Power Tower Technology Roadmap and Cost Reduction Plan

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Abstract

Concentrating solar power (CSP) technologies continue to mature and are being deployed worldwide. Power towers will likely play an essential role in the future development of CSP due to their potential to provide dispatchable solar electricity at a low cost. This Power Tower Technology Roadmap has been developed by the U.S. Department of Energy (DOE) to describe the current technology, the improvement opportunities that exist for the technology, and the specific activities needed to reach the DOE programmatic target of providing competitively-priced electricity in the intermediate and baseload power markets by 2020. As a first step in developing this roadmap, a Power Tower Roadmap Workshop that included the tower industry, national laboratories, and DOE was held in March 2010. A number of technology improvement opportunities (TIOs) were identified at this workshop and separated into four categories associated with power tower subsystems: solar collector field, solar receiver, thermal energy storage, and power block / balance of plant.

In this roadmap, the TIOs associated with power tower technologies are identified along with their respective impacts on the cost of delivered electricity. In addition, development timelines and estimated budgets to achieve cost reduction goals are presented. The roadmap does not present a single path for achieving these goals, but rather provides a process for evaluating a set of options from which DOE and industry can select to accelerate power tower R&D, cost reductions, and commercial deployment.

Contents

List of Figures

List of Tables

1. Introduction

In recent years there has been a resurgent interest in concentrating solar power (CSP) power tower technologies, with at least five companies currently pursuing the development of commercial power tower projects: Abengoa Solar, BrightSource Energy, eSolar, SolarReserve, and SENER. One of the reasons for the renewed interest in power tower technology is that power towers offer high efficiencies and, therefore, the opportunity for low-cost electricity. In addition, power towers can readily integrate thermal energy storage into their operation to achieve high capacity factors, which can provide for cost-effective, dispatchable electricity to serve the needs of the intermediate and baseload power markets.

In March 2010, the U.S. Department of Energy (DOE) and Sandia National Laboratories hosted a Power Tower Roadmap Workshop that included participation of the power tower industry, the national laboratories, and DOE. At the workshop, areas of discussion included the current status of power tower technology, a number of Technology Improvement Opportunities (TIOs), and cost-reduction goals for power tower systems and subsystems. After the workshop, further evaluation of the TIOs was performed, resulting in a levelized cost of energy (LCOE) analysis that identified the potential for a 40% reduction in power tower LCOE by the end of the decade. If this LCOE reduction can be achieved, power towers will likely become competitive with newly constructed conventional fossil-fired power plants in both the intermediate and baseload power markets.

Commercial power tower plants with power ratings greater than 100 MW$_e$ or more are now being pursued and constructed in the USA. These tower projects are more than ten times larger than the 10 MW$_e$ Solar One and Solar Two power tower demonstrations sponsored by DOE in the 1980s and 1990s. The success of these first projects should lead to investment in future power tower projects. For commercial power tower projects to be successful, close cooperation will be required among all stakeholders, including the power tower industry, DOE, national laboratories, international partners, utilities, and the financial community.

1.1. Power Tower Background

The Solar One project — a joint undertaking of the U.S. DOE, Southern California Edison Company (SCE), Los Angeles Department of Water and Power, and the California Energy Commission — was a 10 MW$_e$ water-steam solar power tower facility built in Barstow, CA. Solar One was instrumental in helping to prove that central receiver technology is effective, reliable, and practical for utility-scale power generation. It operated from 1982 to 1988 and ultimately achieved 96% availability during hours of sunshine [1].

A few years later, the Solar One steam-receiver plant was redesigned into a power tower plant named Solar Two, which employed a molten-salt receiver and thermal energy storage system. The change from steam to a molten-salt working fluid was made primarily because of the ease of integrating a highly efficient (~99%) and low-cost energy storage system into a molten-salt plant design. The project was developed by the U.S. DOE along with a consortium of utilities led by SCE. Solar Two operated from 1996 to 1999 and helped validate nitrate salt technology, reduce the technical and economic risks of power towers, and stimulate the commercialization of CSP power tower technology. The baseline power tower used in this roadmap utilizes the data generated by the Solar Two project.

Due to budget constraints, DOE removed most power tower activities from the CSP Program portfolio after the decommissioning of Solar Two. As a result, virtually no work was performed on power towers in the U.S. for nearly a decade. Recent increases in budgets and a renewed interest in power towers have led the DOE CSP Program to reintroduce power towers into its portfolio. As mentioned above, the primary reasons for this reintroduction are the broad interest among industry to develop power towers, the potential for high-temperature operation, and the ability to effectively integrate thermal energy storage, thereby producing dispatchable electricity.

Experimental power tower test facilities are currently located at Sandia's National Solar Thermal Test Facility (NSTTF) in Albuquerque, New Mexico, USA; the Plataforma Solar de Almeria in Spain; the Julich Solar Tower in Germany; the Weizmann Institute of Science in Israel; the CSIRO National Solar Energy Centre in Australia; and the Odeillo and THEMIS Solar Power Towers in France. In addition, private industry has built small-scale tower demonstration facilities in the USA, Spain, and Israel.

Commercial electricity-generating power tower plants in operation today include Abengoa's PS10 (11 MW_e) and PS20 (20 MW_e) steam towers in Spain and eSolar's Sierra SunTower (5 MW_e) steam towers in California. Commercial electricity-generating power tower plants under construction include BrightSource Energy's Ivanpah (392 MW_e) steam towers in California and Torresol Energy's (SENER and Masdar) Gemasolar (17 MW_e) molten-salt tower in Spain. SolarReserve has also announced their intention to construct utility-scale, molten-salt power towers near Tonopah, Nevada, and Palm Springs, California.

1.2. Roadmap Approach

As outlined in the DOE Solar Energy Technologies Program (SETP) Multi-Year Program Plan 2007-2011, the development of a technology roadmap consists of four steps:

1. Determine baseline and goals for component costs and performance;

2. Identify technology improvement opportunities (TIOs);

3. Assess and prioritize TIOs; and

4. Develop a multi-year task portfolio.

The first three steps of this process were initiated at a Power Tower Roadmap Workshop held at Sandia's NSTTF in Albuquerque, NM on March 24-25, 2010. Participants were asked to discuss costs, performance, and research needs for the following subsystems:

1. Solar Collector Field (Heliostats);

2. Solar Receiver;

3. Thermal Energy Storage; and

4. Power Block / Balance of Plant.

During the workshop, facilitators led group discussions in each of these four areas. Current and future costs were collectively discussed, and R&D needs associated with component performance and cost reductions were identified. At the end of the two-day workshop,

participants prioritized the topics they thought were most important for cost reduction and could be supported by DOE, and the results were then tabulated. After the workshop, Sandia conducted a more detailed assessment of the potential impact of the identified TIOs on LCOE.

1.3. Purpose and Objectives

One of the goals of the DOE CSP Program is to achieve large-scale deployment of CSP technologies, including power tower systems, so that they become major contributors to domestic energy supply. Of course, deployment will be encouraged by lower power tower system costs, higher costs of the competition (e.g. carbon pricing), or a combination of the two. However, large-scale deployment will also require that utilities and investors observe the successful operation of power tower plants and recognize the value of energy storage and dispatchability of electricity. There are currently Power Purchase Agreements (PPAs) for approximately 8,200 MW of new CSP plants in the U.S. and, of these, approximately 3,100 MW involve power towers [2]. For even a fraction of these plants to be financed and built, it is critically important that the first round of new plants be successful. DOE and the national laboratories can provide support for these first commercial power tower projects, including component testing, systems analysis, process optimization, and rapid feedback to industry.

DOE has developed this Power Tower Technology Roadmap to describe the current technology, the improvement opportunities that exist for the technology, and the specific activities needed to reach the DOE programmatic target of providing competitively-priced electricity in the intermediate and baseload power markets by 2020. The roadmap will be used to evaluate the current DOE CSP Program portfolio and guide future funding areas and budget allocations. Furthermore, it will be a source of input for the next Solar Energy Technologies Program (SETP) Multi-Year Plan.

The remainder of this roadmap is broken into the following three main sections:

- Power Tower Cost and Performance Goals: describes the baseline system, current costs, and cost goals for power tower systems;

- Technology Improvement Opportunities: identifies and discusses specific TIOs that will lead to the required cost reductions; and

- Recommended Activities and Spend Plan: provides a 10-year schedule of potential programmatic activities, costs, and their impact on LCOE.

2. Power Tower Cost and Performance Goals

In 2009, the DOE CSP Program set a goal to reduce the LCOE of CSP technology of a hypothetical 100 MW plant from today's costs of approximately 15¢/kWh to a value in 2020 of 9¢/kWh or less.[1] In other words, the goal was to cut the cost by 40% over ten years. Although a 30% investment tax credit (ITC) is in effect until 2016, this analysis uses a 10% ITC for both present and future costs to reveal the actual improvement that is necessary.

Table 1 summarizes the baseline costs and future cost goals for power tower subsystems.

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[1] In 2011, this goal was updated to a value of 6¢/kWh or less with no subsidies by the end of the decade as part of the DOE SunShot Initiative. For more information, see Section 5.

Table 1. Baseline costs and Roadmap Workshop cost goals for commercial power towers

	Solar Field	Solar Receiver	Thermal Storage	Power Block	Steam Generation	O&M
Today's Baseline	$200/m^2	$200/kW$_t$	$30/kWh$_t$	$1000/kW$_e$	$350/kW$_e$	$65/kW-yr
Workshop Goal	$120/m^2	$170/kW$_t$	$20/kWh$_t$	$800/kW$_e$	$250/kW$_e$	$50/kW-yr

The baseline costs identified above are based on information from four sources:

- responses to a confidential questionnaire that was distributed by Sandia to power tower developers;

- escalation to 2010 dollars of power tower subsystem costs reported in the 1988 U.S. Utility Study [3];

- a recent study by Abengoa Solar that included molten-salt power towers [4]; and

- a 2007 study of heliostat costs by Sandia National Laboratories [5].

The baseline power tower used in this roadmap is a 100 MW$_e$ plant assumed to have a solar multiple of 2.1, a heliostat field size slightly larger than 1,000,000 m^2, a 540 MW$_t$ surround receiver, and 9 hours of thermal storage. The receiver and field size represent a direct scale-up of the technology demonstrated at DOE's Solar Two project. Furthermore, this baseline is only 15% larger than the plant that was chosen for the U.S. Utility Study, allowing for a more direct use of the cost data that was developed in that study. Given a power tower plant with a 540 MW$_t$ receiver and a 100 MW$_e$ turbine, the System Advisor Model (SAM) predicts the lowest LCOE to result with 9 hours (i.e. 2340 MWh$_t$) of 2-tank, sensible heat, molten-salt thermal storage. It should be noted that the majority of U.S. utilities do not presently value storage beyond a few hours; however, the focus of this analysis is reaching the lowest possible LCOE[2]. Using the baseline subsystem costs shown in Table 1, SAM models were run to predict the performance of a baseline plant with a direct capital cost of $552M and an indirect cost of $192M, yielding a total installed cost of $744M, or $7400/kW. The annual capacity factor of the baseline plant is 48%. As shown in Figure 1, the LCOE for this plant with a 10% ITC is 15.0¢/kWh. Figure 1 also includes the LCOE impact of realizing the cost goals displayed in Table 1. If these targets are reached, power tower systems can achieve a real LCOE of less than 8¢/kWh.

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[2] If the same 540 MW$_t$ receiver is coupled with a 200 MW$_e$ turbine, the optimum amount of storage is only a few hours.
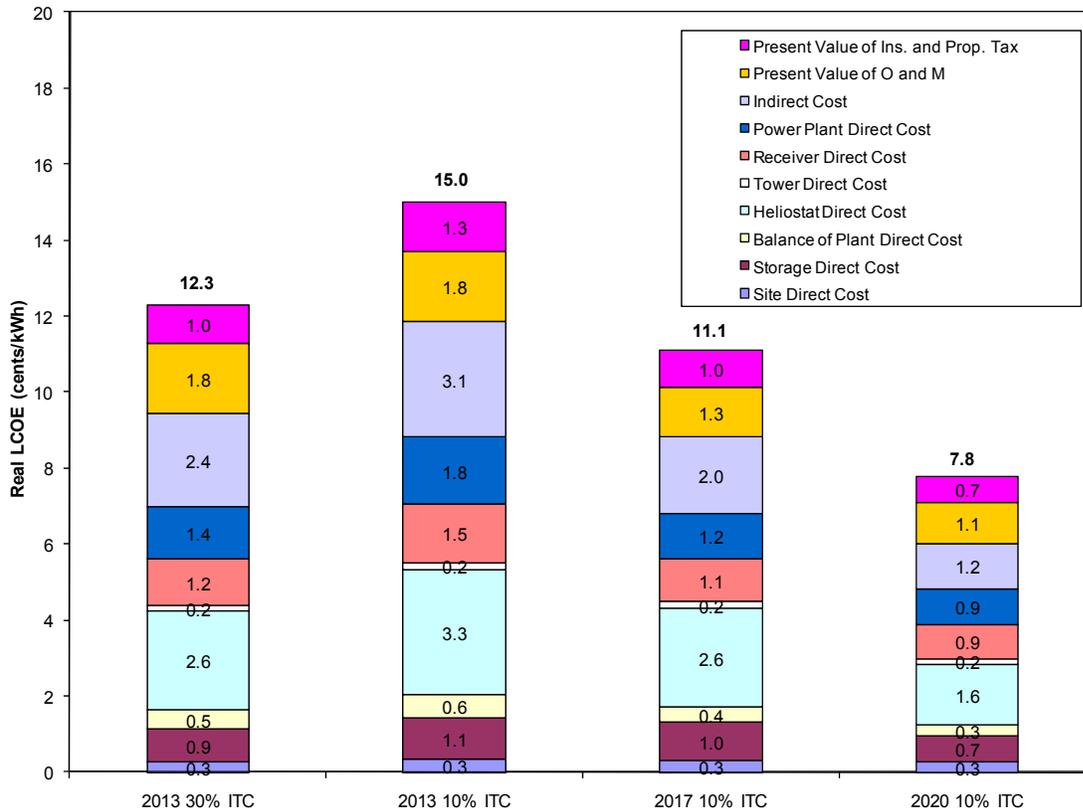
Figure 1. Projected LCOE (real 2010 dollars) and associated costs of individual components (The 2013 case is shown with both a 30% and 10% ITC)

The total installed cost is the sum of direct and indirect costs; direct costs are essentially the capital costs of the plant, and indirect costs are obtained by multiplying direct costs by a given percentage. For the 2013 10% ITC case in Figure 1, direct costs alone account for 8.8¢/kWh of the 15.0¢/kWh total. Of this 8.8¢/kWh, direct costs break out into 3.3¢/kWh (38%) for heliostats, 1.8¢/kWh (20%) for power plant, 1.7¢/kWh (19%) for receiver/tower, 1.1¢/kWh (13%) for storage, 0.6¢/kWh (7%) for balance of plant, and 0.3¢/kWh (3%) for site preparation. The cost breakdowns for the four main subsystems—solar collector field, solar receiver, thermal energy storage, and power block / balance of plant—are detailed in the following sections of this roadmap.

It is important to note that the predicted baseline LCOEs for steam and molten-salt power tower technologies are nearly identical. Although the analysis presented in Figure 1 is based on a molten-salt power tower with several hours of energy storage, modeling a steam tower system with little to no storage results in an LCOE prediction within 1¢/kWh of the 2013 values shown in Figure 1. In addition, much of the cost reduction potential identified for molten-salt power towers also applies to steam receiver towers.

3. Technology Improvement Opportunities (TIOs)

From a technical standpoint, the LCOE of a power tower can be reduced in two ways: 1) by increasing annual performance of the plant (both initial and long-term) and 2) by lowering costs

of the plant (both capital and O&M). This roadmap addresses both avenues to power tower plant cost reduction.

Power tower performance can be increased by:
- improving plant availability;
- improving the optical efficiency (including tracking accuracy) of the heliostat field;
- reducing the thermal losses of the receiver;
- increasing receiver operating temperature to power higher-efficiency power cycles;
- increasing thermal storage efficiency; and/or
- reducing parasitic losses and improving operational efficiency.

One way to characterize the annual performance of a power tower plant is through annual solar-to-electric conversion efficiency. This metric includes all of the energy losses that affect the annual electricity produced by the plant, including optical, thermal, electrical parasitics, and equipment unavailability losses.

During Solar One's final year of operation (1988), the annual efficiency was 10.7% gross and 7.7% net (including parasitics) given the achieved plant availability of 96% [1]. Solar Two did not operate long enough to achieve a reliable daily operation; while Solar One operated for 10,000 hours, Solar Two operated for less than 2,000 hours. Thus, it is difficult to estimate an annual efficiency for Solar Two. During PS10's second year of operation (2008), the annual efficiency was 11.5% gross.[3] Since parasitics were not reported, a net annual efficiency could not be estimated.

Due to their small size, the power blocks for Solar One and PS10 did not incorporate a reheat loop, which resulted in a relatively low thermal-to-electric conversion efficiency of approximately 31%. However, reheat will be incorporated into each of the three steam power towers at Ivanpah, which will raise turbine thermal-to-electric conversion efficiency to approximately 42%. If Solar One or PS10 had used reheat, the gross annual efficiencies would have been approximately 15%, which may represent a good target for future water-steam power towers.[4]

The annual efficiency predicted using SAM (Beta version) for the baseline 100 MW_e molten-salt power tower plant operating in Barstow, California is 16.0% gross and 14.8% net assuming a plant availability of 90%. These values are nearly identical to the efficiency values (16.3% gross and 14.6% net) predicted using the SOLERGY code in 1999 for a commercial molten-salt power tower based on lessons learned from Solar Two [1]. Thus, these values are used as the annual efficiencies for the baseline molten-salt power tower.

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[3] PS10 produced 21,400 MWh (gross) in 2008 [6]. The plant is allowed to burn 15% natural gas. Annual DNI in Sevilla near the plant was approximately 2.1 MWh/m^2 in 2008 [7]. Heliostat field area is 74,880 m^2. Thus, 21400*0.85/(74880*2.1) = 11.5%.

[4] Peak efficiencies (i.e. design point) for power towers typically exceed 22%. However, annual efficiency is used here rather than peak efficiency because annual efficiency is more relevant for LCOE calculations. Some power tower developers predict annual efficiencies of 18% or higher; however, such analyses usually assume 100% equipment availability and/or perfectly clean mirrors. The values contained in this roadmap assume outages and other real-world effects.

Power tower cost can be reduced by:

- reducing equipment capital cost via reduced material content, lower-cost materials, more efficient design, or less expensive manufacturing and shipping costs;
- reducing field assembly and installation costs via simpler designs and minimization and/or ease of field assembly;
- lowering operation and maintenance costs through improved automation, reducing need (as with more reliable components), and better O&M techniques;
- building larger systems that provide economies of scale; and/or
- deploying more systems to benefit from learning-curve effects.

The cost of electricity generated by a solar power tower system is dependent on the capital cost, the annual performance, and the annual operations and maintenance cost.[5] The capital equipment for a power tower plant consists of solar components (heliostats, solar receivers, steam generators, and storage) and the use of more-or-less conventional Rankine-steam-cycle components. While current tower projects utilize subcritical Rankine steam cycles, it is feasible for power towers to transition to supercritical Rankine steam cycles that operate at higher temperatures and convert solar heat at a much higher efficiency (50% thermal-to-electric efficiency for supercritical versus 42% for subcritical). This roadmap focuses on improvements to the solar-specific components; however, the need to adapt existing supercritical Rankine plant equipment for power tower applications is also addressed.

In the following sections, potential opportunities for performance improvement and cost reduction in the four subsystem areas, as well as O&M, are described.

3.1. Solar Collector Field

3.1.1 Current Status

There is no consensus among power tower developers regarding the optimum size of a heliostat, and heliostats ranging between 1 m^2 and 130 m^2 are being developed. Simplified heliostat-scaling theory, described in Sandia's Heliostat Cost Reduction Study [5], indicates that capital costs can be proportional to Area$^{1.5}$, which would favor smaller heliostats. However, the more detailed investigation described in the same study (including O&M, field wiring, and some manufacturing quotes on heliostat subcomponents) show that lowest life-cycle cost may ultimately be achieved with heliostats larger than 50 m^2. The optimum heliostat size — if in fact one exists — will be better understood as the power tower industry continues to deploy and operate more systems.

As shown in Table 2, the current cost of the solar field is dominated by four components for both large and small heliostats. For large heliostats, the major cost drivers are drives (27%); manufacturing facilities / profit (23%); mirror modules (22%); and pedestal / mirror support structure / foundation (19%). For small heliostats, the major cost drivers are drives (30%); manufacturing facilities / profit (23%); field wiring and controls (19%); and mirror modules (16%). It is interesting to note that "pedestal / mirror support structure / foundation" costs

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[5] Electricity cost is also dependent on financial assumptions. The financial assumptions used in this analysis are the SAM default values assuming plant ownership by an independent power producer.

13

impact large heliostats more than small heliostats, as large heliostats experience higher wind loads and require more structural steel (per m^2 of surface area) to maintain a rigid structure and survive worst-case wind storms. It is also interesting to note that "field wiring and controls" costs impact small heliostats more than large heliostats, as small heliostats require more complex field wiring and controls due to the increased number of heliostats in the field.

Table 2. Cost of solar collector field subsystem [\$/m^2] expressed in 2010 dollars [5]

Heliostat Component	30 m^2 size 235,000 m^2 7800 helios one time	148 m^2 size 235,000 m^2 1600 helios one time	148 m^2 size 740,000 m^2/yr 5,000 helios/yr	148 m^2 size 7,400,000 m^2/yr 50,000 helios/yr	Roadmap Workshop Baseline
Mirror Modules	39	43	29	25	–
Drives	71	52	52	29	–
Pedestal, Mirror Support Structure, Foundation	17	38	48	44	–
Controls and Wired Connections	27	8	5	4	–
Field Wiring	18	8	9	8	–
Manufacturing Facilities and Profit	54	45	26	20	–
Installation and Checkout	11	4	8	7	–
Total Capital Cost	**\$237/m^2**	**\$196/m^2**	**\$177/m^2**	**\$137/m^2**	**\$200/m^2**
O&M Cost (life-cycle cost)	\$16/m^2	\$7/m^2	–	–	–

As mentioned above, the Roadmap Workshop Baseline cost is a "rolled-up" value based primarily on responses obtained during the Roadmap Workshop. Columns 1 and 2 of Table 2 were estimated in year 2000, and columns 3 and 4 were estimated in year 2006. Due to minor changes in certain aspects of the cost categorization between 2000 and 2006, a normalization

using the year 2000 categories was performed.[6] The values in Table 2 indicate that large heliostats may have lower capital and O&M costs when supplying heliostats for a single plant (comparing columns 1 and 2).[7] However, small heliostats display better optical performance than large heliostats and, with a performance improvement value of $10/m^2 or more, the cost differential is narrowed [5]. Table 2 also indicates that multi-plant / multi-year-production scenarios can significantly reduce the cost for a given heliostat design (comparing columns 2 and 3) and that ramping up to a highly automated production line also has a significant impact on cost reduction (comparing columns 3 and 4).

3.1.2 Future Improvement Opportunities

The solar collector field (materials plus labor) is the largest single capital investment in a power tower plant, and thus represents the greatest potential for LCOE cost reduction among capital equipment costs. Unfortunately, a comprehensive DOE R&D plan for power tower solar fields is complicated by the variations in heliostat designs among industry. As described above, each commercial power tower company is developing their own heliostat, ranging in size from 1 m^2 to 130 m^2. Thus, the solar field TIOs identified attempt to focus on common areas that would be beneficial to the industry at large. These include:

- Drives and controls: The most expensive part of the heliostat is the azimuth drive, and therefore next-generation, low-cost drives that employ less conservative or alternative designs must be developed. Control algorithms that maintain less than 1 milliradian pointing accuracy are also needed for accurate positioning of heliostats at long slant ranges (i.e. for large fields).

- Heliostat support structure: Survival wind-loads dominate heliostat design criteria, and therefore experimental validation of models is necessary to optimize future heliostat designs that are more material-efficient. The optical and structural performance of today's heliostats must be fully characterized during operating and high-wind conditions through both analytical modeling and empirical experimentation.

- Manufacturing facilities: Highly-automated facilities and equipment to support the low-cost manufacture and installation of heliostats will lead to cost reduction. Improved construction, assembly, and installation methods can reduce construction time, which in turn reduces financial risk and improves time to market.

- Reflectors, coatings, and cleaning techniques: Optical efficiency is critical to overall plant performance, and a highly reflective facet surface — in terms of both total hemispherical and specular reflectance — is the first step in minimizing optical losses. In addition, passive (e.g. anti-soiling coatings) and active (e.g. optimized low-to-no water cleaning techniques) methods of keeping the reflector surface clean play a key role in reducing the O&M of the solar field. Developing low-cost reflectors —

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[6] See Appendix A of [5] to fully understand the cost categories defined in year 2000. A few relatively small inconsistencies can be seen between the year 2000 and year 2006 studies; for example, mirror support structure and installation and checkout costs increased in year 2006 even though production rates were higher in the 2006 study.

[7] Reflector area would power an early-deployment plant on the order of 30 MW$_e$.

both glass and non-glass — with increased reflectivity and durability is also imperative to reducing the cost of heliostats.

Figure 2 shows the potential impact of solar collector field cost reductions and performance improvements on LCOE. Results are based on the baseline power tower model with individual parameters varied one at a time in SAM.[8]
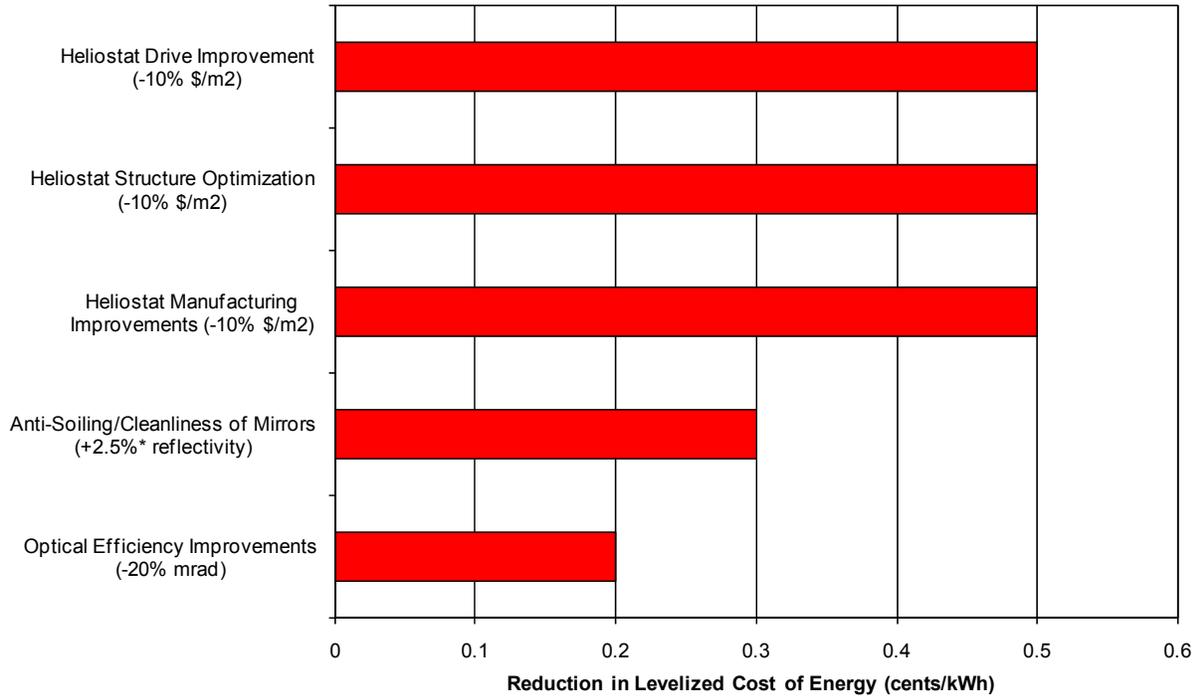
Figure 2. Potential impact of solar collector field cost reductions and performance improvements on LCOE (*absolute percentage improvement)

3.2. Solar Receiver

3.2.1 Current Status

The baseline solar receiver is a scaled-up version of the receiver used at Solar Two. The external receiver used at Solar Two consisted of 24 panels of thin-walled, metal tubes through which salt flowed in a serpentine path. The panels formed a cylindrical shell that surrounded the associated piping, structural supports, and control equipment. The external surfaces of the tubes were coated with a black Pyromark paint that provided an absorptivity of 95% and an emissivity of 88%. The receiver was designed to accept a maximum amount of solar energy in a minimum area to reduce heat losses due to convection and radiation. In terms of function and basic

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[8] The results shown in Figure 2 are not additive; in other words, the overall impact of simultaneously implementing all of the TIOs is less than and not the sum of the individual cost reductions.

description, a steam receiver is similar to a molten-salt receiver; however, steam receivers are a more mature technology than molten-salt receivers.

Table 3 identifies the costs associated with a typical molten-salt solar receiver system using a single tower. The cost of the receiver system is dominated by two components: the solar receiver (59%) and tower (21%). The calculations are based on the Utility Study plant since it is closer in size to the baseline plant.

As mentioned above, the Roadmap Workshop Baseline cost is a "rolled-up" value based primarily on responses obtained during the Roadmap Workshop. Whereas columns 1 and 2 are from single studies, column 3 represents a consolidated value from numerous individuals and organizations, which may explain the discrepancy in receiver costs. Furthermore, the discrepancy in receiver costs may also be attributable to different receiver sizes.

Table 3. Cost of solar receiver subsystem [$/kW$_t$] expressed in 2010 dollars

Receiver System Component	Utility Studies 470 MW$_t$	Abengoa Study 910 MW$_t$	Roadmap Workshop Baseline
Receiver	71	58	–
Tower	25	27	–
Riser/Downcomer	16	13	–
Cold Salt Pumps	6	7	–
Controls and Instruments	1	1	–
Spare Parts and Other Directs	1	3	–
Contingency	18	16	–
Total Capital Cost	**$138/kW$_t$**	**$125/kW$_t$**	**$200/kW$_t$**

3.2.2 Future Improvement Opportunities

Smaller and simpler receivers will result in higher efficiencies (due to reduced heat-loss area) and improved reliability. For advanced central receivers, this translates into a durable, high-temperature absorber (solar spectrum) with reduced thermal emissivity (infrared) that is capable of operating unprotected in ambient air conditions. Specific TIOs identified to achieve these design characteristics include:

- High thermal conversion efficiency and receiver materials database: One way to increase thermal-to-electric conversion efficiency is by interfacing a power tower with a supercritical Rankine cycle, which can be accomplished by raising the receiver outlet temperature to approximately 650°C. Thus, receiver tube materials that can reliably operate above 650°C with incident flux concentrations exceeding 1000 suns

must be developed or identified, evaluated, and catalogued.

- Solar selective absorbers and coatings: Current receiver surfaces possess a high solar absorptivity but do not possess low infrared emissivity. New materials and formulations must be examined that exhibit the desired thermal/optical properties and are resistant to oxidation or degradation when operating in air. Thermal cycling testing is also required to ensure candidate materials can operate over a wide range of temperatures for many years.

- Receiver thermal loss and flux measurements: Characterization of thermal losses and incident fluxes for a thermal receiver will lead to optimized receiver designs. Thermal losses from a receiver are primarily the result of radiation and convection to the environment. A rotating flux mapper for characterizing the solar flux incident on the receiver is currently under development at Sandia, and other advanced measurement techniques are necessary to accurately characterize and evaluate receiver designs and optical surface characteristics at high temperatures.

- Steam receiver studies and optimization: Current steam receivers are based on mature steam boiler technology and designs. Further development of direct steam receivers can be achieved through studies, monitoring, and optimization of initial commercial steam-receiver power tower plants.

- Tall tower acceptance: Towers that exceed 100 meters in height are typically used in commercial power tower projects. As can be expected, public opinion of such tall structures is mixed; while some have a positive reaction to the aesthetics of power towers, others take a more negative view. The U.S. Air Force (USAF) has also expressed concern that power towers may encroach on their flight testing grounds in the desert Southwest. The USAF and DOE are working together to address these concerns. In addition, Sandia currently performs glint and glare studies and participates in public meetings to support power tower acceptance.

Figure 3 shows the potential impact of solar receiver cost reductions and performance improvements on LCOE. Results are based on the baseline model with individual parameters varied one at a time in SAM.[9]

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[9] The results shown in Figure 3 are not additive; in other words, the overall impact of simultaneously implementing all of the TIOs is less than and not the sum of the individual cost reductions.
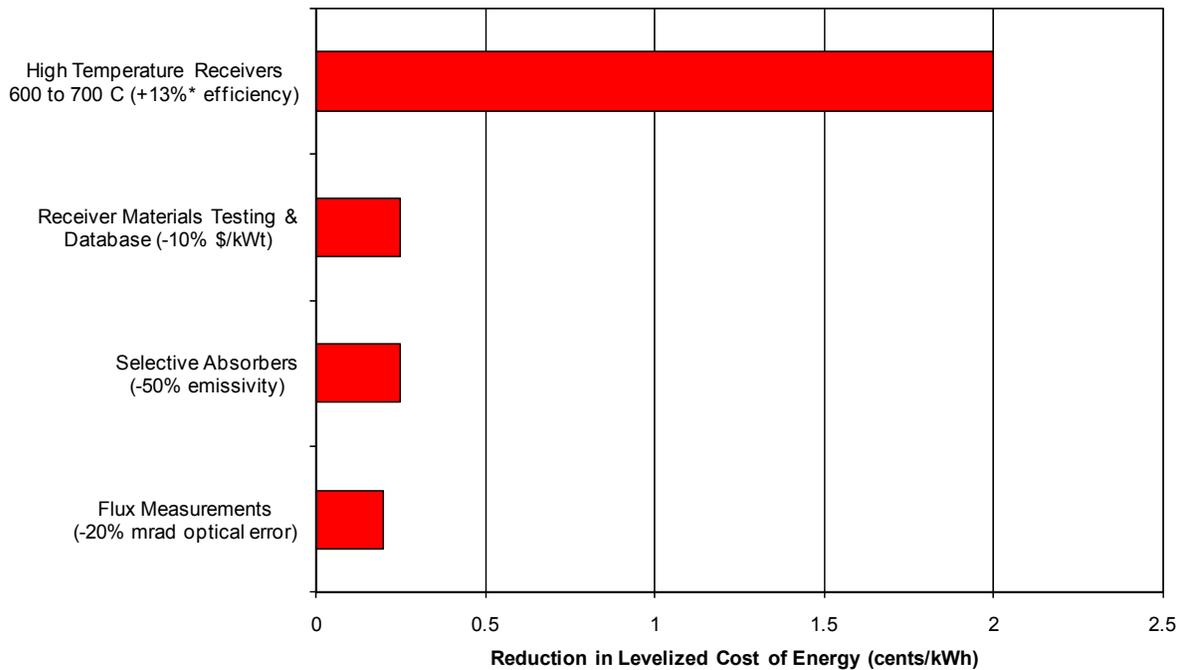
Figure 3. Potential impact of solar receiver cost reductions and performance improvements on LCOE (*absolute percentage improvement)

3.3. Thermal Energy Storage

3.3.1 Current Status

The 2-tank, sensible-heat molten-salt thermal storage system is the current state-of-the-art for power towers. This storage configuration was originally demonstrated at Solar Two and has been adapted for use in commercial trough systems deployed in Spain. As shown in Table 4, the cost of this type of storage system is dominated by two components: salt media (57%) and tanks (29%). The calculation is based on the Utility Study plant since it is closer in size to the baseline plant.

As mentioned above, the Roadmap Workshop Baseline cost is a "rolled-up" value based primarily on responses obtained during the Roadmap Workshop. Whereas columns 1 and 2 are from single studies, column 3 represents a consolidated value from numerous individuals and organizations, which may explain the discrepancy in storage costs. Furthermore, the discrepancy in storage costs may also be attributable to different storage sizes.

Table 4. Cost of thermal energy storage subsystem [\$/kWh$_t$] expressed in 2010 dollars

Storage System Component	Utility Studies 1560 MWh	Abengoa Study 8140 MWh	Roadmap Workshop Baseline
Tanks	6	6	–
Foundations	0.7	1	–
Salt Media	12	11	–
Piping and Small Support Pumps	1	0.2	–
Controls and Instrumentation	0.5	0.1	–
Spare Parts and Other Directs	1	0.9	–
Contingency	4	3	–
Total Capital Cost	**\$25/kWh$_t$**	**\$22/kWh$_t$**	**\$30/kWh$_t$**

3.3.2 Future Improvements Opportunities

In support of advanced heat transfer fluid and thermal storage research, a molten-salt component testing facility is currently under development at Sandia to test hardware at operating conditions. In addition, the DOE CSP Program is currently supporting multiple projects that are exploring a number of thermal storage techniques, including thermoclines, phase change materials, nanoparticle fluids, thermochemical and solid-state storage. Specific TIOs identified in the area of thermal energy storage include:

- Salt valves and other hardware: Valves and other flow-loop hardware need to be improved relative to the experience at Solar Two. There is a particular need for materials suitable for use as valve packing and flange gaskets, as well as for instrumentation (e.g. flow and pressure sensors) capable of operation in a high-temperature molten-salt environment. In addition, the melting of large volumes of salt during facility start-up, along with the NO$_x$ emissions that can occur, is a significant challenge. Sandia will leverage its molten-salt test loop and high-temperature corrosion test facility to evaluate components under realistic conditions.

- High-temperature operation: Thermal storage cost is inversely proportional to the hot and cold temperature differential; in other words, as the temperature differential increases, the capital cost of the storage subsystem is reduced because of the increase in sensible heat capacity, which leads to a reduction in storage media volume and tank size. The baseline 2-tank, molten-salt storage system operates at temperatures of 565°C in the hot tank and 290°C in the cold tank. An increase in temperature to 650°C may be feasible with nitrate salts [8] but will necessitate the use of higher-temperature containment designs. Higher temperature storage also supports high-

efficiency power cycles.

- High-temperature, single tank thermal storage: Replacing the 2-tank storage approach with a 1-tank, thermocline system using liquids or particles has the potential to reduce the cost of the thermal energy storage subsystem. However, thermal ratcheting resulting in increased tank stresses (i.e. thermal cycling causing the thermocline inside the tank to slump, placing excessive pressure on the tank walls) is a serious challenge that must be resolved before the predicted cost reduction can be realized. This problem is exacerbated in power tower thermoclines due to the high temperature differential between the top and bottom of the tank (as high as 300°C). Potential solutions such as tank inserts or sloping tank walls, as well as new materials for fluids and tanks, must be sought.

- Advanced high temperature heat transfer fluids: Power towers can potentially operate at very high temperatures (>1000°C), but available, low-cost, non-exotic engineering materials are required to increase the practical upper temperature limit. These advanced heat transfer fluids will enable high-temperature receivers and high-efficiency power cycles.

- Storage systems for steam towers: Future direct steam power towers will likely include at least a few hours of thermal storage to increase the value of electricity produced and increase capacity factor. Many of the storage options for steam towers are similar to molten-salt towers; however, they must be specifically adapted for compatibility with a direct steam system. Prior research at Sandia has been devoted to studying a variety of storage options for DSG systems [9].

Figure 4 shows the potential impact of thermal energy storage cost reductions and performance improvements on LCOE. Results are based on the baseline model with individual parameters varied one at a time in SAM.[10]

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[10] The results shown in Figure 4 are not additive; in other words, the overall impact of simultaneously implementing all of the TIOs is less than and not the sum of the individual cost reductions.

High Temperature Hardware
(+4%* plant availability)

High Temperature Storage
(-15% $/kWht)

Single Tank Thermocline
Storage (-15% $/kWht)

0   0.1   0.2   0.3   0.4   0.5   0.6   0.7   0.8

Reduction in Levelized Cost of Energy (cents/kWh)
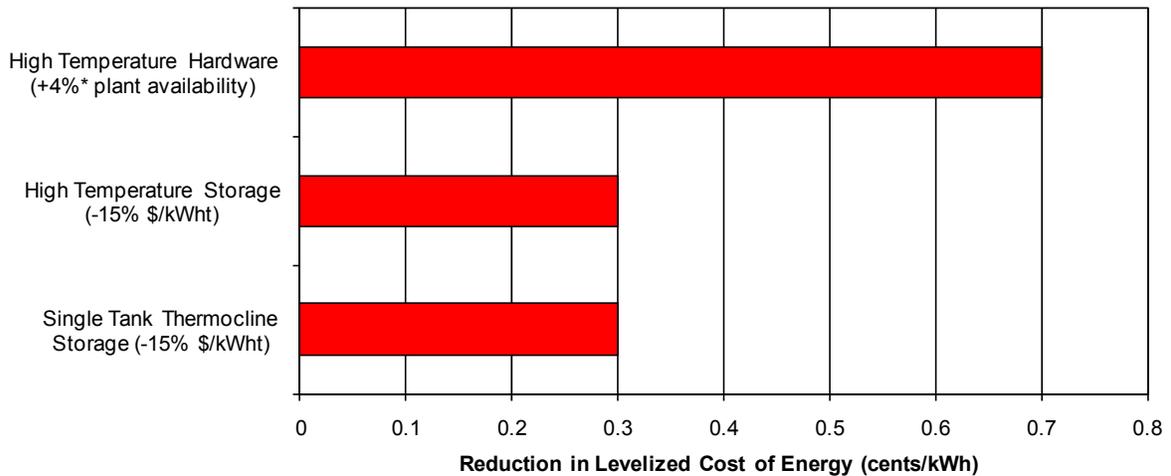
Figure 4. Potential impact of thermal energy storage cost reductions and performance improvements on LCOE (*absolute percentage improvement)

3.4. Power Block / Balance of Plant

3.4.1 Current Status

The current power tower power blocks used in both steam and molten-salt power tower designs have been promoted since the 1980s and utilize steam Rankine cycle components representative of a conventional fossil-fired plant. The baseline power block consists of a molten-salt steam generator that feeds a subcritical Rankine cycle with reheat. The inlet steam temperature is 540°C, and the turbine thermal-to-electric conversion efficiency is approximately 42% with a wet-cooled condenser [1]. While subcritical Rankine cycles are already commercially available in the 100-200 MW$_e$ size range and employ conventional turbomachinary, the molten-salt steam generator is solar-specific hardware that has only been demonstrated at a relatively modest scale.

As shown in Table 5, the cost of the steam generator system is dominated by a single class of components: salt heat exchangers (85%). The calculation is based on the Utility Study plant since it is closest in size to the baseline plant.

As mentioned above, the Roadmap Workshop Baseline cost is a "rolled-up" value based primarily on responses obtained during the Roadmap Workshop. Whereas columns 1 and 2 are from single studies, column 3 represents a consolidated value from numerous individuals and organizations, which may explain the discrepancy in steam generator costs. Furthermore, the discrepancy in steam generator costs may also be attributable to different power block sizes.

Table 5. Cost of steam generator subsystem [$/kW$_e$] expressed in 2010 dollars

Steam Generator System Component	Utility Studies 100 MW$_e$ (260 MW$_t$)	Abengoa Study 400 MW$_e$ (1000 MW$_t$)	Roadmap Workshop Baseline
Heat Exchangers	214	110	–
Structures/Foundations	1	0.5	–
Piping	22	12	–
Hot Salt Pumps	10	12	–
Auxiliary Equipment	3	2	–
Spare Parts and Other Directs	1	9	–
Contingency	38	22	–
Total Capital Cost	**$290/kW$_e$**	**$168/kW$_e$**	**$250/kW$_e$**

3.4.2 Future Improvement Opportunities

Many of the issues surrounding the power block and balance of plant are non-solar in nature and are beyond the scope of the DOE CSP Program; however, "exceptions" do exist. TIOs identified during the Roadmap Workshop include:

- Advanced power cycles: Three advanced power cycles applicable to power towers — supercritical steam Rankine, high temperature air Brayton, and supercritical CO_2 Brayton — offer the potential to increase the efficiency of the power block to nearly 50% relative to today's subcritical steam Rankine cycle efficiency of 42%. The "next step" power cycle is likely supercritical steam Rankine since this cycle readily exists at commercial utility-scale fossil plants. However, existing systems are 400 MW$_e$ or larger and may need to be scaled down to better accommodate power tower systems.

- Parasitic power reduction: Parasitic power consumption at Solar One and Solar Two were relatively high. Although most of the consumption can be attributed to the small size of the plants, studies of proposed commercial-scale plants suggest that parasitics will consume 10% or more of the gross annual electricity. Receiver pumps are a major source of consumption, and thus head-recovery options should be explored to reduce their impact. A campaign to reduce plant-wide parasitics in early commercial plants should also be implemented.[11]

- Hybridization: A promising lower-cost market-entry strategy is augmentation of existing fossil-fired plants with power tower systems. Integration with existing natural-gas combined cycle and coal-fired plants is being studied by EPRI and the

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[11] Simulations with SOLERGY suggest a 50/40/10 parasitics split between turbine plant/solar plant/offline sources for a baseload plant. For a peaking plant without storage, the parasitic split is approximately by 20/30/50.

national laboratories, among others. Hybridization of power towers and existing fossil-fired plants holds several distinct advantages, including reduction in capital and O&M costs through the use of existing power block hardware and O&M crews, respectively. In addition, new "solar-only" power tower plants can benefit from a small amount of fossil backup to ensure dispatchability by increasing capacity factor.

- Dry cooling: Power towers are typically built in desert areas where water is a scarce resource. A standard power tower power block that employs wet cooling requires approximately 650 gallons of water to produce one megawatt-hour of solar electricity [10]. The issue of water use will likely require power towers to transition to dry or hybrid cooling; therefore, a dry cooling system that does not significantly reduce the efficiency of the power block is needed.

- Designs for rapid temperature change: Initial steam receiver power towers will not incorporate a thermal energy storage system. Thus, cloud transients affecting the solar receiver will rapidly impact the operation of the turbine generator. If cloud duration lasts more than a few minutes, steam conditions will degrade and the turbine generator may trip offline. When sun returns, the turbine must be able to quickly restart to mitigate energy losses. The inability to quickly restart the turbine at Solar One led to significant energy losses, and the problem is only intensified in commercial plants.

Figure 5 shows the potential impact of power block cost reductions and performance improvements on LCOE. Results are based on the baseline model with individual parameters varied one at a time in SAM.[12]

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[12] The results shown in Figure 5 are not additive; in other words, the overall impact of simultaneously implementing all of the TIOs is less than and not the sum of the individual cost reductions.
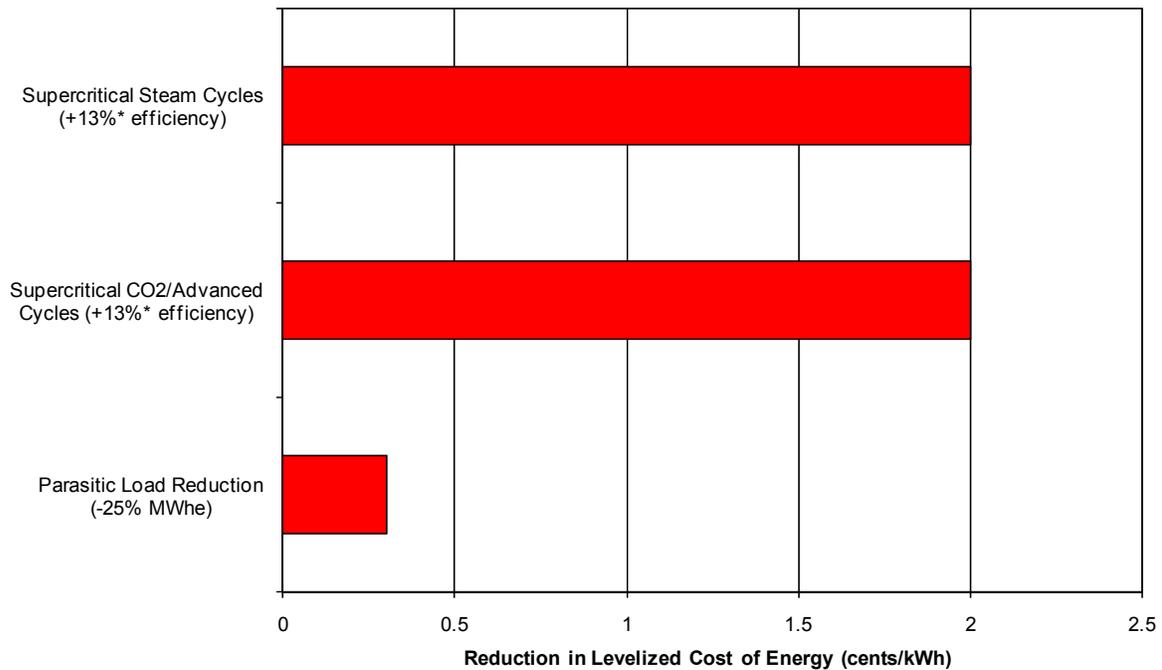
Figure 5. Potential impact of power block and balance of plant cost reductions and performance improvements on LCOE (*absolute percentage improvement)

3.5. Operation and Maintenance Costs

3.5.1 Current Status

Very little data exists on the annual O&M costs for power towers; the best data available to the DOE CSP Program is from Solar One, which operated in a daily power-production mode for approximately four years after the test and evaluation phase was completed. As time progressed at Solar One, fewer O&M personnel were required to maintain a high degree of plant availability.[13] During the final years of Solar One's operation, the SEGS I parabolic trough plant, located near Solar One, began its early phase of commercial operation. Both Solar One and SEGS I produced approximately 10 MW$_e$ of solar power. Based on discussions between key staff from the two plants, it was discovered that the number of O&M staff required for a tower and trough plant is very similar. Thus, to a first order, O&M costs for towers and troughs should be comparable. Sandia worked with the SEGS III-VII trough plants (150 MW$_e$ total) at Kramer Junction, CA throughout the 1990s to reduce O&M costs [9]. Table 6 shows estimated O&M costs for towers (columns 1, 2, and 4) and troughs (column 3).

As mentioned above, the Roadmap Workshop Baseline cost is a "rolled-up" value based primarily on responses obtained during the Roadmap Workshop. Whereas columns 1 and 2 are

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[13] The O&M staff numbered approximately 25 in the third year of operation, compared to 15 in the fourth year.

from single studies, column 4 represents a consolidated value from numerous individuals and organizations, which may explain the discrepancy in O&M costs. Furthermore, the discrepancy in O&M costs may also be attributable to different plant sizes.

Table 6. Cost of O&M [$/kW-yr] expressed in 2010 dollars

	Utility Studies 100 MW$_e$	Abengoa Study 400 MW$_e$	Trough 150 MW$_e$	Roadmap Workshop Baseline
Annual O&M Costs	$87/kW-yr	$67/kW-yr	$100/kW-yr	$65/kW-yr

One reason for the discrepancy between the O&M costs shown for towers and troughs in Table 6 is that the 150 MW$_e$ plant at Kramer Junction is actually composed of five 30 MW$_e$ plants, each with its own turbine and operating crew. If the Kramer Junction facility had only one turbine and operating crew, O&M costs would likely be more in agreement with the tower values.

3.5.2 Future Improvement Opportunities

As the first commercial power towers come online in the USA, the actual O&M costs should be closely monitored, which in turn should lead to plant optimization and O&M cost reduction. As mentioned, the O&M costs of the SEGS plants at Kramer Junction were reduced through collaboration between the plant owner and DOE. The Kramer Junction SEGS plants initially experienced high O&M costs, and a joint project with DOE was established to address the problem. Over a six year period, O&M improvements were made in 28 technical areas, resulting in O&M LCOE cost reductions of over 35% [9]. Figure 6 shows the potential impact of O&M cost reductions and performance improvements on LCOE. Results are based on the baseline model with individual parameters varied one at a time in SAM.
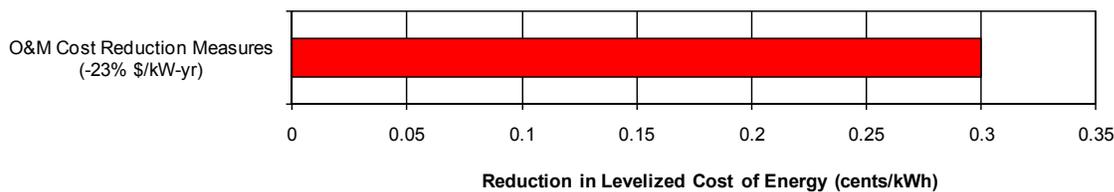
Figure 6. Potential impact of O&M cost reductions and performance improvements on LCOE

3.6. Summary of TIO Impacts

In summary, all four subsystems should be the focus of a cost reduction plan for power towers. The relative importance of each cost category can be identified using the percentage breakdowns described in the preceding sections, which is shown in Table 7. The top three capital-cost categories identified are 1) heliostat drives for both large and small heliostats; 2) receiver module; and 3) manufacturing facilities for both large and small heliostats. In Table 7, the

percentages in column 3 result from the multiplication of the values in columns 1 and 2.

Table 7. Relative ranking of capital cost categories per subsystem[14]

Subsystem Impact on LCOE	Subsystem Capital Cost Breakdown	Total Relative Impact on LCOE
38% Large Heliostats	27% Drives	10.3%
	23% Manufacturing	8.7%
	22% Mirror Modules	8.4%
	19% Structure support	7.2%
38% Small Heliostats	30% Drives	11.4%
	23% Manufacturing	8.7%
	16% Mirror Modules	6.1%
	19% Field Wiring/Control	7.2%
19% Receiver System	59% Receiver Module	11.2%
	21% Tower	4.0%
13% Storage System	57% Salt media	7.4%
	29% Tanks	3.8%
7% Steam Generator	85% Salt Heat Exchangers	6.0%

Figure 7 summarizes the impact of the TIOs on LCOE. It is important to emphasize that each TIO was evaluated independently of the others, and therefore the incremental impact of each TIO on LCOE cannot be added together to determine the cumulative impact of all TIOs on the system LCOE.

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[14] Only the most significant capital cost categories within each subsystem are shown. Thus, totals do not add to 100%.
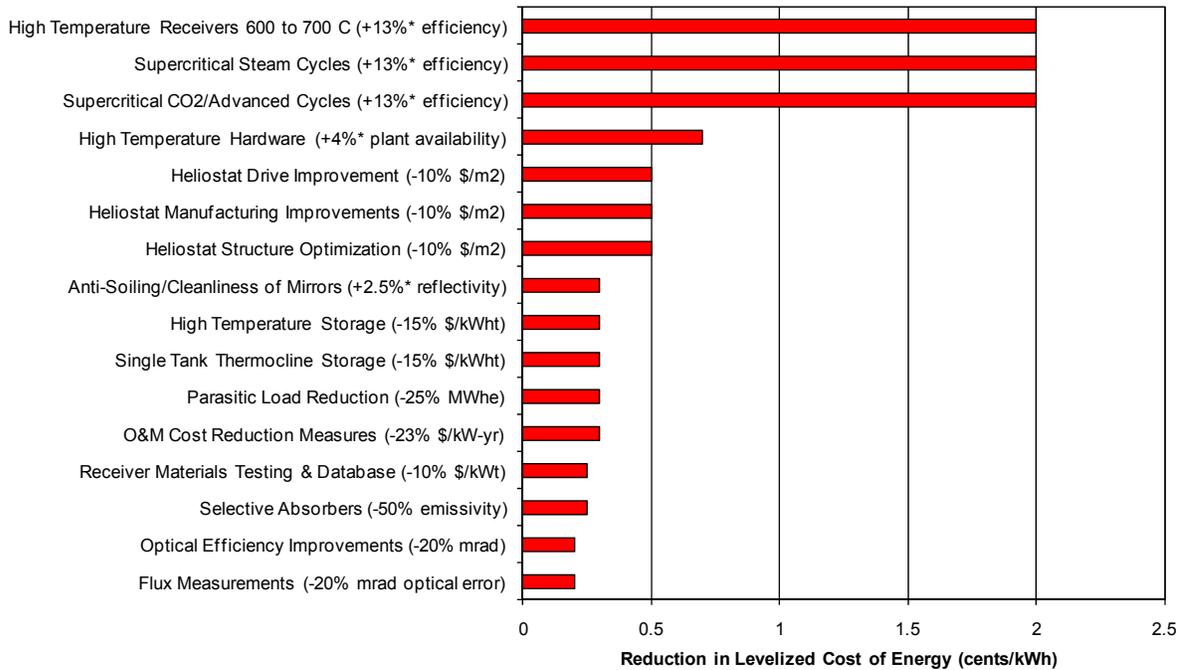
Figure 7. Potential impact of power tower cost reductions and performance improvements on LCOE (*absolute percentage improvement)

4. Recommended Activities and Spend Plan

In this section, specific potential activities to achieve the cost reductions outlined in this roadmap are listed. These activities are largely the product of the TIOs identified during the Roadmap Workshop. SAM simulations were used to estimate the impact of each activity on LCOE. Table 8Table 8, which served as an input into Figure 1, shows projected performance and cost improvement scenarios for years 2013 (improvements "in the pipeline"), 2017, and 2020. The year 2013 case is shown with both a 30% and 10% ITC.

Table 8. Projected performance and cost improvement scenarios

Power Tower Inputs	Case 1 2013 Sandia & Industry Studies	Case 1.1 2013 Sandia & Industry Studies	Comments on Case 2.1 Values	Case 2.1 2017	Comments on Case 3.1 Values	Case 3.1 2020
Design Assumptions:						
Turbine MWe (gross/net)	110/100	110/100		165/150		165/150
Receiver Outlet Temperature (degC)	565	565	Raise salt temperature	600	Raise salt temperature some more	650
Solar Multiple	2.1	2.1		2.6		2.9
Receiver Design Point Rating MWt	540	540		1000		1000
Thermal Storage hours	9	9		13		14
Investment Tax Credit	30%	10%		10%		10%
Cost/Performance Assumptions:						
System Availability	90	90	Learning	94		94
			Higher operating temperature gain is			
Turbine efficiency	0.425	0.425	negated by switch to dry cooling	0.425	Switch to supercritical Rankine cycle	0.48
Heliostat reflectivity	0.935	0.935		0.95		0.95
Heliostat cleanliness	0.95	0.95		0.95		0.975
Heliostat image error (mrad)	1.53	1.53		1.31		1.25
Heliostat Field ($/m2)	200	200		170		120
Receiver emissivity	0.88	0.88		0.88	Selective surface	0.4
Receiver System ($/kWht)	200	200	Plant scale reduces cost	165	Optimized design	150
Thermal Storage ($/kWht)	30	30	Optimized 2 tank, higher temperature	25	Thermocline 1 tank, higher temperature	20
Steam Generator ($/kWe)	350	350	Plant scale reduces cost	300	Optimized design	250
Power Block ($/kWe)	1000	1000	Plant scale reduces cost	900	Optimized design	800
			Start O&M cost reduction project, plant			
O&M ($/kW-yr)	65	65	scale	57	Complete O&M cost reduction project	50
EPC, Project, land (% of direct costs)	35	35		30	Modular plant, learning, lower project risk	25
Outputs						
Total Installed Cost ($/kW)	7427	7427		7403		5677
Debt Fraction (optimized)	41.1	54.2		54.2		54.1
Capacity factor	48.1	48.1		64.5		72
Annual Efficiency (Enet/Q_DNI*SF_area)	14.8%	14.8%		15.7%		17.8%
LCOE (c/kWh, real)	12.3	15.0		11.1		7.8
PPA Price (c/kWh, 1st year)	14.1	17.2		12.7		8.9
LCOE (c/kWh, nominal)	15.6	19.0		14		9.8

A potential multi-year task and spend plan for DOE-funded power tower R&D from FY12 through FY22 is shown in Table 9. Table 9 includes the following for each activity:

- the activity title,

- the activity participants,

- whether it is a new (N) or existing (E) activity,

- the relevant section of this plan to which the activity applies,

- the priority of the activity: high (H), medium (M), or low (L),

- an appropriate metric for the activity,

- the potential improvement in the metric,

- the potential impact of the activity on the levelized cost of electricity (LCOE),

- the time frame: Near, Mid, or Long Term,

- the recommended funding for each activity from FY12 through FY22, and

- a description of the activity.

It should be noted that each activity is individually evaluated; in reality there will be overlap in the contributions of the various activities to LCOE reduction, and thus the potential improvements in the metrics and LCOE cannot simply be added together. The identification of activities as high, medium, or low, as well as near, mid, or long term, was designated through a voting and ranking process during the Roadmap Workshop. *Only high and medium priority activities are displayed in Table 9.* The content of the multi-year task and spend plan in Table 9 is organized to aid DOE in allocating a finite budget. The plan will be periodically revisited and updated based on industry feedback, programmatic objectives, and budget allocations. It is important to recognize that not all activities in the plan are necessary to achieve the target cost goals; the purpose of the plan is to list the R&D options available, from which the activities that will have the highest impact can be selected.

Table 9. Potential multi-year activities and budgets for DOE-funded power tower R&D

AOP Power Tower R&D Activity	Participant(s)	New/ Exist	Plan ID Section	Priority	Metric	Metric Impact	LCOE Impact	Time-frame	FY12	FY13	FY14	FY15	FY16	FY17	FY18	FY19	FY20	FY21	FY22	Description
Heliostats									1650	2250	2450	1250	1050	600	600	400	400	400	400	
Drives	Sandia/Industry	N	3.1.2	H	$/m2	-10%	0.5 ¢/kWh	Near	500	750	750	100	100	100	100	0	0	0	0	Low-cost drive study in FY12. Build and test prototypes in FY13/14. Evauate new drives in commercial plants FY15 to 18.
Optical Methods and Testing	Sandia/NREL	E	3.1.2	H	optical error (mrad)	-20%	0.2 ¢/kWh	Near	200	200	200	200	200	200	200	200	200	200	200	Develop methods in early years. Apply methods to optimize commercial plants in later years.
Wind Loads Measurement and Mitigation	Sandia/NREL	E	3.1.2	H	$/m2	-10%	0.5 ¢/kWh	Near/Mid	250	250	250	250	250	0	0	0	0	0	0	Develop methods and demonstrate on NSTTF heliostats in FY12/13. Measure wind loads at commercial plants FY15/16.
Manufacturing FOA	Sandia/Industry	N	3.1.2	M	$/m2	-10%	0.5 ¢/kWh	Near	500	750	750	200	200	0	0	0	0	0	0	Manfacturing study in FY12. Cost-shared upgrade of manufacturing plant in FY13/14. Optimization of manufacturing process in FY15/16.
Anti-Soiling/Cleaning of Mirrors	NREL/Industry	N	3.1.2	M	Cleanliness	2.5%	0.3 ¢/kWh	Near/Mid	0	100	300	300	100	100	100	0	0	0	0	Evaluation of existing anti-soiling products in FY13. Adapt product for solar application in FY14/15. Evaluate improved product in commercial plants FY16 to 18.
Basic Structure Optimization	Sandia/Industry	E	3.1.2	M	$/m2	-10%	0.5 ¢/kWh	Mid	200	200	200	200	200	200	200	200	200	200	200	Perform CFD analysis of industry heliostats and recommend design improvements
Receiver System									750	1200	2300	5300	2300	2200	2700	1700	1700	1700	1700	
Receiver Materials Testing & Database	Sandia	N	3.2.2	H	$/kWt	-10%	0.25 ¢/kWh	Near/Mid	200	200	200	200	200	200	200	0	0	0	0	Recommend and test receiver materials
Steam Receivers and Hybrid	Sandia/Industry	N	3.2.2	H	Plant Availability	4%	Note 1	Near/Mid	0	100	300	300	300	300	0	0	0	0	0	Work with industry to solve steam-receiver problems that occur at initial commercial plants
Selective Absorbers	Sandia/NREL	E	3.2.2	H	Emissivity	-50%	0.25 ¢/kWh	Mid	200	200	200	200	200	200	1000	200	200	200	200	Continue to develop low-emmissivity coating for central receiver application from FY12-17. Implement a test panel at commercial plant in FY18. Evaluate test panel and improve FY19-22.
High Temperature Receivers (600 to 700 C)	Sandia/Industry	E	3.2.2	H	Thermal-to-Electric Conversion Efficiency	13%	2 ¢/kWh	Mid/Long	150	500	1000	4000	1500	1500	1500	1500	1500	1500	1500	Complete studies to identify preferred next-generation high temperature receivers in FY12 to 14. Upgrade current <600 C test facility to operate up to 650 C in FY15. Through cost-shared projects, build and test next generation high temperature receiver concepts of interest to industry FY16-22.
Flux Measurements	Sandia/Industry	E	3.2.2	M	optical error (mrad)	-20%	0.2 ¢/kWh	Near	100	100	500	500	0	0	0	0	0	0	0	Complete the development and testing of Sandia's receiver flux monitor in FY12/13. Through cost-shared project(s), implement a commercial scale device at existing plant(s) in FY14/15.
Tall Tower Acceptance	Sandia	E	3.2.2	M	Public Acceptance	N/A		Mid	100	100	100	100	100	0	0	0	0	0	0	Continue to perform glint/glare studies and participate in legal proceedings that are important to acquiring an operating permit for commercial tower plants.
Thermal Storage System									1000	1000	1500	6000	1800	6300	1800	1800	1800	1300	1300	
High Temperature Storage	Sandia	N	3.3.2	H	$/kWht	-15%	0.3 ¢/kWh	Mid/Long	0	0	500	5000	500	500	500	500	500	500	500	Perform study in FY14 to identify preferred high-temperature storage to interface with preferred high-temperature receiver identified in FY12-13. Build a multi MWt storage test facility in FY15. Operate and maintain high temperature storage test facility FY16-FY22.
Valves and Non-Welded Flanges	Sandia	E	3.3.2	M	Plant Availability	4%	0.7 ¢/kWh	Near/Mid	500	500	500	500	500	500	500	500	500	500	500	Test valves/components to be used in <600 C towers from FY12-FY15. After FY15, test components for applications up to 650 C.
Single Tank Thermocline Storage	Sandia/University	E	3.3.2	M	$/kWht	-15%	0.3 ¢/kWh	Mid	200	200	200	200	500	5000	500	500	500	0	0	Perform small scales tests at U of Arizona or Purdue to resolve thermal ratcheting and thermocline performance issues from FY12 to 15. Design a multi-MW thermocline system in FY16 and build it in FY17. Test it from FY18-20.
Alternative Fluids at 700 C+	Sandia/NREL	N	3.3.2	M	$/kWht	?		Mid/Long	300	300	300	300	300	300	300	300	300	300	300	Perform basic research on >700 C fluids for power tower application
Power Block/BOP									250	225	375	1000	700	650	550	100	100	100	100	
Low-Water Cooling	NREL/Sandia	N	3.4.2	H	gal/MWh water usage	-75%		Near/Mid	50	25	25	0	0	0	0	0	0	0	0	NREL is leading this effort, as described in Trough Roadmap.
Hi-Efficiency Hybrid Configurations	Industry/Sandia/NREL	E	3.4.2	H	$/kWe	-25%	3 ¢/kWh	Near/Mid	50	50	50	50	50	0	0	0	0	0	0	EPRI and others in industry are studying hybrid solar plants. Sandia/NREL are participating in these studies.
Designs for Rapid Temperature Change	Sandia/Industry	N	3.4.2	M	Annual Efficiency	1pt	Note 1	Near/Mid	0	0	50	300	0	0	0	0	0	0	0	Steam towers need a power block that can rapidly change temperature. In FY14 assess this ability within initial commercial steam towers. If a problem, perform study in FY15 to recommend design changes.
Parasitic Load Reduction	Sandia/Industry	N	3.4.2	M	MWhre	-25%	0.3 ¢/kWh	Near/Mid	0	0	100	100	100	100	0	0	0	0	0	Study the parasitic consumption in early commercial plants and recommend changes to design/operation to reduce parasitics.
Supercritical Steam Cycles	Sandia/Industry	E	3.4.2		Thermal-to-Electric Conversion Efficiency	13%	2 ¢/kWh	Mid/Long	100	100	100	500	500	500	500	50	50	50	50	Establish subcontracts with turbine suppliers to investigate feasibility of scaling down today's 450 MWe turbine to ~150 MWe for tower application. Design/build solar-specific hardware FY15-18.
Supercritical CO2/Advanced Cycles	Sandia/NREL	E	3.4.2		Thermal-to-Electric Conversion Efficiency	13%	2 ¢/kWh	Long	50	50	50	50	50	50	50	50	50	50	50	Keep abreast of advanced alternate power blocks being developed by others. If supercritical steam is no longer preferred, use Supercritical Steam cycle budget to pursue alternate power block.
O&M Cost Reduction									0	100	100	1100	1100	1100	1100	1100	1100	1100	1100	
O&M Analysis of Initial Commercial Plants	Industry/Sandia/NREL	N	3.5.2	H Note 2	$/kW-yr			Near	0	100	100	100	100	100	100	100	100	100	100	Forge relationships with commercial power tower projects and analyze O&M costs.
O&M Cost Reduction Measures	Industry/Sandia/NREL	N	3.5.2	H Note 2	$/kW-yr	-23%	0.3 ¢/kWh	Near	0	0	0	1000	1000	1000	1000	1000	1000	1000	1000	Results of O&M cost analysis will be used to define cost-shared O&M cost reduction and reliability improvement programs.
FOA Support									50	50	0	0	0	0	0	0	0	0	0	
Baseload FOA Support	Industry/Sandia/NREL	E	5		Plant LCOE	-20%	Note 1	Near	50	50	0	0	0	0	0	0	0	0	0	Review ongoing Baseload FOA project
TOTALS									3700	4825	6725	14650	6950	10850	6750	5100	5100	4600	4600	

Note 1: The improvement in this metric assumes the base case power tower is a steam receiver without storage. Base case LCOEs have not been calculated for this type of power tower.
Note 2: Plant-wide O&M cost reduction was not discussed during the Roadmap Workshop. Sandia believes this is an important activity based on our experience with early commercial trough projects.

5. Power Towers and the SunShot Initiative

On February 4, 2011, United States Secretary of Energy Steven Chu officially unveiled the U.S. Department of Energy's SunShot Initiative, an aggressive R&D plan to make large-scale solar energy systems cost competitive without subsidies by 2020. The SunShot Initiative takes a systems-level approach to revolutionary, disruptive (as opposed to incremental) technological advancements in the field of solar energy. The overarching goal of the SunShot Initiative is reaching cost parity with baseload energy rates, estimated to be 5-6¢/kWh without subsidies, which would pave the way for rapid and large-scale adoption of solar electricity across the United States.

For the SunShot Initiative, CSP provides the following benefits:

- *Thermal Energy Storage*: CSP offers a firm, dispatchable solar solution to meet utility demand for power, offsetting some of the intermittency and ramp-rate issues surrounding PV.

- *Hybridization*: Combined with thermal storage, a small amount of natural gas hybridization in a CSP plant can increase capacity to 75-85%, which would allow CSP to displace conventional (e.g. fossil) power plants.

- *Supply Chain*: The CSP supply chain is overwhelmingly domestic, from materials to manufacturing, including significant domestic job creation. Most, if not all, materials necessary to build a CSP plant can be found in the US.

- *Plant Size*: The size of utility-scale CSP facilities is consistent with the SunShot goal of large-scale solar installations. Two CSP plants (BrightSource Energy's Ivanpah and Abengoa Solar's Solana) currently under construction in the U.S. will be the largest and second largest solar plants in the world.

The SunShot Initiative goal for CSP is 6¢/kWh or less. While many of the TIOs identified in this roadmap are applicable to the SunShot cost reduction goal, it is clear that an "extra step" is necessary to move from the power tower roadmap projections — 7.8¢/kWh with a 10% ITC (or 8.6¢/kWh with a 0% ITC) — to the SunShot Initiative goal of 6¢/kWh with no ITC (as shown in Figure 8). Therefore, the DOE CSP Program is currently in the process of defining a corresponding R&D path forward. SunShot-level cost reductions for power towers likely includes an increase in system efficiency by moving to higher temperature operation (i.e. maximize conversion efficiency) without sacrificing efficiency elsewhere in the system (i.e. minimize collection efficiency losses). Likewise, reducing the cost of the solar field and developing high-temperature storage compatible with high-efficiency, high-temperature power cycles are critical to driving costs down.
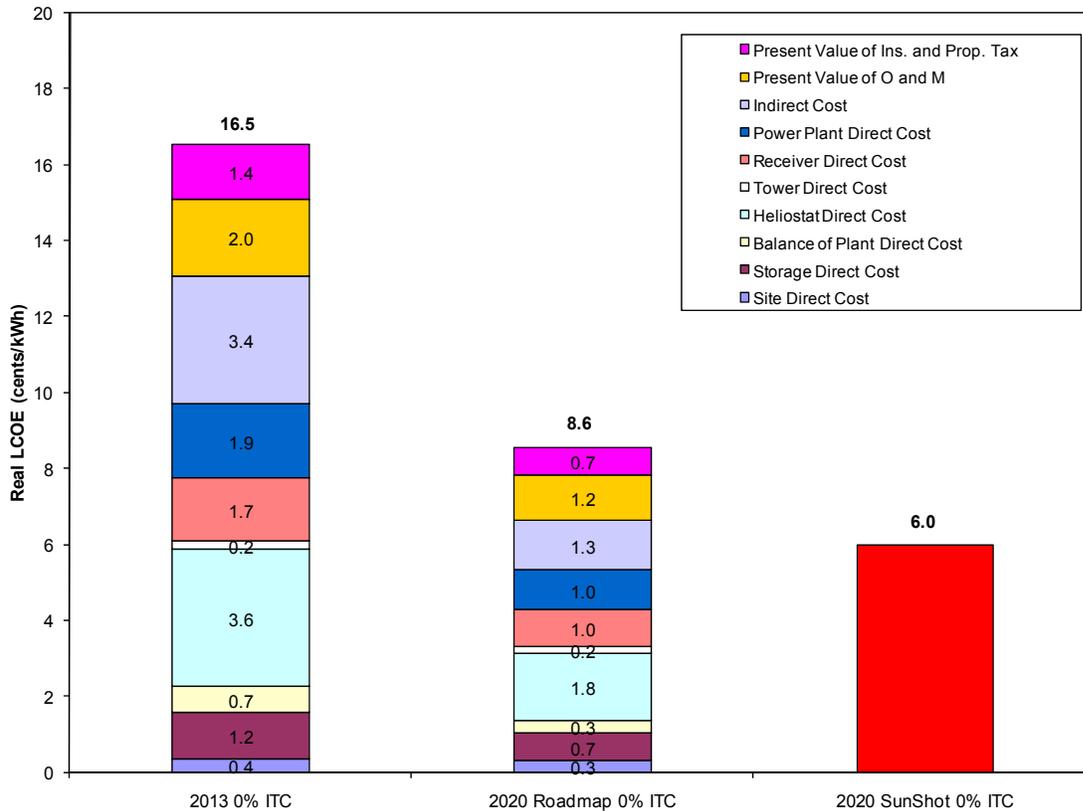
Figure 8. LCOE reduction (real 2010 dollars) pathway to SunShot Initiative goal (all cases are shown with a 0% ITC)

Based on industry comments, including a DOE-CSP Industry Meeting held in conjunction with SEIA on March 8-9, 2011 in Arlington, VA, the following list outlines TIOs in addition to those already mentioned that could potentially lead to SunShot-level cost reductions for power towers.

Solar Collector Field

- Alternative heliostat designs that use significantly less material.

- Non-steel-based support structures.

- Reliable wireless methods for heliostat power and communication.

- Advanced, self-aligning control systems.

- Closed-loop tracking.

- Curved heliostat facet optimization.

- Low-profile heliostats that are subject to less wind-loading.

- Utilization of secondary concentrator designs with improved optics.

- Automatic soiling detection and reflectivity assessment.

33

- Driven-pylon or ground-mounted pedestals.

- Minimal field grading and site preparation.

- Increase in volume production.

Solar Receiver

- High-temperature materials capable of reliable operation over many thermal cycles.

- Cavity receiver designs or other alternative concepts (e.g. particle, beam down, volumetric, modular) that enable efficient solar collection at high temperature.

- Appropriate models to simulate receiver performance at part-load conditions.

- Coverings for receiver designs that employ quartz windows.

- Integration of the tower as a container for the thermal energy storage system.

- For modular designs, lightweight towers that can be rapidly assembled and installed.

Thermal Energy Storage

- High-temperature storage concepts with enhanced thermal stability and increased storage density, such as novel inorganic liquids, solid particles, phase change materials, or thermochemical approaches.

- Additives that augment the heat capacity of existing fluids such as 60% $NaNO_3$ / 40% KNO_3 solar salt.

- Non-nitrate salts capable of operation at higher temperatures.

- Lightweight, compact thermal storage systems that could potentially be integrated with the tower (located within or on top).

Power Block / Balance of Plant

- Advanced power cycles "beyond" supercritical steam, such as supercritical CO_2 or air Brayton.

- Industrial micro-turbines that lead to reduced turbomachinery size and cost.

- Combined-cycle power systems that lead to higher efficiency cycles.

- Development of high-temperature metal or ceramic heat exchangers that are compatible with advanced power cycles.

- Corrosive-resistant hardware (e.g. piping, structure, valves, valve packing, flanges, ducting, blowers, dampers, insulation, pressure and flow measurement devices) that can reliably operate at elevated temperatures.

- Efficient absorption chilling systems to cool compressor inlet for gas turbines.

- Modular plant designs that can be replicated and combined to create larger systems.

- Non-electricity applications (e.g. solar fuels, desalination, cogeneration, enhanced oil recovery).

6. Conclusions

Since the inception of the Power Tower Technology Roadmap, the DOE CSP Program budget distribution has significantly shifted to include an increased emphasis on advanced R&D and power towers. This is primarily due to the selection and funding of a group of CSP industry projects that are evaluating and designing complete power tower baseload systems. As Figure 9 shows, power towers jumped from 4% to 20% of total DOE CSP budget as a result of the Baseload Funding Opportunity Announcement (FOA) solicitation project awards.

(a)   (b)
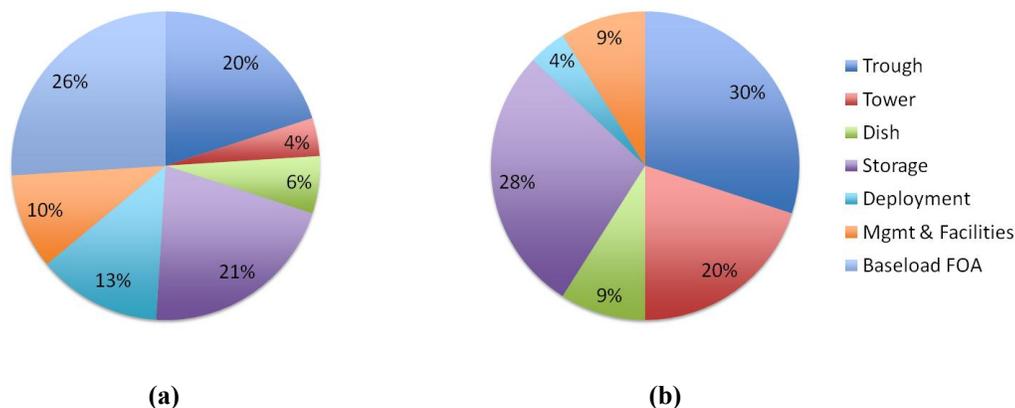
Figure 9. 2010 DOE CSP budget activity levels ($49.7M USD) (a) before and (b) after the Baseload FOA project award announcements [12]

Moving forward, it is anticipated that power tower R&D will continue to receive funding through competitive solicitations to industry and universities, as well as through activities at the national laboratories. During this ramp-up phase for power towers within the DOE CSP Program, the Power Tower Technology Roadmap will continue to be utilized as a tool to guide DOE towards those tasks that will create the most benefit and have the highest impact on reducing the cost of power tower systems.

Reducing the cost of power tower systems by up to 75% by the end of the decade is clearly a significant challenge; however, pursuing these aggressive goals will enable considerable advancements in power tower technology. This roadmap has outlined multiple pathways to achieve these ambitious cost reduction targets. DOE is poised to work alongside industry to make power towers competitive with fossil fuels through both technology activities (e.g. RDD&D, modeling, studies, testing) and non-technology activities (e.g. manufacturing, transmission, land, permitting, financing).

Acknowledgments

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