other thin-film PV technologies primarily due to the success of First Solar, which utilizes CdTe technology.

Concentrating PV

Concentrating photovoltaics (CPV) technologies use mirrors or lenses to concentrate sunlight 2–1,200 times onto high-efficiency silicon or multijunction (MJ) PV cells. CPV uses concentrating optics made out of inexpensive materials such as glass, steel, and plastic to focus sunlight onto a relatively small semiconductor area. This approach offers several significant benefits. First, it minimizes the amount of active semiconductor material (the material that converts sunlight into electricity) needed to produce a given amount of electricity. On an area basis, the active semiconductor material is the most complex and expensive component of many PV modules; this is particularly true for MJ cells. MJ cells are capable of much higher efficiencies than single junction silicon or thin-film cells. This is because each junction of a MJ cell is designed to collect a different part of the solar spectrum: MJ cells are typically a stack of three different cells on top of one another. This higher efficiency comes at an increase in manufacturing cost, and thus MJ devices are too expensive to use in terrestrial applications without concentration. The downside to CPV, especially for higher concentration levels, is that, in order to maintain the concentration of sunlight on the cell, the module must accurately track the sun throughout the day. Tracking results in a more complex and expensive installation. Recent improvements to MJ PV cells have produced cell efficiencies of 43.5% in the laboratory. Use of CPV systems for utility-scale electricity generation has been growing.

Emerging PV Options

A number of other PV technologies—frequently referred to as third-generation PV—are being developed. Dye-sensitized solar cells use dye molecules absorbed onto a nanostructured substrate and immersed in a liquid or gel electrolyte to absorb solar radiation and have demonstrated laboratory efficiencies as high as 11.1%. Organic PV (OPV) solar cells, based on polymers or small molecules with semiconductor properties, have demonstrated laboratory cell efficiencies above 8%; organic modules have the potential for low-cost manufacturing using existing printing and lamination technologies (Shaheen et al. 2005). Quantum dots—nanospheres with physical properties similar to both bulk semiconductors and discrete molecules—have the potential to achieve higher efficiencies through multiple exciton generation, but they have not yet been used to produce efficient PV cells.

There are significant challenges to the commercialization of solution-processed organic solar cells, dye-sensitized cells with certain electrolytes, and quantum dots due to the stability of the materials against oxygen and water ingress. This limits the lifetime of these devices to anywhere from a few hundred hours to 2 years. This issue is being addressed through efforts to develop improved, yet cost-effective, encapsulants. In addition, organic and dye-sensitized solar cells use dyes that have been shown to degrade when put in direct sunlight for long periods of time, a significant issue to have in a solar cell. Further research and development (R&D) is needed to improve the viability of these materials.

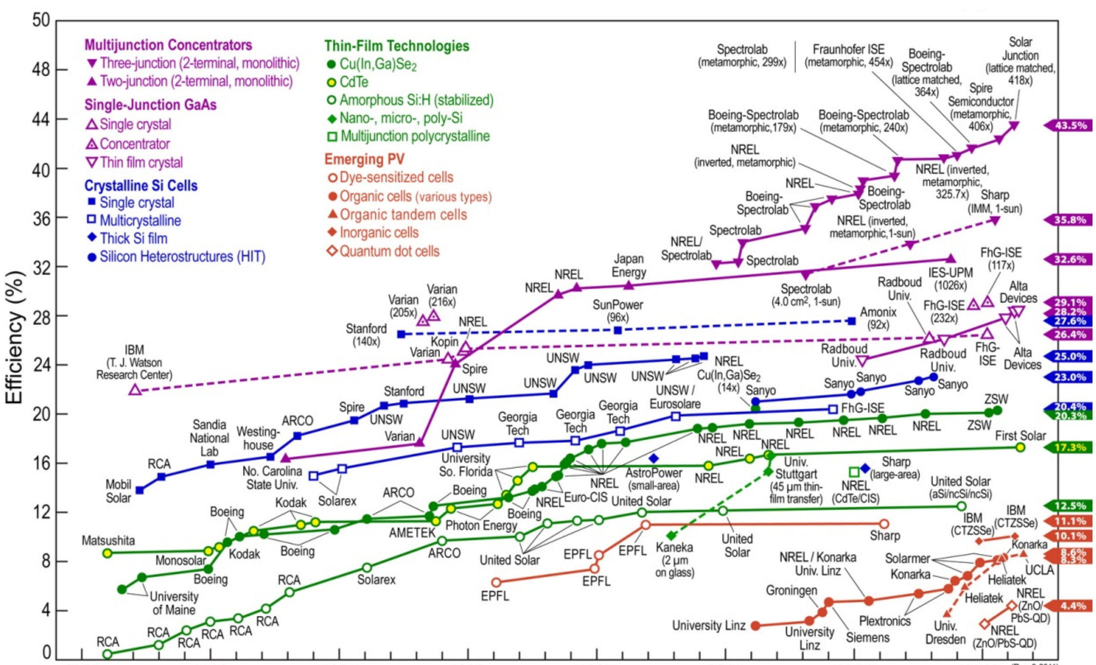
4.2.3 PV Performance and Price

The performance of PV technologies has improved substantially, while PV manufacturing costs have declined during the past several decades due to a combination of technological innovation, improved manufacturing processes, and growing PV markets. All of these factors have contributed to a downward trend in PV prices.

PV Efficiency

Figure 4-2 shows the increase in laboratory best-cell efficiencies by PV technology over the past few decades. These are laboratory prototype cells, developed through successful R&D. A number of challenges—such as simplifying or modifying cell properties to improve manufacturability and economics—must be overcome before laboratory cell innovations lead to improvements in commercial products. Some cell

Figure 4-2. Laboratory Best-Cell Efficiencies for Various PV Technologies



Source: NREL (2011)

efficiency improvements are simply too expensive to implement at the commercial scale. Further challenges are encountered as small cells are linked together (e.g., c-Si or flexible thin film on metal substrate) or made in much larger areas (e.g., thin films) and then encapsulated to form commercial modules. Commercial module efficiencies typically track best-cell efficiency improvements, with a time and performance lag.

PV Module Prices

Photovoltaic modules have followed a well-documented historical trend of price decline. Since 1976, global module prices declined about 20% on average for every doubling of cumulative global production, resulting in a price decline of roughly 95%—from about \$60/W to about \$2/W—between 1976 and 2010 (Figure 4-3).

Historic PV module prices stem from a long-term trend of continued technology and manufacturing improvements, along with shorter-term trends driven by supply and demand dynamics. As the industry has matured over the long term, factories have increased in scale and efficiency. During 1980–2001, cost reductions related to increasing plant size, often called economies of scale, had the single greatest impact of any factor on PV module prices (Nemet 2006). As the annual production capacity of manufacturers grew from hundreds of kilowatts (kW) to hundreds of megawatts (MW), economies of scale were realized in purchasing raw materials and equipment. Companies also adopted leaner process control techniques found in more mature, analogous sectors such as semiconductors.

As an example of shorter-term price variations, PV module prices rose from 2005–2008, reflecting both a supply-constrained market and high polysilicon feedstock prices. The resulting high market prices led to a global expansion of polysilicon feedstock supplies, which increased PV manufacturing capacity. These market forces brought module prices back to the long-term trend line by 2010 (Figure 4-3).

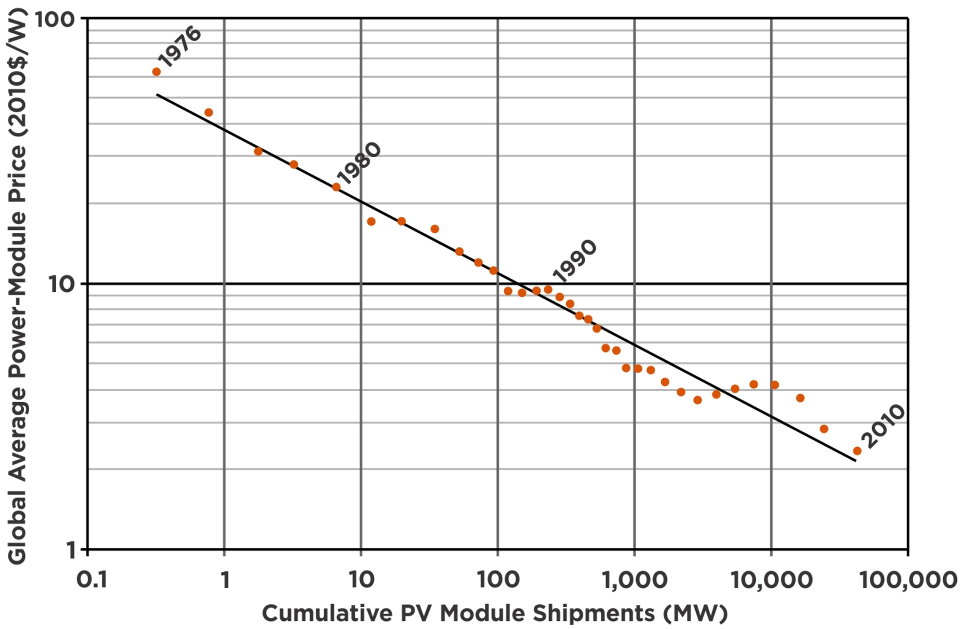
Module production costs vary by technology and manufacturer. For example, cost leaders for mono- and multicrystalline silicon modules have cited costs as low as \$1.10/W (Trina Solar 2010), but this manufacturing cost is not representative of all manufacturing processes, products, and financial assumptions. Typical module prices in 2010 ranged from about \$1.5–\$2/W (Mints 2011).

PV modules achieved significant price and performance improvements in 2011, relative to the benchmarked 2010 numbers in Figure 4-3. PV module prices trended toward \$1.5/W for several technologies in the first half of 2011 (First Solar 2011a, UBS 2011). Also, both thin-film and c-Si PV technologies achieved modest efficiency gains (First Solar 2011a, SunPower 2011).

PV System Prices

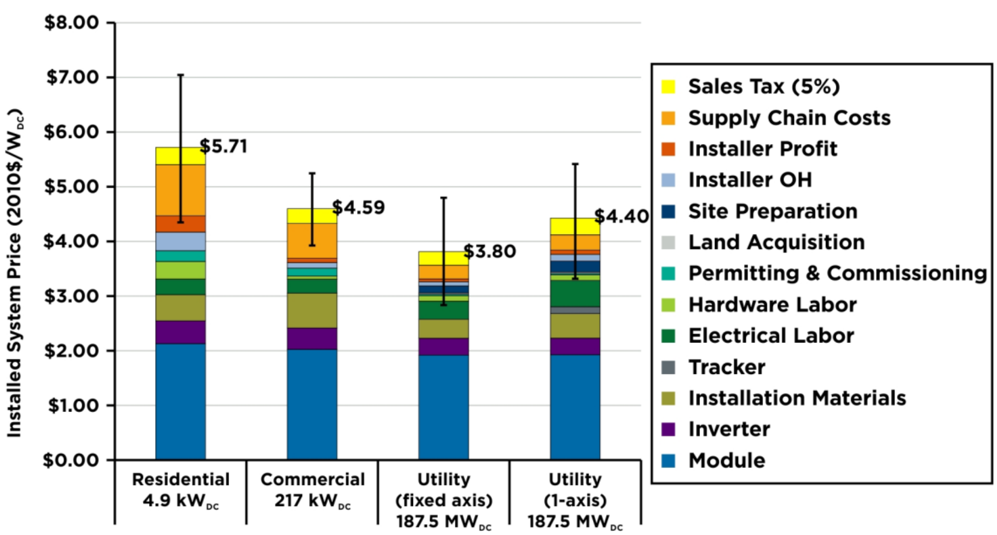
Installed PV system prices include the price of the module and power electronics and the BOS costs. Figure 4-4 shows benchmarked installed PV system prices in 2010, assuming typical monocrystalline silicon PV module prices and efficiencies for each of the key PV market segments: residential, commercial, and utility-scale installations. Residential systems have the highest installed system prices, at roughly \$6/W in 2010. This is because of their small size (typically 3–5 kW), fragmented

Figure 4-3. Decline in Factory-Gate PV Module Prices with Increasing Cumulative Module Shipments



Sources: Mints (2011), Mints (2006), Strategies Unlimited (2003)

Figure 4-4. Benchmarked 2010 Installed PV System Prices with Uncertainty Ranges for Multiple Sectors and System Configurations with Three Standard Deviation Confidence Intervals Based on Monte Carlo Analysis[42]



Source: Goodrich et al. (2012)

[42] For all market segments, the uncertainty analysis considers a range of module assumptions based on c-Si technologies (standard c-Si up to super monocrystalline-based products), including market-appropriate module sizes. In the case of "utility fixed axis" only, modules based on cadmium telluride were also considered.

distribution channels, and high customer acquisition and installation costs. Residential PV modules typically pass through multiple distributors between the factory gate and local installers, each of which adds a price markup.

Commercial systems, such as those on the flat roofs of big-box retail stores, can be tens of kilowatts to multiple megawatts in size. Even though they are much larger than residential systems, they are not typically large enough to attain all economies of scale in purchasing components and installation labor. As shown in Figure 4-4, the installed price of a commercial system in 2010 was roughly $5/W, about 20% lower than for a residential system. While commercial systems typically cost more than utility-scale systems, a growing number of commercial systems are being developed by third-party installers using power purchase agreements (PPAs). These third-party installers are frequently able to achieve significant economies of scale in component purchasing and can finance, permit, and build commercial projects more quickly than larger utility projects.

Utility-scale PV systems typically have the lowest installed price: roughly $4/W in 2010. These systems are large enough to realize significant economies of scale in component purchasing and installation labor, significantly reducing installed system prices. Many module manufacturers act as the engineering, procurement, and construction (EPC) firm for large-scale utility installations, achieving an improvement in supply chain costs over traditional third-party installers.

4.2.4 LEVELIZED COST OF ENERGY

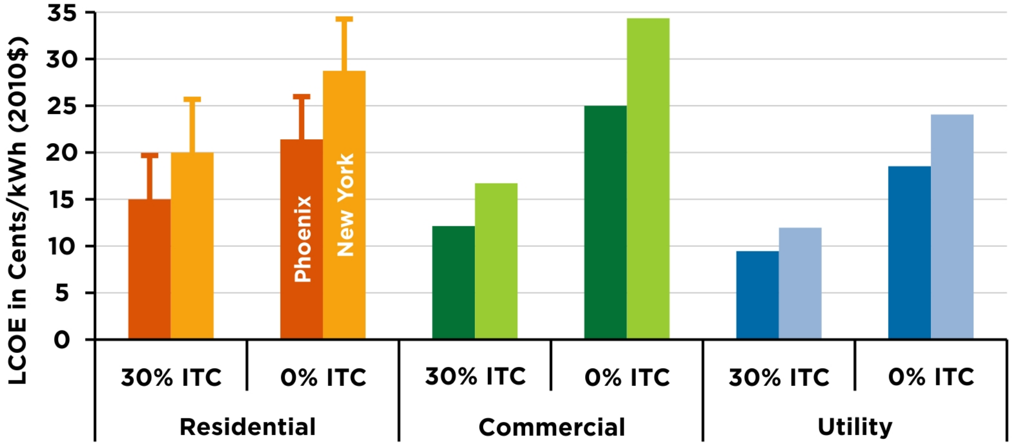
LCOE is the ratio of an electricity-generation system's costs—installed cost plus lifetime operation and maintenance (O&M) costs—to the electricity generated by the system over its operational lifetime, given in units of cents/kilowatt-hour (kWh). The calculation of LCOE is highly sensitive to installed system cost, O&M costs, local solar resource and climate, PV panel orientation, financing terms, system lifetime, taxation, and policy. Thus, PV LCOE estimates vary widely depending on the assumptions made when assigning values to these variables.

Figure 4-5 shows the LCOE for residential, commercial, and utility-scale (1-axis tracking) PV systems as benchmarked above, i.e., priced at roughly $6/W, $5/W, and $4/W, respectively. Because local solar resource is such an important factor, LCOE is calculated in two locations: Phoenix and New York City. Figure 4-5 shows the LCOEs both with and without the 30% federal investment tax credit (ITC). With the ITC, LCOE ranges from $0.15–$0.20/kWh for residential systems, $0.12–$0.17/kWh for commercial systems, and $0.9–$0.12/kWh for utility systems. Without the ITC, LCOE ranges from $0.22–$0.28/kWh for residential systems, $0.25–$0.34/kWh for commercial systems, and $0.18–$0.24/kWh for utility-scale systems.

The LCOEs in Figure 4-5 were calculated using monocrystalline silicon PV performance characteristics[43] and the standard financing assumptions provided in Table 8-1 in Chapter 8. Residential systems are assumed to be fixed tilt and south facing, commercial systems are assumed to be a mix of flat mount and fixed tilt, and

[43] Several PV performance characteristics, such as the temperature sensitivity of cell efficiency, vary across technologies. These differences lead to annual output changes that can affect annualized LCOEs.

Figure 4-5. LCOE for PV Systems in Phoenix (left bars) and New York City (right bars) in 2010, with and without the Federal Investment Tax Credit



Note: For residential systems, mortgage financing is shown on the main bars, and cash purchase is represented by the high error bars.

utility systems are assumed to use 1-axis tracking. Residential and commercial systems are assumed to be owned by the site host, and utility systems are assumed to be owned by an independent power producer (IPP) or investor-owned utility (IOU) that pays taxes on electricity revenues. Even though the installed price of commercial systems is lower than the price of residential systems, the LCOEs are comparable due to multiple factors including higher cost of capital for commercial systems, different performance characteristics, and different tax impacts. Table 4-1 lists other important assumptions used in the LCOE calculations.

4.3 Overview of Strategies for Reducing PV System Prices

The SunShot targets require that the following installed PV system price reductions be achieved by 2020, relative to benchmarked 2010 installed system prices:

- Residential system prices reduced from \$6/W to \$1.50/W
- Commercial system prices reduced from \$5/W to \$1.25/W
- Utility-scale system prices reduced from \$4/W to \$1.00/W.

Figure 4-6 shows the SunShot targets broken out by subsystem prices. The per-watt price of a PV system is directly proportional to the total installed system price and inversely proportional to the system efficiency:

$$\frac{\$}{\mathrm{W}} \propto \frac{\text{Total installed system price (\$)}}{\text{System efficiency (\%)}}$$

4

Table 4-1. Assumptions for LCOE Calculations

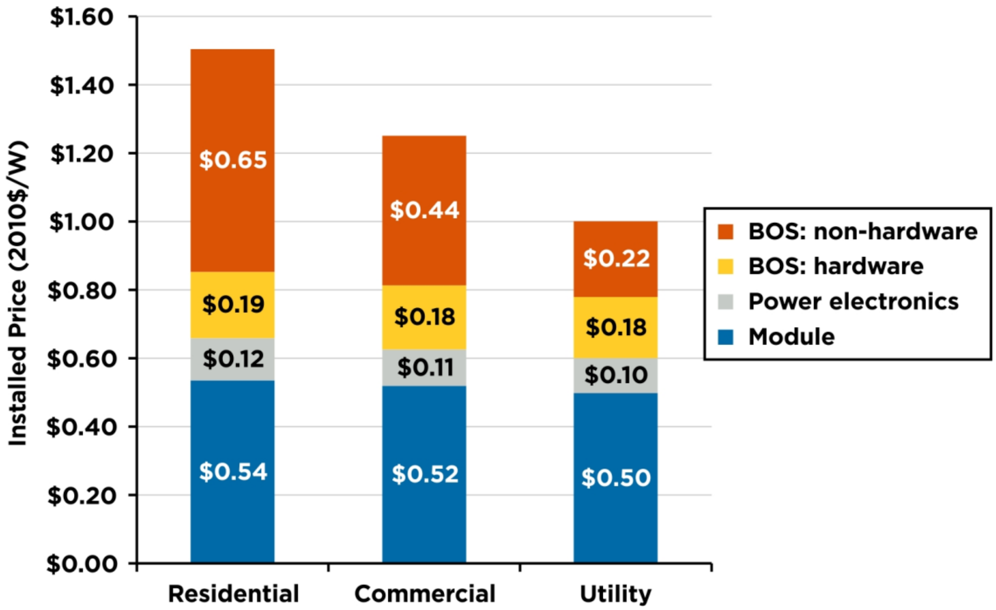
PV Performance and O&M Costs (2010$)	Residential		Commercial		Utility	
	2010 Actual	SunShot Proj.	2010 Actual	SunShot Proj.	2010 Actual	SunShot Proj.
System Lifetime (Years)	30	30	30	30	30	30
Annual Degradation (%)	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Inverter Replacement Price ($/W, at time of replacement)	$0.25	$0.12	$0.20	$0.11	$0.17	$0.10
Inverter Replacement Labor[a] ($/inverter, at time of replacement)	$600	$600	$3,000	$3,000	$1,000	$1,000
Inverter Lifetime (Years)	10	20	15	20	15	20
O&M Expenses ($/kW-yr)	$32.8	$10.0	$23.5[d]	$7.5	19.93[e]	$6.5
Pre-Inverter Derate[b] (%)	90.0%	93.0%	90.5%	93.5%	90.5%	93.5%
Inverter Efficiency[c] (%)	94.0%	97.0%	95.0%	98.0%	96.0%	98.0%
System Size (kW-DC)	5.0	7.5	200	300	20,000	30,000

[a] Residential and commercial values for inverter replacement labor costs are based on a 2009 estimate from Standard Solar. Estimates of residential and commercial values for inverter replacement labor costs are also provided by Standard Solar. The utility value is discounted from commercial inverter replacement labor costs due to ground, rather than rooftop, location.
[b] Includes losses in wiring, soiling, connections, and system mismatch.
[c] 2010 inverter efficiencies for residential, commercial, and utility systems are based on data from the California Energy Commission, available at www.gosolarcalifornia.org/equipment/inverters.php.
[d] Based on LBNL (Lawrence Berkeley National Laboratory) (2009). Internal survey of commercial rooftop O&M costs.
[e] Based on average O&M costs at Arizona Public Service's 1-axis tracking PV installations, available at www.resourcesaver.org/ewebeditpro/items/O63F5452.pdf.

Thus, the per-watt PV system price can be reduced by reducing the total installed system price or increasing system efficiency. The total installed system price can be reduced by reducing the price of one or more of the three PV subsystems: PV modules, power electronics, and BOS. System efficiency can be increased by increasing the sunlight-to-electricity efficiency of the PV modules and/or increasing the electrical efficiency of the integrated PV system (including power electronics and wiring losses).

Total installed system price and efficiency are interrelated. For example, high-efficiency PV modules might cost more than lower-efficiency PV modules on a per-watt basis. However, their higher efficiency might reduce non-module costs, e.g., per-watt power electronics and BOS prices could be lower because the amount of

Figure 4-6. Estimated Subsystem Prices Needed to Achieve 2020 SunShot Targets



equipment, labor, and land required per watt of installed capacity is lower with higher-efficiency modules. It is important to consider these tradeoffs and to understand that there are a number of potential PV system pathways (e.g., low-cost, low-efficiency modules versus higher-cost, high-efficiency modules) for reducing total installed PV system prices. The following sections explore the methods for reducing total installed system price and increasing system efficiency via improvements to PV modules, power electronics, and BOS.

4.4 Reducing PV Module Prices

As Figure 4-4 shows, benchmark 2010 PV module prices were about $2.00/W. As Figure 4-6 shows, the SunShot targets for PV module prices are $0.50/W for utility systems, $0.52/W for commercial systems, and $0.54/W for residential systems. Module prices can be reduced by reducing module material, manufacturing, and shipping costs and by increasing module efficiency. This section explores these approaches.

4.4.1 Reducing PV Module Material, Manufacturing, and Shipping Costs

Substantial PV system price reductions have been achieved over the past several decades via reductions in material, manufacturing, and shipping costs. These approaches are discussed below, including historical improvements and potential pathways to the improvements needed to achieve the SunShot targets.

Reducing Material Costs

There are a number of ways to reduce material costs in support of the SunShot targets. The active semiconductor material is a complex and expensive component of most PV modules, accounting for about 60% of c-Si module cost and 8%–22% of CdTe and CIGS module cost (Goodrich et al. 2011a, Woodhouse et al. 2011). The cost of polysilicon for c-Si modules could be reduced by making thinner wafers, minimizing polysilicon losses during the wafering process, improving polysilicon scrap recycling capabilities and costs, and introducing low-cost polysilicon feedstock-purification methods. Replacing c-Si with thin-film and CPV technologies is potentially another way to reduce semiconductor material costs. However, although CPV and thin films use less semiconductor material per watt than c-Si, the materials used can be rare and expensive. Using these materials more efficiently or identifying substitutes that are less expensive, earth-abundant, and non-toxic or recyclable could reduce semiconductor material costs in these technologies.

It will also be important to ensure that the supply of PV feedstock materials remains sufficient to meet demand, since supply constraints can significantly increase feedstock prices. For example, when demand for polysilicon outpaced supply in 2007 and 2008, polysilicon contract prices increased from about \$50–\$60/kilogram (kg) up to \$150/kg, and spot market prices peaked above \$500/kg (Mehta 2010).

The front and back cell contacts are another important cost component in c-Si PV modules. PV manufacturers strive to design cells that balance the cost of these materials with their effect on module performance.

Module-encapsulation materials—such as front and back glass, adhesives to bind the layers and the cells, edge seals, and frames—can add considerable cost to PV modules (Mehta and Bradford 2009) and dominate the material costs of many thin-film modules. Cost reductions may be possible via depositing semiconductor material on substrates that are lighter and cheaper than glass and replacing traditional framing material and encapsulation glass with flexible ultra barrier encapsulation material. Again, manufacturers must balance the benefits of using less-expensive materials against resulting effects on module performance and reliability. Other materials to be considered are those used in edge seals, mounting hardware, cell interconnections, bus bars, and junction boxes.

Manufacturers may also be able to reduce materials costs by becoming more vertically integrated. In particular, vertical integration can help manufacturers reduce exposure to volatile market prices and improve the efficiency of handling materials.

Improving Manufacturing Processes

PV manufacturing process improvements stem from mass-production efficiency and labor-reduction strategies analogous to those of any manufacturing operation. In addition, improved manufacturing processes can minimize the cell-to-module losses that occur during the transition from laboratory-scale PV technologies to mass-produced commercial products.

Manufacturing equipment costs, which are frequently characterized in dollars per watt of annual manufacturing capacity, can be estimated from capital expenditure (CapEx) investments, which should not be confused with the per-watt module and system costs. New PV manufacturing facilities are being developed at costs from \$1–\$2/W (First Solar 2011b, Goodrich et al. 2011a, Woodhouse et al. 2011). Because equipment is depreciated over time (e.g., 7 years), the contribution of CapEx costs to module cost is about one-seventh of the per-watt CapEx costs. For example, a \$1.4/W CapEx would add approximately \$0.2/W to module costs. There are also additional costs related to the cost of capital for the manufacturer and equipment maintenance costs.

Several factors affect manufacturing cost structure, including speed, yield, labor, and energy prices. Increasing manufacturing speed results in higher throughput and lower capital costs per watt, but often comes as a result of a tradeoff in other categories, such as yield, cell efficiency, and materials costs. Speed can be enhanced by measures such as increasing deposition rates, increasing the width of an in-line reaction chamber, and building large furnaces that can process many substrates at once.

Increasing yield—the proportion of manufactured product that meets commercial specifications—is another way to increase throughput and reduce cost per watt. Crystalline silicon production lines typically operate at yields of at least 93%. However, yields can vary widely depending on the quality of the incoming material, such as wafers, and the desired minimum product quality, such as cell efficiency. Having a wide variation in cell efficiencies would create unacceptable module-stringing losses later. As polysilicon prices have dropped, the use of recycled silicon in casting operations has diminished, increasing the overall quality of materials on the market. The point in the manufacturing process at which defective parts are identified is also critical. Bad parts that are not identified until the end of a process increase costs more than those identified at the beginning or middle of the manufacturing process.

Reducing labor and energy-use requirements also reduces manufacturing costs. Labor costs frequently depend on the maturity of the manufacturing approach and local labor rates. Labor costs are expected to decline as PV matures and manufacturing plants become larger and more automated. Energy use can be reduced by implementing several strategies, including faster processing techniques, lower-temperature processes, and replacing vacuum with non-vacuum processes where possible. Past improvements of this sort have lowered the PV energy payback periods—the length of time the system must operate to match the energy used to make it—to 1–3 years, which has important policy implications. See the discussion of greenhouse gas (GHG) emissions in Chapter 7.

To reach the SunShot price targets, new technologies likely will need to be developed and brought quickly to commercial maturity. Moving technological innovations from the laboratory to commercial production quickly and efficiently will be critical. Potential manufacturing strategies for achieving the SunShot targets include increasing manufacturing throughput, using roll-to-roll thin-film module manufacturing, using high-frequency plasma deposition for thin films, and using atmospheric-pressure liquid washing. Another strategy is to reduce the cost of fabrication equipment and facilities to achieve a CapEx of \$0.7/W of annual manufacturing capacity, or lower.

Reducing Module Shipping Costs

The PV industry relies on a global supply chain. As the industry matures, the economies-of-scale advantages captured by large suppliers likely will increase the average distance that a PV product travels from manufacturer to installer. Sea-transport (container) rates are currently at historic lows, and the cost of shipping modules by sea is about \$0.05–\$0.06/W (Goodrich et al. 2011a), adding 5%–10% to module costs. As module costs decrease, shipping costs for some types of module manufacturing could become a more significant factor and may lead to disaggregated manufacturing models, with separate cell manufacturing and module assembly facilities, for example.

Many PV components—including polysilicon, wafers, and cells—can be shipped cheaply due to their low weight and volume and high value. In fact, cells can often be shipped by air to module manufacturing facilities. The glass content of both thin-film and c-Si modules adds the most to shipping costs, because glass is dense and tends to fill a shipping container based on weight rather than volume. Lower-efficiency modules have more glass per watt—and thus cost more to ship—per unit of power.

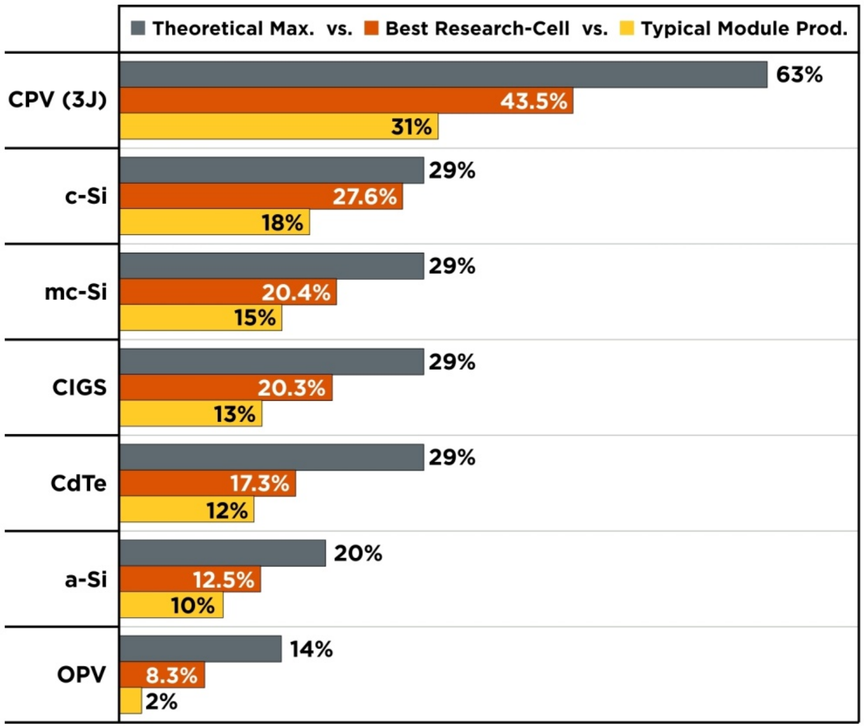
Crystalline silicon module manufacturers frequently have a disaggregated supply chain, where wafers, cells, and modules are manufactured by different companies in different locations. Thin-film manufacturers typically have an aggregated supply chain that is inherent to their device design, where there are no intermediate products. This can be an advantage for reducing c-Si shipping costs: wafer and cell manufacturing can be located in low-cost regions, and module-manufacturing facilities can be sited near end-use markets. This reduces the need to ship glass and encapsulation materials over long distances.

4.4.2 Increasing PV Module Efficiency

Increasing module efficiency is the other major strategy for reducing per-watt module price. Consistent improvements in PV cell efficiency have been realized for virtually every PV technology (Figure 4-2), and module efficiency has followed this trend, albeit with a time and performance lag. This trend is projected to continue, owing to R&D improvements that produce higher best-cell efficiencies and manufacturing technology improvements that advance commercial modules toward best-cell efficiencies. As single-junction PV technologies approach the theoretical (Shockley-Queisser) efficiency limit for their respective semiconductor materials, the extent to which further cost reduction may be attributable to efficiency gains will be reduced, and more substantial cost reductions will need to be realized via other avenues. Nevertheless, as shown in Figure 4-7, there is still significant room for efficiency improvements for many PV technologies.

Module efficiencies greater than 25% (with much of this efficiency maintained for a 30-year module lifetime) may be required to achieve the SunShot PV system price-reduction targets. Multi-year, even multi-decade, R&D programs—such as the U.S. Department of Energy (DOE) Thin Film PV Partnership, which drove several of the improvements shown in Figure 4-2—have improved the industry's understanding of PV technologies and helped develop this knowledge into commercial products. Additional R&D efforts will be required to increase laboratory PV efficiency and to

Figure 4-7. Closing the Gap: Production, Laboratory, andTheoretical (Maximum) PV Module Efficiencies



Source: NREL

transition high-efficiency laboratory technologies to large-scale commercial production.

R&D must support the many stages leading to commercialization: proof of concept, prototype development, product and process development, demonstration-system deployment, and commercialization/scale-up. A substantial base of scientific knowledge exists for c-Si PV technologies, largely owing to integrated circuit R&D, but such a base is still being developed for other leading PV technologies. This current advantage for c-Si PV is true for materials, interfaces, processes for making and altering PV devices, advanced PV device layers, device scale-up from square inches to square meters, and process scale-up to square miles of annual output at high yield. Additional challenges include maintaining or improving device efficiency, device stability, and process stability. Several key R&D issues are discussed below.

Interfaces

Many of the most critical issues of PV device performance and reliability occur at interfaces such as the device junction, back contact, front contact, and between various additional layers that modify device behavior, such as light and carrier reflectors. Examples of critical interface challenges include the following:

- Recombination of free carriers within the junction region of high-efficiency PV devices

- Poor, non-ohmic contacting and instability to high-work-function, resistive p-type material such as CdTe
- The physics, chemistry, and stability of grain boundaries in multicrystalline semiconductors
- The adherence and lifetime of semiconductor/encapsulant and thermal interface materials
- The numerous interfaces resulting from the use of different materials that respond to different parts of the spectrum in multijunction cells.

There is a need for increasing the fundamental knowledge around the interfaces of a PV device. Although most work to date has been empirical, there is an opportunity to use more sophisticated R&D tools and expertise to better understand the optical, electrical, mechanical, and chemical properties of these interfaces.

Performance of Large-Area PV

Sophisticated computational models, tools, and analysis could assist in the correlation of processing parameters with fundamental device physics to accelerate research and commercial product development. One opportunity for existing silicon- and thin-film-based modules is the further exploration of material parameter space for optimizing electronic and optical properties. Another is the development and employment of *in situ* process controls and in-line metrology and diagnostics for improved manufacturing yield.

Degradation Science

An improved understanding of degradation mechanisms in devices and protective materials would allow for further improvements that can increase module lifetimes and further reduce PV LCOE. It is important to increase understanding in the following areas:

- Photochemical degradation
- Dielectric breakdown
- Leakage current in the presence of water and oxygen
- Impurity diffusion processes in semiconductors and through interfaces, especially in large-area devices (which have inevitable compositional variations in all dimensions).

Well-designed stress tests are needed to define and test degradation mechanisms, as are parallel accelerated lifetime models that correlate these new tests with actual outdoor performance through many decades. Also, better qualification tests would standardize PV performance metrics and drive reliability improvements.

The above list is not all inclusive, and there are several technology-specific R&D challenges. For example, thermal management of CPV devices will be important for optimizing performance and durability under the high-operating temperatures common with concentrating solar devices.

Long-Term, High-Potential R&D

R&D funding for universities, companies, and national laboratories to explore non-traditional, high-potential PV technologies promotes innovation and the development and expansion of future PV technology. This R&D funding also expands the pool of scientists and engineers with PV expertise, of which there is a critical shortage.

The PV research community is exploring a portfolio of promising new materials in the category of abundant, non-toxic, easily processed inorganic semiconductors for direct-bandgap thin-film cells. Wadia et al. (2009) highlighted these novel R&D efforts. Subsequent to this study, there has been renewed interest among the basic science community in exploring underdeveloped materials for PV such as metal oxides and metal sulfides for new PV absorbers. Such long-term efforts build on lessons learned from developing the existing, successful direct-bandgap inorganic thin films and could open up new avenues for low cost while avoiding issues of toxic materials and material availability.

Beyond new materials, there are new PV device concepts that could reduce costs. Examples include organic, nanostructured, and dye-sensitized cells, which are in early stages of commercial development (see Section 4.2.2). They offer the potential for lower module costs through use of less-expensive materials and simpler processing. However, there have been challenges in attaining high efficiency and long-term reliability with the materials that have been used to date.

4.5 Reducing Power Electronics Costs

Power electronics include inverters, which convert DC electricity produced by the PV module into AC electricity used by the grid, and transformers, which step the electricity up to the appropriate voltage. These are often combined into a single integrated device and referred to as the inverter.

As Figure 4-4 shows, benchmark 2010 inverter prices were about \$0.20/W–\$0.30/W for utility systems and about \$0.40/W for residential and commercial systems. As Figure 4-6 shows, the SunShot targets for power electronics prices are \$0.10/W for utility systems, \$0.11/W for commercial systems, and 0.12/W for residential systems. Power electronics prices can be reduced via exploiting economies of scale, developing advanced components, improving reliability, and enabling smart grid integration. Specific power electronics strategies that may be needed to achieve the SunShot targets include the following:

- Solving fundamental power electronics problems at the component level that can be leveraged by advances across multiple industries.
- Reducing the cost of advanced components (e.g., silicon carbide and gallium nitride), which will reduce the size and cost of the magnetic materials (and other components) traditionally used in power electronic inverters and converters.
- Addressing reliability failures due to the thermal cycling of materials with different coefficients of thermal expansion.

- Developing technologies that allow high penetrations of solar technologies onto the grid (e.g., reactive power, energy storage, and advanced functionalities).
- Developing PV system technologies that reduce overall BOS costs (e.g., high-voltage systems).
- Developing technologies that harvest more energy from the sun (e.g., maximum power point tracking and micro-inverters).
- Integrating micro-inverters into modules, reducing installation effort and achieving further cost reductions through mass production.

4.6 Reducing Balance-of-Systems Costs

BOS comprises the non-module, non-power electronics components and procedures required to produce a complete PV system. "Hard" BOS elements include support structures (including trackers), mounting hardware, wiring, monitoring equipment, shipping, and land. "Soft" BOS elements include system design and engineering, customer and site acquisition, installation, permitting, interconnection and inspection, financing, contracting, market-regulatory barriers, and operation and maintenance.

As Figure 4-4 shows, benchmark 2010 BOS prices were about $2.00/W for utility systems, about $2.40/W for commercial systems, and about $3.00/W for residential systems. As Figure 4-6 shows, the SunShot targets for BOS prices are $0.40/W for utility systems, $0.62/W for commercial systems, and $0.84/W for residential systems. BOS prices can vary substantially based on the size and type of PV system, its location, and profit margins. Specific BOS strategies that may be needed to achieve the SunShot targets include the following:

- Hard BOS
  - Improve supply chains for BOS components
  - Develop high-voltage systems
  - Develop racking systems that enhance energy production or require less robust engineering
  - Integrate racking and mounting components in modules
  - Develop innovative materials (e.g., steel or aluminum alloys designed specifically for solar industry applications) for applications such as lightweight, modular mounting frames
  - Create standard packaged system designs
  - Develop building-integrated PV (BIPV) to replace traditional roofing and building facade materials.
- Soft BOS
  - Identify strategies for streamlining permitting and interconnection processes and disseminate best practices to a broad set of jurisdictions
  - Develop improved software design tools and databases
  - Address a wide range of policy and regulatory barriers, as well as utility business and operational challenges
  - Streamline installation practices through improved workforce development and training, including both installers and code officials

- Expand access to a range of business models and financing approaches
- Develop best practices for considering solar access and PV installations in height restrictions, subdivision regulations, new construction guidelines, and aesthetic and design requirements
- Reduce supply chain margins (profit and overhead charged by suppliers, manufacturers, distributors, and retailers); this is likely to occur as the PV industry becomes more mature.

4.7 SunShot versus Evolutionary-Roadmap PV System Price Projections

Before the SunShot Initiative was launched, modeling was performed to project the effect of aggressive—but incremental/evolutionary—PV system improvements to today's dominant PV technologies: c-Si and CdTe. This section compares the PV price projections from this evolutionary roadmap with the more aggressive SunShot price targets.

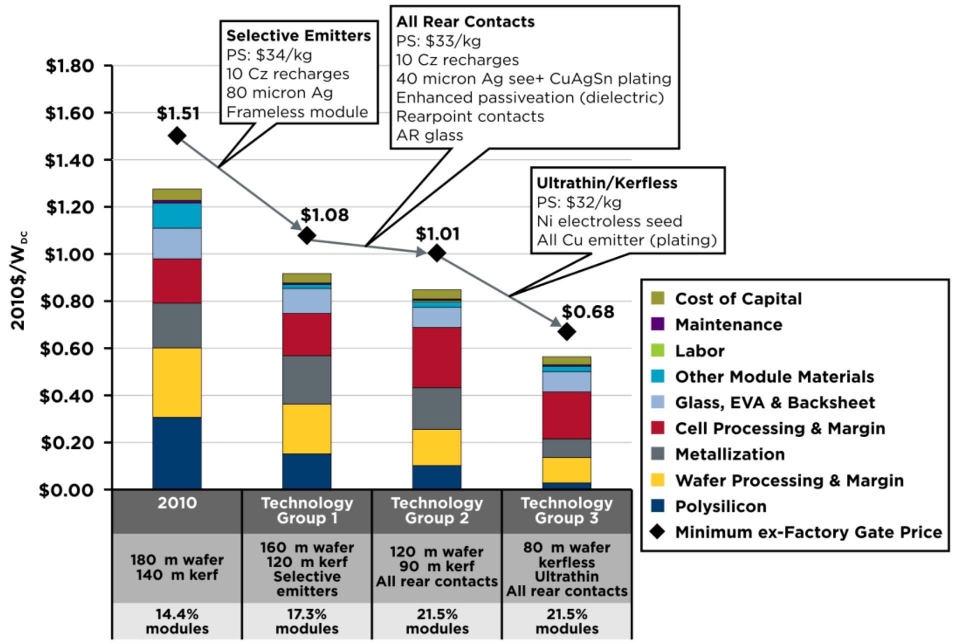
To develop the evolutionary roadmap, NREL created detailed models, in collaboration with industry stakeholders, to quantify residential and commercial distributed (residential and commercial rooftop) and utility-scale (ground-mounted) PV installation prices. Because the results of these models were validated against industry input for current installation prices, the models could be used to estimate future installed system prices. Forecast system prices considered a range of assumptions, including a range of inverter (0%–66%), installation materials (0%–50%), and installation labor (0%–50%) cost or content reductions. Further, in the case of residential and commercial rooftop installations, it was assumed that, over time, competition and industry growth would reduce installer overhead and margins for all sectors to ranges typical of a mature electrical contractor service business (i.e., 16% for residential and 10% for commercial).

Projected PV module price reductions were a primary part of the evolutionary roadmap modeling effort. Figure 4-8 shows a modeled pathway to c-Si module cost reductions. The modeling showed that evolutionary improvements could lead to industry median c-Si modules with an ex-factory gate price of about $1.01/W by 2020 ("Technology Group 2" in Figure 4-8) (Goodrich et al. 2011a). Importantly, it was estimated that this price could be achieved along with a substantial increase in median production module efficiency, to 21.5%—equivalent to a production cell efficiency of approximately 24%. Increasing module efficiency reduces many system costs.

Figure 4-9 shows the system-level results of the evolutionary roadmap modeling. The projected PV system prices are based on forecasted lower cost limits and upper efficiency limits for c-Si and CdTe modules, as well as the range of non-module cost improvements discussed above. The 2010 benchmarks and SunShot PV system price targets are also plotted on Figure 4-9 for comparison.[44]

[44] The official SunShot price targets are $1.5/W for residential systems, $1.25/W for commercial systems, and $1/W for utility-scale fixed-mount systems. Tracking PV systems could have slightly higher costs and still reach comparable LCOEs. As discussed in Chapter 3, $1/W tracking PV systems were modeled for the SunShot scenario, but this is not to imply that 1-axis tracking systems will dominate all markets; the types of mounting/tracking technologies deployed likely will vary regionally.

Figure 4-8. Evolutionary Module Manufacturing Cost Reduction Opportunities C-Si PV



PS: polysilicon
Ag: silver
Cz: Czochralski
Cu: copper
Sn: tin
AR: anti-reflection
EVA: ethylene vinyl acetate

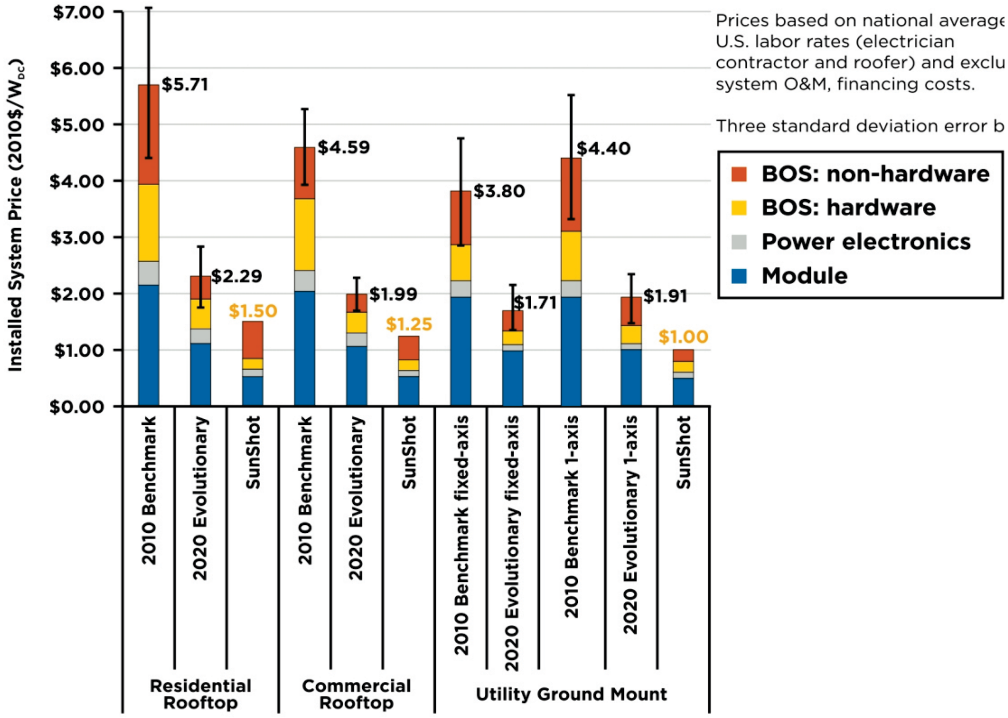
Source: Goodrich et al. (2011a)

Under the evolutionary roadmap assumptions, the installed price of utility-scale PV systems could reach about $1.70–$1.90/W by 2020.[45] Although CdTe has a steeper module price-reduction trajectory and lower estimated module average selling-price limit, CdTe systems have higher non-module costs relative to c-Si owing to lower module efficiency and smaller module size. Residential and commercial installed system prices are projected to reach about $2.30/W and $2.00/W, respectively, by 2020. All of these projected prices are well above the SunShot targets. Even assuming a more optimistic evolutionary module price reduction ($0.68/W, “Technology Group 3” in Figure 4-8), the evolutionary system prices would still be well above the SunShot targets.

The key insight gained through this analysis is that evolutionary change is not likely to be sufficient to reach the SunShot price-reduction targets via today’s dominant technologies (single-junction c-Si and CdTe). Instead, reducing the installed price of PV systems by roughly 75% likely will require significant technological improvements, such as, through the acceleration of innovative technologies into the

[45] See Appendix C for several sensitivity analyses which explore deployment projections based on different cost assumptions for solar and other technologies.

Figure 4-9. Installed PV System Prices: 2010 Benchmark, Projected 2020 Evolutionary, and 2020 SunShot Target[46]



Source: Goodrich et al. (2012)

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marketplace and the pursuit of more radical change by developing new, R&D-driven PV technologies.

For example, multi-junction device architectures theoretically could achieve much higher efficiencies than single-junction c-Si and CdTe; however, to be viable in the marketplace, they would need to do so at a competitive cost structure. Alternative module configurations, such as flexible encapsulation of thin films, could also offer pathways to the SunShot price-reduction targets. Such pathways are important to consider because they leverage the experience of researchers and manufacturers gained over each technology's long history. The actual technological pathways to revolutionary PV improvement are not known today—continued R&D and sustained focus on meeting the price-reduction targets will be necessary to identify and realize these pathways.

[46] For all market segments, the uncertainty analysis considers a range of module assumptions based on c-Si technologies (standard c-Si up to super monocrystalline-based products), including market-appropriate module sizes. In the case of "utility fixed axis" only, modules based on CdTe were also considered.

4.8 SunShot LCOE Projections

Figure 4-10 shows the LCOEs resulting from achieving the SunShot installed PV system prices. These LCOEs are calculated using assumptions about O&M expenses, inverter efficiencies, and derate factors (due to losses in wiring, diodes, or shading) as provided in Table 4-1. Moreover, Figure 4-10 represents LCOEs with no ITC and no state, utility, or local incentives. The financing assumptions are the same as those listed in Table 8-1 in Chapter 8. Finally, three locations—Phoenix, Kansas City, and New York City—and a number of system orientations are used to represent a range of PV LCOEs.

Figure 4-10. SunShot PV LCOEs by Year and Market Segment[47,48]

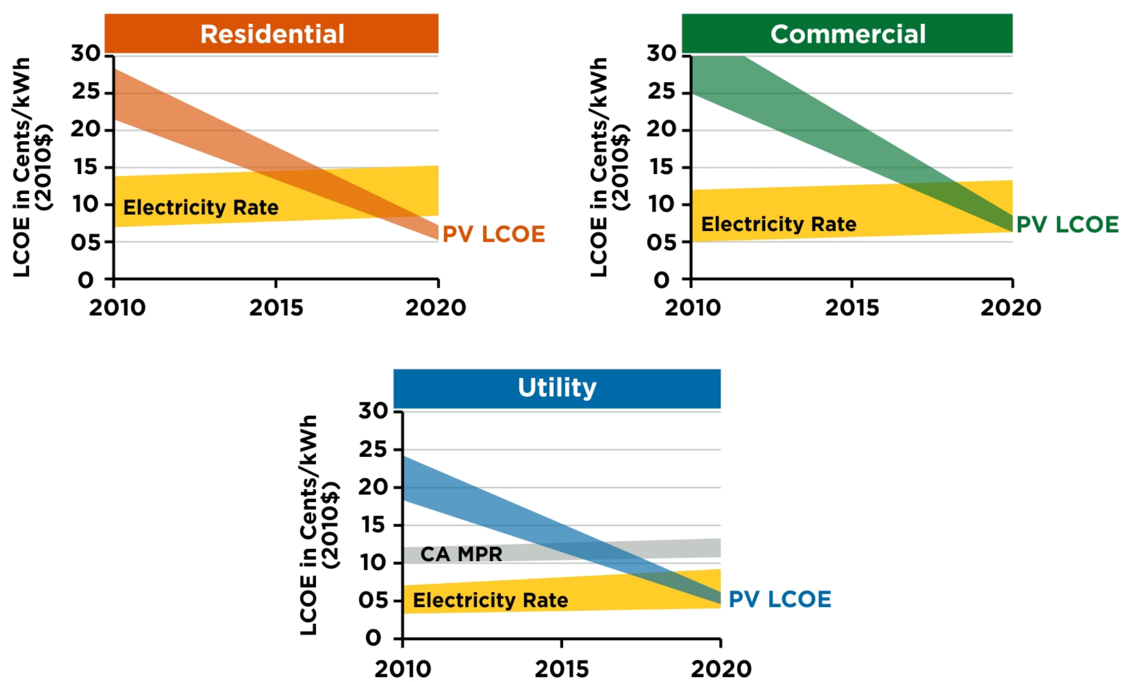

Figure 4-10 shows that, assuming the SunShot targets are met by 2020, residential PV is projected to be increasingly competitive with residential electricity rates, commercial PV is projected to be increasingly competitive with commercial electricity rates, and utility-scale PV is projected to be increasingly competitive with wholesale electricity rates. Utility-scale PV LCOEs become competitive with California's Market Price Referent (MPR), which is used as a benchmark to assess the value of renewable generation in California (CPUC 2011), by 2015 at higher

[47] Note that commercial systems assume site-host ownership, in contrast to utility systems, which are owned by IPPs or IOUs and pay taxes on electricity revenue. However, the apparent tax advantage of site ownership is reduced by the fact that for-profit commercial entities may deduct electricity expenses from their taxable income. Thus, the LCOE of a site-owned commercial system must be compared to the after-tax commercial electricity rate.

[48] The electricity-rate range represents one standard deviation below and above the mean U.S. electricity prices for the respective market segment, including residential, commercial, and utility. The California Market Price Referent (MPR) is in real terms and includes adjustments by utility for the time of delivery profile of solar.

costs than those targeted in the SunShot scenario. This illustrates that, while achieving SunShot price targets will allow PV to compete broadly with conventional generation in several U.S. markets, PV will become competitive in some markets more quickly and at higher prices.

4.9 Materials and Manufacturing Resources

The SunShot scenario reaches 302 gigawatts (GW) of cumulative PV capacity by 2030 and 632 GW by 2050. To achieve this, annual U.S. PV installations will stabilize at about 25–30 GW per year (see Chapter 3). Satisfying these high levels of demand will increase the PV industry's raw materials requirements significantly and require rapid expansion of manufacturing capacity. Essential raw materials include polysilicon feedstocks for c-Si PV technologies and relatively rare elements for several thin-film and CPV technologies. This section evaluates the materials and manufacturing challenges to meeting SunShot PV demand.

4.9.1 Raw Materials Requirements

Raw material availability can become a concern when there is a supply/demand mismatch or a material shortage. These two conditions are discussed below.

Supply/Demand Mismatch

A supply/demand mismatch is a temporary market imbalance resulting in a shortage of available material due to a lack of exploration, extraction, or refining efforts—even when the basic accessibility of the underlying material is presumably not a problem. An example of this type of mismatch in the PV sector is the recent shortage of polysilicon feedstock, which occurred because demand for polysilicon-based modules rose more rapidly than polysilicon production capacity.

Although the polysilicon shortage has dissipated over the past few years, it is useful to examine its causes. The delay between perceiving the opportunity and increasing polysilicon production resulted from the time and expense required to build, start up, and qualify a new polysilicon plant. From initiating plant construction to beginning qualified production, it takes 2–3 years and costs hundreds of millions of dollars. This constraint on response time was further exacerbated by the lack of vertical integration within the industry as cell manufacturers had to wait for producers to respond to the market signals of increased demand. Lower capital-cost processes such as the use of thinner silicon wafers and less-refined, solar-grade silicon could help mitigate this type of imbalance in the future (provided that the most successful cell architectures will still not require the higher-quality material and that the yield losses from thinner wafers are still acceptable).

Such a temporary supply/demand mismatch is familiar to other industries and is likely to remain a part of the PV landscape as it evolves. Better planning can help to minimize these types of disruptions but cannot eliminate them completely in the future.

Material Shortage

A more serious challenge is a fundamental shortage of raw material availability. For example, a shortage can occur when not enough material is being mined, when material cannot be economically mined at prices the PV industry can support, or when competing uses can afford higher prices for the material. Prices can rise significantly long before supply is truly exhausted, which incentivizes the exploration and development of new supply and helps balance demand for each technology.

There are five main ways that material constraints can be mitigated:

- Increase ore extraction and refining—both the amount and material extraction efficiency
- Increase PV efficiency
- Reduce the thickness of semiconductor layers in PV devices
- Improve process utilization and in-process recycling
- Recycle semiconductor materials at the end of module life.

Crystalline silicon feedstocks are virtually unlimited. However, silver, which is currently used for contacts, has some limitation. If different contact materials are used, such as nickel-copper (which is currently under development), the c-Si supply is virtually unconstrained. The glass, steel, and aluminum used as encapsulation and support structures are not subject to rigid supply constraints, but their costs will be tied to changing commodity prices.

Material shortages are a concern for several semiconductor materials used in some thin-film, concentrating, and emerging PV technologies: tellurium in CdTe; indium, selenium, and gallium used in CIGS; indium, germanium, and gallium used in some III-V multijunction cells; and ruthenium, sometimes used in dye-sensitized PV cells. Conductive materials may also be a concern in the longer term, including molybdenum used for CIGS PV contacts. Of these, the primary concerns are the tellurium supply for CdTe and the indium supply for CIGS; thus, this discussion focuses on these two materials.

In its *Critical Materials Strategy*, DOE (2010) estimated current (2010) and projected (2015) supplies of several materials, including tellurium and indium. It estimates 2010 tellurium production at 500 metric tons (MT)/yr and projects it to rise to 1,220 MT/yr in 2015 based on assumptions about increased production from copper anode slimes. It also estimates that global tellurium production could increase four-fold by 2020 due to increased production from copper anode slimes, assuming copper refiners do not move away from electrolytic processing (to promote larger tellurium supplies, the PV industry could incentivize an increased use of electrolytic copper refining). Copper production historically has grown by about 3% per year (ICSG 2006) and is, with planned new capacity additions, projected to grow around 4.5% per year from 2011–2014 (Edelstein 2011). According to Ojebuoboh (2008), the efficiency of tellurium extraction from copper could increase substantially, although the impact on tellurium prices is unknown. Mining of tellurium ores and recovery of tellurium from gold concentrates are additional potential tellurium sources (DOE 2010, Green 2009). The cost of alternative tellurium sources and extraction techniques is not well known. However, the cost of recovering any element is inversely proportional to its concentration (Green 2009). Therefore, tellurium costs are likely to increase if the industry shifts to these new sources.

Indium is a relatively rare coproduct of zinc refining. Nearly all of the indium supply is used in thin-film coatings, such as in the production of indium tin oxide for flat-panel liquid-crystal displays, which could present a challenge to the PV industry because other uses could potentially accommodate a higher indium price. The *Critical Materials Strategy* estimates the 2010 indium supply at 1,345 MT/year (yr) (480 MT virgin and 865 MT reclaimed) (DOE 2010). It estimates 2015 indium supplies could increase to 1,612 MT/yr based on increased recovery from additional zinc production and recycling.

CPV modules frequently use indium and gallium but do not face the same resource limitations as flat-plate PV technologies. Optical concentration reduces the amount of semiconductor material required by a factor nearly equivalent to the concentration ratio.

Table 4-2 summarizes how reduced material requirements and increased tellurium and indium availability could increase potential PV production capacity for CdTe and CIGS PV technologies.[49] Under the SunShot scenario, annual U.S. PV installations could reach 27 GW/yr by 2030. If global PV penetration roughly follows SunShot-like trajectories, global PV demand could reach well over 100 GW/yr by 2030. Table 4-2 shows that, at current material requirements and availability, the ability of tellurium- and indium-dependent PV technologies alone to meet projected U.S. and global demand would be limited. However, with reduced materials requirements, even current tellurium and indium availability could enable these technologies to play a substantial role in satisfying projected demand, and the projected increase in tellurium and indium availability is substantial even in the 2015 time frame. Availability could increase even further by the time annual U.S. SunShot demand is in the 20–30 GW/yr range and global demand is on the order of 100 GW/yr. Of course, competing uses of these materials will reduce the amounts available for PV. See DOE (2010) for long-term tellurium and indium demand scenarios and additional discussion about materials availability.

4.9.2 Manufacturing Scale-Up

The PV industry is currently expanding its manufacturing capacity to meet growing demand. This has been helped, in large part, by new market entrants bringing manufacturing and supply chain management experience from other successful industries, including computers, semiconductors, and liquid crystal displays. The expansion has also been aided by improved manufacturing throughput, based on technology improvements and efficiency gains. The annual production capacity of PV manufacturing lines has typically increased by an order of magnitude over the last decade, from tens to hundreds of megawatts per year.

[49] Because of the success of cadmium telluride (CdTe) in the marketplace, the amount of CdTe production potential has been examined by a number of investigators (Green 2006, Green 2009, Feltrin and Freundlich 2007, Ojebuoboh 2008, Fthenakis 2009).

Table 4-2. Potential Annual PV Capacity Supply Based on Current and Potential PV Material Requirements and Material Availability

Material	PV Type	Material Requirement (MT/GW)[a]	Material Availability (MT/yr)[b]	Potential PV Capacity (GW/yr)
Current (2010) Material Requirements and Current (2010) Material Availability				
Tellurium	CdTe	60–90	500	**6–8**
Indium	CIGS	52	1,345	**26**
Reduced (Future) Material Requirements and Current (2010) Material Availability				
Tellurium	CdTe	19	500	**26**
Indium	CIGS	5	1,345	**270**
Reduced (Future) Material Requirements and Increased (2015) Material Availability				
Tellurium	CdTe	19	1,220	**64**
Indium	CIGS	5	1,612	**320**

[a] The reduced material requirement estimates listed here are not projected to a specific year, e.g., not to 2015. Rather, they represent estimates of practical minimum limits on tellurium and indium requirements for CdTe and CIGS PV technologies. Accelerated R&D may reduce the time required to reach these levels.

Current CdTe production module efficiencies have been demonstrated to be as high as 11.7% (First Solar 2011a), with CdTe layers that are 2–3 µm thick (Green 2011). Process materials use is about 90% for current CdTe module production techniques (with in-process recycling), which implies tellurium requirements of about 7–10 grams (g)/m^2 and, correspondingly, 60–90 MT/GW of tellurium. According to Woodhouse et al. (2011), if R&D-driven improvements could increase CdTe efficiency to 18% and decrease layer thickness to about 1 µm—roughly the amount of semiconductor thickness needed to efficiently fully absorb the solar spectrum (without significant drops in photocurrent)—tellurium requirements could drop to 19 MT/GW.

The CIGS indium requirements are from Goodrich et al. (2011b). The 2010 CIGS (coevaporation technique) indium requirement of 52 MT/GW is based on current estimates of material yield losses, 10% module efficiency, and a 1.5-µm absorber. The reduced CIGS indium requirement of 5 MT/GW includes estimated material yield losses, 20.8% module efficiency, a 1.0-µm absorber, and a high gallium-to-indium ratio.

[b] Current/2010 and increased/2015 material availability are from DOE (2010); although this report does not project longer-term tellurium and indium availability, availability may be higher beyond 2015. The large projected increase in tellurium availability between 2010 and 2015 is based, in part, on assumptions about greatly increasing the rate of tellurium recovery from copper refining; the added cost of this increased recovery rate is unknown, thus it is unknown whether the process will prove economically viable.

The need to scale up PV manufacturing capacity will not limit PV deployment under the SunShot scenario. For example, global PV manufacturing capacity has grown from 1.4 GW/yr in 2004 to 22.5 GW/yr by the end of 2010 (Mints 2011). Given that U.S. PV manufacturing capacity at the end of 2010 was 1.4 GW/yr, expanding U.S. PV production to 27 GW/yr over the next 20 years under the SunShot scenario is very realistic. The capital equipment and land costs required to build a 1-GW/yr PV manufacturing facility has been estimated at \$1–\$3 billion for c-Si (Mehta and Bradford 2009), and has been reported to be as low as \$0.64/W for CdTe (First Solar 2010). Thus, the cost of building new PV manufacturing capacity should not limit SunShot-scale deployment.

That said, supply chain planning and clear market signals are needed to enable the required scale-up. For an “emerging” technology such as PV, strong and consistent government policy support can help to create initial demand. Prospective PV investors and manufacturers must see a clear market-growth pathway before committing the substantial resources needed to scale up production capacity and output.

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5. Concentrating Solar Power: Technologies, Cost, and Performance

5.1 Introduction

At the end of 2010, about 1,300 megawatts (MW) of concentrating solar power[50] (CSP) capacity was in operation worldwide, with 512 MW in the United States. More than half of the U.S. capacity was built in southern California in the 1980s. More recently, there has been increased interest in CSP technologies as a result of greater demand for renewable energy, government-supported research and development (R&D), and improved economics through policy initiatives. In the past few years, multiple utility-scale plants have been built, and almost 12 gigawatts (GW) of capacity were under construction or under contract worldwide during 2010. Of this total, almost 10 GW represented CSP plants with signed power purchase agreements (PPAs) under development in the U.S. Southwest (SEIA 2010).

CSP is composed of a diverse mix of technologies, at different stages of maturity, which convert sunlight into thermal energy and then use this thermal energy to generate electricity. A key characteristic of CSP is its built-in thermal inertia, which can provide stability in plant output during slight changes in solar radiation, such as when a cloud passes overhead. Because CSP uses thermal energy, it can also incorporate thermal energy storage (TES), fossil-fuel backup/hybridization, or both for higher levels of stability and dispatchability and increased duration of energy output. These attributes allow CSP plants to obtain capacity credits similar to those for fossil-fuel power systems and provide a firm energy resource that improves grid operations.

This chapter evaluates the current cost, performance, and potential of several CSP technologies. A detailed discussion of the opportunities for potential cost reductions to existing and emerging CSP technologies is provided. Key challenges to achieving the level of CSP growth envisioned in the SunShot scenario are evaluated, including potential materials-supply constraints as well as manufacturing scale-up issues. This analysis makes it clear that continued CSP technology advances and cost reductions, through both continued R&D investments and increased deployment activities, will be necessary for achieving the SunShot scenario. In particular, CSP's ability to provide firm, dispatchable power generation will play a critical role in enabling the U.S. electricity generation system to operate safely and reliably under the SunShot scenario's levels of solar technology deployment.

[50] CSP may also be called concentrating solar thermal power or solar thermal electric power.

5.2 TODAY'S CSP TECHNOLOGY

There are four demonstrated types of CSP systems: parabolic trough, linear Fresnel, power tower (also called central receiver), and dish/engine. All of these technologies involve converting sunlight into thermal energy for use in a heat-driven engine. The first three have been demonstrated in hybrid configurations with fossil-fuel technologies and/or adapted to use TES. These options provide operating flexibility and greater reliability. TES and hybridization are expected to play increasingly important roles as renewable energy contributions to the electric grid increase.

5.2.1 TECHNOLOGY TYPES

Parabolic Trough

Parabolic trough systems are currently the most proven CSP technology owing to a commercial operating history starting in 1984, with the Solar Energy Generating Systems (SEGS) plants in the Mojave Desert of California, and continuing with Nevada Solar One (Figure 5-1) and several recent commercial trough plants in Spain.

Figure 5-1. Example of a Parabolic Trough Plant

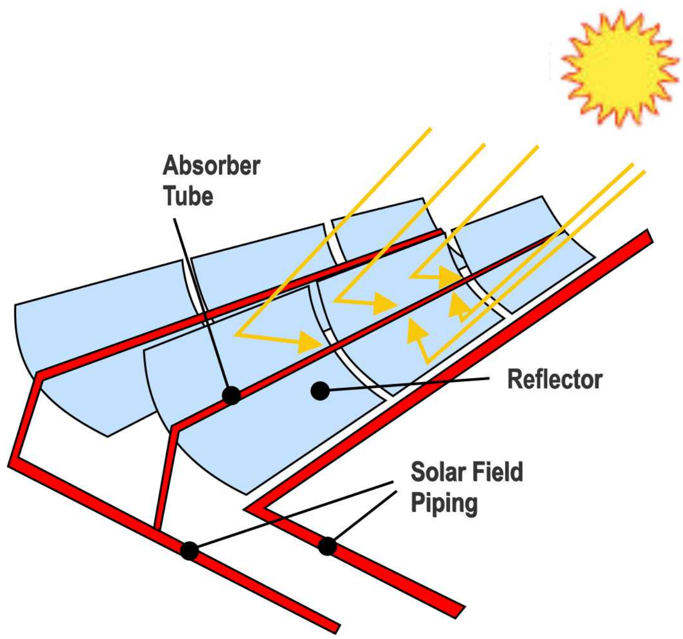
Source: EPRI (2010)

Parabolic trough power plants consist of large fields of mirrored parabolic trough collectors, a heat-transfer fluid (HTF)/steam-generation system, a power system such as a Rankine steam turbine/generator, and optional TES and/or fossil-fuel-fired backup systems. The use of TES results in both dispatchable generation and higher annual generation per unit of capacity, although the larger collector field and storage system lead to a higher upfront capital investment. Trough solar fields can also be deployed with fossil-fueled power plants to augment the steam cycle, improving performance by lowering the heat rate of the plant and either increasing power output or displacing fossil-fuel consumption.

The solar field is made up of large modular arrays of 1-axis[51] tracking solar collectors arranged in parallel rows, usually aligned on a north-south horizontal axis. Each solar collector has a linear parabolic-shaped reflector that focuses the direct-beam solar radiation onto a linear receiver (absorber tube) located at the focal line of the parabola (Figure 5-2). The collectors track the sun from east to west during the day, with the incident radiation continuously focused onto the linear receiver, within which an HTF is heated to approximately 390ºC.[52]

[51] Note that 1-axis tracking may also be referred to as "single-axis" tracking.
[52] To convert temperature to Fahrenheit, multiply the Celsius value by 1.8 and then add 32 degrees.

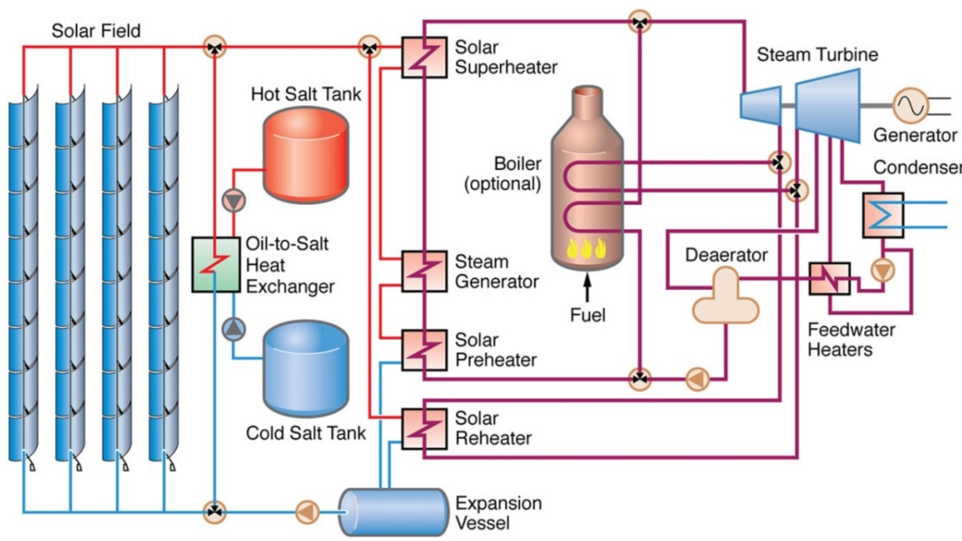
Figure 5-2. Parabolic Trough Field Components



Source: NREL

After circulation through the receivers, the HTF flows through a heat exchanger to generate high-pressure superheated steam (typically 100 bar at 370ºC). The superheated steam is fed to a conventional reheat steam turbine/generator to produce electricity. The spent steam from the turbine is condensed in a standard condenser and returned to the heat exchangers via condensate and feed-water pumps to be transformed back into steam. Wet, dry, or hybrid cooling towers can be used for heat rejection from the condenser; the selection will influence water use, cycle performance, and cost (see the water discussion in Chapter 7). Figure 5-3 shows a trough plant with a fossil-fuel-fired backup boiler and TES.

Figure 5-3. Trough Plant Operation with Fossil-Fuel-Fired Backup System



Source: EPRI (2010)

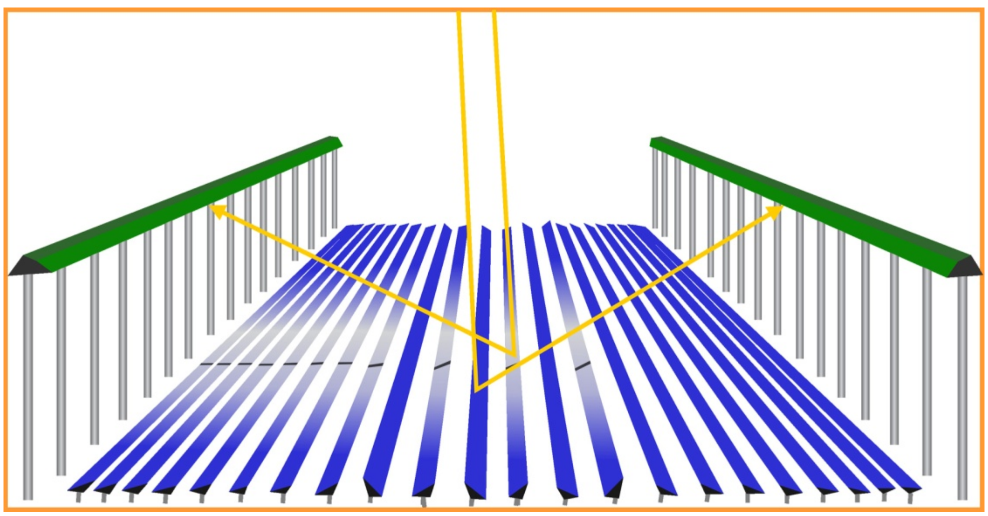
The current design-point solar-to-electric efficiency—the net efficiency in the ideal case when the sun is directly overhead—for a parabolic trough plant ranges from 24%–26%, and the overall annual average conversion efficiency is about 13%–15%. The design-point values represent an ideal case that is useful for comparing between different components, such as two different receiver designs. This metric is also used for evaluating photovoltaic (PV) panels. The annual average efficiency provides a better assessment of actual operation.

Linear Fresnel

Linear Fresnel reflectors (LFRs) approximate the parabolic shape of a traditional trough collector with long, ground-level rows of flat or slightly curved reflectors that reflect the solar rays up onto an overhead linear receiver. Flat reflectors and fixed receivers lead to lower capital costs relative to a traditional trough-based plant, but LFR plants are less efficient on a solar-to-electricity basis. Recently, superheated steam at about 380°C has been demonstrated in an LFR plant, and there are proposals for producing steam at 450°C; higher operating temperatures enable higher efficiency. Because LFRs are in the demonstration phase of development, their relative energy cost compared with parabolic troughs remains to be established.

Compact LFR technology uses a design with two parallel receivers for each row of reflectors (Figure 5-4). This configuration minimizes blocking of adjacent reflectors and reduces required land area. Another advantage is that, depending on the position of the sun, the reflectors can be alternated to point at different receivers, thus improving optical efficiency.

Figure 5-4. Compact Linear Fresnel Reflector Field



Source: NREL

Power Tower

Power towers (also called central receivers) are in the demonstration to early-commercialization stage of development. Because of their higher operating temperatures, power towers have the potential to achieve higher efficiency and lower-cost TES compared with current trough technology.

Power towers use heliostats—reflectors that rotate about both the azimuth and elevation axes—to reflect sunlight onto a central receiver. A large power tower plant can require from several thousand to more than one-hundred thousand heliostats, each under computer control. Because they typically constitute about 50% of the plant cost, it is important to optimize heliostat design. Heliostat size, weight, manufacturing volume, and performance are important design variables, and developers have selected different approaches to minimize cost. Some heliostat technology can be installed on relatively uneven land, with 5% or more slope, thereby reducing site-preparation costs for new projects. Figure 5-5 shows an example of a heliostat array and receiver.

Figure 5-5. Example of a Power Tower and Heliostat Array

Source: BrightSource (2010)

The two principal power tower technology concepts currently being pursued by developers are defined by the HTF in the receiver: steam or molten salt. Both concepts have unique operating characteristics, which are detailed below.

In direct-steam power towers, heliostats reflect sunlight onto a receiver on a tower, which is similar to a boiler in a conventional coal-fired power plant. The feed water, pumped from the power block, is evaporated and superheated in the receiver to produce steam, which feeds a turbine generator to generate electricity. Current steam conditions for direct-steam generation towers range from saturated steam at 250°C to superheated steam at over 550°C. Several characteristics of direct-steam power towers make them attractive: their straightforward design; use of conventional boiler technology, materials, and manufacturing techniques; high thermodynamic efficiency; and low parasitic power consumption. Short-duration direct-steam/water storage has been demonstrated at the 20-MW PS20 tower in Spain. Like many CSP technologies, steam towers can be hybridized with natural gas to provide additional operating flexibility and enhanced dispatchability. Figure 5-6 shows two examples of direct-steam receivers in operation.

Figure 5-6. Examples of Direct Steam Receivers in Operation

Source: eSolar (2010) (left) and BrightSource (2010) (right)

In a molten-salt power tower, salt at about 290°C is pumped from a cold storage tank to a receiver, where concentrated sunlight from the heliostat field heats the salt to about 565°C. The salt is typically a blend of sodium and potassium nitrate, which are ingredients sold commercially as fertilizer. The hot salt is held in a storage tank, and when electric power generation is required, hot salt is pumped to the steam generator, which produces high-pressure steam at nominal conditions of 100–150 bar and up to 540°C. The now-cooler salt from the steam generator is returned to the cold salt storage tank to complete the cycle. Owing to the negligible vapor pressure of the salt, both storage tanks are at atmospheric pressure. The steam is converted to electrical energy in a conventional steam turbine/generator. By placing the storage between the receiver and the steam generator, solar energy collection is decoupled from electricity generation. Thus, passing clouds that temporarily reduce direct-normal irradiance (DNI) do not affect turbine output. In addition, the TES could be less than half the cost of salt TES in trough plants because the larger temperature range across the storage system enables more energy to be stored per mass of salt. The combination of salt density, salt-specific heat, and temperature difference between the two tanks allows economic storage capacities of up to 15 hours of turbine operation at full load. Such a plant could run 24 hours per day, 7 days per week in the summer and part-load in the winter to achieve a 70% solar-only annual capacity factor. The Gemasolar plant in Spain is designed for such performance. Figure 5-7 shows a 43-MW thermal (MW_t) receiver at the 10-MW Solar Two central receiver demonstration project, which was completed in 1995 in Barstow, California.

The annual average solar-to-electric conversion efficiency of a power tower is about 14%–18%, with direct-steam towers slightly higher than molten-salt towers. The design-point efficiency is about 20%–24%. As discussed for troughs, annual average efficiency represents overall real-world performance, whereas design-point values are useful for comparing the performance of individual components. The choice of wet, dry, or hybrid cooling towers can influence water use, cycle performance, and cost (see Chapter 7).

Dish/Engine

Figure 5-7. Example of a Molten-Salt Receiver

Source: Sandia National Laboratories (2010)

Dish/engine CSP technology uses a collection of reflectors assembled in the shape of a parabolic dish to concentrate sunlight onto a receiver cavity at the focal point of the dish. Within the receiver, the heater head collects this solar energy, running an engine-driven generator to produce electricity. Similar to heliostats, all dishes rotate along two axes to track the sun for optimum capture of solar radiation. There are currently three major types of engines used at the core of dish/engine technology: kinematic Stirling engines, free-piston Stirling engines, and Brayton turbine-alternator based engines. Dishes have also been proposed with air receivers that feed hot air to a steam generator. Both kinematic and free-piston Stirling engines harness the thermodynamic Stirling cycle to convert solar thermal energy into electricity by using a working fluid, such as hydrogen or helium. Brayton systems use turbine-alternator engines with compressed hot air to produce electricity. Current dish/Stirling systems generate 3–30 kilowatts (kW) of electricity, depending on the size of the dish and the heat engine used. The first dish/Stirling commercial demonstration began operation in January 2010. Dish/Brayton systems have been proposed at sizes up to 200 kW.

Some dish/engine technology can be installed on relatively uneven land—with 5% or more slope—thereby reducing the cost of site preparation for new projects. Dish/engine systems are cooled by closed-loop systems (similar to an automobile engine), which, combined with the lack of a steam cycle, endow them with the lowest water use per megawatt-hour (MWh) among all the CSP technologies. As a modular technology, dish/engine systems are built to scale to meet the needs of each individual project site, potentially satisfying loads from kilowatts to gigawatts. This scalability makes dish/engine technology applicable for both distributed and utility-scale generation. Dish/Stirling systems have demonstrated the highest recorded CSP design-point solar-to-electric efficiency (31.4%) and have an estimated annual conversion efficiency in the low 20% range. Two types of dish/engine systems are shown in Figure 5-8.

5.2.2 Cost and Performance

The current performance and cost of CSP plants varies by technology, configuration, solar resource, and financing parameters. However, it is possible to evaluate different plant designs and technologies in terms of a single index: the levelized cost of energy (LCOE). LCOE takes into account the available solar resource, upfront capital investment, plant capacity factor, operation and maintenance (O&M) costs, and financing parameters. LCOE is generally expressed in terms of cents per kilowatt-hour (kWh). Alternatively, the cost of a CSP plant can be expressed in terms of dollars per watt (W) or, more commonly, dollars per kilowatt. LCOE takes

Figure 5-8. Examples of Dish/Engine Systems

Sources: Stirling Energy Systems (SES) (2010) (left) and Infinia (2010) (right)

capacity factor and O&M costs into account, but dollars per kilowatt does not. For example, a 100-MW CSP plant can be built with TES and additional collector area to increase its capacity factor. This hypothetical design might generate 100% more energy per year and have a 60% higher installed cost than an alternative design without TES and additional collector area; such a plant would have a higher installed dollars-per-kilowatt cost but a lower LCOE than the alternative-design plant.

Assuming fixed financial inputs, the LCOE of a CSP plant can be reduced in two ways: 1) by lowering capital or O&M costs, and 2) by increasing annual performance. The capital equipment for a CSP plant involves solar components (e.g., solar collector field, heat-transfer piping, and TES system) and more-or-less conventional thermodynamic power-cycle components (e.g., pump, turbine, and generator). The O&M cost per megawatt-hour, of which staff is the largest contributor, decreases with an increase in plant size or co-location of multiple units at one site. Decreasing capital and operating costs can be achieved by technology advances and increased manufacturing volume and supply chain efficiency.

The performance of a CSP plant is characterized by its annual solar-to-electric conversion efficiency. This metric includes all of the energy losses that affect the annual electricity produced by the plant, including optical, thermal, and electrical parasitic losses, as well as forced and planned outages for maintenance. Although higher efficiency often costs more up front, it may more than pay for itself over the operating life of the plant. Also, plants with higher efficiency require less land to produce a given amount of electricity. In other cases, a slightly lower overall efficiency may be advantageous. For example, if the marginal cost of a heliostat is less than the return in revenue it provides, it may be worth adding heliostats—increasing the capacity factor, but lowering the efficiency, of the plant. Capacity factor is defined as the ratio of actual annual generation to the amount of generation had the plant operated at its nameplate capacity for the entire year. Capacity factors vary greatly between different locations, technologies, and plant configurations; for example, plants with TES achieve higher capacity factors because their power block can have more hours of operation. CSP plants with TES are likely to be more cost effective in the future as compared to plants without TES, because while the addition of low-cost TES does increase capital costs, it has the potential to reduce the LCOE.

One of the most recent utility-scale CSP plants built in the United States is the Nevada Solar One parabolic trough plant, which came on line in 2007 at a reported cost of about \$4,100/kW (\$266 million cost, nominal 64-MW capacity). Several similar-size trough plants have been built in Spain, including the Andasol plants that include TES; however, those project costs have not been disclosed. The estimated direct capital costs for building a CSP plant today are about \$4,000–\$8,500/kW. The upper end of the range reflects plants with TES, whereas the lower end includes no-TES troughs, direct-steam generation towers, and dish/engine systems (see Section 5.3.6 for more information). Plant capacity factors extend from 20%–28% for plants with no TES and 40%–50% for plants with 6–7.5 hours of TES. Larger amounts of TES and higher capacity factors are technically viable but subject to project economics. The LCOE varies greatly depending on the location, ownership, values of key financing terms, available financial incentives, and other factors. For locations in the southwestern United States, the LCOE is currently in the 12–18 cents/kWh range with a 30% investment tax credit (ITC).

5.3 Projected Technology and Cost Improvements to Existing and Emerging CSP Technologies

Anticipated reductions in the delivered cost of electricity from CSP plants will occur primarily from decreasing the upfront investment cost and improving performance. Reduced capital cost will be a consequence of manufacturing and installation scale-up as well as technology advancements through R&D aimed at cost reduction and performance improvements. A number of component- and system-level advancements are currently being pursued, which generally can be classified into five sub-systems: solar field, HTF, TES, cooling technology, and power block. Each of these sub-systems is discussed below, followed by a detailed discussion of current and projected cost improvements by sub-system.

5.3.1 Solar Field

The solar collector field (materials plus labor) represents the single largest capital investment in a CSP plant and thus represents the greatest potential for LCOE reduction among capital equipment costs. The key to reducing solar field costs is reducing the cost of the collector support structure, reflectors, and receivers.

The support structure must support the weight of the reflectors and have sufficient strength to keep the reflectors aligned, even during high-wind conditions. Survival wind loads (the maximum wind loads that structures must withstand), which vary by location, tend to drive the overall design of the collector. The support structures must also have sufficient torsional rigidity to minimize twisting. For the collectors, developers are working to reduce the amount of material and labor necessary to provide accurate optical performance. The choice of material also plays an important role in structural design: steel is stronger and stiffer than aluminum, but aluminum is lightweight, corrosion resistant, and more easily processed. Advanced collector designs that use integrated structural reflectors reduce the installation cost of both the structure and reflectors by making assembly of the solar field easier and faster. For troughs, several advanced frame designs are being evaluated, such as space frame, torque tube, and monocoque. Troughs are generally moving toward larger-aperture collectors to reduce total costs for piping, receivers, drives, and controls. For towers, heliostat sizes from 1–130 square meters (m^2) are being used. In addition, improvements in other collector components—such as drives, controls, and foundations —are needed to reduce the support structure cost further.

The optical performance of reflectors is also critical to minimizing LCOE, because it has an approximately one-to-one ratio with LCOE—i.e., a 1% increase in reflectance will cause a 1% reduction in LCOE. For CSP reflectors, it is important for the reflective surface to not only be highly reflective, but also to be highly specular; in other words, the reflector must not only reflect the sunlight, but also reflect it into a narrow cone angle that intercepts the receiver. Currently, most CSP plants use 4-millimeter (mm) second-surface silvered glass reflectors, and current glass reflectors have proven field performance and reflectivity values of about 93.5%. Costs may be reduced by moving from these heavy glass reflectors to lightweight thin glass, polymeric film, or coated aluminum reflectors. Figure 5-9 shows a recently installed parabolic trough system operating at SEGS-II as an example of a large-aperture trough that uses a silvered polymer reflector. Compared with glass reflectors, thin-film reflectors have the potential to provide a lightweight, high-reflectance, low-cost alternative, while also allowing a greater degree of design freedom and reduced breakability. Advanced reflectors are being developed to increase reflectivity to 95% or higher, but time is required to prove their long-term durability. Reflector coatings are being explored to increase durability and to reduce the amount of water used for cleaning.

Figure 5-9. Parabolic Trough Undergoing Testing in Southern California

Source: SkyFuel (2010)

Receivers have optical and thermal performance characteristics. The optical efficiency is a measure of the percentage of incoming DNI that is absorbed by the receiver, whereas the thermal efficiency is the proportion of energy absorbed by the receiver that is transferred to the HTF. Current solar selective coatings for receiver surfaces display high absorptivity of short-wave radiation (sunlight), but a challenge is to reduce the emissivity of long-wave radiation (infrared) while maintaining high absorptivity at high temperatures. Selective coatings for vacuum-jacketed trough receivers are fairly advanced, but tower receivers would benefit from new selective coatings that can withstand their higher temperatures and are resistant to oxidation.

For trough receivers in particular, receiver tubes in the field have exhibited a problem of hydrogen permeation from the HTF into the vacuum space, resulting in greatly increased heat loss. Solutions being studied to solve this problem include adjusting the amount and location of hydrogen getters, centrally removing the hydrogen, using an inert gas to block the motion of hydrogen, and deploying HTFs that do not generate hydrogen.

5.3.2 Heat-Transfer Fluid

A major focus of improved CSP performance is achieving higher operating temperatures to take advantage of increased thermal-to-electric conversion efficiencies and—for systems with TES—lower TES cost.

For commercial parabolic trough systems, the maximum operating temperature is limited by the HTF, currently a synthetic oil with a maximum operating temperature of approximately 390°C. Other limitations of this HTF include the cost of the fluid and the need for heat-exchange equipment to transfer thermal energy to the power cycle or storage system. Several parabolic trough companies are experimenting with alternative HTFs that would allow operation at much higher temperatures. Examples of HTFs currently under investigation include molten salts, water for direct-steam generation, organic silicones, ionic liquids, and polyaromatic napthalenes. In addition, researchers are investigating the incorporation of nanoparticles into many of these fluids to improve their heat capacity, heat-transfer rate, and/or thermal stability at high temperatures.

The maximum practical concentration ratio possible coupled with the lowest practical heat loss from the receiver tubes suggest an upper temperature limit of approximately 500°C for parabolic trough systems. Water/steam and molten-salt HTFs can be used at this temperature; however, there are concerns with the freezing temperature of molten salts as well as a need for salt-compatible components, such as flex-joints and valves. The salt currently used in tower projects and TES systems is a 40/60-weight-percent blend of potassium nitrate and sodium nitrate, which starts melting at 220°C. A small demonstration trough plant in Sicily is also currently running with this salt HTF. A shift to molten-salt HTFs running at 500°C is predicted to significantly reduce trough plant costs, primarily by improving thermal conversion efficiency, reducing TES costs, and reducing HTF system cost (piping, insulation, and fluid) (Turchi et al. 2010a). For this reason, considerable R&D efforts are underway to find lower-melting-point salts that are more attractive for use in commercial parabolic trough plants. However, lowering the melting point of salts typically requires the incorporation of more expensive salt components and hardware, and these tradeoffs must be weighed carefully. Efforts to address material compatibility are also underway, including new packing materials for ball joints and testing of both piping components and instrumentation. Direct-steam troughs have also been proposed and tested, but no commercial plants have yet been built owing to the greater control complexity of these systems.

In contrast to parabolic trough systems, molten salt and direct steam are currently used as the HTFs in power tower systems operating at temperatures near 565°C. This is possible because of the considerably smaller amount of piping required for the HTF in a tower system. Owing to higher concentration ratios associated with tower systems as compared with parabolic troughs, operating temperatures of 1,000°C or higher may be feasible, depending on the medium used for the HTF. Research efforts are investigating systems and materials capable of operating at these elevated temperatures. Systems that operate at moderately higher temperatures (600°C–700°C) may allow molten-salt and steam towers to adapt and use commercial supercritical steam turbines (as opposed to the current subcritical Rankine cycles).

The choice of HTF greatly influences whether a particular design can be integrated with TES. For example, although small amounts of steam can be stored in steam accumulators, such designs are not economically feasible at higher storage capacities. Steam-compatible options such as phase-change storage show promise but have yet to be demonstrated beyond pilot scale. Alternatively, molten-salt receivers can efficiently store the high-temperature salt HTF directly in tanks at a relatively low cost. Potential storage options are discussed in greater detail in the following section.

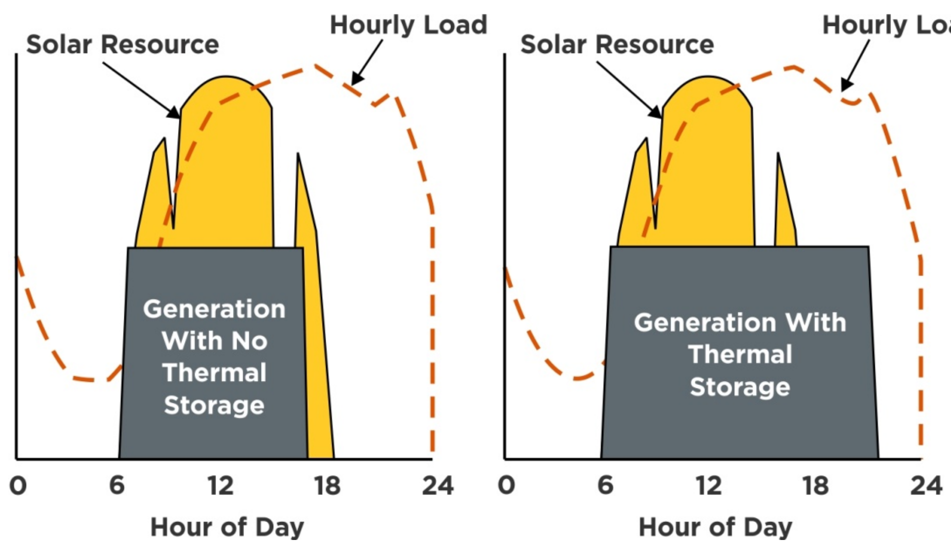
5.3.3 Thermal Energy Storage

A very important characteristic of CSP technologies is their ability to dispatch power beyond the daytime sun hours by incorporating TES systems. During summer months, for example, plants typically operate for up to 10 hours per day at full-rated electric output without TES. However, full-load generation hours can be added or shifted if TES is available, allowing for greater utilization of the power block and potentially reducing LCOE. Incorporating TES normally is accompanied by increasing the size of the collector area to produce excess thermal energy during the day that can be put into the TES system for later use. An alternative to TES that does not require collector-area expansion is to configure the systems as hybrid plants, i.e., provide a secondary backup system to supplement the solar output during periods of low solar irradiance. Use of natural gas is typical, but the use of renewable fuels such as biomass is also possible. Hybrid plants provide good dispatchability at relatively low cost and risk, albeit with a diluted solar contribution.

Large-scale TES systems have only recently appeared in commercial CSP plants. Plants with TES typically have collector fields that are much larger than the minimum size required to operate the power cycle at full load. The ratio of the collector-field thermal power to the power required to operate the power cycle at full load is termed the “solar multiple.” For example, a system with a solar multiple of 1.0 means that the solar field delivers exactly the amount of energy required for the generator to produce the maximum rated power, or “nameplate capacity,” for the plant’s turbine at a defined insolation value—e.g., solar noon on the summer solstice. At all other times, the solar field would be delivering less power than required to run the turbine at maximum capacity. Even plants without explicit TES are designed with an oversized solar collector field (i.e., with a solar multiple greater than one) so that they can operate the turbine at its maximum power capacity (design point) for more hours of the year. The plant may need to reduce collection of some solar energy during summer afternoons, but the larger solar field allows for full-load operation for more total hours throughout the year. If TES is included, any excess heat from the collector field is sent to the TES system. When power is needed, the heat is extracted from the TES system and sent to the steam cycle. An example of a commercial plant with storage is Andasol 1 in Spain, which incorporates a two-tank molten-salt system. The 50-MW plant uses 28,500 metric tons (MT) of nitrate salts, offering a storage capacity of 1,000 MW_t, equivalent to about 7.5 hours of power production. The salt temperature ranges from 292°C in the cold tank to 386°C in the hot tank.

Additional capital investment is required to expand the collector area and add storage tanks so that a CSP plant may incorporate TES; however, these costs are offset by increasing the operational hours of the power block. If solar field and TES costs are low enough, the net effect is a decrease in LCOE. In addition, TES provides greater operating flexibility and enhances dispatchability, which provides additional value to the utility. Figure 5-10 shows how CSP plants with TES can tailor their output to match load curves, thereby maximizing value to the utility and revenue to the owner. TES allows CSP plants to extend and/or shift energy generation to coincide with peak load demands. The only current commercial TES option for parabolic trough, linear Fresnel, and power tower systems uses molten nitrate salt as the storage medium in a two-tank, sensible heat system. Two-tank, sensible heat TES tends to be highly efficient in both energy (energy stored is recovered) and exergy (energy stored is recovered at nearly the same temperature); roundtrip energy efficiencies of up to 98% were reported for the storage system at the Solar Two power tower demonstration (Pacheco 2002). The major limitation to two-tank, sensible TES is the amount of storage media required, especially at the lower operating temperatures used by current trough technology.

Figure 5-10. Thermal Storage and Utility Demand



Source: NREL

To reduce the cost of TES, industry and the U.S. Department of Energy (DOE) have made considerable investments in improvements and alternatives to two-tank, sensible TES. Examples of research topics include the following:

- Low-melting-point salt mixtures, which are identical to research efforts in HTFs
- Solid-media storage, such as graphite, concrete, or ceramics
- Phase-change material (PCM) systems, in which a solid, such as metal or salt, is melted, capturing a considerable amount of energy in the latent heat of the material
- Single-tank thermoclines, in which hot and cold molten salt are stored in one tank and separated by the difference in density between the hot and cold salt
- Thermochemical storage, in which energy is captured using a chemical reaction and, when needed, released by reversing the reaction
- Specially engineered additive materials such as dispersed nanoparticles within salts to increase heat capacity.

These TES options must be compatible with the corresponding HTF, because the most economical TES option is largely contingent on the HTF being used.

For most TES systems, the operational temperature range has an effect on the cost of storage. For example, molten-salt power tower plants can operate at higher temperatures and therefore can reduce the amount of salt required for TES by approximately a factor of three, for a given storage capacity, relative to a current parabolic trough plant.[53] This significant reduction in storage-material mass and the associated reduction in costs make it possible to economically add higher TES capacities. Longer-duration storage (~12 hours) makes near-baseload operation possible. However, at least for the near term, most troughs and towers likely will be built with low levels (6 hours or less) of storage owing to time-of-delivery rate schedules that pay more for peak-power electricity delivery. For example, the Nevada Solar One plant does not have a TES system, although it does provide about 30 minutes of storage via the extra HTF capacity held in the expansion tank.

The storage methods described above are largely focused on TES for parabolic trough, linear Fresnel, and power tower systems. The modular nature of dish/engine systems make them less suitable for large, centralized TES systems. However, several methods for incorporating better dispatchability into dish/engine technologies are being explored, including TES using PCMs and hybrid systems using fossil fuels to augment power production, similar to hybrid options in other CSP systems.

Although delivered cost of electricity, as measured by LCOE, is the most important cost metric for CSP, it does not fully capture the value of CSP as a dispatchable power source. Adding storage to a CSP plant adds value by decreasing variability, increasing predictability, and providing firm capacity during peak load when it is most valuable. CSP plants with TES can bid into ancillary services and capacity

[53] The mass of salt required is inversely proportional to the temperature differential in the storage system; thus, a tower operating from 290°C–565°C requires approximately three times less storage salt than a trough system operating from 300°C–390°C.

markets, where they exist, to realize additional revenue. Even in the absence of explicit markets, the greater capacity value of CSP with TES is recognized in resource planning, where CSP can be given additional consideration due to its dispatchability. This can be observed in the discussion about system dispatch in Section 3.2.6, where CSP is used to follow the significant variability of net load. This ability will become increasingly important to system planners and operators as they seek to maintain the reliability of the bulk power system while integrating large amounts of variable generation such as PV and wind.

5.3.4 Cooling Technology

All CSP systems require cooling, but they differ in their selection of cooling technology. Dish/engine systems are inherently air cooled, whereas trough, Fresnel, and power tower technologies can use wet, dry, or hybrid (a combination of wet and dry) cooling. The selection of cooling technology depends on economics, water availability, and policy. If available, wet cooling is often preferred and provides the lowest cost; however, some CSP developers have voluntarily opted for dry cooling to reduce water consumption. Chapter 7 provides additional discussion on the water use of CSP and other electricity-generating technologies.

CSP facilities need to be built in areas of high DNI, which generally translates into arid, desert areas where water is a scarce resource, making water use a major concern for CSP plants. A typical trough or power tower plant that employs wet cooling can consume 750–1,020 gallons of water to produce 1 MWh of solar electricity (see Chapter 7, Table 7-3). Several strategies can reduce the freshwater consumption of CSP plants: using dry cooling, using degraded water sources, capturing water that would otherwise be lost, and increasing thermal conversion efficiencies. Dry and hybrid cooling systems are commercial technologies that have the potential to reduce CSP water consumption by 40%–97%, depending on the generating technology and project location (see Chapter 7).

Compared with wet cooling, dry and hybrid cooling systems have a higher equipment cost and, depending on design, may have a performance penalty. Various studies have sought to define the cost and performance effects of dry cooling to minimize the impact on LCOE. For example, a recent analysis estimated that switching to dry cooling would raise the LCOE of a trough plant by 3%–8%, depending on location and plant design (Turchi et al. 2010b). The performance and cost penalty for power tower systems should be lower, because CSP technologies operating at higher temperatures experience smaller penalties as a result of using dry or hybrid cooling systems. Nevertheless, the importance of this issue may warrant additional research on indirect air cooling or other aspects to improve efficiencies and reduce costs for dry cooling. Examples of R&D efforts to reduce water use for wet or hybrid cooling include recovering water that is evaporated in cooling towers or using non-traditional sources for cooling water, such as treated saline groundwater, reclaimed water, or water produced from oil and gas extraction.

The effect of cooling technology on CSP system cost and performance varies by technology, location, and climate. Cooler climates make dry cooling more attractive, whereas the performance penalty is greatest for lower-temperature CSP systems in hot climates. Lastly, using TES systems enables some electricity production to be shifted to cooler evening hours, which offsets some of the penalties associated with dry or hybrid cooling systems (Sioshansi and Denholm 2010).

5.3.5 Power Block and Other Cost-Reduction Potential

The current CSP power block for trough, Fresnel, and power tower systems uses many conventional steam Rankine cycle components. It consists of a steam generator that feeds a subcritical Rankine cycle with reheat. The main cost-reduction potential in the current power block is correlated to increased size. For example, the SEGS units in California were built in the 1980s over a period of 7 years, with an increase in size from 14 to 80 MW. The recent Nevada Solar One plant is 64 MW, and several announced CSP plants exceed 200 MW. Increasing the size of the power block results in improved cycle efficiency and lower amortized O&M costs. Sargent & Lundy (2003) report a scaling factor of 0.7 for the power block, indicating that a doubling of gross turbine capacity results in only a 62% increase in power block cost (i.e., $2^{0.7} = 1.62$). However, some developers prefer to use multiple, smaller turbines within a single plant because this can yield higher annual availability. For the long term, alternative power cycles—such as supercritical steam, supercritical carbon dioxide (CO_2) Brayton, and air Brayton—are being investigated, which offer the potential to increase the efficiency and/or decrease the cost of the power block.

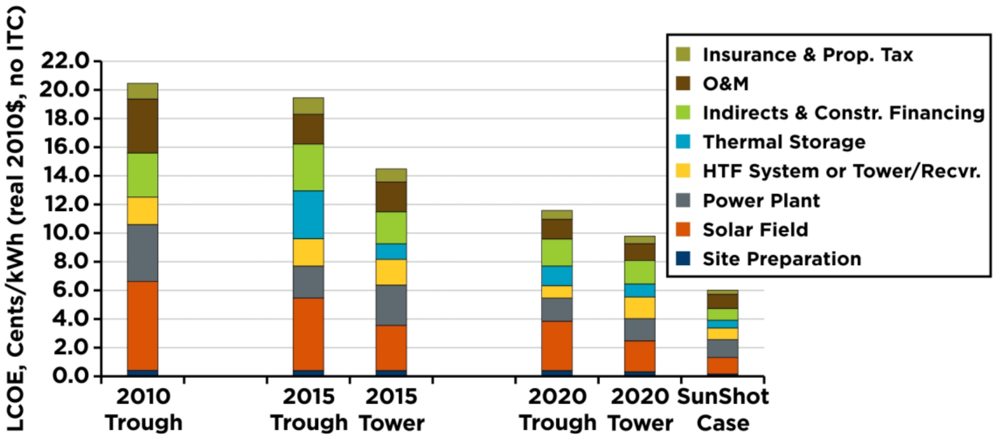
The next generation power cycle is likely the supercritical steam Rankine cycle, because this cycle readily exists at commercial utility-scale fossil plants. However, existing systems are 400 MW electric (MW_e) or larger and may need to be scaled down to better accommodate CSP systems. Operating at temperatures above 650°C may require advanced cycles such as supercritical CO_2 Brayton or air Brayton, which could provide high thermodynamic efficiencies compared with a traditional Rankine cycle. Commercial natural gas Brayton cycles currently exist; however, supercritical-CO_2 and air-Brayton systems do not currently exist beyond the pilot and demonstration scale, respectively. Research efforts are underway to better understand the feasibility of using Brayton cycles for CSP applications.

As unit size increases, the per-megawatt-hour costs for balance of plant and O&M staffing decrease. For plants with multiple units, there is a cost reduction associated with shared infrastructure, such as substations and buildings, and O&M staffing (KJC Operating Co. 1994, Sargent & Lundy 2003). The average O&M cost for CSP is currently about 2.9 cents/kWh and drops to about 1.0 cent/kWh by 2020 in the SunShot target case defined below (Figure 5-11). The main drivers behind the O&M cost reduction are the increase in capacity factor and larger plant sizes. Potential areas for automation, such as reflector cleaning, are also being considered.

Parasitic power consumption can account for 10%–15% of gross turbine output in a CSP plant. Much of this consumption is due to pumping losses, and various options—including pressure-drop reduction, head-recovery, and joint minimization—are being explored to reduce this impact.

A promising low-cost market-entry strategy is augmentation of existing fossil-fired plants with CSP systems. Adding a solar component to an existing fossil-fired plant holds several distinct advantages, including reduction in capital and O&M costs through the use of existing power block hardware and O&M crews, respectively. Such projects have lower risk than stand-alone solar plants and benefit from existing

Figure 5-11. Current and Projected Costs for CSP Trough and Tower Technologies, per Table 5-1



grid connections and inherent fossil backup. A joint study by the National Renewable Energy Laboratory (NREL) and the Electric Power Research Institute (EPRI) suggested that 10–20 GW of solar capacity could be added in the United States through solar augmentation of existing fossil plants (Turchi 2011).

5.3.6 Summary of Technology Improvements and Cost-Reduction Potential

In 2009, the DOE CSP subprogram set a goal to reduce the LCOE of CSP technology to 9 cents/kWh or less by 2020. In pursuit of this goal, two multi-year planning exercises—a parabolic trough roadmap and power tower roadmap—were initiated with representatives from the CSP industry, NREL, and Sandia National Laboratories (Kutscher et al. 2010, Kolb et al. 2011). The purpose of these documents was to describe the current technology, the technology improvement opportunities (TIOs) that exist, and the specific activities needed to advance CSP technology.

In 2011, DOE officially unveiled the SunShot Initiative, an aggressive R&D plan to make large-scale solar energy systems cost competitive without subsidies by the end of the decade. The SunShot Initiative takes a systems-level approach to revolutionary, disruptive (as opposed to incremental) technological advancements in the field of solar energy. The overarching goal of the SunShot Initiative is reaching cost parity with baseload energy rates, estimated to be 6 cents/kWh without subsidies, which would pave the way for rapid and large-scale adoption of solar electricity across the United States.

The SunShot Initiative's target for CSP is 6 cents/kWh or less. Although many of the TIOs identified in the roadmaps are applicable to the SunShot cost-reduction target, it is clear that an "extra step" is necessary to move from the roadmap goals to the SunShot targets. In other words, although the roadmaps laid out pathways to next-generation CSP technologies, SunShot requires even more advanced CSP technological breakthroughs.

Estimated current costs and projected future costs for roadmap and SunShot scenarios are presented in Table 5-1 and Figure 5-11. Current CSP costs are largely based on parabolic trough technology, which is the most mature CSP technology. Trough plants without TES are benchmarked by Nevada Solar One, whereas the Andasol plants in Spain represent the state-of-the-art for plants with TES.

Table 5-1 outlines representative cases for current and future CSP technology costs based on the DOE roadmap exercises. A SunShot target case, outlined later in this section, is also shown. The LCOE estimates for the different cases are presented in Figure 5-11. These values are based on the financial assumptions described in Chapter 8. No ITC is applied when calculating these LCOEs. Both the current and projected LCOE estimates for CSP technologies shown in Figure 5-11 are based on values shown in Table 5-1. The contingency percentage shown in Table 5-1 has been added to each direct cost category.

In Table 5-1 and Figure 5-11, 2010 costs are estimated based on a 100-MW parabolic trough plant with no TES, while the 2015 costs are based on a 250-MW parabolic trough plant with 6 hours of TES and a 100-MW molten-salt power tower plant with 6 hours of TES.[54] Both 2015 configurations are representative of current projects with existing PPAs. After 2015, salt-HTF trough and tower systems are assumed to be proven technologies with expanding deployment that leads to reduced costs via learning and manufacturing volume.

Future Parabolic Troughs

The 2020 trough roadmap case is based on a 250-MW molten-salt HTF trough at a field temperature of 500°C, similar to the configuration being tested by Enel at the 5-MW Archimede demonstration in Sicily. The higher temperature improves power-cycle efficiency and dramatically lowers TES cost. Direct storage of the molten-salt HTF in a thermocline system is assumed, and no adjustment in the performance of the TES system is applied, which assumes improvement in the ability to maintain a sharply stratified thermocline and/or sliding pressure turbine operation with minimal efficiency impacts, as has been suggested by Kolb (2010). Advanced collector designs, employing novel reflector materials and larger-aperture troughs, account for the reduced solar field cost. Operating experience and manufacturing volume are also assumed to lower O&M and capital costs. The major challenge for this case is successful deployment of salt-HTF systems for troughs.

Future Power Towers

The 2020 tower roadmap case is based on a 150-MW molten-salt HTF tower with a supercritical steam power cycle at 650°C. A slight power block cost increase is included based on the current ratio of subcritical-steam to supercritical-steam power blocks for coal plants.

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[54] Although the 2015 power tower analysis presented in Table 5-1 and Figure 5-11 is based on a molten-salt power tower with several hours of TES, the predicted LCOEs for steam and molten-salt power tower technologies are nearly identical. Modeling a steam tower system with little to no storage results in an LCOE prediction within 1 cent/kWh of the 2015 tower values. In addition, much of the cost-reduction potential identified for molten-salt towers also applies to steam towers.

Table 5-1. Current and Projected Costs and Performance Estimates for CSP Trough and Tower Technologies (Analysis with System Advisor Model Version 2010-11-09)

Case	2010 Trough	2015 Trough Roadmap	2015 Tower Roadmap	2020 Trough Roadmap	2020 Tower Roadmap	2020 SunShot Target
Design Assumptions						
Technology	Oil-HTF trough	Oil-HTF trough	Salt tower	Salt-HTF trough	Salt tower	Supercrit. CO_2 combined cycle tower
Solar Multiple	1.3	2.0	1.8	2.8	2.8	2.7
TES (hours)	-	6	6	12	14	14
Plant Capacity (MW, net)	100	250	100	250	150	200
Power Cycle Gross Efficiency	0.377	0.356	0.416	0.397	0.470	0.550
Cooling Method	wet	dry	dry	dry	dry	dry
Cost Assumptions						
Site Preparation ($\$/m^2$)	20	20	20	20	20	10
Solar Field ($\$/m^2$)	295	245	165	190	120	75
Power Plant ($/kW)	940	875	1,140	875	1,050	880
HTF Sys or Tower/Rcvr ($\$/m^2$ or $\$/kW_{th}$)	90	90	180	50	170	110
Thermal Storage ($\$/kWh_{th}$)	-	80	30	25	20	15
Contingency	10%	10%	10%	10%	10%	10%
Indirect (% of direct costs + contingency)	17.6%	17.6%	17.6%	17.6%	17.6%	13%
Interest during Construction (% of overnight installed cost)	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%
O&M ($/kW-yr)	70	60	65	50	50	40
Performance and Cost						
Capacity Factor	25.3%	42.2%	43.1%	59.1%	66.4%	66.6%
Total Overnight Installed Cost ($/kW)[a]	4,250	7,420	5,600	6,160	6,070	3,560
Total Installed Cost ($/kW)[a]	4,500	7,870	5,940	6,530	6,430	3,770
LCOE (cents/kWh, real) [SunShot financial assumptions]	20.4	19.4	14.4	11.6	9.8	6.0

Costs for trough and tower systems are based on analyses made in 2009 and 2010 dollars. No adjustments were made to these costs—net changes in labor and commodity prices for the period are assumed to be within the error of the analysis.

[a] A project's "overnight installed cost" is the total direct and indirect costs that would be incurred if the project was built in an instant, that is, there are no additional costs for financing the construction period. A project's "total installed cost" is its overnight installed cost plus any financial costs incurred to cover payments made during the period between the start of construction and plant commissioning.

Direct storage of the molten-salt HTF in a thermocline system is assumed, and, as with troughs, no adjustment in performance of the TES system is applied. System availability increases and O&M cost reductions are due to increased operating experience. Improved heliostat designs, along with manufacturing experience and scale, account for the reduced solar field cost. The major challenge for this case is scale-down of supercritical steam turbomachinery from the 400-MW or larger scale currently deployed for coal plants to the 150-MW size proposed for CSP.

SunShot Options

The 2020 SunShot case requires more aggressive advances in performance improvements and cost reductions than assumed by the roadmap cases. SunShot-level cost reductions likely include an increase in system efficiency by moving to higher-temperature operation (i.e., maximizing power-cycle efficiency) without sacrificing efficiency elsewhere in the system (i.e., minimizing optical and thermal efficiency losses). Likewise, reducing the cost of the solar field and developing high-temperature TES compatible with high-efficiency, high-temperature power cycles are critical to driving costs down further.

Reaching the SunShot cost target of 6 cents/kWh will require improvements to all subsystems within a CSP plant. The primary source of efficiency gains is the development and implementation of advanced power cycles, with the leading candidates for CSP applications being supercritical-CO_2 Brayton and air-Brayton power cycles. Although there are multiple potential pathways to reaching SunShot targets, the 2020 SunShot case presented in Table 5-1 is based on a 200-MW power tower utilizing a supercritical-CO_2-Brayton power cycle. Power towers may have the highest potential for achieving the SunShot target due to their combination of high optical concentration, high temperature, ease of TES integration, and ability to scale over a wide range of capacities. The development of these new CSP power blocks will require detailed modeling of power systems, followed by the development and testing of new turbomachinery, instrumentation, and heat exchanger designs. The 2020 SunShot case shown in Table 5-1 and Figure 5-11 assumes the deployment of a supercritical-CO_2 power cycle combined with a Rankine bottom cycle. A high-temperature salt serves as receiver HTF, and TES is provided by direct storage of the HTF in a thermocline. Fourteen hours of storage was selected as a value that minimizes LCOE for the assumed case conditions. Supercritical CO_2 power cycles are under development by a variety of academic, laboratory, and industry players for application to solar, advanced fossil, and other energy applications (Rochau 2011). Such a design offers the potential of high overall system efficiency while running at temperatures several hundred degrees lower than required for air-Brayton cycles, thereby lessening materials and thermal loss concerns.

Regardless of the power-cycle design, achieving the SunShot target will require significant reductions in collector costs while minimizing optical efficiency losses. It is essential to remove material weight from the solar field while maintaining adequate wind-load rigidity and optical accuracy. The primary cost components of heliostats include the reflector module, support structure and pylon, drive systems, wiring, and manufacturing infrastructure, all of which will need to be addressed. Proposed improvements include polymeric or thin-glass reflectors, anti-soiling coatings to maintain reflectivity while decreasing O&M costs, novel structures with significantly reduced material content, low-cost drives with wireless field controls, and highly automated manufacturing and installation procedures.

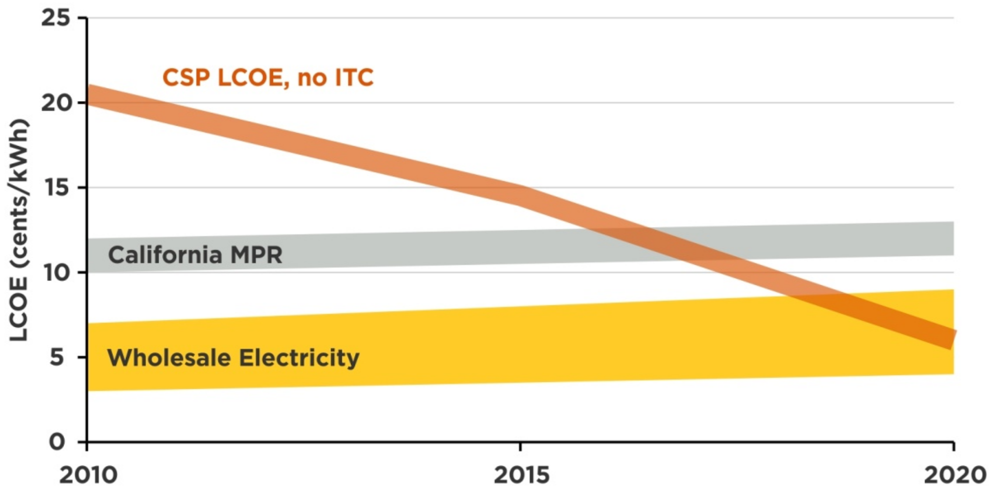
The development and testing of new solar receiver designs and materials will be necessary to accommodate the deployment of advanced, high-temperature power cycles. Air-Brayton systems running at temperatures of 1,000°C and higher may require volumetric receivers or designs with secondary concentrators; such designs are currently being investigated as part of the European Solugas project. Although supercritical-CO_2 systems will run at lower temperatures (600°C–800°C), they will still require the determination of compatible materials and receiver designs for high-pressure CO_2 systems. Selective receiver tube surface coatings that maintain high absorptivity while minimizing emissivity and are stable at high temperatures in air are needed for new receiver designs. Initial research suggests that candidate materials may be found among those originally investigated for trough receiver coatings.

Lastly, as temperatures are increased and new HTFs are deployed, TES systems will need to advance to maintain the relatively high efficiency and low cost of current CSP TES systems. Supercritical steam and CO_2 are compatible with thermocline and two-tank storage concepts, but salts with stability and low corrosivity at the proposed higher temperatures may be required. Air-Brayton cycles in particular would benefit from low-cost solid-phase storage media or other novel TES concepts. Although the SunShot case presented in Table 5-1 and Figure 5-11 assumes a supercritical-CO_2 combined cycle with salt storage, alternative approaches are being considered and may prove a better fit.

The combined effect of lower capital costs, improved performance, and learning should lead to a rapid drop in LCOE by the end of the decade. Figure 5-12 shows the calculated decrease in LCOE if the CSP industry achieves the SunShot cost and performance targets presented above. The LCOE estimates in Figure 5-12 are based on the financial assumptions listed in Table 8-1 of Chapter 8, which are applied to both CSP and utility PV cases. In the near term, CSP with a 30% ITC is competitive with the solar-weighted California Market Price Referent (MPR). The California MPR represents the market price of electricity in California and is used as a benchmark to assess the above-market costs of renewable portfolio standard (RPS) contracts in California (CA PUC 2009). Solar weighting refers to the time-of-delivery credit applied to solar generation due to its good coincidence with peak load. When the 30% ITC expires at the end of 2016, CSP is projected to remain competitive with the California MPR. The LCOE projections shown in Figure 5-12 do not include any ITC, even though current U.S. law maintains a 10% ITC after 2016. This choice is made to be consistent with the SunShot Initiative’s goal of making large-scale solar energy systems cost competitive without subsidies by the end of the decade.

Finally, although installed cost and LCOE are dominant metrics, they are not the sole criteria for technology selection. For example, CSP with TES is recognized to achieve close to 100% capacity value—much higher than wind or PV systems (Lew 2010). This dispatchability provides greater grid stability, especially as renewable generation penetration increases. As one example of this value, Arizona Public Service applied up to a 3 cents/kWh of credit to CSP for operational and capacity credit (APS 2009).

Figure 5-12. Projected SunShot CSP LCOE (2010 U.S. Dollars, Real) versus Future Market Prices



5.4 Materials and Manufacturing Requirements

The long-term availability of materials and manufacturing capacity is critical for increased deployment of CSP plants. The analysis here focuses on the most important raw materials needed for the SunShot scenario: aluminum, steel, glass, HTF, and molten salt. In general, these materials are not subject to rigid supply limits, but they are affected by changes in commodity prices. Manufacturing and supply chain issues are also considered.

5.4.1 Materials

Table 5-2 provides the construction material breakdown for a 100-MW parabolic trough plant with 6 hours of TES and a solar multiple of 2.2, i.e., for 2010 technology design and performance characteristics as adapted from Burkhardt et al. (2010), which assumes a 103-MW plant with 6.3 hours of TES. The estimates shown in Table 5-2 do not include commonly available construction materials such as gravel, asphalt, and various plastics, which may be used in significant volumes in CSP plants but generally are not subject to supply constraints. The baseline plant depicted in Table 5-2 generates approximately 426,000 MWh of net energy per year.

Table 5-3 uses the data in Table 5-2 to provide a preliminary estimate of the annual material requirements for CSP assuming the SunShot targets are met. The SunShot scenario assumes peak annual U.S. CSP installations of 4 GW. Similar to the baseline plant shown in Table 5-2, in order to be conservative, a 100-MW trough plant capacity is assumed, although the solar multiple and hours of TES have been increased to 2.8 and 12, respectively. In addition, material requirements have been adjusted to account for the estimated efficiency improvements in the SunShot case. Whereas Table 5-2 is for a parabolic trough plant, Table 5-3 assumes a mix of CSP technologies. This scenario assumes that the transition to next-generation CSP technologies includes higher-temperature operation and a transition away from synthetic oil as an HTF.

Table 5-2. Construction Materials for Nominal 100-MW Parabolic Trough Plant with 6 Hours of TES

Material	Trough Plant Subsystem (MT)				
	Solar Field	HTF System	Power Block	Thermal Storage	Total
Aluminum	16	51	18	0	86
Other Non-Ferrous Metal	68	6	66	2	142
Steel and Iron	17,556	3,346	2,277	3,654	26,833
Glass	10,971	-	11	0	10,982
Concrete	27,184	5,709	18,738	9,339	60,970
Synthetic Oil	0	4,146	0	0	4,146
Nitrate Salts	0	0	0	57,328	57,328

Source: Adapted from Burkhardt et al. (2010)

Table 5-3. Projected Annual Material Requirements for CSP Assuming Maximum SunShot (4 GW/year) U.S. Deployment

Scenario	Material Requirements (MT)				
	Glass	Aluminum	Steel and Iron	Synthetic Oil	Molten Salt
SunShot	360,000	2,700	840,000	—	1,000,000

Glass for CSP reflectors is manufactured via a float glass process. Global production of common float glass in 2007 was approximately 44 million MT, while global production capacity was estimated at 65 million MT (AGC Flat Glass 2010). U.S. production of float glass in 2007 was approximately 5.5 million MT, with additional available capacity of approximately 0.5 million MT (Headley 2008). Based on this standard float glass capacity, the glass requirements in the SunShot case correspond to approximately 7% of 2007 U.S. production or less than 1% of 2007 global production. However, CSP plants use low-iron glass, which is produced through a similar process as common float glass, but with specific feedstock sand and rigorous contamination requirements. Current production of low-iron glass is limited by relatively low demand, which in turn leads to reduced production runs and increased cost. Increased demand for low-iron glass would result in the operation of dedicated production lines and reduced costs.

Although glass is clearly not a constraint on increased CSP deployment, it is possible that non-glass reflectors—such as reflective films laminated onto aluminum sheets—may be used in commercial CSP facilities as the technology continues to mature. If all CSP were to use non-glass films as reflectors, approximately 40 million m^2 of reflecting material would be required on an annual basis. This volume is roughly half of the current production volume of solar-control window film (which requires a similar production process) of approximately 80 million m^2 annually.

The SunShot scenario relies primarily on steel for the solar field structures, with additional steel needed for HTF piping, molten-salt storage tanks, heat exchangers, and the power block. The peak steel requirement in the SunShot scenario is less than 1 million MT/year, or approximately 1% of the 84 million MT of U.S. steel production in 2008 (Fenton 2010).

Aluminum can serve as a replacement material for a significant fraction of the structural steel in CSP plants and can also be used as the reflector material in CSP plants using thin-film reflectors. Each MW of solar collector field using aluminum-based structures would require approximately 50 MT of aluminum with a solar multiple of two. An additional 22–29 MT/MW would be required for plants using coated aluminum or thin-film laminated reflectors. A deployment scenario including a shift to aluminum would reduce steel requirements in Table 5-3 by approximately 50%; however, it would also require approximately 300,000 MT of aluminum per year for SunShot scenario deployment. Aluminum production in the United States in 2008 was approximately 2.4 million MT, with another 4.1 million MT imported (Fenton 2010). Thus, a deployment scenario including a shift to aluminum could require up to 5% of current annual U.S. aluminum use.

The current HTF for existing parabolic trough systems consists of a eutectic mixture of diphenyl oxide and biphenyl. This fluid type is widely used in large volumes in the global chemical industry, and there appears to be no supply constraints. Regardless, the SunShot scenario assumes a shift away from synthetic oil as an HTF to other materials that can operate at higher temperatures, such as molten salt.

Molten salt is currently used as the TES medium in most CSP storage system designs and as the HTF in salt-receiver power towers. Much of the world's nitrate salts are derived from deposits in the Atacama region of Chile. Proven reserves are 29.4 million MT, although this figure is based on exploration of only 16% of total reserves (SQM 2009). Burkhardt et al. (2010) estimate that the nitrate salt requirement for a thermocline storage system is approximately 32% of the two-tank system assumed in Table 5-2 and that higher-temperature TES would reduce this requirement even further. As a result, Table 5-3 assumes a MT/MW nitrate salt requirement equal to approximately 22% of the requirement in Table 5-2. For SunShot scenario total deployment levels, the cumulative required salt is roughly two-thirds of proven Chilean reserves. Although alternative salts for storage and/or HTFs could be used, the use of nitrate salts is still feasible. If nitrates remain the salt of choice, it is possible that increased CSP deployment would require expansion of nitrate salt production, possibly including synthetic production via the Haber-Bosch process, which is used worldwide for fertilizer production.

5.4.2 Manufacturing and Supply Chain

The CSP supply chain is overwhelmingly domestic, from materials to manufacturing. Most, if not all, materials necessary to build a CSP plant can be found in the United States. However, substantial increases in the manufacturing capacity of CSP components will be required to achieve the SunShot scenario. CSP plants require a number of components; some are similar to other industrial components and others are unique to the industry. In addition to the structural and reflector components, CSP plants require manufacturing of receiver components and the power block.

Reflectors are manufactured from readily available materials. The current manufacturing capacity is consistent with the requirements for facilities under construction or scheduled for construction in the near term. It takes approximately 1 year to construct a glass reflector manufacturing line. Therefore, as the demand for reflectors increases, the reflector industry should be able to ramp up production quickly enough to meet demand. As a result, the availability of reflectors should not be a bottleneck to achieving the SunShot scenario.

Receiver tubes for parabolic troughs and linear Fresnel plants are fabricated from readily available materials such as glass tubing, stainless-steel tubing, and steel bellows. Although the materials are basic, manufacturing high-quality receivers does require expertise and specialized processes. This could create short-term constraints on scaling-up manufacturing of receivers. The current manufacturing capacity, however, is adequate to meet the demands for facilities currently under construction and scheduled for construction in the near term. Experience with current manufacturers of receiver tubes shows that significant manufacturing lines can be brought to production in approximately 1–2 years.

Power tower receivers are similar in design to standard industrial boiler equipment. All developed countries and many developing countries have boiler manufacturing capabilities and are capable of fabricating components such as steam boilers and pressure vessels. Boilers and turbines to be used in CSP plants will replace similar products that would have been manufactured for fossil-fuel power systems. The manufacturing capability that exists to build conventional fossil-fuel boilers can be readily adapted to fabricate multiple gigawatts per year of steam or molten-salt receivers. A good example of this adaptation is the steam receivers fabricated for the Sierra Sun Tower in Lancaster, California. These receivers were manufactured by two separate conventional boiler shops in the United States without significant changes to the shop floor or development of new manufacturing techniques.

In a dish/engine system, the receiver and power block subsystems are well integrated into a single unit. Dish/Stirling engines use materials and manufacturing processes common to the automotive industry that allow for efficient mass production.

For parabolic trough, power tower, and linear Fresnel systems, the current power block is very similar to those used in conventional fossil-fired plants, thus, manufacturing capabilities for these power blocks and other system components are available worldwide. The development of new turbomachinery—such as that required for new supercritical-CO_2 or air-Brayton solar turbines—will also use materials and manufacturing processes common to the existing gas and steam turbine industries.

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6. Integration of Solar into the U.S. Electric Power System

6.1 INTRODUCTION

The *SunShot Vision Study* lays out a scenario in which solar energy technologies satisfy a significant fraction of U.S. electricity demand. The contribution of solar energy in this scenario is projected to be 14% and 27% of total contiguous U.S. electric demand by 2030 and 2050, respectively, which introduces several integration challenges.

The first challenge is to ensure that the system can operate reliably with increased variability and uncertainty. Unlike the hydropower and thermal generation sources that currently provide most of the nation's electricity, PV generation in particular has limited dispatchability. Another challenge is planning for and building the new transmission facilities that will be required to access high-quality solar resources. A third major challenge involves evaluating and addressing the impacts of distributed solar generation on electricity distribution systems, most of which were not designed to accommodate generation at the point of use. Previous work on solar integration, along with substantial work on wind integration, reveals several potential solutions for these challenges to widespread deployment of solar-powered generation technologies.

This chapter gives an overview of the major integration challenges along with potential solutions needed to achieve the SunShot scenario. Section 6.2 describes the operation of the electric power system and the important role of reliability standards in ensuring adequate balancing of generation and demand. It then discusses the characteristics of the solar resource and generation technologies, including variability, uncertainty, and capacity value. Section 6.2 also addresses the integration of solar into power system operations and planning, including lessons learned in this and other studies (DOE 2008) to maximize the role of solar energy and minimize integration costs. In addition, it discusses the specific role of markets in providing flexibility and incentivizing efficient use of generation and demand resources. Section 6.3 discusses the feasibility of developing the transmission infrastructure required to accommodate increased development of solar power installations and to connect high-quality solar resource regions to load centers. This section highlights the importance of developing models and performance standards to ensure the reliable operation of the transmission system with significant levels of solar energy. Section 6.4 covers the feasibility of integrating significant levels of solar energy into the existing and future distribution grid, which will include improved monitoring, information exchange, and control at the distribution level.

6.2 Planning and Operation of Electric Power Systems with Solar Electric Generation

The electric power system has developed historically with thermal power plants as the main source of generation. Nearly 90% of the installed generation capacity in the United States is composed of dispatchable natural gas, coal, and nuclear power resources. Incorporating a large fraction of electricity from photovoltaic (PV) and concentrating solar power (CSP) systems will require changes to many of the practices and policies that are designed for dispatchable thermal plants. The variability and uncertainty associated with solar generation requires new sophistication of real-time operations and planning practices. Maintaining reliability and the most economic dispatch will undoubtedly require new strategies to manage the grid. The need to evolve new grid operating paradigms becomes even more significant considering the likely deployment of both solar and other variable generation sources such as wind.

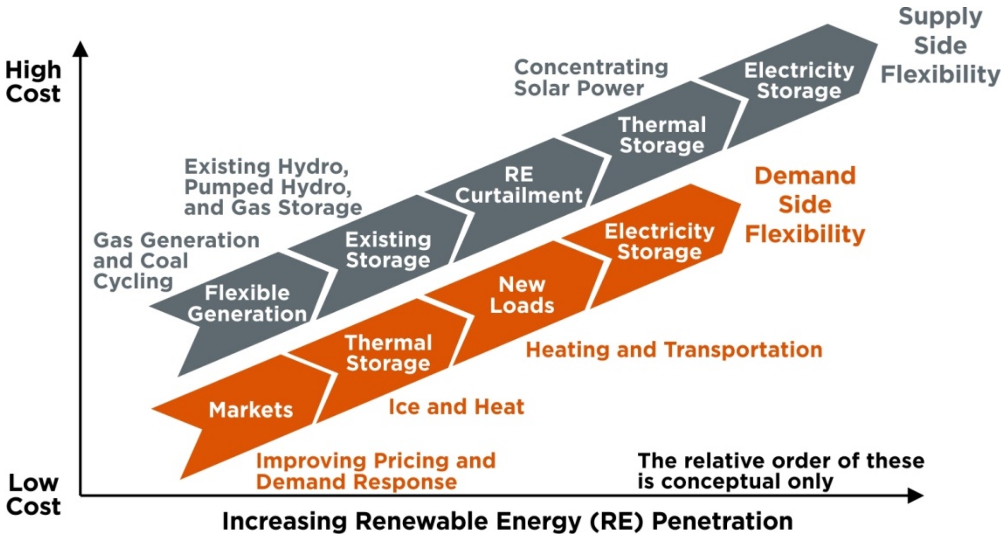
Studies of increased levels of solar and wind generation show that the variability and uncertainty associated with weather-dependent resources can be managed with increased operating reserves, increased access to flexibility in conventional generation plants, demand response and storage, better cooperation among adjacent electrical operating areas, and incorporation of solar and wind generation forecasting into system operations. The set of technologies and mechanisms enabling greater penetration of solar energy can be described in terms of a flexibility supply curve that can provide responsive energy over various timescales. Figure 6-1 provides a conceptual flexibility supply curve that summarizes the options for incorporating variable generation. The optimal mix of these technologies has yet to be determined, but several sources of flexibility will likely be required for the most cost-effective integration of solar at high penetrations.

6.2.1 Power System Design, Planning, and Operations

Power systems are planned and operated to meet established performance and reliability standards. System operators work with existing system assets—generation, network, and responsive demand—to maintain safe and reliable system operation in real time and in compliance with established standards. As the standards generally do not dictate how they must be met, different system planning and operations practices have evolved to meet system performance and reliability targets while minimizing costs. An effective way to reduce the operating cost of producing electricity and increasing reliability of supply is to aggregate a large number of different generation resources and loads. This type of aggregation relies on a dynamic transmission and distribution network and associated communication and control infrastructure.

Continually balancing generation and load, even with a degree of uncertainty and unpredictability in both load and generation, is among the primary requirements for operating the power system reliably. Balancing Authorities (BAs) accomplish this

Figure 6-1. Options for Increasing Power System Flexibility to Accommodate Renewables

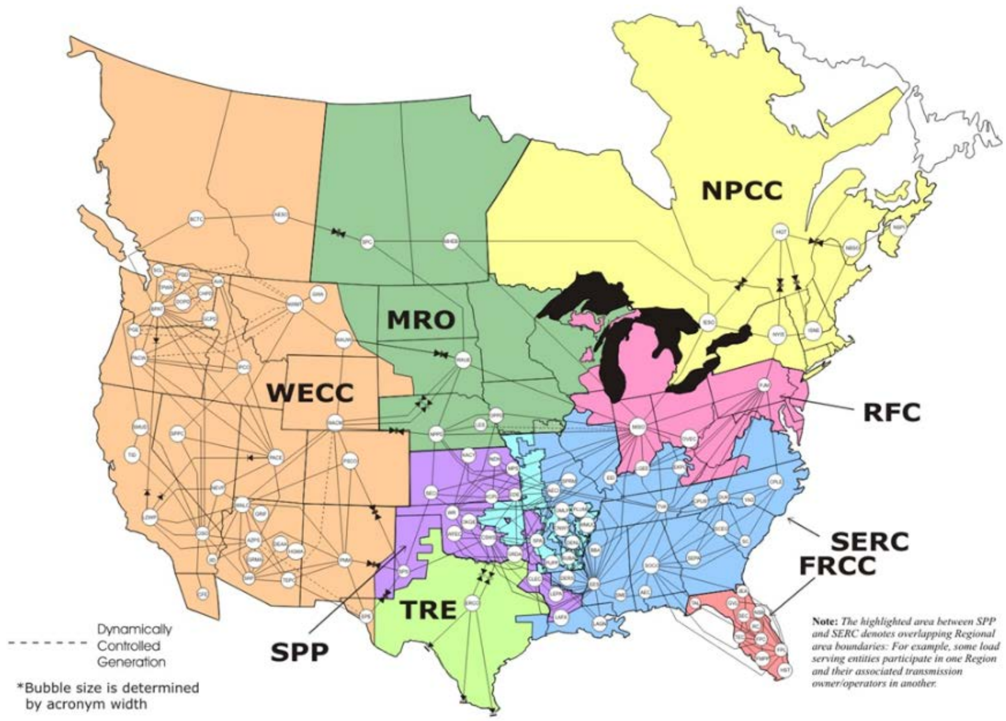


Source: Denholm (2008)

by scheduling, dispatching, and controlling generation and by facilitating exchange of electricity with other BAs. The map depicted in Figure 6-2 identifies the eight regional entities[55] and well over 100 BAs that coordinate the supply of electricity within the bulk power system. Each BA is responsible for balancing energy supply with demand and maintaining reliable service in an assigned BA area (NERC 2008). The interchange of power among BA areas must be scheduled and managed to avoid exceeding the capacity of transmission interties. Because load forecasts are imperfect and generation cannot respond instantaneously, it is neither possible nor required to match perfectly at all times the actual interchange to the desired or scheduled interchange across BA area boundaries. To balance changes in load and generation that occur over a short time frame—from seconds to minutes—automated systems continually adjust the output of generators that are able to ramp up and down relatively quickly. This class of operating reserves is required to address regulation (the ability to respond to small, random fluctuations around normal load), load-forecasting errors (the ability to respond to a greater or less than predicted change in demand), and contingencies (the ability to respond to a major contingency such as an unscheduled power plant or transmission line outage) (NERC 2008). Over periods on the order of tens of minutes to hours, operators optimally readjust the output of online generators in a least-cost order, taking into account short-term forecasts and system constraints. Over longer periods, spanning hours to days, operators commit least-cost generators so they are available for dispatch during real-time operations. Unit commitment takes into consideration, among other

[55] The North American Electric Reliability Corporation (NERC) works with eight regional entities to improve the reliability of the bulk power system, accounting for most of the electricity supplied in the United States, Canada, and a portion of Mexico. The entities responsible for regions in the Eastern Interconnection include: Florida Reliability Coordinating Council (FRCC); Midwest Reliability Organization (MRO); Northeast Power Coordinating Council (NPCC); Reliability First Corporation (RFC); SERC Reliability Corporation (SERC); and Southwest Power Pool, RE (SPP). The Electric Reliability Council of Texas (ERCOT) Interconnection is covered by the Texas Reliability Entity (TRE) and the Western Interconnection by the Western Electricity Coordinating Council (WECC).

Figure 6-2. Regions and Balancing Authorities in North America



Source: NERC (2011)

factors, forecast demand, generation availability, and operating constraints of individual generators.

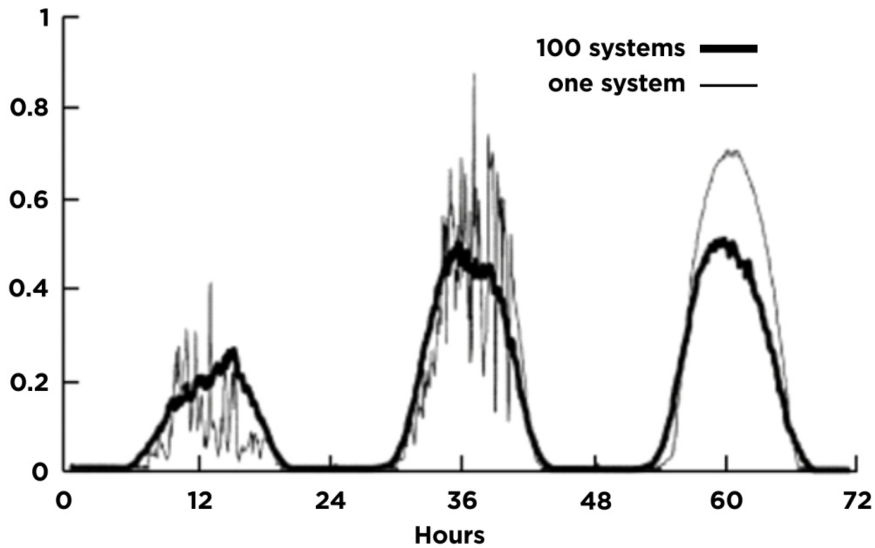
System planners are responsible for ensuring that the assets are adequate for the reliable operation of the system. Complex models and operational experience are used to evaluate the adequacy of the transmission and generation infrastructure. One measure of adequacy is the ability of the system to serve load with a certain level of reliability (measured by the effective load-carrying capability of the generation fleet). Power systems must also be able to operate reliably under abnormal conditions; that is, they should be sufficiently robust to recover from significant contingencies, such as the unplanned loss of a large generator or a large transmission line. System planners design upgrades and operating procedures to ensure that minimum margins of transmission and generation capacity can be maintained at all times.

6.2.2 Solar Resource and Technology Characteristics Relevant to Grid Integration

Solar electricity has unique attributes relative to conventional generation that need to be accounted for to reach high penetrations in the electric power system. The primary characteristics of solar generation relevant to system operation and planning are variability (and associated uncertainty) and capacity value. Although significant measurement data are not available for analysis of variability, some general characteristics of the solar resource are known.

With respect to power-system operations, the most relevant characteristics of solar generation are the output variability and rate of change—ramping—over different time periods, and the predictability of these ramping events. Figure 6-3 illustrates the high degree of variability and high ramp rates that can occur in a single PV plant over a short time frame—from seconds to minutes—resulting from passing clouds. Figure 6-3 also shows that the aggregate of multiple solar plants over a wide geographical area, but within a single BA area, has far less variability and smaller short-term ramp rates relative to the amount of PV deployed. This demonstrates the value of geographic diversity in mitigating short-term variability (Mills and Wiser 2010).

Figure 6-3. Solar Variability: 100 Small PV Systems Throughout Germany, June 1995



Source: Wiemken et al. (2001)

The variability and predictability of the aggregated solar electric generation in a system depends on the degree of correlation of cloud-induced variability between solar plants. The correlation between solar plants, in turn, depends on the locations of solar plants and the regional characteristics of cloud patterns. Generally, the variability of solar plants that are farther apart are less correlated, and variability over shorter time periods—minutes—is less correlated than variability over longer time periods, such as multiple hours (Murata et al. 2009). The decrease in correlation with distance leads to much less relative variability, i.e., a smoothing effect. Consequently, forecast accuracy improves as the number of solar plants aggregated over larger areas increases.

Unlike PV systems, most CSP plant designs have inherent thermal inertia that greatly reduces or eliminates short-term variability. Parabolic trough plants using oil as the heat-transfer fluid and modern direct-steam systems with integrated steam storage vessels can typically operate in a predictable manner with no solar input for a period of about one-half hour (Steinmann and Eck 2006). Dish/engine CSP plants have less thermal inertia than the other CSP technologies, and thus the output of these plants can vary much more with passing clouds.

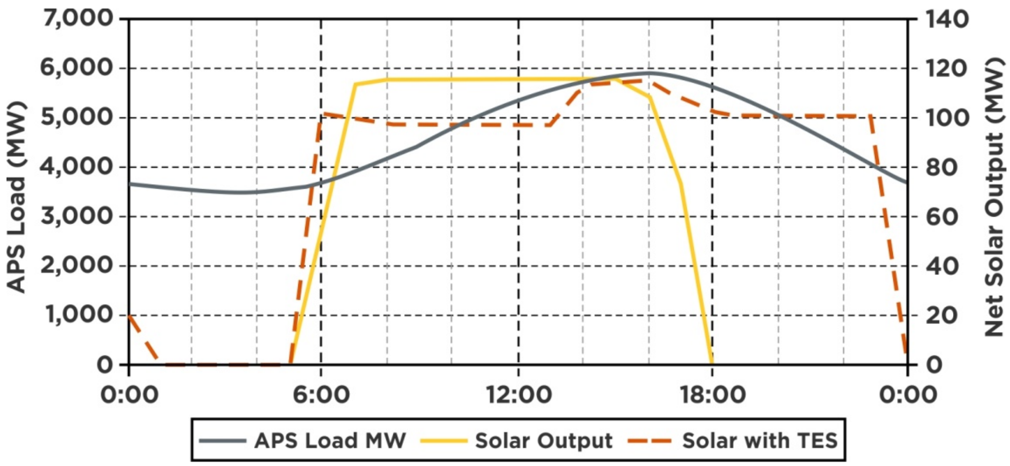
Some CSP plants are designed with several hours of thermal energy storage (TES), allowing them to generate electricity even during periods with low or zero solar input. This provides operating flexibility and the ability to shift solar generation into the evening hours or other periods to better match the load profile and provide more value to the grid. The additional capital costs for multi-hour thermal storage must be justified by the reduced levelized cost and/or increased value of energy delivered by the plant (Sioshansi and Denholm 2010). A number of cost projections indicate that the addition of thermal storage will reduce the levelized cost of solar energy for parabolic trough plants (DOE and EPRI 1997, Sargent & Lundy 2003, Stoddard et al. 2006). Thermal storage with molten-salt power tower plants is projected to produce even more pronounced reductions in the levelized cost of energy (LCOE) relative to power towers without storage.

With the exception of dish/engine plants, existing CSP plant designs can also be augmented readily with fossil-fueled generation, providing either short- or long-term dispatchable output in the absence of solar input. The Solar Energy Generating Systems (SEGS) plants in southern California, for example, include natural gas fuel augmentation. The reverse is also true; in some cases, fossil steam-cycle generation plants have been augmented with CSP, e.g., the Florida Power & Light Company (FPL) Martin Next Generation Solar facility (FPL 2010). This approach could result in lower CSP cost by using generation components already in place.

With respect to system planning, the most relevant characteristic of solar is the correlation of solar power with periods of high electricity demand and, therefore, high system risk. The correlation between solar resources and high demand affects the capacity value that can be assigned to solar generation for the purposes of generation resource planning. The capacity value assigned to the generation resource indicates the fraction of its nameplate capacity that contributes to the overall capability of the system to reliably meet demand. The capacity value of new solar plants is expected to be greatest where electricity load and solar production are strongly correlated. Electricity demand in most of the United States, and particularly in the Southwest, is the greatest during summer afternoons when solar insolation is also generally high. Figure 6-4 illustrates the coincidence of electricity load and modeled solar output for a CSP plant with no storage or with 6 hours of thermal storage. In Figure 6-5, PV acts to reduce the peak demand during the summer, reducing not only the fuel used, but also potentially the need to construct new generation capacity. PV plants would be slightly less correlated with load because their output tapers off in the evening when demand is highest.

As suggested in Figure 6-4, the incorporation of on-site energy storage and the amount of such storage greatly increases the probability that solar generation will be available when the system is most in need of that generation. A detailed probability analysis of the capacity value for CSP with 6 hours of thermal storage in the western states found capacity values of 90%–95% (GE Energy 2010), which is similar to conventional power plants, at a 3.5% energy penetration level. At higher penetrations, the larger amount of storage deployed (up to 14 hours) should maintain very high capacity values. A more detailed discussion of the capacity value of CSP plants with thermal energy storage is provided by Madaeni et al. (2011).

Figure 6-4. Southwestern Utility Load and CSP Generation Profile Illustrating That Thermal Energy Storage Can Increase the Coincidence of High Load Periods and Solar Plant Output



APS: Arizona Public Service
Source: Price et al. (2007)

For solar generation without storage or fossil-fuel augmentation, either PV or CSP, the capacity value depends much more heavily on the correlation between system peak load and solar insolation. A variety of methods and technologies has been used to estimate the capacity value of PV, and they result in a wide range of estimates. The *Western Wind and Solar Integration Study*, which used a traditional loss of load probability technique, found a 27%–38% capacity value for PV—based on the direct current (DC) rating—in the U.S. Southwest for penetration levels up to 1.5% by energy (GE Energy 2010). Xcel Energy's Public Service of Colorado used a similar technique at a penetration level of 1.4% by capacity and found a 53%–70% capacity value for PV and 66%–83% for CSP without storage (Xcel Energy 2009). Other studies have estimated the effective capacity of PV plants in the Southwest greater than 60% and sometimes greater than 80% of the nameplate capacity of the solar plant (Hoff et al. 2008, Perez et al. 2006). In other parts of the United States, these studies have found capacity values greater than 50% for many regions, but lower value in others such as 30% for parts of the Pacific Northwest, where peak electricity demand occurs during winter evenings.

It is misleading to compare capacity value results directly because of the differences in methodologies, technologies, orientation, load shapes, and penetration levels. For example, the Xcel study compared PV to a natural gas plant, and the *Western Wind and Solar Integration Study* compared PV to a perfect plant (Xcel Energy 2009, GE Energy 2010). The high capacity values (60%–80%) from the Perez et al. (2006) study are for two-axis tracking PV systems. It is also important to note that most of these high capacity values occur at relatively low penetration, below 5%, and the capacity value drops significantly as penetration of PV increases. Hoff et al. (2008) show an example of a Southwest utility where the capacity value of PV decreases from about 80% to about 60% as the nameplate capacity of PV increases from 1% of the peak load to 20% of the peak load. The reason for this decline in reliability contribution is that, as solar output increases, the times of peak net electricity demand will increasingly occur when solar output is low.

6.2.3 System Operations with Solar and Lessons Learned

Utility operators are already accustomed to dealing with variability in the load. Accommodating the variability in the net load—load minus solar (and wind) generation—is possible with approaches similar to those used currently. Because wind generation has characteristics that are similar to solar generation, the large body of experience with wind integration can provide valuable insights regarding costs of solar integration, as well as the changes to operations and markets needed to facilitate large-scale integration of solar generation. This includes significant international experience in locations such as Germany and Spain where penetration of wind energy exceeds that in the United States.

The wind-integration studies find modest cost impacts (Gross et al. 2007, Smith et al. 2007), and a summary of wind-integration costs in the United States shows the expected range to be between $5 and $10/megawatt-hour (MWh) for penetrations up to 30% on a capacity basis, i.e., about 20% on a generation basis (Wiser and Bolinger 2009). The modest cost impacts of wind integration have been based on exploitation of low-cost options for flexibility to balance the system. For example, full utilization of the existing flexibility in the utility's dispatchable fleet or existing storage systems can help accommodate the increased variability and uncertainty. At higher penetrations, when these low-cost options have been fully tapped, integration costs are expected to rise.

A few studies have quantified specific aspects of solar-integration costs. EnerNex Corp. (2009) evaluated the costs of managing day-ahead forecast errors for up to 800 megawatts (MW) of solar in the Public Service of Colorado system. The cost of the day-ahead forecast error with 200 MW of PV, 200 MW of CSP with 4 hours of thermal storage, and 400 MW of CSP without thermal storage was between $4 and $7/MWh, depending on assumptions about natural gas prices. More detailed studies are needed to develop integration cost estimates for solar generation scenarios.

The existing power system evolved over a long history with dispatchable generation with controllable and largely predictable output. Operational strategies and tools, market structures, and system planning were developed for a dispatchable generation paradigm. Significant institutional and physical steps need to be undertaken to transform the existing power system to one that is planned with and integrates high levels of variable and uncertain resources. A "one size fits all" solution does not exist for solar electric integration, but in general, more flexible markets and operational practices can significantly reduce the cost of solar integration and can allow for cost-effective deployment of higher penetration levels. Based on U.S. and international experience (DeCesaro et al. 2009, Ackermann et al. 2009, Milligan et al. 2009a, EnerNex Corp. 2010, GE Energy 2010, Smith et al. 2007), several key conclusions have emerged, which are listed here and described in greater detail below:

- Managing the net load economically and reliably will require flexibility in conventional generation.

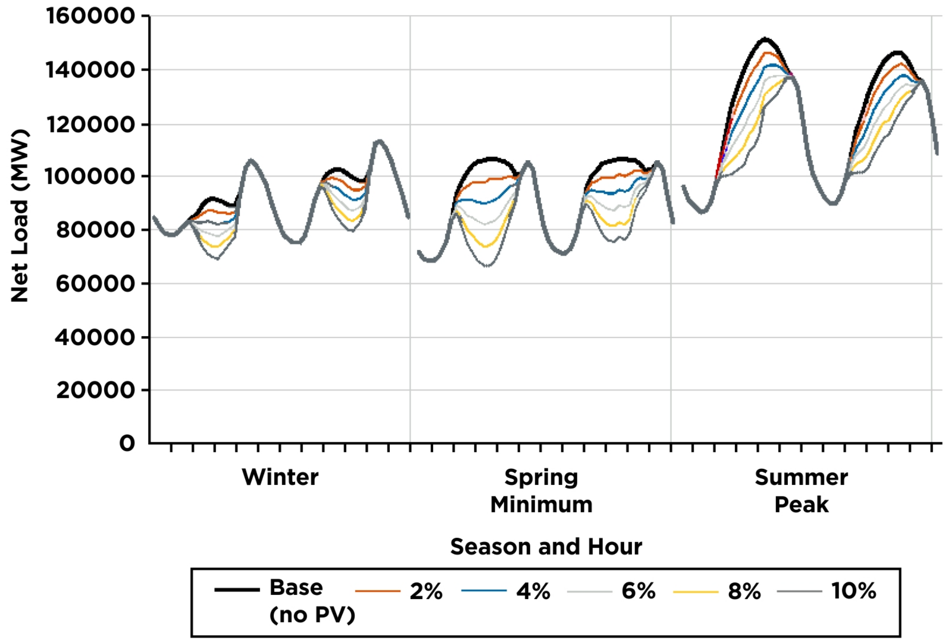
- Aggregation over greater load and generation sources provides opportunities to handle the additional variability and uncertainty of solar generation more efficiently.
- Power system operations must be focused on managing the net variability of aggregated load *and* generation, not the variability of individual plants.
- Increased reserves may be required to manage the additional net variability and uncertainty.
- Better integration of solar forecasting into scheduling and dispatch helps reduce integration costs.
- Shorter-term scheduling can decrease reserve requirements and integration costs.
- Full participation of load as a controllable resource is a cost-effective way to increase system flexibility.
- New mechanisms are needed to incorporate distributed energy resource (DER) assets efficiently.
- Different generation mixes and sources of flexibility will provide the lowest overall cost of energy.

Managing the net load economically and reliably will require flexibility in conventional generation. Increased flexibility of the conventional generation fleet will be required to accommodate large penetrations of solar energy. Even at lower penetration levels, increased penetration of solar without storage can lead to a net load shape that requires thermal generation units to ramp more than they would without the solar. Additional start-ups and shut-downs, part-load operation, and ramping will be required from the conventional units to maintain the supply/demand balance (Goransson and Johnsson 2009).

This additional flexibility comes with some cost and may increase plant operation and maintenance costs (Troy et al. 2010). Figure 6-5 shows the new load shapes with several penetrations of PV in the Western Interconnection territory. Following the net load will require more flexible generation units and may increase generation costs. This may also require increased use of natural gas storage to increase the use of flexible gas turbines and decrease contractual penalties for forecast errors in natural gas use (Zavadil 2006). At higher penetration, energy prices may fall toward zero when minimum generation limits on thermal plants are reached. In an inflexible system, this would lead to curtailment of solar and an increase in the relative cost of energy from PV (Denholm and Margolis 2007). Proper market incentives, as discussed in the next section, can ensure that the ability of a generator to provide flexibility is made available to the system operator.

Aggregation over greater load and generation sources provides opportunities to handle the additional variability and uncertainty of solar generation more efficiently. Aggregation can be in the form of larger BA Areas or through cooperation among BAs, allowing for greater ability to share supply and demand resources. This simultaneously gives access to more responsive resources and reduces net variability, providing several benefits. First, aggregation of dispersed solar resources and load mitigates the net load variability because short-term variability is largely uncorrelated for solar systems at multiple locations. The larger

Figure 6-5. Seasonal Average Load Net PV Generation Shape for Several PV Penetration Scenarios in the Western Interconnection



Source: Denholm et al. (2008)

the region over which the solar plants and load are aggregated, the lower the variability will be. Second, increased BA Area size allows operators to access a larger pool of reserves, reducing the proportional cost of managing the variability. Aggregation of resources and load can be accomplished by physically increasing the size of BA Areas. In several regions with restructured electricity markets, such as PJM Interconnection LLC (PJM) and the Midwest Independent Transmission System Operator (Midwest ISO or MISO), BA Area consolidation has taken place in recent years (see Figure 6-2). In locations without structured wholesale markets—such as the Southwest, Northwest, and Southeast—effective cooperation among BAs can still provide substantial opportunities for resource sharing and lower integration costs for variable generation. Dynamic scheduling of variable generation and sharing of contingency reserves, as well as regulating reserves, are examples of effective collaboration among BA Areas that increase flexibility and reduce cost of integrating variable generation, without physical consolidation of BA Areas.

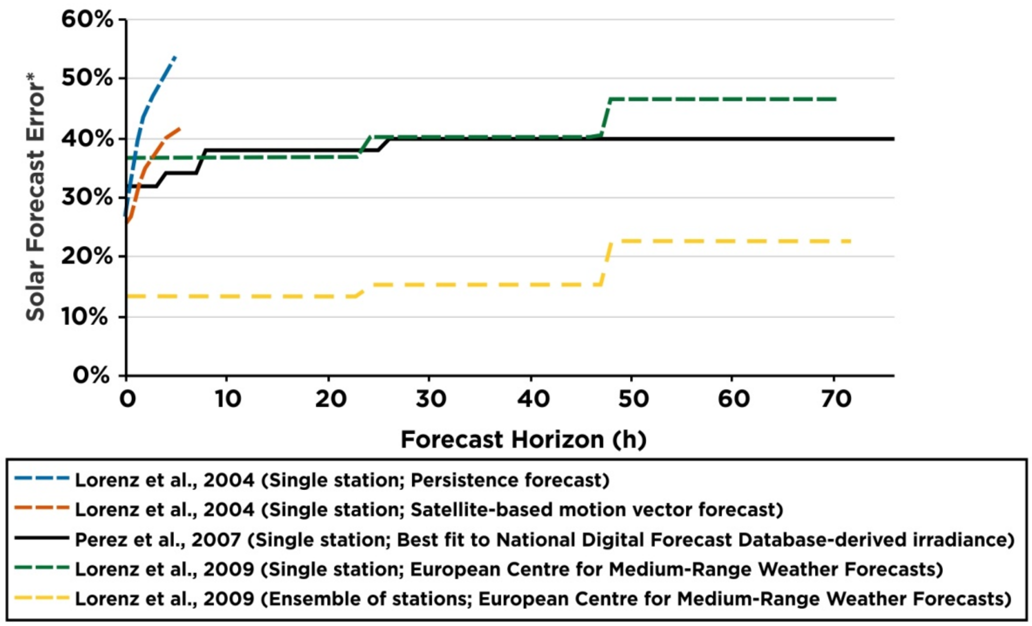
Power system operations must be focused on managing the net variability of aggregated load and generation, not the variability of individual plants. It is neither efficient nor necessary to manage PV plant variability on a project-by-project basis by trying to create firm power from PV output. There will be times when PV moves in the same direction as load, or when down-ramps in one plant are offset by up-ramps in other plants in the same BA Area. Firming up PV output on a project-by-project basis would unnecessarily increase cost and result in suboptimal use of power system assets. Any local impacts on the transmission or sub-transmission system of variability from PV plants potentially could be mitigated through systems-level changes rather than addressed on a project-by-project basis.

Increased reserves may be required to manage the additional net variability and uncertainty. Greater solar penetration will increase the ramping rate of the net load due to the morning and afternoon PV ramping, as well as short-term fluctuations due to clouds. This may require an increased need for fast response generation and reserves. The actual amount of increased ramping and regulation reserves has yet to be extensively studied and quantified, especially considering the effects of widely distributed PV and the lack of spatially diverse sub-hourly solar radiation data. However, based on operational studies with wind, it is anticipated that solar-generation variability aggregated over a wide geographical region will reduce the impact of variability and reduce the relative increase in operating reserves requirements (EnerNex Corp 2010, GE Energy 2010). Detailed analysis, however, is required to determine specific requirements on factors such as location, penetration level, and balance of generation. Forecasts of weather events that may result in large changes in solar generation locally—if it is a large plant—or over a large region would be valuable. With advance warning, operators can temporarily increase ramping reserves, and thus reduce the cost of solar variability and uncertainty without compromising overall system reliability. Finally, a forecast that alerts operators to potentially faster fluctuations caused by fast-moving clouds could be useful so that sufficient regulating reserves can be available or variable generation plants can be controlled to given set points. Similar actions are already taken by system operators for forecasted lightning storms, which increase the risk of transmission line outages (Alvarado and Oren 2002, NERC 2009). Some aspects of solar integration may be easier than wind integration because the clear-sky output is predictable, and reserves will likely need to be held only in proportion to the clear-sky output.

Better integration of solar forecasting into scheduling and dispatch helps reduce integration costs. Integration of solar forecasting into operations on a day-ahead, hour-ahead, and real-time basis improves operational efficiency and reduces integration costs. When good day-ahead and short-term forecasts are available and are fully used, operators can optimize dispatch strategies. Forecasts for both energy production and variability—ramping events and higher frequency fluctuations—should be taken into account during system operations. Inclusion of state-of-the-art wind forecasts has been shown to dramatically reduce scheduling costs relative to not taking such forecasts into account (Smith et al. 2007, GE Energy 2010). Similarly, operational decisions based on an understanding that forecasts are imperfect allow for more conservative and overall lower-cost scheduling decisions (Tuohy et al. 2009). Full integration of solar forecasts into dispatch and scheduling decisions may require operator training and new decision-support tools. Additional research and development is needed in this area.

Shorter-term scheduling can decrease reserve requirements and integration costs. Reserve requirements can be reduced by making unit-commitment decisions closer to the real time. Currently, many utilities make their unit-commitment decisions the morning before the day being planned, pursuant to long-standing regional guidelines. Forecasted information that feeds into this process is based on meteorological data that is 24–48 hours ahead of the hour being planned, and thus is likely to have a higher forecast error than forecasts made closer to real time (Lorenz et al. 2004, Perez et al. 2007, Lorenz et al. 2009, GE Energy 2010). Rolling unit-commitment approaches or moving unit-commitment decisions closer to real time should result in decreased forecast error between load and generation and reduced requirements for expensive short-term reserve capacity. Figure 6-6 illustrates the magnitude of solar forecasting errors for forecast horizons up to 76 hours using different forecasting methods. All methods are more accurate over shorter forecast horizons. In addition, the bottom line in Figure 6-6 shows that forecasting the aggregate output of multiple sites is much more accurate than forecasting the output of an individual site.

Figure 6-6. Solar Forecast Error for Different Forecast Horizons and Different Prediction Methods



*Relative Root Sq. Mean Error of Global Solar Insolation Forecast

Likewise, sub-hourly system dispatch can also reduce integration costs. This includes sub-hourly scheduling of all balancing resources such as generators and voluntary responsive loads and sub-hourly scheduling of interchanges between BAs. Without sub-hourly scheduling, expensive regulating generators must account for all the sub-hourly variability of the solar instead of the less-expensive load following generators.

Full participation of load as a controllable resource is a cost-effective way to increase system flexibility. It may be less costly for load to respond to system needs by shifting or curtailing consumption than to increase reserve requirements or procure additional flexible generation. ERCOT's Loads acting as a Resource (LaaR) program is a good example of load participation to increase flexibility. The LaaR program is able to curtail load during those specific hours when additional reserves would be necessary, achieving the same objective as deploying operating reserves for 8,760 hours of the year (Ela and Kirby 2008). Expanding this type of load-participation arrangement could decrease the costs of solar integration.

New mechanisms are needed to incorporate DER assets efficiently. Because of their small size, customer-owned PV installations are typically not incorporated into system operations and markets. As future "smart grid" concepts and technologies are implemented on the distribution system, it will become increasingly feasible to integrate DERs into grid planning and operations. Better visibility of DERs from the utility control room, coupled with inverter technology that can be responsive to system needs via operator commands and price signals, would enable DERs to participate in energy and capacity markets and help support system reliability. To accommodate high penetration at the distribution level, technical changes to the distribution circuit devices may be needed to make them more responsive to the impacts of variable resources (for additional discussion of this topic see Section 6.4).

Different generation mixes and sources of flexibility will provide the lowest overall cost of energy. Adding a large amount of solar generation to the power system can have a significant impact on generation planning assumptions. Adding solar to the existing mix of generation will displace energy from plants with higher operating costs (Denholm et al. 2008). As the penetration of solar expands, however, solar will increasingly displace lower cost generation, and the value of additional solar to the generation mix will start to decline. In the long run, however, the generation mix with significant solar will begin to look different than the current generation mix. Adding solar will, in the long run, influence the "balance of system" mix, likely toward less baseload capacity and more flexible generation capacity than a similar system without solar (Lamont 2008). The set of technologies and mechanisms enabling greater penetration of solar energy can be described in terms of a flexibility supply curve that can provide responsive energy over various timescales. Figure 6-1 provides a conceptual flexibility supply curve that summarizes the options for incorporating variable generation. The optimal mix of these technologies has yet to be determined, but many sources of flexibility will be required for the most cost-effective integration of solar at high penetration.

6.2.4 Operational Feasibility of the SunShot Scenario

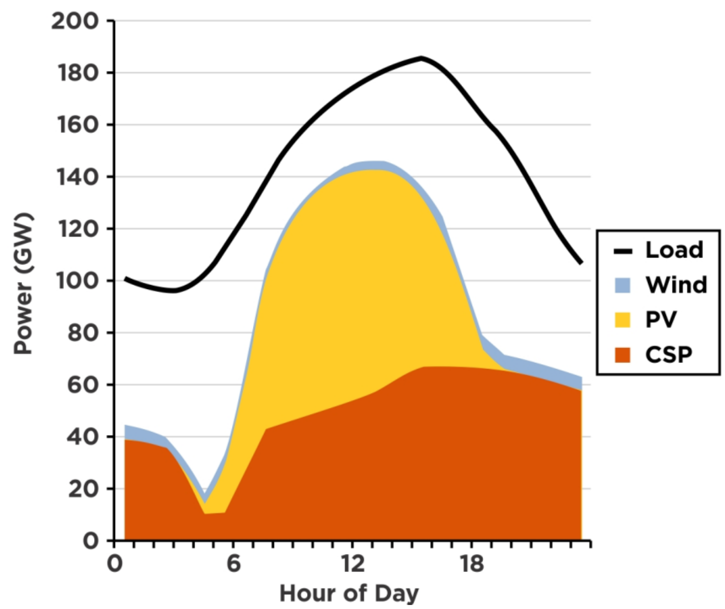
In the SunShot scenario, the most challenging region of the country in terms of electric system operation would likely be the Western Interconnection. The SunShot scenario envisions meeting 31% of the Western Interconnection's demand with solar (and 6% from wind) in 2030. This increases to 56% of demand from solar by 2050. The operational feasibility of the SunShot scenario was modeled using GridView, in particular, to investigate the flexibility required to balance hourly supply and demand for the system as envisioned in 2050. GridView simulations indicate that hourly load could be met at all locations throughout the year. Flexibility in these simulations was provided by CSP with thermal storage, hydropower and pumped hydro storage, transmission capacity and power exchanges between the Western Interconnection and the other interconnections, curtailment, demand response, and the fleet of existing and new fossil-fueled generators. While this type of modeling validates the ability to operate the electric system on an hourly basis, in order to evaluate the complete operational feasibility of the SunShot scenario, additional modeling of sub-hourly balancing, system stability, and voltage stability would be required.

The biggest challenge with the SunShot scenario from a systems operation perspective is integrating variable generation, including PV and wind. By 2050, 29% of the electricity demand in the Western Interconnection is met with wind and PV generation, and 33% is met with CSP. CSP is deployed with up to 12 hours of thermal storage and provides dispatchable energy. As a result, the fraction of demand met by variable sources (29%) is similar to previous studies modeling

6

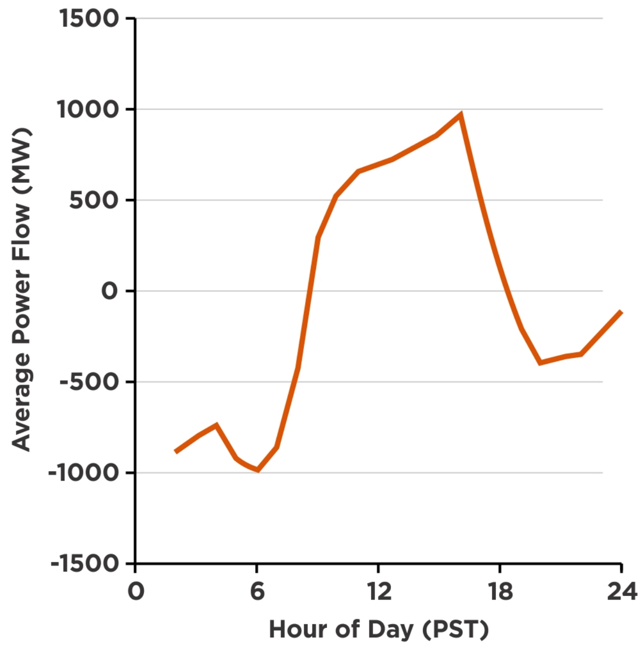
renewable penetration in the western United States, including the *Western Wind and Solar Integration Study* (GE Energy 2010) and the ongoing assessment of the California independent system operator (ISO) 33% renewable portfolio standard (CPUC 2008). Figure 6-7 shows the GridView average diurnal dispatch of CSP generators with thermal storage during July, along with PV output, wind output, and load in the Western Interconnection. During this time of the year, CSP in the Western Interconnection coupled with 12 hours of storage allows most CSP generators to operate 24 hours per day. CSP generators also typically generate at close to 100% of their capacity during the evening hours, i.e., after PV has stopped producing electricity, but the load is still relatively high.

Figure 6-7. Average Hourly Dispatch in the Western Interconnection during July



Another major source of flexibility in the SunShot scenario is the ability to exchange energy with other interconnections. The Western Interconnection currently has very limited transmission capacity to other interconnections [less than 2 gigawatts (GW)]. To accommodate solar penetration levels in the West, the SunShot scenario develops a total of 18 GW of transfer capacity on DC connections between the Western Interconnection and the Eastern Interconnection. Although the Western Interconnection does export more than it imports, the transfer capacity is not used simply to export excess solar electricity. The interties are used to import and export electricity to optimize the total system production cost, which adds additional flexibility to the system. Figure 6-8 is an example of the average annual diurnal profile of the AC-DC-AC interconnection between Wyoming (in the Western Interconnection) and South Dakota (in the Eastern Interconnection) modeled in the SunShot scenario in 2050. Power exchange along this line is usually near the capacity of the line, yet the direction of power flow changes twice per day on most days.

Figure 6-8. Annual Hourly Power Flow from Wyoming (Western Interconnection) to South Dakota (Eastern Interconnection), SunShot Scenario, 2050



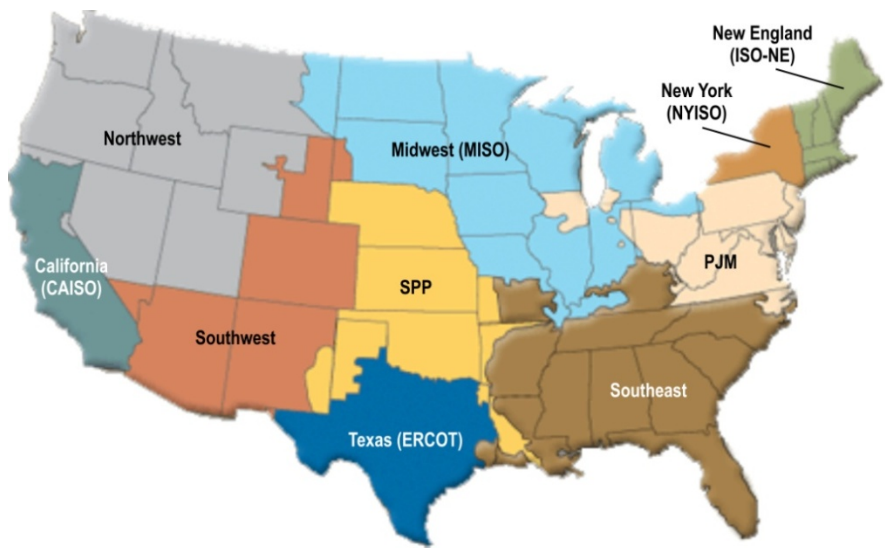
There are several other major sources of flexibility that could facilitate penetration levels discussed here. Hydro generators, including pumped hydro storage, are flexible and have inherent storage capabilities. Existing and new fossil-fuel generators can also provide flexibility. Although coal and natural gas combined cycle (gas-CC) units are relatively expensive to start, they can be ramped and operated at part-load to allow for changes in generation. This may, however, have implications for nitrogen oxide (NO_x) and sulfur dioxide (SO_2) emissions (Mills et al. 2009) and long-term maintenance costs (Agan et al. 2008). Natural gas combustion turbines (gas-CT) are more flexible and can be cycled regularly to help provide generation for relatively short periods. Interruptible loads can also be a cost-effective solution for providing operating reserves. Finally, curtailment of wind and solar generation can provide flexibility to the system.

The ability to curtail generation can be used by the system operator to reduce system ramp rates or avoid transmission congestion or minimum generation problems. A generator that is curtailing energy may also be able to use that capacity to provide operating reserves (Miller et al. 2010). The GridView simulations indicate that by using a combination of CSP with thermal storage, other generation technologies, transmission, and curtailment, the SunShot scenario can feasibly balance supply and demand on seasonal and hourly time scales.

6.2.5 The Role of Energy Markets

Market structures have an important role in the integration of solar generation, and nearly all the factors discussed in Section 6.2.3 are affected by the design and implementation of markets. Markets provide a mechanism for buying and selling electric power to meet the system load and maintain an acceptable level of reliability. In the United States, electricity market structures vary widely by region (Figure 6-9). Some markets, such as the MISO, PJM, New York Independent System Operator (NYISO), Independent System Operator-New England (ISO-NE), ERCOT, California Independent System Operator (CAISO), and increasingly the SPP, are integrated, flexible, and efficient. Some of them offer a wide variety of energy as well as capacity and ancillary services products that can be accessed day-ahead, hour-ahead, or in some cases, on a sub-hourly basis. In other areas such as the Southwest, Southeast, and Northwest, however, electricity markets are less flexible and require BAs to rely more heavily on bilateral transactions to access electricity and capacity resources that are not under their direct control. However, it is possible that areas without electricity markets could develop cooperative agreements that would provide some of the benefits of markets (Milligan et al. 2009b).

Figure 6-9. Electricity Markets in the United States



Source: FERC (2010)

Market characteristics, including size, sub-hourly interval, and product options and rules, can significantly affect how effectively and economically system operations are able to use the flexibility that is physically available to deal with increasing levels of solar generation. Whether operating in a large liquid market or in a regulated utility with limited resource access, the market features listed here and described following the list can help enable more efficient integration of solar generation:

- Markets that are more flexible, larger, and more diverse provide opportunities for the integration of solar generation at a lower cost.
- Market flexibility, such as shorter transaction closure intervals, can significantly lower the cost of solar integration.
- Market-based incentives can produce optimal solutions to uncertainty and variability and maximize system flexibility.

Markets that are more flexible, larger, and more diverse provide opportunities for the integration of solar generation at a lower cost. Larger, more flexible markets tend to be more adaptable to changes in system requirements, such as the need for additional generation flexibility to handle increased levels of variability. Such markets provide a mechanism to access the flexibility that is physically available from all generators in the area and all responsive loads. The larger the market is, the larger the pool of generators and responsive load and the smaller the relative variability of aggregated load. Larger markets also have the advantage of more geographic diversity of solar resources, as discussed earlier. The results of numerous wind-integration studies and actual experience have shown that, for the same level of penetration, integration cost is significantly lower in markets such as the MISO compared to a smaller BA Area without the ability to exchange resources across a larger area (Milligan et al. 2009b). This conclusion will almost certainly hold for solar generation as well.

Market flexibility, such as shorter transaction closure intervals, can significantly lower the cost of solar integration. A key measure of flexibility is how often system operators can interact with the market to optimize operating cost. For example, markets that allow for faster transactions—scheduling power exchanges every 5 or 10 minutes as opposed to 1 hour—reduce requirements for regulation, which is the most expensive ancillary service.

Market-based incentives can produce optimal solutions to uncertainty and variability and maximize system flexibility. Efficient market structures can incentivize the most cost-effective technical alternatives to deal with variability at the system level. This includes flexible generation, storage, better forecasting, and full participation of load as a resource. Some electricity markets do not include capacity or ancillary services options. Real-time prices for ancillary services should provide sufficient incentive for the right amount and type of generation capacity and responsive load needed to maintain system reliability. Studies have shown that the existing generating fleet is capable of providing a large amount of flexibility; however, much of that capability is not tapped due to a lack of appropriate market incentives or prices for flexibility services (Kirby and Milligan 2005). Markets can also be designed to deal with transmission congestion through mechanisms such as location marginal pricing (LMP). Flexible generation that has shorter commitment times—the time required to start and begin delivering energy—and lower cycling costs will be more valuable in an environment with high solar and/or wind penetration. Markets can be structured to motivate new capacity entrants to be more flexible, for example, by providing the amount of expected variable generation to help inform conventional generation owners/investors of future opportunities for flexible generation response.

6.3 Feasibility of the New Transmission Infrastructure Required for the SunShot Scenario

Both the SunShot and reference scenarios require significant transmission expansion. In the reference scenario, transmission is expanded primarily to enable new conventional and wind resources to meet growing electricity demand. In the SunShot scenario, transmission is expanded at a similar level, but in different locations in order to develop solar as well as wind and conventional resources. In the

SunShot scenario, concentration of large-scale CSP and central utility-scale PV would occur in some areas such as the Southwest where solar electricity can be generated at a significantly lower cost based on the higher-quality solar resources in the region. Additional transmission capacity will be needed to deliver solar-generated electricity from these areas to load centers—for more information, see Chapter 3. Transmission development represents a major challenge based on cost, cost allocation, permitting, and the long time frames involved. Major transmission lines typically take 7–10 years to plan, permit, and construct. Therefore, it is important that large-scale deployment of renewable generation be considered proactively as part of the regional transmission planning process. Furthermore, because only 1–2 years of transmission-project time lines are devoted to construction, there could be opportunities to reduce transmission development timescales. In particular, new frameworks to address transmission siting and cost allocation could facilitate the transmission development needed for solar.

Several challenges are associated with integrating solar energy into the United States transmission system. There is a clear need to develop or improve planning models and methodologies to represent solar generation properly in grid-planning and interconnection studies. Another challenge is the need to develop, improve, or adapt performance and interconnection standards to ensure that solar generation can be integrated reliably and cost effectively into the transmission system. Perhaps the most difficult challenges will be the permitting and financing of the new transmission infrastructure required to move large amounts of solar generation, as discussed in Chapters 7 and 8, respectively. This section discusses the technical issues and solutions associated with the integration of SunShot-level solar generation onto the grid.

6.3.1 Methodologies for Transmission Planning

Transmission planning is a complex process whereby system planners identify system-expansion requirements to meet future needs. The process is driven by predictions of load growth and generation patterns that are informed by decades of accumulated experience. There is a growing trend toward regional transmission planning to capture the benefits of obtaining least-cost renewable energy, increasing reliability through diversification of the resource areas employed, and decreasing the need for ramping/ancillary services when balancing occurs over larger areas. As the penetration level of solar and other variable sources of generation increases, the analysis techniques and study approaches employed in transmission planning must become more sophisticated. Below are some examples.

- Regional planning studies are conducted on a limited set of scenarios that represent peak and off-peak conditions during different seasons of the year. For the most part, the generation pattern assumed for each load scenario can be inferred based on the use of dispatchable generators. The accelerated introduction of large amounts of solar as well as other sources of variable generation, primarily wind, will give rise to a wider range of operating conditions that need to be considered in the transmission planning process.
- Large and potentially frequent changes in generation are possible with PV and CSP without storage. As the amount of solar generation increases relative to the strength of the local transmission system, additional reactive power support may be needed to maintain voltage levels and system

stability. However, variability scenarios are not typically considered as part of transmission-planning and interconnection studies.

- The existing grid relies, in part, on the mechanical inertia of large generators. The inherent inertia of the collective synchronous generators in an interconnected system provides frequency stability that helps the system withstand severe disturbances. Certain solar-generation technologies, such as PV and dish/engine CSP systems, have no effective inertia and provide relatively low short-circuit currents during faults. Inverter-based wind generation exhibits similar behavior unless specifically designed to provide an inertial response. Technically, displacing a significant amount of conventional generation with solar generation that has no mechanical inertia has the potential to affect the dynamic performance of the interconnection negatively. This characteristic must be taken into account in the design of control and protection systems. That said, tower and trough CSP plants use synchronous generators that provide inertia in the same manner as conventional generators, thus minimizing the potential for additional challenges.

None of the issues discussed above constitute insurmountable challenges to achieving significant penetration levels of solar energy. However, new approaches are needed to integrate solar into the grid. Three issues have been identified as requirements for improving the integration of solar into the U.S. transmission system. These issues are listed here and described in greater detail below.

- New and improved models of solar-generation technologies will be needed.
- Interconnection procedures and requirements will need to evolve.
- Solar systems will need to be integrated into utility operations via supervisory control and data acquisition (SCADA) systems.

New and improved models of solar-generation technologies will be needed. Adequate solar-generation electrical models for transmission-planning and interconnection studies are indispensable to achieving high solar penetration levels. Transmission-planning and interconnection studies consist mainly of power flow, dynamics, and short-circuit simulations that take into account the effect of a large number of system components. Because trough and tower CSP technologies employ conventional generators, well-established electrical models can be used to represent these types of systems. However, PV and dish/engine technologies require different types of dynamic and short-circuit models that still need to be developed or improved. PV systems are inverter-based generators, which are fundamentally different from conventional generators. Inverters exhibit a very quick electrical response, which results from fast switching capability and lack of mechanical inertia. Unlike conventional generators, inverters are able to quickly control current with little or no oscillatory behavior following system disturbances. Dish/engine systems are induction generators driven by low-inertia reciprocating engines. Models that represent this behavior and these characteristics need to be developed or improved. Models also need to be validated and supported by the various industry-standard simulation software platforms and be readily shared among multiple system planning entities and consultants. For example, the Western Electricity Coordinating Council (WECC) initiated an effort to develop models for solar generation, following a similar effort for wind generation that started in 2006.

Interconnection procedures and requirements will need to evolve. In addition to the new models needed, interconnection requirements for solar and other variable-generation resources, both distribution-connected and transmission-connected, must continue to evolve to adequately cover solar-generation technologies. At the transmission level, existing interconnection procedures can be applied to solar-generation technologies that use conventional generators, such as CSP troughs and towers, but are not adequate to address PV and dish/engine systems.

The North American Electric Reliability Corporation (NERC) has already identified several gaps in the standards related to transmission planning and operations with high levels of solar and wind generation (NERC 2009). One of them is the need to reconcile key aspects of the standards that apply to distribution-connected generation. Distribution-level connected solar systems typically are required to follow the Institute of Electrical and Electronics Engineers (IEEE) 1547 interconnection standard. The existing IEEE 1547 requirements carry the implicit risk that a large amount of distribution-connected PV generation may trip as a result of transmission system disturbances if voltage and frequency levels fall outside narrow windows. A recent study performed by General Electric (GE) as part of the U.S. Department of Energy's (DOE) Renewable Systems Integration (RSI) study effort shows that, in high-penetration scenarios, PV inverter tripping caused by transmission disturbances can exacerbate voltage instability in load centers (Achilles et al. 2008). As solar penetration increases, voltage tolerance or low voltage ride-through (LVRT) will start to be required, as it is required for wind generation today. In high-penetration scenarios, solar plants should also provide reactive support of a character similar to conventional power plants. In Europe, several jurisdictions have adopted new voltage and frequency standards that add LVRT and reactive support for PV generation connected to the high- and medium-voltage networks (Troester 2009).

Future standards for solar generation should also address power control and frequency support. All solar-generation technologies could be designed to limit power output, control ramps to some extent, and even contribute to frequency support. This capability would essentially mimic the behavior found in rotating machines. For PV and dish/engine systems, power control and frequency support functionality could be achieved by curtailing some amount of solar power, although the costs of this approach would need to be compared to the value of curtailed energy.

Because PV systems are inverter based, evolutionary changes in capabilities could take place relatively quickly. Wind turbines, which use the same type of inverter technology as PV systems, have rapidly evolved over the last 5 years to meet rather stringent voltage ride-through requirements and are able to support advanced active and reactive power-management options. It is expected that PV inverters will be able to adapt rapidly to expected changes in performance standards or grid codes.

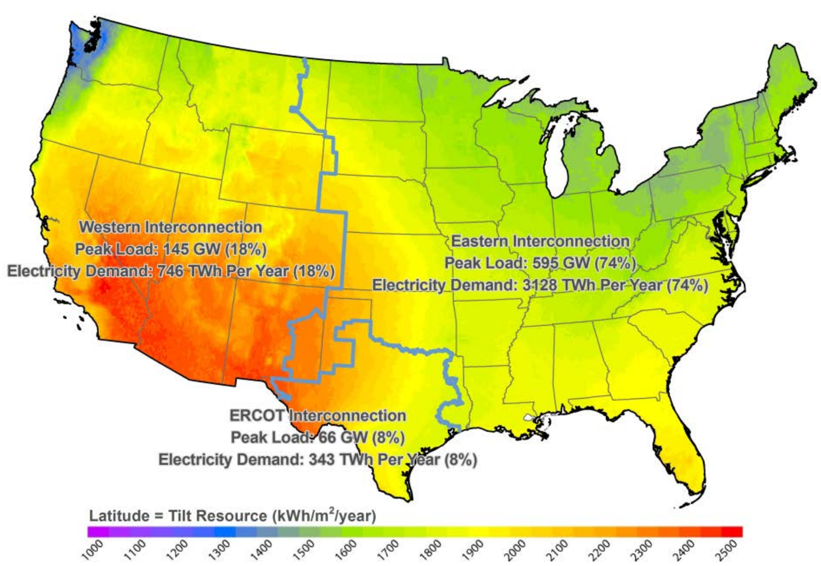
Solar systems will need to be integrated into utility operations via SCADA systems. For full integration into utility operations, centralized solar plants, and, increasingly, distribution-connected PV plants, should be integrated into a utility's SCADA systems. This integration not only provides visibility to system operators, but also allows solar systems to participate in energy and ancillary services markets. During periods of system stress or reliability risk, SCADA integration would allow system operators to request dynamic voltage support, frequency support, and power management from solar plants, assuming the plants have the capability to do so. Integration of distributed solar installations into SCADA is significantly more challenging than integrating centralized solar installations, because the distributed plants could be deployed in extremely large numbers. Aggregation of these distributed systems is a promising approach to integrating with utilities' SCADA systems.

6.3.2 Transmission Capacity Needs to Facilitate Solar Growth Scenario

The need for new transmission for a high solar-penetration scenario will be driven primarily by the location of new solar plants and the availability of existing transmission capacity. The economics of exploiting high-quality solar resources may be favorable, even if long transmission lines are required to deliver the power, because the lower cost of electricity from these remote sources could offset the capital cost of additional infrastructure to deliver the power to demand centers. In other cases, however, it may be preferable to place new facilities closer to areas of high population density. These tradeoffs will be a central concern when considering the balance between centralized and distributed solar electricity deployment.

It is expected that a large fraction of the infrastructure additions to carry power from high-quality solar resources to nearby load centers are, in the near term, likely to be built in the Southwest. This is especially true for transmission to access CSP capacity. Figure 6-10 shows the solar insolation for a south-facing latitude-tilt array along with electricity capacity and demand statistics for the three large power system interconnections in the United States. As shown in the figure, the locations

Figure 6-10. Global Horizontal Solar Resource (South Facing, Tilted at Latitude) with Electricity Use Statistics by Interconnection



Source: NREL

with the highest insolation are concentrated in southwestern states such as Arizona, New Mexico, California, and Nevada. The concentration of resources in the southwestern states is even more pronounced for direct-normal irradiance (DNI) with two-axis tracking, such as, for CSP and concentrating photovoltaic (CPV) technologies.

Although CSP and central utility-scale PV deployment in the SunShot scenario is concentrated in the Southwest, there are notable exceptions where they are deployed in areas with lower insolation, like Florida, to access greater load-density regions.

PV deployment in the SunShot scenario is highly concentrated in the Western Interconnection in the early years of the analysis. Later deployment, benefiting from continued technology cost reductions, has a broader geographic scope; however, it is clear that the western United States faces the more significant integration challenge in these scenarios (see Chapter 3). This deployment trajectory for CSP and PV, coupled with the fact that the Western Interconnection accounts for less than one-fifth of the national electrical load, results in very high solar penetrations in the Western Interconnection. By 2050 in the SunShot scenario, the solar penetration in the Western Interconnection is 56% on an energy basis. While this is a very high level of solar penetration, as discussed in Section 6.2.4, GridView simulations indicate that through a combination of CSP with thermal storage, other generation technologies, transmission, and curtailment, it would be feasible to balance supply and demand on seasonal and hourly timescales.

Significant transfer capacity between the interconnections, in addition to long-distance transmission lines, is required to accommodate the large solar deployment in the western United States. Increased transfer capability between the three electrical interconnections (Eastern, Western, and ERCOT) could facilitate integration of larger quantities of solar. The SunShot scenario shows this type of transfer capacity increasing substantially (with a total of 18 GW between the Eastern and Western Interconnections and 5 GW between the Eastern and ERCOT Interconnections by 2050). The SunShot scenario also requires substantial transmission system additions within the interconnections.

The low capacity factors for solar electric systems raise asset utilization concerns for transmission systems. Several methods can be employed to enhance line-load factors or otherwise address these issues. In particular, where night-peaking wind is prevalent, such resources can provide a suitable complement to the day-peak output characteristics of solar electricity. Fast-ramping, dispatchable generating capacity, such as from gas-CT or energy storage, can also provide balancing capacity for solar (NERC 2009). Other tools to maximize the use of new and existing lines for variable energy resources include dynamic line rating and conditional firm service agreements (WIRES 2008). However, in the case of solar, the applicability of these tools will be limited because peak solar output will occur during the hottest times of the day when line ratings are at their minimum, system load is highest, and available transfer capacity (ATC) is most scarce.

Based on the vast size of high-quality solar resource areas and economies of scale for transmission, the optimal scale of transmission to access a given resource is often much larger than is required for any individual facility. The mismatch of individual project size and scale of transmission creates complications for system planning and transmission cost allocation. Lines built for each individual plant in a resource area would be much more expensive than bundling multiple projects together on a single transmission line. Furthermore, the time required to develop new transmission (about 7–10 years) is often much longer than the 1–3 years that are typically needed to develop individual solar projects. It will be increasingly important to meet these challenges with multi-regional system planning to exploit the economies of scale and reduced land use—right-of-way width per unit of capacity—that higher-voltage lines offer. If long-distance power transfer (greater than 500 miles) becomes necessary, high-voltage direct current (HVDC) lines offer lower losses and further reduced rights-of-way widths (Bahrman and Johnson 2007).

Integrating large quantities of solar electricity into the power system will require substantial additional transmission infrastructure to deliver the power from the point of generation to where it is needed. The concentration of the highest-quality solar resources poses significant integration challenges in the West. Targeted transmission development, however, can help address these issues and, in many cases, BA Area transfer capacity will be most critical. Finally, as PV system costs continue to come down, the viability of solar will be less dependent on solar resource strength, potentially broadening the geographic distribution of PV development.

6.4 Feasibility of the New Distribution Infrastructure Required for the SunShot Scenario

In the SunShot scenario, 121 GW and 240 GW of rooftop PV will be installed by 2030 and 2050, respectively. In addition, a significant fraction of utility-scale PV is expected to be connected to the distribution system. The main difference between transmission and distribution system planning is that generation, except for emergency backup power, rarely has been connected at the distribution level, and even more rarely has been part of dispatch and control for load balancing. Distribution feeders are typically designed to manage one-way power flows from the transmission system to the customer.

The benefits of siting generation near loads include reducing line losses, increasing reliability due to fuel diversity, increasing access to an emergency backup supply for consumers, and potentially deferring equipment upgrades. However, adding significant quantities of generation to the distribution system presents several challenges. At high levels of PV penetration on distribution lines, the distribution system will be required to manage two-way power flow. Significant penetration of PV or any other form of DER sited on distribution lines will require modifications to standards, practices, and equipment to manage two-way power flow safely and cost effectively while maintaining the same level of power quality for customers. In particular, equipment upgrades and advanced communication and monitoring equipment may be required to accommodate high levels of power exported from the distribution system to other parts of the grid and avoid interference with the operation of local-protection-system and voltage-control devices.

6.4.1 Integrating Solar with the Distribution System

Interconnection of PV with the distribution system requires the involvement of the utility, which must approve interconnection of the electricity source, as well as building inspectors who are responsible for the safety of the installation. Processing the paperwork required by the utility or building departments is typically handled by the solar installer and can be time consuming. As the number of distributed PV installations increases, it will be important for utilities and building departments to be able to handle the high number of applications. With greater penetration of PV, improvements in inverter technologies, and increasing comfort with the technology on the part of developers, utilities, and building departments, interconnection processes are being streamlined in many states to allow expedited treatment for PV systems smaller than 25 kilowatts (kW) that are connected to the distribution system. Currently, most utilities will allow up to 15% capacity penetration (rated output divided by peak load) per circuit of the DER to be connected to the grid using a simplified interconnection process. Once that threshold has been reached, a detailed, costly interconnection requirements study is usually mandatory before interconnecting. The 15% penetration level at which a detailed interconnection study is required may be a barrier for large deployments on the distribution system. As more real-world experience is gained, it is possible the level at which in-depth interconnection studies are required could rise above 15% penetration, and/or gradations could occur where studies at lower penetrations are not as in-depth as studies for higher penetration levels. The impact of high penetrations of PV on distribution circuits and the conditions under which issues occur is an important area of research.

There are several technical concerns for integrating solar on distribution systems. In most cases, the magnitude of the influence of DERs on the distribution system depends on the size, nature, and operation of the generation system as well the characteristics of the distribution system. At low penetration levels, the existing standards are adequate to address the technical concerns. For example, the industry standard IEEE 1547 "IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems," applies to any distributed energy resource up to 10 mega-volt amperes, or MVA (roughly equivalent to megawatts), in nameplate capacity connected through to a single point of common coupling (PCC), and includes requirements for connecting PV systems deployed on the distribution system. Most PV inverters are designed and tested to this standard, which prevents PV and other distributed generation from controlling voltage and requires them to disconnect from the utility when voltage or frequency fall outside a narrow operating range.

An important limitation of IEEE 1547 is that it provides neither the guidance nor technical specifications for protection requirements that might be needed for aggregated DERs along a supply feeder or in a network, but is only applicable to the single PCC between the DER and the utility. This limitation should be kept in mind when considering potential impacts of high penetration of PV on the distribution system—for some cases, the high-penetration scenarios will need to be studied further. Prior studies have shown virtually no impacts at low (5%) penetration levels on a capacity basis, and possible system instability at higher (20%) penetrations on a capacity basis, when the DER follows the requirements of IEEE 1547 (Achilles et al. 2008, Liu and Bebic 2008). As penetration levels of distributed PV increase, interconnection standards will need to be updated to ensure the safety and reliability of distribution systems.

As the penetration levels of DERs increase and their role in grid operations and the grid's dependence on DER capacity and energy increases, it may be useful to define different rules for different levels of PV involvement in the operation of an electric distribution system. As shown in Table 6-1, three different levels are used to illustrate this point. The actual penetration values that constitute low, medium, and high penetration will vary depending on distribution circuit and PV system characteristics. The main point is that different penetration levels will, by practical necessity, lead to different roles and operating requirements.

Table 6-1. Grid-Penetration Scenarios and Impacts

Penetration Level	Impacts on Power System and Standards Defining Role and Operating Rules for Distributed PV
Low	• No impact on normal feeder or grid operation. • Current interconnection standards are sufficient.
Medium	• Distributed PV affects feeder voltage, may need to widen voltage trip limit, adjust circuit voltage regulation, and adapt circuit-protection settings. • Under-frequency tripping needs to be widened to coordinate with load-shedding schemes. • Evolve interconnection standards to consider feeder-level interactions.
High	• PV systems affect utility feeder and grid balancing (transmission system) and will need to be integrated with both planning and operations. • Ramp rates may be controlled at the PV system level. • Update interconnection standards to integrate PV for voltage and energy support, allowing voltage regulation, low-voltage ride-through, and enhanced anti-islanding schemes.

Source: Key et al. (2003)

It is clear that at the higher penetration levels, standards may need to be changed or requirements expanded to address changing requirements for interaction with PV systems. Issues of concern include steady-state voltage regulation, voltage flicker, harmonics, unintentional islanding, and protection design and coordination. These are discussed in detail below.

Steady-state voltage regulation. Steady-state voltage is the voltage of the power system over a sustained period, usually defined as anywhere from about 1–3 minutes or longer in duration. Utilities require generation on the distribution system to be operated in a manner that does not cause the voltage regulation to go outside the applicable limits. In addition, operation of the DER may not cause interference with the normal operation of the utility's voltage regulation equipment. Because DERs raise voltage levels when they inject power into the grid, they may cause high-voltage conditions at high penetration levels. A solution to increased voltage levels at high penetrations would be to allow the PV inverters to have the ability to regulate voltage at the local level. Because voltage regulation has historically been done by the utility, proper coordination with existing voltage-regulation schemes would be necessary. If the operation of the voltage regulation on the distribution circuits is not coordinated, there may be additional costs associated with wear and tear on transformer tap changers and power-factor management devices.

Voltage flicker. Voltage flicker is a sudden change in voltage that occurs in seconds or fractions of a second that can cause objectionable changes in the visible output of lighting systems. The PV inverter standards and designs can evolve to help mitigate any potential voltage-flicker issues that might emerge as penetration increases.

Harmonics. Harmonics are distortions in the regular 60-hertz (Hz) sine wave in North American power systems. Too much harmonic distortion can cause adverse operation of customer and utility equipment. Improvements over the last 10 years in the quality of inverter output have drastically reduced issues with PV system harmonics. The existing standards including requirements for the amount of harmonics that inverters can produce are likely adequate for high penetration of distribution-system-connected PV. Inverters could be designed to cancel harmonics at local loads and provide a benefit to the utility.

Unintentional islanding. Utilities are regularly required to isolate a section of the power system by disconnecting the section with network protectors or switches. Unintentional islands can be established when a section of the grid is isolated from the substation supply while the load continues to be maintained by an energy source within the isolated section. Unintentional islands pose a threat to proper utility system operation for a number of reasons:

- The upstream utility system might attempt to reclose into the island unsynchronized with voltage, frequency, and/or power factor, which can damage switchgear, power-generation equipment, and customer equipment.
- An unintentional island can increase public exposure to unsafe, energized downed conductors.
- Line crews working on power restoration following storms or other events may encounter unintentional energized islands, making their job more hazardous and slowing down the power-restoration process.
- Unintentional islands do not usually have their generators set up with the proper controls to maintain voltage and frequency conditions adequate to the customer loads.
- Unintentional islands can increase the likelihood of dangerous spikes or surges in the system.

Because of the possibility of unintentional islands, the IEEE 1547 standard and utility interconnection guidelines require DER systems connecting to the network to disconnect from the utility grid in the event that the network voltage or frequency goes outside of predefined limits. Certified inverters do this by employing an active anti-islanding scheme. As a result, unintentional islands are not currently considered a significant concern at low-penetration levels. Under high-penetration levels, however, current anti-islanding techniques may not adequately detect island formation and cease to energize the utility within a suitable amount of time. Furthermore, current anti-islanding techniques require DER systems to drop offline rather than ride through temporary faults, contributing to voltage drop or frequency problems. Large amounts of DERs could be prone to tripping during severe transmission-system disturbances that typically affect a wide geographical area. A recent study shows that, in high-penetration scenarios, PV inverter tripping caused by transmission disturbances can exacerbate voltage instability in load centers (Achilles et al. 2008).

Protection design and coordination. Utility protection systems are designed to reduce the impact of faults that can be caused by lightning or other problems on the utility system. All power-generation equipment should meet the applicable surge-voltage withstand and insulation ratings found in current standards. PV systems also need to coordinate with the protection systems employed on distribution circuits. Typically, a distribution system will employ a protection scheme that consists of fuses, circuit breakers, reclosers, and sectionalizers that are coordinated to operate with a protective relay scheme. Adding additional sources of power to the distribution circuit will affect the coordination of these devices. PV inverters contribute relatively small levels of short-circuit current. This can have potential benefits, or cause issues, depending on distribution circuit characteristics (Keller and Kroposki 2010).

6.4.2 Integrating Distributed Resources at the System Level

Incorporating distributed energy resources requires ensuring their safe and reliable operation on the distribution network. However, as discussed in Section 6.2, maximizing their usefulness to the grid as a whole will require new methods to communicate with and control resources at the grid system level. A variety of strategies can be employed to incorporate high-penetration PV as a safe and reliable energy resource for the grid and reduce concerns of distribution system integration.

Managing energy supply from the distribution system, rather than the transmission system, requires a new strategy for system design, planning, and operations. New models of the PV systems will be needed to evaluate the potential impacts of DERs and ensure proper system protection. These models will need to be able to simulate the full range of steady-state and dynamic conditions encountered in the operation of the power system. As the penetration of DERs increases and the necessary technology is developed, it is anticipated that the distribution system will evolve to accommodate two-way power flows and will take full advantage of the benefits of DERs.

Integrating large numbers of DERs into utility SCADA systems from a systems-operation perspective is needed. Based on their larger size, distributed utility-scale PV plants can be integrated into utility SCADA systems more easily than customer-owned PV and other DERs. As smart grid concepts are implemented on the distribution system, it will become increasingly feasible to integrate distributed PV into grid operations. Managing large amounts of data from multiple DER and demand side management (DSM) sites will add complexity, along with cyber security concerns. All of these data will also need to be time synchronized for proposer coordination. Better visibility of distributed PV system output from the control room, coupled with PV inverter technology that can be responsive to system needs via operator commands and price signals, would enable distributed PV to participate in energy and capacity markets and help support system reliability.

Emerging communication and control technologies make it feasible for DERs to be aggregated into “virtual power plants.” Combining solar with demand response creates a compelling reliability product, but this concept is in its infancy. All of these changes will add complexity to the operations of the distribution system. Rules and performance standards for such a product need to be established, and system operators need to be assured that the resource will be available before they can plan to it and operate with it. Markets and systems operations should evolve guided by the expectation that DERs will play a part. Changes to the regulatory environment may be needed to allow DERs to participate fully in markets and ancillary services.

Updating interconnection standards is also an important aspect to handling increasing DER penetrations. One example is changes to existing interconnection standards, such as IEEE 1547, to permit active voltage regulation, and possibly new anti-islanding techniques that can be used. Communication capability could be added to the PV inverter to allow the distribution system to signal the inverter to dispatch power and loads to optimize power flow to the utility. Such communication could be in the form of time-of-use rates and demand charges or could be real-time pricing via smart-metering technology. Communications between the PV inverter and distribution-system protection equipment, utility control room, and customer or utility storage systems are expected to help overcome variability and power-export concerns.

Benefits of such interactivity would include allowing PV systems to stay connected and ride through during temporary faults as needed. Utilities could command an inverter to ride through voltage sag, rather than having a large number of inverters go offline while leaving the loads online. Interactive control would also enable the distribution system to direct the inverter to go offline when there is a fault, rather than relying on multiple inverters, each supplying power to the grid, to detect a fault or islanding condition independently.

Combining energy storage with solar energy systems can also address some of the issues associated with solar energy integration. A relatively small amount of energy storage can be used to minimize the rate of change of system output to the grid to avoid demand charges. Storage on a distribution feeder could also be used to avoid reverse power flows at the substation. Much more storage would be required to provide significant capability for energy shifting or off-grid operation.

A variety of research and development activities can help with integrating high penetrations of DERs at the distribution level. These include the development of advanced inverter and control technologies, advanced distribution voltage and reactive power management, aggregation of distributed resources systems, and integration of PV systems with local load control and energy management.

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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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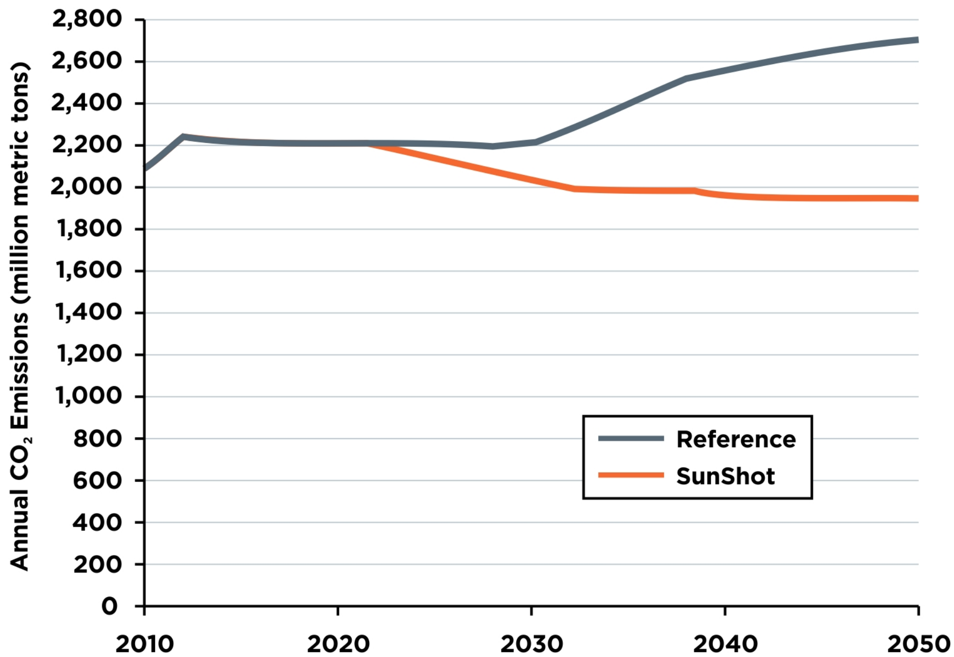
Significant reductions in U.S. GHG emissions are projected under the SunShot scenario. Combined with other efforts worldwide, these reductions have the potential to contribute significantly to the deceleration of global climate change. Figure 7-1 compares the CO_2 emissions projections, for the period 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.

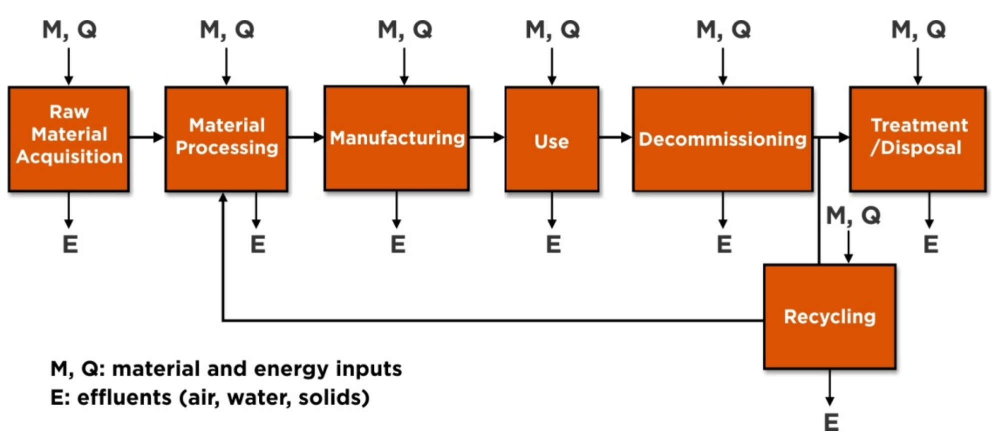
[58] Ecological impacts are defined here as "the effect that a man-caused or natural activity has on living organisms and their non-living (abiotic) environment" (EPA 2006).

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



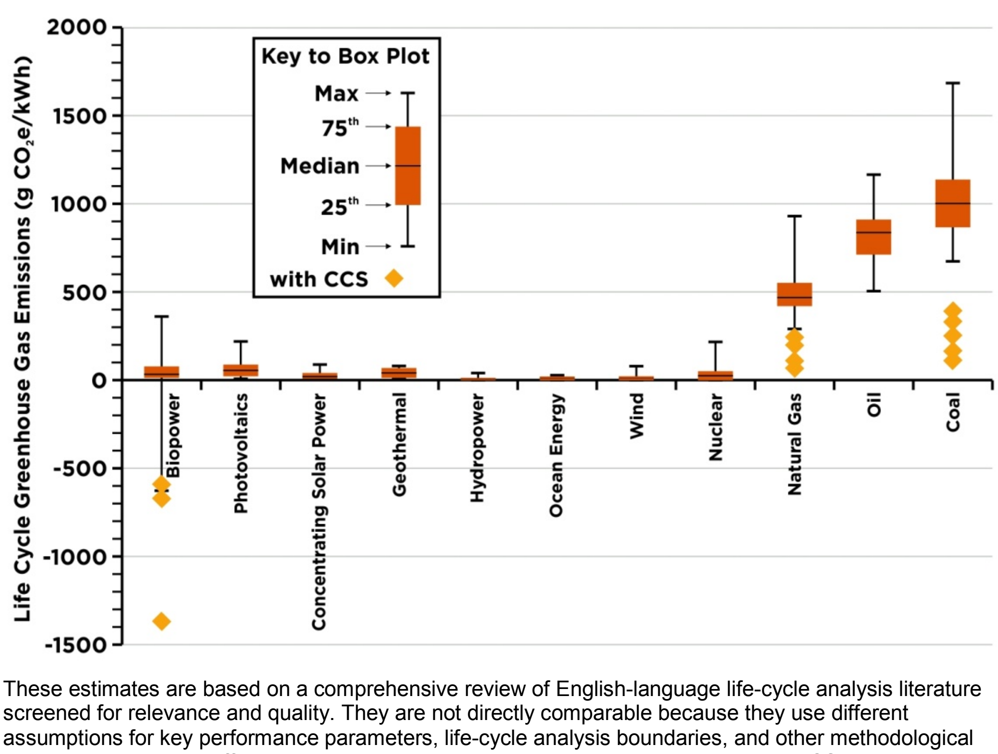
Source: Fthenakis and Kim (2007)

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

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).

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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).

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.

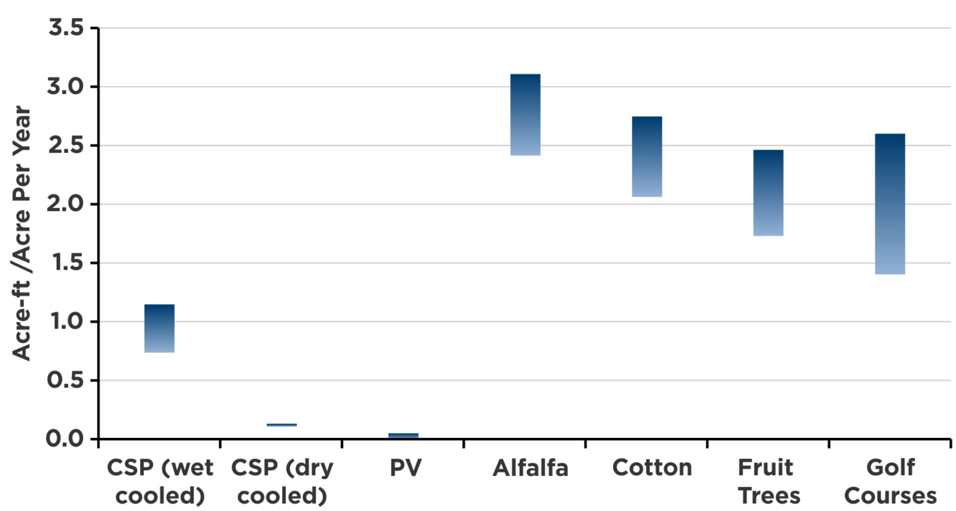
To overcome the cost and performance penalty associated with dry cooling, some developers are considering hybrid systems that employ dry cooling when temperatures are below 38°C (100°F) and wet cooling for hotter periods. Hybrid systems can consume 40%–90% less water than a wet-cooled system while maintaining 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

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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.

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

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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]

[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.

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8. Solar Industry Financial Issues and Opportunities

8.1 INTRODUCTION

Although sunshine is free, capturing the sun's rays to generate electricity is a capital-intensive undertaking. Photovoltaic (PV) and concentrating solar power (CSP) technologies have high up-front costs and low operating costs. This means that improving their electricity-production economics is highly dependent on reducing their capital costs (addressed in previous chapters) and reducing the cost of financing those capital costs (addressed in this chapter). Solar technologies also tend to be long-lived assets, which means that long-term financing arrangements are not only appropriate, but are needed to enable investment recovery to be spread out over an extended period, resulting in lower lifetime per-unit electricity costs.
To date, government policies have driven the expansion of solar energy worldwide, and these policies have defined the amounts and types of financing used by solar market participants. In Europe, feed-in tariffs have been the primary stimulus for investment in renewable electricity, enabling a more traditional project finance approach to be used (i.e., usually involving significant amounts of non-recourse debt). In the United States, tax incentives—such as the production tax credit (PTC), investment tax credit (ITC), and accelerated tax depreciation—have been the primary policy tools.

Achieving the SunShot price targets is projected to make solar electricity broadly cost-competitive with electricity from other sources by 2020. This should stimulate private solar investment—and facilitate the use of mainstream financial instruments—by 2020 and beyond. During the transition to becoming fully cost-competitive, solar expansion will still likely be dependent on government incentives.

Under the SunShot scenario, there are two categories of solar financing challenges: financing the solar supply chain and financing solar projects (and associated transmission infrastructure). Financing the expansion of the solar supply chain—such as manufacturing facilities for PV modules and CSP mirrors—and the electrical transmission infrastructure should be relatively straightforward because many of the mechanisms for doing so are already well developed and liquid. Financing SunShot-scale solar project deployment—the widespread construction of distributed and utility-scale solar electricity-generating plants—is a greater challenge, with different considerations in the pre-2020 and post-2020 periods.

After reviewing the finance-related inputs used in the SunShot analysis, this chapter quantifies the amount of supply-chain and project financing required under the SunShot scenario. This is followed by a discussion of current and emerging financial structures and incentives that could help stimulate solar energy growth, especially in the pre-2020 transition period.

8.2 REVIEW OF FINANCE-RELATED INPUTS USED IN THE SUNSHOT ANALYSIS

Table 8-1 provides an overview of the financial assumptions used in the SunShot analysis for the deployment of residential, commercial, and utility-scale PV and utility-scale CSP. As discussed in Chapter 3, the Solar Deployment System (SolarDS) model was used to analyze the residential and commercial PV markets, and the Regional Energy Deployment System (ReEDS) model was used for utility-scale PV and CSP, as well as for all other renewable and conventional generation technologies.

As of May 2011, neither SolarDS nor ReEDS is capable of modeling the intricate financial structures involving tax-equity investors, such as the partnership flip structures and leases described in this chapter, that are common in the industry today.[70] Instead, both models approximate the financial aspects of these structures by assuming that long-term debt financing is available for a significant portion of capital costs—i.e., the debt serves as a proxy for tax equity. Moreover, ReEDS assumes financing costs and capital structures that average the financial characteristics of utility-owned projects and projects owned by independent power producers (IPPs), as both ownership types contribute to the expansion of generation capacity. Finally, with the 40-year time horizon of the *SunShot Vision Study*, the SolarDS and ReEDS models use financial assumptions based on long-term historical data, where appropriate and available. The details on specific financing assumptions are provided in the notes below Table 8-1.

8.3 FINANCING REQUIREMENTS FOR THE SOLAR SUPPLY CHAIN

Under the SunShot scenario, annual U.S. PV and CSP installations (including rebuilds) could stabilize at about 25–30 gigawatts (GW)/year (yr) and 3–4 GW/yr, respectively. Building out the U.S. PV and CSP manufacturing capacity to meet this demand would require investing roughly \$25 billion by 2030 and \$44 billion by 2050.[71,72] Although the investments required to finance these manufacturing capacity

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[70] As of May 2011, the System Advisor Model (SAM) is able to model these advanced financing structures and can be found at www.nrel.gov/analysis/sam.

[71] Assumes: 1) Manufacturing capital expenditure (CapEx) costs, in terms of annual production capacity, decline from about \$2/watt (W) in 2010 to about \$0.5/W in 2020; the CapEx requirements for concentrated solar power (CSP) technologies are not well documented, so, conservatively, the CSP CapEx is assumed to be equal to the PV CapEx. 2) Annual U.S. installations (including rebuilds) grow to 25 GW/yr by 2030 and 30 GW/yr by 2050 for PV, and 3 GW/yr by 2030 and 4 GW/yr by 2050 for CSP. 3) Average economic life of manufacturing equipment is 10 years. 4) The manufacturing utilization rate is 80%.

[72] All cumulative values in this chapter are in net present value calculated using a 7% discount rate per the U.S. Office of Management and Budget (OMB) 2003 guidance.

Table 8-1. Solar Financing Assumptions

	SolarDS		ReEDS[a]	
	Residential Rooftop (new/retrofit)	Commercial Rooftop	Utility PV	Utility CSP
Inflation rate [b]	3%	3%	3%	3%
Loan rate (real)	4.5%[c]/6%[d]	4.5%[e]	4%[f]	4%[f]
Loan term (years)	30/15	20	15	15
Debt fraction	80%–100%[g]	60%	60%	60%
Equity rate (real)	N/A	N/A	11.7%[h]	11.7%[h]
Down payment (equity fraction)	0%–20%[g]	40%	40%	40%
Discount rate (real)	N/A[i]	N/A[j]	5.5%[k]	5.5%[k]
Depreciation	N/A	MACRS[l]	MACRS	MACRS
Federal tax	25%–33%[m]	35%	35%	35%
State tax	by state	by state	5%	5%
PV/CSP lifetime (years)	30	30	30	30

[a] The financial assumptions in ReEDS for utility-scale PV and CSP are the same for other renewable and conventional generation technologies. The one exception is loan terms, which vary between 15 and 30 years depending on technology.

[b] Conservative estimate of inflation based on historical U.S. Gross Domestic Product (GDP) deflator data over the last 30 years. Accessed November 2010 at: http://research.stlouisfed.org/fred2/data/GDPDEF.txt.

[c] Based on a 20-year historical average of real U.S. 30-year fixed mortgage rates. Accessed January 20, 2010, at: www.freddiemac.com/pmms/pmms30.htm (Freddie Mac 2010).

[d] Based on a 3-year historical average of real rates for $30,000 U.S. home equity loans. Accessed January 20, 2010, at: www.wsjprimerate.us/home_equity_loan_rates.htm.

[e] Based on a 12-year historical average of real yields of corporate bonds rated Aa and A by Moody's (SIFMA 2010).

[f] Reflects a nominal cost of debt of approximately 7%, the midpoint between the nominal costs of debt for higher-risk projects owned by investor-owned utilities and those owned by independent power producers (Wimer 2008).

[g] Assumes that 80% of residential customers use a 20% down payment, and 20% of residential customers use a 0% down payment to characterize the alternate ownership structures such as third-party PV ownership (NREL 2009, SEIA/GTM Research 2011a) or property-assessed clean energy (PACE) style financing (NREL 2010).

[h] Reflects a nominal cost of equity of 15%, the midpoint between the nominal costs of equity for investor-owned utilities and independent power producers (EEI 2009, Wimer 2008).

[i] SolarDS uses a simple payback time to adoption relationship for residential customers.

[j] SolarDS uses a payback time to adoption rate for commercial customers that use the internal rate of return of future cash flows.

[k] Reflects a nominal after-tax weighted average cost of capital (WACC) of 8.6%.

[l] MACRS (modified accelerated cost recovery system) is applied to taxable commercial customers.

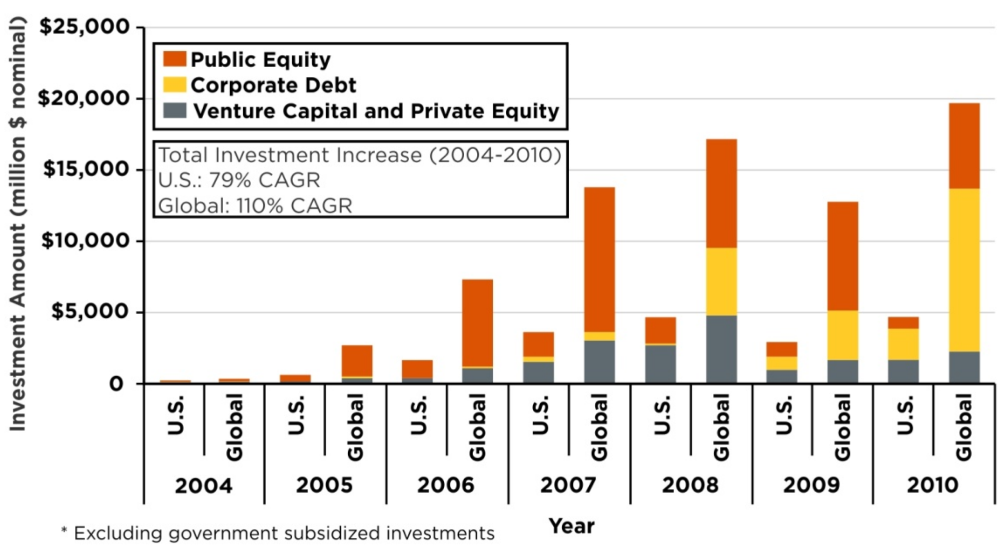
[m] Assumes that 50% of residential customers are at a 25% federal tax rate, and the other 50% are at a 33% federal tax rate.

expansions are not trivial, on an annual basis they would require investments on the order of $1–$3 billion, well below levels seen during the past couple of years (as discussed below). Moreover, the necessary financing instruments and structures are well developed and well understood in the capital markets.

Historically, the solar supply chain has been financed primarily by a mix of venture capital (VC), private equity (PE), public equity, and corporate debt. VC investments are often the earliest form of private investment in corporations, when both the potential reward and risk are the greatest. In the solar industry, PE is usually the next source of funding, as companies require additional and greater amounts of capital for manufacturing expansions. Finally, companies can issue public equity, selling shares of the company on the open market. In addition to equity financing, corporate debt can be used to fund a company's operations and expansions.

Figure 8-1 shows the dramatic increase in investment in the U. S. and global solar supply chain, including PV and CSP, over the past 6 years. In 2004, only $142 million and $231 million were invested in solar companies in the United States and globally, respectively. In 2010, solar supply chain investment reached more than $4.7 billion in the United States and nearly $20 billion globally, corresponding to 6-year compound annual growth rates (CAGRs) of 79% and 110%, respectively. Such rapid expansion indicates the ability of the VC, PE, public equity, and corporate debt capital markets to respond swiftly to signals of the solar industry's growth potential. In addition to the growth of total supply chain investment, the proportional mix of investment has shifted from riskier to more-secure financial instruments. In the years between 2004 and 2006, for example, corporate debt accounted for between 0% and 6% of total global investment, whereas in 2010 almost 60% of total investment in solar companies came from corporate debt.

Figure 8-1. U.S. and Global Solar Supply Chain Investment

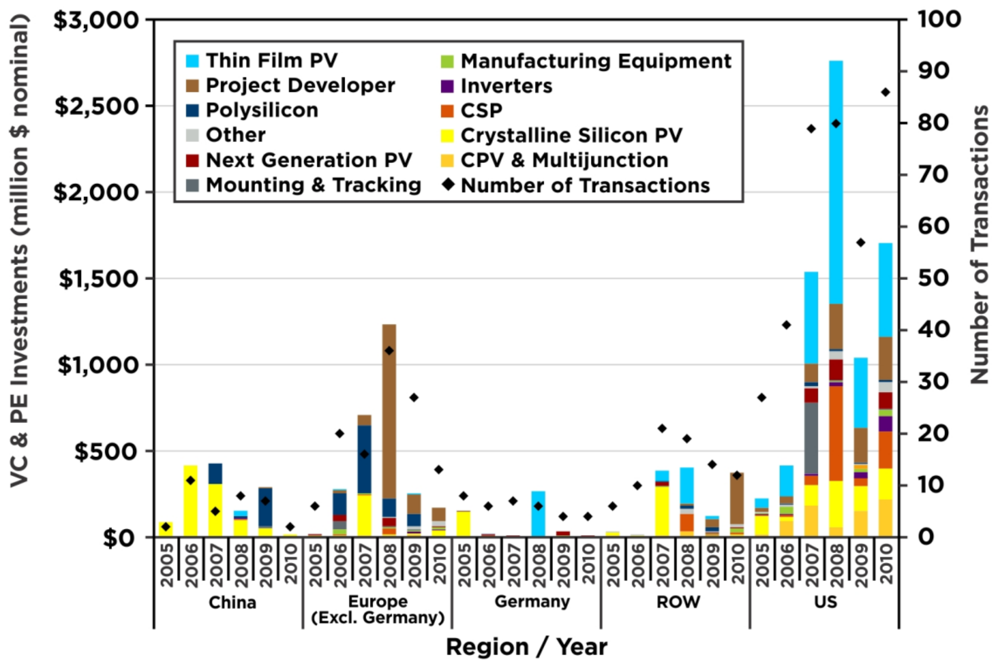


Source: Bloomberg New Energy Finance (2011)

Figure 8-1 excludes government-subsidized investments. Government-supported debt grew from $579 million in 2009 to $32.8 billion in 2010, to become greater than any other source of capital. Most of this government-supported debt was issued by the China Development Bank.

Figure 8-2 illustrates VC and PE investment in the solar supply chain, including PV and CSP, showing the technological and regional breakdown of such funding. U.S. companies have consistently received the most VC and PE funding, and a far more diverse set of solar technologies is financed in the United States than in the other active solar markets.

Figure 8-2. VC and PE Investment in the Solar Supply Chain



Source: Bloomberg New Energy Finance (2011)

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8.4 Financing Requirements for Solar Project and Transmission Deployment

Deploying solar projects—i.e., deploying PV and CSP electricity-generating facilities—and associated transmission infrastructure will cost much more than expanding the solar supply chain under the SunShot scenario. This section explores the potential project and transmission costs.

8.4.1 Financing Solar Projects

Under the SunShot scenario, solar capacity in the United States is projected to meet 14% of total contiguous U.S. electricity demand by 2030 and 27% by 2050. To achieve these penetration levels, annual solar installations are projected to stabilize around 25–30 GW/yr for PV and 3–4 GW/yr for CSP. On an annual basis, this translates into roughly \$40–\$50 billion/yr.[73] On a cumulative basis, the required investments are roughly \$250 billion through 2030 and \$375 billion through 2050. Although these are significant investments, the total capital required to build all types of electric-generating equipment—conventional and renewable—in the SunShot scenario through 2050 is actually only \$2 billion more than in the reference scenario. When other costs are considered—such as fuel, transmission, and operation and maintenance (O&M)—less money is actually spent in the SunShot

[73] Assumes solar technology costs and mix of PV and CSP technologies per SunShot scenario as described in Chapter 3 and Appendix A.

scenario than in the reference scenario (see Chapter 3). However, it is still relevant to consider what effect financing may have in achieving the SunShot scenario.

8.4.2 Financing Transmission

In both the SunShot and reference scenarios, the U.S. transmission infrastructure must be reinforced and expanded to accommodate new generation resources. Technical aspects of the transmission requirements are detailed in Chapters 3 and 6.

As discussed in Chapter 3, the projected cost of expanding transmission in both the SunShot and reference scenario from 2010 to 2050 is about $60 billion dollars (2010$, net present value). The discounted cost for the SunShot scenario is approximately the same as the reference, even though more transmission capacity is built, because this additional capacity is developed later in the study whereas the reference scenario develops more transmission capacity earlier in the study. Regardless, the entire cost of transmission expansion is equivalent to less than a few years of fuel savings in the SunShot scenario. The $60 billion transmission investment required in both scenarios is spread out over 40 years, representing about 2% of the total electric-sector costs. While building out the transmission infrastructure at this level will present many challenges (especially related to siting), it 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).

8.5 Financial Structures and Incentives

As previously noted, although substantial investments will be required to finance SunShot-scale expansion of the solar manufacturing supply chain, there is sufficient capital to do so, and the necessary financing instruments and structures are well developed and understood in the capital markets. However, financing solar project deployment (e.g., new power plants) under the SunShot scenario will cost much more than financing the supply chain. Especially in the pre-2020 period, new financing options will be required before solar electricity is cost competitive with other electricity sources. In 2020 and beyond, cost-competitive solar energy should stimulate private solar investment and facilitate use of mainstream financial instruments. This section discusses the current financial incentives and financing structures that support U.S. solar and transmission projects, followed by a description of emerging solar project financing structures that may support solar deployment in the coming years.

8.5.1 Current Financial Incentives and Structures

Current financial incentives and structures for solar projects are based on the availability of government incentives, particularly the federal ITC. Although the *SunShot Vision Study* assumes that no solar projects receive an ITC after 2016, this incentive—and government incentives at other levels—will be important for stimulating solar deployment during the transition to solar cost competitiveness.[74]

[74] Although the SunShot scenario costs assumptions do not include any ITC after 2016, under the current Internal Revenue Service (IRS) tax code, the 30% ITC will revert to a 10% ITC for commercial and utility systems after 2016.

This subsection begins with a discussion of government incentive-based financing and then describes current solar financing structures, which are based on the availability of government incentives. Lastly, transmission financing considerations are discussed.

Government Incentives

Financial incentives for U.S. solar projects are provided by the federal government, state and local governments, and some local utilities. Historically, federal incentives have been provided primarily through the U.S. tax code, in the form of an ITC (which applies to residential, commercial, and utility-scale installations) and accelerated 5-year tax depreciation (which applies only to commercial and utility-scale installations). For commercial installations, the present value to an investor of the combination of these two incentives—which can be used only by tax-paying entities—amounts to about 56% of the installed cost of a solar project (Bolinger 2009).[75]

Most solar project developers are not in a financial position to absorb tax incentives themselves (due to lack of sufficient taxable income to offset deductions and credits[76]), and so they have had to rely on a small cadre of third-party "tax equity investors" who invest in tax-advantaged projects to shield the income they receive from their core business activities (e.g., banking). In doing so, these tax-equity investors monetize the tax incentives that otherwise could not be efficiently used by project developers and other common owners of the renewable energy plants.

Federal tax-based incentives may play a significant role in stimulating solar development until 2017, when the ITC is assumed to expire under the SunShot scenario. However, the amount of tax equity available for solar projects is uncertain. Due to the global financial crisis, tax-equity investments in renewable power projects in the United States peaked at $6.1 billion during 2007, declined to $3.4 billion during 2008, and plunged to $1.2 billion during 2009 (US PREF 2010). Assuming that the tax equity market is able to return to its former level of 2007 ($6.1 billion per year), that utilities enter the tax-equity market in force (UBS 2008), and other new tax-equity investors make significant contributions, the total size of the tax equity market could grow to about $10 billion per year in a relatively short period. However, solar energy would have to compete with other renewable energy technologies for this tax equity.

Federal benefits can be used in combination with state and local incentives, which come in many forms, including—but not limited to—up-front rebates, performance-based incentives, state tax credits, renewable energy certificate (REC) payments, property tax exemptions, and low-interest loans. Incentives at both the federal and state levels vary by sector and by whether or not the systems are utility scale or distributed. Incentive levels and eligibility also vary by type of technology.

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[75] Although the accelerated 5-year tax depreciation has a present value to an investor of about 26%, only 12% of that value is from the accelerated schedule. The remaining 14% would have been realized under a conventional 20-year straight-line schedule.
[76] Offsetting income is particularly difficult for certain developers given the IRS's "passive income" rules affecting individuals, personal service corporations, and closely held corporations, which state that "passive income" can only offset "passive losses."

In most cases, solar project developers need to combine several of these federal, state, and local incentives to make projects economically viable. Given the complexity of capturing some of these incentives—particularly in combination—solar financiers have adopted (and in some cases, modified) complex ownership structures previously used to invest in other tax-advantaged sectors in the United States, such as low-income housing, historical buildings, and commercial wind projects. These financing structures—for projects on both the utility and customer sides of the meter—are described below.

Utility Side of the Meter

Although a number of utility-scale[77] CSP projects were built in California during the 1980s (and are still operating), the proliferation of large solar projects interconnected on the utility side of the meter has been a relatively recent phenomenon. Before 2010, there were only 113 megawatt (MW) direct current (MW_{DC}) of utility-scale PV capacity in the United States. In 2010, the United States installed 242 MW_{DC} of such projects. There were no CSP plants built from 1992–2006; since then, several facilities less than 10 MW alternating current (MW_{AC}) in size have been placed in service as well as a 64-MW_{AC} project in Nevada (2007) and a 75-MW_{AC} plant in Florida (2010) (SEIA/GTM Research 2011b). In most cases, these projects are owned by IPPs (in conjunction with tax equity investors), who sell the power to utilities under a long-term power purchase agreement (PPA).

Most of these projects are financed using one of the following three structures: a partnership flip, a sale/leaseback, or an inverted lease. Each of these tax-driven structures allocates the benefits of ownership among the project developer and various project investors. Solar projects can have multiple benefits: cash proceeds from the sale of power or lease of equipment to the site host, a federal ITC or cash grant, depreciation benefits, RECs, and state or local grants. Financial structures are chosen and modified to optimize each party's return, exposure to risk, and desired long-term ownership of a solar asset. Each transaction is complex and includes sophisticated structuring among the project developer, equity provider, debt provider, and sometimes even the end-users. Not surprisingly, these one-off arrangements are expensive and time consuming as they involve multiple attorneys, accountants, and other professional advisory services. This complexity results from having project developers go to great lengths to fully monetize incentives that are designed to increase the proliferation of solar projects. Wind projects, which must be structured similarly to monetize the tax credit and depreciation incentives, sacrifice approximately 40% of the value of the PTCs to use the tax capacity provided by tax equity investors (Hudson Clean Energy Partners 2009).

To date, most solar projects interconnected on the utility side of the meter have been financed by IPPs using one of the aforementioned three structures, with power sold to the utility under a long-term PPA. There are, however, some emerging issues with this IPP/PPA model. Under certain conditions, accounting principles may require the utility to essentially carry the project from which it is buying power on its balance

[77] Solar projects on the utility side of the meter are often referred to as utility-scale projects because they tend to be large (multi-megawatts) in size. However, smaller, distributed utility-scale generation—sometimes called wholesale distributed generation (DG)—often falls under the "utility side of the meter" category. In addition, utilities may explore other distributed-level opportunities in the future that are also on the utility side of the meter.

sheet as a long-term liability. This, in effect, means that the utility will be taking on risk that it cannot necessarily control. Similarly, debt-rating agencies increasingly view long-term PPAs as debt-equivalent obligations, meaning that an over-reliance on PPAs may negatively impact a utility's debt rating. Finally, with the price of solar power expected to decline rapidly in the coming years, a regulatory commission might question retroactively why a utility would have agreed to sign a PPA or even directly own a solar project at current solar power prices. As such, the risk of a retroactive disallowance of an investment in solar needs to be carefully explored with the governing regulatory commission and comfort established that the investment is prudent, regardless of the future projections of solar power prices.

Now that utilities are able to access the ITC utility ownership of solar projects interconnected on the utility side of the meter is becoming more common. There are a number of benefits and a number of challenges to utility ownership.

The largest benefit of utility ownership of solar assets is that utilities have "built-in" financing arrangements available to them through their ability to rate-base investments. This means that as long as a utility's regulatory commission supports the investment and allows the utility to participate in the generation ownership arena, the investment (plus a return on the equity invested) would be recovered through a cost-of-service revenue requirement that would be paid by all ratepayers over the life of the investment. This approach could eliminate the need to access capital markets on a project-level basis. In this model, the capital is provided through the utility's balance sheet, using traditional equity and debt instruments. A utility's investment in solar would be valued at the utility's weighted average cost of capital (WACC), which is typically significantly lower than that of an IPP. Further, a utility's rate-recovery period for investments in solar would likely be 25–30 years (i.e., based on the expected life of the asset), which is significantly longer than the 10–20-year recovery period typically seen in the IPP/PPA model. This longer financing horizon for utilities spreads out the annual revenue requirement, making the burden on customers less than through an IPP/PPA structure. An additional benefit of utility ownership is that they do not have to renegotiate contracts coming to an end with third-party generation owners; negotiating new terms, including PPA price has the potential to add costs over the life of an asset. Utilities also have a better knowledge of where the most appropriate places to site solar systems are in order to improve grid reliability and reduce grid congestion during peak hours.

However, there are two key challenges to utility ownership. First, utility regulators might not consider rate-basing of solar projects as prudent and may not approve the full value of the investment. Many utilities will not move forward without preauthorization from their regulators for owning solar assets above their utility's current avoided cost.

Second, regulations constrain how utilities are able to use the ITC. The economics of utility ownership are challenged by a regulatory measure that limits utilities' ability to pass on the full advantage of a solar project's tax benefits to their rate bases. In particular, the IRS currently requires that the benefit of the ITC to ratepayers be amortized over the life of the facility—a process called "normalization." Normalization defers the up-front tax benefit and dilutes the incentive intended under the federal tax code. Utilities cannot take the ITC without normalizing the tax benefit. Due to this normalization issue, many utilities have not purchased solar assets. Instead, they have allowed IPP's to monetize the ITC and pass along the benefit through lower-priced electricity.

Customer Side of the Meter

Despite the increasing interest in utility-scale solar power projects (using both PV and CSP technologies), to date most solar-electric systems have been installed "behind the meter," meaning on the customer, rather than utility, side of the meter. These customer-side systems have been installed in both residential and non-residential applications and have primarily used PV technologies. Variations in tax rules between the residential and non-residential sectors, as well as varying tax status within the non-residential sector (e.g., commercial versus non-profit versus governmental) have given rise to a variety of different financing or ownership structures used in each sector or sub-sector.

Table 8-2 summarizes the principal financing options available, categorized as either self financed or third-party financed. Self-financed projects rely on some mix of equity (i.e., cash) provided and debt assumed by the site host, with the sources of that equity and debt varying considerably among the residential, non-residential taxable, and non-residential tax-exempt sectors. Prior to 2006, almost all behind-the-meter PV projects were self financed.

Table 8-2. Categorization of Financing Approaches for Behind-the-Meter PV Projects

<table>
<tr><th colspan="2" rowspan="2"></th><th>Residential</th><th colspan="2">Non-Residential</th></tr>
<tr><th>Taxable</th><th>Taxable</th><th>Tax-Exempt</th></tr>
<tr><td rowspan="2">Self financed</td><td>Equity (Cash)</td><td>Cash savings</td><td rowspan="2">Balance-sheet finance</td><td>Internal funds or reserves</td></tr>
<tr><td>Debt</td><td>Mortgage; home equity loans; property tax loans</td><td>Bank loans; muni bonds; CREBs[a]</td></tr>
<tr><td rowspan="2">Third-party financed</td><td>Lease</td><td>Operating lease</td><td>Operating lease</td><td>N/A</td></tr>
<tr><td>Service contract (PPA)</td><td>Not as common as lease</td><td>More common than lease</td><td>Very common</td></tr>
</table>

[a] CREBs = clean renewable energy bonds.

Starting in 2006, however, third-party financing began to expand rapidly, particularly in the non-residential sector. This rapid expansion was driven in large part by an increase in the federal ITC from 10% to 30%. A 30% ITC coupled with accelerated tax depreciation was large enough to attract the attention of institutional tax equity investors, who partnered with PV project developers to offer solar leases and service contracts to mostly non-residential site hosts.

Under a solar lease, the tax equity investor, often in partnership with the project developer, owns the project and benefits from lease payments and tax benefits, while the site host makes lease payments and benefits from the power generated. Project operations may be managed by the site host or the tax equity investor, depending on local conditions. Another third-party financing mechanism is the solar service contract, which is often loosely referred to as a third-party PPA. Although the contract itself is similar to a PPA on the utility side of the meter, on-site generation hosted by a customer entails a contract between the customer and the project owner (the utility is not involved), and it needs to be legally structured as a contract for solar services. Under this arrangement, the tax equity investor—again, often in partnership with the project developer—owns and operates the project, takes the tax benefits, and sells the energy to the site host, while the site host pays for the energy generated and uses it to displace energy that it would otherwise purchase from the utility. In either case, the goal has been to structure the lease or PPA payments such that the site host is paying no more than it would have otherwise paid to the utility, thereby making solar a budget-positive, or at least budget-neutral, proposition for the site host right from inception.

These third-party financing options have proven to be popular with site hosts for three primary reasons: 1) they reduce or eliminate the up-front cost to the host; 2) they enable full and efficient use of the federal tax incentives; and 3) system operations and maintenance are the responsibility of the third-party owner in the case of a solar service contract (and sometimes for solar leases). In the non-residential sector, PPAs have proven to be more popular than solar leases. Furthermore, for tax-exempt entities, traditional operating leases are not an option, and tax-exempt leases are not as favorable as service contracts (Bolinger 2009). Although relatively new in the residential sector, third-party financing options have recently made substantial inroads in this market segment as well, accounting for more than 20% of residential systems, and 30% of total systems, installed under the California Solar Initiative (CSI) incentives in 2010 (CSI 2011).

Financing Transmission

Transmission regulatory approvals (see Chapter 7) and cost allocation (i.e., who pays for transmission) for transmission expansion are among the most significant barriers to renewable energy development in the United States. Although there are many models for transmission cost allocation, the most common U.S. model to date requires the generator to fund transmission expansion, further explained below. However, a July 2011 federal order could change transmission cost allocation going forward, once implemented.

Under existing Federal Energy Regulatory Commission (FERC) rules for network—as opposed to radial, or one-way—transmission development or expansion, the transmission operator [typically the investor-owned utility (IOU)] can finance the transmission development itself and recover costs from ratepayers or require the generator to finance the cost for network upgrades up front. Utilities are often reluctant to finance transmission to serve renewable projects for fear that such investment would be deemed unreasonable by regulatory authorities if the generation failed to come online, potentially creating stranded costs that must be borne by their shareholders. To avoid such risks, they typically require developers to pay for all or a significant portion of the required network upgrades instead. Alternatively, developers may have to post a security deposit for the time it takes to build the new line. However, developers find it difficult to finance both a generating project and significant network upgrades. This situation has created a large logjam of generator interconnection waiting lists for transmission, known as interconnection queues.

An alternative to generator-funded cost allocation is socialization of transmission costs, i.e., distributing costs for transmission expansion and upgrades to all customers, which has had some success in enabling the financing of transmission for renewables. The reasoning is that expanding the transmission system benefits all customers by increasing competition, enhancing reliability, and providing access to renewable resources, among other benefits (Pfeifenberger et al. 2009). Within the Electric Reliability Council of Texas (ERCOT) Interconnection, these costs have been spread among all customers of all utilities for more than a decade. Transmission connecting Texas' recently created competitive renewable energy zones (CREZs) will be financed the same way.

The California Independent System Operator Corporation (CAISO) has implemented a cost-allocation model for the Tehachapi Transmission Project, which involved policymakers (CAISO and FERC) cooperating with local participants to approve a $1.8-billion transmission line that will allow about 4,500 MW of wind capacity to reach markets by 2013. This project involved up-front financing by Southern California Edison, using tariff-based cost recovery through transmission rates and pro rata fees paid by generators, with installation of the line preceding installation of the renewable generators that largely justify construction of the line (Pfeifenberger et al. 2009). Costs are spread among all generators interconnecting, but costs that are incurred prior to full subscription by generators are socialized. Similar arrangements can be contemplated for expansion of transmission for solar generating capacity.

In July 2011, FERC issued Order 1000, "Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities." The new order has the potential to facilitate transmission expansion as it relates to renewable energy projects in two main ways. First, local and regional transmission planning processes must consider transmission needs driven by state or federal laws or regulations [e.g., renewable portfolio standard (RPS) requirements]. Depending on how this is implemented, it could mean that utilities do not need to be concerned with regulatory stranded costs for renewable energy-specific transmission, because the FERC order could be used to prove the investment was prudent. Second, regional transmission cost allocation methods cannot require "participant funding" of transmission facilities. This could mean that generators may not be required to cover the full cost of transmission facilities. Implementation of this new FERC rule could help finance transmission for renewable energy projects going forward.

8.5.2 Emerging Solar Project Financing Structures

In addition to the more prevalent solar project financing structures described above, three emerging project financing structures have not yet been widely used to finance solar projects in practice; these include prepaid service contracts, property-assessed clean energy finance (PACE), and on-bill financing.

Prepaid Service Contract

A prepaid service contract is similar to a regular service contract (or third-party PPA) between the project owner and an offtaker (i.e., power purchaser) as described above, with one important exception: a significant portion of the power is purchased upfront, before it is delivered. This structure works well with governmental institutions that can issue low-cost debt and use the proceeds to make an up-front payment. Because the project effectively benefits from both low-cost (and in certain cases tax-exempt) debt financing and the private sector tax benefits generated by the project, the effective cost of power under a prepaid service contract can be significantly lower than under other financing options (Bolinger 2009). Although several large wind projects built since 2007 have used prepaid service contracts, this financing structure has been slower to catch on with solar projects. In particular, it is difficult to justify the use of this rather involved and complex structure for relatively small PV projects—as opposed to larger wind projects. However, as larger PV and CSP projects, or portfolios of projects, have proliferated the prepaid service contract has begun to gain favor among developers and tax-exempt governmental offtakers.

Property-Assessed Clean Energy Finance Programs

In PACE programs, municipal financing districts lend the proceeds of bonds or other funds to property owners to finance end-user renewable energy and energy-efficiency improvements. The property owners then repay these loans over 15–20 years via annual assessments on their property tax bills. These programs offer the advantage of 100% financing with tax-deductible interest payments, as well as the loan being tied to the property rather than to the homeowner. Since the City of Berkeley, California, first announced the basic structure of its program in October 2007, PACE programs have spread rapidly across the country; 27 states and Washington DC have authorized PACE financing policies thus far (DSIRE 2011). Residential PACE programs hit a significant roadblock in mid-2010, however, when Fannie Mae and Freddie Mac, which underwrite a significant portion of home mortgages, determined that they would not purchase mortgages with PACE loans because PACE loans, like all other property tax assessments, are written as senior liens.[78] These issues are still being resolved, and while it is not yet known whether or how residential programs will move forward, PACE assessments remain a viable option in the commercial space. As of March 2011, there were four commercial PACE programs in operation, which had approved $9.69 million in funding for 71 projects, many of which were PV. There were also nine commercial programs in formal planning stages, and at least seven in preliminary planning stages (LBNL 2011).

On-Bill Financing

On-bill financing is a relatively new form of financing that combines a state subsidy, such as an up-front rebate or interest rate buy-down, with a loan from the electric utility. The goal is to reduce or eliminate the up-front cost of the project to the customer by financing all of the costs not covered through rebates with an on-bill adder. The loan payments are made over a period that is long enough—and with a low-enough interest rate—to create cost savings from the first day (Brown 2009b). This mechanism has been used only for energy efficiency and there are not any

[78] On July 6, 2010 the Federal Housing Finance Agency (FHFA), which regulates Fannie Mae, Freddie Mac, and the 12 Federal Home Loan Banks, issued a statement determining that PACE loans “present significant safety and soundness concerns” and called for a halt in PACE programs for these concerns to be addressed. FHFA determined that, “the size and duration of PACE loans exceed typical local tax programs and do not have the traditional community benefits associated with taxing initiatives” (FHFA 2010). Because Fannie Mae and Freddie Mac do not consider PACE loans to conform with traditional taxing initiatives, they are not interested in purchasing mortgages on homes with PACE liens. Certain PACE programs are attempting to solve the problem by setting up programs as second-tier liens.

known applications for solar; however, legislation was introduced (and failed to pass) in Hawaii, directing public utilities to implement on-bill financing for solar technologies (Brown 2009a). Despite the advantages of on-bill loans, this type of financing mechanism faces a number of implementation challenges (Brown 2009b): the need for a sizable amount of initial capital to fund the revolving loan, concern about the potential for defaults, uncertainty about how utilities will be regulated with respect to providing a loan versus a financing product, and the need to update utility billing systems to allow for automated and electronic management of on-bill loans.

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Appendix A. Model Descriptions

A.1 Modeling Overview

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

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

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

A.2 Regional Energy Deployment System

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

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

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

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

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

A.2.1 ReEDS Calculations

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

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

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

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

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

A.2.1.2 Constraints

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

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

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

A

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

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

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

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

A

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

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

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

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

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

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

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

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

A.2.1.3 Sets (subscripts)

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

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

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

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

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

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

A.2.1.4 Parameters (constants)

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

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

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

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

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

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

A

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

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

plan_res_marg*$_{reg}$* (dimensionless): Planning reserve margin in each region.

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

old_trans_cap*$_{reg,reg'}$* (MW): Existing transmission capacity connecting each region to neighboring regions.

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

old_var_om*$_{tech}$* ($/MWh): Variable costs associated with electricity generation from existing capacity. This includes variable O&M costs.

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

A

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

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

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

A.2.1.5 Variables

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

NEW_ELEC_GEN*$_{tech,reg,ts}$* (MW): Average electricity generation from new technologies in each region in each time slice.

OLD_ELEC_GEN*$_{tech,reg,ts}$* (MW): Average electricity generation from existing technologies in each region in each time slice.

NEW_CAP*$_{tech,reg}$* (MW): New electricity generation capacity of each technology in each region.

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

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

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

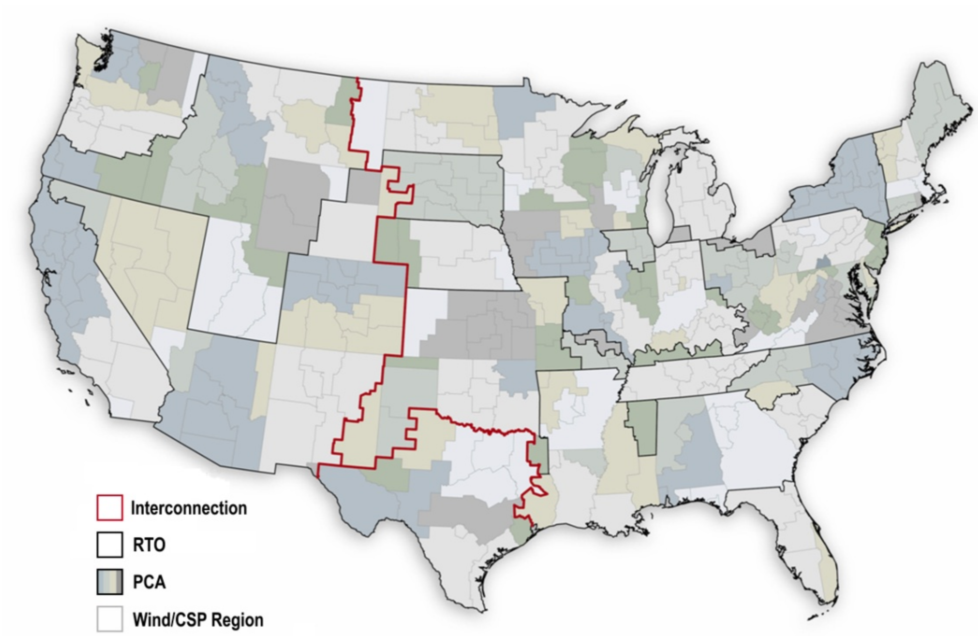
OLD_RES_CAP$_{dtech,reg,ts}$ (MW): Electricity generation capacity from existing dispatchable technologies that has been committed to providing operating reserves in each region in each time slice.

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

A.2.2 ReEDS Regions

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

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



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

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

A.2.3 ReEDS Time Slices

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

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[79] Although existing boundaries for Balancing Authority Areas (BA Areas) are considered in the design of the power control areas (PCAs), the PCA boundaries are generally not aligned with the boundaries of real BA Areas.

[80] Examples of existing Regional Transmission Organizations (RTOs) include Midwest Independent Transmission System Operator (MISO), Independent System Operator New England (ISO-NE), PJM Interconnection LLC (PJM), Southwest Power Pool (SPP), and California Independent System Operator Corporation (CAISO).

[81] The seasons are defined based on the following definitions: Summer = June, July, and August; Fall = September and October; Winter = November, December, January, and February; Spring = March, April, and May.

Table A-1. ReEDS Time Slice Definitions

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

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

A.2.4 ReEDS Technologies

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

A.2.4.1 Photovoltaics

There are three PV technologies modeled in ReEDS:

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

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

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

A.2.4.1.1 Central PV

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

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

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

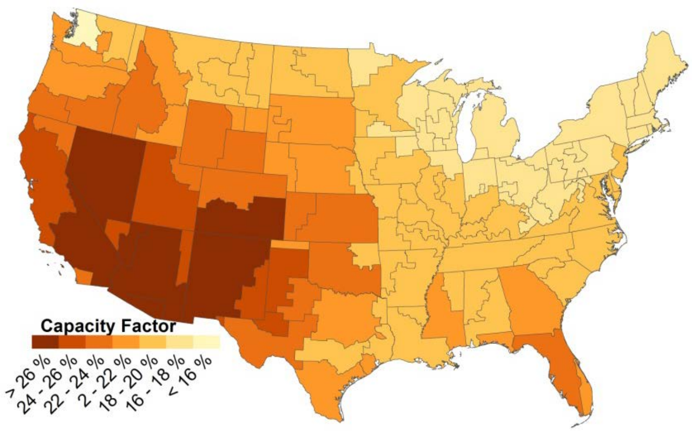
O&M: operation and maintenance; kW: kilowatt; yr: year; Mwh: megawatt-hour

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

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

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

Figure A-2. Central PV Capacity Factors



A.2.4.1.2 *Distributed Utility-Scale PV*

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

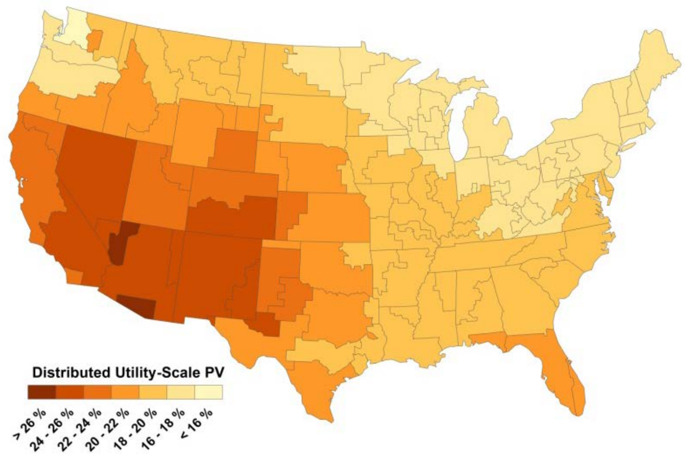
Table A-3. Distributed Utility-Scale PV Technology Cost Projections (2010$)

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

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

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

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



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

A.2.4.2 Concentrating Solar Power

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

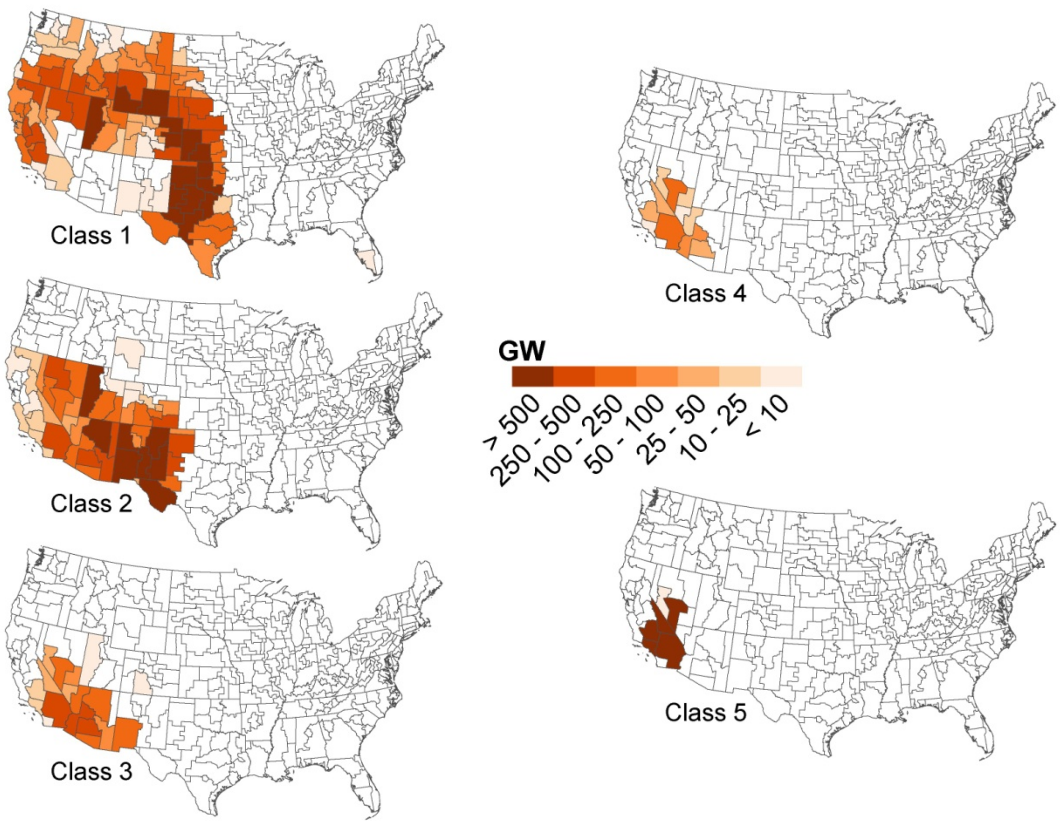
- Class 1: 5–6.25 kilowatt-hours (kWh)/square meter (m^2)/day
- Class 2: 6.25–7.25 kWh/m^2/day
- Class 3: 7.25–7.5 kWh/m^2/day
- Class 4: 7.5–7.75 kWh/m^2/day
- Class 5: > 7.75 kWh/m^2/day.

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

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

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

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



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

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

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

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

A.2.4.2.1 CSP without Storage

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

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

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

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

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

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

A.2.4.2.2 CSP with Storage

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

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

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

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

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

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

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

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

A.2.4.3 Wind

ReEDS considers five resource classes of wind, shown in Table A-8, based on wind power density and wind speed at 50 meters above ground. Available land area of each wind class in each CSP/wind resource region is derived from state wind resource maps and modified for environmental and land-use exclusions. The available wind area is converted to available wind capacity using the constant multiplier of 5 MW/km^2. Available wind capacity is shown in Figure A-5. The colored areas just outside of the coastal regions represent offshore wind.

Table A-8. Classes of Wind Power Density

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

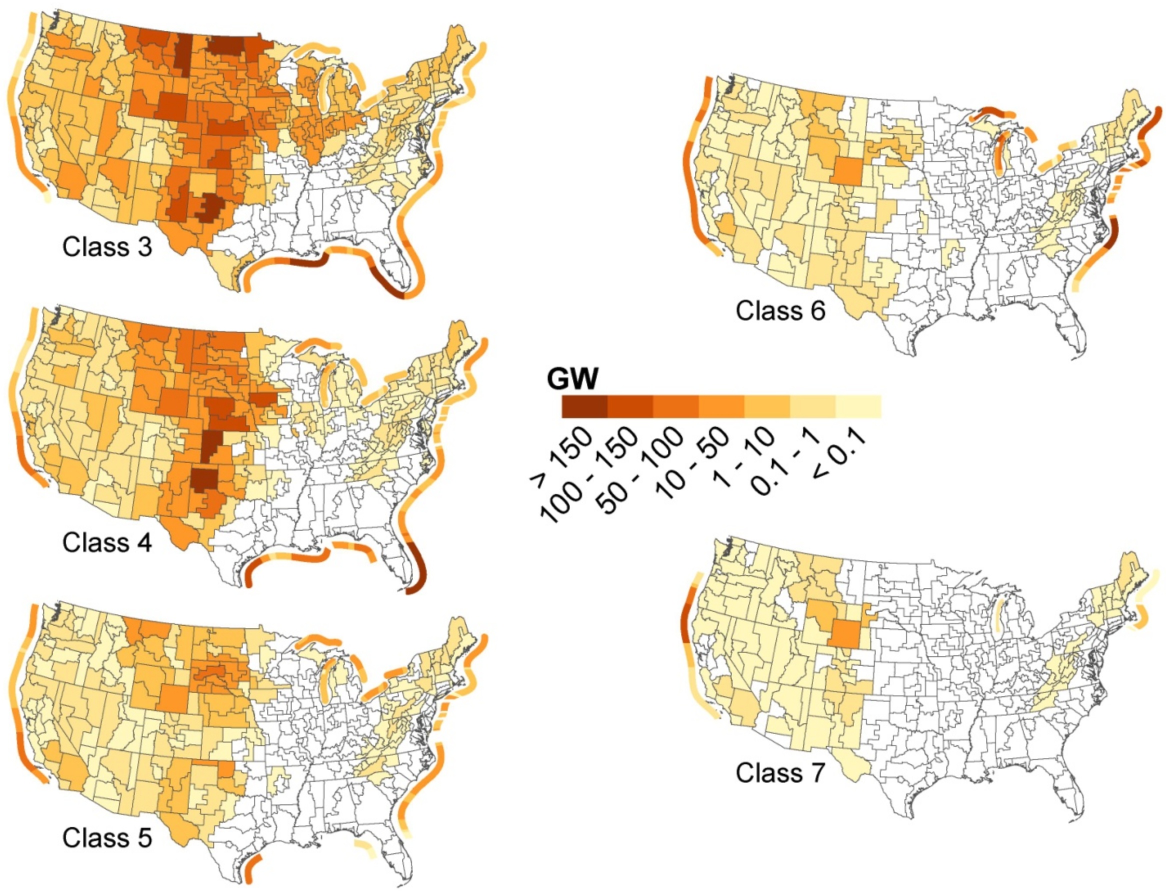
W/m^2 = watts per square meter; m/s = meters per second. Wind speed measured at 50 m above ground level.

Source*:* Elliott and Schwartz (1993)

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

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

Figure A-5. Wind Available Resource by Class



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

A.2.4.4 Conventional and Other Renewable Generators

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

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

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

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

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

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

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

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

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

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

A.2.4.4.1 Retirements

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

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

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

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

10^6 Btu: million British thermal units

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

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

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

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

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

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

SO_2: sulfur dioxide
NO_x: nitrogen oxides
Hg: mercury

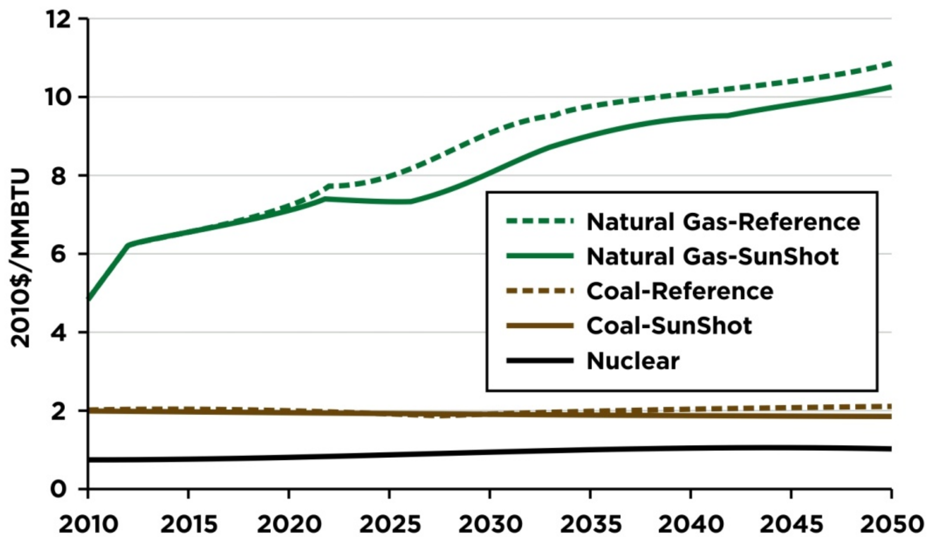
A.2.4.4.2 Fuel Prices

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

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

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

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



A.2.4.5 Storage and Interruptible Load

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

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

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

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

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

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

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

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

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

A.2.5 Transmission

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

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

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

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

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

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

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

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

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

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

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

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

A.2.6 Financial Parameters

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

Table A-17. General Financial Parameters in ReEDS

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

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

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

Table A-18. Financial Parameters by Technology in ReEDS

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

ITC: investment tax credit

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

A.2.6.1 State Renewable Portfolio Standards and Incentives

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

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

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

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

Source: DSIRE (2010)

A.2.7 Resource Variability and System Reliability

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

In ReEDS, the variability of each VER technology is characterized using simulated hourly power output data, described in the PV, CSP, and wind sections: A.2.4.1 – A.2.4.3. The hourly data were used to calculate the standard deviation of power output for each VER technology in each of the ReEDS time slices. The standard deviation was used to characterize variability of individual technologies, but reserve sharing entities—in ReEDS, the 21 RTO regions shown in Figure A-1—are more concerned with the aggregate variability of all demand and generation on the system. To more fully capture aggregate variability, correlation statistics were also calculated between the power outputs of geographically separated wind, CSP, and PV plants. In general, greater geographic distance between two CSP, PV, or wind plants leads to a lower degree of correlation between power outputs, which decreases the variability of their combined generation. Because of this, all else being equal, ReEDS will choose to separate generators of a given type to reduce variability of the output.

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

A.2.7.1 Variable Energy Resource Curtailment

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

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

A.2.7.2 Planning Reserve Requirements and VER Capacity Value

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

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

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

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

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

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

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A.2.7.3 Operating Reserves

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

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

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

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

Operating reserve requirements included in ReEDS are:

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

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

A.2.8 Direct Electric-Sector Costs

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

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

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

A.2.9 Electricity Price

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

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

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A.2.10 Electric Power Demand Projections

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

A.3 Solar Deployment System Model

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

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

A.3.1 Rooftop PV Economics

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

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

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

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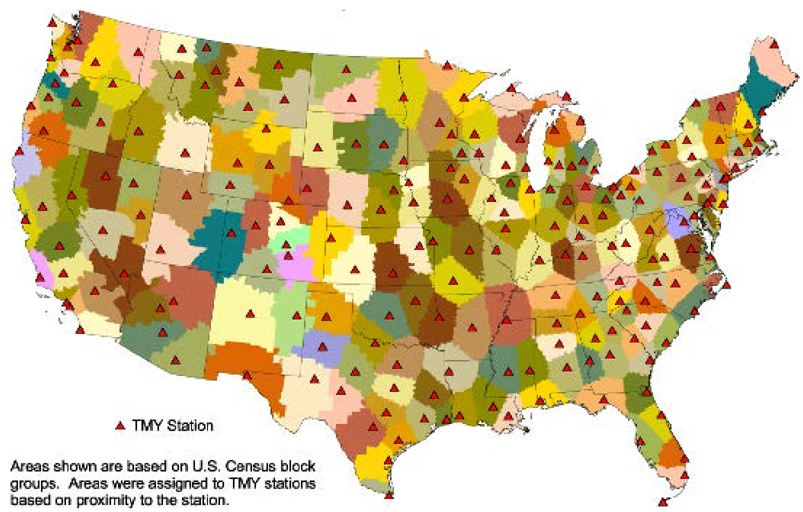
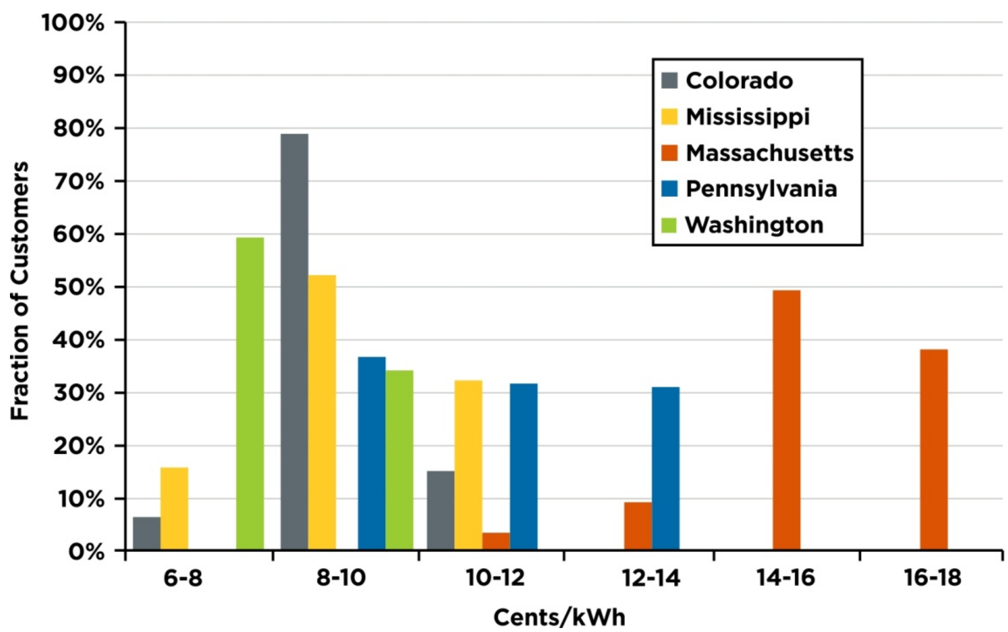
Figure A-7. The 216 Solar Resource Regions Used in SolarDS, with Observation Stations Shown as Red Triangles



Source: NREL

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



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

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

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

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

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

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

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

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

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

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

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

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

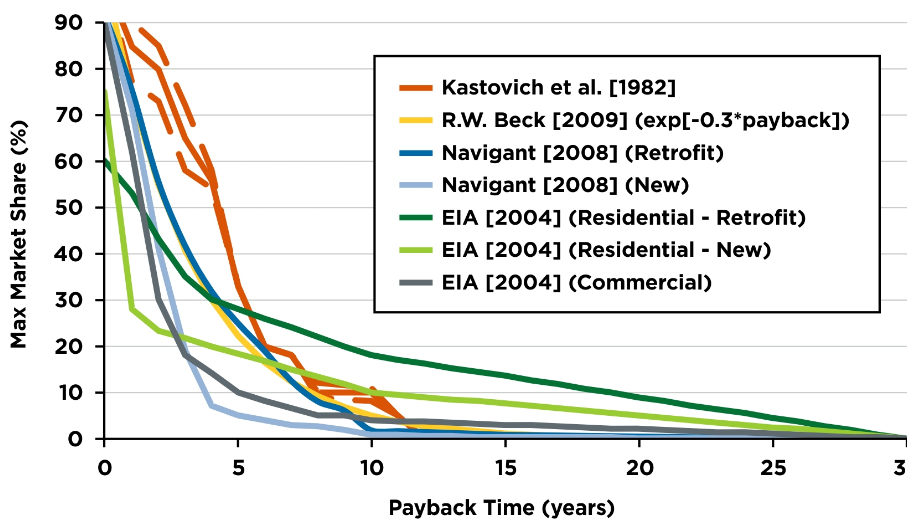
$$Payback\ Time = \frac{log(2)}{log(1+IRR)}$$

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

A.3.2 Rooftop PV Adoption

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

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



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

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

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

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

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

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

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

A.4 GridView Model

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

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

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

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

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

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

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

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

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

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

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

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Appendix B. Tables Supporting Chapter 3 Figures

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

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

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

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

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

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

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

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

Quad: quadrillion British thermal units

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

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

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

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

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

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

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

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

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

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

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

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

O&M: operation and maintenance

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

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

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

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

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

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

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

C.1 Introduction

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

C.2 Sensitivity of Solar Deployment to Solar Prices

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

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

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

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

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

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

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

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

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

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

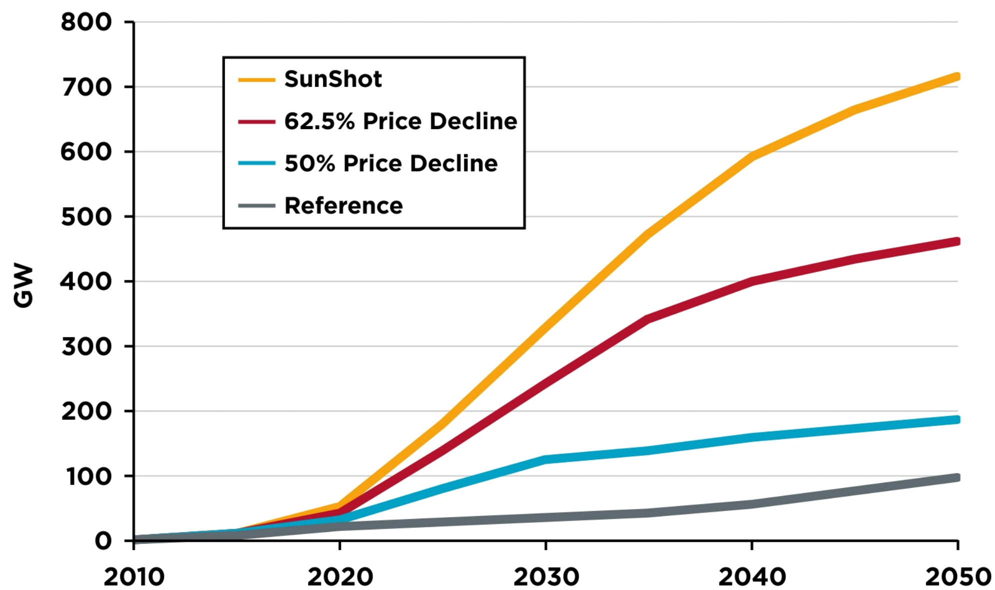

Figure C-2. Total Solar Generation Fraction Under a Range of Solar Price-Reduction Scenarios

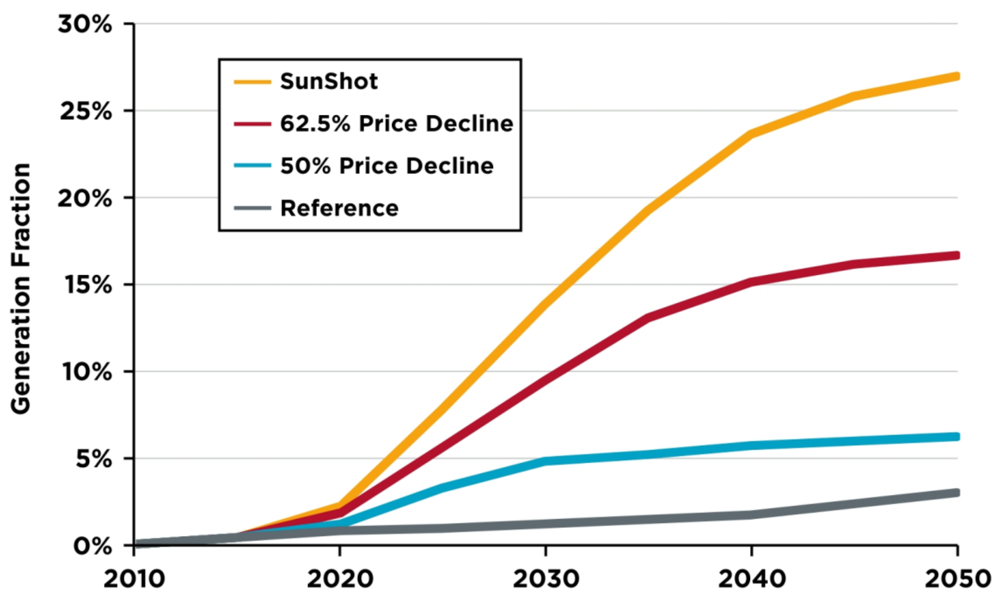

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Table C-2. Price and Performance Inputs for SunShot and SSRE-ETI Scenarios

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

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

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

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

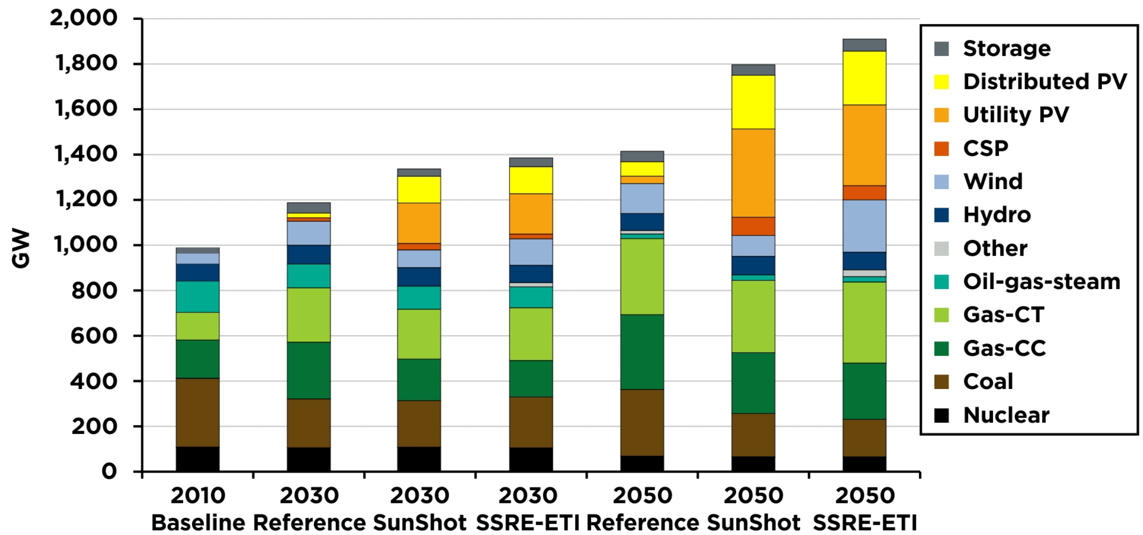
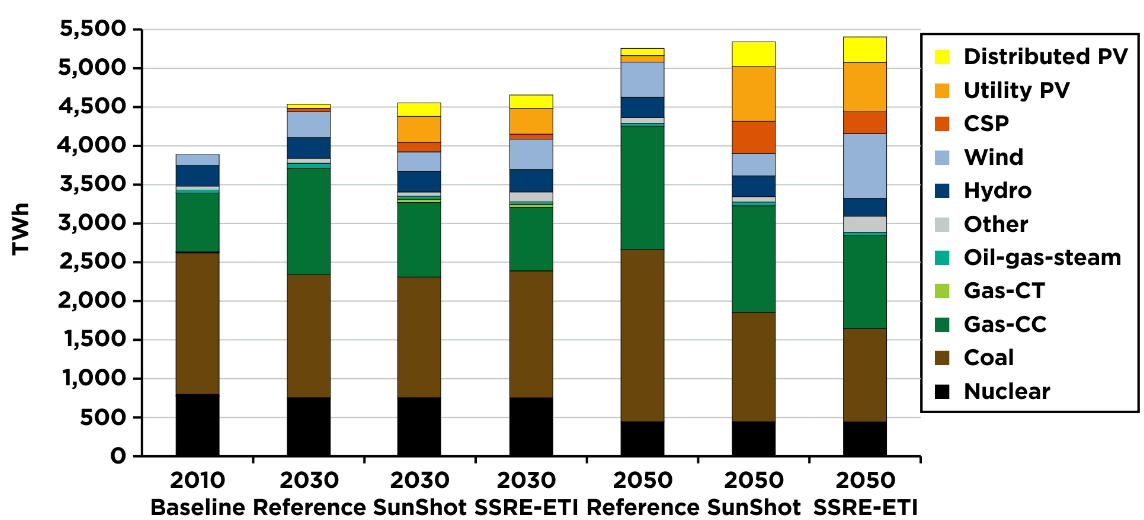


Figure C-4 shows the electricity generation results of the sensitivity analysis. In 2030, wind contributes 8% of generation in the SSRE-ETI scenario, compared with 5% in the SunShot scenario with low technology costs for solar alone. In 2050, wind contributes 16% of generation in the SSRE-ETI scenario,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

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



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

C.4 Sensitivity of Solar Deployment to Natural Gas Prices

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

C.5 References

U.S. Energy Information Administration, EIA. (2010). *Annual Energy Outlook 2010*. Report No. DOE/EIA-0383 (2010). Washington, DC: U.S. EIA.

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

Appendix D. Authors, Reviewers, and Other Contributors

D.1 Overview

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

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

D.2 Coordination and Production

D.2.1 Lead Editors and Coordinators

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

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

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

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D.3.1 Authors and Editors

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

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D.3.2 Internal Reviewers

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

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D.3.3 External Reviewers

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

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

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

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

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

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

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

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

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Ole Pilgaard	Heliodyne, Inc.
Hank Price	Abengoa Solar
Selya Price	National Renewable Energy Laboratory (formerly)
Michael Rader	Solar Energy Industries Association
Tanya Raterman	Cascade Consulting Partners
Christopher Raup	Consolidated Edison, Inc.
Rick Raushenbush	GreenVolts, Inc.
Rick Reed	*SunEarth, Inc.*
Rhone Resch	*Solar Energy Industries Association*
Wilson Rickerson	Meister Consultants Group
Sally Rosauer	FAFCO
David Rubin	*Pacific Gas and Electric Company*
Andrew Sabel	Alanod Solar
Rob Sargent	Environment America
Vishal Shah	Barclays Capital (formerly)
Charlie Shipp	SC Partners, LLC
Walter Short	National Renewable Energy Laboratory
Gianluca Signorelli	MMA Renewable Ventures (formerly)
Eric Silagy	*Florida Power & Light Company*
Katherine Stainken	Solar Energy Industries Association
Cai Steger	Natural Resources Defense Council
Joshua Stein	Sandia National Laboratories
Joe Stekli	U.S. Department of Energy
Scott Stephens	U.S. Department of Energy
Samir Succar	Natural Resources Defense Council
Patrick Sullivan	National Renewable Energy Laboratory
Dick Swanson	SunPower Corporation
Blair Swezey	SunPower Corporation
Andy Taylor	BrightSource Energy, Inc.
Mike Taylor	Solar Electric Power Association

Dan Ton	U.S. Department of Energy
Craig Turchi	National Renewable Energy Laboratory
Cyrus Wadia	U.S. Executive Office of the President
Johanna Wald	Natural Resources Defense Council
Peter Weiner	Paul Hastings
Kathy Weiss	*First Solar, Inc.*
Frank Wilkins	U.S. Department of Energy (formerly)
Ryan Wiser	*Lawrence Berkeley National Laboratory*
Ahmar Zaman	UBS
Carl Zichella	Sierra Club (formerly)
Jarett Zuboy	Consultant
Ken Zweibel	*George Washington University Solar Institute*

D.4.2 External Reviewers

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

Mark Alstrom	WindLogics Inc. (a NextEra Energy company)
Rahim Amerkhail	Federal Energy Regulatory Commission
Bulent Basol	EncoreSolar
Chip Bircher	Utility Solar Water Heating Initiative (USH20)
Travis Bradford	Greentech Media
Bob Carver	New York State Energy Research and Development Authority
Matt Clouse	U.S. Environmental Protection Agency
Jessica Cockrell	Federal Energy Regulatory Commission
James Critchfield	U.S. Environmental Protection Agency
Ed DeMeo	Renewable Energy Consulting Services, Inc.
Joel Dickinson	Salt River Project
Jay Diffendorfer	U.S. Geological Survey
Ronald Flood	Arizona Public Service
Kevin Fox	Keyes & Fox, LLP
Yoel Gilon	BrightSource Energy, Inc.
Jennifer Gleason	Environmental Law Alliance Worldwide (ELAW)
Richard Halvey	Western Governors' Association

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Heidi Hartmann	Argonne National Laboratory
David Hochschild	Solaria Corporation
Tom Hoff	Clean Power Research
Mark Jacobsen	Stanford University
Charles Jennings	AGL Energy Limited
Sue Kateley	California Solar Energy Industries Association
Jonathan Kelves	Sierra Club
Jason Keyes	Keyes & Fox, LLP
Mike King	NERA Economic Consulting
Ron Lehr	Western Grid Group
Robert Litwin	Pratt-Whitney Rocketdyne
Thomas Mancini	Sandia National Laboratories
Adam Mendelson	SunPower Corporation
Dave Menucicci	Building Specialist Inc
John Miller	Sentech, Inc.
Joe Morabito	Alcatel-Lucent
Babul Patel	Nexant Inc.
Cedric Philibert	International Energy Agency
Bill Powers	Powers Engineering
Linda Resseguie	U.S. Bureau of Land Management
Jacques Roeth	New York State Energy Research and Development Authority
Andrew Ryan-Smith	National Grid
Jigar Shah	Carbon War Room
Larry Sherwood	Interstate Renewable Energy Council
Greg Smestad	Solar Energy Materials and Solar Cells
J Charles Smith	Utility Wind Integration Group
Marty Smith	Xcel Energy
Phil Smithers	Arizona Public Service
Kathleen Sullivan	Abengoa Solar
Ted Sullivan	Lux Research
Cecilia Tam	International Energy Agency
Craig Tyner	eSolar, Inc.
Joe Tyrrell	3M
Harin Ullal	National Renewable Energy Laboratory
Bolko vonRoedern	National Renewable Energy Laboratory
Thomas Wells	Southern Company
Sahm White	FIT Coalition
Cherif Yousseff	Sempra Energy

D.4.3 Solar Vision Workshop, October 26, 2009

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

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

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Lori Glover	SOLID Energy
Susan Gouchoe	North Carolina Solar Center
Bill Gould	SolarReserve
Richard Gruber*	First Solar, Inc.
Micah Haman*	Puget Sound Energy
Charles Hanley	Sandia National Laboratories
Dennis Harper	First Solar, Inc.
Bob Hassett	U.S. Department of Energy
Arthur Haubenstock	BrightSource Energy, Inc.
Jim Haugen*	Clean Power Research
Tom Hoff	Clean Power Research
Roland Hulstrom*	National Renewable Energy Lab
Eric John	SkyFuel, Inc.
Izumi Kaizuka*	RTS Corporation
Juris Kalejs*	American Capital Energy
Bill Kammerer*	FIT Coalition
David Kearney	Kearney & Associates
Tom Kimbis	The Solar Foundation
Ben Kroposki	National Renewable Energy Laboratory
Hal LaFlash	Pacific Gas and Electric Company
Mark Lausten	Sentech, Inc.
Craig Lewis	RightCycle
Joshua Linn	Massachusetts Institute of Technology
Craig Lund*	1366 Technologies
John Lushetsky	U.S. Department of Energy
Jeffrey Luth*	Az4Solar.org
Robert Margolis	National Renewable Energy Laboratory
Alex Marker	SCHOTT Solar, Inc.
Joseph McCabe*	Ascent Solar
Jan McFarland	California Alternative Energy & Advanced Transportation Financing Authority
Jim McVeigh	Sentech, Inc.
Mark Mehos	National Renewable Energy Laboratory
Tim Merrigan	National Renewable Energy Laboratory
Paula Mints	Navigant Consulting
Ray Morgan*	SEMI PV Group
Fred Morse	Morse Associates, Inc.
Matt Mowers	National Renewable Energy Laboratory
Terry Murphy	SolarReserve
Denise Nelson	Consolidated Edison, Inc.
James Nelson*	University of California, Berkeley
Sam Newman*	Rocky Mountain Institute
Patricia Nugent*	Dow Chemical
Bob O'Hara	Sargent & Lundy
Steve O'Rourke	Deutsche Bank
Ben Pasquier	Clean Power Research

Craig Patterson*	K.R. Saline & Associates PLC
Terry Peterson	Terry M. Peterson, Ph.D.
Selya Price	National Renewable Energy Laboratory (formerly)
Hank Price	Abengoa Solar Inc.
Richard Raushenbush	GreenVolts
Rick Reed	SunEarth Inc.
Sally Rosauer	FAFCO
Vishal Shah	Barclays Capital
Gianluca Signorelli	MMA Renewable Ventures (formerly)
Eric Silagy	Florida Power & Light Company
Chrissy Skudera	New West Technologies
Cai Steger	Natural Resources Defense Council
Joshua Stein	Sandia National Laboratories
Mark Storch*	Plextronics
Samir Succar	Natural Resources Defense Council
Dick Swanson	SunPower Corporation
Blair Swezey	SunPower Corporation
Mike Taylor	Solar Electric Power Association
Andy Taylor	BrightSource Energy
Cindy Tindell	Florida Power & Light
Craig Turchi	National Renewable Energy Laboratory
Cyrus Wadia	U.S. Executive Office of the President
Johanna Wald	Natural Resources Defense Council
Peter Weiner	Paul Hastings
Carl Zichella	Sierra Club (formerly)
Ken Zweibel	George Washington University Solar Institute

Appendix E. Glossary

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Dish: See "Solar thermal parabolic dishes".

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Solar thermal electric system: See "concentrating solar power".

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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