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Reducing the Cost of Energy from Parabolic Trough Solar Power Plants

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REDUCING THE COST OF ENERGY FROM PARABOLIC TROUGH SOLAR POWER PLANTS

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ABSTRACT

Parabolic trough solar technology is the most proven and lowest cost large-scale solar power technology available today, primarily because of the nine large commercial-scale solar power plants that are operating in the California Mojave Desert. However, no new plants have been built during the past ten years because the cost of power from these plants is more expensive than power from conventional fossil fuel power plants. This paper reviews the current cost of energy and the potential for reducing the cost of energy from parabolic trough solar power plant technology based on the latest technological advancements and projected improvements from industry and sponsored R&D. The paper also looks at the impact of project financing and incentives on the cost of energy.

INTRODUCTION

This paper provides an assessment of the cost of power for parabolic trough solar power technology for large-scale grid-connected power applications, for both near-term and future parabolic trough solar power plants.

The development and operation of the SEGS plants by Luz International Ltd. – totaling 354 MWe net installed capacity – provide a firm initial basis for future performance and cost projections. All are still in operation, best represented by the five 30-MWe plants operated by KJC Operating Co. at Kramer Junction, California. The Luz group failed in 1991, but technology development in the United States continued in the 1990s [1, 2].

The cost of energy can be reduced through technology improvements, scale-up in individual plant MW capacity, increased deployment rates, competitive pressures, use of thermal storage, and advancements in O&M methods. The cost of energy can also be reduced through lower cost financing and through taxation or investment incentives. The United States and European parabolic trough industries have developed proprietary plans for lowering costs in future trough power plants. The evaluation given here provides a cost estimate that generally agrees with industry expectations for R&D advances in component and subsystem improvements.

METHODOLOGY

This paper draws upon known data from technology improvements, R&D plans, and expected gains to project both reductions in investment costs and increases in performance. These data have been utilized in an NREL-developed model for evaluating the performance and economics of parabolic trough power plants, the primary metric being the levelized cost of electricity [3]. The model includes an hourly performance simulation module, a capital cost module, an O&M cost module, and a project-financing module. The performance module has been validated against the actual performance at the SEGS plants. For this study, the model predicted the annual gross solar-to-electric performance of SEGS VI during 1999 within 1% when using actual solar field availabilities, collector receiver conditions, mirror reflectivity and site solar radiation data. The capital cost module is in part based on detailed cost data from Flabeg Solar International [4]. The O&M cost module is based in part on data from KJC Operating Company. The project finance module is a 30-year cash flow model for evaluating independent power producer (IPP) power plant projects.

The evaluation reported here also draws from a recent study [5] that examines the cost expectations for near-term, mid-term, and long-term trough power plants, generally covering the time frames of 2004, 2010, and 2020.

Reference Plant

Potential parabolic trough plant cost reductions are discussed from a reference point of the operating SEGS plants in the California Mojave Desert. The efficiency of existing parabolic trough plants has been well characterized and provides a good basis for evaluating the potential performance improvements of future parabolic trough plants. We have used the 30-MWe SEGS VI plant as our reference plant for evaluating future cost and performance of trough plants. We selected SEGS VI as a reference because:

- it is the last of the SEGS plants that uses the LS-2 collector for the full solar field. The LS-2 collector has demonstrated the best overall O&M characteristics of the three collector designs used at the SEGS plants.
- it operates at the higher temperature also used at the later 80-MWe plants, with steam conditions of 100 bar and 371°C.
- the operator (KJC Operating Company) has provided detailed operation and maintenance data on the plant.

The NREL model has been used to model the cost and performance of the 30-MWe SEGS VI plant. The SEGS VI plant is a hybrid plant and can produce electricity from both solar energy and natural gas. Federal law allows the SEGS plants to use 25% fossil fuel heat input into the steam on an annual basis. Table 1 shows the general design, cost, and performance characteristics of the 30-MWe trough plant. The solar field constitutes approximately 60% of the direct costs. While the technology is assumed to be the same as used in SEGS VI, the capital costs are based on current cost projections [4]. The calculated levelized cost of energy or LCOE [6] is based on current financial assumptions assumed to be available to a large-scale trough plant built in the United States[1] and is stated in constant or real 2002 U.S. dollars. Unless otherwise noted, the analysis uses the 1999 insolation data from Kramer Junction, California (2,940 kWh/m2-yr).

The resulting cost of power for the 30-MWe SEGS VI trough plant, if built today, is 17.0¢/kWh for a solar-only plant and 14.1¢/kWh for the hybrid plant.

Near-Term Trough Plants

A number of new parabolic trough power plant projects are currently under consideration around the world. The technology used in these projects will build on the equipment and experience from the SEGS plants. In addition, important advances have occurred since the last parabolic trough plant was built that will have an impact on the efficiency and cost of the next plants built.

[1] Financing Assumptions: 8.5% debt interest rate, 20-year debt term, 1.35 debt service coverage ratio, 14% equity internal rate of return, 30-year project life, annual insurance cost 0.5% of capital cost, annual property tax 0.5% of capital cost, 10% Investment Tax Credit (ITC), 5-year MACRS, 2.5% inflation.

Table 1 Reference 30 MWe SEGS Plant

Site: Kramer Junction	Solar Only	Hybrid (25%)
Plant size, net electric (Mwe)	30	30
Collector aperture Area (km^2)	0.188	0.188
Thermal storage (hours)	0	0
Solar-to-electric efficiency (%)	10.6%	10.7%
Plant Capacity factor (%)	22.2%	30.4%
Capital cost ($/kWe)	3,008	3,204
O&M cost ($/kWh)	0.046	0.034
Fuel cost ($/kWh)	0.000	0.013
LCOE [2002$/kWh]	0.170	0.141

The KJC Operating Company (KJCOC) operation and maintenance (O&M) cost reduction program [1] resulted in a number of key advances that have significantly reduced O&M costs. Key among these are improvements in mirror washing-techniques, improved heat-transfer fluid pump seal O&M practices, improved O&M practices for reducing receiver tube failures, and improved control and information systems.

Solel Solar Systems has recently developed a new parabolic trough receiver referred to as the universal vacuum (UVAC) receiver. The UVAC has improved thermal and optic properties. Field tests of the new receiver at SEGS VI shows a 20% increase in thermal performance compared to original receiver tubes.

KJCOC has also implemented a new piping interconnection for the piping interface between collectors, referred to as ball-joint assemblies, for replacement of the original flexible hoses. A demonstration test of new ball-joint assemblies has been shown to reduce the hydraulic pressure drop in the solar field by approximately 50%. This results in significantly lower solar field heat transfer fluid pumping electric parasitics.

Based on the advances in parabolic trough technology mentioned above, our baseline reference near-term plant will have the following characteristics:

- 50 MWe net electric output. This size is currently being planned for several new trough plants
- LS-2 parabolic trough collectors. The LS-2 is one of several collector configurations being considered in near-term projects. The LS-2 represents the lowest risk and most conservative technology assumption
- UVAC receiver. The new Solel receiver has been demonstrated at the SEGS plants and will be the receiver of choice for new projects
- Ball-joint assemblies in place of flex hoses. These have been extensively demonstrated at the SEGS plants
- O&M improvements to reduce receiver failures and improve mirror reflectivity.

Table 2 shows the characteristics of the near-term baseline trough configuration. Solar-to-electric efficiency is expected to improve by approximately one-third in near-term plants over the original SEGS plants, in large part due to the new Solel receiver and the use of ball-joint assemblies. Unit capital costs are lower because of the larger plant capacity and the more efficient solar field, which helps reduce the size of solar field required. The levelized cost of energy is reduced by about 30-35% from the original SEGS plants.

Table 2 Baseline Near-Term Trough Plant

Site: Kramer Junction	Solar Only	Hybrid (25%)
Plant size, net electric (MWe)	50	50
Collector aperture area (km^2)	0.312	0.312
Thermal storage (hours)	0	0
Solar-to-electric efficiency (%)	13.9%	14.1%
Plant capacity factor (%)	29.2%	39.6%
Capital cost ($/kWe)	2,745	2,939
O&M cost ($/kWh)	0.024	0.018
Fuel cost ($/kWh)	0.000	0.010
LCOE (2002$/kWh)	0.110	0.096

COST REDUCTION OPPORTUNITIES

Although significant cost reductions have occurred since the SEGS plants, these prices are not attractive in the current competitive power market. Studies have shown [7] that the cost of power from a trough plant would need to be on the order of 5¢/kWh to be directly competitive with fossil fuel alternatives at current 2002 fossil prices. A recent assessment has just been completed for the U.S. Department of Energy (DOE) to evaluate the long-term cost reduction potential of parabolic trough technology [5]. A basic conclusion of that study was that the cost of power from parabolic trough technology could be markedly reduced through scale-up of the plant, technology advances, commercial deployment, and financial incentives.

In this section we quantify, using the NREL model, the cost reduction potential of the following specific opportunities: plant scale-up, integration with combined cycle plants, improved receiver technology, advanced concentrator designs, the addition of thermal energy storage, and financial incentives.

Plant Scale-up

One of the primary opportunities for reducing cost is to increase the size of the power plant. In general, power plant equipment costs ($/kWe) decrease with the size of the plant [5]. O&M costs also reduce with plant capacity because it typically takes a power plant O&M crew of about the same size to run a 30-MWe steam plant as it would to run a 200-MWe steam plant. The largest plant built by Luz was limited to 80 MWe by then-current FERC rules for plants to qualify as renewal energy plants under applicable laws. Luz planning also included consideration of larger plant sizes in the 150 to 200 MWe range [8]. The upper limit is defined by a tradeoff between economies of scale and the parasitics involved with the pumping of heat-transfer fluid through the solar field. By replacing flexible hoses with ball-joint assemblies, sizes of 400 MWe or more are feasible because of the much lower pumping parasitics since the major solar system pressure losses are found in the solar collector loops, not in the main headers.

Figure 1 shows the impact on the cost of energy for different size power plants. A 400-MW solar-only trough plant has the potential to produce power for less than 8¢/kWh, whereas the cost of power from the baseline 50-MW plant is 11¢/kWh, independent of other factors such as technical improvements. This is obviously a very important parameter. It should also be noted that many of the advantages achieved in scaling up a plant can also be achieved by siting multiple plants together in a power park.

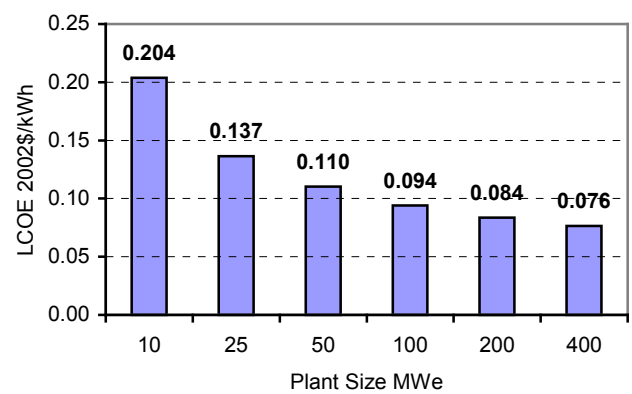

Figure 1 Impact of Plant Size on Cost of Energy

Integrated Solar Combined-Cycle System (ISCCS)

The ISCCS configuration is currently being considered for a number of the Global Environment Facility (GEF) trough projects [5]. The ISCCS integrates solar steam into the Rankine steam bottoming cycle of a combined-cycle power plant. The general concept is to oversize the steam turbine to handle the increased steam capacity. At the high end, steam turbine capacity can be approximately doubled, with solar heat being used for steam generation and gas turbine waste heat being used for preheating and superheating steam. However, when solar energy is not available the steam turbine must run at part load and thus at reduced efficiency. Doubling the steam turbine capacity would result in approximately a 25% design point solar contribution. Because solar energy is only available about 25% of the time, the annual solar contribution for trough plant without thermal storage would only be about 10% for a baseload combined-cycle plant. Studies show that the optimum solar contribution is typically less than the maximum. This is because the more the steam turbine is oversized, the greater the off-design impact on the fossil plant when solar is not available.

These issues are discussed in detail in a recent paper by Dersch [9]. Table 3 shows the cost and performance of the 40-MW solar increment of an ISCCS plant[2] compared to the baseline 50-MWe Rankine cycle plant. The fuel cost is the result of the steam turbine heat rate performance penalty when solar is not available compared to the reference combined cycle plant. The ISCCS configuration offers a significant opportunity to reduce the cost of solar power.

Table 3 ISCCS Cost Reduction Potential

Site: Kramer Junction	Solar Rankine	ISCCS Solar Increment
Plant size, net electric (MWe)	50	40[2]
Collector aperture area (km^2)	0.312	0.222
Thermal storage (hours)	0	0
Solar-to-electric efficiency (%)	13.9%	15.7%
Plant capacity factor (%)	29.2%	29.2%
Capital cost ($/kWe)	2,745	1,988
O&M cost ($/kWh)	0.024	0.008
Fuel cost ($/kWh)	0.000	0.003[3]
LCOE [($/kWh)	0.110	0.073

Receiver Technology Development

The Solel UVAC receiver tube is a significant advance over the previous Luz cermet receiver design [10].

Table 4 shows the key thermal and optical properties of both receivers. In addition, improving reliability of the receiver has a significant impact on the cost of energy. New O&M procedures and are expected to improve receiver reliability at future plants. The new UVAC receiver should reduce the cost of electricity by about 17%. Of this, approximately 7% is due to the improved solar transmittance of the glass envelope, 2% is due to improved solar absorptance of the black absorber, 5% is due to reduced thermal emittance of the absorber, and 3% is due to improved receiver reliability. With continued development of receiver design and selective coatings, further improvements in receiver tube properties and reliability are believed to be possible. Targets of 96% absorptance and a 7% thermal emittance at 400°C appear to be feasible. Reducing receiver failures to 0.5% per year and improving properties can reduce the cost of energy by an additional 5%. Of this, approximately 2% is from the improved solar absorptance, 2% from the improved thermal emittance, and 1% from the improved receiver reliability.

[2] The full ISCCS capacity would be much larger (e.g., on the order of 310 MWe).

[3] Due to lower Rankine cycle efficiency when solar is not available, additional natural gas must be burned to achieve the same electric output as the reference combined cycle plant.

Table 4 Trough Receiver Thermal/Optic Properties

Site: Kramer Junction	Luz Cermet	Solel UVAC	Future Goal
Data source	[11]	[12]	
Envelope solar transmittance	0.915	0.96	0.96
Coating solar absorptance	0.915	0.941	0.96
Coating thermal emittance	0.14	0.091	0.07
@ temperature (°C)	350	400	400
Assumed annual failure rate of glass envelope	5%	2%	0.5%
LCOE 2002$/kWh	0.133	0.110	0.104

Concentrator Size

The size of the collector can have a significant effect on the cost. Luz increased the length and aperture of the LS-3 collector significantly from the LS-2 size. The EuroTrough consortium is looking to further increase the length of the collector [13]. We compare the cost of collectors that are the size of the LS-2, the size of the LS-3, and a collector that is 1.5 times as long as the LS-3 — similar to the EuroTrough design. This analysis assumed that the cost of the structure and mirrors are constant on a per–square-meter basis for all three sizes. This is not completely correct because the cost of the structure will be slightly higher for the larger sizes assuming similar structural stiffness [14]. However, the reduction in cost because of fewer interconnections, drives, electronics and controls, and receivers is a much more significant impact. For example, because the LS-3 uses the same receiver as the LS-2, but has a larger aperture, an LS-2 field of the same size would require 15% more receivers. Although not accounted for in this analysis, mirror costs on a per-square-meter basis are also likely to be lower for the LS-3 size mirrors in comparison to the LS-2 size. Table 5 shows a comparison of cost of the three sizes of collectors. Collector costs for this analysis are based on cost data from Pilkington [4].

Table 5 Effect of Concentrator Size on Cost of Energy

Site: Kramer Junction	LS-2 50	LS-3 100	LS-3 150
Aperture (m)	5	5.75	5.75
Length (m)	50	100	150
Aperture area (m^2)	235	545	818
Number of collectors relative to LS-2 collector	100%	43%	29%
Number of receivers relative to LS-2 collector	100%	87%	87%
Estimated cost ($/$m^2$)	233	208	202
LCOE 2002$/kWh	0.110	0.103	0.102

Thermal Energy Storage

Some of the most significant advances in parabolic trough technology is the development of a thermal energy storage (TES) technologies that will work with the higher solar field operating temperatures required for the later more efficient SEGS plants.

A near-term TES option is a two-tank system that uses molten nitrate salt as the storage medium and has an oil-to-salt heat exchanger to transfer thermal energy from the solar field to the storage system [15]. When the storage system is discharged, the molten salt is circulated back through the heat exchanger to reheat the solar field heat-transfer fluid, which is then sent to the solar steam generator to make steam to operate the power plant. The thermal energy storage system described here is relatively expensive due to the need for a large oil-to-salt heat exchanger and the relatively small temperature difference between hot and cold storage tanks (80-90°C), which means a larger storage volume is required than if a larger temperature difference were possible. The temperature difference in the storage system is currently constrained by upper temperature limit of the heat-transfer fluid (400°C) on the hot side and the steam power cycle on the cold end.

Figure 2 shows the cost of energy from the 50-MWe plant with difference amounts of thermal storage [16]. Small amounts of thermal storage, up to 6 hours of full power output, result in an increase in the cost of energy, while storage capacities between 6 and 16 hours lower the cost of energy. It should be noted that small capacities might still be warranted by virtue of revenue considerations because they would allow the plant to dispatch solar power during the time of day with the highest electricity rates. Note that the lowest cost of energy occurs with approximately 12 hours of TES. Increasing TES beyond 12 hours results in increased dumping of energy during the summer when the plant would already be operating 24 hours a day.

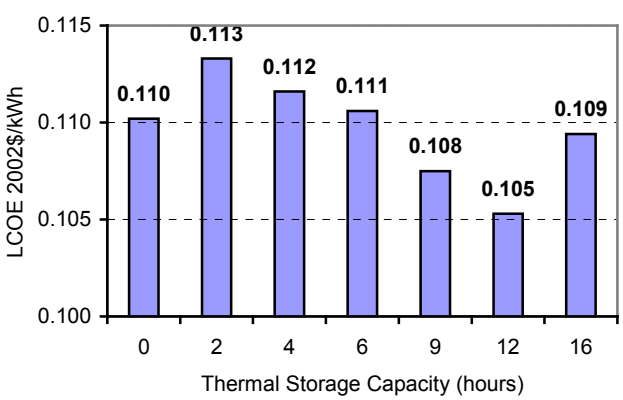

Figure 2 Effect of Thermal Storage on Cost of Energy

A number of advanced storage concepts have been identified that have the potential to significantly reduce the cost of thermal energy storage for parabolic trough plants. The current near-term TES option has a unit cost of \$30 to 40/kWh$_t$ depending on storage capacity. For comparison, the cost of storage for large molten-salt power towers, with a larger operating temperature difference, is expected to be less than \$10/MWh$_t$ [5]. Three approaches are considered for reducing TES costs for troughs. The first is to move from a two-tank system to a single tank thermocline storage system. The second is to go from an indirect system that requires a heat exchanger to one that uses the same fluid in the solar field and storage system (similar to SEGS I or the Solar Two power tower). The third approach is to find a way to increase the hot and cold temperature differential in the storage system, thereby shrinking the storage volume required.

Pacheco [17] evaluated the thermocline TES system concept. This approach eliminates one of the storage tanks and allows most of the liquid stored in the tank to be replaced with a lower cost filler material, in this case quartzite rock and sand. The disadvantage of the thermocline is that there is a thermocline zone that occupies part of the tank, which reduces the useful capacity of the tank and also causes an increase in solar field supply temperature at end of the charge cycle as well as a decay in supply temperature to the power plant at the end of the storage discharge cycle. Appropriate design measures must be taken to maintain a tight thermocline zone in the storage system. The use of the thermocline can reduce the cost of storage by 30% to 50%, depending on the relative cost of liquid to the low cost filler material.

In the two-tank TES configuration, the heat exchanger and related equipment add between 15 to 30% to the total system cost. In addition, the heat exchanger reduces the maximum temperature difference between the hot and cold fluids. Therefore, eliminating the need for a heat exchanger will reduce the TES cost. In a recent study [18, 19], the use of molten-salts directly in the solar field as the heat-transfer fluid and the storage medium has been proposed. This concept eliminates the need for a heat exchanger and allows the solar field operating temperature to be increased to 450°C or possibly higher. The major concern with molten-salts as a heat-transfer fluid in a trough plant is the high freeze point. A ternary nitrate salt mixture has been identified that has a freeze point of approximately 120°C. This temperature appears to make the use of molten-nitrate salt a possibility, although other issues such as loop freeze recovery, maintenance practices and ball-joint seals in molten salt remain technical issues.

Figure 3 below shows the potential impact of advanced thermal energy storage technologies on the cost of energy for a 50-MWe SEGS plant with 12 hours of thermal storage. The chart shows the cost of energy for a plant without thermal storage, a plant with the near-term storage options (a two-tank indirect system), an indirect thermocline system, a direct (molten salt) two-tank system operating at 450°C, and direct thermocline molten-salt system operating at 450°C and 500°C. The advanced thermal storage systems offer a 14% reduction in the cost of energy over the near-term thermal storage option.

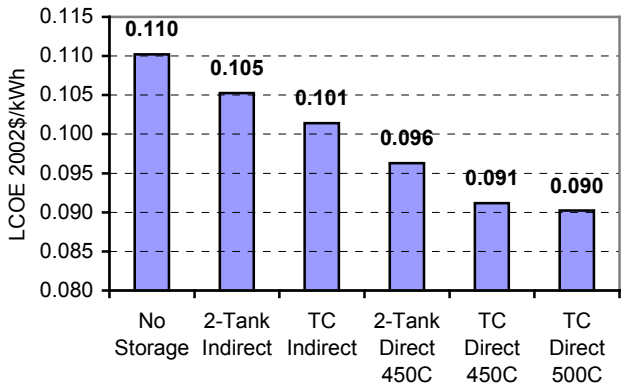

Figure 3 Impact of Advanced Storage Technologies on the Cost of Energy

The advanced TES cases shown in Figure 3 assume that inorganic molten salts are used as the heat-transfer fluid in the solar field. It should be noted that a number of alternative advanced TES concepts are being developed in parallel that may be used for these future higher temperature cases. NREL is currently working to develop organic salt heat-transfer fluids that remain liquid at ambient temperatures [20]. These fluids, if they can be developed to be stable at high temperatures and at a reasonable cost, could substantially reduce the technical risk of moving to a direct TES and a higher operating temperature in parabolic trough plants.

Operation and Maintenance

The KJCOC O&M study [1] has shown that significant reductions in O&M cost have been possible at the existing SEGS plants through improved equipment and methods. It is likely that not all of the O&M cost reduction potential has been realized at the existing plants. Future plants will likely benefit from further improvements in O&M equipment and methods, reductions in solar field spare part costs due to improved technology, increases in capacity factors through implementation of thermal energy storage, and economies of scale with scale-up in plant size and power park developments. All of these cost reductions were not explicitly illustrated above, but are implicitly included in the cost of energy.

Financial Incentives

Capital is the money invested to build a project. This is the complete cost including equipment, construction, and project development. There are two major types of capital investments in a project: equity and debt. The equity investment is made by the parties that will own the plant. Equity investments in typical independent power producer (IPP) projects require a 12 to 18% internal rate of return (IRR) after taxes. The debt investment is similar to a mortgage on a house. IPP projects typically use non-recourse debt, which simply means that the loan is secured by the cash flow of energy sales from the project and the debt investors cannot go after the owners if the project cannot make the loan payments.

A primary difference between solar and fossil plants is that the solar plant has a large solar field that is equivalent to a 30-year fuel supply at the fossil plant and that incurs a high front-end capital investment. Even if the capital cost of the solar field is the same as the fuel cost at the fossil plant, the cost of power from the solar plant will end up being more expensive primarily because of two factors. First any capital investment must be paid back to investors at a high rate of return. Second, tax policy typically treats capital investment less favorably than expense type investments such as fuel. Access to low-cost capital can significantly reduce the cost of solar power. Our baseline 50-MW trough plant assumes an IRR to equity of 14% and a debt interest rate of 8.5%. Figure 4 shows the impact on the cost of energy from our baseline 50 MWe plant for different debt interest rates and equity IRRs when the other is held constant. The availability of low cost sources of debt and equity capital can significantly reduce the cost of energy from capital-intensive solar plants. A more detailed discussion of project finance for trough plants is presented by Kistner and Price [21].

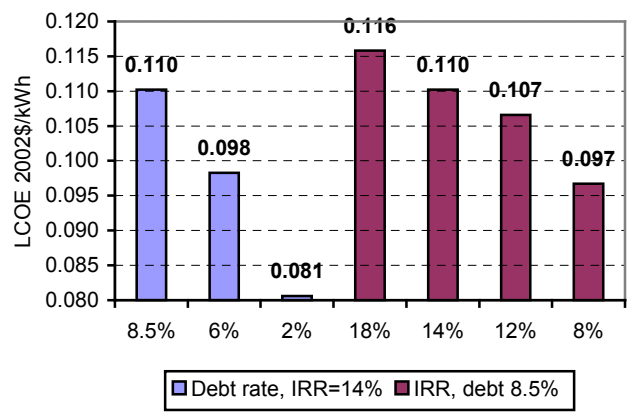

Figure 4 Effect of the Cost of Capital on the Cost of Energy

As previously mentioned, taxation policy tends to penalize capital-intensive solar projects. Without special property tax exemptions, a solar power plant would be forced to pay property tax on the solar field land and equipment. Because the solar field represents a major portion of the total capital cost of the plant, property tax on this equipment represents a significant cost penalty for solar technologies. Similarly, fossil plants also do not pay sales tax on their fuel. To help achieve tax neutrality with fossil technology, solar plants should be exempted from paying sales tax on solar equipment. In addition, because of the greater amount of capital investment for solar plants, the state and federal governments collect more taxes on the income received by debt and equity investors. Thus, the state and federal governments can offer special incentives to help encourage investment in capital-intensive renewable technologies and still remain whole through increased tax revenues.

Historically, several types of incentives have been offered to renewable energy technologies. The SEGS plants benefited from federal and state investment tax credits (ITC) ranging from 10 to 50%[4] of the capital investment. A 10% federal ITC is currently still in place. The SEGS plants also benefited from a property tax exemption on all solar equipment, which is currently still in existence in California. The ITCs proved to be very successful for encouraging the development of the SEGS plants. Currently production-based incentives are the preferred approach for encouraging the development of a healthy renewables industry. A 1.8¢/kWh production tax credit (PTC) is currently available to wind and biomass technologies and is largely responsible for the rapid growth in wind capacity in the United States. The 1.8¢/kWh PTC is also being considered for large-scale solar technologies, but is currently not sufficient to encourage near-term projects. In the recent DOE 1000-MWe CSP Report [22], tax incentives including a 1.8¢/kWh PTC and a 30% ITC were considered necessary in the short term to help CSP technologies be competitive.

Figure 5 shows the impact on the cost of power with different tax incentives. Note that the current 10% ITC already reduces the cost of power by almost 1¢/kWh from the case with no ITC. The 1.8¢/kWh PTC is only marginally better than the current 10% PTC. The last bar shows the impact of the 30% ITC, the 1.8¢/kWh PTC, and property tax exemption. These incentives reduce the cost of power to under 8¢/kWh for the near-term solar-only 50-MWe trough plant.

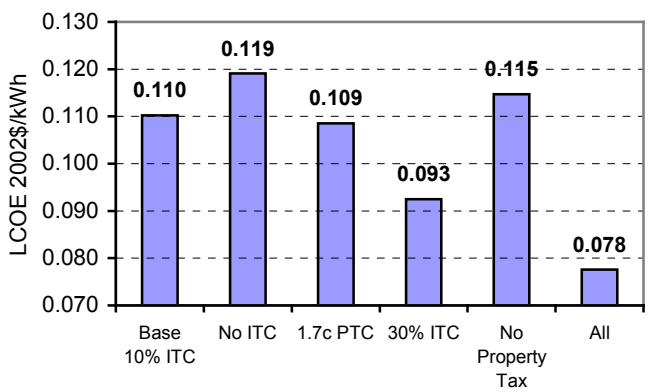

Figure 5 Effect of Tax Incentives on the Cost of Energy

Site Solar Resource

The direct normal solar resource has a significant impact on project economics. For the most part, the analysis presented in this paper uses the 1999 solar resource data from Kramer Junction, California. Table 6 shows the effect of site solar resource on the cost of energy for the baseline near-term trough plant for other locations. This highlights the need for finding sites with good solar resources. This also shows the importance of having good solar resource data for the specific plant site.

Table 6 Effect of Solar Resource on the Cost of Energy

Site	DNI Resource kWh/m^{2}yr	LCOE $/kWh	Source
Kramer Junction, Calif.	2,940	0.110	a
Daggett, Calif.	2,792	0.115	b
Las Vegas, Nevada	2,606	0.125	b
Phoenix, Ariz.	2,519	0.124	b
El Paso, Texas	2,488	0.127	b
Cedar City, Utah	2,340	0.147	b
Reno, Nevada	2,333	0.147	b

Source: a – KJC Operating Company, 1999 DNI data
b – NREL TMY 2 Data, http://rredc.nrel.gov/

FUTURE COST POTENTIAL

In looking at the potential future cost of parabolic trough technology, two advanced technology scenarios are considered.

Mid-term scenario:

- 100-MWe Plant
- molten-salt HTF operating at 450°C.
- thermocline TES with 12 hours of storage
- larger LS-3 collector aperture and 150m length
- Improved receiver with 96% absorptance and 7% emittance at 400°C
- 5% cost reduction from current due to production volume

Long-term scenario:

- 400-MWe Plant
- Molten-salt HTF operating at 500°C.
- Thermocline TES with 12 hours of storage
- Same collector and receiver assumptions
- 20% cost reduction from current due to production volume.

Table 7 shows the key cost and performance parameters of the current, near-term, and future parabolic trough plants.

Table 7 Technology Characteristics and Cost

Case	SEGS VI	Near-Term	Mid-Term	Long-Term
Size, MWe	30	50	100	400
Solar field size, km^2	0.19	0.31	1.03	3.91
Solar field cost, $/m^2	234	245	184	122
TES size, hours	0	0	12	12
TES cost, $/kWh	na	na	14	13
Power block, $/kWe	1022	854	657	363
Annual capacity factor	22%	29%	56%	56%
Solar-to-electric efficiency	10.6%	13.9%	16.2%	17.2%
Total capital cost, $/kWe	3,008	2,745	3,416	2,225
O&M cost, $/kWh	0.046	0.024	0.010	0.006

[4] During 1984-86 the SEGS projects benefited from a 10% Federal Investment Tax Credit, a 15% Federal Energy Tax Credit, and a 25% California Solar Energy Tax Credit [8].

For this analysis, we consider four different financing scenarios. The first assumes the current financial incentives for an IPP power project. The second assumes the 1.8¢/kWh PTC in place of the 10% ITC. The third assumes the 30% ITC, the 1.8¢/kWh PTC, and a property tax exemption. The final case is similar to the low-cost capital assumption, which assumes that the project is purchased by a municipal utility. Municipal utilities have access to low cost financing with interest rates as low as 6%.

Figure 6 shows the results of the analysis for the current and future plants for each of the financing scenarios. The analysis shows that parabolic trough technology has significant potential for reducing the future cost of energy. The cost of energy forecast for future parabolic trough technologies can be very competitive with fossil power if 5¢/kWh is the target. Financial incentives can be used to help make near-term projects more competitive. The 1.8¢/kWh PTC is slightly more attractive than the current 10% ITC for the baseline parabolic trough plant; however, the PTC becomes much more attractive in the future when the capital cost and thus the value from the ITC is reduced. However, increased incentives, municipal financing, or special above market prices are likely to be necessary in the short-term.

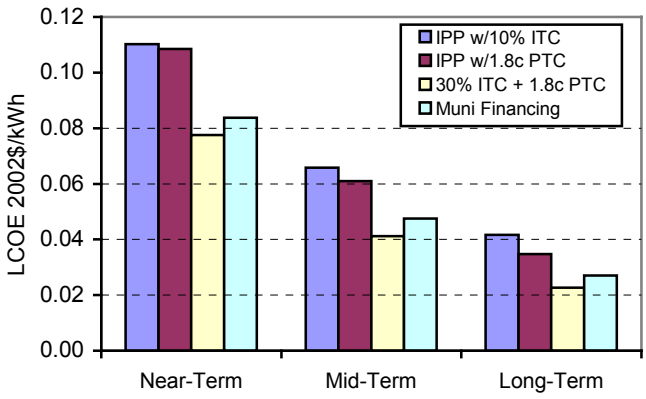

Figure 6 The Cost of Energy for Near-Term and Future Parabolic Trough Power Plants with different Financing Assumptions

CONCLUSIONS

Many factors have an effect on the cost of power: plant configuration, size, financing structure, and tax incentives. Even for current technology there is a wide range in costs for potential near-term plants. The costs presented here are for plants located in the Mojave Desert. The cost of power would be higher for locations with a lower solar resource.

There is significant opportunity for reducing the cost of power from parabolic trough power plants. Under various realistic scenarios, future plants appear to have the potential to directly compete with fossil power. While increasing plant size offers the easiest opportunity for reducing the cost of power, a number of technology advances have been identified that can also significantly reduce costs. These include increasing the collector size, improvements in receiver selective coatings, and development of advanced thermal storage technologies.

Financial incentives, market incentives such as renewable portfolio standards, and other approaches such as hybridization or integration into combined cycle power plants may be necessary to encourage near-term projects to be realized and set the stage for accelerated growth of this attractive large-scale solar technology.

NOMENCLATURE

CSP	Concentrating Solar Power Program at DOE
DNI	Direct Normal Insolation
DOE	U.S. Department of Energy
FERC	Federal Energy Regulatory Commission
GEF	Global Environment Facility
HTF	heat-transfer fluid
IPP	independent power producer
IRR	internal rate of return
ITC	investment tax credit
ISCCS	integrated solar combined cycle system, a trough solar plant integrated with a combined cycle power plant
KJCOC	KJC Operating Company, operator of SEGS III-VII
LCOE	Levelized cost of energy
LS-2	Luz second generation parabolic trough collector
LS-3	Luz third generation parabolic trough collector
MWe	Mega-watt electric
O&M	operation and maintenance
NREL	National Renewable Energy Laboratory
PTC	production tax credit
R&D	Research and development
SEGS	solar electric generating system
TES	thermal energy storage
TMY	typical meteorological year
UVAC	Solel Universal Vacuum parabolic trough receiver

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Parabolic trough solar technology is the most proven and lowest cost large-scale solar power technology available today, primarily because of the nine large commercial-scale solar power plants that are operating in the California Mojave Desert. However, no new plants have been built during the past ten years because the cost of power from these plants is more expensive than power from conventional fossil fuel power plants. This paper reviews the current cost of energy and the potential for reducing the cost of energy from parabolic trough solar power plant technology based on the latest technological advancements and projected improvements from industry and sponsored R&D. The paper also looks at the impact of project financing and incentives on the cost of energy.

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