Solar Parabolic Troughs

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SOLAR PARABOLIC TROUGH

1.0 System Description

Parabolic trough technology is currently the most proven solar thermal electric technology. This is primarily due to nine large commercial-scale solar power plants, the first of which has been operating in the California Mojave Desert since 1984. These plants, which continue to operate on a daily basis, range in size from 14 to 80 MW and represent a total of 354 MW of installed electric generating capacity. Large fields of parabolic trough collectors supply the thermal energy used to produce steam for a Rankine steam turbine/generator cycle.

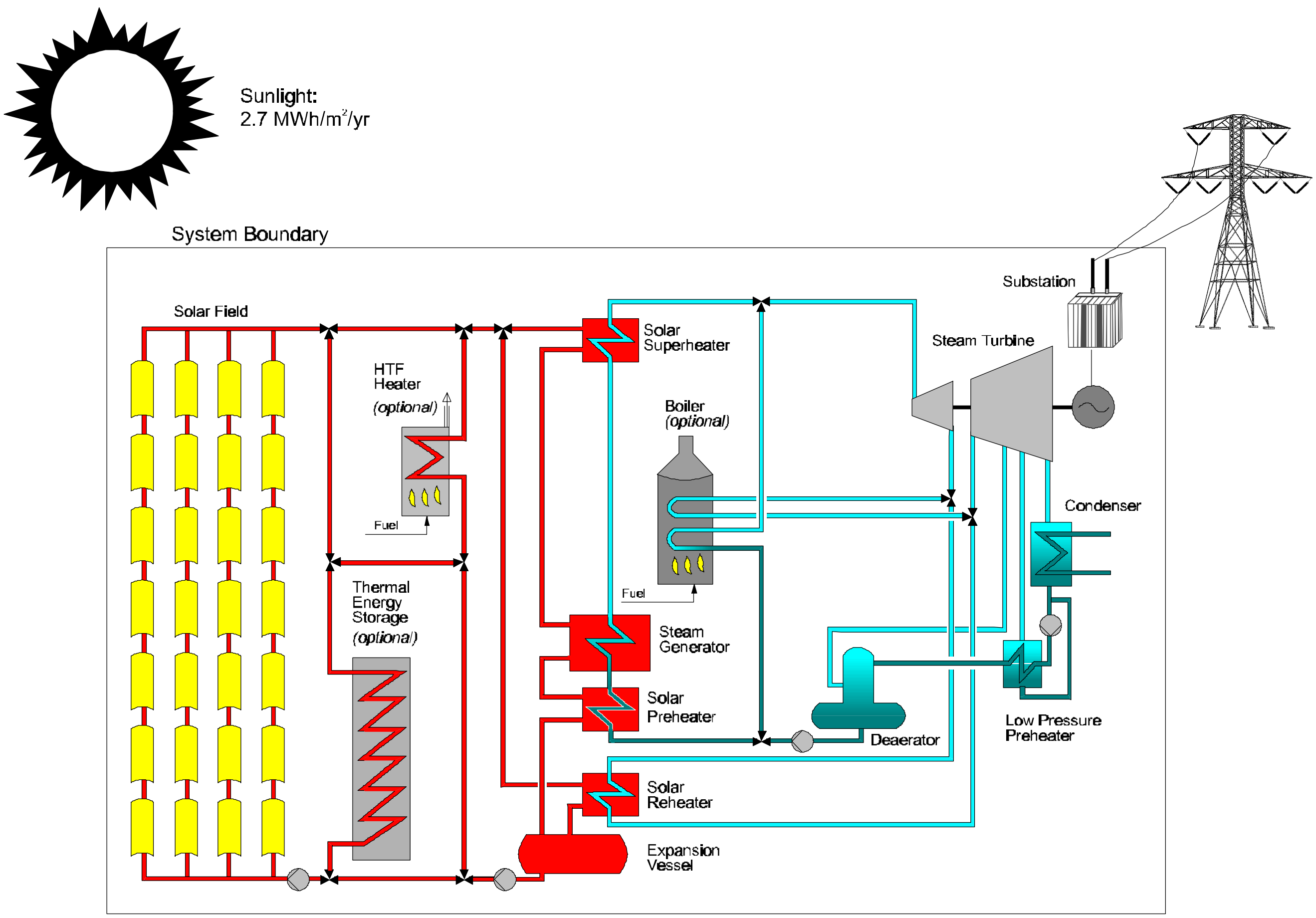

Figure 1. Solar/Rankine parabolic trough system schematic [1].

Plant Overview

Figure 1 shows a process flow diagram that is representative of the majority of parabolic trough solar power plants in operation today. The collector field consists of a large field of single-axis tracking parabolic trough solar collectors. The solar field is modular in nature 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 generate high-pressure superheated steam. The superheated steam is then fed to a conventional reheat steam turbine/generator to produce electricity. The spent steam from the turbine is condensed in a standard condenser and returned to the heat exchangers via condensate and feedwater pumps to be transformed back into steam. Condenser cooling is provided by mechanical draft wet cooling towers. After passing through the HTF side of the solar heat exchangers, the cooled HTF is recirculated through the solar field.

Historically, parabolic trough plants have been designed to use solar energy as the primary energy source to produce electricity. The plants can operate at full rated power using solar energy alone given sufficient solar input. During summer months, the plants typically operate for 10 to 12 hours a day at full-rated electric output. However, to date, all plants have been hybrid solar/fossil plants; this means they have a backup fossil-fired capability that can be used to supplement the solar output during periods of low solar radiation. In the system shown in Figure 1, the optional natural-gas-fired HTF heater situated in parallel with the solar field, or the optional gas steam boiler/reheater located in parallel with the solar heat exchangers, provide this capability. The fossil backup can be used to produce rated electric output during overcast or nighttime periods. Figure 1 also shows that thermal storage is a potential option that can be added to provide dispatchability.

Integrated Solar Combined Cycle System (ISCCS)

The ISCCS is a new design concept that integrates a parabolic trough plant with a gas turbine combined-cycle plant [2,3]. The ISCCS has generated much interest because it offers an innovative way to reduce cost and improve the overall solar-to-electric efficiency. A process flow diagram for an ISCCS is shown in Figure 2. The ISCCS uses solar heat to supplement the waste heat from the gas turbine in order to augment power generation in the steam Rankine bottoming cycle. In this design, solar energy is generally used to generate additional steam and the gas turbine waste heat is used for preheat and steam superheating. Most designs have looked at increasing the steam turbine size by as much as 100%. The ISCCS design will likely be preferred over the solar Rankine plant in regions where combined cycle plants are already being built.

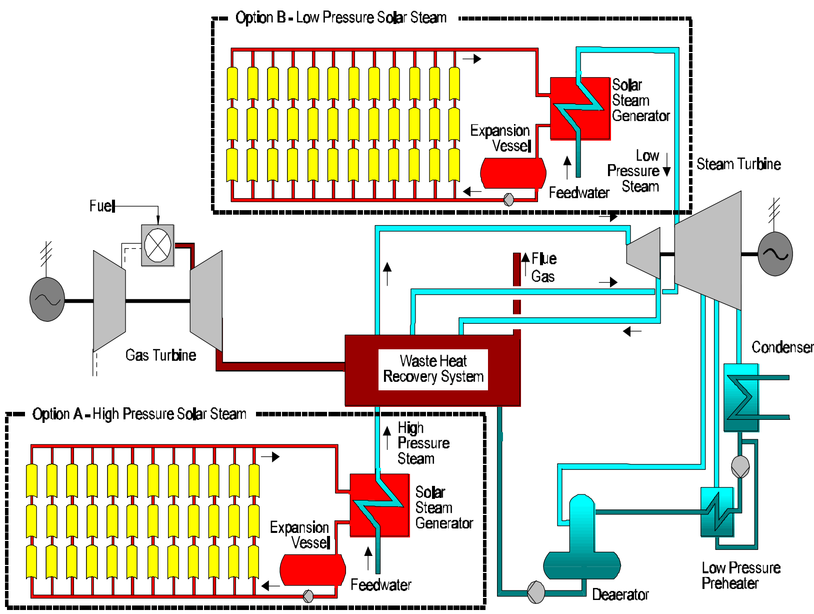

Figure 2. Integrated Solar Combined Cycle System [1].

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Coal Hybrids

In regions with good solar resources where coal plants are currently used, parabolic trough plants can be integrated into the coal plant to either reduce coal consumption or add solar peaking, much like the ISCCS configuration. Due to the higher temperature and pressure steam conditions used in modern coal plants, the solar steam may need to be admitted in the intermediate or low-pressure turbine.

History

Organized, large-scale development of solar collectors began in the U.S. in the mid-1970s under the Energy Research and Development Administration (ERDA) and continued with the establishment of the U.S. Department of Energy (DOE) in 1978. Parabolic trough collectors capable of generating temperatures greater than 500ºC (932ºF) were initially developed for industrial process heat (IPH) applications. Much of the early development was conducted by or sponsored through Sandia National Laboratories in Albuquerque, New Mexico. Numerous process heat applications, ranging in size from a few hundred to about 5000 m^2 of collector area, were put into service. Acurex, SunTec, and Solar Kinetics were the key parabolic trough manufacturers in the United States during this period.

Parabolic trough development was also taking place in Europe and culminated with the construction of the IEA Small Solar Power Systems Project/Distributed Collector System (SSPS/DCS) in Tabernas, Spain, in 1981. This facility consisted of two parabolic trough solar fields with a total mirror aperture area of 7602 m^2. The fields used the single-axis tracking Acurex collectors and the double-axis tracking parabolic trough collectors developed by M.A.N. of Munich, Germany. In 1982, Luz International Limited (Luz) developed a parabolic trough collector for IPH applications that was based largely on the experience that had been gained by DOE/Sandia and the SSPS projects.

Although several parabolic trough developers sold IPH systems in the 1970s and 1980's, they generally found two barriers to successful marketing of their technologies. First, there was a relatively high marketing and engineering effort required for even small projects. Second, most potential industrial customers had cumbersome decision-making processes which often resulted in a negative decision after considerable effort had already been expended.

In 1983, Southern California Edison (SCE) signed an agreement with Acurex Corporation to purchase power from a solar electric parabolic trough power plant. Acurex was unable to raise financing for the project. Consequently, Luz negotiated similar power purchase agreements with SCE for the Solar Electric Generating System (SEGS) I and II plants. Later, with the advent of the California Standard Offer (SO) power purchase contracts for qualifying facilities under the Public Utility Regulatory Policies Act (PURPA), Luz was able to sign a number of SO contracts with SCE that led to the development of the SEGS III through SEGS IX projects. Initially, the plants were limited by PURPA to 30 MW in size; later this limit was raised to 80 MW. Table 1 shows the characteristics of the nine SEGS plants built by Luz.

In 1991, Luz filed for bankruptcy when it was unable to secure construction financing for its tenth plant (SEGS X). Though many factors contributed to the demise of Luz, the basic problem was that the cost of the technology was too high to compete in the power market. Lotker [5] describes the events that enabled Luz to successfully compete in the power market between 1984 and 1990 and many of the institutional barriers that contributed to their eventual downfall. It is important to note that all of the SEGS plants were sold to investor groups as independent power projects and continue to operate today.

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Table 1. Characteristics of SEGS I through IX [4].

SEGS Plant	1st Year of Operation	Net Output (MW_e)	Solar Field Outlet Temp. (ºC/ºF)	Solar Field Area (m^2)	Solar Turbine Eff. (%)	Fossil Turbine Eff. (%)	Annual Output (MWh)
I	1985	13.8	307/585	82,960	31.5	-	30,100
II	1986	30	316/601	190,338	29.4	37.3	80,500
III & IV	1987	30	349/660	230,300	30.6	37.4	92,780
V	1988	30	349/660	250,500	30.6	37.4	91,820
VI	1989	30	390/734	188,000	37.5	39.5	90,850
VII	1989	30	390/734	194,280	37.5	39.5	92,646
VIII	1990	80	390/734	464,340	37.6	37.6	252,750
IX	1991	80	390/734	483,960	37.6	37.6	256,125

Collector Technology

The basic component of the solar field is the solar collector assembly (SCA). Each SCA is an independently tracking parabolic trough solar collector made up of parabolic reflectors (mirrors), the metal support structure, the receiver tubes, and the tracking system that includes the drive, sensors, and controls. Table 2 shows the design characteristics of the Acurex, single axis tracking M.A.N., and three generations of Luz SCAs. The general trend was to build larger collectors with higher concentration ratios (collector aperture divided by receiver diameter) to maintain collector thermal efficiency at higher fluid outlet temperatures.

Table 2. Solar collector characteristics [4,6].

Collector	Acurex 3001	M.A.N. M480	Luz LS-1	Luz LS-2		Luz LS-3
Year	1981	1984	1984	1985	1988	1989
Area (m^2)	34	80	128	235		545
Aperture (m)	1.8	2.4	2.5	5		5.7
Length (m)	20	38	50	48		99
Receiver Diameter (m)	0.051	0.058	0.042	0.07		0.07
Concentration Ratio	36:1	41:1	61:1	71:1		82:1
Optical Efficiency	0.77	0.77	0.734	0.737	0.764	0.8
Receiver Absorptivity	0.96	0.96	0.94	0.94	0.99	0.96
Mirror Reflectivity	0.93	0.93	0.94	0.94	0.94	0.94
Receiver Emittance	0.27	0.17	0.3	0.24	0.19	0.19
@ Temperature (ºC/ºF)			300/572	300/572	350/662	350/662
Operating Temp. (ºC/ºF)	295/563	307/585	307/585	349/660	390/734	390/734

Luz System Three (LS-3) SCA: The LS-3 collector was the last collector design produced by Luz and was used primarily at the larger 80 MW plants. The LS-3 collector represents the current state-of-the-art in parabolic trough collector design and is the collector that would likely be used in the next parabolic trough plant built. A more detailed description of the LS-3 collector and its components follows.

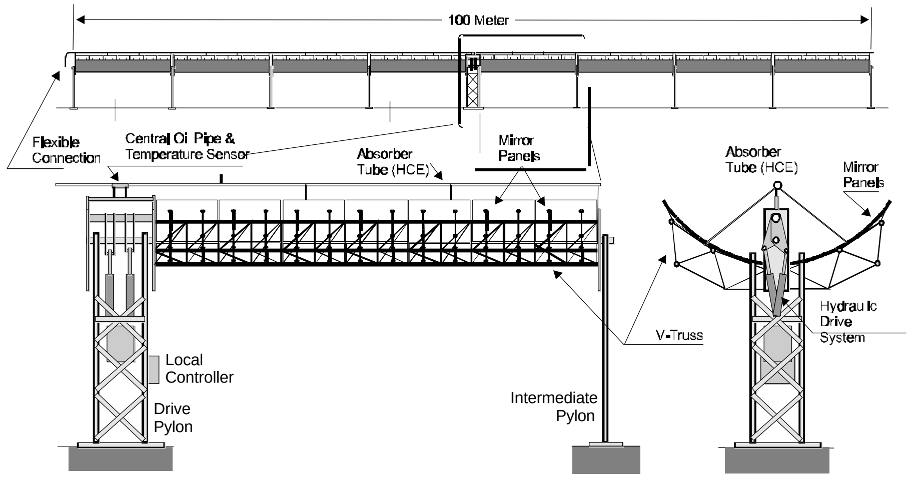

Figure 3. Luz System Three Solar Collector Assembly (LS-3 SCA) [1].

Figure 3 shows a diagram of the LS-3 collector. The LS-3 reflectors are made from hot-formed mirrored glass panels, supported by the truss system that gives the SCA its structural integrity. The aperture or width of the parabolic reflectors is 5.76 m and the overall SCA length is 95.2 m (net glass). The mirrors are made from a low iron float glass with a transmissivity of 98% that is silvered on the back and then covered with several protective coatings. The mirrors are heated on accurate parabolic molds in special ovens to obtain the parabolic shape. Ceramic pads used for mounting the mirrors to the collector structure are attached with a special adhesive. The high mirror quality allows 97% of the reflected rays to be incident on the linear receiver.

The linear receiver, also referred to as a heat collection element (HCE), is one of the primary reasons for the high efficiency of the Luz parabolic trough collector design. The HCE consists of a 70 mm steel tube with a cermet selective surface, surrounded by an evacuated glass tube. The HCE incorporates glass-to-metal seals and metal bellows to achieve the vacuum-tight enclosure. The vacuum enclosure serves primarily to protect the selective surface and to reduce heat losses at the high operating temperatures. The vacuum in the HCE is maintained at about 0.0001 mm Hg (0.013 Pa). The cermet coating is sputtered onto the steel tube to give it excellent selective heat transfer properties with an absorptivity of 0.96 for direct beam solar radiation, and a design emissivity of 0.19 at 350ºC (662ºF). The outer glass cylinder has anti-reflective coating on both surfaces to reduce reflective losses off the glass tube. Getters, metallic substances that are designed to absorb gas molecules, are installed in the vacuum space to absorb hydrogen and other gases that permeate into the vacuum annulus over time.

The SCAs rotate around the horizontal north/south axis to track the sun as it moves through the sky during the day. The axis of rotation is located at the collector center of mass to minimize the required tracking power. The drive system uses hydraulic rams to position the collector. A closed loop tracking system relies on a sun sensor for the precise alignment required to focus the sun on the HCE during operation to within +/- 0.1 degrees. The tracking is controlled by a local controller on each SCA. The local controller also monitors the HTF temperature and reports operational status, alarms, and diagnostics to the main solar field control computer in the control room. The SCA is designed for normal operation in winds up to 25 mph (40 km/h) and somewhat reduced accuracy in winds up to 35 mph (56 km/h). The SCAs are designed to withstand a maximum of 70 mph (113 km/h) winds in their stowed position (the collector aimed 30º below eastern horizon).

The SCA structure on earlier generations of Luz collectors was designed to high tolerances and erected in place in order to obtain the required optical performance. The LS-3 structure is a central truss that is built up in a jig and aligned precisely before being lifted into place for final assembly. The result is a structure that is both stronger and lighter. The truss is a pair of V-trusses connected by an endplate. Mirror support arms are attached to the V-trusses.

Availability of Luz Collector Technology: Although no new parabolic trough plants have been built since 1991, spare parts for the existing plants are being supplied by the original suppliers or new vendors. The two most critical and unique parts are the parabolic mirrors and the HCEs. The mirrors are being provided by Pilkington Solar International (PilkSolar) and are manufactured on the original SEGS mirror production line. The Luz HCE receiver tube manufacturing facility and technology rights were sold to SOLEL Solar Systems Ltd. of Jerusalem, Israel. SOLEL currently supplies HCEs as spare parts for the existing SEGS plants. Should a commercial opportunity arise, it is likely that a consortium of participants would form to supply Luz parabolic trough collector technology.

SEGS Plant Operating Experience

The nine operating SEGS plants have demonstrated the commercial nature of the Luz parabolic trough collector technology and have validated many of the SEGS plant design concepts. Additionally, many important lessons have been learned related to the design, manufacture, construction, operation, and maintenance of large-scale parabolic trough plants [7,8,9].

Solar Field Components: A simple problem with a single component, such as an HCE, can affect many thousands of components in a large solar field. Thus it is essential that each of the SCA components is designed for the 30-year life of the plant and that a sufficient QA/QC program is in place to ensure that manufacture and installation adhere to design specifications. Luz used three generations of collector during the development of the nine SEGS plants. Each time a new generation of collector was used, some form of component failure was experienced. However, one of the major achievements of Luz was the speed with which they were able to respond to new problems as they were identified. Problems with components were due to design or installation flaws. An important lesson from the plants has been the recognition that O&M requirements need to be fully integrated into the design. Three components in particular are worthy of discussion because they have represented the largest problems experienced: HCEs, mirrors, and flexhoses.

Heat Collection Elements (HCEs): A number of HCE failure mechanisms have been identified at the SEGS plants, with all of these issues resolved through the development of improved installation practices and operation procedures, or through a design modification. Loss of vacuum, breakage of the glass envelope, deterioration of the selective surface, and bowing of the stainless steel tube (which eventually can lead to glass breakage) have been the primary HCE failures, all of which affect thermal efficiency. Several of the existing SEGS plants have experienced unacceptably high HCE glass envelope breakage rates. The subsequent exposure to air accelerates degradation of the selective surface. Design improvements have been identified to improve durability and performance, and these have been introduced into replacement parts manufactured for the existing plants. In addition, better installation and operational procedures have significantly reduced HCE failures. Future HCE designs should: (1) use new tube materials to minimize bowing problems; (2) allow broken glass to be replaced in-situ in the field; and (3) continue to improve the selective coating absorptance, emittance, and long-term stability in air.

Mirrors: The current low iron glass mirrors are one of the most reliable components in the Luz collectors. Separation of the mirror mounting pads from the mirrors was an early problem caused by differential thermal expansion between the mirror and the pad. This problem was resolved by using ceramic pads, a more pliable adhesive, and thermal shielding. In addition, methods have been developed that allow the O&M crew to retrofit the older mirror pad design and strengthen them to greatly reduce failures. Mirror breakage due to high winds has been observed near the edges of the solar field where wind forces can be high. Strengthened glass mirrors or thin plastic silvered film reflectors have been designed to circumvent this problem. In general, there has been no long-term degradation in the reflective quality of the mirrors; ten year old mirrors can be cleaned and brought back to like-new reflectivity. However, the glass mirrors are expensive and for the cost of the collector to be reduced, alternative mirrors are necessary. Any new mirror must be able to be washed without damaging the optical quality of the mirror. Front surface mirrors hold potential to have higher reflectivity, if the long-term performance and washability can be demonstrated.

<u>Flexhoses:</u> The flexhoses that connect the SCAs to the headers and SCAs to each other have experienced high failure rates at the early SEGS plants. Later plants used an improved design with a substantially increased life that significantly reduced failures. In addition, a new design that replaces the flexhoses with a hard piped assembly with ball joints is being used at the SEGS III-VII plants located at Kramer Junction. The new ball joint assembly has a number of advantages over flexhoses including lower cost, a significant reduction in pressure drop, and reduced heat losses. If ball joint assemblies can be proven to have a life comparable to the new longer-life flexhoses, then they will be included in all future trough designs.

<u>Mirror Washing & Reflectivity Monitoring:</u> Development of an efficient and cost-effective program for monitoring mirror reflectivity and washing mirrors is critical. Differing seasonal soiling rates require flexible procedures. For example, high soiling rates of 0.5%/day have been experienced during summer periods. After considerable experience, O&M procedures have settled on several methods, including deluge washing, and direct and pulsating high-pressure sprays. All methods use demineralized water for good effectiveness. The periodic monitoring of mirror reflectivity can provide a valuable quality control tool for mirror washing and help optimize wash labor. As a general rule, the reflectivity of glass mirrors can be returned to design levels with good washing.

<u>Maintenance Tracking:</u> In recent years, computerized maintenance management software (CMMS) has found wide acceptance for use in conventional fossil power plant facilities. CMMS systems can greatly enhance the planning and efficiency with which maintenance activities are carried out, reduce maintenance costs, and often result in improved availability of the power plant. CMMS programs have been implemented at trough power plants as well, but the software is not ideally suited for the solar field portion of the plant. CMMS systems excel in applications that have a thousand unique pieces of equipment, but are not really suited to handle systems with a thousand of the same kind of equipment, like SCAs in a solar field. For this reason, custom database programs have been developed to track problems and schedule maintenance in the solar plant. These programs have proven to be an essential tool for tracking and planning solar field maintenance activities and should be considered to be essential for any new project.

<u>Collector Alignment:</u> Operational experience has shown that it is important to be able to periodically check collector alignment and to be able to correct alignment problems when necessary. Collector designs should allow field alignment checks and easy alignment corrections.

<u>Project Start-up Support:</u> Operation of a solar power plant differs from conventional fossil-fuel power plant operation in several ways, primarily due to the solar field equipment and operations requirements, integration of the solar field with the power block, and the effects of cyclic operation. Much knowledge has been gained from the existing SEGS plants that is applicable to the development of procedures, training of personnel, and the establishment of an effective O&M organization.

<u>Thermal Cycling and Daily Startup:</u> Typically, parabolic trough plants are operated whenever sufficient solar radiation exists, and the backup fossil is only used to fill in during the highest value non-solar periods. As a result, the plants are typically shut down during the night and restarted each morning. The plants must be designed to not only be started on a daily basis, but also to start up as quickly as possible. Since the current SEGS plant design does not include thermal storage, the solar field and power block are directly coupled. The use of thermal storage can significantly

mitigate these problems. In general, equipment/system design specifications and operating procedures must be developed with these requirements in mind. Both normal engineering considerations and the experience from the SEGS plants provide important inputs into these needs. Mundane design features such as valves, gaskets, and seals and bolt selection can be an expensive problem unless properly specified.

2.0 System Application, Benefits, and Impacts

Large-scale Grid Connected Power: The primary application for parabolic trough power plants is large-scale grid connected power applications in the 30 to 300 MW range. Because the technology can be easily hybridized with fossil fuels, the plants can be designed to provide firm peaking to intermediate load power. The plants are typically a good match for applications in the U.S. southwest where the solar radiation resource correlates closely with peak electric power demands in the region. The existing SEGS plants have been operated very successfully in this fashion to meet SCE's summer on-peak time-of-use rate period. Figure 4 shows the on-peak performance of the SEGS III through SEGS VII plants that are operated by KJC Operating Company. The chart shows that all 5 plants have produced greater than 100% of their rated capacity during the critical on-peak period between 1200 and 1800 PDT on weekdays during June through September. This demonstrates the continuous high availability these plants have been able to achieve. Note that 1989 was the first year of operation for SEGS VI and SEGS VII.

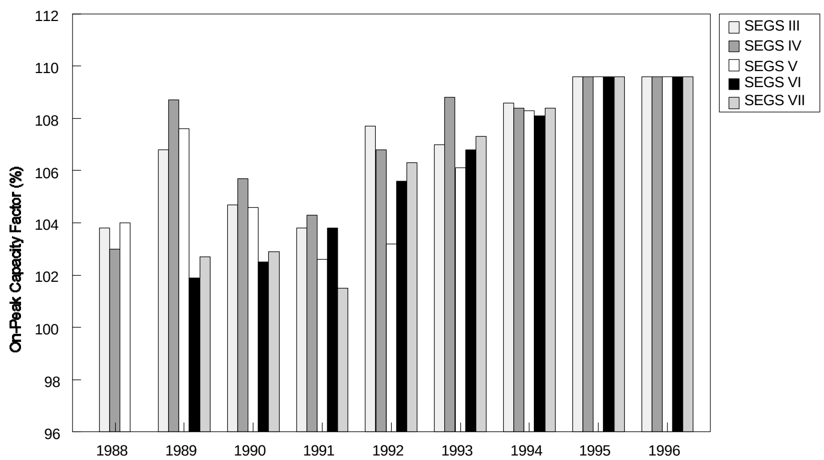

Figure 4. On-peak capacity factors for five 30 MW SEGS plants during 1988 to 1996 [10].

Domestic Market: The primary domestic market opportunity for parabolic trough plants is in the Southwestern deserts where the best direct normal solar resources exist. These regions also have peak power demands that could benefit from parabolic trough technologies. In particular, California, Arizona, and Nevada appear to offer some of the best opportunities for new parabolic trough plant development. However, other nearby states may provide excellent opportunities as well. The current excess of electric generating capacity in this region and the availability of low cost natural gas make future sustained deployment of parabolic trough technology in this region unlikely unless other factors come into play. However, with utility restructuring, and an increased focus on global warming and other environmental issues, many new opportunities such as renewable portfolio standards and the development of solar enterprise zones may encourage the development of new trough plants. All of the existing Luz-developed SEGS projects were developed as independent power projects and were enabled through special tax incentives and power purchase agreements such as the California SO-2 and SO-4 contracts.

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International Markets: With the high demand for new power generation in many developing countries, the next deployment of parabolic troughs could be abroad. Many arid regions in developing countries are ideally suited for parabolic trough technologies. India, Egypt, Morocco, Mexico, Brazil, Crete (Greece), and Tibet (China) have expressed interest in trough technology power plants. Many of these countries are already planning installations of combined cycle projects. For these countries, the trough ISCCS design may provide a cheap and low risk opportunity to begin developing parabolic trough power plants. In regions such as Brazil and Tibet that have good direct normal solar resources and existing large hydroelectric and/or pumped storage generation resources, parabolic trough technologies can round out their renewable power portfolio by providing additional generation during the dry season.

Benefits

Least Cost Solar Generated Electricity: Trough plants currently provide the lowest cost source of solar generated electricity available. They are backed by considerable valuable operating experience. Troughs will likely continue to be the least-cost solar option for another 5-10 years depending on the rate of development and acceptance of other solar technologies.

Daytime Peaking Power: Parabolic trough power plants have a proven track record for providing firm renewable daytime peaking generation. Trough plants generate their peak output during sunny periods when air conditioning loads are at their peak. Integrated natural gas hybridization and thermal storage have allowed the plants to provide firm power even during non-solar and cloudy periods.

Environmental: Trough plants reduce operation of higher-cost, cycling fossil generation that would be needed to meet peak power demands during sunny afternoons at times when the most photochemical smog, which is aggravated by NO_X emissions from power plants, is produced.

Economic: The construction and operation of trough plants typically have a positive impact on the local economy. A large portion of material during construction can generally be supplied locally. Also trough plants tend to be fairly labor-intensive during both construction and operation, and much of this labor can generally be drawn from local labor markets.

Impacts

HTF Spills/Leaks: The current heat transfer fluid (Monsanto Therminol VP-1) is an aromatic hydrocarbon, biphenyl-diphenyl oxide. The oil is classified as non-hazardous by U.S. standards but is a hazardous material in the state of California. When spills occur, contaminated soil is removed to an on-site bio-remediation facility that utilizes indigenous bacteria in the soil to decompose the oil until the HTF concentrations have been reduced to acceptable levels. In addition to liquid spills, there is some level of HTF vapor emissions from valve packing and pump seals during normal operation [11]. Although the scent of these vapor emissions is often evident, the emissions are well within permissible levels.

Water: Water availability can be a significant issue in the arid regions best suited for trough plants. The majority of water consumption at the SEGS plants (approximately 90%) is used by the cooling towers. Water consumption is nominally the same as it would be for any Rankine cycle power plant with wet cooling towers that produced the same level of electric generation. Dry cooling towers can be used to significantly reduce plant water consumption; however, this can result in up to a 10% reduction in power plant efficiency. Waste water discharge from the plant is also an issue. Blowdown from the steam cycle, demineralizer, and cooling towers must typically be sent to a evaporation pond due to the high mineral content or due to chemicals that have been added to the water. Water requirements are shown in Section 5.

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Land: Parabolic trough plants require a significant amount of land that typically cannot be used concurrently for other uses. Parabolic troughs require the land to be graded level. One opportunity to minimize the development of undisturbed lands is to use parcels of marginal and fallow agricultural land instead. A study sponsored by the California Energy Commission determined that 27,000 MW_e of STE plants could be built on marginal and fallow agricultural land in Southern California [12]. A study for the state of Texas showed that land use requirements for parabolic trough plants are less that those of most other renewable technologies (wind, biomass, hydro) and also less than those of fossil when mining and drilling requirements are included [13]. Current trough technology produces about 100 $kWh/yr/m^2$ of land.

Hybrid Operation: Solar/fossil hybrid plant designs will operate with fossil fuels during some periods. During these times, the plant will generate emissions consistent with the fuel.

3.0 Technology Assumptions and Issues

Trough Technology: The experience from the nine SEGS plants demonstrates the commercial nature of parabolic trough solar collector and power plant technologies. Given this experience, it is assumed that future parabolic trough plant designs will continue to focus on the Luz parabolic trough collector technology and Rankine cycle steam power plants. The next plants built are assumed to copy the 80 MW SEGS plant design and use the third generation Luz System Three parabolic trough collector.

Cost and Performance Data: The information presented is based on existing SEGS plant designs and operational experience. In addition, much of the cost data comes from PilkSolar [1] who has been actively pursuing opportunities for parabolic trough developments in many international locations. Performance projections assume a solar resource that would be typical for plants located in the California Mojave Desert. PilkSolar developed a detailed hour-by-hour simulation code to calculate the expected annual performance of parabolic trough plants. This model has been validated by baselining it against an operating SEGS plant. The model was found to reproduce real plant performance within 5% on an annual basis. The model can be used to perform design trade-off studies with a reasonable level of confidence.

Power Plant Size: Increasing plant size is one of the easiest ways to reduce the cost of solar electricity from parabolic trough power plants. Studies have shown that doubling the size reduces the capital cost by approximately 12-14% [1]. Figure 5 shows an example of how the levelized energy cost for solar electricity decreases by over 60% by only increasing the plant size. Cost reduction typically comes from three areas. First, the increased manufacturing volume of collectors for larger plants drives the cost per square meter down. Second, a power plant that is twice the size will not cost twice as much to build. Third, the O&M costs for larger plants will typically be less on a per kilowatt basis. For example, it takes about the same number of operators to operate a 10 MW plant as it does a 400 MW plant [2]. Power plant maintenance costs will be reduced with larger plants but solar field maintenance costs will scale more linearly with solar field size.

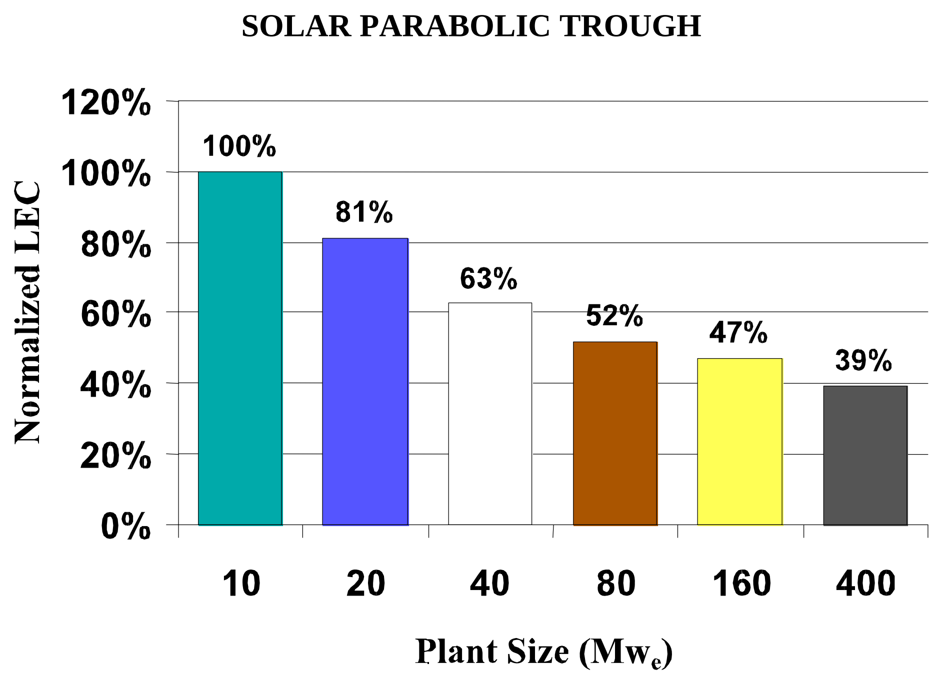

Figure 5. Effect of power plant size on normalized levelized COE.

The latest parabolic trough plants built were 80 MW in size. This size was a result of limitations imposed by the Federal government. Luz had investigated sizes up to 160 MW. The main concern with larger plants is the increased size of the solar field which impacts HTF pumping parasitics. In future plants, pumping parasitics will be reduced by replacing the flexible hoses with the new ball joint assemblies [8], allowing for plants in excess of the 160 MW size to be built.

Hybridization: Hybridization with a fossil fuel offers a number of potential benefits to solar plants including: reduced risk to investors, improved solar-to-electric conversion efficiency, and reduced levelized cost of energy from the plant [14]. Furthermore, it allows the plant to provide firm, dispatchable power.

Since fossil fuel is currently cheap, hybridization of a parabolic trough plant is assumed to provide a good opportunity to reduce the average cost of electricity from the plant. Hybridizing parabolic trough plants has been accomplished in a number of ways. All of the existing SEGS plants are hybrid solar/fossil designs that are allowed to take up to 25% of their annual energy input to the plant from fossil fuel. Fossil energy can be used to superheat solar generated steam (SEGS I), fossil energy can be used in a separate fossil-fired boiler to generate steam when insufficient solar energy is available (SEGS II-VII), or fossil energy can be used in an oil heater in parallel with the solar field when insufficient solar energy is available (SEGS VIII-IX). The decision on type of hybridization has been primarily an economic decision. However, it is clear from the SEGS experience that hybridization of the plants has been essential to the operational success of the projects.

The alternative ISCCS design offers a number of potential advantages to both the solar plant and the combined cycle plant. The solar plant benefits because the incremental cost of increasing the size of the steam turbine in the combined cycle is significantly less than building a complete stand-alone power plant. O&M costs are reduced because the cost of operation and maintenance on the conventional portion of the plant is covered by the combined cycle costs. Also, the net annual solar-to-electric efficiency is improved because solar input is not lost waiting for the turbine plant to start up, and because the average turbine efficiency will be higher since the turbine will always be running at 50% load or above. The combined cycle benefits because the fossil conversion efficiency is increased during solar operation since the gas turbine waste heat can be used more efficiently. Solar output will also help to offset the normal reduction in performance experienced by combined cycle plants during hot periods. Figure 6 shows how the LEC for an 80 MW solar increment ISCCS plant compares to those of a solar only SEGS and a conventional hybrid SEGS plant.

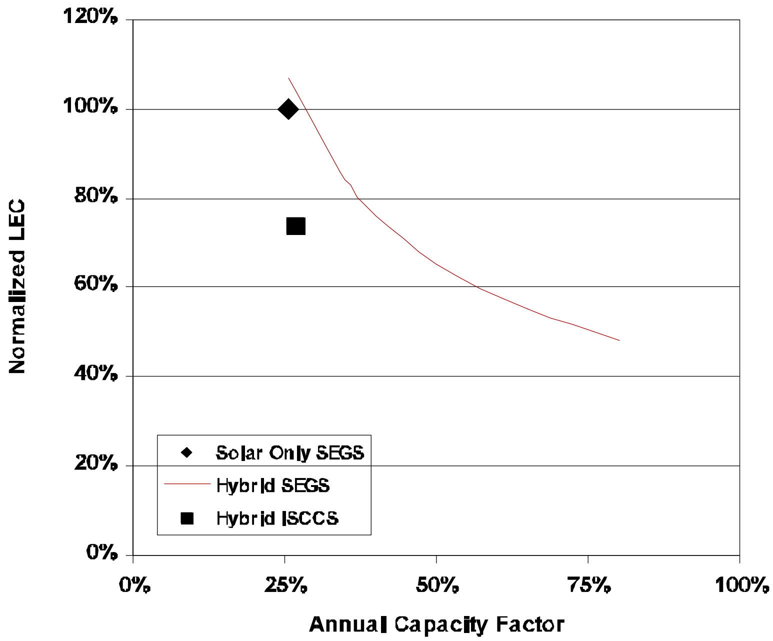

Figure 6. Effect of hybridization on LEC.

Thermal Storage: The availability of efficient and low-cost thermal storage is important for the long-term cost reduction of trough technology and significantly increases potential market opportunities. A parabolic trough plant with no fossil backup or thermal storage, located in the Mojave Desert, should be capable of producing electricity up to about a 25% annual capacity factor. The addition of thermal storage could allow the plant to dispatch power to non-solar times of the day and could allow the solar field to be oversized to increase the plant's annual capacity factor to about 50%. Attempting to increase the annual capacity factor much above 50% would result in significant dumping of solar energy during summer months. An efficient 2-tank HTF thermal storage system has been demonstrated at the SEGS I plant. However, it operates at a relatively low solar field HTF outlet temperature (307ºC/585ºF), and no cost effective thermal storage system has yet been developed for the later plants that operate at higher HTF temperatures (390ºC/734ºF) and require a more stable (and expensive) HTF. A study of applicable thermal storage concepts for parabolic trough plants has recommended a concrete and steel configuration, though other methods are possible [6].

Advanced Trough Collector: One of the main performance improvements possible for single axis tracking parabolic trough collectors is to tilt the axis of rotation above horizontal. Luz looked at tilting their LS-4 design 8º above horizontal and estimated a 9% increase in annual solar field performance.

Direct Steam Generation (DSG): In the DSG concept, steam is generated directly in the parabolic trough collectors. This saves cost by eliminating the need for the HTF system and reduces the efficiency loss of having to use a heat exchanger to generate steam. The solar field operating efficiency should improve due to lower average operating temperatures and improved heat transfer in the collector. The trough collectors require some modification due to the higher operating pressure and lower fluid flow rates. Control of a DSG solar field will likely be more complicated than the HTF systems and may require a more complex design layout and a tilted collector. DSG offers a number of advantages over current HTF systems, but controllability and O&M risks have yet to be resolved. A pilot demonstration of DSG technology is in progress at the Plataforma Solar de Almería in Spain [15].

Project Development Issues: The environment in which a trough project is developed will have a significant impact on the eventual cost of the technology. As mentioned in the Overview of Solar Thermal Technologies, building multiple plants in a solar power park environment, the type of project financing, and access to incentives which levelize the tax burden between renewables and conventional power technologies can dramatically improve the economics of STE technologies. Although project financing and tax equity issues are not addressed in this doccument, the technology cases presented in Section 4 assume that multiple projects are built at the same site in a solar power park environment. This assumption seems reasonable since a stand-alone plant would be significantly more expensive and less likely to be built.

Performance Adjustment Factor for Solar Radiation at Different Sites: Direct normal insolation (DNI) resources vary widely by location. The performance projections presented in the following sections assume a solar resource equivalent to Barstow, California. Table 3 shows the DNI resources for other locations [2,16] and the approximate change in performance that might be expected due to the different solar radiation resources. From Table 3 it can be seen that a 1% change in DNI results in a greater than 1% change in electric output. It is important to note that the table does not correct for latitude which can have a significant impact on solar performance. In general, solar field size can be increased to offset reduced performance resulting from lower clear sky radiation levels, but increased size cannot help reductions resulting from increased cloud cover, unless the plant also includes thermal storage.

4.0 Performance and Cost

Table 4 summarizes the performance and cost indicators for the parabolic trough system characterized in this report.

4.1 Evolution Overview

The parabolic trough plant technology discussion presented focuses on the development of Luz parabolic trough collector designs and the continued use of Rankine cycle steam power plants. Although the ISCCS concept is likely to be used for initial reintroduction of parabolic trough plants and could continue to be a popular design alternative for some time into the future, the approach used here is to look at how parabolic trough plants will need to develop if they are going to be able to compete with conventional power technologies and provide a significant contribution to the world’s energy mix in the future. To achieve these long-term objectives, trough plants will need to continue to move towards larger solar only Rankine cycle plants and develop efficient and cost effective thermal storage to increase annual capacity factors.

Table 3. Solar radiation performance adjustment.

Location	Site Latitude	Annual DNI (kWh/m^2)	Relative Solar Resource	Relative Solar Electric Output
United States				
Barstow, California	35ºN	2,725	1.00	1.00
Las Vegas, Nevada	36ºN	2,573	0.94	0.93
Tucson, Arizona	32ºN	2,562	0.94	0.92
Alamosa, Colorado	37ºN	2,491	0.91	0.89
Albuquerque, New Mexico	35ºN	2,443	0.90	0.87
El Paso, Texas	32ºN	2,443	0.90	0.87
International				
Northern Mexico	26-30ºN	2,835	1.04	1.05
Wadi Rum, Jordan	30ºN	2,500	0.92	0.89
Ouarzazate, Morocco	31ºN	2,364	0.87	0.83
Crete	35ºN	2,293	0.84	0.79
Jodhpur, India	26ºN	2,200	0.81	0.75

1997 Technology: The 1997 baseline technology is assumed to be the 30 MW SEGS VI plant [17]. The SEGS VI plant is a hybrid solar/fossil plant that uses 25% fossil input to the plant on an annual basis in a natural gas-fired steam boiler. The plant uses the second generation Luz LS-2 parabolic trough collector technology. The solar field is composed of 800 LS-2 SCAs (188,000 m^2 of mirror aperture) arranged in 50 parallel flow loops with 16 SCAs per loop. Similar to the 80 MW plants, the power block uses a reheat steam turbine and the solar field operates at the same HTF outlet temperature of 390ºC (734ºF). Solar steam is generated at 10 MPa and 371ºC (700ºF). The plant is hybridized with a natural gas fired steam boiler which generates high pressure steam at 10 MPa and 510ºC (950ºF).

2000 Technology: The year 2000 plant is assumed to be the next parabolic trough plant built which is assumed to be the 80 MW SEGS X design [4]. The primary changes from the 1997 baseline technology is that this plant size increases to 80 MW, the LS-3 collector is used in place of the LS-2, the HCE uses an improved selective coating, and flex hoses have been replaced with ball joint assemblies. The solar field is composed of 888 LS-3 SCAs (510,120 m^2 of mirror aperture) arranged in 148 parallel flow loops with 6 SCAs per loop. The plant is hybridized with a natural gas fired HTF heater.

2005 Technology: The power plant is scaled up to 160 MW. Six hours of thermal storage is added to the plant to allow the plant to operate at up to a 40% annual capacity factor from solar input alone. No backup fossil operating capability is included. The LS-3 parabolic trough collector continues to be used, but the solar field size is scaled up to allow the plant to achieve higher annual capacity factor using 2,736 SCAs (1,491,120 m^2 of mirror aperture) arranged in 456 parallel flow loops with 6 SCAs per loop.

2010 Technology: The power plant is scaled up to 320 MW and operates to an annual capacity factor of 50% from solar input. Again no fossil backup operation is included. This design incorporated the next generation of trough

Table 4. Performance and cost indicators.

INDICATOR NAME	UNITS	1997 SEGS VI * Base Case	+/-%	2000 SEGS LS-3 25% Fossil †	+/-%	2005 SEGS LS-3 w/Storage	+/-%	2010 SEGS LS-4 w/Storage	+/-%	2020 SEGS DSG w/Storage	+/-%	2030 SEGS DSG w/Storage	+/-%
Plant Design													
Plant Size	MW	30		80		161		320		320		320	
Collector Type		LS-2		LS-3		LS-3		LS-4		LS-4		LS-4	
Solar Field Area	m^2	188,000		510,120		1,491,120		3,531,600		3,374,640		3,204,600	
Thermal Storage	Hours	0		0		6		10		10		10	
	MWh_t	0		0		3,000		10,042		9,678		9,678	
Performance													
Capacity Factor	%	34		34		40		50		50		50	
Solar Fraction (Net Elec.)	%	66		75		100		100		100		100	
Direct Normal Insolation	kWh/m^2-yr	2,891		2,725		2,725		2,725		2,725		2,725	
Annual Solar to Elec. Eff.	%	10.7		12.9		13.8		14.6		15.3		16.1	
Natural Gas (HHV)	GJ	350,000		785,000		0		0		0		0	
Annual Energy Production	GWh/yr	89.4		238.3		564.1		1,401.6		1,401.6		1,401.6	
Development Assumptions													
Plants Built Per Year		2		2		2		3		3		3	
Plants at a Single Site		5		5		5		5		5		5	
Competitive Bidding Adj.		1.0		1.0		0.9		0.9		0.9		0.9	
O&M Cost Adjustment		1.0		0.9		0.85		0.7		0.6		0.6	
Operations and Maintenance Cost													
Labor	$/kW-yr			32	25	21	25	14	25	11	25	11	25
Materials				31	25	31	25	29	25	23	25	23	25
Total O&M Costs		107		63		52		43		34		34	

Notes:

1. The columns for "+/- %" refer to the uncertainty associated with a given estimate.
2. The construction period is assumed to be 1 year.
3. Totals may be slightly off due to rounding.

* SEGS VI Capital cost of $99.3M in 1989$ is adjusted to $119.2M in 1997$. Limited breakdown of costs by subsystem is available. Performance and O&M costs based on actual data.

† By comparison, an ISCCS plant built in 2000 with an 80 MW solar increment would have a solar capital cost of $2,400/kW, annual O&M cost of $48/kW, and an annual net solar-to-electric efficiency of 13.5%[1].

‡ To convert to peak values, the effect of thermal storage must be removed. A first-order estimate can be obtained by dividing installed costs by the solar multiple (i.e., SM={peak collected solar thermal power}÷ {power block thermal power}).

Table 4. Performance and cost indicators.(cont.)

INDICATOR NAME	UNITS	1997 SEGS VI * Base Case	+/-%	2000 SEGS LS-3 25% Fossil †	+/-%	2005 SEGS LS-3 w/Storage	+/-%	2010 SEGS LS-4 w/Storage	+/-%	2020 SEGS DSG w/Storage	+/-%	2030 SEGS DSG w/Storage	+/-%
Capital Cost													
Structures/Improvements	$/kW	54		79	15	66	15	62	15	60	15	58	15
Collector System		3,048		1,138	25	1,293	25	1,327	25	1,275	25	1,158	25
Thermal Storage System		0		0		392	+50/-25	528	+50/-25	508	+50/-25	508	+50/-25
Steam Gen or HX System				109	15	90	15	81	15	80	15	79	15
Aux Heater/Boiler		120		164	15	0	15	0	15	0	15	0	15
Electric Power Generation				476	15	347	15	282	15	282	15	282	15
Balance of Plant		750		202	15	147	15	120	15	120	15	120	15
Subtotal (A)		3,972		2,168		2,336		2,400		2,326		2,205	
Engr, Proj./Const. Manag.	A * 0.08			174		187		192		186		176	
Subtotal (B)		3,972		2,342		2,523		2,592		2,512		2,382	
Project/Process Conting	B * 0.15			351		378		389		377		357	
Total Plant Cost		3,972		2,693		2,901		2,981		2,889		2,739	
Land @ $4,942/ha				11		15		18		17		17	
Total Capital Requirements	$/kW	3,972		2,704		2,916		2,999		2,907		2,756	
	$/kW$_{peak}$ ‡	3,972		2,704		1,700		1,400		1,350		1,300	
	$/m^2	634		424		315		272		276		275	
Operations and Maintenance Cost													
Labor	$/kW-yr			32	25	21	25	14	25	11	25	11	25
Materials				31	25	31	25	29	25	23	25	23	25
Total O&M Costs		107		63		52		43		34		34	

Notes:

1. The columns for "+/- %" refer to the uncertainty associated with a given estimate.
2. The construction period is assumed to be 1 year.
3. Totals may be slightly off due to rounding.

* SEGS VI Capital cost of $99.3M in 1989$ is adjusted to $119.2M in 1997$. Limited breakdown of costs by subsystem is available. Performance and O&M costs based on actual data.

† By comparison, an ISCCS plant built in 2000 with an 80 MW solar increment would have a solar capital cost of $2,400/kW, annual O&M cost of $48/kW, and an annual net solar-to-electric efficiency of 13.5%[1].

‡ To convert to peak values, the effect of thermal storage must be removed. A first-order estimate can be obtained by dividing installed costs by the solar multiple (i.e., SM={peak collected solar thermal power}÷ {power block thermal power}).

collector, possibly something like the Luz LS-4 advanced trough collector (over 3,500,000 m^2 of mirror aperture). The solar field continues to use a heat transfer fluid but the collector is assumed to have a fixed tilt of 8º.

2020 - 2030 Technology: Power plant size is assumed to remain at 320 MW with 50% annual capacity factor. This design assumes the technology will incorporate direct steam generation (DSG) into the collector in the solar field (over 3,200,000 m^2 of mirror aperture).

4.2 Performance and Cost Discussion

Plant Performance

Increasing the performance of the solar collectors and power plant are one of the primary opportunities for reducing the cost of trough technology. Collector performance improvements can come from developing new more efficient collector technologies and components but often also by improving the reliability and lifetime of existing components. Table 4 shows the annual performance and net solar-to-electric efficiency of each of the technology cases described above.

The 1997 baseline case performance represents the actual 1996 performance of the 30 MW SEGS VI plant (its 8th year of operation). During 1996, the SEGS VI plant had an annual net solar-to-electric efficiency of 10.7% [10,18]. This performance was somewhat reduced by the high level of HCE breakage at the plant (5% with broken glass and 1% with lost vacuum). Since the HCE problems at SEGS VI are due to a design error that was later corrected, we assume that HCE breakage at future plants should remain below 1%, a number consistent with the experience at the SEGS V plant. The SEGS VI plant was selected as the baseline system because substantially more cost and performance data is available and more analysis of plant performance has been completed than at either of the existing 80 MW SEGS plants. Note, even though only 25% of the annual energy input to the plant comes from natural gas, since this energy is converted only at the highest turbine cycle efficiency, 34% of the annual electric output from the plant comes from gas energy.

The year 2000 technology shows a 20% improvement in net solar to electric efficiency over the 1997 baseline system performance. This is achieved by using current technologies and designs, by reducing HCE heat losses and electric parasitics. New HCEs have an improved selective surface with a higher absorptance and a 50% lower emittance. This helps reduce trough receiver heat losses by one third. The ball joint assemblies and the reduced number of SCAs per collector loop (6 for LS-3 versus 16 for LS-2 collectors) will reduce HTF pumping parasitics. Adjusting for reduced parasitics, improved HCE selective surface, and lower HCE breakage, a new 80 MW plant would be expected to have a net solar-to-electric efficiency of 12.9%.

The 2005 technology shows a 7% increase in efficiency primarily as a result of adding thermal storage. Thermal storage eliminates dumping of solar energy during power plant start-up and during peak solar conditions when solar field thermal delivery is greater than power plant capacity. Thermal storage also allows the power plant to operate independently of the solar field. This allows the power plant to operate near full load efficiency more often, improving the annual average power block efficiency. The thermal storage system is assumed to have an 85% round-trip efficiency. Minor performance improvements also result from scaling the plant up to 160 MW from 80 MW. Annual net solar-to-electric efficiency increases to 13.8% [1].

The 2010 technology shows a 6% increase in net solar-to-electric efficiency primarily due to the use of the tilted collector. Power plant efficiency improves slightly due to larger size of the 320 MW power plant. Thermal storage has been increased to 10 hours and the solar field size increased to allow the plant to operate up to a 50% annual capacity factor. As a result, more solar energy must be stored before it can be used to generate electricity, thus the 85% round-trip efficiency of the thermal storage system tends to have a larger impact on annual plant performance. The resulting annual net solar-to-electric efficiency increases to 14.6%.

The 2020 and 2030 technologies show 5% and 10% improvements in performance over the 2010 trough technology. The is due to the introduction of the direct steam generation trough collector technology. DSG improves the efficiency in the solar field and reduces equipment costs by eliminating the HTF system. Power cycle efficiency is assumed to improve due to higher solar steam temperatures. Solar parasitics are reduced through elimination of HTF pumps. Although feedwater must still be pumped through the solar field, it is pumped at a much lower mass flow rate. This design also assumes that a low cost thermal storage system with an 85% round-trip efficiency is developed for use with the DSG solar field. Conversion to the DSG collector system could allow the net solar-to-electric efficiency to increase to over 16% by 2030. The changes between 2020 and 2030 are assumed to be evolutionary improvements and fine tuning of the DSG technology.

Cost Reductions

Table 4 shows the total plant capital cost for each technology case on a $/kW/m^2 basis. The technology shows a 30% cost reduction on a $/kW basis and a 55% reduction on a $/m^2 basis. These cost reductions are due to: larger plants being built, increased collector production volumes, building projects in solar power park developments, and savings through competitive bidding. In general, the per kW capital cost of power plants decreases as the size of the plant increases. For trough plants, a 49% reduction in the power block equipment cost results by increasing the power plant size from 30 to 320 MW. The increased production volume of trough solar collectors, as a result of larger solar fields and multiple plants being built in the same year, reduces trough collector costs by 44%. Power parks allow for efficiencies in construction and cost reduction through competitive bidding of multiple projects. A 10% cost reduction is assumed for competitive bidding in later projects.

The annual operation and maintenance (O&M) costs for each technology are shown in Table 4. O&M costs show a reduction of almost 80%. This large cost reduction is achieved through increasing size of the power plant, increasing the annual solar capacity factor, operating plants in a solar power park environment, and continued improvements in O&M efficiencies. Larger plants reduce operator labor costs because approximately the same number of people are required to operate a 320 MW plant as are required for a 30 MW plant. The solar power park assumes that five plants are co-located and operated by the same company resulting in a 25% O&M savings through reduced overhead and improved labor and material efficiencies. In addition, about one third of the cost reduction is assumed to occur because of improved O&M efficiency resulting from improved plant design and O&M practices based on the results of the KJC O&M Cost Reduction Study [8].

Summary

The technology cases presented above show that a significant increase in performance and reduction in cost is possible for parabolic trough solar thermal electric technologies as compared with the 1997 baseline technology case. Figure 7 shows the relative impacts of the various cost reduction opportunities or performance improvements on the baseline system's levelized cost of energy. It is significant to note that the majority of the cost reduction opportunities do not require any significant technology development. Conversely, significant progress must be made in these non-technology areas if parabolic troughs are to be competitive with conventional power technologies and make any significant market penetration.

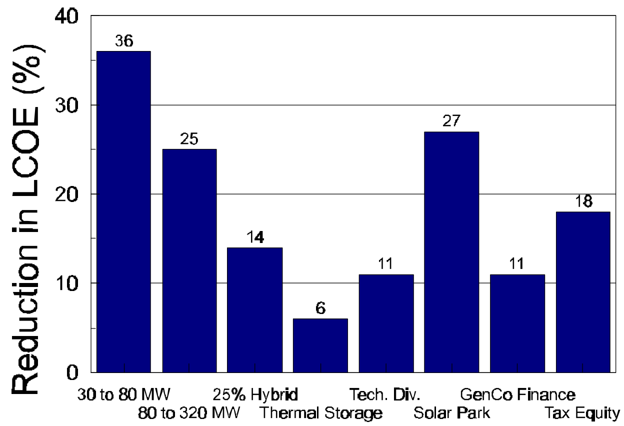

Figure 7. Cost reduction opportunities for parabolic trough plants.

5.0 Land, Water, and Critical Materials Requirements

Land and water requirements are shown in the table below for each of the technology cases. The land and water requirements initially increase as a result of increasing plant annual operating capacity factors. The land requirements begin to decrease as a result of improving solar-to-electric efficiencies. Note, the plant capacity factor increases over time because future plants are assumed to include thermal storage and proportionally larger solar fields.

Table 4. Resource requirements [2].

Indicator Name	Units	Base Year 1997	2000	2005	2010	2020	2030
Plant Size	MW	30	80	161	320	320	320
Land	ha/MW	2.2	2.2	3.1	3.7	3.6	3.4
	ha	66	176	500	1,190	1,150	1,090
Water	m^3/MW-yr	18,500	14,900	17,500	21,900	21,900	21,900

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