ASSESSMENT OF CONCENTRATING SOLAR POWER TECHNOLOGY COST AND PERFORMANCE FORECASTS

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INTRODUCTION

In 2002 and 2003, Sargent & Lundy undertook a review of the cost of electricity generation using concentrating solar power (CSP) technology. The study was done for the United States Department of Energy (USDOE) and National Renewable Energy Laboratory (NREL) [Ref. 1]. This paper updates that work to include information from a feasibility study Sargent & Lundy performed for the World Bank regarding an Integrated Solar Combined Cycle System (ISCCS) project proposed for Baja California. This discussion also introduces cost comparisons between CSP-generated electricity and other generating technologies, which were not a part of the original USDOE/NREL project.

Increased production of electricity from renewables is widely regarded as desirable for reducing consumption of non-renewable resources and as a means of reducing greenhouse gas emissions. Renewable electricity generating technologies include hydro, geothermal, solar, wind, and biomass.

Electric power from renewables faces cost challenges compared with conventional approaches to generating electricity. In most cases, the problem for renewables is primarily high capital cost, which is partially, but not entirely, offset by lower operation and maintenance costs. Dispatchability is another important issue. Measures aimed at achieving competitiveness for renewable technologies include tax incentives, green power incentives, and renewable portfolio standards. Such incentives have been helpful in increasing the amount of renewable generating capacity attached to the U.S. generating grids, particularly for wind power, over the last few years.

Besides being more costly than conventional generating sources, CSP electricity generation also is more costly than certain other renewable power generating technologies (notably wind) due primarily to CSP's higher capital cost. CSP cost-competitiveness relative to other renewables is important because CSP will be compared with other renewable technologies in states that have adopted renewable portfolio standards.

Presented at Electric Power 2005, April 5-7, 2005.

CSP will be able to compete favorably against wind in many circumstances because it has a higher potential for dispatch, in spite of having somewhat higher generating costs.

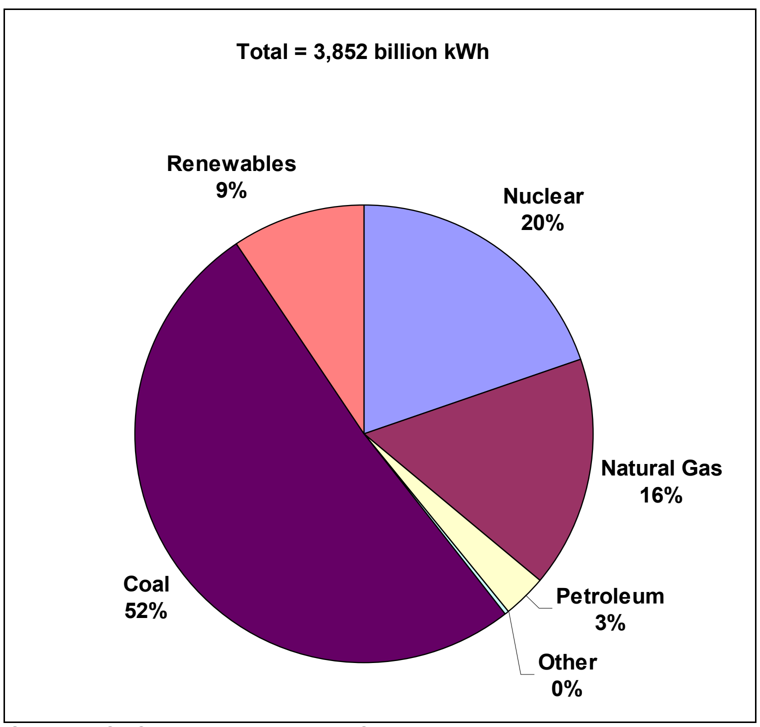
This paper compares the generating cost of CSP with that of conventional technologies and other renewable technologies, focusing on identifying and quantifying cost reduction potential of CSP technology to become more cost-effective over the next 10 to 20 years. The discussion covers current plans for the next plants to be built and industry projections for scale-up by year 2020. Cost projections are based on technology research and development progress, economies of scale, learning curve economies associated with increased deployment, and experience-based O&M cost reductions arising from deployment.

ELECTRICAL GENERATION MARKETS IN THE UNITED STATES

Electrical generation for the United States in 2003 was 3.9 trillion gigawatt-hours (GWh), including both the electric supply industry and end-user self-generated electricity. Figure 1 presents a breakdown of electric energy production by fuel source. Renewable energy is 9% of production, and conventional hydro represents 77% of production from renewables.

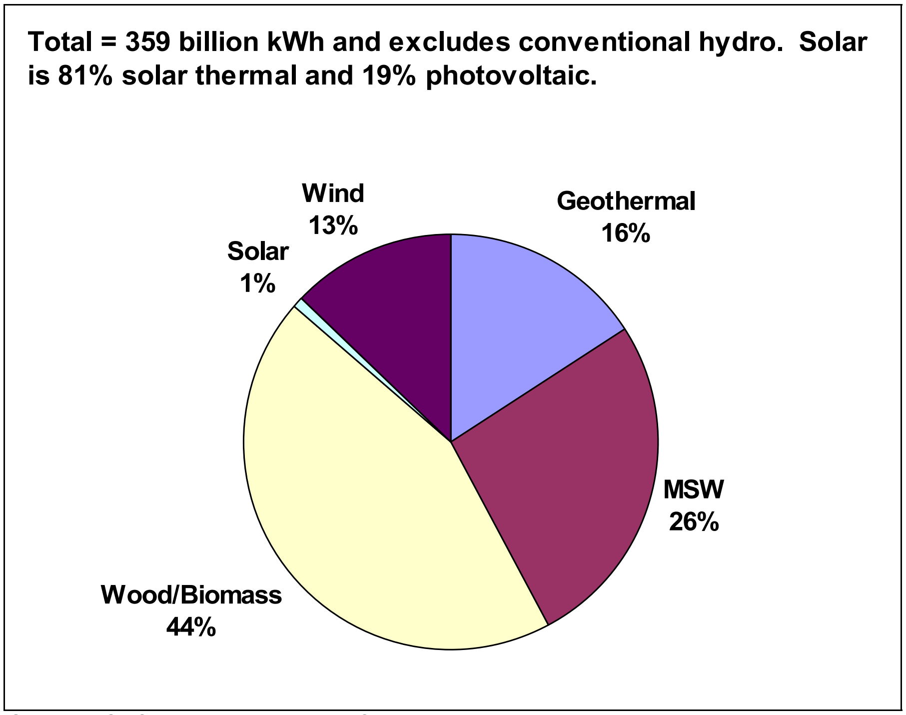
Figure 2 shows a breakdown of renewable production (energy) other than from conventional hydro. The solar contribution, equal to 1% of renewable generation from renewable sources other than conventional hydro, is composed of 81% solar thermal production and 19% photovoltaic production.

Figure 1 — U. S. Electricity Profile



Source: USDOE/EIA Annual Energy Outlook 2005. Includes both electric power sector and end-use sector.

Figure 2 — U.S. Renewable Electricity Profile



Source: USDOE/EIA Annual Energy Outlook 2005. Includes both electric power sector and end-use sector.

Although electricity might be thought of as a commodity market, where one kilowatt-hour is the same as the next, electricity markets are actually complex and structured. The competitive position of a given generating technology arises from the segment of the market it serves. Electricity, in general, is consumed exactly when it is produced, with no inventories carried, so production costs for electricity vary throughout a given day, week, and year, as demand fluctuates. During periods of high demand, it becomes cost-justifiable to operate units having high variable costs, such as gas-fired combustion turbines. Such equipment is not economically competitive during periods of low demand, when low variable cost generators (primarily nuclear and coal-fired) are most competitive. Solar technology has nearly zero variable cost but is most productive at times of day when market prices are high in most markets, due to air conditioning loads. For this reason, solar technologies can be competitive in the marketplace even when not producing power as inexpensively as the least-expensive capacity such as nuclear, coal-fired, or combined-cycle capacity.

In addition, consumer preferences and regulatory requirements have caused electricity from renewables to be differentiated in the marketplace, as a premium product. So-called "green" electricity from renewables is being sold at a price premium to electricity generated by conventional technologies. Renewable portfolio standards established in many states in the U.S. and elsewhere in the world create a demand for renewable electricity that is to a degree decoupled from normal competitive pricing, further opening the door to expansion of renewable technologies such as solar.

In addition to market segmentation from cost variation through time and segmentation from consumer preference and utility regulation, commercial acceptability of solar power is affected by government tax incentives that are aimed at subsidizing the technology in order to create a “critical mass” of installation that can lead to reduced cost.

These issues all must be kept in mind when considering generating costs and whether CSP, or any other renewable technology, will be broadly accepted in the marketplace, but cost also is very important. Because electricity production is a highly competitive industry, tax breaks and “green” premiums will go only so far. Ultimately, CSP will have to be cost competitive for large-scale CSP deployment.

CONCENTRATING SOLAR POWER TECHNOLOGY

Concentrating solar power consists of three types of technology: power tower, parabolic trough, and parabolic dish. We focused on the power tower and parabolic trough technologies, both of which are now capable of being developed as large-scale power generating facilities (troughs > 100MW and towers > 15 MW).

Troughs

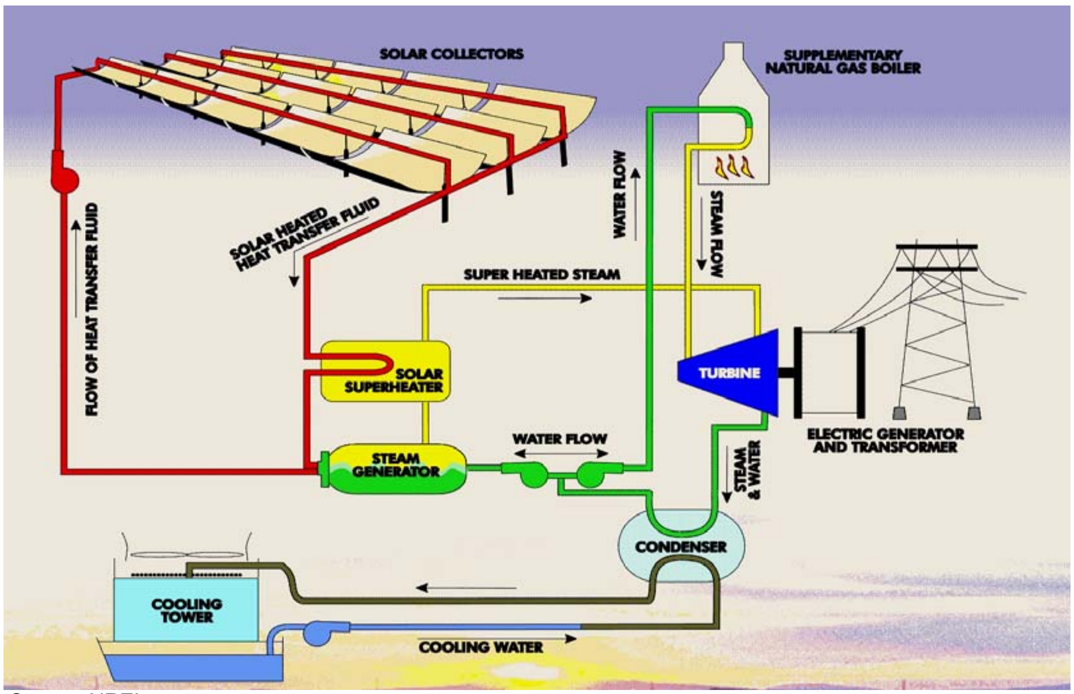
Parabolic trough technology is currently the most proven of the solar thermal electric technologies. Nine large commercial-scale solar power plants exist, the oldest of which has been operating in California’s Mojave Desert since 1984. These plants, which continue in operation, range in size from 14- to 80-megawatts electric (MWe) and represent a total of 354 MWe of installed electric generating capacity. The inherent capital-intensive nature of the technology, along with the current high costs and early mass-production hurdles, are disadvantages for trough technology. While this technology was commercialized for a brief period, no additional trough plants have been built in more than a decade.

The collector field in trough plants consists of a large field of single-axis tracking parabolic trough solar collectors, as shown in Figure 3. The solar field is modular and is composed of many parallel rows of solar collectors aligned on a north-south horizontal axis. Each solar collector has a linear parabolic-shaped reflector that focuses the sun’s direct beam radiation on a linear receiver located at the focus of the parabola. The collectors track the sun from east to west during the day to ensure that the sun is continuously focused on the linear receiver. A heat transfer fluid (HTF) is heated as it circulates through the receiver and returns to a series of heat exchangers in the power block, where the fluid is used to

Figure 3 — Solar Trough Generating Plant

generate high-pressure superheated steam. The superheated steam is then fed to a conventional steam turbine/ generator to produce electricity. The exhaust steam from the turbine is condensed in a standard condenser and returned to the heat exchangers via condensate and feedwater pumps, to be transformed back into steam. After passing through the HTF side of the solar heat exchangers, the cooled HTF is recirculated through the solar field to be reheated. Figure 4 is a process flow diagram for the trough technology.

Figure 4 — Process Flow Diagram for Trough Technology



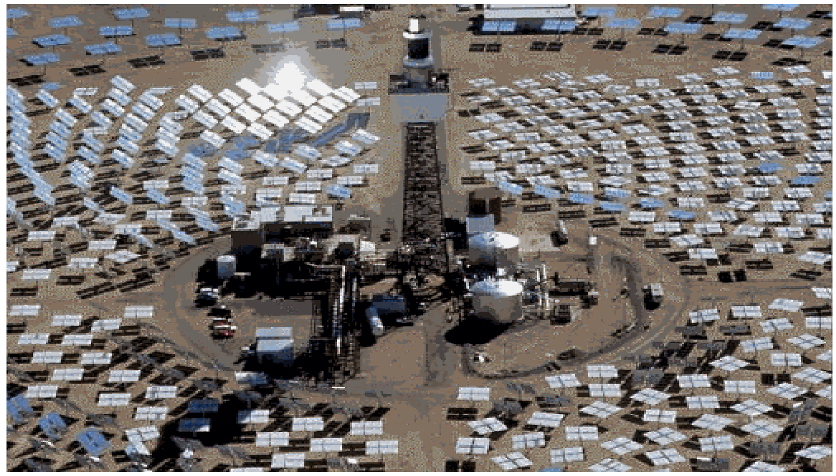
Source: NREL

Towers

The largest power towers built to date were the 10-MWe Solar One and Solar Two demonstration plants in southern California, neither of which is operating at present. Although power towers are commercially less mature than parabolic trough systems, a number of component and experimental systems have been field tested around the world during the last 15 years, demonstrating the engineering feasibility and economic potential of the technology. Operation of the Solar One pilot plant from 1982 to 1988 was an important step in the development of power tower technology. After its initial test and evaluation phase, Solar One operated reliably.

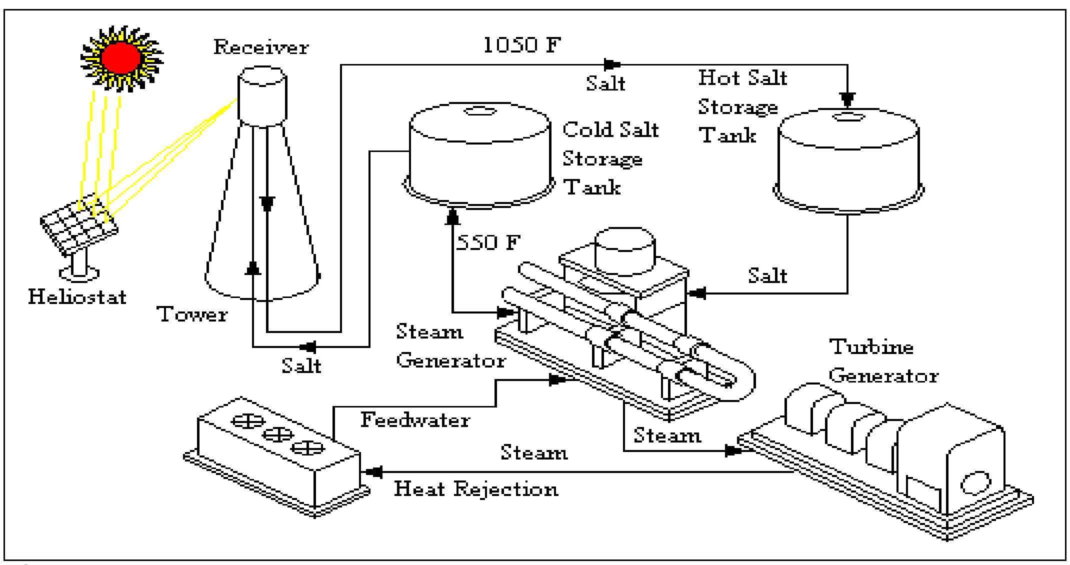
Solar power towers generate electric power from sunlight by focusing concentrated solar radiation on a tower-mounted heat exchanger (receiver). The system uses hundreds to thousands of sun-tracking mirrors called heliostats to reflect the incident sunlight onto the receiver (see Figure 5). These plants are best suited for utility-scale applications in the 30- to 400-MWe ranges.

Figure 5 — Solar Tower Generating Plant



In a molten-salt solar power tower, liquid salt at 290°C (554°F) is pumped from a "cold" storage tank through the receiver, where it is heated to 565°C (1,049°F) and then on to a "hot" tank for storage. When power is needed from the plant, hot salt is pumped to a steam generating system that produces superheated steam for a conventional turbine/ generator system. From the steam generator, the salt is returned to the cold tank where it is stored and eventually reheated in the receiver. Figure 6 is a schematic diagram of a molten salt power tower system.

Figure 6 — Molten-Salt Power Tower System Schematic (Solar Two, Baseline Configuration)



Source: NREL

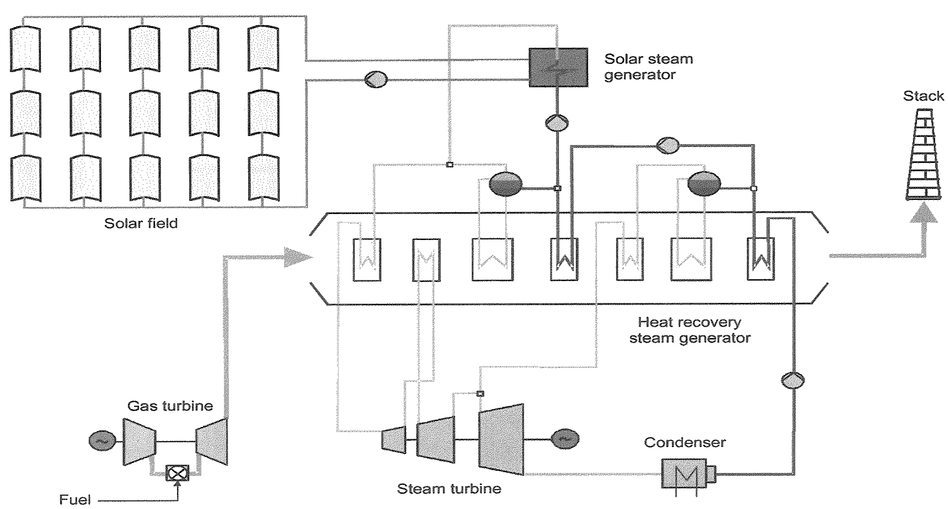
Hybrid

Various solar-fossil hybrid options are possible with natural gas combined-cycle and coal-fired or oil-fired Rankine-cycle plants, and these options may accelerate near-term deployment of CSP projects due to improved economics and reduced overall project risk. The Integrated Solar Combined Cycle System (ISCCS) initially was proposed as a way of integrating a parabolic trough solar plant with modern combined-cycle power plants. The ISCCS approach reduces the effective cost of the conventional power plant equipment, leveraging O&M and project development costs over a larger plant, and potentially increasing the solar-to-electric conversion efficiency in a facility that delivers dispatchable power.

With an ISCCS plant, costs of the power block (steam turbine and balance-of-plant equipment) are significantly less than costs for the power block of a stand-alone trough solar plant such as the SEGS plants. The ISCCS plant power block cost is the incremental cost for the additional capacity added by the steam produced from solar field. To use the solar-produced steam, the steam turbine typically is oversized by between 25% and 50%, beyond what the turbine can produce in the combined-cycle only mode. Over sizing beyond this range is not recommended, because the thermal-to-electric conversion efficiency is degraded at the partial loads associated with operating in the combined-cycle mode without solar contribution.

Since the solar field in an ISCCS plant supplements the combined-cycle steam production, thermal storage is not considered. The ISCCS plant operates at its combined-cycle output during non-solar periods, and then output is increased by up to one third when solar energy (referred to as the solar increment) is available. If the combined-cycle plant is operated in a baseload operating profile, the annual solar fraction (percent of electric generation from solar) will be about 10%. Detailed design integration issues must be considered to make sure the solar integration does not have a significant negative impact on the combined-cycle fossil operation. Several recent studies have looked at the best approaches for this integration. ISCCS plants are being considered for all four of the Global Environmental Facility[1] (GEF) grant projects discussed later in this paper (India, Egypt, Morocco, and Mexico). Figure 7 shows a process flow schematic of a parabolic trough ISCCS plant concept. No ISCCS plants are in operation as yet.

Figure 7 — Scheme of an ISCCS Power Plant with a Dual-Pressure-Reheat Steam Cycle and the Use of Solar Energy to Replace Latent Heat of Evaporation in the High-Pressure Part



[1] The Global Environment Facility (GEF) helps developing countries fund projects and programs that protect the global environment. Established in 1991, GEF is the designated financial mechanism for international agreements on biodiversity, climate change, and persistent organic pollutants. GEF also supports projects that combat desertification and protect international waters and the ozone layer. GEF funding comes via the World Bank and the United Nations Development Programme (UNDP).

SOURCES OF POSSIBLE PRODUCTION COST IMPROVEMENTS

Technical Improvements

Projected technical improvements that reduce CSP costs by improving plant efficiency or by reducing initial capital costs were evaluated with respect to probability of the improvement and the estimated magnitude of cost reduction. The projected technical improvements investigated were those identified in SunLab's cost models [Ref. 2]. The probability and magnitude of cost reductions are based on data from DOE, NREL, Sandia National Laboratories, and members of the CSP industry, including technology assessments and supporting studies for troughs and towers.

Economies of Scale

Economy of scale effects were considered, as appropriate, to estimate or evaluate cost estimates for components. Scaling factors were used to estimate the cost of a new size or capacity from the known cost for a different size or capacity.

Volume Production (Volume and Learning Curve)

Experience curves define how unit costs decrease as a function of cumulative production. The specific characteristics of experience curves are that costs decline by a constant percentage with each doubling of the total number of units produced [Ref. 3].

Engineering assumptions, industry data, and studies for the major cost drivers were reviewed. An experience curve and engineering judgments were used to estimate cost reduction potential. The progress ratio was compared with actual cost reduction experience in other industries. Cost reductions were estimated as a function of rate of deployment and progress ratio.

Operation and Maintenance Cost Reduction

Operations and maintenance cost reduction potential and cost projections were estimated by applying engineering judgment to actual operations and maintenance data provided to us during a site visit to Kramer Junction, for troughs, and to the best information available regarding towers.

COST REDUCTION POTENTIAL

Sargent & Lundy's analysis of the cost-reduction potential for CSP technology over the next 10 to 20 years included the following:

- Examination of the current trough and tower baseline technologies that are expected for the next plants to be built, including a detailed assessment of the cost and performance basis for these plants.

- Analysis of the industry projections for technology improvement and plant scale-up to 2020, including an assessment of the cost and performance projections for future trough and tower plants based on factors such as R&D progress, economies of scale, economies of learning resulting from increased deployment, and experience-related O&M cost reductions resulting from deployments.

- Judgment regarding the level of cost reductions and performance improvements that appear most likely to be achieved.

The impacts of cost reductions on the levelized cost of electricity (LEC) from CSP plants were estimated using a spreadsheet pro forma financial model of the type used in competitive industry to support power project planning and financing. The main analysis engine is a standard income/cashflow statement that combines energy production, revenue, costs (investment, operation and maintenance, fuel, etc.) and financial inputs (depreciation, insurance, taxes, interest, tax credits, return on equity, etc.) to arrive at levelized costs of electricity on a lifetime \$/MWh basis. All evaluations were done on a lifetime \$/MWh evaluated cost basis, in constant 2005 dollars, assuming 30 years of service for the facility.

Certain tax incentives currently exist for encouragement of renewable energy development, both at the federal level and, in some states, at the state level. Public Law No. 108-357 expanded applicability of the Production Tax Credit to a wider range of renewables used to produce electricity than in the past, so that it now includes wind, biomass, geothermal, solar, small irrigation power, and municipal solid waste. The expiration date of the Production Tax Credit (1.5¢/kWh in 1992 dollars, indexed for inflation and now equal to 1.8¢/kWh) was extended in Public Law 108-311 until the end of 2005. This credit has been allowed to expire numerous times before being restored, so there is some doubt whether it will exist as long-term economic support for renewables, but for most analyses in this paper, we have assumed the production tax credit remains in place indefinitely. Other tax incentives (use of five-year accelerated depreciation for renewables and the limited investment tax credit available for solar and geothermal, for example) also are assumed to continue indefinitely into the future. The tax and other incentives are left out in the comparisons of CSP economics against other technologies presented at the end of this paper.

The base case financial analyses here assume development by independent power project (IPP) developers, with costs of capital equal to today's market rates.[2] Ownership by other types of developer is considered in the sensitivity studies.

Trough Technology

Trough Technology Summary

The cost, performance, and risk of parabolic trough technology are fairly well established by the experience of the existing operating parabolic trough plants. That body of experience provides a starting point for evaluating potential cost reductions in the future. Assuming (1) that technology improvements are limited to currently demonstrated or tested improvements, (2) the deployment of 2.8 GWe of installed capacity by the year 2020, and (3) the successful development of a thermal storage system, then the levelized cost of electricity (LEC) for trough plants should be able to drop to approximately 6.5¢/kWh, expressed in year 2005 dollars, from a cost of about 11¢/kWh.

[2] Financial assumptions here are somewhat different from those used in our 2003 study [Ref. 1], reflecting changes in market conditions.

Trough Technology Analysis Base Case

Changes in cost and performance that are assumed for the LEC improvement just mentioned are shown in Table 1.

Table 1 — Trough Technology Improvement Base Case

	Near Term	**Future**
Startup year	2006	2020
MW capacity	100	400
Investment cost, $/kW (net)	$4,820	$3,220
O&M cost, $/kW/year	$66	$35
Capacity factor	54%	56%
Storage, hours	12	12

Trough Technology Cost Sensitivity

Variations in the inputs for the levelized energy cost calculation were considered to illustrate the sensitivity to input assumptions. Incentives in the form of maintaining the current 5-year MACRS and the current investment tax credit provide a significant cost advantage (~22%). Significant LEC reductions can be obtained from ownership by entities having low costs of capital and exemption from income tax (municipal utilities and cooperatives).

Table 2 — Technology Variations in Inputs for Levelized Energy Costs

Studies	¢/kWh	Change
Base Case Results, 2020	6.5	
Impact of eliminating 5-year MACRS	7.4	14%
Impact of eliminating 10% ITC	7.0	8%
Replacement of ITC with PTC	6.0	(8%)
10% higher investment cost	7.1	9%
20% higher O&M cost	6.6	2%
Utility ownership	6.5	(1%)
Municipal ownership	5.3	(19%)

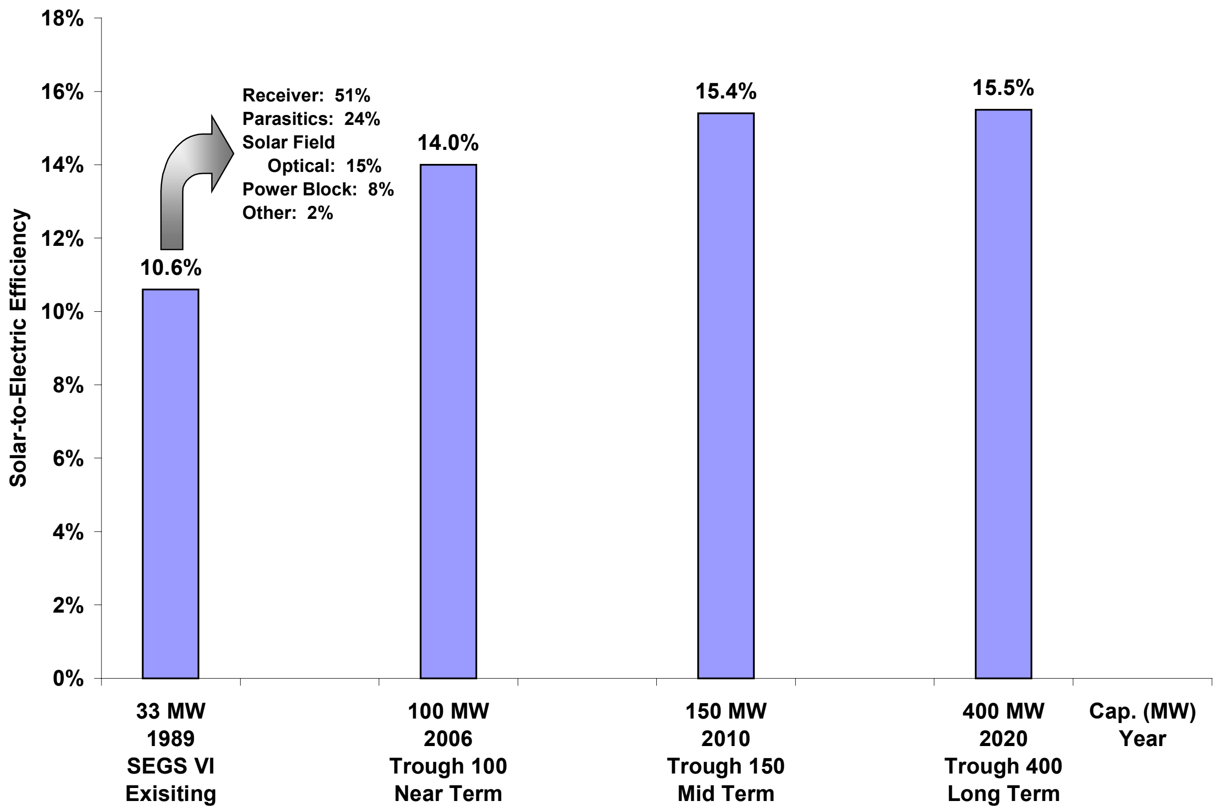
Trough Technology Risk Analysis

The technology projection for trough technology development is shown in Table 3, and overall solar-to-electric efficiencies for these technology configurations are shown in Figure 8.

Table 3 — Technology Development Projection for Trough Technology

Case	**Baseline**	**Near Term**	**Mid Term**	**Long Term**
Project	**SEGS VI Hybrid**	**Trough 100**	**Trough 100**	**Trough 400**
In Service	**1989**	**2006**	**2010**	**2020**
Net Power (MWe)	30	100	150	400
Capacity Factor (%)	22 (solar only)	53.5%	56.2%	56.5%
Solar Field (km^2)	0.188	1.139	1.632	4.349
Heat Transfer Fluid	VP-1	VP-1	Hitec XL	Advanced
Solar Field Operating Temperature (°C) (°F)	391 736	391 736	500 932	500 932
Thermal Storage (hours)	0	12	12	12
Thermal Energy Storage	NA	Indirect 2-Tank	Direct Thermocline	Direct Thermocline
Thermal Storage Fluid	NA	Solar Salt	Hitec XL	Advanced
Annual solar-to-electric efficiency	10.6%	14.0%	15.4%	15.5%
Land Area (km^2)	0.635	3.9	5.2	13.4

Figure 8 — Efficiency Gains from Trough Technology Improvement



The major risk for parabolic trough solar plants to reach market acceptance is the availability of tax subsidies and the owners' abilities to market the power at premium prices, reflecting its "green" status. Assuming tax incentives are provided and a green power premium can be realized, so that deployment is great enough for significant production economies of scale to be realized, the likelihood for achieving cost reduction over the next 10 to 20 years is average to high.

The capital cost estimate for initial deployment was developed by SunLab from the cost experience of the SEGS plants, from detailed cost models developed by industry, and from spare parts cost data of the SEGS plant. Sargent & Lundy reviewed the available cost data, updating it as necessary to incorporate recent receiver cost estimates from Solel, mirror cost information from FlagSol, collector structure costs from EuroTrough and Solargenix, and electrical power generation system and balance-of-plant costs from other sources (Sargent & Lundy's internal cost database, etc.), with contingencies to reflect cost uncertainties.

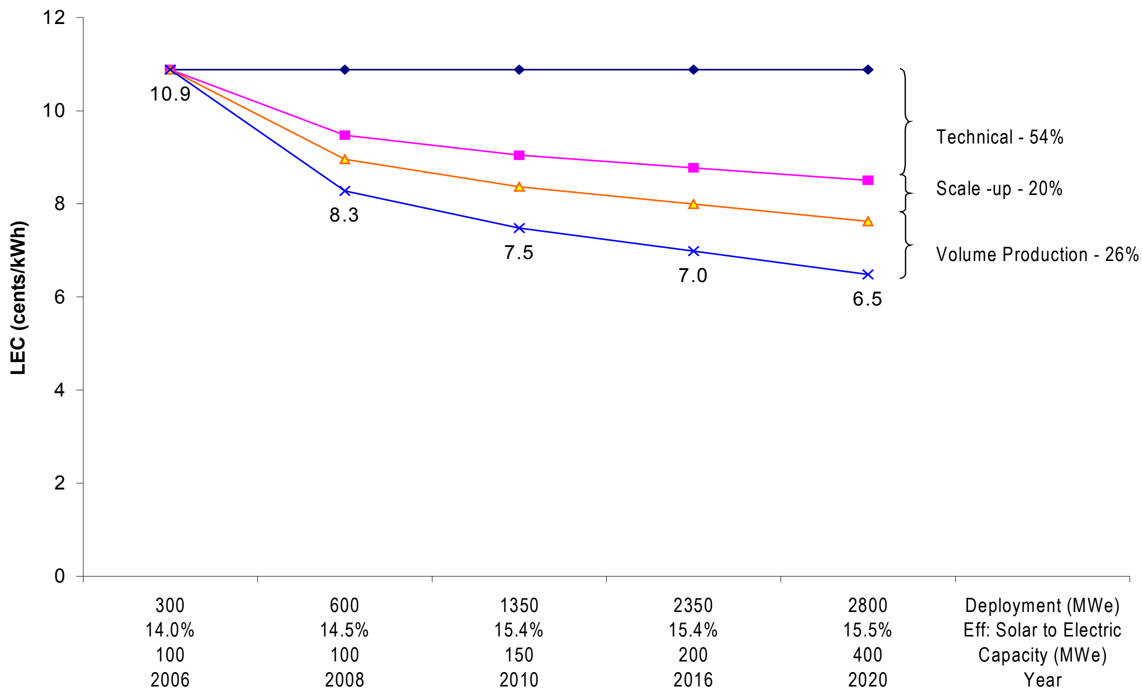
Cost reductions achieved from technology improvements, economies of scale, and volume production are shown in Figure 9 for the zero-storage case.

- The likelihood of achieving the technology improvements is projected by Sargent & Lundy to be high based on field-demonstrated technology at the SEGS plants and ongoing research by Solargenix, Solel, FlagSol, and others. One significant technology risk element is the switch to molten-salt heat transfer fluid (HTF) and incorporating thermal storage, which is a key for driving down future costs.

- It is well-established that cost economies of scale result from increases in component sizes and capacity. The likelihood of achieving the scale economies is projected by Sargent & Lundy from economy of scale to be high based on well-established scaling relationships for certain cost components based on experience (e.g., balance-of-plant components, receivers, and electric power system).

- The likelihood of achieving the cost improvements from volume production is projected by Sargent & Lundy to be high based on the cost reduction experience of the SEGS plants and other industries.

Figure 9 — Sources of CSP Trough Cost Reductions



Key Trough Technology Conclusions

The following key technology advances should cause near-term trough plants to be a significant improvement over the existing SEGS units:

- Development of the new Solel UVAC receiver, improving collector field thermal performance by 20%.

- Development of a near-term thermal storage option for troughs by Nexant and SunLab. The design is likely to be demonstrated at the first trough plant to be built in Spain.

- Replacement of flex hoses with ball joint assemblies in the collector field, significantly reducing HTF pumping losses and increasing the potential size of future parabolic trough solar fields.

The development of longer-term, more advanced thermal storage technologies is critical. This path offers the largest cost reduction potential. Integral with advanced thermal storage is the implementation of a higher temperature heat transfer fluid in the 450°–500°C (842°–932°F) range. SunLab and international R&D groups have significant efforts underway.

Significant cost reductions appear supportable regarding the three key trough components—structure, receiver, and reflectors—though arising from different cost reduction mechanisms:

- Concentrator cost reduction will depend largely on size scale-up, production volume, and increased competition. Significant development efforts are currently in progress by Solargenix & EuroTrough.
- Alternative reflector (mirror) options and high production volume are projected to reduce mirror costs significantly.
- Achieving an operating temperature of 450°C (842°F) with current receiver technology appears feasible. However, development of a higher performing and more reliable receiver is very important to achieving long-term cost and performance goals. Laboratories and industry are addressing this issue.
- O&M costs are expected to fall with facility scale-up, increased experience, and technology-driven improvements in reliability.

Tower Technology

Tower Technology Summary

Because no commercial power tower plants have been built, there is more uncertainty in the cost, performance, and technical risk of tower technology than for troughs. Assuming (1) that technology improvements are limited to current demonstrated or tested improvements and (2) deployment of 2.6 GWe of installed capacity by the year 2020, the levelized cost of electricity from tower-based plants should be able to drop to approximately 5.7¢/kWh, expressed in year 2005 dollars.

Tower Technology Analysis Base Case

The base case for the base case tower technology cost estimates is as follows:

Table 4 — Tower Technology Improvement Base Case

	Near Term	Future
Startup year	2006	2020
MW capacity	50	200
Investment cost, $/kW (net)	$6,180	$3,620
O&M cost, $/kW/year	$75	$46
Capacity factor	76%	73%

Tower Technology Cost Sensitivity

Variations in the inputs for levelized energy costs were calculated to illustrate the sensitivity to input assumptions. Incentives in the form of maintaining the current 5-year MACRS and the current investment tax credit provide a significant cost advantage (~22%). Significant LEC reductions can be obtained from ownership by entities having low costs of capital and exemption from income tax (municipal utilities and cooperatives).

Table 5 — Tower Technology Variations in Inputs for Levelized Energy Costs

Studies	¢/kWh	Change
Base Case Results, 2020	5.7	
Impact of eliminating 5-year MACRS	6.5	14%
Impact of eliminating 10% ITC	6.2	8%
Replacement of ITC with PTC	5.2	(10%)
10% higher investment cost	6.2	9%
20% higher O&M cost	5.9	3%
Utility ownership	5.7	(1%)
Municipal ownership	4.7	(18%)

Tower Technology Risk Analysis

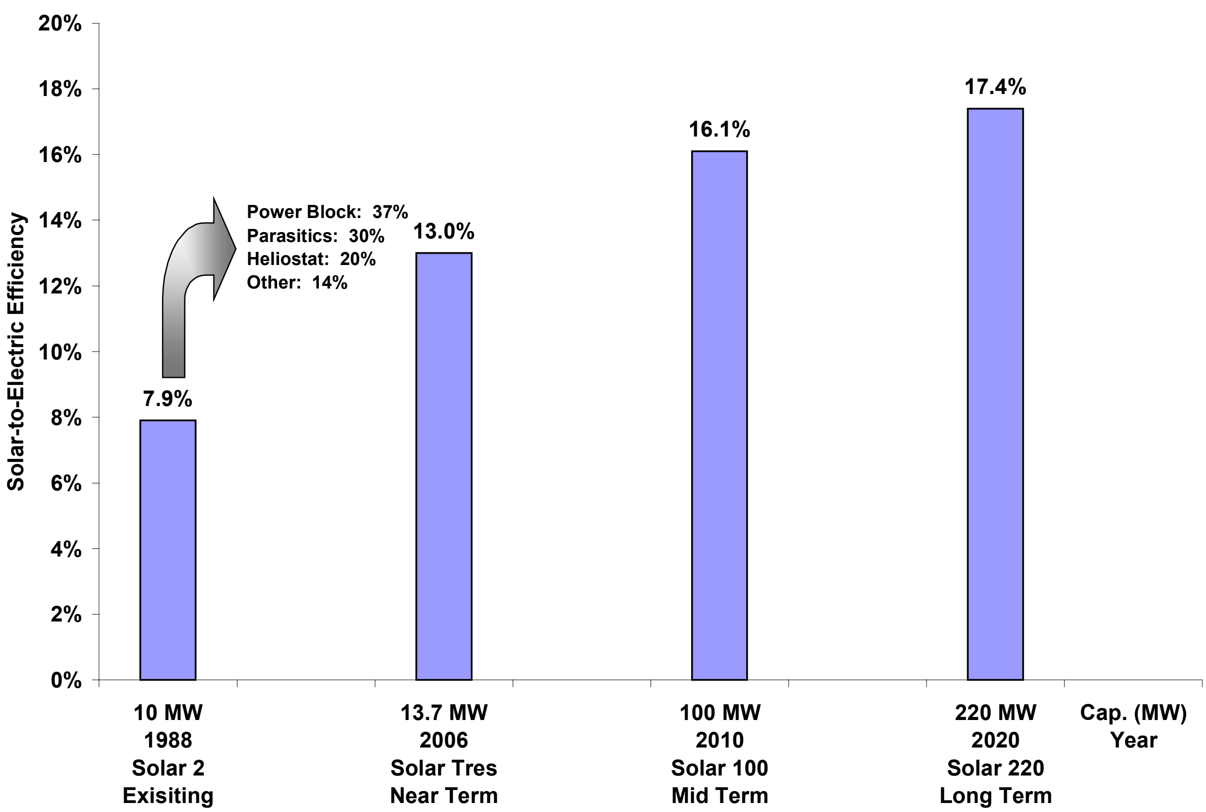
The technology projection for tower technology development is shown in Table 6. As shown in Figure 10, the largest step increase in solar-to-electric efficiency is from Solar Two to Solar Tres.

Table 6 — Technology Development Projection for Tower Technology

Case	**Baseline**	**Near -Term**	**Mid-Term**	**Long Term**
Project	**Solar Two**	**Solar Tres USA**	**Solar 100**	**Solar 220**
In Service Date	**1996**	**2006**	**2008**	**2020**
Power Cycle	Rankine	Rankine	Rankine	Super-Rankine
Net Power, MWe	10	13.65	100	220
Capacity Factor, %	19%	78%	73%	73%
Heliostat Size	39/95	95	148	148
Heliostat Design	glass/metal	glass/metal	glass/metal	glass/metal
Solar Field Size, km^2	0.08	0.245	1.366	2.67
Receiver Area, m^2	100	280	1,110	1,990
Heat Transfer Fluid	solar salt	solar salt	solar salt	solar salt
Operating Temperature, °C °F	565 1,049	565 1,049	565 1,049	650 1,202

Case	Baseline	Near -Term	Mid-Term	Long Term
Project	**Solar Two**	**Solar Tres USA**	**Solar 100**	**Solar 220**
In Service Date	**1996**	**2006**	**2008**	**2020**
Thermal Storage Fluid	solar salt	solar salt	solar salt	solar salt
Thermal Storage, hr	3	16	13	13
Annual solar-to-electric efficiency	7.9%	13.0%	16.1%	17.4%
Land Area, km^2	0.4	1.3	6.8	14.4

Figure 10 — Efficiency Gains from Tower Technology Improvement



As with troughs, the major risk for tower solar plants to reach initial market acceptance is the availability of tax subsidies and the owners' abilities to market the power at premium "green" prices. Assuming incentives are provided and a green power premium can be achieved, the likelihood for achieving cost reduction over the next 10 to 20 years is average to high.

The capital cost estimate for the initial deployment was developed by SunLab based on actual costs for Solar Two, the Central Receiver Utility Studies, the AD Little heliostat detailed cost estimate, detailed heliostat design from ATS, and industry data. Sargent & Lundy reviewed published cost data and updated the information to include the latest cost estimate for receivers from Boeing, electrical power generation system and balance-of-plant costs from other sources (Sargent & Lundy's internal cost database, etc.), with contingencies to reflect cost uncertainties.

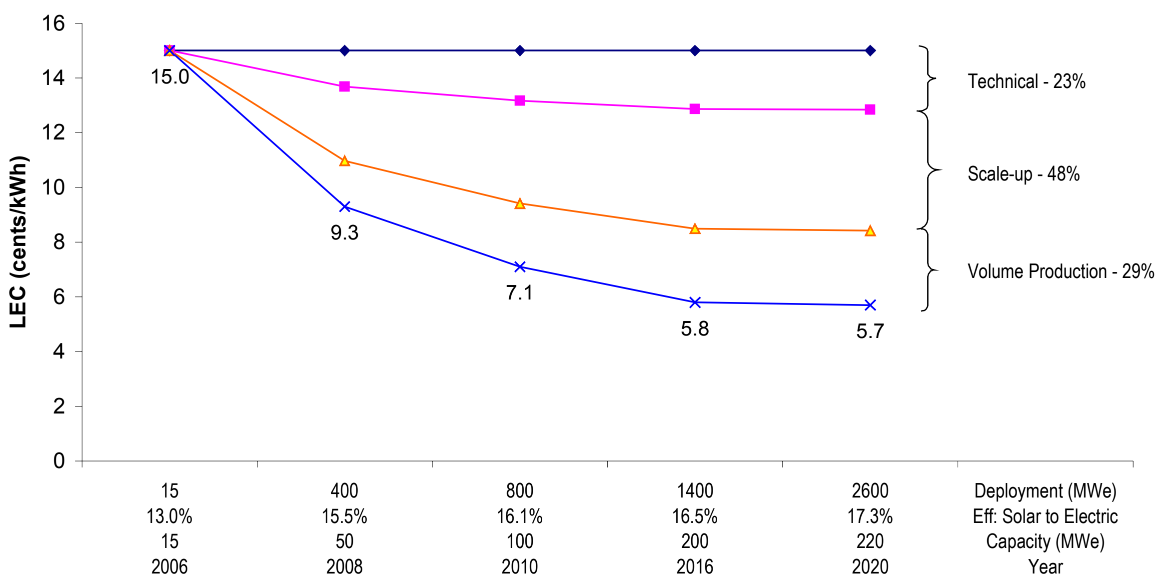
Cost reductions achieved from technology improvements, economies of scale, and volume production are shown in Figure 11.

- The likelihood of achieving the technology improvements is projected by Sargent & Lundy to be high based on demonstrated technology, design enhancements from lessons learned during Solar Two, advances in control technology since Solar Two, and ongoing research by Boeing.

- It is well established that cost economies of scale result from increases in component size and capacity. The likelihood of achieving the scale economies is projected by Sargent & Lundy to be high based on well-established scaling relationships for certain components (e.g., balance-of-plant components, receivers, and electric power system).

- The likelihood of achieving the cost improvements from volume production is projected by Sargent & Lundy to be high based on using a progress ratio of 0.97, which is at the upper end (conservative) of published data. Studies on learning curves from actual data suggest a progress ratio of 0.82 for development of photovoltaics and 0.95 for development of wind power.

Figure 11 — Sources of CSP Tower Cost Reductions



Key Tower Technology Conclusions

Solar plant and power plant scale-up provide the largest cost reduction opportunities for power tower technologies.

- Scale-up of the tower solar plant requires a total re-design and re-optimization of the field, tower, and receiver. This should greatly reduce capital and O&M costs, but would have only a small effect on efficiency. R&D support in the design, development, and testing of larger receivers, larger heliostats, and larger heliostat fields would reduce scale-up risk.

- Scale-up of the steam turbine increases efficiency and reduces capital and O&M costs. Probability of success here is very high.

Key technical advances include increasing receiver solar flux levels, development of new heliostat designs with significantly lower costs, and use of new highly efficient steam turbines.

- Increased receiver flux levels have been demonstrated at the prototype scale and require improved heliostat field flux monitoring/management systems and design optimization for use at large plants.

- Revolutionary heliostat designs with significantly lower cost have been proposed that use flexible, durable thin mirrors with a lower-weight stretched-membrane design and which can be manufactured in high volumes.

- High-efficiency supercritical steam turbines are now being demonstrated that operate at temperatures compatible with current tower technology or at temperatures that require increasing the operating temperature of the tower technology to between 600°C and 650°C (1,112°–1,202°F).

The major volume manufacturing benefit evaluated for tower technology is the impact of high manufacturing volume on heliostat cost reduction. Sargent & Lundy's evaluation of the current heliostat design and cost indicates that cost should decrease 3% with each doubling of cumulative capacity. A fifteen-fold increase in cumulative production would reduce the cost of a field of 148 m^2 heliostats from \$148/m^2 to about \$94/m^2

Integrated Solar Combined Cycle System (ISCCS)

As part of the funding process of the World Bank's Global Environmental Facility (GEF) for the Integrated Solar Thermal Power Generation Project, planned for installation in Mexico to serve Comisión Federal de Electricidad (CFE), Sargent & Lundy evaluated three cases for integration of parabolic trough concentrating solar technology with conventional combined-cycle technology as an Integrated Solar Combined Cycle System (ISCCS). The three cases are as follows:

- **Case 1: Maximum Solar Generation.** 41.3 MWe (39.7 MWe net) provided by solar to provide a total net generation of 285,200 kW at the base design conditions

- **Case 2: Solar Generation to Recapture Lost Summer Capacity.** 26.1 MWe (25.1 MWe net) provided by solar to maintain a total net generation of 245,500 kW at summer peak conditions (43.4°C [110°F] and 27% relative humidity) to recover the combined-cycle capacity loss due to higher ambient temperature.

- **Case 3: Solar Generation for Absorption Chillers.** Use solar generated steam for absorption chillers, which will be used to cool the gas turbine inlet air to maintain a constant 10°C inlet air temperature and eliminate the combined-cycle generation loss due to higher ambient temperatures.

An economic comparison of the three cases is summarized below:

Table 7 — Economics of ISCCS Project Proposed for Baja California

25-Year Levelized Values (US$1000s), Excluding GEF Grant	Case 1	Case 2	Case 3
Capital Charges	25,896	23,054	22,723
O&M	7,765	7,508	8,495
Fuel	98,676	97,563	100,317
Total	132,337	128,125	131,535
US$/MWh	66.32	65.38	67.12

25-Year Levelized Values (US$1000s), Including GEF Grant	Case 1	Case 2	Case 3
Capital Charges	23,473	22,005	16,498
O&M	7,765	7,508	8,495
Fuel	98,676	97,563	100,317
Total	129,914	127,076	125,310
US$/MWh	65.10	64.84	63.95

Addition of solar thermal input increases the baseline conventional combined-cycle levelized cost $1.22/MWh for Case 1, $0.54/MWh for Case 2, and $3.17/MWh for Case 3. Case 1 and Case 2 provide the best opportunities for near-term deployment of trough technology on a competitive basis with conventional technologies.

Annual and 25-year levelized costs were calculated on the basis of the following assumptions:

- Developer fees are 7.5% of the EPC costs
- CFE cost of debt is 9.0%/year with a 12-year repayment period (US$ basis)
- CFE uses 100% debt financing for the project
- CFE is exempt from income taxes and property taxes
- Escalation rate is 2.5%/year for capital and O&M costs
- Project construction period is approximately 24 months
- Commercial operation date is 2009
- Net electrical output is 1,995,568 MWh/year
- Capacity factor for combined cycle is 87.3%; for solar, 28.1%

- Natural gas prices are CFE's long-term projections for the Mexicali area

- Evaluation period is 2009–2033 (25 years)

- The GEF grant is the difference in the 25-year present value of capital, O&M, and fuel costs between the ISCCS plant and a baseline CTCC plant of identical electrical output

Overall technology risks for all three cases are considered moderate, for the following reasons:

- Parabolic trough technology currently is the most proven solar thermal electric technology. A total of 354 MW of installed electric generating capacity, ranging in size from 14 to 80 MW, have been operating since 1984. Although no parabolic trough solar plants have been constructed in more than a decade, research and development activities for efficiency and technology improvements are currently being conducted under funding by the U.S. government and by independent contractors, offering the potential of lower costs than for earlier facilities.

- The proposed combined-cycle configuration (conventional F-Frame gas turbine, three-pressure reheat heat recovery steam generator, and steam turbine) is a proven combination. The General Electric F-Frame was introduced in 1987, and the fleet has more than 6 million operating hours. The General Electric Model S107FA combined-cycle 1x1x1 configuration has over 10 years of operating experience. The industry also has considerable operating experience with comparable-sized combined-cycle configurations from other manufacturers such as ABB, Mitsubishi, and Siemens.

- Absorption cooling technology was patented in 1860, and absorption chillers are manufactured internationally. Low-pressure, steam-driven absorption chillers are commercially available in capacities ranging up to 1,500 tons. The concept of using absorption chillers to cool the gas turbine inlet air has been applied at six plants totaling 668 MW. The largest gas turbine using this type of inlet air cooling is 100 MW (Frame 501D5).

CURRENT CSP MARKET ACTIVITY

Several international and national project developments for commercial or commercial-entry trough or tower power plants are being pursued by industry. These projects typically are in the capacity range of 15 MWe to 100 MWe. Entry opportunities largely arise from activities of the GEF, selected nations' programs on renewable portfolio standards, and other incentives to encourage renewable energy. Industry is actively participating in research and development, marketing, and engineering in support of tower and trough technology. Nexant, Boeing, and Solargenix are the key participants in the United States. Internationally, the key participants are Solel, Flabeg, Solar Millennium, and Fichtner.

A summary of the current market is as follows:

- **Global Environmental Facility.** The GEF has identified CSP technology as one of its most promising renewable energy options and has approved four $50M grants for CSP solar power plants in India, Egypt, Morocco, and Mexico.

- **United States.** The Department of Energy (DOE) is supporting seven states in the effort to install 1,000 MW of CSP power systems through a five-year cooperative cost-sharing agreement. According to Assistant Secretary of Energy David Garman, "The federal long-term goal is to lower the cost of CSP technology to 7 ¢/kWh from the current cost of 12 to 14 ¢/kWh." The

Western Governor's Association (WGA) has set a goal of 100 MW of CSP power by 2010. The parabolic trough industry—specifically Solargenix—is aggressively pursuing individual IPP project opportunities in Nevada, California, Arizona, and Oregon. Ongoing projects include a 1-MW trough plant being built in Arizona, a 50-MW trough plant in Nevada to be built in 2005, and task force to develop solar strategy in New Mexico and California.

- **South Africa.** ESKOM, the national utility in South Africa, has been comparing troughs and towers to select a single technology for the first CSP plant in South Africa. A 25-kW Dish/Stirling system is presently being installed in Midrand.

- **Spain.** In August 2002, the Spanish Government approved a modification of Royal Decree 2818 providing substantial incentives for the erection of IPP solar thermal power plants fueled exclusively by solar radiation (i.e., no hybrid operation). This modification of Royal Decree 2818 grants a premium of €0.12 above the market price for electricity generated from solar thermal energy in facilities with a maximum unit power of 50 MW. Four projects have been proposed by industry: a 10-MWe tower project based on European technology; a 15-MWe tower project based on U. S. technology; a 10-MWe trough prototype based on U. S. technology; and two 50-MWe trough projects based on European technology. Work now is proceeding on commercial financing and development of these projects.

- **Israel.** The Israeli Ministry of National Infrastructures, which is responsible for the energy sector, decided in November 2001 to propose CSP as a strategic ingredient for the Israel electricity market over the next several years, with consideration of towers, advanced conversion technologies, and concentrating photovoltaic systems.

COST COMPARISON WITH OTHER TECHNOLOGIES

A common question when renewable technologies such as CSP are being considered is how their economics compare with the economics of conventional generating technologies. This question is simpler to ask than answer, but some indication of the relative economics appears in the comparison of levelized cost of electricity (LEC) for different technologies and type of financing presented in Table 8. The table includes the two types of new generating plant that are expected to generate the most energy in the future—conventional pulverized-coal and gas-fired combined-cycle (CC)—along with CSP (represented here by troughs) and two other renewables being widely developed in areas where the renewable resources can support installations. Generating costs for the conventional technologies are shown both at the high capacity factor assumptions used for planning baseload installations of this type and at the capacity factors expected for the CSP technology shown here. Economics for the other renewables are shown at the capacity factors typically used for planning with those technologies. In all cases, these comparisons are done without subsidies; all are evaluated using 20-year MACRS for depreciation, with no investment tax credit or production tax credit, to allow comparison when no subsidies are included. Costs used for the CSP information are our projections for year 2020. Costs for the other technologies are typical for today. All figures are in constant 2005 dollars.

Table 8 — Comparison of Levelized Cost of Electricity (No Subsidies)

			Thirty-Year Levelized ¢/kWh (2005 Dollars)			
	CF	$/kW	IOU	IPP	Coop	Muni
Coal (high capacity factor)	90%	$1,275	3.5	3.5	2.9	2.8
CC (high capacity factor)	90%	$650	5.7	5.7	5.4	5.4
Coal (trough capacity factor)	56%	$1,275	4.7	4.7	3.8	3.7
CC (trough capacity factor)	56%	$650	6.3	6.3	5.9	5.8
CSP (trough)	56%	$3,220	8.0	8.0	5.6	5.3
Geothermal	90%	$2,300	3.7	3.7	2.8	2.7
Wind	40%	$940	3.8	3.8	2.9	2.8

Note: CF= Capacity factor; IOU= Investor-owned utility; IPP= Independent power producer.

Table 8 shows that if the economies projected to be realized for CSP by 2020 can be achieved, and if no technological or cost improvements take place for the other technologies shown, then CSP is less economical than geothermal or wind. CSP provides a different service, however—dispatchable power (when storage or hybrid designs are considered) rather than as-available energy—so power from CSP has higher value than that of wind power or other technologies, which are not dispatchable. CSP also is less economical than conventional coal or gas-fired combined cycle when all are operated at the same capacity factor. The conventional technologies have much lower cost when operated at the capacity factors normally assumed for planning such capacity, although the gap is fairly small in the comparison with gas-fired CC capacity for owners who can access low-cost capital and which do not pay income tax. With such low-cost financing, CSP would be less expensive than CC plants by 2020, even without subsidies, under the cost assumptions used in this paper.

Regional circumstances and regulatory developments could cause much different cost comparisons in the real world than indicated in Table 8. For example, geothermal and wind resources might not be available in an area where abundant insolation and level terrain are favorable for CSP, and in those instances CSP would likely be the economic choice as a renewable resource when compared with wind or geothermal. Also, the above comparison includes no favorable tax treatment for the renewable options. If tax policies are structured to favor renewables and penalize sources of greenhouse gases, the economic gaps between conventional resources and renewables in Table 8 would be narrowed.

A further consideration is the segmentation, discussed earlier, of the electricity market from cost variation through time, and segmentation from consumer preference and utility regulation. The conventional technologies appearing in Table 8 are best suited for high-capacity-factor operation, serving customers year-round. CSP's greatest contributions will normally be during the day, in peak periods when costs of electricity are highest, and the price premiums for those periods help support the economics of CSP generation. In addition, consumer willingness to pay more for electricity from a renewable, non-polluting source also supports the economics of CSP generation going forward. The electricity business is a competitive one, so getting costs down is the best source of security for CSP in the long run.

SUMMARY

It is our opinion that CSP technology is a proven technology for energy production, that there is a potential market for CSP technology, and that significant cost reductions are achievable assuming significant deployment of CSP technologies occurs. Sargent & Lundy independently projected capital and O&M costs, from which the levelized energy costs were derived, based on a conservative approach whereby postulated technology improvements are limited to currently demonstrated or tested improvements and with a relatively low rate of deployment. This does not mean that there is no additional technology development but that no technological break-throughs are required in order to support our conclusions about the technologies.

The consensus of forecasts is that a significant increase in installed electric generating capacity will be required to support increased demand through 2020. Trough and tower solar power plants can compete, in their markets, with technologies that provide bulk power to the electric utility transmission and distribution systems if market entry barriers can be overcome:

Both tower and trough technology currently produce electricity that is more expensive than that from conventional fossil-fueled technology. Market expansion of trough and tower technology will require incentives and funding to reach initial market acceptance as listed below:

- **Funding.** Continued Federal funding of research and development is necessary.

- **Tax credits.** Production tax credits (PTC) have expired three times in the past five years. PTC have been extended through 2005, but are not sufficient to sustain long-term growth of renewable power. A longer-term PTC extension is necessary to support development of renewable power.

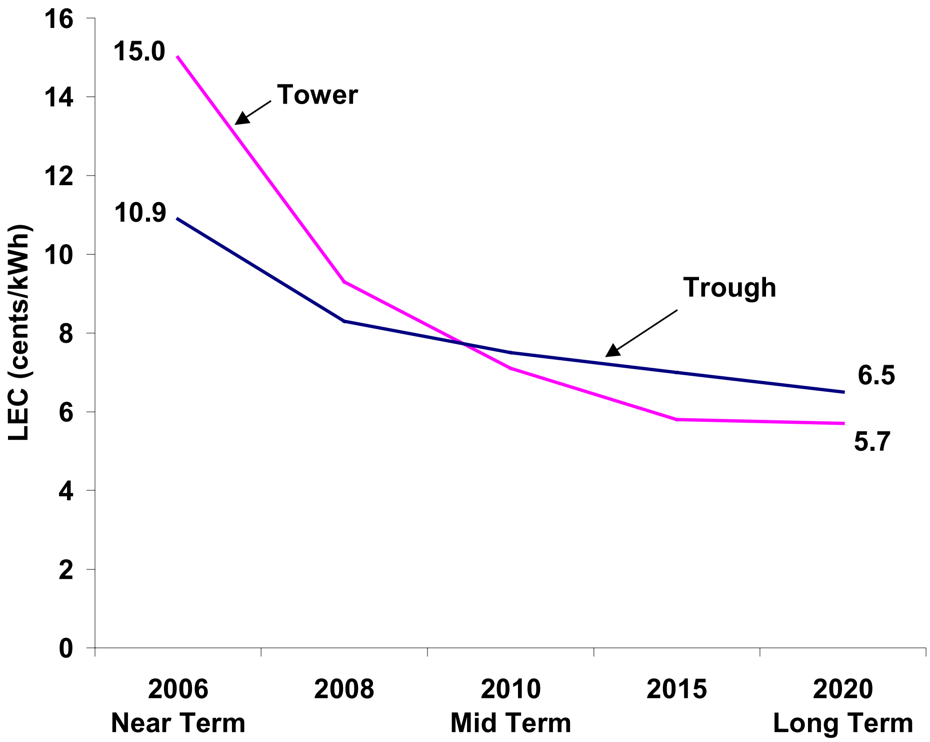
- **Renewable Portfolio Standards.** As of February 2005, there are 18 states which have adopted renewable portfolio standards, which mandate that electricity retailers provide a specific amount of power from renewables.

- **Green Power.** As of June 2004, there are 137 utilities with green pricing programs in operation: 40 investor-owned utilities, 31 electric cooperatives, 65 municipal/public utilities, and 1 federal utility. The premiums for renewable power range from 0.5¢/kWh to 10¢/kWh, with the average being about 2¢/kWh to 3¢/kWh.

Significant cost reductions will be required to achieve long-term market acceptance. Sargent & Lundy focused on the potential of cost reductions with the assumption that incentives will occur to support deployment through market expansion. There is current industry interest in possible near-term deployment of CSP plants again, at least to the extend of restudying the technologies. If that interest leads to project configurations that pass risk and financial hurdles, the amount of world electricity production from CSP could expand beyond what now is being produced by the SEGS plants in California.

The projections by Sargent & Lundy to represent a "best-case analysis" in which the technology is optimized and a high deployment rate is achieved. The figure below highlights these results, with initial electricity costs in the range of 11¢ to 15¢/kWh and eventually achieving costs in the range of 5.7¢ to 6.5¢/kWh. The specific values will depend on total capacity of various technologies deployed and the extent of R&D program success. In the technically aggressive cases for troughs / towers, our analysis found that cost reductions were achievable due to volume production (26%/28%), plant scale-up (20%/48%), and technological advance (54%/24%).

Figure 12 — Levelized Energy Cost Summary



Trough technology is further advanced than tower technology. The long-term projection has a higher risk due to technology advances needed in thermal storage. The advantage of tower technology is that if commercial development is successful (e.g., if expected cost and performance targets can be achieved), then the levelized electricity cost for long-term deployment will be less than for trough technology.

Tower technology needs to proceed from demonstration to commercial development. There is a higher technical and financial risk in developing a first-of-its-kind commercial plant. The addition of a solar system into baseline conventional combined-cycle power plants (ISCCS) provides the best opportunity for large-volume near-term deployment of trough technology.

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ACKNOWLEDGEMENTS

Sargent & Lundy thanks the following individuals and organizations for important contributions to the NREL/DOE study, with the clarification that any errors or omissions are our own responsibility:

R. D. (Dale) Rogers	Boeing
Robert Litwin	Boeing
Pat DeLaquil	Clean Energy Commercialization
Frank Wilkins	Department of Energy
Gilbert Cohen	Solargenix (formally Duke Solar)
David Kearney	Kearney & Associates
Mark Mehos	National Renewable Energy Laboratory
Fredrick Morse	Morse Associates, Inc.
Henry Price	National Renewable Energy Laboratory (SunLab)
William Gould	Nexant
Scott Jones	Sandia National Laboratories (SunLab)