CONCENTRATING SOLAR POWER

DESCRIPTION

Concentrating Solar Power (CSP), also referred to as solar thermal power, uses mirrors to concentrate the sun's rays to heat a fluid that is then used to generate electricity, often using conventional steam turbines. There are three primary CSP technologies: parabolic trough, solar tower, and dish engine.

The most common CSP system is the **parabolic trough**, which uses curved mirrors with single-axis tracking to concentrate sunlight on a receiver tube or collection element that contains a heat transfer fluid, such as synthetic oil, molten salt or steam. The heated fluid is passed through a heat exchanger to produce steam, which then drives a turbine to generate electricity.

CSP **tower** systems employ a field of mirrors to concentrate sunlight on a receiver at the top of a tower. Tower systems typically achieve higher operating temperatures, which in turn allows for increased energy storage.

Dish engine systems use parabolic reflectors that concentrate solar energy on a receiver located at the focal point of the reflector. The receiver includes a Stirling engine or small gas turbine that generates electricity.

Unlike photovoltaic installations, solar thermal facilities can store energy in molten salt or other medium, allowing them to dispatch energy to the grid even after the sun has gone down. Solar thermal power requires about 3 to 8 acres per MW of installed capacity, depending on the technology and amount of thermal storage.

COST

Installed cost for parabolic trough systems in 2011 ranged from $4.6 million/MW for systems with no thermal storage to $9.8 million/MW for systems with up to 6 hours of thermal storage. For solar tower systems, installed costs ranged from $6.3 million/MW (6 hours of storage) to $10.5 million/MW (up to 15 hours of storage).

Fixed O&M costs were estimated at $20 to $35 per MWh.

CAPACITY FACTOR

Capacity factor for a parabolic trough system with no storage is estimated to be around 25%. For CSP systems with 6 hours of thermal storage, a capacity factor of 40% to 50% is realistic.

TIME TO PERMIT AND CONSTRUCT

Land acquisition and permitting are the most significant time constraints for CSP. Once those hurdles have been overcome, physical construction can generally be completed within 2 to 3 years, depending on the size of the facility.

NOTES

Abengoa is currently constructing what is billed as the world's largest CSP facility near Gila Bend, AZ. The Solana Generating Station is a 280 MW parabolic trough installation estimated to cost around $2B and cover about 3 square miles. It will have about 6 hours of storage using molten salts. APS has agreed to purchase the entire power output of the Solana Generating Station for a reported 14¢/KWh or $140/MWh. Construction began in December 2010 and the facility is expected to be operational in 2013.

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Concentrating Solar Power

Solar Energy Technologies Program

Concentrating Solar Power

Concentrating Solar Power (CSP) is electricity generated from mirrors to focus sunlight onto a receiver that captures the sun's energy and converts it into heat that can run a standard turbine generator or engine. CSP systems range from remote power systems as small as a few kilowatts up to grid-connected power plants of 100's of megawatts (MW). CSP systems work best in bright, sunny locations like the Southwest. Because of the economies of scale and cost of operation and maintenance, CSP technology works best in large power plants.

Why CSP?

- Clean, reliable power from domestic renewable energy
- Operate at high annual efficiencies – Firm power delivery when integrated with thermal storage
- Easily integrated into the power grid
- Boosts national economy by creating many new solar companies and jobs.

CSP Power Plants

More than 350 MW of CSP systems were installed in California in the 1980s. More recently, CSP has experienced a rebirth. Two plants were completed in 2006 and 2007: the 64-MW Nevada Solar One in the U.S. and the 11-MW PS10 power plant in Spain. Three 50-MW plants were under construction in Spain at the end of 2007 with 10 additional 50-MW plants planned. In the U.S., utilities have announced plans for at least eight new projects totaling more than 2,000 MW. Numerous integrated CSP/combined-cycle gas turbine power plants are under development in North Africa and California.

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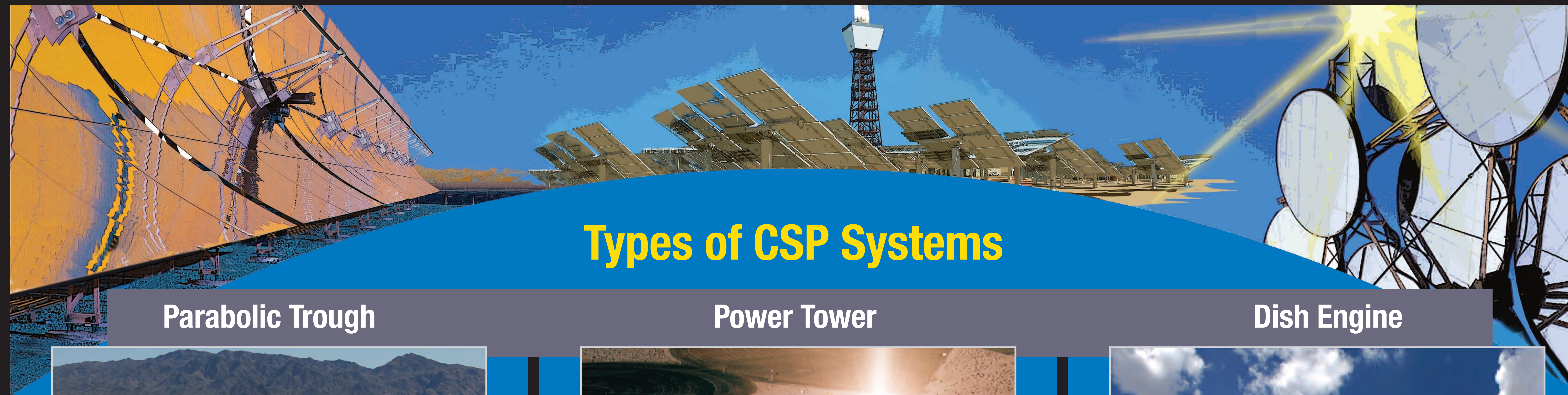

Types of CSP Systems

Parabolic Trough

A section of the parabolic troughs from the Nevada One project tracking the sun.

Power Tower

This 10-MW power tower facility known as Solar Two near Barstow, California, demonstrated molten salt storage.

Dish Engine

These new record-performing dish engine systems are being commercialized.

Key Environmental Topics

Energy Payback (Input vs. Output) – The energy payback time of CSP systems is about 5 months. CSP power plants also pay back in jobs, tax revenue, and increase gross state product.

Greenhouse Gas Mitigation – Compared to fossil-fueled power plants, CSP power plants generate significantly lower levels of greenhouse gases and other emissions.

Toxic Emissions – CSP is clean, non-polluting, and has no carbon emissions that contribute to climate change.

Land Use – CSP plants use approximately 5 acres of land per MW of installed capacity. Enough suitable land is available in the Southwest to generate six times the current U.S. demand for electricity.

Health & Safety – The health and safety risks associated with CSP power plants are the same for any power plant. Employee health and safety measures are in place to protect workers from injury.

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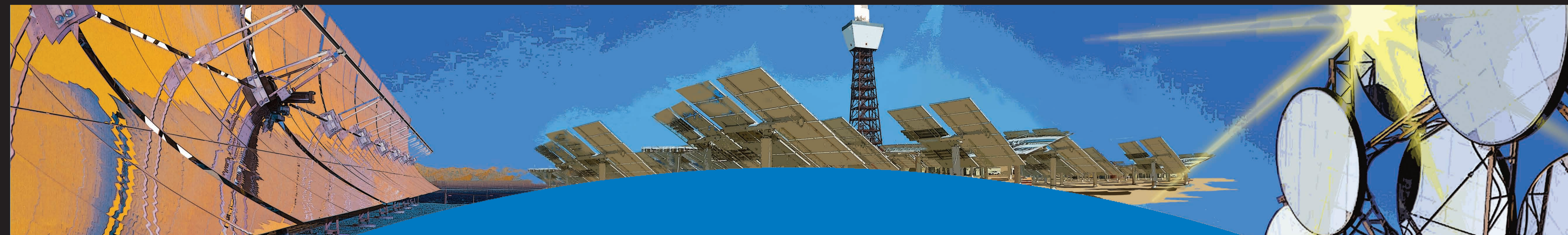
Concentrating Solar Power - Point Focus Reflector Technologies

Solar Energy Technologies Program

In January 2008, Stirling Energy Systems (SES) set a new solar-to-grid system conversion efficiency record at 31.25% on SES's "Serial#3" solar dish Stirling system at Sandia National Laboratories Solar Thermal Test Facility. It produces up to 150 kW of grid-ready electricity. Each dish unit consists of 82 mirrors.

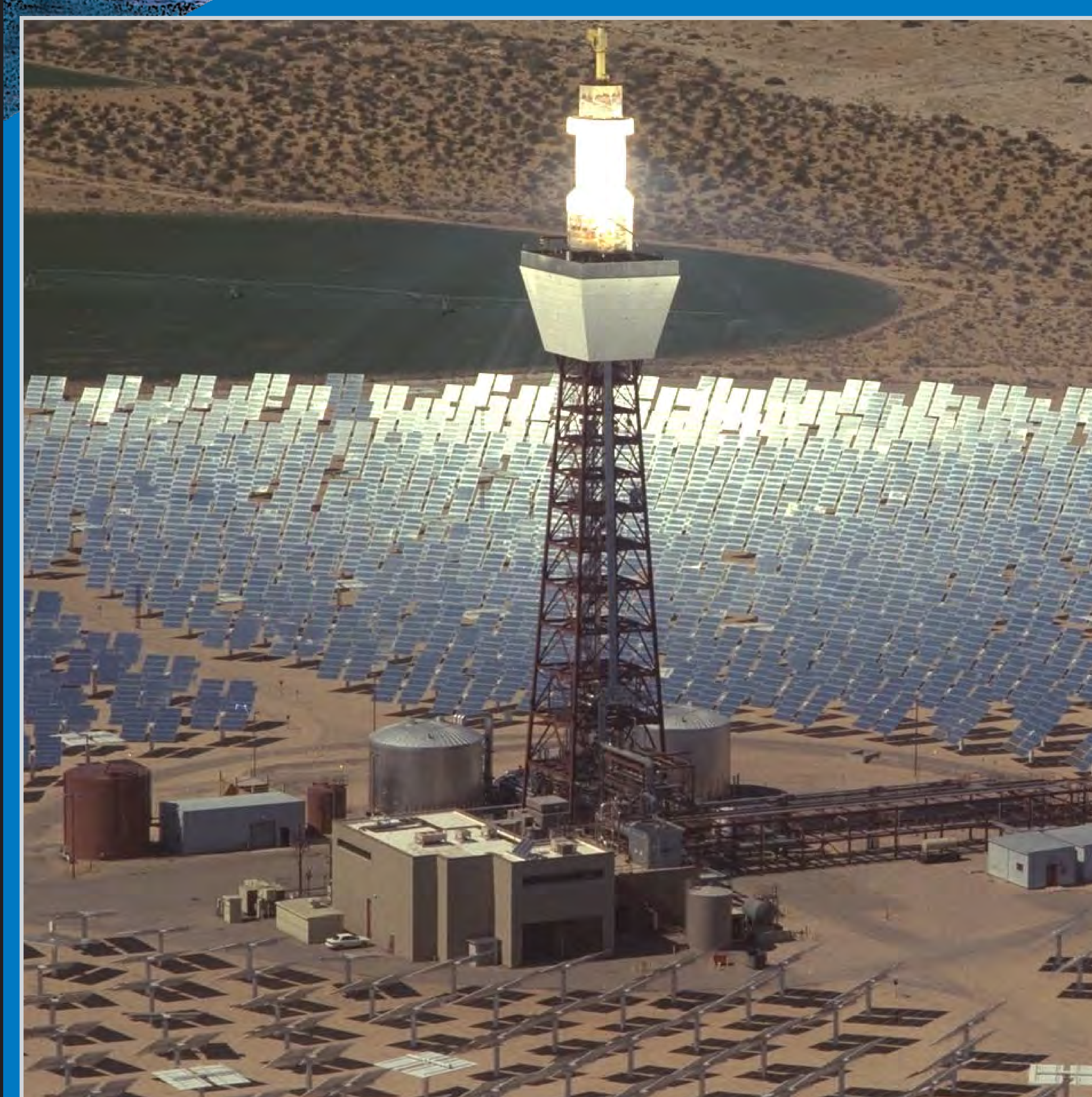
Future Power Plants

- Spain – Solar Tres (Solar Three), a 15-MW power plant using Solar Two technology will be three times as large as Solar Two.
- California – BrightSource Energy is building 500 MWs of distributed towers.
- Spain – Abengoa is constructing a larger version of PS10 called PS20 near Seville.
- Australia – Announced plans to build a 10-MW plant with heat storage near the town of Cloncurry.
- California – Announced plans to build an 800 MW of dish engine systems in the Mojave Desert and Imperial Valley.



Types of Systems

Power Tower

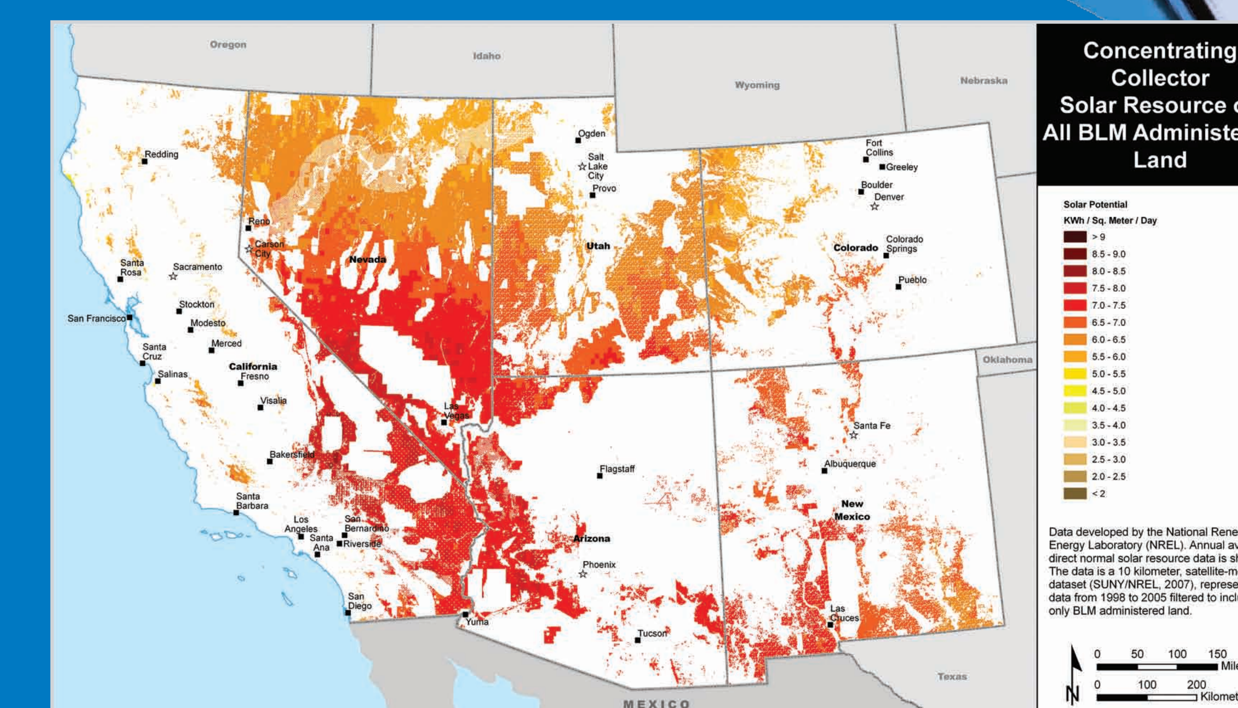


Solar Two, located in Daggett, California, generated 10-MW of solar electricity before it was decommissioned in 1999.

Dish Engine

This solar dish-engine system collects the sun's energy and concentrates it on a small receiver. The thermal receiver absorbs the concentrated beam of solar energy, converts it to heat, and transfers the heat to the engine/generator.

Solar Resource in 6 States

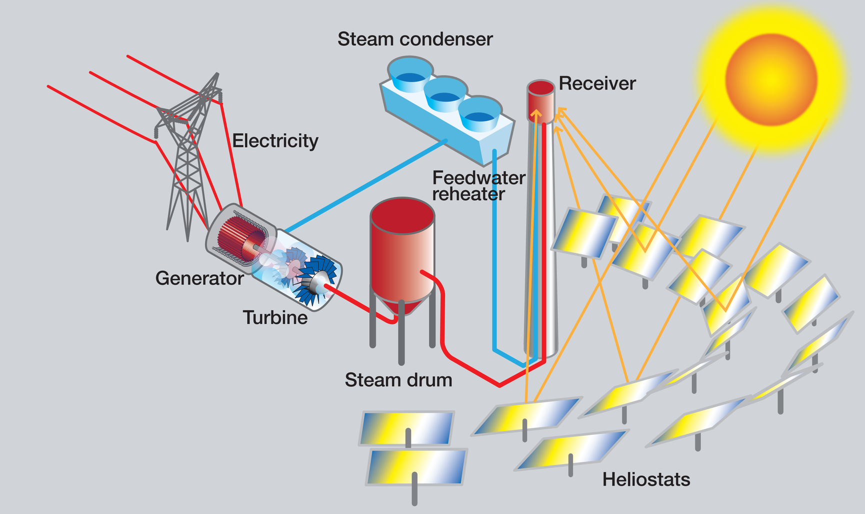


Operational Receiver Technology Power Plants

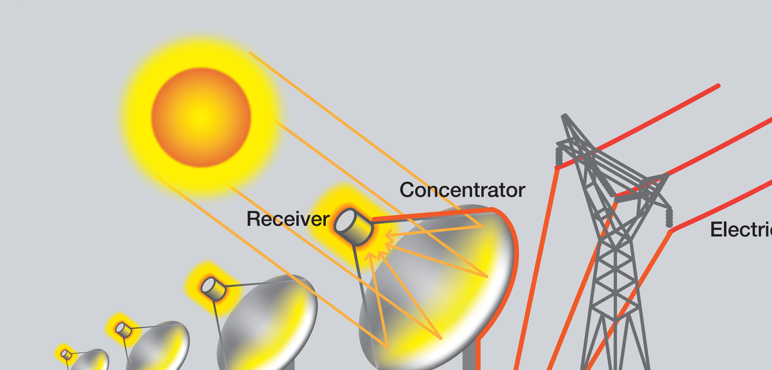
Plant Name	Location	First Year of Operation	MW	Solar Field Area (m^2)
Solar One	Barstow, CA, USA	1982	10	72,650
Solar Two	Barstow, CA, USA	1995	10	82,750
Planta Solar (PS10)	Seville, Spain	2007	11	624 120

How They Work

Receiver technology focuses concentrated sunlight onto a receiver to power an engine that produces electricity.



Power Towers–use large sun-tracking mirrors, called heliostats, to focus the sun's energy on a receiver located atop a tall tower. In the receiver, molten nitrate salts absorb the heat, which is then used to boil water to steam, which is sent to a conventional steam turbine-generator to produce electricity.



Solar Dish-Engine System–an electric generator that uses sunlight to produce electricity. The dish, a concentrator, collects the sun's energy and concentrates it onto a receiver. A thermal receiver absorbs the concentrated beam of solar energy, converts it to heat, and transfers the heat to the engine/generator.

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Concentrating Solar Power - Parabolic Reflector Technologies

Solar Energy Technologies Program

Nevada Solar One is the 3rd largest parabolic solar power plant in the world.

Future Power Plants

Arizona
- Abengoa Solar is constructing a 280-MW parabolic trough project with 6-hour molten salt storage.

California
- Solel is constructing a 553-MW complex of parabolic trough power plants in the Mojave Desert.
- Beacon Solar Energy Project announced plans to build a 250-MW parabolic trough plant.
- Victorville 2 Hybrid Power Project announced plans to build a 563-MW natural gas plant with a 50-MW parabolic trough addition.
- Hybrid Gas-Solar Project – The city of Palmdale plans to build a 570-MW natural gas plant with a 50-MW parabolic trough addition.
- Harper Lake Solar LLC announced plans to build a 250-MW parabolic trough power plant in San Bernadino County.
- Ausra Inc. announced plans to build a 177-MW CSP power plant using compact linear Fresnel reflectors near San Luis Obispo.

Spain
- Solar Millennium, Flagsol, Cobra S.A., and Sener S.A., are building a 50-MW parabolic trough plant called Andasol 1 in Granada. An Andasol 2 and 3 are already being planned.
- Iberdrola is constructing a 50-MW parabolic trough plant at Puertollano in southern Castile.

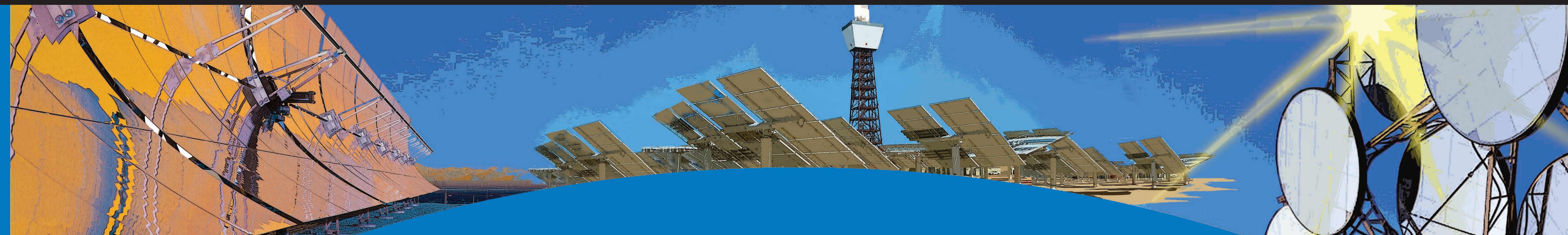
Israel
- Solel is constructing a 150-MW parabolic power plant in the Nevada desert.

Egypt
- Egypt announced plans to build a 40-MW steam input for a gas-powered plant with parabolic trough design.

Algeria
- Algeria announced plans to build an integrated solar combined cycle power station near the town of Hassi R'mel. The plant will combine a 25-MW parabolic trough array in conjunction with a 130-MW combined cycle gas turbine plant.

Abu Dhabi
- The Shams Project announced plans to build a 100-MW parabolic trough power plant near the town of Madinat Zayad.

Morocco
- The announced Beni Mathar Plant is an integrated power station with an installed capacity to generate 472-MW of electricity, including 20-MW from a parabolic trough solar power addition.



Types of Systems

Parabolic Trough

Close-up of a parabolic trough showing collector tube containing oil at trough focal point.

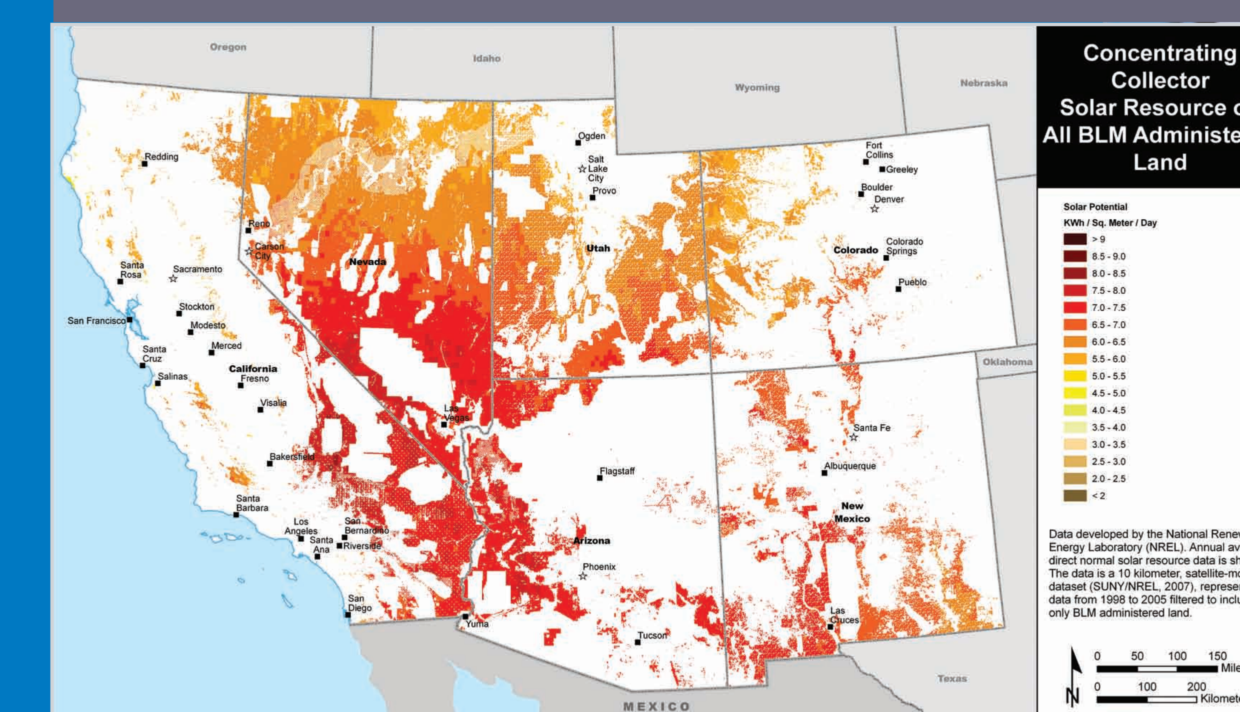
Linear Fresnel Reflectors

Close-up of compact linear Fresnel reflectors focusing sunlight onto a receiver.

Operational U.S. Parabolic Power Plants

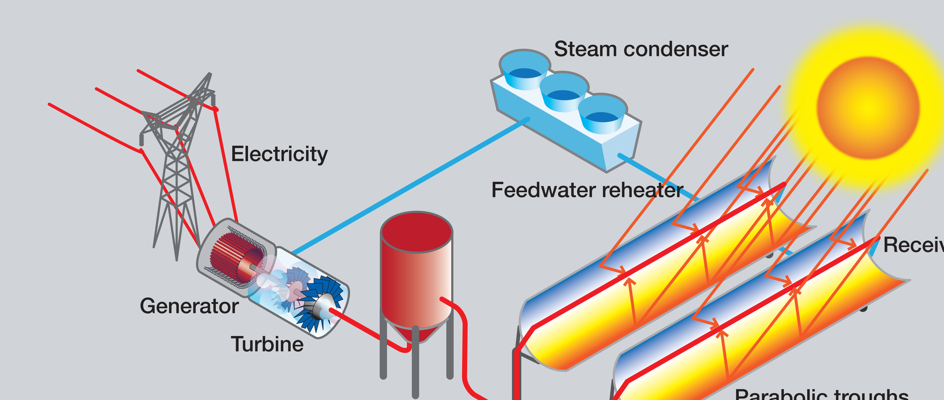
Plant Name	Location	First Year of Operation	MW	Solar Field Area (m2)
Nevada Solar One	Boulder City, NV	2007	64	357,200
APS Saguaro	Tucson, AZ	2006	1	10,340
SEGS IX	Harper Lake, CA	1991	80	483,960
SEGS VIII	Harper Lake, CA	1990	80	464,340
SEGS VI	Kramer Junction, CA	1989	30	188,000
SEGS VII	Kramer Junction, CA	1989	30	194,280
SEGS V	Kramer Junction, CA	1988	30	250,500
SEGS III	Kramer Junction, CA	1987	30	230,300
SEGS IV	Kramer Junction, CA	1987	30	230,300
SEGS II	Daggett, CA	1986	30	190,338
SEGS I	Daggett, CA	1985	13.8	82,960

Solar Resource in 6 States

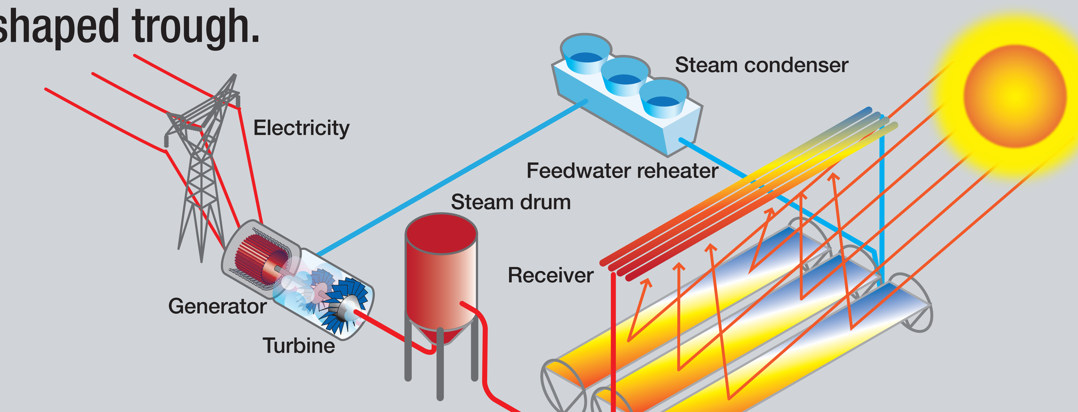


How They Work

Parabolic trough solar systems use long, parabolic-shaped mirrors or linear Fresnel reflectors to collect and focus sunlight onto a receiver tube that contains a fluid. The fluid inside the tube is heated to create superheated steam that powers a turbine generator to produce electricity.



Parabolic Trough Collector - The sun's energy is concentrated on an oil-filled, solar absorbing transparent glass tube running along the focal line of the parabolically shaped trough.



Linear Fresnel Reflectors - Differ from parabolic trough in that the absorber is fixed in space above the slightly curved or flat Fresnel reflectors. Sometimes a small parabolic mirror is added to the top of the receiver to further focus sunlight.

OVERVIEW OF SOLAR THERMAL TECHNOLOGIES

Introduction

There are three solar thermal power systems currently being developed by U.S. industry: parabolic troughs, power towers, and dish/engine systems. Because these technologies involve a thermal intermediary, they can be readily hybridized with fossil fuel and in some cases adapted to utilize thermal storage. The primary advantage of hybridization and thermal storage is that the technologies can provide dispatchable power and operate during periods when solar energy is not available. Hybridization and thermal storage can enhance the economic value of the electricity produced and reduce its average cost. This chapter provides an introduction to the more detailed chapters on each of the three technologies, an overview of the technologies, their current status, and a map identifying the U.S. regions with best solar resource.

Parabolic Trough systems use parabolic trough-shaped mirrors to focus sunlight on thermally efficient receiver tubes that contain a heat transfer fluid (Figure 1). This fluid is heated to 390°C (734°F) and pumped through a series of heat exchangers to produce superheated steam which powers a conventional turbine generator to produce electricity. Nine trough systems, built in the mid to late 1980's, are currently generating 354 MW in Southern California. These systems, sized between 14 and 80 MW, are hybridized with up to 25% natural gas in order to provide dispatchable power when solar energy is not available.

Cost projections for trough technology are higher than those for power towers and dish/engine systems due in large part to the lower solar concentration and hence lower temperatures and efficiency. However, with 10 years of operating experience, continued technology improvements, and O&M cost reductions, troughs are the least expensive, most reliable solar technology for near-term applications.

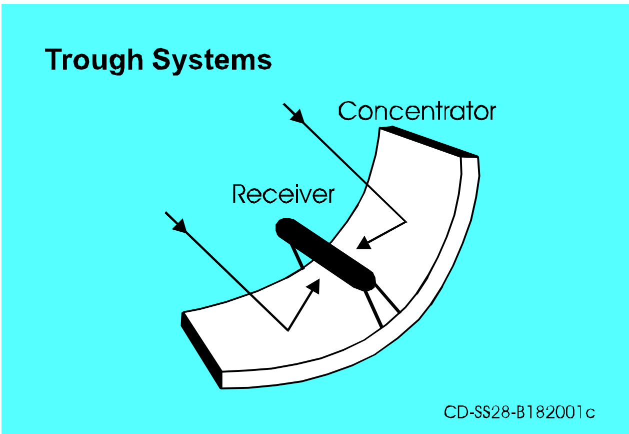


Figure 1. Solar parabolic trough.

Power Tower systems use a circular field array of heliostats (large individually-tracking mirrors) to focus sunlight onto a central receiver mounted on top of a tower (Figure 2). The first power tower, Solar One, which was built in Southern California and operated in the mid-1980's, used a water/steam system to generate 10 MW of power. In 1992, a consortium of U.S. utilities banded together to retrofit Solar One to demonstrate a molten-salt receiver and thermal storage system.

The addition of this thermal storage capability makes power towers unique among solar technologies by promising dispatchable power at load factors of up to 65%. In this system, molten-salt is pumped from a “cold” tank at 288°C

(550°F) and cycled through the receiver where it is heated to 565°C (1,049°F) and returned to a "hot" tank. The hot salt can then be used to generate electricity when needed. Current designs allow storage ranging from 3 to 13 hours.

"Solar Two" first generated power in April 1996, and is scheduled to run for a 3-year test, evaluation, and power production phase to prove the molten-salt technology. The successful completion of Solar Two should facilitate the early commercial deployment of power towers in the 30 to 200 MW range.

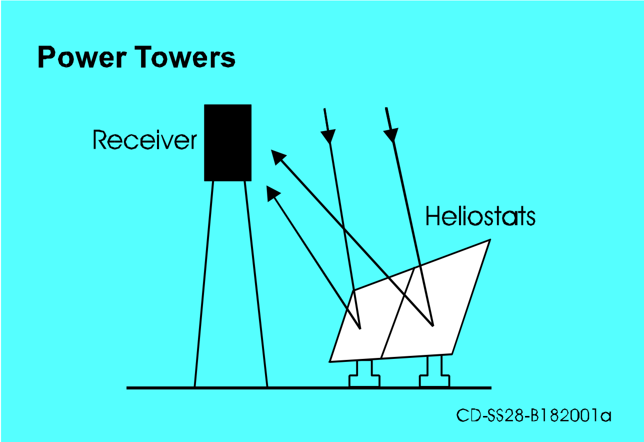


Figure 2. Solar power tower.

Dish/Engine systems use an array of parabolic dish-shaped mirrors (stretched membrane or flat glass facets) to focus solar energy onto a receiver located at the focal point of the dish (Figure 3). Fluid in the receiver is heated to 750°C (1,382°F) and used to generate electricity in a small engine attached to the receiver. Engines currently under consideration include Stirling and Brayton cycle engines. Several prototype dish/engine systems, ranging in size from 7 to 25 $kW_{e,}$ have been deployed in various locations in the U.S. and abroad.

High optical efficiency and low startup losses make dish/engine systems the most efficient (29.4% record solar to electricity conversion) of all solar technologies. In addition, the modular design of dish/engine systems make them a good match for both remote power needs in the kilowatt range as well as hybrid end-of-the-line grid-connected utility applications in the megawatt range. If field validation of these systems is successful in 1998 and 1999, commercial sales could commence as early as 2000.

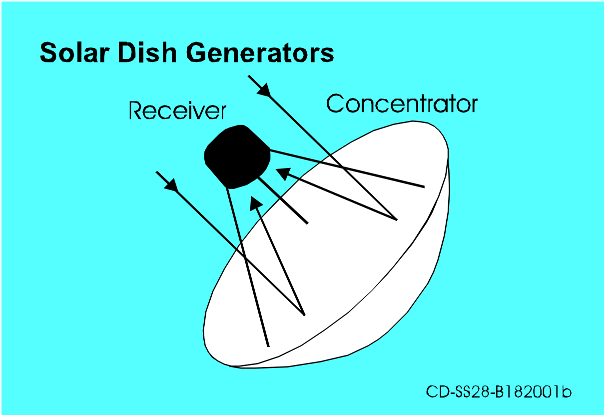


Figure 3. Solar dish/engine system.

OVERVIEW OF SOLAR THERMAL TECHNOLOGIES

Technology Comparison

Table 1 below highlights the key features of the three solar technologies. Towers and troughs are best suited for large, grid-connected power projects in the 30-200 MW size, whereas, dish/engine systems are modular and can be used in single dish applications or grouped in dish farms to create larger multi-megawatt projects. Parabolic trough plants are the most mature solar power technology available today and the technology most likely to be used for near-term deployments. Power towers, with low cost and efficient thermal storage, promise to offer dispatchable, high capacity factor, solar-only power plants in the near future. The modular nature of dishes will allow them to be used in smaller, high-value applications.

Towers and dishes offer the opportunity to achieve higher solar-to-electric efficiencies and lower cost than parabolic trough plants, but uncertainty remains as to whether these technologies can achieve the necessary capital cost reductions and availability improvements. Parabolic troughs are currently a proven technology primarily waiting for an opportunity to be developed. Power towers require the operability and maintainability of the molten-salt technology to be demonstrated and the development of low cost heliostats. Dish/engine systems require the development of at least one commercial engine and the development of a low cost concentrator.

Table 1. Characteristics of solar thermal electric power systems.

	Parabolic Trough	Power Tower	Dish/Engine
Size	30-320 MW*	10-200 MW*	5-25 kW*
Operating Temperature (ºC/ºF)	390/734	565/1,049	750/1,382
Annual Capacity Factor	23-50%*	20-77%*	25%
Peak Efficiency	20%(d)	23%(p)	29.4%(d)
Net Annual Efficiency	11(d')-16%*	7(d')-20%*	12-25%*(p)
Commercial Status	Commercially Available	Scale-up Demonstration	Prototype Demonstration
Technology Development Risk	Low	Medium	High
Storage Available	Limited	Yes	Battery
Hybrid Designs	Yes	Yes	Yes
Cost			
$/m^2	630-275*	475-200*	3,100-320*
$/W	4.0-2.7*	4.4-2.5*	12.6-1.3*
$/W$_p$ †	4.0-1.3*	2.4-0.9*	12.6-1.1*

* Values indicate changes over the 1997-2030 time frame.

† $/W$_p$ removes the effect of thermal storage (or hybridization for dish/engine). See discussion of thermal storage in the power tower TC and footnotes in Table 4.

(p) = predicted; (d) = demonstrated; (d') = has been demonstrated, out years are predicted values

Cost Versus Value

Through the use of thermal storage and hybridization, solar thermal electric technologies can provide a firm and dispatchable source of power. Firm implies that the power source has a high reliability and will be able to produce power when the utility needs it. Dispatchability implies that power production can be shifted to the period when it is needed. As a result, firm dispatchable power is of value to a utility because it offsets the utility's need to build and operate new power plants. This means that even though a solar thermal plant might cost more, it can have a higher value.

OVERVIEW OF SOLAR THERMAL TECHNOLOGIES

Solar Thermal Power Cost and Development Issues

The cost of electricity from solar thermal power systems will depend on a multitude of factors. These factors, discussed in detail in the specific technology sections, include capital and O&M cost, and system performance. However, it is important to note that the technology cost and the eventual cost of electricity generated will be significantly influenced by factors "external" to the technology itself. As an example, for troughs and power towers, small stand-alone projects will be very expensive. In order to reduce the technology costs to compete with current fossil technologies, it will be necessary to scale-up projects to larger plant sizes and to develop solar power parks where multiple projects are built at the same site in a time phased succession. In addition, since these technologies in essence replace conventional fuel with capital equipment, the cost of capital and taxation issues related to capital intensive technologies will have a strong effect on their competitiveness.

Solar Resources

Solar resource is one of the most important factors in determining performance of solar thermal systems. The Southwestern United States potentially offers the best development opportunity for solar thermal electric technologies in the world. There is a strong correlation between electric power demand and the solar resource due largely to the air conditioning loads in the region. Figure 4 shows the direct normal insolation for the United States.

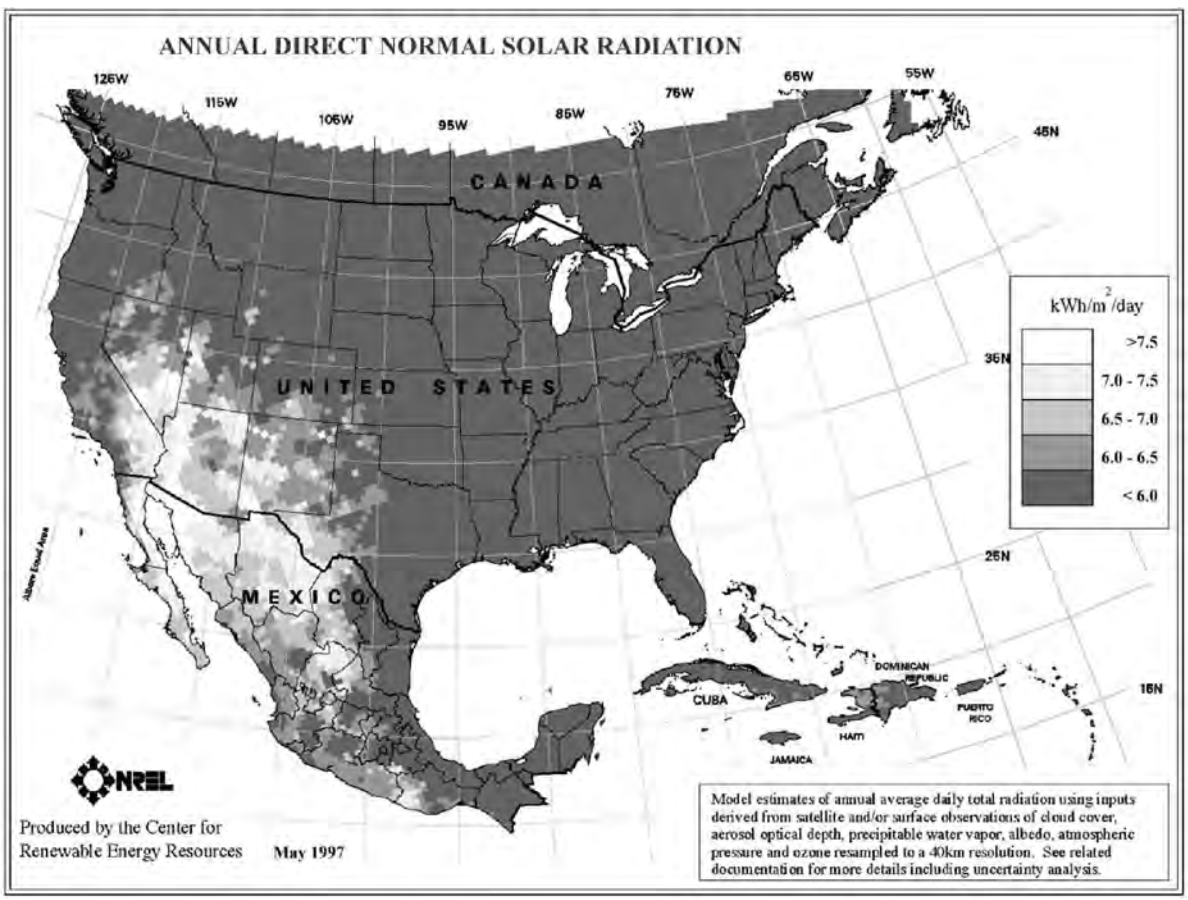


Figure 4. Direct normal insolation resource.

OVERVIEW OF SOLAR THERMAL TECHNOLOGIES

Summary

Solar thermal power technologies are in different stages of development. Trough technology is commercially available today, with 354 MW currently operating in the Mojave Desert in California. Power towers are in the demonstration phase, with the 10 MW Solar Two pilot plant located in Barstow, CA., currently undergoing at least two years of testing and power production. Dish/engine technology has been demonstrated. Several system designs are under engineering development, a 25 kW prototype unit is on display in Golden, CO, and five to eight second-generation systems are scheduled for field validation in 1998. Solar thermal power technologies have distinct features that make them attractive energy options in the expanding renewable energy market worldwide. Comprehensive reviews of the solar thermal electric technologies are offered in References 1 and 2.

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Utility-Scale Concentrating Solar Power and Photovoltaics Projects: A Technology and Market Overview

Michael Mendelsohn, Travis Lowder, and Brendan Canavan

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List of Acronyms

AC	alternating current
a-Si	amorphous silicon
b	bar
Bell	Bell Solar Thermal
BLM	Bureau of Land Management
CEC	California Energy Commission
CdTe	cadmium telluride
CIGS	copper indium gallium selenide
CPV	concentrating photovoltaic
c-Si	crystalline silicon
CSP	concentrating solar power
DC	direct current
DOE	Department of Energy
FPL	Florida Power and Light
ft	foot
HTF	heat transfer fluid
ISO	independent system operator
IOU	investor-owned utility
MW	megawatt
NERC	North American Energy Reliability Corporation
PEIS	Programmatic Environmental Impact Statement
PG&E	Pacific Gas and Electric
PPA	power purchase agreement
PV	photovoltaic
RPS	renewable portfolio standard
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SEGS	Solar Energy Generating System
SGIP	small generator interconnection process
TEP	Tucson Electric Power
TES	thermal energy system

Executive Summary

Solar energy technologies continue to be deployed at unprecedented levels, aided significantly by the advent of large-scale projects that sell their power directly to electric utilities. Such utility-scale systems can deploy solar technologies far faster than traditional "behind-the-meter" projects designed to offset retail load. These systems achieve significant economies of scale during construction and operation, and in attracting financial capital, which can in turn reduce the delivered cost of power.

This is the first in a series of three reports on utility-scale solar installation in the United States. This report serves as: (1) a primer on utility-scale solar technologies and (2) a summary of the current state of the U.S. utility-scale solar market. The second report overviews policies and financing of utility-scale solar systems; the third report assesses the impact of financial structures on the cost of energy from utility-scale systems.

Utility-scale solar projects are generally categorized in one of two basic groups: concentrating solar power (CSP) and photovoltaic (PV). CSP systems generally include four commercially available technologies: CSP trough, CSP tower, parabolic dish, and linear Fresnel reflector, although only CSP trough and CSP tower projects are currently being deployed. CSP systems can also be categorized as hybrid systems, which combine a solar-based system and a fossil fuel energy system to produce electricity or steam.

PV systems usually include either crystalline silicon (c-Si) or thin-film technologies. Thin film includes an array of advanced materials, but only one—cadmium telluride (CdTe)—has had significant success in utility-scale solar development. Additionally, this report covers concentrating photovoltaic (CPV) systems,[1] which only recently have gained traction in the utility-scale market with several signed contracts.

According to a database maintained by the National Renewable Energy Laboratory (NREL),[2] there are approximately 16,043 megawatts (MW) of utility-scale solar resources under development[3] in the United States as of January 2012 (see Figure ES-1). PV projects make up the overwhelming majority (about 72%) of facilities under development. While many developers have specified that their projects will use PV (e.g., c-Si or CdTe), in some cases the technology will be selected just prior to construction. This selection will likely depend on module pricing at the time of order placement once all necessary permits have been obtained and pre-construction activities completed. It is not uncommon, especially given the recent drop in c-Si module prices, for developers to switch technologies in the planning phase.

According to NREL's internal database, CdTe thin-film technology represents about one-fifth of the total inventory of planned utility-scale solar projects and nearly one-third of total planned PV

[1] This report categorizes CPV as a PV technology, though some analysts group it under CSP.
[2] This database was corroborated by similar databases maintained by the Solar Energy Industries Association (SEIA 2011a) and SNL Financial.
[3] For this paper, "utility-scale" is defined as projects 5 MW or larger. These projects were either publicly announced and hold a long-term power purchase agreement or were announced directly by a utility. Public announcements are made via press releases.

projects[4]. First Solar was once considered the sole or joint developer of all utility-scale CdTe projects under development in the United States, though this is changing with the entrance of General Electric into the CdTe market. GE is currently contracted to supply panels to the 20 MW Illinois Solar plant being developed by Invenergy.

Approximately 8,224 MW of developing projects are utilizing c-Si modules or have not indicated final technology selection. The majority of these projects are expected to select c-Si-based modules. Per NREL's criteria—5 MW or larger and holding a long-term contract—approximately 11,500 MW of total PV capacity is under development in the United States, including c-Si, CdTe, copper-indium-selenide (CIS) [5] modules, and CPV technologies.

Among CSP projects, tower systems have a slight market penetration edge over parabolic troughs (about 16% versus 9% of all utility-scale solar systems under development). NREL's project announcements database indicates that the tower market is dominated by one developer, BrightSource Energy, who holds over 2.2 GW of PPAs with California utilities. Solar Millennium was the principal developer in the trough space, but the company's announced switch to PV and subsequent sale of all proposed projects[6] to solarhybrid has left only six trough developers and no clear market front-runners.

Figure ES-1 provides an overview of the U.S. utility-scale solar market. Two cutting-edge solar technologies, Enviromission's solar chimney and Solaren's space solar project, are indicated as "Other" because they hold PPAs and constitute significant additions to the total capacity under development, but they are not categorized as traditional CSP or PV technologies. Two solar/fossil hybrid plants representing a combined 100 MW of solar capacity are included as a separate category to note their distinct approach; both plants will use solar power to supplement natural gas-fired generation. Finally, CIS is included because of the recent announcement that Solar Frontier, the Japanese CIS manufacturer, will supply up to 150 MW of panels to energy developer enXco for use in their PPA contracts with San Diego Gas and Electric (SDG&E).

[4] In the energy industry, some, if not many, planned projects will not reach completion. Therefore, we assume this figure to be greater than what will be delivered by the current pipeline of projects.
[5] Copper-indium-gallium-selenide (CIGS) is perhaps the more common version of this thin-film technology. Solar Frontier, the sole supplier of CIS/CIGS thin-film modules to the utility-scale market (as of January 2012), does not use gallium in their semi-conductor blend.
[6] Solar Millennium also filed for insolvency in December 2011 (Wesoff and Prior 2011).

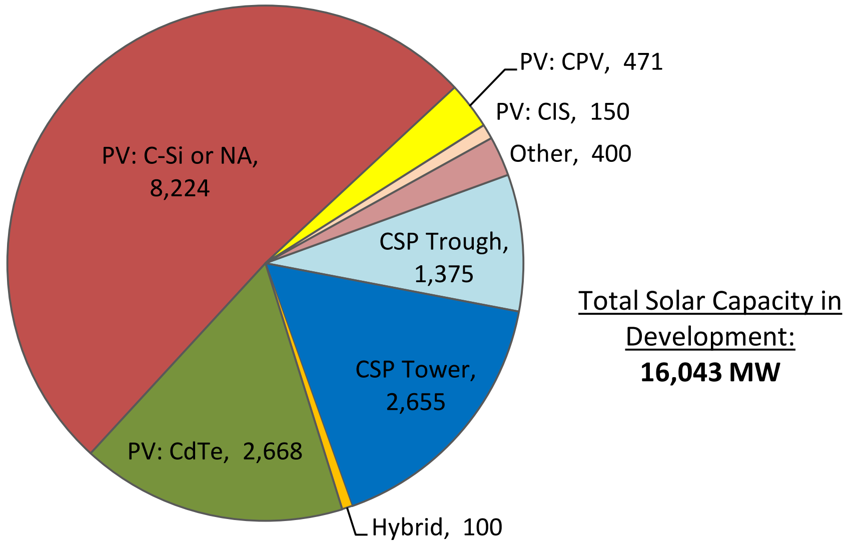

Figure ES-1. Total U.S. utility-scale solar capacity under development (all numbers in MW)

Currently, multiple utility-scale systems are producing power on a consistent basis. The nine solar trough CSP plants that comprise the solar energy generating system (SEGS) in California's Mojave Desert constitute the majority of CSP. The SEGS units commenced commercial operation from 1984–1991 with several additional utility-scale CSP projects coming online recently (EIA 2008). In 2007, the 64 MW Nevada Solar One project, a CSP trough plant developed by Acciona Solar Power, became operational (Acciona 2010). Two 5-MW demonstration facilities developed by Ausra and eSolar also became operational in 2008 and 2009, respectively (Ausra 2008; eSolar 2009). There are over 40 utility-scale PV facilities currently operational in the United States, amounting to some 673 MW of capacity. See Appendix Table A-1 for a full list of operating utility-scale PV plants.

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1 Introduction

Drivers ranging from energy security and cleaner air to global economic competitiveness and rapidly falling costs are sparking a significant shift in energy generation policy and planning. Electric utilities in the United States and the regulatory agencies that oversee them are increasing renewable energy use to meet electric load. Technological advances in materials and components and heightened experience among market entities are leading the way to more cost-effective renewable power production. Renewables have also significantly benefitted from a raft of support policies and incentives at the municipal, state, and federal levels. These include federal tax credits, cash grants, loan guarantee programs, feed-in tariffs, and state renewable portfolio standards (RPS),[7] which are discussed in detail in the second utility-scale solar report. For example, California's RPS, the most robust in the United States, with a required 33% of renewable generation from its investor-owned utilities (IOUs), has touched off a spate of solar procurement in the last two years. Today, California's three IOUs hold PPAs with nearly 72% of the total solar capacity under development in the United States (see Appendix C).

Supportive policies, financial innovations, and plummeting technology costs have spurred utility-scale[8] solar market development in the United States. This report introduces that growing market. It has two objectives: (1) to summarize solar technologies deployed at utility-scale installations, and (2) to provide a market overview of U.S. deployment activities. The report is divided by technology type: Section 2 deals with CSP technologies, and Section 3 deals with PV solar power technologies. Market overviews for each technology are provided at the conclusion of each subsection. This report only considers projects already contracted to sell power [typically in the form of a power purchase agreement (PPA)].

1.1 Utility-Scale Market Overview

Approximately 1,176 MW of utility-scale solar power was operational as of January 2012 (see Figure 1). About 43% (503 MW) of this capacity is furnished by CSP facilities, all but 10 MW of which utilize trough technology; the remaining 57% of this capacity comes from PV installations. Crystalline silicon (C-Si) and cadmium telluride (CdTe) comprise the majority of technologies deployed at these installations with 58.0% and 34.5% representation, respectively. Amorphous silicon (a-Si), another thin-film technology, represents about 7.0% of total PV installations, and concentrating photovoltaic (CPV) about 0.5%.

[7] RPS policies are essentially mandated quotas for renewable energy generation as a proportion of total electricity production.

[8] For this paper, "utility-scale" is defined as any solar electric system with a capacity of 5 MW and above. Such utility-scale installations can deploy solar technologies far faster than traditional "behind-the-meter" projects designed to offset retail load. These systems employ significant economies of scale during construction, operation, and financial capital attraction, which can reduce the delivered cost of power.

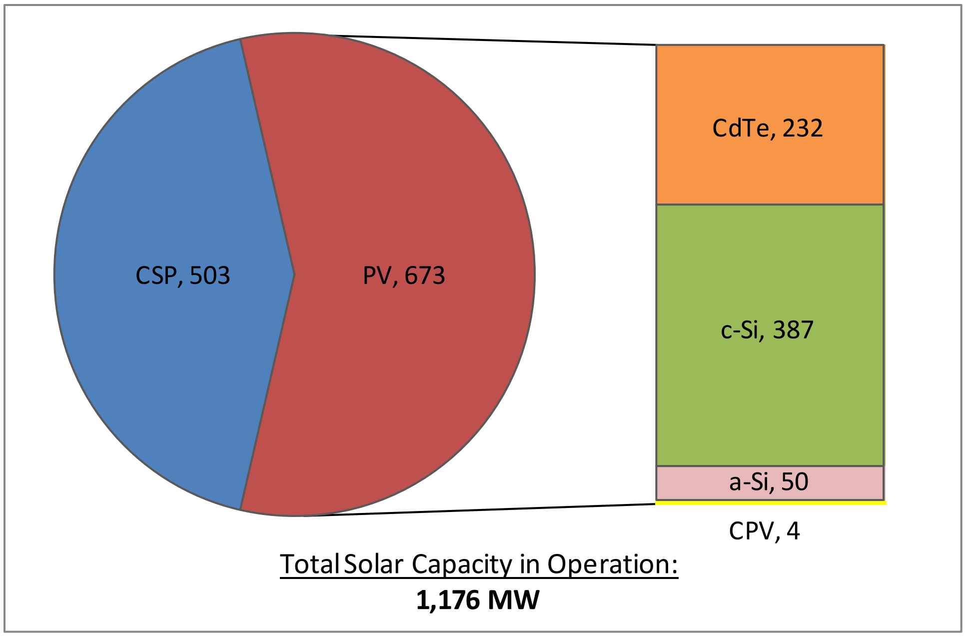

Figure 1. Total U.S. utility-scale solar capacity in operation as of January 2012 (all numbers in MW)

Figure 2 illustrates that PV capacity will continue to outpace CSP in the United States as more developing projects come online. Nearly all utility-scale CSP plants today use troughs; however, most planned CSP capacity will not use troughs. Instead, CSP towers have become the preferred technology, with over 2,655 MW of projects under contract. CSP tower developer BrightSource holds the majority of the PPAs, with about 2.2 GW of capacity (82% of the total planned CSP capacity). Recent CSP trough market contraction was largely the result of developer Solar Millennium's technology swap for their Blythe, Amargosa, and Palen facilities. At least 2 GW of CSP troughs were scrapped for PV because of what Solar Millennium described as more "favorable conditions in the PV and commercial bank markets" (PV Magazine 2011).

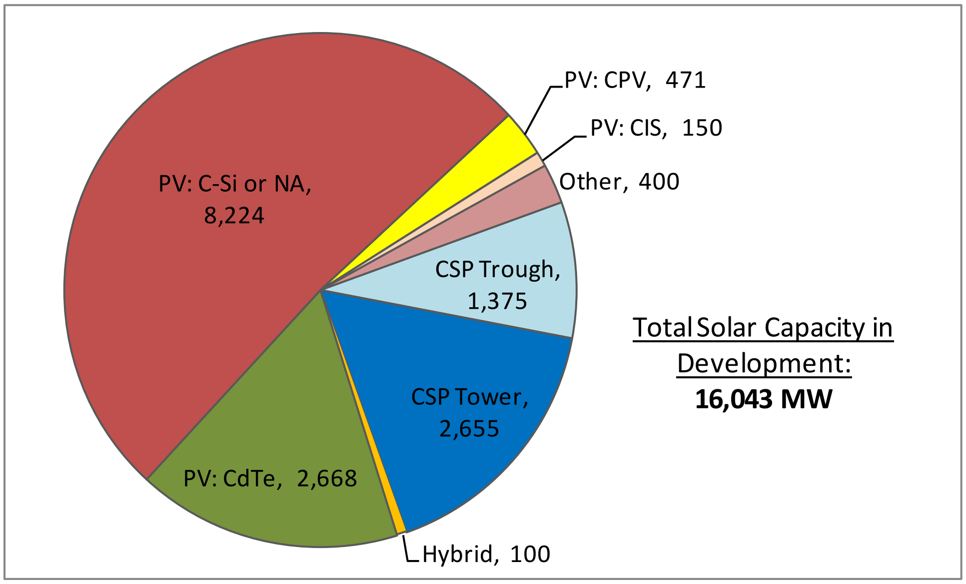

Figure 2. Total U.S. utility-scale solar capacity under development (all numbers in MW)

2 Concentrating Solar Power

CSP systems produce electricity by focusing sunlight to heat a fluid. The fluid then boils water to create steam that spins a conventional turbine and generates electricity or it powers an engine that produces electricity (Richter et al. 2009). CSP plants consist of three major subsystems: one that collects solar energy and converts it to thermal energy; a second that converts the thermal energy to electricity; and a third that stores thermal energy collected from the solar field and subsequently dispatches the energy to the power block.

There are currently 503 MW of utility-scale CSP facilities operating domestically.

Table 1. Operating Utility-Scale CSP Projects in the United States

Plant	Capacity (MW)	Developer	Technology	Location	PPA With
Kimberlina	5	Areva	Linear Fresnel	Bakersfield, California	Pacific Gas & Electric (PG&E)
Martin Next Generation Solar	75	Florida Power & Light	CSP Trough	Martin County, Florida	Florida Power and Light (FPL)
Nevada Solar One	64	Acciona	CSP Trough	Boulder City, Nevada	PG&E
Sierra SunTower	5	eSolar	CSP Tower	Lancaster, California	Southern California Edison (SCE)
SEGS 1-9	354	Luz International	CSP Trough	Mojave Desert, California	SCE
Total	**503**				

The first large-scale, commercial CSP stations were the solar energy generating systems (SEGS) built by Luz International, Ltd. from 1984–1991 (DOE 2010c). Nine plants were built in three separate locations for a total of 354 MW. Figure 3 shows SEGS 4, located in Kramer Junction, California, which has a peak output of 150 MW. SEGS 1 and 2 have a combined maximum output of 44 MW and are located in Daggett, California. SEGS 8 and 9 have a combined maximum output of 160 MW and are located in Harper Lake, California. NextEra operates and partially owns SEGS 3–9, with a combined maximum output of 310 MW (NextEra 2010).

The latest CSP plant to be developed was the 75 MW Martin Next Generation Solar Energy Center developed by and for NextEra subsidiary Florida Power and Light (FPL). The plant was completed in 2010 (FPL 2010). This facility uses CSP trough technology to supplement the 3,705 MW gas- and oil-fired Martin Generation facility and is considered in this report to be a solar/fossil hybrid plant.

Figure 3. SEGS 4, Kramer Junction, California

Source: PIX 14955

CSP systems are unique in the renewable energy sector in that they can integrate large-scale thermal energy storage (TES). The first utility-scale plants with storage are now operating in Spain (Andasol 1–3) and were developed by Solar Millennium (Solar Millennium 2010). At least six plants with TES are currently in development in the United States—the 250 MW Solana Solar plant by Abengoa Solar (6 hours of dispatchable storage), the 110 MW Crescent Dunes plant by Solar Reserve (10 hours of dispatchable storage), the 5 MW Bell Solar Thermal by Bell Energy (storage capacity unknown), and three BrightSource projects whose locations and storage capacities are yet undisclosed (Wesoff 2010; Wesoff 2011; Environmental Leader 2010; BrightSource Energy 2011a). Solana and Crescent Dunes finalized loan guarantees from the U.S. Department of Energy (DOE) for $1.45 billion and $737 million, respectively, to support project development (DOE 2011c).

CSP plants can be functionally integrated with fossil fuel plants to create hybrid CSP-fossil power plants that can offer peak and base-load power capability. Fossil hybrid plants, also known as integrated solar combined cycle, are under construction in the United States (Florida) and North Africa, including Egypt, Algeria, and Morocco (Richter et al. 2009).

Solar thermal power requires approximately 3–8 acres/MW, depending on the technology and amount of TES. For example, SEGS 3–9 (with a combined capacity of 310 MW) cover more than 1,500 acres, averaging 4.84 acres/MW of gross maximum output (NextEra 2010). In contrast, the Solana station with 6 hours of dispatchable storage will cover approximately 3 square miles, or 6.86 acres/MW of gross maximum output (Solana Solar 2009).

Like other steam-based technologies, CSP (other than parabolic dish) utilizes steam to spin a turbine. Water consumption is a primary consideration for these facilities and can vary from

700–900 gal/MWh, although alternative cooling methods, such as air cooling, can drastically reduce this value at the expense of some efficiency loss and increased cost (Stoddard 2008).

CSP systems are generally classified by the process in which each device collects solar energy. Sections 2.1–2.4 illustrate and compare four primary technologies—CSP trough, CSP tower, parabolic dish, and linear Fresnel reflector. Although only the first two are currently in utility-scale development in the United States, information on CSP-related thermal storage and cooling technologies is also provided.

2.1 CSP Trough

2.1.1 Technology Overview

CSP trough (also referred to as parabolic trough) systems use curved mirrors and single-axis tracking to follow the sun throughout the day, concentrating sunlight on thermally efficient receiver tubes or heat collection elements. A heat transfer fluid (HTF)—typically synthetic oil, molten salt, or steam—circulates in the tubes absorbing the sun's heat before passing through multiple heat exchangers to produce steam. The steam spins a conventional steam cycle turbine to generate electricity or it is integrated into a combined steam and gas turbine cycle when used in hybrid configurations. Utility-scale collector fields are made up of many parallel rows of troughs connected by receiver tubes in series. Rows are typically aligned on a north-south formation axis to track the sun from east to west. Site requirements for a solar trough system include relatively level land, although the solar fields can be divided into two or more terraces. Figure 4 provides a schematic of a CSP trough plant.

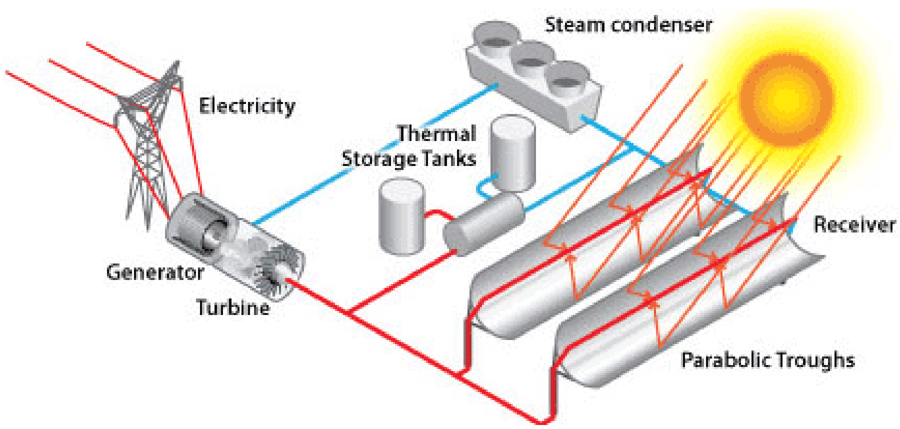

Figure 4. CSP trough schematic

Source: Department of Energy 2011b

Solar troughs are considered the most mature and commercially proven of the CSP technologies. In utility settings, solar trough power plants have shown consistent performance when connected to the electric grid.[9] Improved operating flexibility and dispatchability has been achieved through integration with hybrid fossil systems as well as through demonstrated TES capabilities.

[9] Beyond SEGS and Nevada Solar One, applications exist in Israel, Algeria, and Spain.

There are advantages and disadvantages of different HTFs. Synthetic fuels remain viscous at lower temperatures during the night and on cloudy days but lose efficiency in the heat transfer process (Herrmann et al. 2002). Molten salt, on the other hand, is a highly efficient heat transfer medium that solidifies at lower temperatures. Neither synthetic fuels nor molten salts can directly drive a turbine and therefore must use heat exchangers to boil water and spin a steam turbine. Using steam directly as an HTF is advantageous because it does not require heat exchange equipment; however, it is not very efficient relative to other transfer fluids because it cannot reach high enough temperatures. Further discussion of TES is provided in Section 2.6.

Figure 5. The Nevada Solar One CSP trough system came online in 2007

Source: PIX 16603

2.1.2 CSP Trough Market Overview

At present, roughly 1,375 MW of utility-scale CSP trough plants are in development with PPAs[10] in place (Table 2). This figure excludes the 100 MW of solar/fossil hybrid plants currently in development. Pacific Gas and Electric (PG&E) holds the majority of trough PPAs, totaling 530 MW.

[10] PPAs are contracts between power producers and power purchasers for the long-term sale of electricity. See Appendix B for more information.

Table 2. U.S. Utility-Scale CSP Trough Plants in Development

Plant	MW	Developer	Location	PPA With
Bell Solar Thermal	5	Bell Energy	Tucson, Arizona	Tucson Electric Power
Bethel Energy	50	Bethel Energy, LLC	Imperial Valley, California	San Diego Gas & Electric
Ft. Irwin Solar Power Project	500	Acciona Solar Power	Ft. Irwin, California	U.S. Army
Genesis Solar Energy Project	250	NextEra	Riverside County, California	PG&E
Mojave Solar Power Project	280	Abengoa	San Bernardino County, California	PG&E
Solana Generating Plant	280	Abengoa	Gila Bend, Arizona	Arizona Public Service
Westside Solar Project	10	Pacific Light & Power	Kaua'I, Hawaii	Kaua'I Island Utility Coop.
Total	**1,375**			

Sources: Solar Thermal Magazine 2010; NASDAQ QMS 2006; NREL 2009; CEC 2010b; Solana Solar 2009; Bloomberg 2009; CEC 2010b

Solar Millennium made headlines in 2011 when it decided to change its Blythe (1 GW), Amargosa (500 MW), and Palen (500 MW) projects from CSP troughs to PV (PV Magazine 2011; Wesoff and Prior 2011). In doing so, Solar Millennium forfeited a DOE loan guarantee that was acquired to assist development of the Blythe project. Solar Millennium's technology switch was reportedly due to shifting economics as PV modules and other costs have come down in price significantly over the past several years (Clean Energy Authority 2011a). Solar Millennium is currently in insolvency proceedings and has sold its U.S. project pipeline to German developer solarhybrid.[11]

2.2 CSP Tower

2.2.1 Technology Overview

CSP tower systems, often referred to as power towers or central receivers, use a field of mirrors called heliostats that individually track the sun on two axes and redirect sunlight to a receiver at the top of a tower. Sunlight is concentrated 600–1,000 times, making it possible to achieve working fluid temperatures of 500°–800°C (930°–1,470°F) (Australian National University 2010).

[11]In March, 2012, solarhybrid began its own insolvency proceeding due to concerns of illiquidity (i.e., not enough cash to pay bills) (PV Magazine 2012).

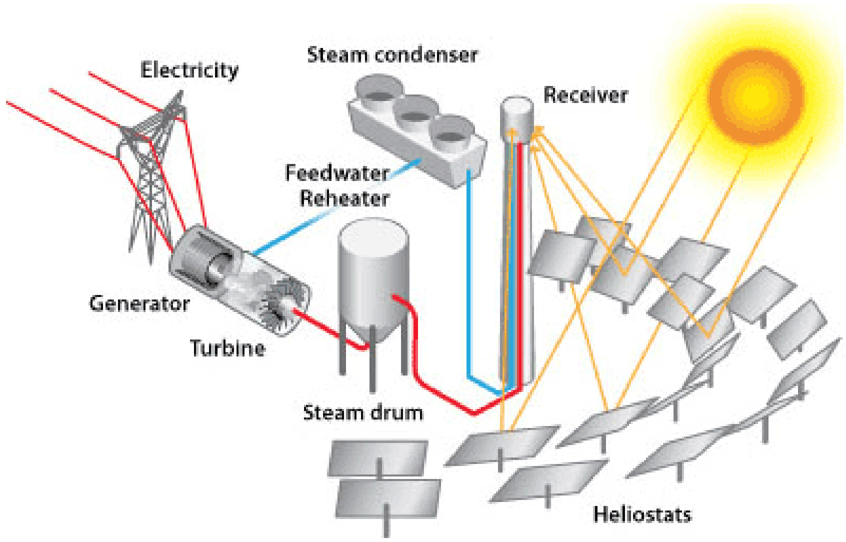

Figure 6. CSP tower schematic

Source: U.S. Department of Energy 2011c

Pilot CSP tower plants have proven the technical feasibility of using various HTFs including steam, air, and molten nitrate salts. Early CSP tower systems generated steam directly in the receiver; however, current designs use both steam and molten salt as HTFs. When integrating storage, CSP tower systems have an advantage over CSP troughs since they are able to obtain higher operating temperatures, resulting in a lower required salt inventory for the storage system (Richter et al. 2009).

Figure 7. The Solar One facility in California employed CSP tower technology

Source: PIX 00036

The largest CSP tower system currently in operation is the PS20 station, designed by Abengoa Solar in Seville, Spain (LaMonica 2009). The 20 MW facility, which began operation in April 2009, features a 531 foot (ft) solar tower and 1,255 heliostats. The PS20 is adjacent to the world's first commercial CSP tower, the PS10, also designed by Abengoa Solar.

In Israel, BrightSource is operating the 4–6 MW Solar Energy Development Center (BrightSource Energy 2011b). According to BrightSource, the facility generates the highest quality steam of any operational solar thermal plant at a temperature of 550°C (1,022°F) and 140 bar (b) pressure.

Also worth noting, the 23 MW Coalinga solar project in central California, recently commissioned in the San Joaquin Valley, utilizes a 327 ft tower system to produce steam (but no electricity) and improve output from an aging nearby oil field. Chevron owns the Coalinga field and the development company that installed the system, Chevron Technology Ventures (IBM 2011).

2.2.2 CSP Tower Market Overview

Some 2,655 MW of proposed CSP tower systems are currently under contract with U.S. utilities. BrightSource Energy has the most megawatts under contract. In April 2011, BrightSource closed on a $1.6 billion DOE loan guarantee for its Ivanpah, California, facility (DOE 2011c). Of BrightSource's 2.2 GW portfolio under contract, Ivanpah represents 392 MW, which allocated about evenly between PG&E and SCE. Many of BrightSource's other projects are at undisclosed locations. In October 2010, BrightSource broke ground on the Ivanpah project and received a $300 million investment from NRG Energy. With this investment, NRG Energy will hold a majority equity stake in the project (Murray 2010).

One small utility-scale CSP tower system operates in the United States—eSolar's 5 MW Sierra Suntower. The facility became operational in 2009 and sells power to SCE (NREL 2010b). In co-development with NRG Energy, eSolar has two proposed facilities, the Gaskell Sun Tower phases 1 and 2, under long-term contracts with IOUs for a total of 245 MW. To help lower costs, eSolar deploys a modular design surrounding a conventional turbine (eSolar 2010).

SolarReserve has two CSP tower facilities under development—Crescent Dunes and Rice Solar Energy Project—totaling 260 MW and 25-year contracts with PG&E and NV Energy (Reuters 2009). SolarReserve was founded by United Technologies Corp., whose Rocketdyne subsidiary demonstrated the solar tower technology at the Solar One and Solar Two power plants in southern California. However, both facilities were demonstration projects and are no longer operating (Solar Reserve 2010). U.S. Renewables Group, a large private equity firm exclusively focused on clean fuel projects, supports SolarReserve (SolarReserve 2011).

Table 3. U.S. Utility-Scale Central Receiver Projects in Development

Plant	MW	Developer	Location	PPA With
BrightSource, PG&E PPA	108	BrightSource	California	PG&E
Coyote Springs 1 & 2	400	BrightSource	Coyote Springs, Nevada	PG&E
Crescent Dunes	110	SolarReserve	Nye County, Nevada	NV Energy
Gaskell Sun Tower (Phases 1 & 2)	245	NRG/eSolar	Kern County, California	SCE
Hidden Hills 1 & 2	500	BrightSource	Inyo County, California	PG&E
Ivanpah Phases 1–3	392	BrightSource	Ivanpah, California	PG&E
Rice Solar Energy Project	150	SolarReserve	Blythe, California	PG&E
Rio Mesa 1–3	750	BrightSource	Riverside County, California	SCE
Total	**2,655**			

2.3 Parabolic Dish

2.3.1 Technology Overview

Parabolic dish, or dish engine, systems are individual units comprised of a solar concentrator, a receiver, and an engine or generator. The concentrator typically consists of multiple mirror facets that form a parabolic dish, which tracks the sun on two axes and redirects solar radiation to a receiver (Richter et al. 2009). The receiver is mounted on an arm at the focal point of the reflectors and contains a motor-generator combination that operates using either a Stirling engine or a small gas turbine. Dish systems are generally between 10 kilowatts (kW) and 25 kW in size. Compared with other CSP technologies, parabolic dish conversion efficiencies are the highest, reaching over 30% (SolarPACES 2010).

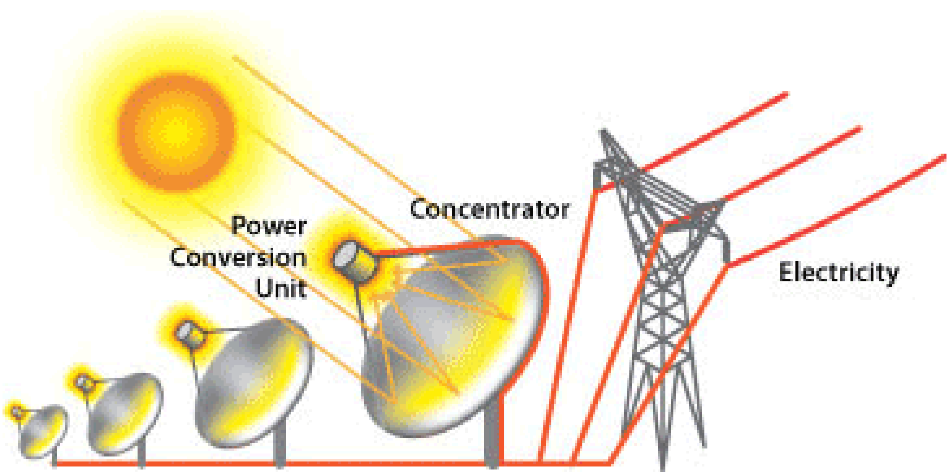

Figure 8. Schematic of a parabolic dish system

Source: DOE 2011d

Parabolic dish systems are considered highly modular, allowing individual deployment for remote applications or groupings for small-grid or large-scale utility applications (SolarPACES 2010). Individual placement also enables greater flexibility than other CSP systems since dish systems can be placed on varied terrain with grades up to 5% (TEEIC 2010). In addition, parabolic dish technology only uses small quantities of water, mostly for washing concentrators free of dust. However, due to current economies of scale, dish systems are generally only proposed in utility-scale projects.

2.3.2 Parabolic Dish Market Overview

At present, there are no utility-scale parabolic dish projects in development.[12] Through 2010, one company—Tessera Solar—held at least three contracts with western U.S. utilities, representing more than 1,600 MW. Tessera was the development affiliate to Stirling Energy Systems, which was a manufacturer of parabolic dishes and Stirling solar engines before filing for Chapter 7 bankruptcy in 2011 (Wesoff 2011).

In May 2011, Tessera lost its last contract when the developer that bought the project, AES, decided to replace the parabolic dish technology with PV. Greentech Media reported that Tessera could not secure a DOE loan guarantee and was thus unable to fulfill the contract (Wesoff 2011).

2.4 Linear Fresnel Reflector

2.4.1 Technology Overview

Linear Fresnel reflector, also referred to as compact or concentrating linear Fresnel reflector, systems are made up of flat or nearly flat mirror arrays that reflect solar radiation onto elevated linear absorbers or receiver tubes. Water, the typical thermal fluid, flows through the tubes and is converted into steam. Steam can also be generated directly in the solar field, eliminating the need for costly heat exchangers (DOE 2010b). The system is similar to a CSP trough in that the sunlight is concentrated in a linear fashion. However, instead of a single curved mirror, linear Fresnel systems concentrate the insolation of many slightly curved mirrors onto a receiver. The receiver is stationary and does not move with the mirrors as in the CSP trough systems, so it does not require rotating couplings between the receivers and the field header piping, thus providing additional design flexibility.

[12] In March 2011, the Export-Import Bank of the United States supplied a direct loan of $30 million to develop a 10 MW solar dish project in Rajasthan, India. U.S.-based dish manufacturer Infina Corporation will supply the modules for this project (Export-Import Bank 2011).

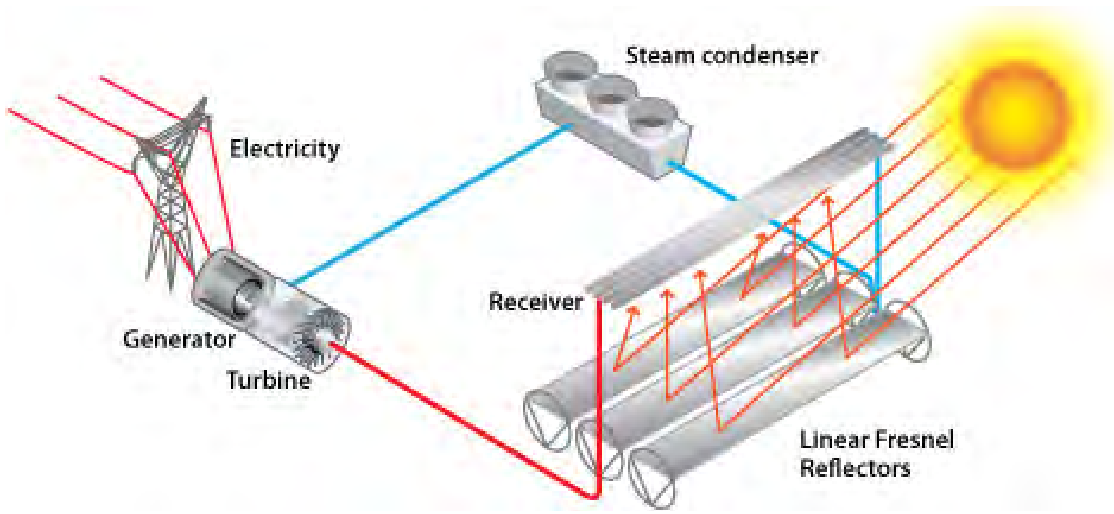

Figure 9. Linear Fresnel reflector schematic

Source: DOE 2011c

2.4.2 Linear Fresnel Reflector Market Overview

In 2010, Ausra—the sole developer of linear Fresnel projects in the United States—sold its technology and development pipeline to the French company Areva (Baker 2010). To date, Areva's 5 MW Kimberlina project in Bakersfield, California (previously developed and owned by Ausra), is the only utility-scale linear Fresnel reflector project in the United States. Prior to the Areva sale, Ausra was developing the Carrizo Energy Solar Farm, a 177 MW project, but that project was suspended.

2.5 Solar-Fossil Hybrid Power

2.5.1 Technology Overview

Hybrid power plants incorporate both solar collector fields and fossil fuel combustion to generate power, often relying on a common steam cycle and allowing for power production during sunlight fluctuations and nighttime hours.[13] There are many variations of hybrid plants, including simple natural gas backup, integrated solar combined cycle plants, and solar plants providing thermal input to existing or newly designed coal-fired plants. To produce steam in hybrid plants, CSP trough, CSP tower, and linear Fresnel collector devices may be used. Figure 10 is a rendering of a solar-fossil (gas turbine/CSP trough) hybrid facility.

[13] For purposes of this report, in NREL's database projects are designated as hybrid if at least 50% of the energy is expected to be derived from fossil fuels. Many CSP systems utilize a small quantity of fossil fuel but are not classified as hybrid systems. For example, the BrightSource Ivanpah project will utilize a small auxiliary boiler, which is expected to provide 2% of its output.

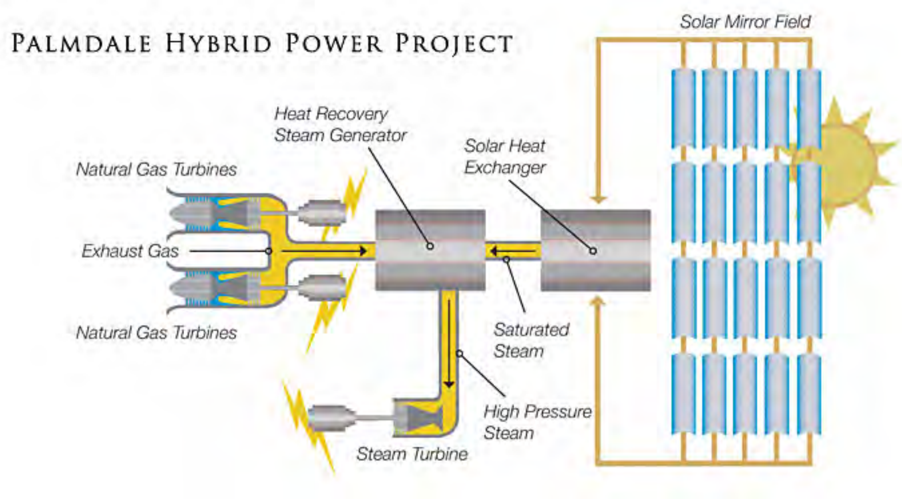

Figure 10. Rendering of a solar/fossil hybrid facility

Source: Inland Energy 2011

Combining CSP and fossil fuel power is not a new concept. In fact, many CSP plants use natural gas as a backup energy source. Assuming space requirements are adequate, it is possible to retrofit existing power plants with solar thermal technology, an option that may be advantageous for utilities looking to increase the efficiency of their fleets. By combining the components of technologically proven fossil fuel plants with the environmental benefits of CSP, there could be an increase in market opportunities and competition with conventional power plants.

2.5.2 Solar/Fossil Hybrid Market Overview

One solar/fossil electric generating plant, as defined by NREL, is currently in operation—the Martin Next Generation Solar Energy Center. The plant combines 75 MW of CSP trough with a 3,705 MW natural gas- and oil-fired generation facility.

As shown in Table 4, two utility-scale solar/fossil hybrid plants are currently in development, the Palmdale and Victorville 2 projects. These two plants feature similar hybrid designs including CSP trough and combined cycle technology designed and constructed as a combined facility (Inland Energy 2011). In each project, the solar field will provide approximately 10% of the thermal input. Both projects are also proposed to be constructed and owned by municipalities. The Victorville 2 project was approved by the California Energy Commission (CEC) in 2008 (City of Victorville 2008). In August 2011, the CEC formally approved development of the Palmdale project (CEC 2011).

Table 4. U.S. Utility-Scale Solar-Fossil Hybrid Projects Under Development

Plant	Solar/ Total MW	Developer	CSP and Fossil Technology	PPA With
Palmdale Hybrid Power Project	50/570	Contractor not selected yet	CSP trough/natural gas combined cycle	City of Palmdale
Victorville 2 Hybrid Power Project	50/513	Contractor not selected yet	CSP trough/natural gas combined cycle	City of Victorville
Solar Total	**100/1,083**			

A large solar hybrid project, the San Joaquin 1 and 2 facilities, was recently cancelled due to "issues regarding project economics" and other aspects of the project (Martifer Renewables 2010). Additionally, the 4 MW Cameo hybrid demonstration project in Grand Junction, Colorado, was recently decommissioned and dismantled. Cameo was the first power plant to hybridize solar troughs and coal-fired generation.

2.6 Thermal Energy Storage

TES provides the ability of a system to store thermal energy collected by a solar field in a reservoir for conversion to electricity at another time. For CSP technologies, storage can be used to balance energy demand between day and night or during times of intermittent sunlight. By oversizing the solar fields and pulling the excess heat to the thermal storage component, the turbine can operate at a fairly constant rate. Figure 11 illustrates this process.

A storage system enables CSP plants to (1) negate the variability in system output due to sudden shifts in the weather and (2) extend the range of operation of a CSP system beyond daylight hours (Biello 2009). The power produced throughout the day can be more effectively matched with energy demand, therefore increasing the value of the power as well as the total useful power output of the plant at a given maximum turbine capacity.

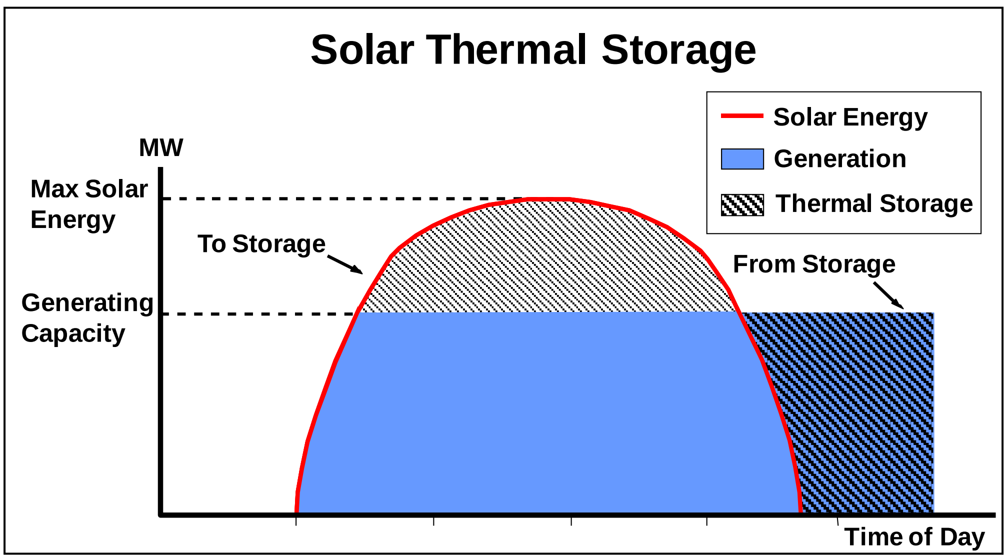

Figure 11. Solar thermal storage extends the power production period

A well-located CSP trough plant with no fossil backup or thermal storage should be able to achieve a 25% annual capacity factor (NREL 2011a). CSP with storage is theoretically capable of capacity factors around 75%, although economic application of storage limits the capacity factor to approximately 50% given current available technology.[14] CSP generation facilities supported through the DOE loan guarantee program have capacity factors that range from 26%–28% for projects without thermal storage to 43%–52% for projects with thermal storage (DOE 2011c).

[14] Capacity factor represents the delivered energy production divided by the theoretic energy production if the plant operated at full output all the time.

2.6.1 Technology Overview

Storage mechanisms are classified as either direct or indirect based on how the storage medium is heated by the solar concentrators. Indirect systems, such as most CSP trough plants, use a separate HTF, such as synthetic oil, that passes through a heat exchanger to heat the storage medium. Direct systems use the same fluid, such as steam, for both the HTF and the storage fluid eliminating the need for expensive heat exchangers.

Figure 12. The Solar Two system in California included a thermal energy storage system

Source: PIX 02185

Molten salt storage systems, which can be used in direct or indirect storage systems, seem to hold the greatest promise of economic commercialization (Price 2009). Molten salt systems allow the solar field to operate at higher temperatures relative to other fluids or storage media, reducing the cost of the system. Because salts melt at very high temperatures (e.g., ordinary table salt melts at around 1,472°F), they can hold significant quantities of heat without vaporizing (Biello 2009). A mixture of sodium nitrate and potassium nitrate, the salts can efficiently return as much as 93% of the energy sent into storage.

However, a technical disadvantage of molten salts is that they freeze at relatively high temperatures, from 120°–220°C (250°–430°F). Sandia National Laboratories is currently developing new salt mixtures with the potential for lower freezing points below 100°C (212°F) to help solve this challenge (Biello 2010).

2.6.2 Thermal Energy Storage Market Overview

TES offers potential long-term cost advantages for CSP plants by amortizing the fixed cost of the power block over greater electricity generation. However, a lack of development and operational experience has limited technology use to date.

The Andasol plant in Spain, developed by Solar Millennium, utilizes 28,500 metric tons of molten salt to provide 7.5 hours of backup generation at full output (Solar Millennium 2010). The salt utilized in the plant is 60% sodium nitrate and 40% potassium nitrate, both commonly found in fertilizers and other materials.

In the United States, no operating CSP plants utilize thermal storage, although several are in development. Abengoa Solar's Solana power station is expected to store 6 hours of thermal energy (NREL 2010a). Located outside Gila Bend, Arizona, the 250 MW (net)[15] facility is projected to cost $2.00 billion, $1.45 billion of which will be paid for with debt financing covered under a DOE loan guarantee (Prior 2010). In late 2011, BrightSource announced that it will add storage capability to three of its PPAs with SCE (BrightSource Energy 2011a).[16]

Bell Independent Power Corporation (Bell) is also developing a CSP and combined thermal storage facility. The 5 MW plant will be part of the new Tech Park in Tucson, Arizona (Environmental Leader 2010), and was the result of Bell's request for proposal submission to Tucson Electric Power (TEP). Bell and TEP signed a 20-year contract, which is currently awaiting approval from the Arizona Corporation Commission (Solar Thermal Magazine 2010). The facility is expected to begin operating in 2012.

[15] Because the generator size will be smaller than actual capacity after the application of storage, these 250 MW are a "net" figure.

[16] According to a BrightSource press release, "Under the original power purchase agreements with Southern California Edison, BrightSource would provide approximately four million megawatt-hours of electricity annually across seven power plants. Due to higher efficiencies and capacity factors associated with energy storage, the new set of agreements will provide approximately the same amount of energy annually but with one less plant, reducing the land impacts of delivering this energy and avoiding transactional costs that ultimately impact California's ratepayers" (BrightSource Energy 2011a, p. 2).

A Discussion on Capacity Factors

Capacity factor is the ratio of actual output of power over a period of time compared to the output of full nameplate capacity operation. Solar technologies have relatively low capacity factors because they only produce power when the sun is shining. Other technologies, such as coal or natural gas, can produce power at a relatively constant rate or as dictated by demand.

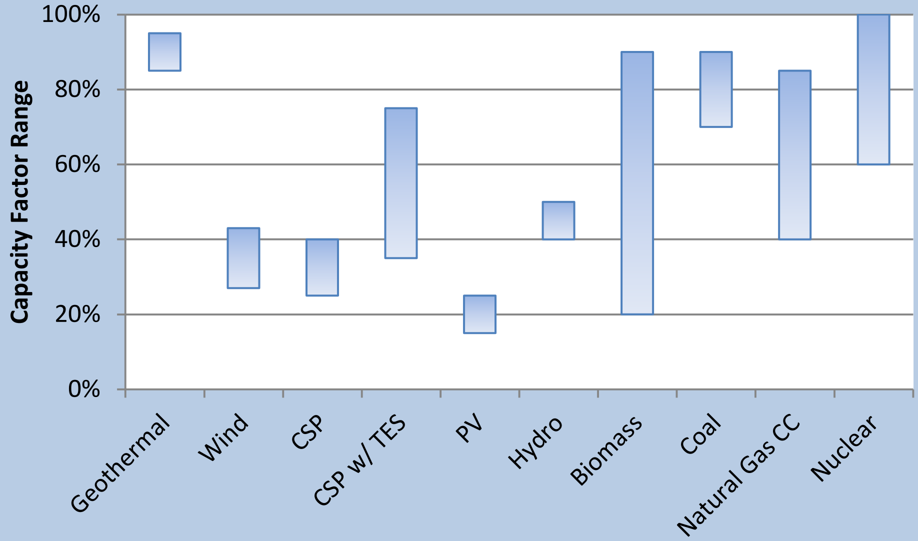

Figure 13. Comparison of capacity factor by technologies

The capacity factor for PV technologies ranges from 14%–18% for thin-film systems and 20%–24% for crystalline installations. Thermal storage can significantly increase the capacity factor of eligible CSP plants from 25% without storage to approximately 75% with storage.

Source: Renewable Energy Research Laboratory 2011

2.7 Cooling Systems

Steam-driven power plants, such as CSP facilities, require a consistent source of fresh water, which can be difficult to obtain in the desert where the solar resource is plentiful. Water consumption is primarily connected to the cooling system. There are three primary types of cooling systems: open loop, closed loop, and dry. Open loop, or once-through, cooling systems pull heat from the power plant by withdrawing large quantities of water from rivers and other sources and returning the now-warmer water to its source. As most of the water used in an open loop system is returned to its source, these systems actually consume (via evaporation) very small quantities of water (DOE 2008).

Due to environmental concerns associated with increasing the temperature of river water, open loop systems were disallowed in new power generation facilities in the early 1970s (California Environmental Protection Agency 2008). Nonetheless, open loop cooling systems grandfathered into the new law are still widely used throughout the United States. According to the DOE, more than half of the existing fleet of thermal generating plants in the United States are estimated to be equipped with once-through cooling systems (DOE 2008). The U.S. Environmental Protection Agency is in the process of developing new rules associated with Section 316(b) of the Clean Water Act that will help determine when open loop cooling will be allowed. Recent revisions to the draft rules gave power developers more flexibility in water cooling, although some may still need to switch from open to closed loop systems.

Table 5. Water Usage Requirements for Electric Generation Technologies

Cooling System	Power Plant Technology	Water Usage (Gallons/MWh)	
		Withdrawal	Consumption
Open loop	Fossil/biomass waste/nuclear steam	20,000–60,000	100–400
	Natural gas combined cycle	7,500–20,000	50–100
Closed loop	Fossil/biomass waste steam	300–600	300–1,100
	Nuclear	500–1,100	700–850
	Geothermal	2,000	1,400
	Solar trough	760–920	720–1,050
	Solar tower	750	740–850
Dry	Various technologies	0	0–80
Hybrid	Various technologies	50–650	100–600

Source: DOE 2008; Macknick et al. 2011

Closed loop cooling systems cool and recirculate water within the power plant and thus withdraw far less water than open loop systems. However, during the cooling process, water is lost via evaporation. Closed loop systems negate thermal pollution of water sources and withdraw far less water but lower plant efficiency by approximately 0.8%–1.4% (DOE 2008).

Dry cooling, or air cooled, systems use air to condense heat and cool power plants. These systems have minimal water requirements—either in withdrawal or consumptive modes—and can generally be used in all steam cycle power plant technologies, including CSP trough and CSP tower facilities (DOE 2008). However, dry cooling systems are more expensive to build and can lower the efficiency and output of the power plant, especially on very hot days.

To help balance cost, plant output, efficiency, and water use, some power plants are being designed with hybrid cooling systems that combine closed loop wet and dry cooling systems (DOE 2006). Air cooling dissipates heat directly into the air, using water only for general plant uses and steam cycle blowdown, which eliminates dissolved solids in the steam. Hybrid cooling systems can reduce water use by 50%–85% with only a 1%–3% drop in power output (DOE 2010a).

4 Summary of Market Highlights

Utility-scale solar capacity additions have grown exponentially in the last several years, and the development pipeline ensures that significant growth will maintain through the near-term. Plunging PV costs have altered the competitive landscape amongst technologies but have generally improved project economics enabling large-scale solar deployment. Key observations from this report include:

- PV leads the utility-scale solar market for projects under development with approximately 72% of the capacity under long-term contract. In contrast, only about 57% of the current operational capacity in the United States derives from PV technologies. About 71% of PV projects under development have indicated or are expected to utilize c-Si modules made from a wide variety of manufacturers; approximately 23% are contracted to use CdTe modules, most of which will be manufactured by First Solar.
- California utilities are priming the market by signing large PPA contracts with utility-scale developers. Combined, California's three IOUs represent 72% of the total utility-scale market in the United States.
- Though CSP trough plants dominate the CSP market today, there is nearly half as much CSP trough capacity in development as that for CSP tower. The contraction of the CSP market is largely due to the exit of Solar Millennium, who announced in late 2011 that they would be switching the technology for their Blyth and Palen facilities from troughs to PV.
- Conversely, CSP tower technologies have risen to prominence in the U.S. development pipeline, representing approximately 2,655 MW, or 16% of planned utility-scale solar capacity. One company, BrightSource, dominates this space, with about 2.2 GW of projects contracted with two of California's IOUs (SCE and PG&E).
- Currently, there are no utility-scale linear Fresnel or parabolic dish systems contracted for development. The principal developers of both technologies, Ausra and Stirling Engine Systems, respectively, have met financial troubles that have disrupted their development pipelines. Ausra sold its linear Fresnel technology to French conglomerate Areva in 2010, and Stirling declared bankruptcy in September 2011.
- CPV technologies have made big gains in the development market, with nine projects totaling 471 MW currently under contract. This is notable for a technology that has only enjoyed a few years of commercialization.

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About IRENA

The International Renewable Energy Agency (IRENA) is an intergovernmental organisation dedicated to renewable energy.

In accordance with its Statute, IRENA's objective is to "promote the widespread and increased adoption and the sustainable use of all forms of renewable energy". This concerns all forms of energy produced from renewable sources in a sustainable manner and includes bioenergy, geothermal energy, hydropower, ocean, solar and wind energy.

As of May 2012, the membership of IRENA comprised 158 States and the European Union (EU), out of which 94 States and the EU have ratified the Statute.

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Key findings

1. **Concentrating solar power (CSP) plants** are capital intensive, but have virtually zero fuel costs. Parabolic trough plant without thermal energy storage have capital costs as low as USD 4 600/kW, but low capacity factors of between 0.2 and 0.25. Adding six hours of thermal energy storage increases capital costs to between USD 7 100/kW to USD 9 800/kW, but allows capacity factors to be doubled. Solar tower plants can cost between USD 6 300 and USD 10 500/kW when energy storage is between 6 and 15 hours. These plant can achieve capacity factors of 0.40 to as high as 0.80.

Table 1: CSP costs and performance in 2011

	Installed cost (2010 USD/kW)	Capacity factor (%)	O&M (2010 USD/kWh)	LCOE (2010 USD/kWh)
Parabolic trough			0.02 to 0.035	0.14 to 0.36
No storage	4 600	20 to 25		
6 hours storage	7 100 to 9 800	40 to 53		
Solar tower				0.17 to 0.29
6 to 7.5 hours storage	6 300 to 7 500	40 to 45		
12 to 15 hours storage	9 000 to 10 500	65 to 80		

Note: the levelised cost of electricity (LCOE) assumes a 10% cost of capital

2. **Operations and maintenance (O&M)** costs are relatively high for CSP plants, in the range USD 0.02 to USD 0.035/kWh. However, cost reduction opportunities are good and as plant designs are perfected and experience gained with operating larger numbers of CSP plants savings opportunities will arise.

3. **The levelised cost of electricity (LCOE)** from CSP plants is currently high. Assuming the cost of capital is 10%, the LCOE of parabolic trough plants today is in the range USD 0.20 to USD 0.36/kWh and that of solar towers between USD 0.17 and USD 0.29/kWh. However, in areas with excellent solar resources it could be as low as USD 0.14 to USD 0.18/kWh. The LCOE depends primarily on capital costs and the local solar resource. For instance, the LCOE of a given CSP plant will be around one-quarter lower for a direct normal irradiance of 2 700 kWh/m^2/year than for a site with 2 100 kWh/m^2/year.

4. **With just 1.9 GW of installed CSP capacity,** not enough data exists to identify a robust learning curve. However, the opportunities for cost reductions for CSP plant are good given that the commercial deployment of CSP is in its infancy. Capital cost reductions of 10% to 15% and modest reductions in O&M costs by 2015 could see the LCOE of parabolic trough plants decline to between USD 0.18 and USD 0.32/kWh by 2015 and that of solar tower plants to between USD 0.15 to USD 0.24/kWh.

5. **Cost reductions** will come from economies of scale in the plant size and manufacturing industry, learning effects, advances in R&D, a more competitive supply chain and improvements in the performance of the solar field, solar-to-electric efficiency and thermal energy storage systems. By 2020, capital cost reductions of 28% to 40% could be achieved and even higher reductions may be possible.

6. **Solar towers** might become the technology of choice in the future, because they can achieve very high temperatures with manageable losses by using molten salt as a heat transfer fluid. This will allow higher operating temperatures and steam cycle efficiency, and reduce the cost of thermal energy storage by allowing a higher temperature differential. Their chief advantage compared to solar photovoltaics is therefore that they could economically meet peak air conditioning demand and intermediate loads (in the evening when the sun isn't shining) in hot arid areas in the near future.

6. The levelised cost of electricity from CSP

The first SEGS plants that have been operating in California since 1984 are estimated to have LCOEs of between USD 0.11 to USD 0.18/kWh. However, current materials and engineering costs are significantly higher than they were during the period of their construction and these are not necessarily a good guide to the current LCOE of CSP plants.

The most important parameters that determine the LCOE of CSP plants are:

- The initial investment cost, including site development, components and system costs, assembly, grid connection and financing costs;
- The plant's capacity factor and efficiency;
- The local DNI at the plant site;
- The O&M costs (including insurance) costs; and
- The cost of capital, economic lifetime, etc.

The economics of CSP and other renewable technologies are, with the exception of biomass, substantially different from that of fossil fuel power technologies. Renewables have, in general, high upfront investment costs, modest O&M costs and very low or no fuel costs. Conventional fossil fuel power tends to have lower upfront costs and high (if not dominant) fuel costs, which are very sensitive to the price volatility of the fossil fuel markets. In contrast, renewable technologies are more sensitive to change in the cost of capital and financing conditions.

Solar tower projects are currently considered more risky by financiers due to their less mature status. However, in the longer-term, greater experience with solar towers will reduce this risk premium and convergence is likely to occur in financing costs. The analysis presented here, as in the other papers in this series, assumes a standard 10% cost of capital for all the technologies evaluated. The LCOE of CSP plants from a developer's perspective will therefore differ from that presented here, due to differences in local conditions and developers' and lenders' perceptions of risk.

The impact of the solar resource and plant design decisions on the LCOE of CSP plants

It is important to note that the LCOE of CSP plants is strongly correlated with the DNI. Assuming a base of 2 100 kWh/m²/year (a typical value for Spain), the estimated LCOE of a CSP plant is expected to decline by 4.5% for every 100 kWh/m²/year that the DNI exceeds 2 100 (Figure 6.1).

An important consideration in the design of CSP plant is the amount of thermal energy storage and the size of the solar multiple. Various combinations of these two parameters yield different LCOE results (Figure 6.2). Thermal storage allows CSP to achieve higher capacity factors and dispatch generation when the sun is not shining. This can make CSP a competitor for conventional base- or intermediate-load power plants. A large-scale example of this technology is the 280 MW Solana 1 power plant under construction by Abengoa for the Arizona Public Service Co, United States.

However, for a given plant, the minimum range of LCOE can be achieved by varying the thermal energy storage and solar multiple values (Figure 6.2). This analysis suggests that the minimum LCOE is achieved with a solar multiple of 3 and 12 hours energy storage. However, there is relatively little difference between a plant with a solar multiple of 1.5 and no thermal energy storage, a solar multiple of 2 and 6 hours energy storage, and a plant with a solar multiple of 3 and 12 hours energy storage. Choosing what plant design is optimal will depend significantly on the project's specifics. However, one important factor to consider is that this assumes all electricity generated has the same value. If this is not the

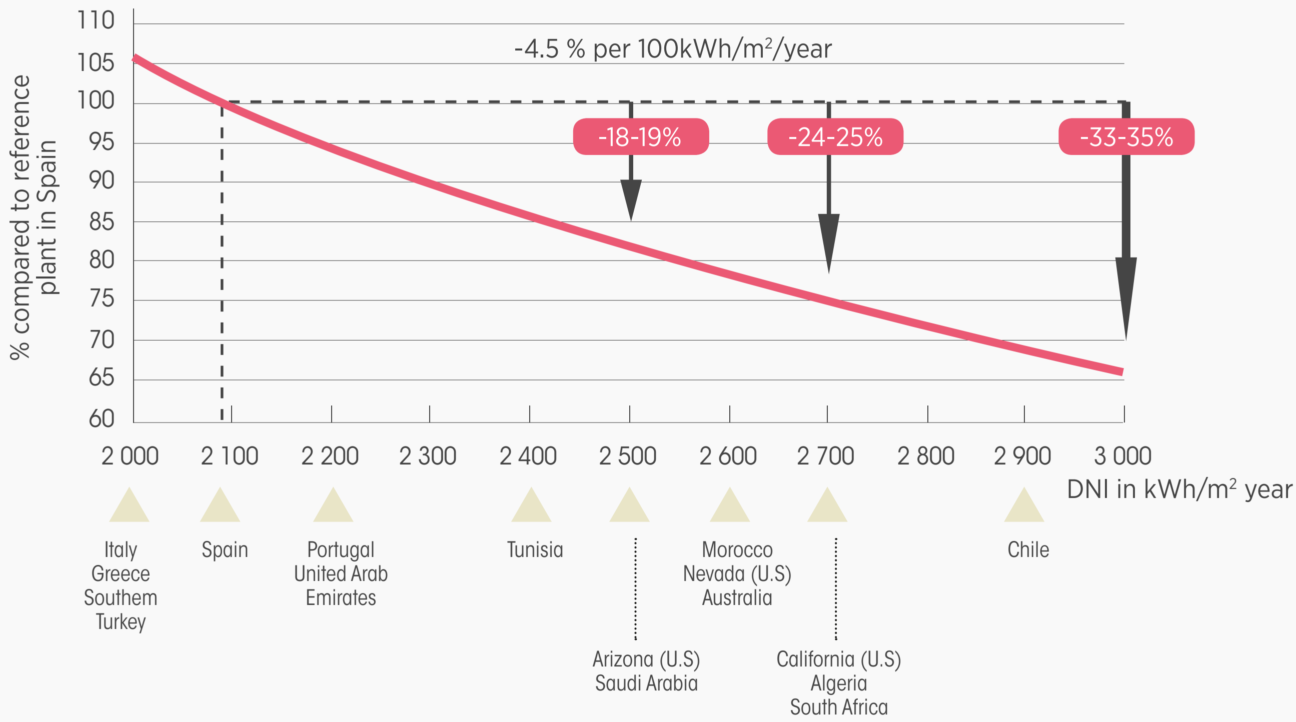

Figure 6.1: The LCOE of CSP plants as a function of DNI

Source: A.T. Kearney and ESTELA, 2010.

case, then plants with higher storage levels are likely to provide more flexibility to capture this increased value. This picture will evolve over time as thermal energy storage costs decline. Lower storage costs, particularly for solar tower projects, will result in a lower LCOE for plants with higher storage.

6.1 THE CURRENT LEVELISED COST OF ELECTRICITY FROM CSP

The current LCOE of CSP plants varies significantly by project and solar resource. Table 6.1 presents the range of estimates for CSP from different sources. Parabolic trough systems are estimated to have an LCOE of between USD 0.20 and USD 0.33/kWh at present, depending on their location, whether they include energy storage and the particulars of the project. These ranges broadly agree with the limited data that are available for recent CSP projects that have been commissioned, or will come online in the near future (Figure 6.3). However, the results need to be treated with caution, given that there are relatively few projects, and not all of the data on the actual costs of recent projects is in the public domain.

Solar tower systems are estimated to have an LCOE of between USD 0.16 and USD 0.27/kWh at present, depending on their location, the size of the thermal energy storage and the particulars of the project.

An important aspect of adding storage to a CSP plant in the context of the profitability of the project is the anticipated increased value of produced energy. This will depend on the existing electricity system, usage patterns and the structure of the electricity market. Adding storage to a CSP plant adds value by decreasing variability, increasing predictability and by providing firm capacity. Where peak demand and prices received coincide with the production of a CSP plant, little or no storage may be justified. In contrast, where early evening

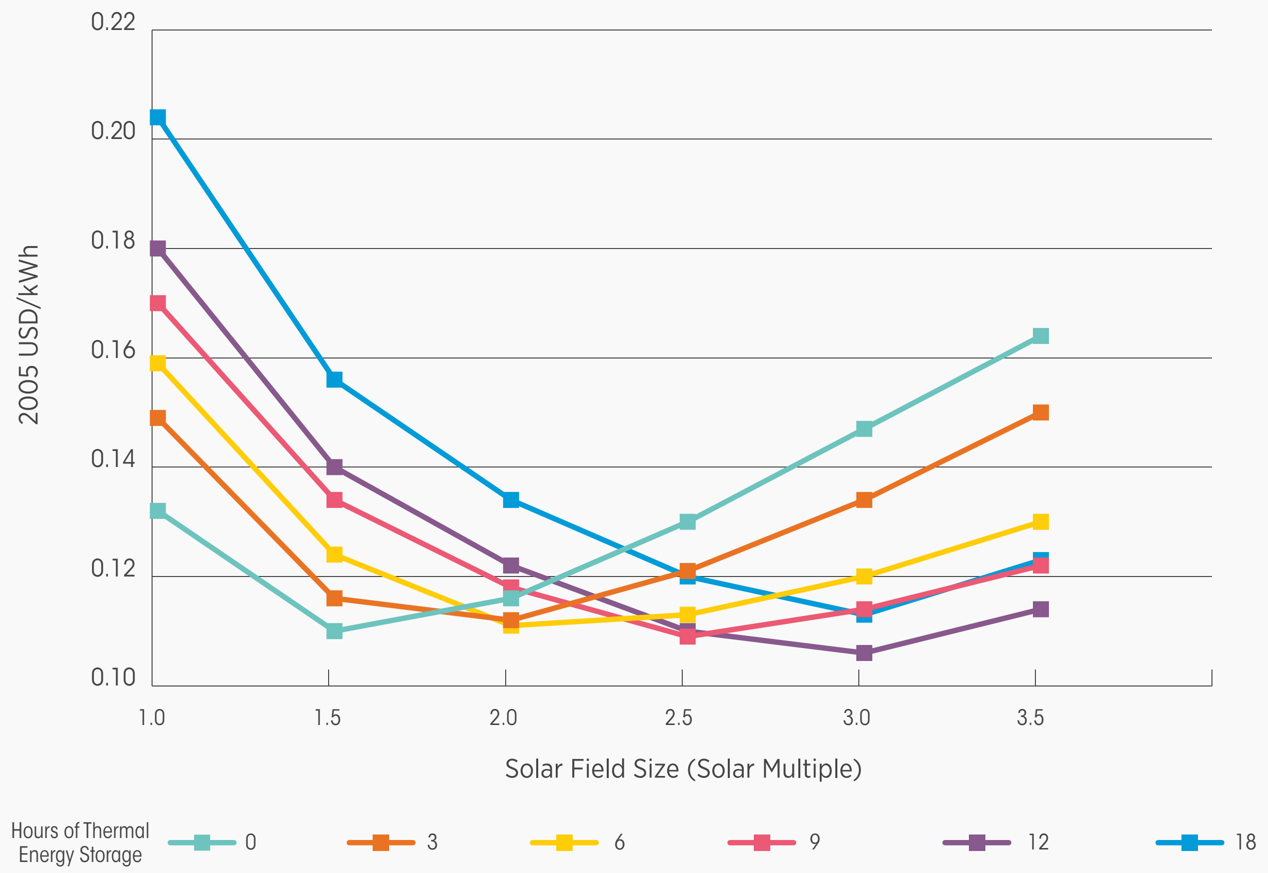

Figure 6.2: Levelised cost of electricity for 100 MW parabolic trough plant as a function of the size of the solar field and thermal storage

Source: Anders, 2005.

peaks occur, storage allows CSP plant to be dispatched at this time of higher value electricity demand. The value of the ability to dispatch a CSP plant's generation into peak demand periods is very country- and project-specific, but the overall increase in value can be in the range of USD 0.015 to USD 0.065/kWh (Richter, 2011).

In Spain, a number of 50 MW CSP units are planned, based on an estimated LCOE of approximately USD 0.30 to USD 0.35/kWh. Other technologies, such as the solar tower and Stirling dish systems, are currently planned for significantly smaller scales of up to 15 MW. For these small systems, the LCOE is significantly higher. The cost of electricity production by parabolic trough systems is currently on the order of USD 0.23 to USD 0.26/kWh (€ 0.18 to € 0.20/kWh) for Southern Europe, where the DNI is 2 000 kWh/m^2/year (CSP Today, 2008).

The LCOE of parabolic trough plants and solar tower plants is dominated by the initial capital investment (Figure 6.4). The analysis of CSP options for South Africa suggests 84% of the LCOE of both parabolic troughs and solar towers will be accounted for by the initial capital investment. The fixed operations and maintenance costs account for 10% to 11% of the LCOE and personnel costs for 4% to 5% of the total LCOE.

Substantial cost reductions for the LCOE of CSP plants can be expected by 2020, given that several GW of CSP power plants are under construction, announced or in the pipeline for 2020. With aggressive deployment policies, this will lead to significant cost reductions from learning effects. Additional reductions in the LCOE of CSP plants will come from the impact of greater R&D investment, greater operational experience and the scaling-up of plants.

The LCOE of parabolic trough systems could decline by between 38% and 50% by 2020 (Table 6.1). This is driven by improvements in performance and capital

Table 6.1: Estimated LCOE for parabolic trough and solar tower projects in 2011 and 2020

	2011		2020		
CSP type and source	**Low estimate**	**High estimate**	**Low estimate**	**High estimate**	**Notes**
			(2010 USD/kWh)		
Parabolic trough					
IEA, 2010	0.20	0.295	0.10	0.14	Large plant, 10% discount rate
Fichtner, 2010	0.22	0.24			Proposed plant in South Africa. 8% discount rate. Lower end is for 100 MW plant with storage
	0.33	0.36			LCOE for India, lower value is for wet-cooled and higher value for dry-cooled
	0.22	0.23			LCOE for Morocco, lower value is for wet-cooled and higher value for dry-cooled
Based on Kutscher, et al., 2010	0.22		0.10	0.11	Data for the United States, adjusted to exclude impact of tax credits
Hinkley, et al., 2011	0.21		0.13		Data for a 100 MW plant in Queensland, Australia. 7% discount rate.
Solar Tower					
Fichtner, 2010	0.185	0.202			Proposed plant in South Africa. 8% discount rate. Lower end is for 100 MW plant with storage
	0.27	0.28			LCOE for India, lower value is for wet-cooled and higher value for dry-cooled
	0.22	0.23			LCOE for Morocco, lower value is for wet-cooled and higher value for dry-cooled
Kolb, et al., 2010	0.16	0.17	0.08	0.09	Data for the United States, adjusted to exclude impact of tax credits
Hinkley, et al., 2011	0.21		0.16		Data for a 100 MW plant in Queensland, Australia. 7% discount rate.
Parabolic trough and solar towers					
A.T. Kearney, 2010	0.23	0.32	0.13	0.16	

cost reductions. The LCOE of solar tower projects could decline by between 30% and 50% by 2020. The lower end of this range is somewhat less than for parabolic troughs, given the less mature status of this technology.

By 2025 a survey of industry expectations and analysis of the bottom-up technology cost reduction potential highlights potentially larger cost reductions for CSP plants (Figure 6.5). Economies of scale in manufacturing and project development are expected to offer the largest cost reduction potential, followed by capital cost reductions and performance improvements.

6.2 THE LCOE OF CSP PLANTS: 2011 TO 2015

The estimated cost of CSP plant varies significantly, depending on the capacity factor, which in turn depends on the quality of the solar resource, thermal energy storage levels and the technical characteristics of the CSP plant.

Based on the data and analysis presented earlier, CSP plant capital costs vary significantly, depending on the level of energy storage. For parabolic trough plants without thermal energy storage, costs could be as low as

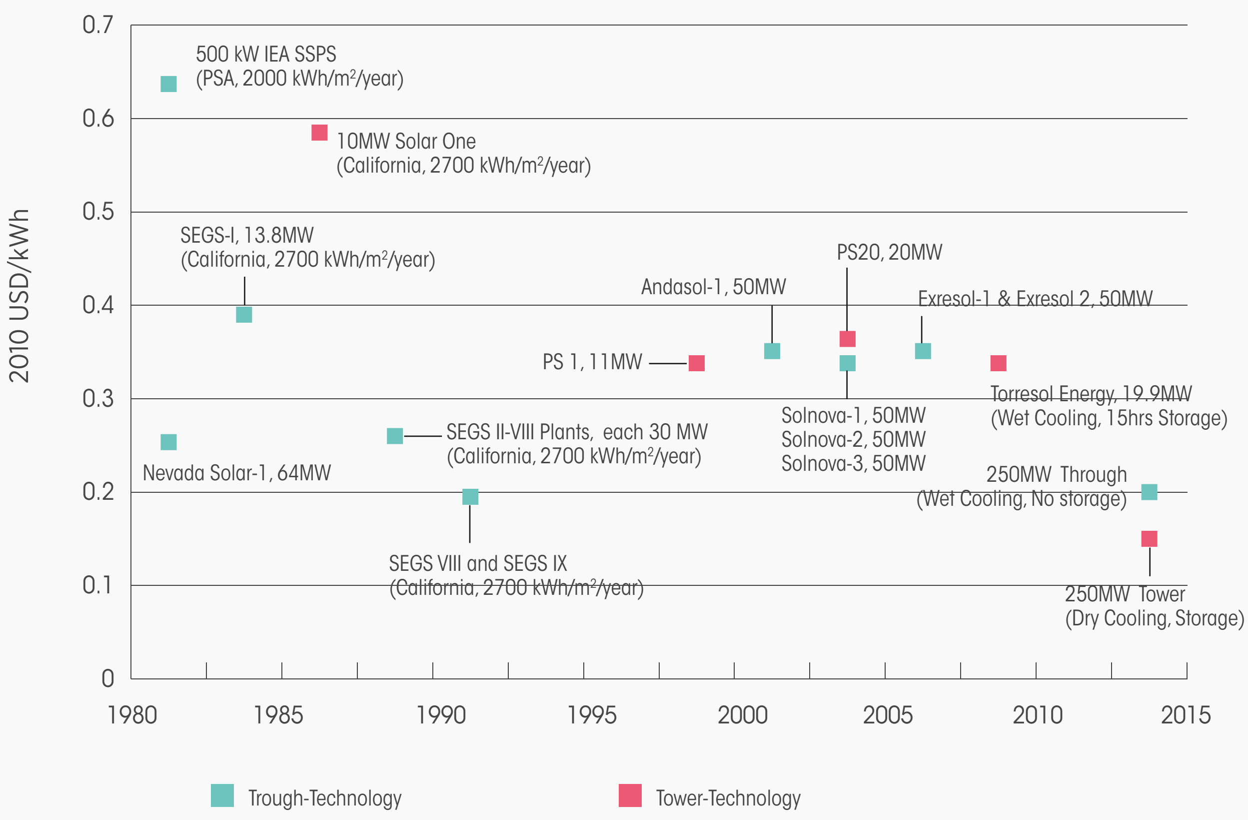

Figure 6.3: Estimated LCOE for existing and proposed parabolic trough and solar tower CSP plants

Source: IRENA analysis

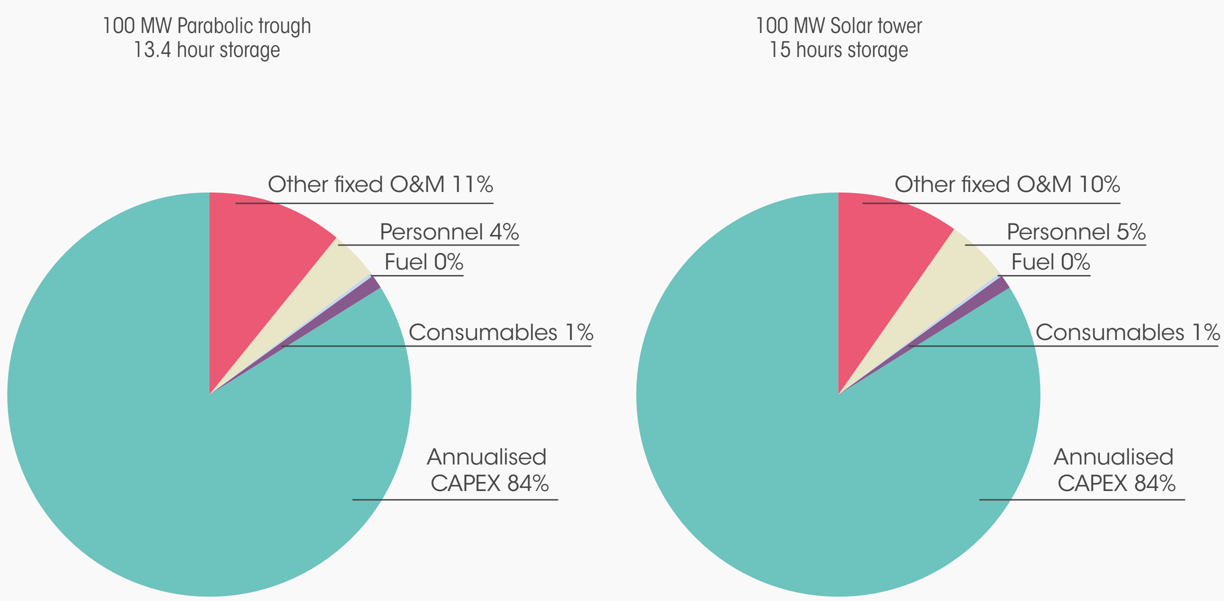

Figure 6.4: LCOE breakdown for a parabolic trough and solar tower plant in South Africa

Source: Fichtner, 2010.

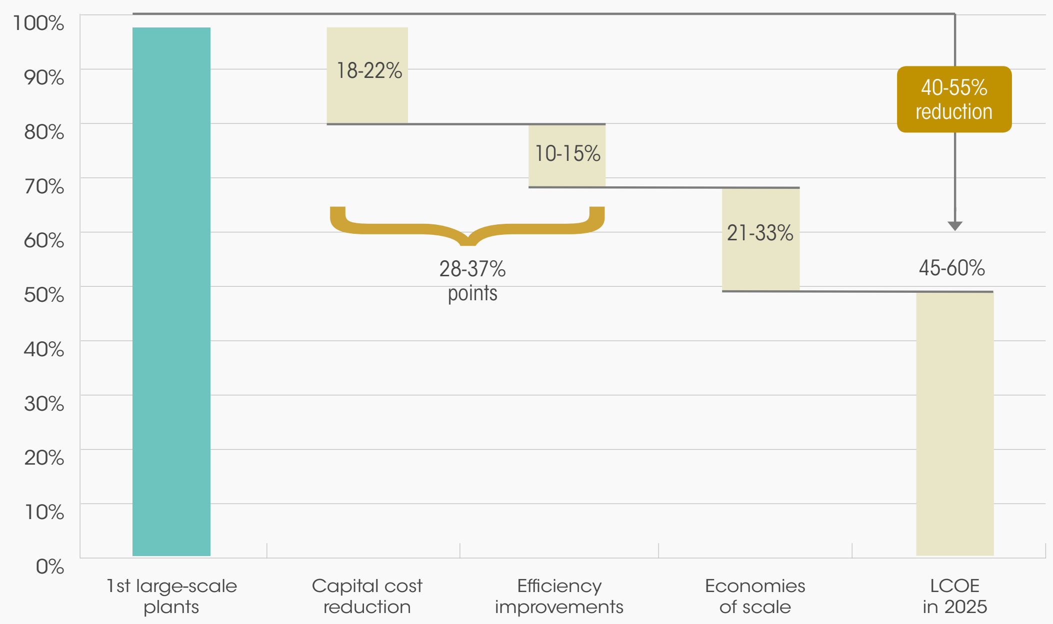

Figure 6.5: Breakdown of LCOE reductions for CSP plant by 2025

Source: A.T. Kearney and ESTELA, 2010.

USD 4 600/kW, but the capacity factor is likely to be just 0.2 to 0.25 (Table 6.2). The total installed capital costs of parabolic trough plant with six hours energy storage is estimated to be in the range USD 7 100 to USD 9 800/kW. These plants will have much higher capacity factors in the range of 40% to 53%.

Solar tower projects, given their potential for higher operating temperatures and therefore cheaper storage and higher performance, tend to be designed with higher thermal energy storage. Solar tower projects with thermal energy storage of 6 to 7.5 hours are estimated to cost USD 6 300 to USD 7 500/kW and have capacity factors between 40% and 45%. Solar tower projects with nine hours energy storage have costs of between USD 7 400 to USD 7 700/kW and have capacity factors between 45% and 55%. Increasing energy storage to between 12 and 15 hours increases the specific costs to USD 9 000 to USD 10 500/kW and could increase the capacity factor to between 65% and 80%.

Given the very early stage of development of linear Fresnel collectors and Stirling dish systems, capital costs and LCOE estimates for these technologies are not presented in this analysis.

The LCOE for parabolic trough plant is presented in Figure 6.6. High and low assumptions for the capital costs and capacity factor are taken from Table 6.1 and are based on the data presented in Section 4 for 2011. The analysis assumes 0.5% per year for insurance, 0.4% degradation in the solar field performance per year and O&M cost escalation at the rate of 1% per year. The LCOE of parabolic trough CSP plants without thermal energy storage is estimated to be between USD 0.30 and USD 0.37/kWh and could decline to between USD 0.26 and USD 0.34/kWh by 2015. Parabolic trough plants with six hours of thermal energy storage have an estimated LCOE of between USD 0.21 to USD 0.37/kWh, depending on the capital costs and capacity factor achieved. By 2015, the LCOE for these plants could fall to between USD 0.18 and USD 0.31/kWh.

The estimated LCOE of solar tower CSP with 6 to 7.5 hours of storage in 2011 is estimated to be between USD 0.22 and USD 0.29/kWh (Figure 6.7). For solar tower plants with 12 to 15 hours of storage, the LCOE drops to between USD 0.17 and USD 0.24/kWh. By 2015, capital cost reductions, performance improvements and lower O&M costs could reduce the LCOE of plants with 6 to 7.5 hours of storage to between USD 0.17 and USD 0.24/kWh.

Table 6.2: Total installed cost for parabolic trough and solar towers, 2011 and 2015

	2011		2015	
	2010 USD/kW	Capacity factor (%)	2010 USD/kW	Capacity factor (%)
Parabolic trough				
No storage	4 600	20 to 25	3 900 to 4 100	20 to 25
6 hours storage	7 100 to 9 800	40 to 53	6 300 to 8 300	40 to 53
Solar tower				
6 to 7.5 hours storage	6 300 to 7 500	40 to 45	5 700 to 6 400	40 to 53
12 to 15 hours storage	9 000 to 10 500	65 to 80	8 100 to 9 000	65 to 80

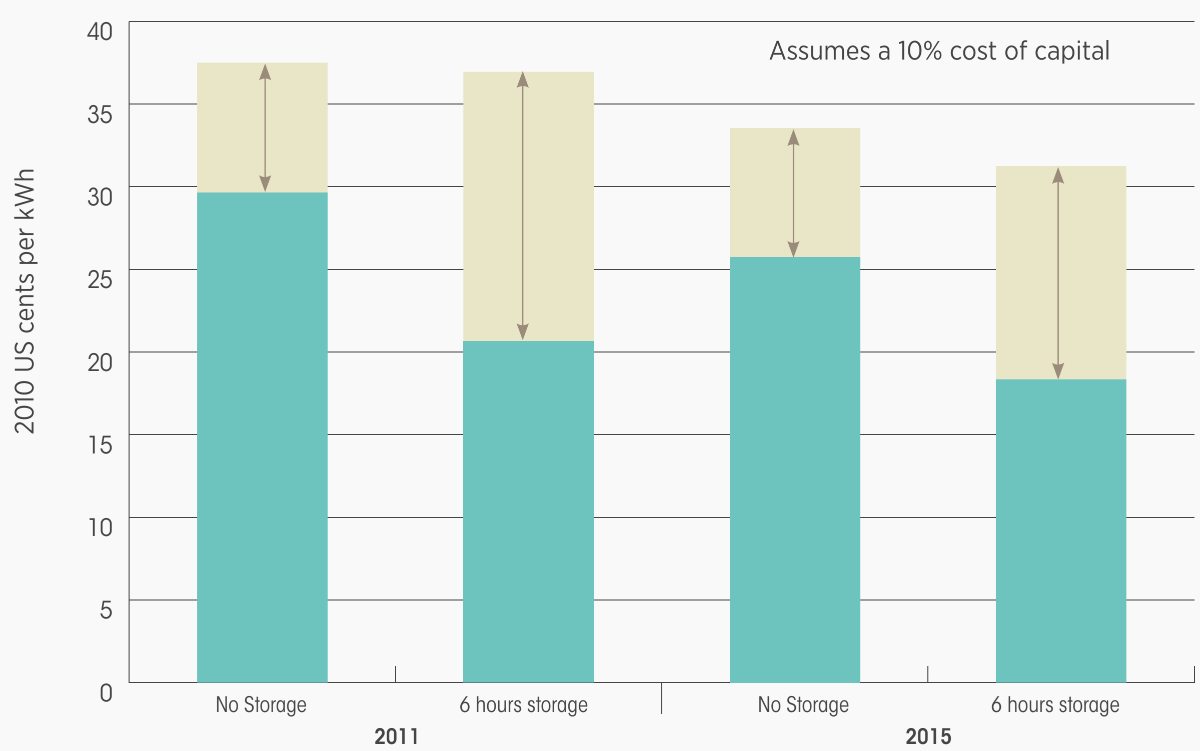

Figure 6.6: LCOE of parabolic trough CSP plant, 2011 and 2015

Note: The LCOE numbers are based on a 10% discount rate, higher or lower rates will have a significant impact on the LCOE.

For plants with 12 to 15 hours of storage, the LCOE could decline to between USD 0.15 and USD 0.21/kWh by 2015.

Solar towers, therefore, have the potential to reduce their costs to the point at which they can compete with conventional technologies for providing intermediate load and peak afternoon air conditioning loads in hot, arid climates in the short- to medium-term, with further cost reductions to 2020 further improving their competiveness.

Sensitivity to the discount rate used

The analysis in this section assumes that the average cost of capital for a project is 10%. However, the cost of debt and the required return on equity, as well as the ratio of debt-to-equity varies between individual projects and countries. This can have a significant impact on the average cost of capital and the LCOE of a CSP project.

In the United States, the required return on equity for CSP projects for which data was available between the

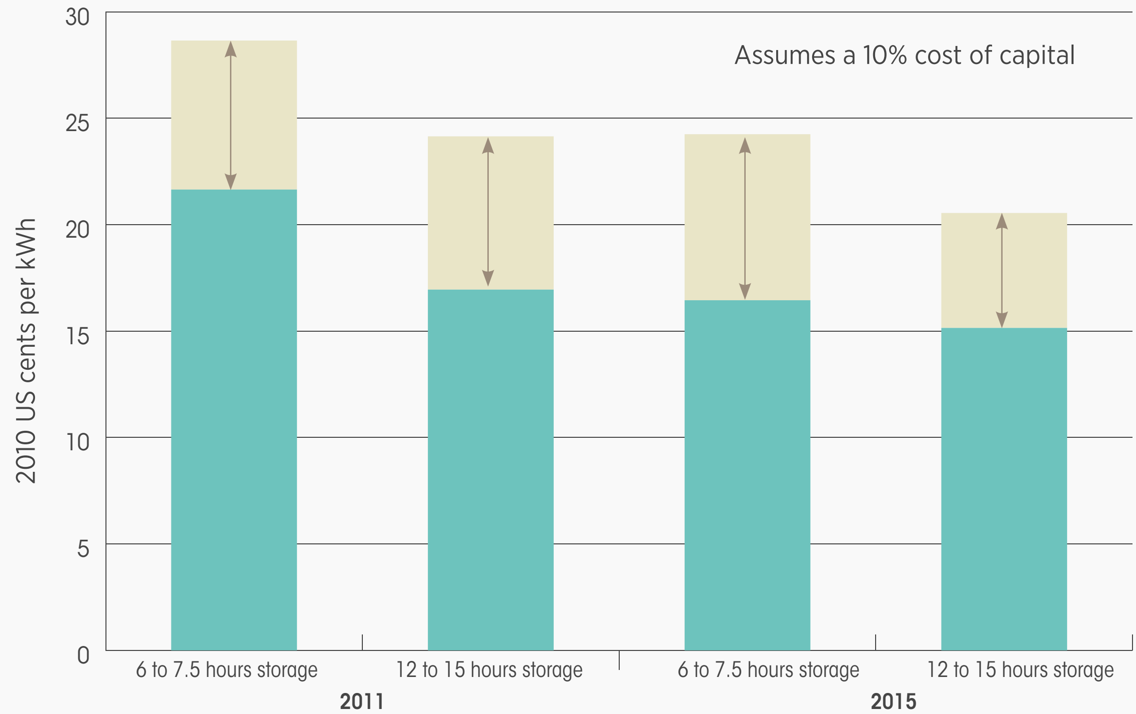

Figure 6.7: LCOE of solar tower CSP plant, 2011 and 2015

Note: The LCOE numbers are based on a 10% discount rate, higher or lower rates will have a significant impact on the LCOE.

fourth quarter of 2009 and the fourth quarter of 2010, inclusive, ranged from a low of 7% to a high of 15%. While the quarterly average cost of debt ranged from a low of 4.4% to a high of 11%.[18] Making the simplifying assumptions that the debt-to-equity ratio is between 50% and 80% and that debt maturity matches project length results in project discount rates of between 5.5% and 12.8%.[19]

Table 6.3 presents the impact of varying the discount rate between 5.5% and 14.5% for CSP projects. The LCOE of a parabolic trough plant with 6 hours storage is around 30% lower when the discount rate is 5.5% instead of 10%. Increasing the discount rate from 10% to 12.8% increases the LCOE of a parabolic trough plant by around one-fifth, depending on the capacity factor. Increasing the discount rate to 14.5% increases the LCOE by around 30%.

Table 6.3: LCOE of CSP parabolic trough and solar tower projects under different discount rate assumptions

	Parabloic trough plant (6 hours storage, USD 8 000/kW)		Solar tower plant (12-15 hours storage, USD 10 000/kW)	
Capacity factor	**40%**	**53%**	**65%**	**80%**
	2010 USD/kWh			
10% discount rate	0.31	0.23	0.23	0.19
5.5% discount rate	0.22	0.16	0.16	0.13
12.8% discount rate	0.37	0.28	0.28	0.23
14.5% discount rate	0.40	0.30	0.31	0.25

Note: Assumes USD 70/kW/year for O&M, 0.5% insurance and a 25 year economic life.

[18] *This data comes from the Renewable Energy Financing Tracking Initiative database and was accessed in November 2011. See https://financere.nrel.gov/finance/REFTI*

[19] *These assumptions aren't representative of how projects are structured, but in the absence of comprehensive data are used for illustrative purposes.*

For solar towers with 12 to 15 hours storage, decreasing the discount rate from 10% to 5.5% reduces the LCOE by between 30% and 32%. Increasing the discount rate to 12.8% increases the LCOE by 21% to 22%, while increasing the discount rate to 14.5% increases the LCOE by between 32% and 35%. This simple comparison shows that reducing the risks associated with CSP projects and ensuring that favourable financing terms can be accessed will have a significant impact on the competitiveness of CSP projects.

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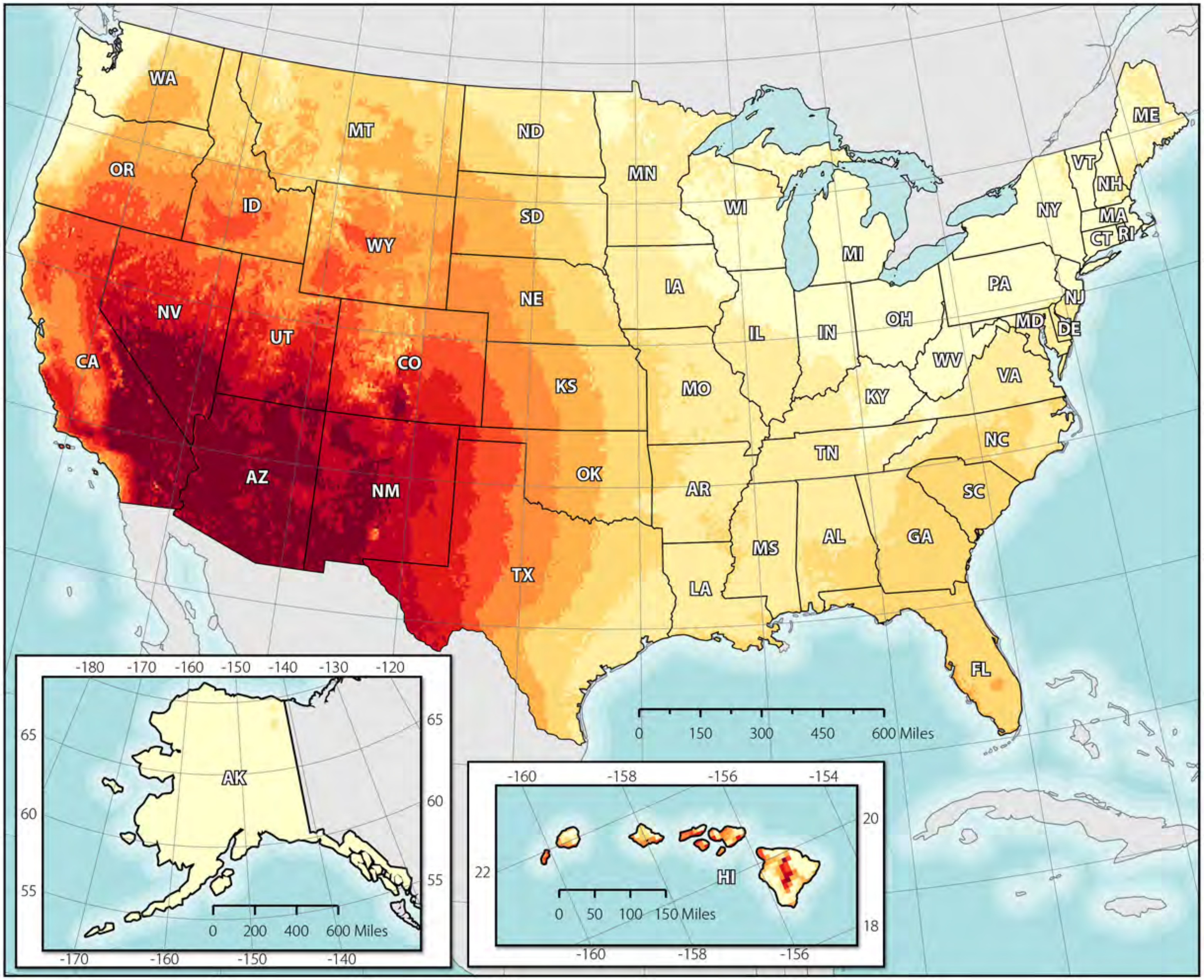
Acronyms

BoP	Balance of plant
CAPEX	Capital expenditure
CIF	Cost, insurance and freight
CSP	Concentrating solar power
DCF	Discounted cash flow
DNI	Direct normal irradiance
DSG	Direct steam generation
EU-27	The 27 European Union member countries
FOB	Free-on-board
GHG	Greenhouse gas
GW	Gigawatt
HTF	Heat transfer fluid
ISCC	Integrated solar combined cycle
kW	Kilowatt
kWh	kilowatt hour
LFC	Linear Fresnel collector
MENA	Middle East and North Africa
MW	Megawatt
MWh	Megawatt hour
LCOE	Levelised cost of energy
O&M	Operating and maintenance
OPEX	Operation and maintenance expenditure
PTC	Parabolic trough collector
R&D	Research and Development
USD	United States dollar
WACC	Weighted average cost of capital

Concentrating Solar Resource of the United States



kWh/m²/Day

- > 7.5
- 7.0 to 7.5
- 6.5 to 7.0
- 6.0 to 6.5
- 5.5 to 6.0
- 5.0 to 5.5
- 4.5 to 5.0
- 4.0 to 4.5
- < 4.0

Annual average direct normal solar resource data are shown. The data for Hawaii and the 48 contiguous states are a 10km satellite modeled dataset (SUNY/NREL, 2007) representing data from 1998-2009.

The data for Alaska are a 40 km dataset produced by the Climatological Solar Radiation Model (NREL, 2003).

This map was produced by the National Renewable Energy Laboratory for the U.S. Department of Energy.
Billy J. Roberts
19 September 2012

NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Solana Generating Station

Abengoa Solar and Arizona Public Service (APS) have announced plans to build a 280-megawatt parabolic trough solar plant about 70 miles southwest of Phoenix, Arizona. The proposed plant could generate enough power to supply 70,000 homes under a 30-year power supply contract with APS. An unspecified heat-storage technology will provide 6 hours of generating capacity after sunset. During 3 years of construction, the project is planned to employ 1,500 workers at the 1,900-acre site near Gila Bend. After completion, Solana will employ 85 permanent workers. Abengoa plans to build a mirror manufacturing facility in an undisclosed location in the southwestern United States.

Status Date:	February 22, 2013

Background

Technology:	Parabolic trough
Status:	Under construction
Land Area:	1,257 hectares
Electricity Generation:	944,000 MWh/yr
Company:	Abengoa Solar
Break Ground:	December 2010
Start Production:	August 2013
Cost (approx):	2 USD billion
Construction Job-Years:	1500
Annual O&M Jobs:	85
PPA/Tariff Date:	January 2008
PPA/Tariff Period:	30 years
Project Type:	Commercial

Participants

Developer(s):	Abengoa Solar
Owner(s) (%):	Abengoa Solar (100%)
EPC Contractor:	Abengoa Solar
Generation Offtaker(s):	Arizona Public Service

Project Overview	
Project Name:	Solana Generating Station (Solana)
Country:	United States
Location:	Phoenix, Arizona (Gila Bend)
Owner(s):	Abengoa Solar (100%)
Technology:	Parabolic trough
Turbine Capacity:	Net: 250.0 MW Gross: 280.0 MW
Status:	Under construction
Start Year:	2013

Plant Configuration

Solar Field

Solar-Field Aperture Area:	2,200,000 m^2
# of Solar Collector Assemblies (SCAs):	3,232
# of Loops:	808
# of SCAs per Loop:	4
# of Modules per SCA:	10
SCA Manufacturer (Model):	Abengoa Solar (E2)
Mirror Manufacturer:	Rioglass
Heat-Transfer Fluid Type:	Therminol VP-1
HTF Company:	Solutia
Solar-Field Outlet Temp:	715°F

Power Block

Turbine Capacity (Gross):	280.0 MW
Turbine Capacity (Net):	250.0 MW
Turbine Description:	2x140 MWe gross
Output Type:	Steam Rankine
Power Cycle Pressure:	100.0 bar
Cooling Method:	Wet cooling
Fossil Backup Type:	Natural gas

Thermal Storage

Storage Type:	2-tank indirect
Storage Capacity:	6 hours
Thermal Storage Description:	Molten salts

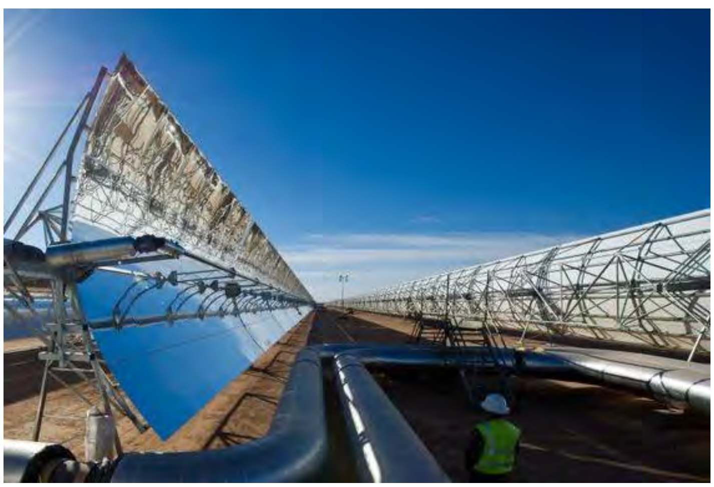
ABENGOA

Solana

Solana is a 280-MW (gross) utility-scale concentrating solar power (CSP) plant being built by Abengoa outside of Phoenix, Arizona. CSP is a technology that uses mirrors to concentrate the thermal energy of the sun to drive a conventional steam turbine.

Financed in part by a Department of Energy loan guarantee, Solana will deliver enough electricity to supply approximately 70,000 Arizona households, with over 70 percent of the construction components, products and services sourced from companies here in the USA.

Aerial view of the solar field
Photo taken July 2013



Parabolic trough collector

Solana's power block

Project benefits

Solana will benefit the entire country by:

- Making over **$2 billion of direct and indirect investment** in 2011-2013 throughout the United States.
- Creating a **national supply chain** that spans 29 states with approximately $966 million in components and services ordered for 165 companies.
- Job creation peaking at **over 2,000 construction jobs** during a 3-year period.
- Creating over **65 full-time, high-paying jobs** for plant operation.
- Generating about **$420 million in tax revenues** over 30 years.
- Providing **clean, sustainable power** for approximately 70,000 homes in Arizona.
- Increasing **Arizona's electricity generation reliability by energy source diversification.**

ABENGOA

Project details

Plant size: **280 MW** output

Abengoa has a signed power purchase agreement with Arizona Public Service to purchase all electricity produced.

Solar field covers **3 square miles** with approximately 3,200 mirrored parabolic trough collectors.

Collectors are about 25 feet wide, 500 feet long, and 10 feet high.

Collectors concentrate the sun's energy onto receiver tubes that contain heat transfer fluid.

Electricity is generated with **conventional steam turbines.**

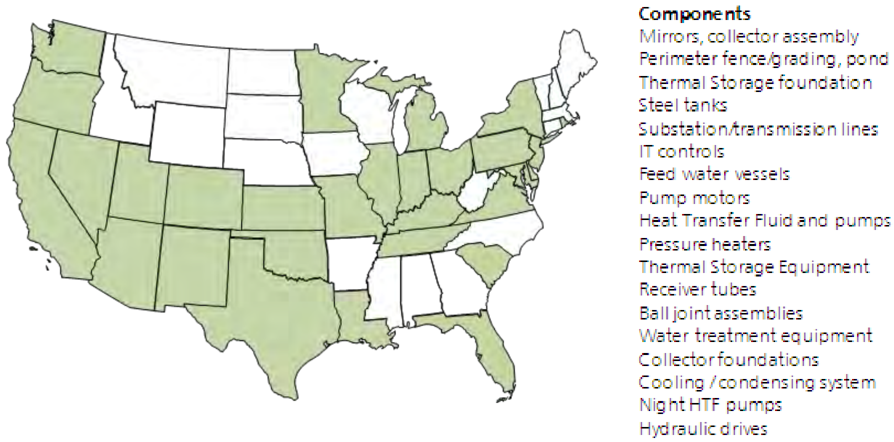
Thermal storage will provide up to **6 hours of dispatchable energy** to be used after sunset or if cloudy.

Approximately **75% less water is consumed** than previous agricultural use at the site.

Operation is scheduled to begin in 2013.

Thermal energy storage tank

Abengoa's Solana project is spurring economic benefits from coast to coast through the CSP supply chain. The supply chain from Solana spans 29 states with approximately $966 million in components and services ordered for 165 companies.



Who is Abengoa?

Abengoa (MCE: ABG) applies innovative technology solutions for sustainability in the energy and environment sectors, generating electricity from renewable resources, converting biomass into biofuels and producing drinking water from sea water.

With US headquarters in Colorado and offices in California and Arizona, Abengoa's solar business develops and applies proprietary CSP and PV solar energy technologies to foster sustainable development and energy independence.

Abengoa continuously improves product manufacturing and installation through rigorous research and development and is one of the world's pioneers in the construction of commercial CSP and PV solar plants through technological advances and financial investments.

Abengoa has two commercial solar power towers, thirteen 50-MW trough plants, a solar-gas combined-cycle plant and five PV plants in commercial operation worldwide. Abengoa has CSP plants under construction in the United States, South Africa, Spain, and the United Arab Emirates, with a total capacity of 810 MW.

www.abengoa.com

September 2013