Arnold Schwarzenegger
Governor

SOLAR THERMAL PARABOLIC TROUGH ELECTRIC POWER PLANTS FOR ELECTRIC UTILITIES IN CALIFORNIA

PIER FINAL PROJECT REPORT

Prepared For:
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PREFACE

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), annually awards up to $62 million to conduct the most promising public interest energy research by partnering with Research, Development, and Demonstration (RD&D) organizations, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following six RD&D program areas:

- Buildings End-Use Energy Efficiency
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy
- Environmentally Preferred Advanced Generation
- Energy-Related Environmental Research
- Strategic Energy Research

What follows is the final report for the contract 4.1 Solar Thermal Parabolic Trough Power Plant, contract number 500-01-042, conducted by Solargenix Energy. The report is entitled "Solar Thermal Parabolic Trough Electric Power Plants for Electric Utilities in California." This project contributes to the PIER Renewable Energy Program.

For more information on the PIER Program, please visit the Energy Commission's Web site at: http://energy.ca.gov/research/index.html or contact the Energy Commission's Publications Unit at 916-654-5200.

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ABSTRACT

The goal of this project was to evaluate the feasibility of developing up to 1000 MWe of parabolic trough solar thermal power plants to serve municipal utility electricity demand in the State of California. Concentrating solar thermal power technology, notably parabolic troughs, has reached commercial status by virtue of the development and operation of the SEGS plants in the Mojave Desert, a high California desert east of the Sierra Nevada Mountains in the southern region of the state near Barstow. Since the SEGS development in the 1980's and early 1990's, trough cost-effectiveness has progressed due to technology advances and the valuable operating experience gained at those facilities. The nine SEGS plants range in capacity from 14 to 80 MW_{net}, and cost projections have shown that the cost of electricity from these systems can drop even further with larger central station power facilities and identified technology cost reductions.

Financing methods and conditions have a very strong impact on the cost of electricity, regardless of the details of the technology. Municipal financing, in particular, offers a very attractive debt interest rate. With these factors in mind, this study undertook to evaluate the key issues related to the development of large advanced parabolic trough plants in California to serve an aggregation of municipal utility needs, including technology, power plant configurations, siting, permitting, business models, financing and the desired elements of a model power purchase agreement between a trough system developer and a group of municipal utilities. The results of the evaluation and associated analyses are presented in this report.

EXECUTIVE SUMMARY

Solar thermal power systems using concentrating systems offer an opportunity for the State of California to utilize its abundant solar energy resources – the best in the United States – to generate electricity at moderate rates that have a strong potential for significant future cost reductions. This report discusses such systems based on solar parabolic trough technology, and proposes specific strategies to pave the way for near term development in the range of 100's to 1000's of MW capacity with the intent of serving municipal utility[1] needs.

To this end, the Hetch Hetchy Water and Power Division of the San Francisco Public Utilities Commission (Hetch Hetchy/SFPUC) retained Solargenix Energy, LLC to provide an assessment of the design, siting, costs and financing of a series of solar thermal parabolic trough power plants in the state of California, serving municipal utility demand needs. This project (Project 4.1) is the concentrating solar thermal power component of the Hetch Hetchy/SFPUC Programmatic Renewable Energy Project, a set of PIER-funded studies to evaluate the potential of a variety of renewable energy sources and options for energy transmission.

Objectives

The primary objective of Project 4.1 was to examine critical issues related to the installation of solar thermal trough plants in California to serve municipal utility demands. The specific technical and economic objectives were:

- Estimate the relative performance and cost in different regions of the state,
- Examine siting issues for solar parabolic trough power plants,
- Identify specific permitting requirements, with an emphasis on unique issues associated with this technology,
- Discuss technology options that include a reduction of cooling water consumption and add a thermal storage capability to the plants,
- Explore financial and business models, and associated incentives, that might lead to accelerated development and deployment in California, and
- Formulate a draft power purchase agreement for use between an IPP developer and a municipal utility.

Approach

The first step was to compare electricity demand patterns for representative utilities in California to the output patterns from parabolic trough solar power plants located either at a southern California or a northern California site. The electrical output from a solar thermal power plant is well matched to municipal utility demand in California, particularly on a daily or hourly basis. When thermal storage or gas-assist is part of the plant configuration, the match to the utility demand is enhanced. To quantify this output/demand match, the concept of solar plant outage rate, defined as the percent of hours that a solar plant fails to deliver at least 75% of rated capacity during the top 100 demand hours, was introduced. With thermal storage in the plant configuration, the "solar plant outage" is always less than 10%. In actual practice, the individual

[1] The abbreviation "Muni" is also used in this report.

plant operating scenarios would lower this percentage further by optimizing the daily use of thermal storage depending on weather and demand. With gas assist, as at the operating plants at Kramer Junction, the solar plant outage falls to zero. On an annual basis, the solar generation peaks in June and July, while utility peak demand tends to extend from June through September. Figure 1 shows how, on a summer day, thermal storage can be used to shift electrical production from mid-afternoon to early evening to better match the peak demand.

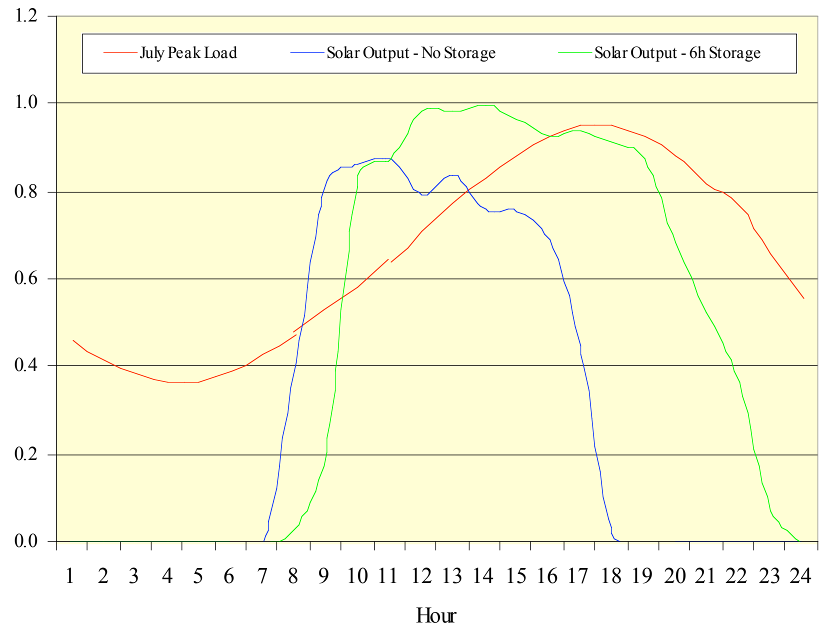

Figure ES-1

Figure 1 – Daily Chart of SoCalMuni Hourly Peak Load compared to Harper Lake Generation with and without Storage

Technology and Siting

Parabolic trough solar technology provides thermal energy to a conventional steam cycle power plant. Parabolic troughs have reached commercial status by virtue of the development and operation of the SEGS plants in the Mojave Desert, a high California desert east of the Sierra Nevada Mountains in the southern region of the state near Barstow. Since the SEGS development in the 1980's and early 1990's, trough plant cost-effectiveness has advanced due to technology advances and the valuable operating experience gained at those facilities. The nine SEGS plants range in capacity from 14 to 80 MW_{net}, totaling 354 MWe. In this study, several technology options were also considered, including dry cooling, use of thermal storage, and use of a supplementary gas-fired steam boiler (hybrid solar/gas energy source).

Siting issues vary broadly in character and importance, and may have either a cost or a more definitive go/no-go impact on a project. Most requirements fall into the former category, or shift from one to the other in the limit. For example, a terrain with a 3% slope has potential, but grading costs would be much higher than a site with <1% slope. However, a very high slope or hilly topography would be totally unsuitable.

While there are many plant cost and construction issues related to siting, the key top-level siting factors for a solar thermal power plant are:

Technical considerations
- Abundance of the solar resource
- Site topography
- Land ownership
- Proximity to transmission and water

Environmental issues
- Fossil fuel air emissions displaced
- Water usage similar to conventional plants
- Solar field heat transfer fluid (HTF)
- Land usage

Possible siting areas (but not specific sites) were examined in southern and northern California, from near Victorville to as far north as Redding. Though transmission access present cost issues in southern California, the higher solar resource there makes that area the most attractive, and subsequent strawman analyses were focused on a plant near Harper Lake, about 15 miles northeast of Edwards Air Force Base. Permitting requirements were thoroughly delineated, with the conclusion that no barrier issues exist.

Economic Outcomes

The cost of electricity from a concentrating solar thermal power (CSP) plant depends on many parameters, including plant ownership, the details of such ownership, the specifics of the financing of the plant and the available incentives. The impact on the cost of electricity of five ownership/ business scenarios was investigated for a nominal 100 MW trough plant of the SEGS type. The base case (1) was private ownership with conventional financing (the IPP model). The other ownership models explored were (2) Muni ownership after debt repayment, (3) Muni (municipal utility) ownership, (4) Private ownership with Muni pre-paid PPA, and (5) Muni ownership of a hybrid solar-combined cycle plant.

Of the various ownership scenarios compared against the base case (#1), the most cost effective was private ownership with Muni prepayment of the PPA (#4). In this scenario, the project is conventionally financed with any and all tax incentives applied to the private ownership. After the plant is built, the Muni pre-pays for the energy to be delivered over the life of the contract. In its purest form, this scenario only requires the private owner to pay for the construction loan as the long term financing is de facto 100% Muni debt financing. This ownership is similar to the privateer owning the plant for a set period and then selling the plant, at an appropriate time, to the Muni. The next most cost effective scenario is simply straight ownership by the Muni (#3). These ownership scenarios allow an energy cost reduction from the IPP conventional financing of approximately 35% to 40% for scenario #4 (Muni pre-payment) and approximately 30% to 35% for scenario #3 (Muni ownership).

The LCOE also depends on the investment cost of the CSP plant, which can be lowered by building larger plants, building more of them, and by incorporating technology improvements. Taken together, it is projected that the LCOE will reach 7 c/kWh after approximately an additional 1,500 MW to 3,000 MW of CSP capacity is installed. This will drop the cost of electricity below that of a new combustion turbine.

Incentives are offered to cover and reimburse the developer for the variety of benefits from the greater use of renewable energy technologies. Currently the incentives available for CSP plants include the federal 10% investment tax credit (ITC) and the federal accelerated depreciation credit plus any applicable state credits. The 1.8 c/kWh production tax credit (PTC) that was granted last year is "either/or" with the 10% ITC, which makes it irrelevant from a practical view. There are currently no California state incentives for Muni-owned CSP plants, or for CSP plants whose power is purchased by Muni's above the normal Muni tax exemptions.

Conclusions

The direct normal solar radiation in specific areas in southern California is large enough to generate thousands of GW using CSP technology. Although currently limited by transmission availability, this still represents a very large and attractive resource for the California Muni's. Trough technology is proven and commercial, but its current cost makes selection difficult for the cost-conscious Muni's; however, as the cost of natural gas continues to rise and fluctuate significantly, and as the costs of CSP technologies fall, Muni's may find that now is the time to include CSP in their renewable energy portfolio. When the added costs of future fuel price volatility and environmental regulations are considered, the near-term costs of CSP appear close to fossil-fueled alternatives. Furthermore, the long-term trend suggests a crossover between CSP and fossil-fueled generation costs within about 5 to 10 years.

Opportunities are certain to be created by the growing interest of the California independently owned utilities in CSP, as well as the interest embodied in the Western Governors' Association 1000 MW CSP Initiative. Taken together, the California Muni's should find a growing number of opportunities to own or contract for CSP generated power.

Commercialization Potential

CSP power plants can only be built on land that is unused for any other activity, that receives a high level of direct solar radiation and preferably that has a slope of about 1% or less. Taking this into account, if just the area in California with the very best direct normal solar radiation (that greater than 8 kWh/m^2/day) is considered, 6,731 MW could be deployed. If a slightly lower, but still very good solar radiation level of 7 kWh/m^2/day is used, this potential increases more that a hundred-fold to 742,305 MW—more than ten fold the State's present electric generation capacity. From the viewpoint of raw potential, California has ample land to produce as much electricity from CSP as needed to fulfill its current and future energy needs. The current voluntary Muni renewable portfolio standards could provide the stimulus to tap this potential, provided the cost issues can be resolved.

Benefits to California

Development of the state's solar energy resource will bring significant economic benefits to the state. While not quantified yet for California, economic impact studies performed in New

Mexico have shown, for example, that building 500 MW CSP in that state adds $2.25 billion to the state's economy, increases the states tax revenues by $1.23 billion and adds 1,696 construction and 397 permanent jobs. Given California's greater economy and greater solar resource, the economic impact will be significantly greater. CSP provides firm dispatchable power which can help meet the states summer peaking needed and peak reserve margins. While clearly the "best fit" renewable options for peak power, the future will likely show that CSP power is the lowest cost option as well.

1.0 Introduction

1.1 Background and Overview

Concentrating solar thermal power technology, notably parabolic trough, has reached commercial status by virtue of the development and operation of the SEGS plants in the Mojave Desert, a high California desert east of the Sierra Nevada Mountains in the southern region of the state near Barstow. Since the SEGS development in the 1980's and early 1990's, trough technology has advanced due to advances in the technology and the valuable operating experience gained at those facilities. The nine SEGS plants range in capacity from 14 to 80 MW_{net}, and cost projections have shown that the cost of electricity from these systems can drop even further with larger central station power facilities. Further, financing methods and conditions also have a very strong impact on the cost of electricity, regardless of the details of the technology. Municipal financing, in particular, offers a very attractive debt interest rate. With these factors in mind, this study undertook to evaluate some of the issues related to the development of large advanced parabolic trough plants in California to serve an aggregation of municipal utility needs, including technology, power plant configurations, siting, permitting, business models, financing and the desired elements of a model power purchase agreement between a trough system developer and a group of municipal utilities.

1.1.1 The Context for CSP in California

The policy framework and market conditions relevant to CSP in California, in the southwestern US and globally, have changed significantly since work on this Task was initiated. In 2002, the California legislature passed SB1078 that set a target of 20% renewable energy generation by the state's IOUs by 2017. While the legislation excluded the Muni's, most of the Muni's have developed their own voluntary targets.

As a result of that legislation, the California Energy Commission and the CPUC held a series of joint hearings to define the implementation rules and procedures for the state's Renewable Portfolio Standard (RPS). In 2004, the three IOUs initiated their bidding process to procure renewable energy resources. While the CSP industry responded to several requests for bids, none have been selected. The current RPS rules favor the lowest cost renewable resource, usually wind, although CSP is a better fit to the utilities load needs.

In 2004, Governor Schwarzenegger formed a Solar Task Force, which recommended that CSP be a part of the state's solar energy strategy. Also in 2004, a bill was introduced into the California legislature to require that one million new homes, built over a ten-year period, incorporate PV. While this bill was defeated, it has been reintroduced and is expected to be voted on in 2005. During the discussions on the new bill, the role of central station solar, that is CSP, has been raised. The many issues related to this bill were the subjects of a Dec 2004 CPUC request for answers to a series of related questions. Several of those questions pertained to CSP.

In 2004, the Western Governors' Association (WGA) included the 1000 MW CSP initiative in the 30 GW Clean and Diversified Energy Initiative. This is likely to stimulate CSP project opportunities in the southwestern US. As California was the co-sponsor of the 30 GW initiative, it is likely that this regional initiative will have a positive influence on CSP in California.

In 2004, California's neighboring states were active in CSP. Nevada Power and Sierra Pacific jointly selected a 50 MW trough plant under that state's RPS. This plant is expected to begin operation towards the end of 2005. Arizona Public Service initiated construction of a 1 MW CSP trough plant as a precursor to larger CSP plants. The Arizona Corporate Commission is reviewing their RPS, called an Environmental Portfolio Standard, and the changes will likely support more CSP in that state. New Mexico governor Richardson, in early 2004, formed a CSP Task Force and charged it with identifying a viable 50-100 MW CSP plant that could be in operation by 2007. The Task Force will issue its report shortly, pointing out several viable project opportunities in that state.

Two major economic impact studies were completed since this Task work began (one by the University of Nevada in Las Vegas and the other by the University of New Mexico). Both looked at the economic impact to their state that would result from building CSP plants there. For example, building a 50 MW plant in New Mexico would add almost $0.5 billion to the state's economy, add $104 million to the state's tax revenues, create 1000 construction jobs and 74 permanent jobs.

The CSP market is also expanding overseas. As a result of changes in key policies in Spain, 500 MW of CSP plants are under active development. In Israel, the bidding process has started for the first 100 MW of a planned 500 MW CSP plant. In Bonn, in June 2004, Ministers from eight countries endorsed the 5000 MW CSP Global Market Initiative

All in all the market for CSP is strengthening and that should make it more attractive for the California Muni's to aggregate their new "RPS" demand and own or purchase power from CSP plants.

1.2 Project Objectives

The feasibility study carried out under this contract was conducted in ten tasks, each of which has been documented in detail. This report assembles and summarizes those reports by providing the essence of each task study; the order of this presentation has been changed slightly from the order of the original tasks to improve the clarity and understanding of the results. The main objectives of this study were to:

- Describe trough technology and discuss the options available for power plant configurations, including thermal storage and dry cooling,
- Evaluate the match of solar system electrical output to utility demand patterns, with and without the use of thermal storage,
- Explore siting issues for parabolic trough plants in California, including environmental considerations, permitting requirements, solar resource intensity, land availability and suitability, general transmission issues and proxy sites,
- Develop plausible business models for development of solar thermal trough plants, identify options for incentives and analyze financing alternatives, and
- Propose a model for a power purchase agreement between an IPP developer and a municipal utility.

1.3 Report Organization

This report is organized as follows:

Section 1.0 Introduction

Section 2.0 Project Approach

Section 3.0 Project Outcomes

Section 4.0 Conclusions and Recommendations

There are 3 appendices:

Appendix A: Project 4.1 Task List
Appendix B: Table of Incentives for CSP
Appendix C: Term Sheet for the Model PPA

2.0 Project Approach

2.1 General

The tasks completed for the solar thermal power plant project are described below in the order in which they appear in this report. Appendix A lists the Project Tasks by original title and in their original order.

- Matching Solar Output to Utility Demand
- Parabolic Trough Solar Power Plant Configurations
- Siting Solar Thermal Plants in California
- Permitting of Parabolic Trough Solar Power Plants in California
- Business Models
- Incentives Report
- Economic Assessment of CSP
- Draft Power Purchase Agreement

To explore the suitability of this type of solar plant to the load, the first step was compare electricity demand patterns for representative utilities in California to the output patterns from parabolic trough solar power plants located at a southern California and a northern California site. We showed that the electrical output from a solar thermal power plant matches quite well with municipal utility demand in California, particularly on a daily basis. This is notably the case when thermal storage or gas-assist is part of the plant configuration. To quantify this point, the concept of solar plant outage rate, defined here to be the percent of hours that a solar plant fails to deliver at least 75% of rated capacity during the top 100 demand hours, was introduced. With thermal storage in the plant configuration, the "solar plant outage" is always less than 10%. In actual practice, the individual plant operating scenarios would lower that level further by optimizing the daily use of thermal storage depending on weather and demand. With gas assist, as at the operating plants at Kramer Junction, the solar plant outage falls to zero. On an annual basis, the solar generation peaks in June and July, while utility peak demand tends to extend from June through September. On a summer day, thermal storage can be used to shift electrical production from mid-afternoon to early evening to better match the peak demand.

2.2 Technology and Siting

Parabolic trough solar technology provides thermal energy to a conventional steam cycle power plant. Parabolic troughs have reached commercial status by virtue of the development and operation of the SEGS plants in the Mojave Desert, a high California desert east of the Sierra Nevada Mountains in the southern region of the state near Barstow. Since the SEGS development in the 1980's and early 1990's, trough-plant cost-effectiveness has advanced due to advances in the technology and the valuable operating experience gained at those facilities. The nine SEGS plants range in capacity from 14 to 80 MWnet, totaling 354 MWe. Several technology options were considered, including dry cooling, use of thermal storage, and use of a supplementary gas-fired steam boiler (hybrid solar/gas energy source).

Siting issues vary broadly in character and importance, and can range from issues that have either a cost impact or a more definitive go/no-go impact on a project. Most requirements fall into the former category, or shift from one to the other in the limit. For example, a terrain with a 3% slope has potential, but grading costs would be much higher than a site with <1% slope. However, a very high slope or hilly topography would be totally unsuitable.

While there are many plant cost and construction issues related to siting, the key top-level siting factors for a solar thermal power plant are:

Technical considerations

- Abundance of the solar resource
- Site topography
- Land ownership
- Proximity to transmission and water

Environmental issues

- Fossil fuel air emissions displaced
- Water usage similar to conventional plants
- Solar field heat transfer fluid (HTF)
- Land usage

Possible siting areas (but not specific sites) were examined in southern and northern California, from a region near Victorville to as far north as Redding. Though transmission access present cost issues in southern California, the higher solar resource there makes that area the most attractive, and subsequent strawman analyses were focused on a plant near Harper Lake, about 15 miles northeast of Edwards Air Force Base. Permitting requirements were thoroughly delineated, with the conclusion that no barrier issues exist.

2.3 Matching Solar Output to Utility Demand[2]

2.3.1 Summary

Electricity demand for representative utilities in California is compared with the output from parabolic trough solar power plants located at a southern California and a northern California

[2] This chapter summarizes the work completed in the task 4.1.2.1 Solar Thermal Plant Assessment Report, dated February 2004.

site. Electricity demand patterns, solar output relative to the demand, and possible dispatchability scenarios are presented or analyzed. Time-of-use pricing implications are discussed.

From the comparisons and analyses presented in the Task 4.1.2 Solar Thermal Plant Assessment Report we conclude that the electrical output from a solar thermal power plant matches quite well with municipal utility demand in California, particularly on a daily basis. This is notably the case when thermal storage or gas-assist is part of the configuration. To quantify this point, the concept of solar plant outage rate, defined here to be the percent of hours that a solar plant fails to deliver at least 75% of rated capacity during the top 100 demand hours, is introduced. With thermal storage in the plant configuration, the "solar plant outage" is always less than 10%. In actual practice, the individual plant operating scenarios would lower that level further by optimizing the daily use of thermal storage depending on weather and demand. With gas assist, as at the operating plants at Kramer Junction, the solar plant outage falls to zero. On an annual basis, the solar generation peaks in June and July, while utility peak demand tends to extend from June through September.

2.3.2 Utility Demand Data Sources

Several municipal utilities were contacted to provide hourly demand data for our analyses. We selected the year 2002 as a representative year. In addition to the municipals, we are also including data from SCE and PG&E as other useful sources to examine solar-demand matching. The load data sources considered in this report, listed alphabetically by abbreviated name and assigned numbers, are:

1. Unnamed northern California Muni (NoCalMuni)
2. Pacific Gas & Electric Co. (PG&E), as a proxy for northern California Muni's
3. Redding Electric Utility (Redding Electric Utility)
4. Southern California Edison (SCE) as proxy for southern California Muni's
5. Sacramento Municipal Utility District (SMUD)
6. Unnamed southern California Muni (SoCalMuni).

The two unnamed municipal utilities provided load data only on condition that they would not be identified and their data would be presented only in a normalized format.

Loads for each utility depend on the mix of customer classes and their own mixes of electrical loads such as production machinery, pumps, refrigeration and air cooling, lighting, appliances, general commercial and general residential use. Loads also depend strongly on weather; e.g., summer temperatures drive up air conditioning needs leading to higher electrical loads on hot days, or at the end of several hot days. As a result, even though a general pattern is apparent on peak days for most California utilities, the details of afternoon or early evening peaking vary from one utility to another as well as from one year to another. These details could affect the appropriate solar thermal plant configuration required to provide reliable power throughout a utility's peak periods.

2.3.2.1 Annual Data

The specific utility data has been represented in two annual representations. Electrical demand data are presented in normalized form, rather than absolute values, with 100% being equivalent to the highest demand for the year for each specific utility (hourly data by peak hour, daily data by peak day). We show:

a) Hourly load plotted for the entire year. Note these features:
   - Significant reductions in demand for weekends and holidays.
   - Daily and seasonal width of the band between the lows and highs. Note, for example, the contrast between bands in winter compared to summer.
   - The peak demand period that generally occurs from June through September, and partially in May and/or October.

b) Daily load for weekdays only (that is, excluding weekend and holidays) over the entire year, with a backward 20 day moving average trend line to give a smoother representation of the pattern. By removing weekends and holidays, we can focus on the peak periods.

The next two figures show data for #6 – SoCalMuni.

Next, in a final year-long graph, the trend lines for each utility's demand are shown together, normalized such that the peak for each utility is placed at 100%. This plot allows the character of the annual patterns to be compared and illustrates the months over which peak demands occur.

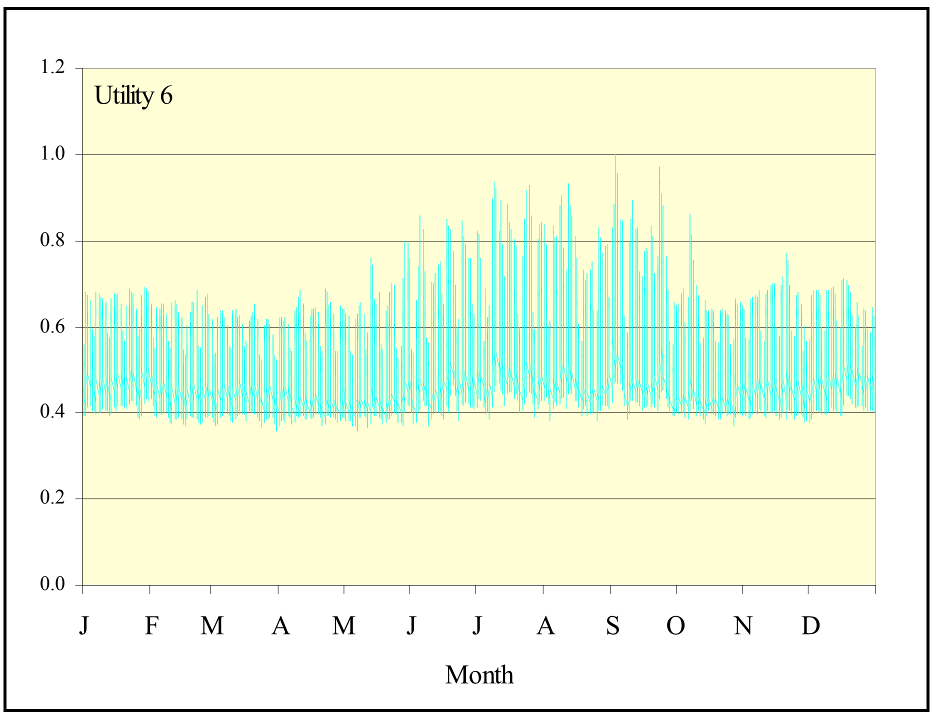

Figure 2 – Annual Normalized Hourly Load – 2002 - SoCalMuni

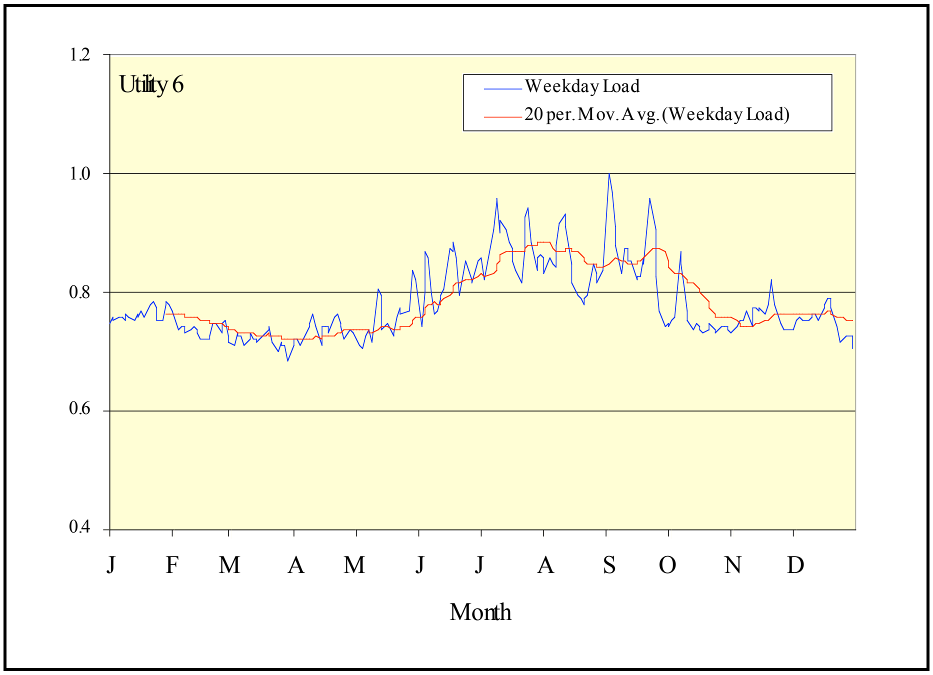

Figure 3 – Annual Normalized Weekday Load – 2002 - SoCalMuni

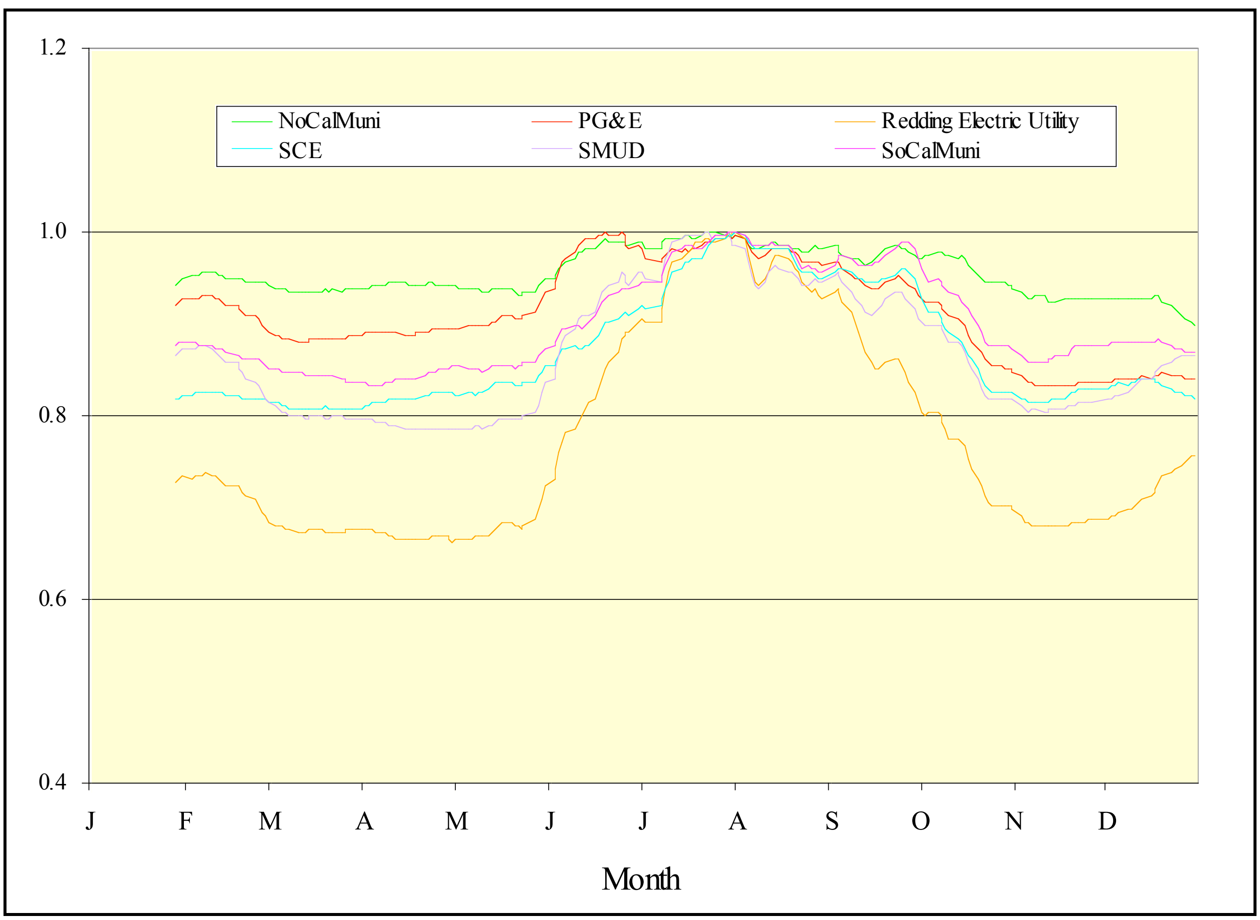

Figure 4 – Annual Demand (based on normalized daily load, 20 day moving averages)

There is a general commonality in these curves in that the peak periods extend from early May through early October. There are significant differences, however, in the relative magnitude of the peaks compared to the low nighttime demand levels. As noted earlier, many factors contribute to these trends, most notably weather and the mix of customer classes.

2.3.2.2 Identification of Peak Days

Intraday patterns are of particular interest because of the variation in solar generation and the impact of thermal storage on that time scale. The three highest daily loads during 2002 for each utility are identified by date and time in Table 1, with the peak load level normalized by the highest load for that utility (i.e., the 100% load). As a general observation, the peak days occur in northern California in the June-August period, while in southern California the peak days occur slightly later.

Table 1 – Highest Load Days and Hours, and Percentage of Peak Load

	3 Highest Peak Days		
Northern California			
SMUD 2714 MW	10-Jul, 6pm 100%	9-Jul, 6pm 92.7%	11-Jul, 5pm 92.6%
PG&E 21456 MW	5-Jun, 4pm 100%	10-Jul, 3pm 97.0%	6-Jun, 4pm 94.7%
NoCalMuni ---	5-Jul, 5pm 100%	10-Jul, 2pm 98.5%	5-Jun, 4pm 98.4%
Redding 227 MW	11-Jul, 4pm 100%	10-Jul, 4pm 99.9%	13-Aug, 4pm 97.0%
Southern California			
SCE 19342 MW	3-Sep, 3pm 100%	23-Sep, 4pm 99.3%	9-Jul, 3pm 98.5%
SoCalMuni ---	3-Sep, 3pm 100%	23-Sep, 3pm 97.2%	4-Sep, 3pm 95.6%

Figure 5 combines all utilities by showing the average peak day for each, defined for this purpose as the mean of the three peak days. Note that the peaks generally occur during the 2pm to 6pm period. Load patterns between regions, and within regions, are largely affected by weather, e.g., summer air-conditioning loads, and utility customer mixes, e.g., industrial, commercial and residential.

We emphasize that the purpose of these plots is to show the pattern of daily demand. For that reason normalized, not absolute, data are used. The 100% peak demand point represents, in fact, different absolute MW levels of peak output corresponding to the specific utility. Comparisons of the demand patterns with solar output patterns, with and without a thermal storage option, are discussed next.

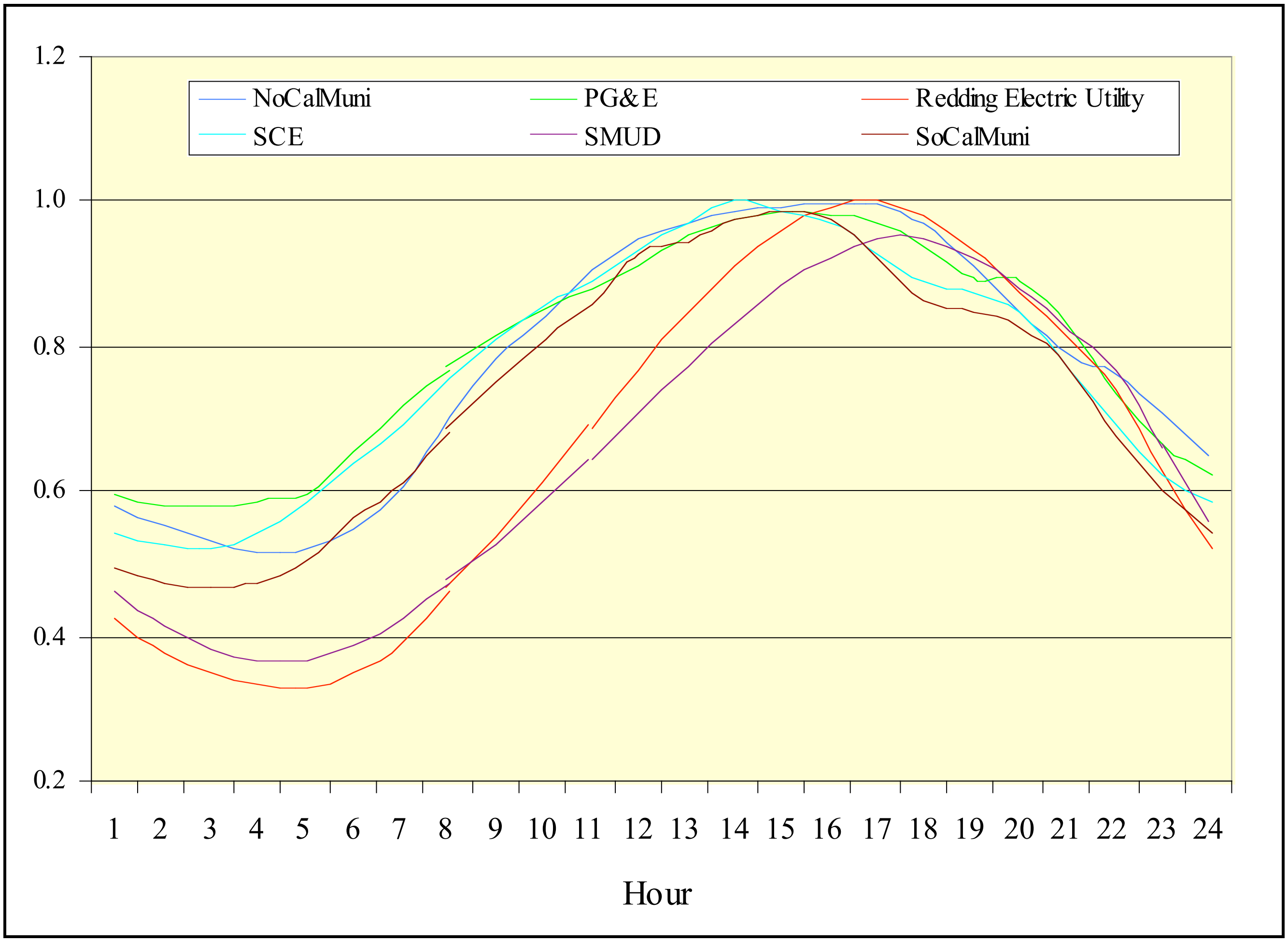

Figure 5 – Utilities 1-6 Average Peak Load Pattern – 2002

2.3.3 Parabolic Trough Solar System Output

In general, the electricity generation from a solar trough power plant on a clear day from approximately May through September rises to full plant capacity early in the day and remains there until late afternoon or early evening. With thermal storage, the generation can be extended for several hours depending on the chosen capacity of thermal storage system and the solar field. From October through April, the output is lower and less regular due to weather patterns. This generalized description can, of course, vary from site-to-site or region-to-region, e.g., northern versus southern California

2.3.3.1 Representative Solar Plant Sites

For purposes of comparing solar power plant electrical output with demand we have chosen two representative sites: the Harper Lake area in southern California and the Sacramento area in northern California. Performance calculations were made for each site, with an identical solar plant, using the solar power plant performance model developed by NREL[3]. The model performs a time-step performance simulation based on plant design and a user-supplied operating strategy. A key feature of the NREL model is that capital cost, operation and maintenance (O&M) cost, and financial calculations have been added directly to the model, allowing the plant design configurations to be more easily optimized. The model is capable of modeling a Rankine-cycle parabolic trough plant, with or without thermal storage, and with or without fossil fuel backup. For both sites the performance is calculated using the appropriate TMY[4] solar resource data for that area.

Typical power plant data is shown in Table 2 for southern California for the no storage case. The capacity factor for this plant, without natural gas assist, is about 26%. Cases were also run with thermal energy storage in the system, allowing collection of the thermal delivery of the solar field to be stored for later use as dictated by grid demand. With storage, the solar field was increased in size by a factor of 1.5 in order to increase the solar-only capacity factor to nearly 39%.

Table 2 – Reference Solar Power Plant Characteristics (Harper Lake Site; no storage case)

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2.3.3.2 Electrical Generation of the Solar Plants

The solar-only electrical production for both sites, with and without thermal energy storage, is shown in Figure 6 and Figure 7. Curves are presented for both annual production, by month. The total annual output at the better solar radiation site (Harper Lake) is about 29% higher than the annual production in Sacramento, largely due to the very low winter, spring and fall generation levels.

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[3] More fully described in Deliverable 4.1.4.1
[4] Typical Meteorological Year data from the National Weather Center.

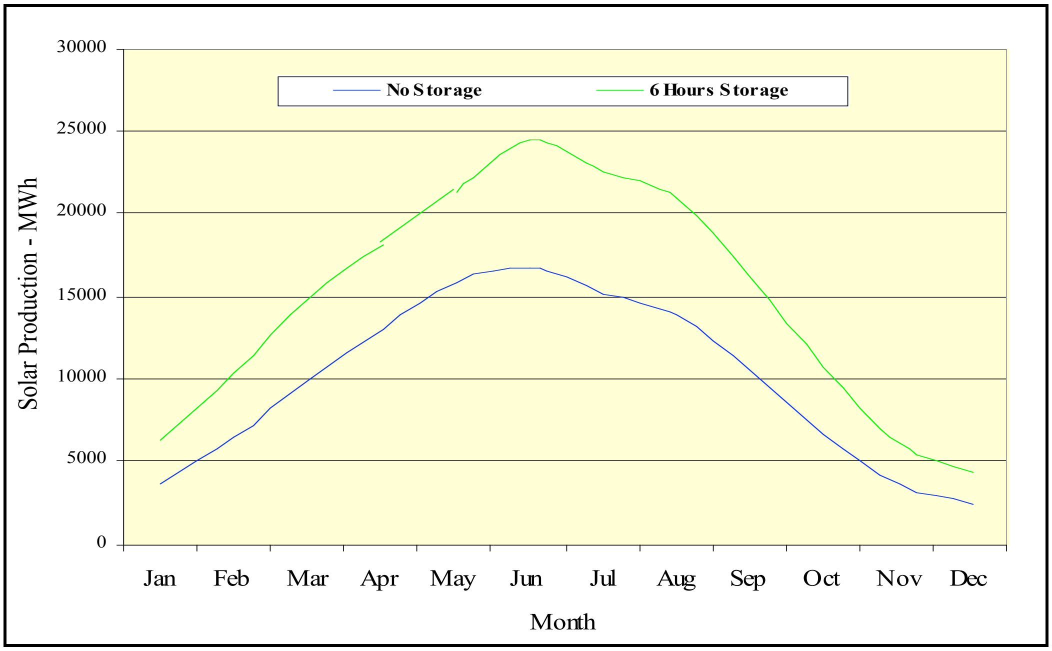

Figure 6 – Harper Lake Annual Solar Production with and without Thermal Storage

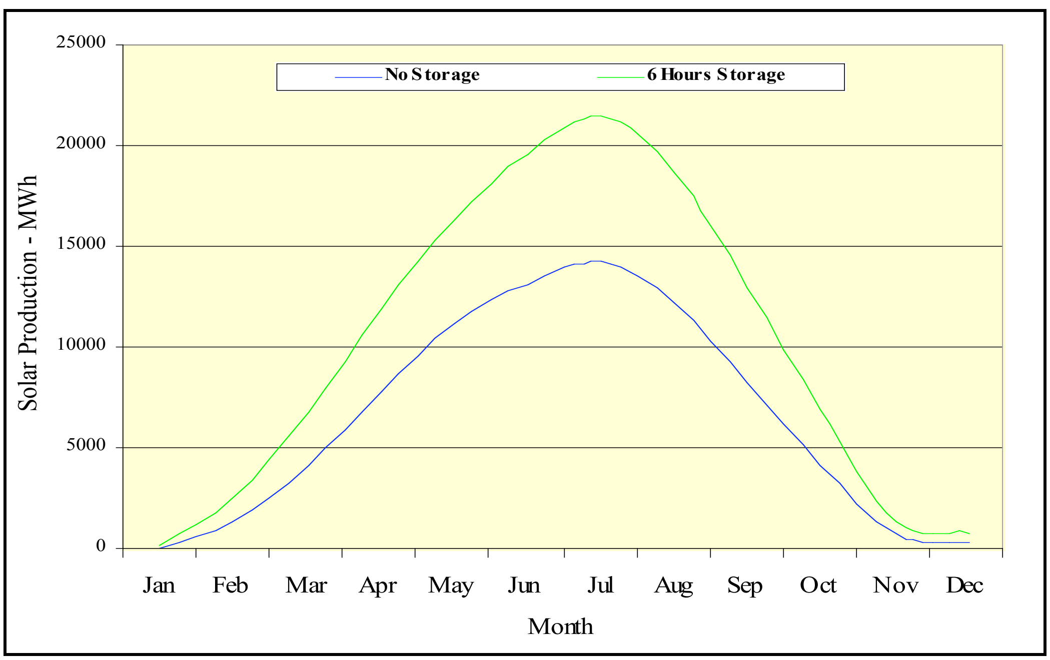

Figure 7 – Sacramento Annual Solar Production with and without Thermal Storage

2.3.3.3 Value of Generation from Peak Plants

Solar thermal power plants configured with natural gas boilers to supplement solar energy input can dispatch power on demand. In periods where the solar radiation resource is low, the decision to use natural gas assist depends on various factors such as the value of electricity at that time, power plant efficiency, plant operation strategies, and the cost of fuel. There is no question, however, that the highest electricity prices occur during peak demand periods.

The value of peaking power is a matter of significant debate in California within the process related to the California Renewable Portfolio Standard (RPS). Relevant to this debate is the recent California Energy Commission publication titled Comparative Cost of California Central Station Generation Technologies[5], which is a resource for ongoing determinations on the Market Price Referent (MPR). The greenfield comparison is viewed to be more representative than evaluation of individual utility rates. For peak power, the Energy Commission has set a cost of electricity based on a simple cycle combustion turbine at 15.71 cents/kWh. For base load power, the cost of generation for a combined cycle is 5.18 cents/kWh. These two systems have estimated capacity factors of 0.11 and 0.85, respectively. A solar thermal power plant, without storage, has a capacity factor of about 0.25. Based on incremental "greenfield" pricing, the true benchmark levelized pricing for on-peak and shoulder dispatchable energy (25% capacity factor) is in the range of 10.5 cents/kWh based on using a GE LM 6000 combustion turbine. Further discussion on the cost and value of solar electricity generation is treated in the Subtask 4.1.8 report and in chapter 2.9 of this report.

2.3.4 Comparison of Utility Demand with Solar Generation

2.3.4.1 Annual Total Comparison for the Year 2002

The correlation between solar power output, both with and without thermal storage in the solar plant configuration, and utility demand is shown graphically to generally illustrate the temporal match that occurs. The solar capacity factor with and without storage is shown for the peak period hours and months based on the performance projection at the southern California site. Finally, the concept of load duration curve is utilized to highlight the solar output during the top 100 hours of demand.

All the calculations and presentations are shown for solar-only electrical generation without natural gas assist in the plant. With natural gas assist, a solar thermal plant could dispatch electricity at a capacity factor of unity during any selected period.

The year 2002 was chosen to illustrate the comparison between demand and solar plant output. Data from 2000 or 2001 were not considered because that data – especially late 2000 and early 2001—very likely contain anomalies as demand patterns at that time were upset by what came to be known as California's energy crisis. While every year has its unique features, we felt from discussions with utilities that 2002 was a sufficiently representative, and recent, "normal" year to make the comparisons presented in this report.

Figure 8 combines the annual utility data (Figure 4) and solar generation data in a single plot. The peak output of both solar sites fall within the peak demand periods, but neither solar plant peak spans the full peak demand periods. The most important observation from this monthly

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[5] Comparative Cost of California Central Station Generation Technologies, Staff Report, Calif. Energy Commission, August 2003, Rept. # 100-03-001

plot is that the solar plant electrical output, on a monthly basis, directly contributes to addressing peak load demand requirements. Though the data is normalized, the solar generation from Sacramento is reduced compared to Harper Lake in order to show the relative solar output between the two sites.

While this graph is useful for a broad-scale view of the correspondence between generation and load, the daily graphs in the next section provide greater detail of the hourly match on peak days. Harper Lake generation is compared with Southern California loads, and Sacramento generation is compared with Northern California loads.

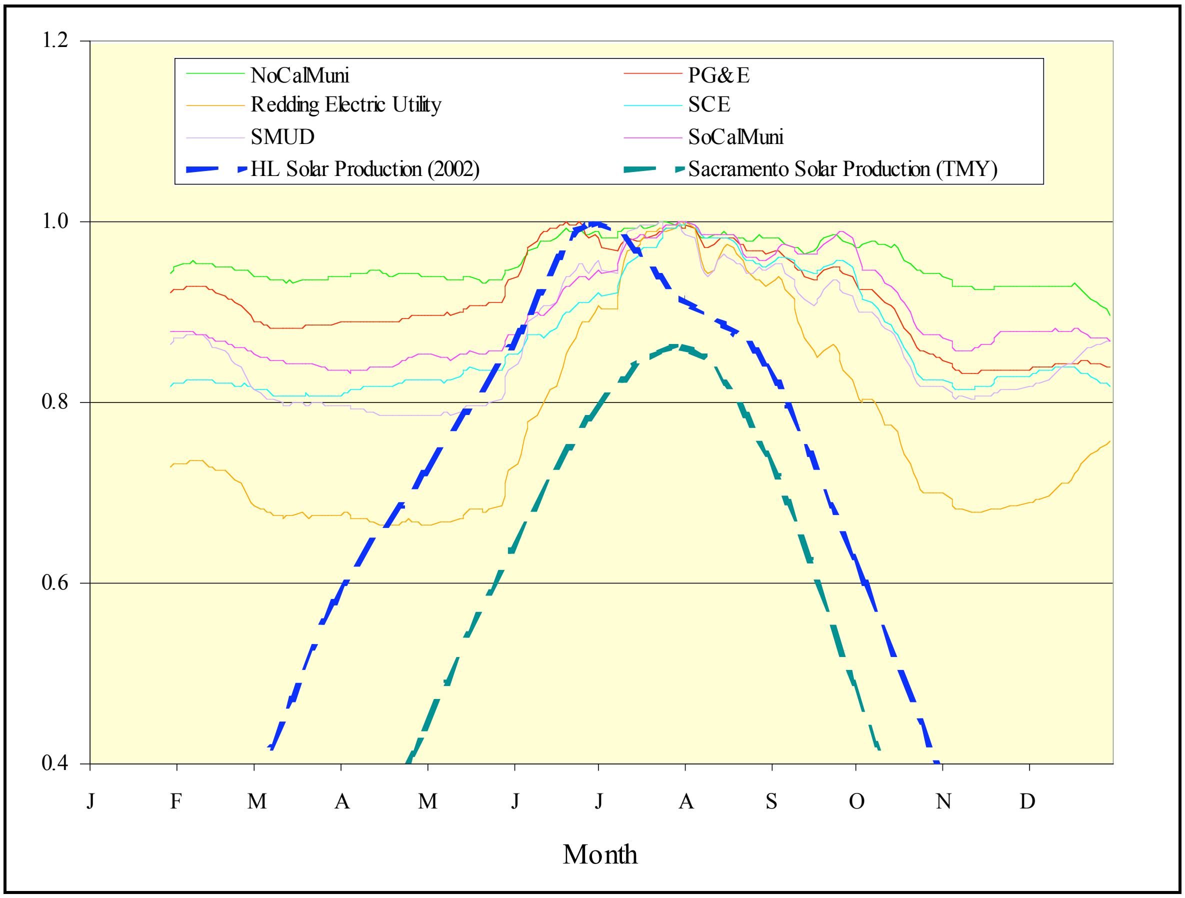


Figure 8 – Utilities 1-6 Demand Load with Harper Lake and Sacramento Solar Production

2.3.4.2 Daily Comparison for Peak Days (hourly data)

The following plot illustrates the match between solar generation and utility demand for selected SoCalMuni and Harper Lake. The operating scenario with 6 hours of thermal storage is predicated on the charging of storage prior to the peak period, and then using both solar generation and stored energy to produce electricity to match the peak demand hours. If the solar resource for that day is high, the storage system will be charged by early afternoon.

For these plots, the solar generation is for the average day of the month for the month represented by the peak utility demand days.

Output for a solar plant configuration with gas assist (supplementary natural gas boiler) is not shown on the graphs. For that case, the solar thermal plant would be fully load-following in peak periods according to the operating scenario chosen by the owners.

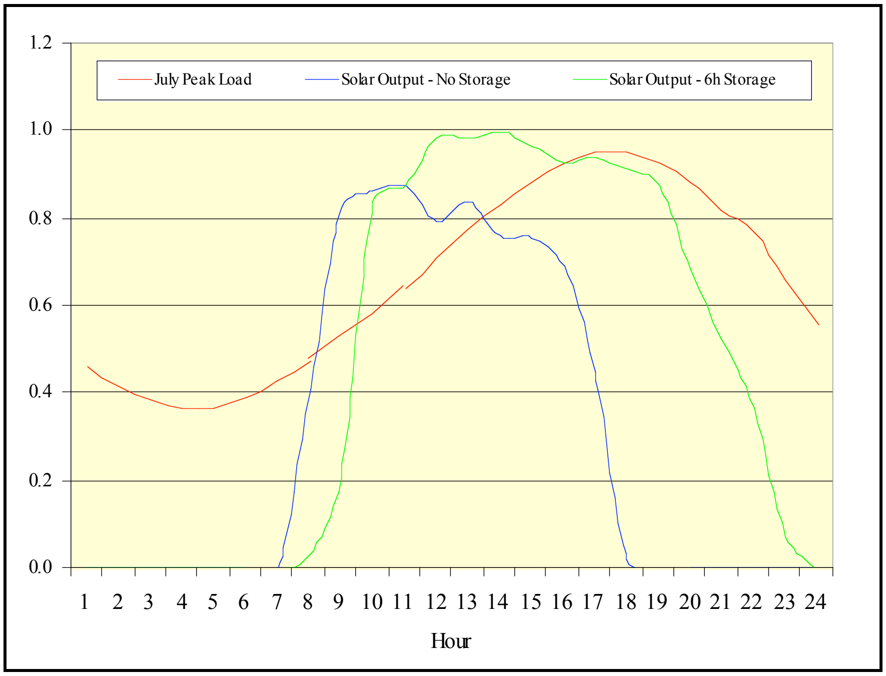


Figure 9 – Daily Chart of SoCalMuni Hourly Peak Load compared to Harper Lake Generation with and without Storage

2.3.4.3 Peak Period Capacity Factors

The period of peak solar output generally occurs in afternoons (12 pm to 6 pm, or 1200-1800) from May through September. The peak periods of municipal utility demand vary somewhat, but in general are on non-holiday weekdays during the same period, with extensions to October in many utilities. The capacity factor[6] is defined here to be the net output of the solar plant normalized by its nominal turbine capacity of 50 MWe. The tables and plots below show the capacity factors for a solar thermal electric plant, operating without gas assist, during this time of year. Results are shown with and without solar thermal storage in the configuration, with significant increases in capacity factor achieved through the use of storage. The site is Harper Lake. With gas assist, the solar plant capacity factor would be 1.0, or 100%.

[6] Capacity factors >1 in a solar plant are not uncommon, which requires some explanation. First, a turbine with a nominal rating of 50 MWe can be run at higher capacities if so designed, and if inlet steam flows are higher than nominal rating. Second, the solar field is sized to produce full power during less than peak conditions, in order to achieve full power over a broader range of weather conditions. The solar plant modeled in these runs is able to produce approximately 58.5 MWe during peak solar conditions, corresponding to a capacity factor of 1.17.

Hourly capacity factors are presented for each peak hour for each peak month; in addition, average values are shown for each hourly time period over the 5 months. The cells in **Table 3** *and* **Table 4** *are color-coded to highlight the results.*

Color Code	*>0.90*	*>0.80*	*>0.70*	*>0.60*	*>0.50*	*>0.40*	*>0.30*

Table 3 – Peak Period Solar Capacity Factors – No Storage

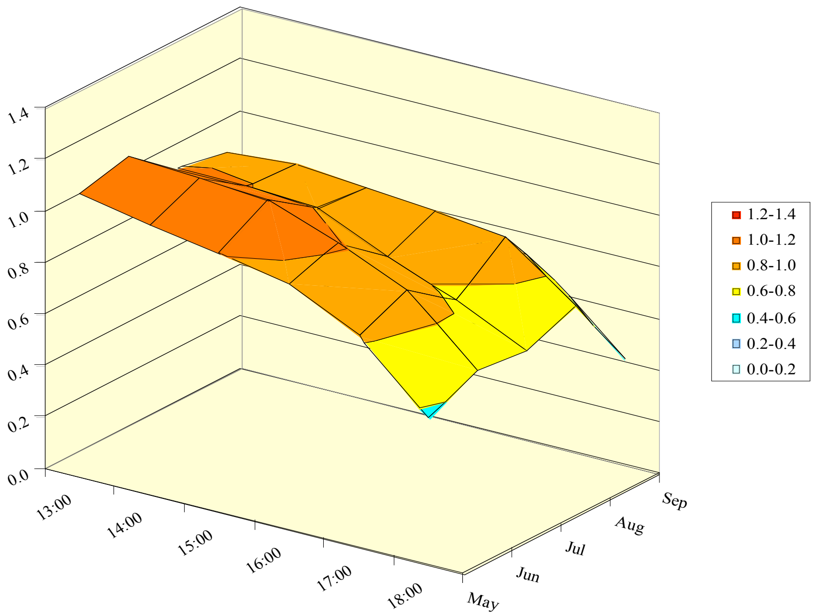
	13:00	14:00	15:00	16:00	17:00	18:00	Average
May	0.94	0.90	0.86	0.82	0.70	0.49	0.78
June	0.98	0.97	0.95	0.87	0.77	0.56	0.85
July	0.86	0.86	0.84	0.74	0.65	0.54	0.75
Aug	0.83	0.85	0.83	0.81	0.78	0.61	0.78
Sept	0.65	0.68	0.60	0.61	0.55	0.35	0.57

Table 4 – Peak Period Solar Capacity Factors – 6 h Storage

	13:00	14:00	15:00	16:00	17:00	18:00	Average
May	0.92	0.95	0.95	0.95	0.92	0.89	0.93
June	0.83	0.86	0.91	0.96	0.97	0.94	0.91
July	0.80	0.81	0.83	0.86	0.89	0.90	0.85
Aug	0.85	0.85	0.85	0.86	0.88	0.90	0.87
Sept	0.82	0.82	0.79	0.75	0.72	0.76	0.78

Figure 10 presents the same information to more graphically show the impact of thermal storage on solar capacity factor during the peak period times.

With no storage



With 6h storage

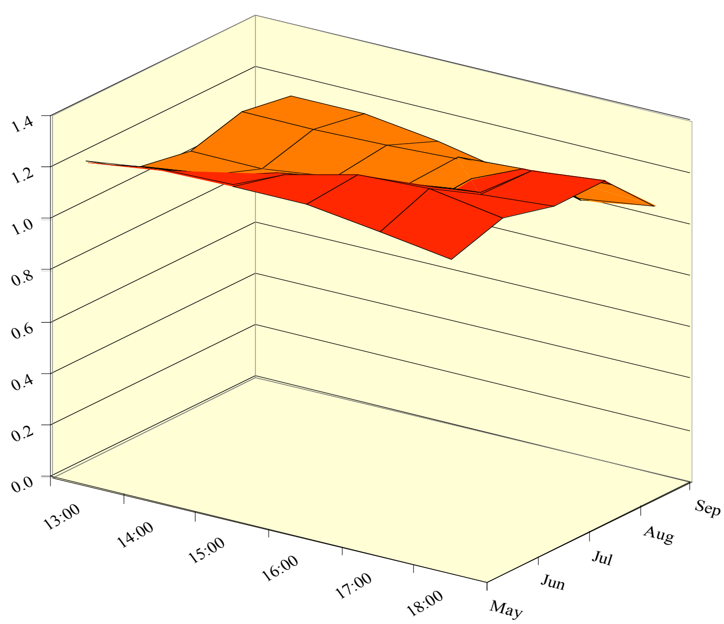


Figure 10 – Solar Capacity Factors during Peak Periods

2.3.5 Load Duration Curves

2.3.5.1 Load Duration Curves

Another perspective useful to compare the match of the solar output to utility demand is the concept of the load duration curve. Utilities have traditionally used load duration curves for capacity planning to summarize how loads compare with available capacity. A load duration curve plots the hourly system loads in descending order, with the highest load on the left and the lowest on the right. The presentation is not chronological since load duration curves focus on points of highest load.

As an illustration, SCE's load duration curve is shown in Figure 11. SCE's highest load, 19342 MW (September 3 at 3pm), is illustrated on the left axis and the lowest load, 7848 MW (January 2 at 3am), is shown on the right axis.

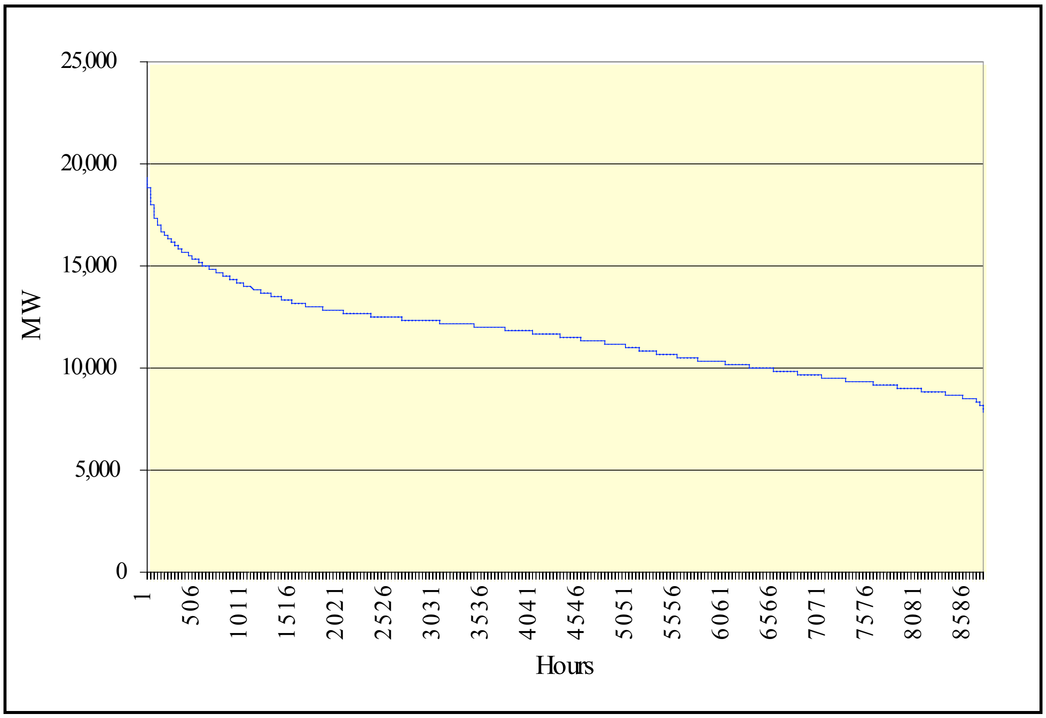


Figure 11 – SCE Load Duration Curve for 2002

Utility analysts recognize that the highest-risk periods are those with highest loads, when the likelihood of insufficient generation to supply customers is greatest. Other factors such seasonal hydro availability, maintenance schedules, transmission outages, and imports from neighboring regions affect this calculation, but all other things being equal, the high risk hours are the ones at the far upper left of the load duration curve.

Therefore, a generating unit is of greater value for reliability if it can be counted during those peak hours of the year. In general, the top 100 hours of the year, whenever they occur, are the riskiest. Solar generation is generally dispatched whenever it can be operated, that is, whenever solar input is adequate, so that the issue is not whether the generation can be dispatched but whether it is operating during peak hours.

2.3.5.2 Comparison of Solar Generation with Demand

For this evaluation we have chosen to show selected results from SoCalMuni, SMUD and Redding that represent the general pattern that can be expected for all the utilities. These three utilities are compared to solar plant output from a Harper Lake site, and SMUD demand is also compared to a solar plant at a Sacramento site.

In Figure 12-15, the top 100 hours of each utility's load duration curve are plotted against the solar output corresponding precisely to those specific hours shown below the load duration curve. These graphs present normalized data, and are shown without a scale to highlight the patterns, not the absolute values (which would be of little use for illustration, as the total grid demand levels are so much greater than the solar output).

An ideal solar generation curve would be a straight line across the graph, representing full solar plant output for all the maximum demand hours. Note that a solar plant without thermal storage (lower blue lines) show a number of hours where solar production is at part-load or zero. With thermal storage (upper green lines), the solar production during the top 100 hours improves considerably. Table 5 gives the quantitative results for all utility-solar site pairs. With gas assist, the solar production would be constant at the solar plant capacity, that is, it would show as a horizontal line at 100% capacity on these charts.

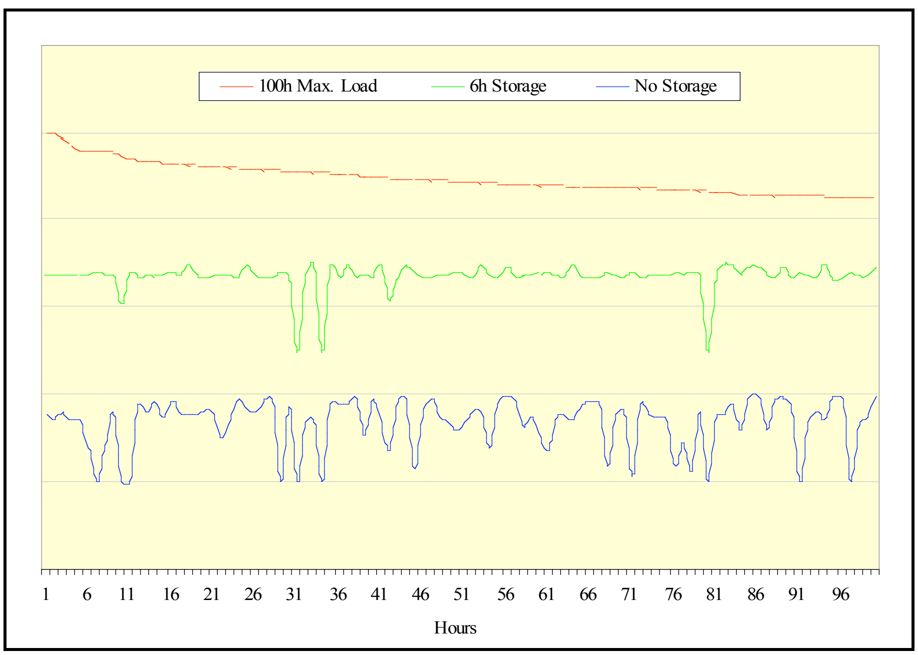


Figure 12 – SoCalMuni Top 100 Hours Load Duration Curve with Harper Lake 2002 Solar Production, With and Without Storage

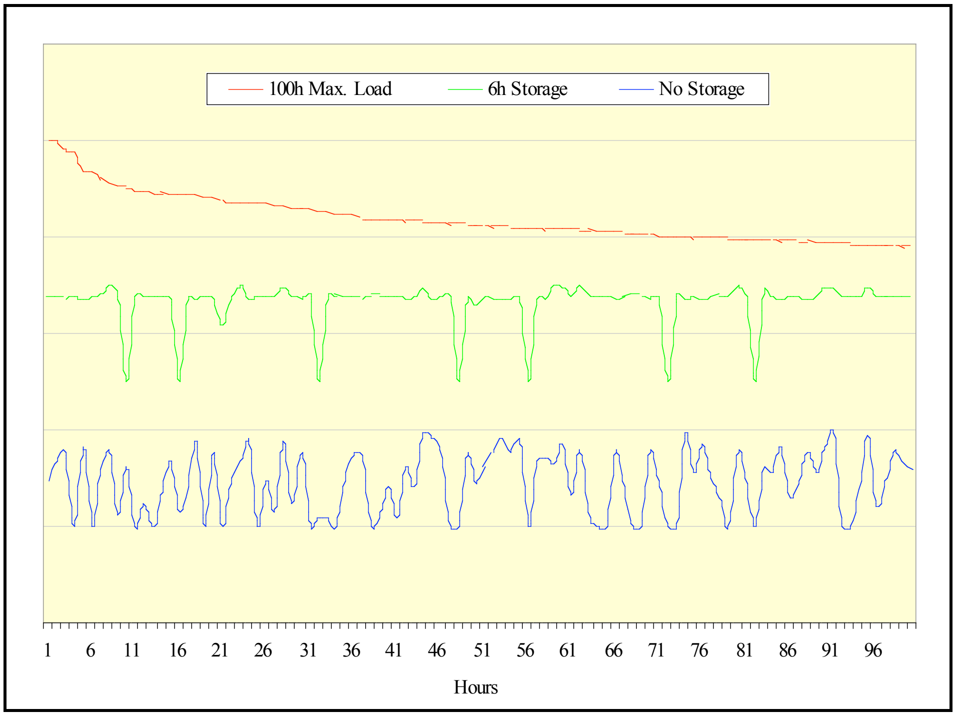


Figure 13 – SMUD Top 100 Hours Load Duration Curve with Harper Lake Solar 2002 Production, with and without Storage

Figure 14 – SMUD Top 100 Hours Load Duration Curve with Sacramento Solar 2002 Production, with and without Storage

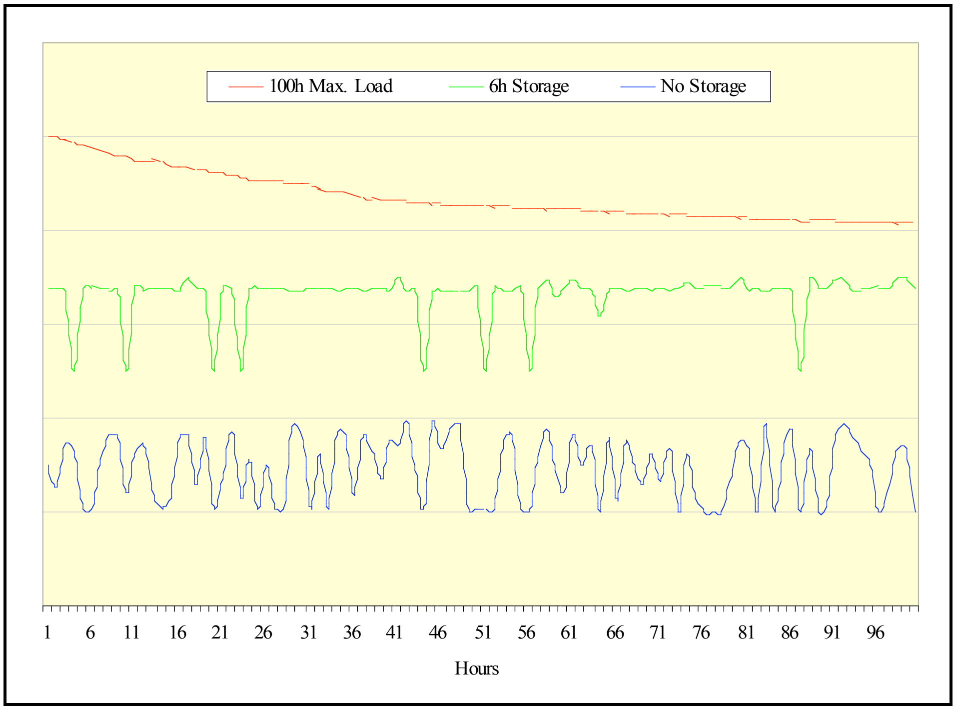


Figure 15 – Redding Electric Utility Top 100 Hours Load Duration Curve with Harper Lake 2002 Solar Production, with and without Storage

2.3.5.3 Concept of Solar Plant Outage Rate

The concept of solar plant outage rate, defined here to be the percent of hours that a solar plant fails to deliver an acceptable power level during the top 100 demand hours, is introduced here as one quantifiable indicator of the performance of a solar plant during peak hours. Specifically, we define a "solar plant outage" hour to be one where the solar plant output is less than 75% of maximum. The value is presented as a fraction. Using this definition, the solar plant outage rates corresponding to the data presented in Figure 12-Figure 15 are shown below. With gas assist, the solar plant outage rate would be zero.

Table 5 – Solar Plant Outage Rate During Top 100 Load Hours

Utility-Solar Site Pair	With 0h Storage	With 6h Storage	With gas-assist
SoCalMuni - HL	0.27	0.05	0.0
SMUD - HL	0.61	0.08	0.0
SMUD - Sacramento	0.42	0.02	0.0
Redding - HL	0.61	0.09	0.0
Redding - Sacramento	0.56	0.07	0.0

Note that, with thermal storage, the "solar outage" is always less than 10%. In actual practice, the individual plant operating scenarios would likely decrease the values shown here by optimizing the daily use of thermal storage depending on weather and demand.

2.3.5.4 Cost and Value Trends with Thermal Storage

Introduction

An analysis was carried out to show the effect of thermal storage of different capacities on plant operation and value of the electricity produced. When thermal storage is added to the system, electricity generation can be shifted to a later time (we examined 3 to 12 hours later) in order to match a high demand period and benefit from the higher value of electricity in those periods. In this analysis, the capacity of the storage system is characterized in terms of the equivalent full-load electrical generation that it can shift. Addition of a thermal storage system increases the investment cost of the plant, but not necessarily the levelized cost of electricity. Further, shifting of electrical generation to a high value period increases the revenues from sale of electricity. This evaluation looks at both aspects.

The time-of-use (TOU) periods for the analysis are shown in Figure 16. The on-peak periods are in yellow, the mid-peak in green, and the off-peak in magenta. A typical shift, for example, would be to shift summer morning solar energy collection to storage to fill the electrical generation in the late afternoon period, or to shift winter afternoon collection to winter evening electrical production.

If the solar field size is fixed, the value of storage is restricted to its ability to shift electrical generation from a lower-valued to higher-valued period. The annual capacity factor would remain approximately fixed, whereas the capacity factor for specific time-of-use periods would vary. The investment cost of the plant will rise due to the storage addition. The levelized electricity cost will rise as storage is added, but the value of the electricity production may rise. Another option is to increase the size of the solar field at the same time that storage capacity is added. In this case capacity factors will rise annually and in all TOU periods. Investment costs will rise due to the cost additions of both storage and the solar field, but the electrical generation will also rise. The solar field size is cast in terms of the "solar multiple". A solar multiple of 1 is the solar field size required to produce the nominal turbine output rating at peak radiation values. Levelized electricity cost and value of electricity sales may both rise in this configuration.

Analysis

Figure 17 and Figure 18 below consider the case where the solar multiple is 1.5. Figure 19 and Figure 20 show a case for a smaller solar field, in fact, smaller than needed to produce nominal turbine output at peak radiation levels. Figure 21 and Figure 22 consider a case where the solar field is increased in size each time the storage capacity is increased. In each set of plots, the relative change of the levelized cost of electricity, annual capacity factor, capital cost, and annual revenues (both annual total and the average annual $/kWh revenues) are shown, as well as the capacity factors during important Time-of-Use periods.

In general the trends suggest that thermal storage capacities of 3-6 hours are suitable to shift electrical production to the peak demand periods, thus gaining value. Case 3 offers the benefits of increased solar contribution (note the increasing solar capacity factor) with the addition of storage. For the addition of thermal storage to be economically viable, the utility revenues must have a time-of-use pattern that reflects demand, and encourages shifting solar generation to later periods. There is no question that electricity is most valuable in the summer peak period when air conditioning loads increase the demand dramatically.

A series of performance/cost model runs were also carried out to compare the impact of thermal storage in the long term, when both solar field and thermal storage costs are reduced, to the near term cost scenario that formed the basis of Figure 17 – Figure 22. In the reduced cost cases, the TES costs were reduced to \$10/kWht, the solar field costs to \$150/m^2 (from about \$265/m^2), and power block costs to 80% of the base system costs. Figure 23 compares absolute (not normalized) values for capital \$/kW and levelized cost of electricity, as a function of storage capacity, for this scenario.

Let us consider the LCOE trends. With near-term costs, the LCOE remains fairly level at about 12.5 cents/kWh with the addition of storage. With long-term costs, not only is the level reduced by 40%, but the addition of thermal storage continues to drop the electricity cost as storage capacities rise. The capital costs rise with storage capacity due to the costs of the increased solar field size and storage system. With long term costing, the capital cost is reduced by 45%, and the increase with thermal storage capacity is at a lower rate.

<u>Conclusions</u>
The results of this analysis suggest that the addition of thermal storage systems to trough power plants will be cost-effective if time-of-use revenues appropriately reflect levels of demand. In today's market, with high costs of the solar field and TES system due to the market-entry stage of the technology, thermal storage is markedly cost effective and very sensitive to revenue rates and schedules. With expected cost reductions in both solar field and TES systems, it is likely that the use of TES systems will be cost effective in a wider range of future applications. One case is shown to illustrate this point.

A more detailed analysis of operation with thermal storage requires improvement of the analytical techniques, for such analysis if beyond the present capability of the current performance model used to estimate TES cost-effectiveness. Specifically, the current model does adequately allow the implementation of detailed plant operating scenarios that would optimize TES operation.

Figure 16 – Time of Use Periods for this evaluation

	season	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Jan	2	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	5	6	6
Feb	2	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	5	6	6
Mar	2	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	5	6	6
Apr	3	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	6	6
May	3	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	6	6
Jun	1	3	3	3	3	3	3	2	2	2	2	2	2	1	1	1	1	1	1	1	2	2	2	3	3
Jul	1	3	3	3	3	3	3	2	2	2	2	2	2	1	1	1	1	1	1	1	2	2	2	3	3
Aug	1	3	3	3	3	3	3	2	2	2	2	2	2	1	1	1	1	1	1	1	2	2	2	3	3
Sep	1	3	3	3	3	3	3	2	2	2	2	2	2	1	1	1	1	1	1	1	2	2	2	3	3
Oct	1	3	3	3	3	3	3	2	2	2	2	2	2	1	1	1	1	1	1	1	2	2	2	3	3
Nov	2	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	5	6	6
Dec	2	6	6	6	6	6	6	5	5	5	5	5	5	5	5	5	5	5	4	4	4	4	5	6	6

Key:

1	Summer On Peak
2	Summer Mid Peak
3	Summer Off
4	Winter On Peak
5	Winter Mid Peak
6	Winter Off

Figure 17 – Relative Effect of Storage Capacity on Selected Plant Metrics

(with a fixed solar field size, at a solar multiple of 1.5)

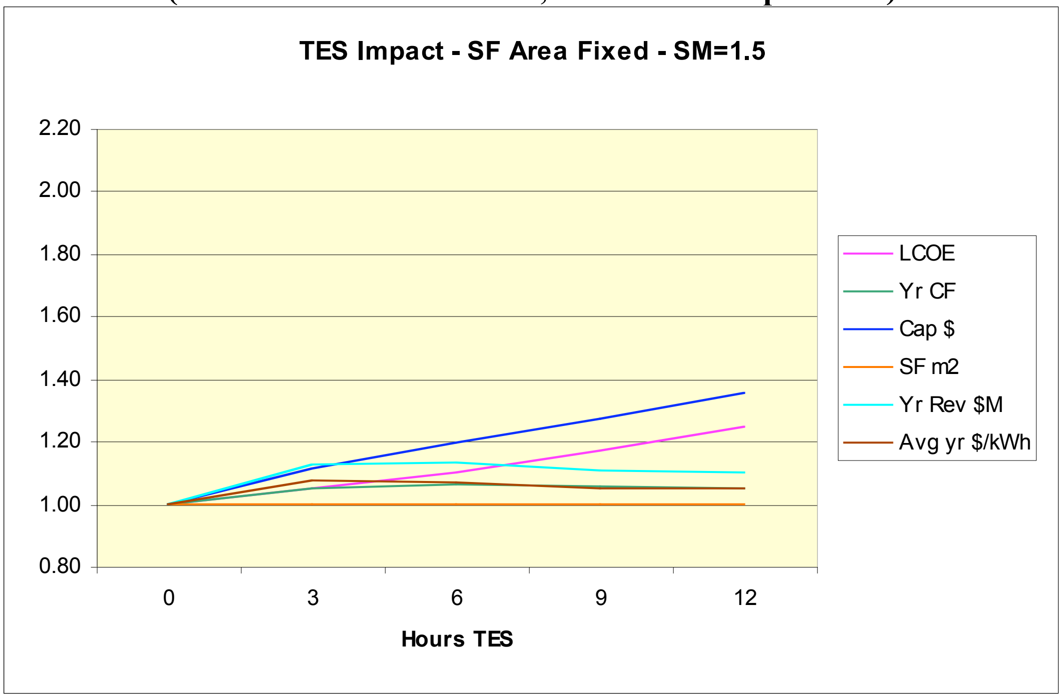


Figure 18 – Effect of Storage Capacity on Plant Capacity Factors in Specific Time of Use Periods

(with a fixed solar field size, at a solar multiple of 1.5)

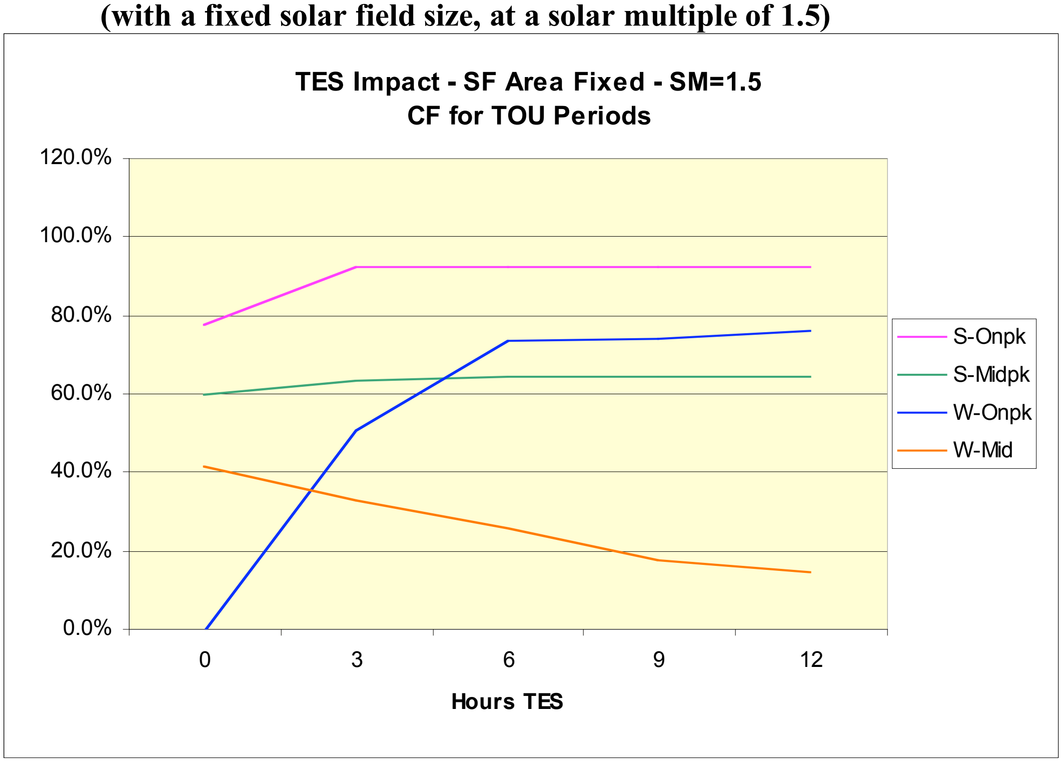


Figure 19 – Relative Effect of Storage Capacity on Selected Plant Metrics

(with a fixed solar field size, at a solar multiple of 0.75)

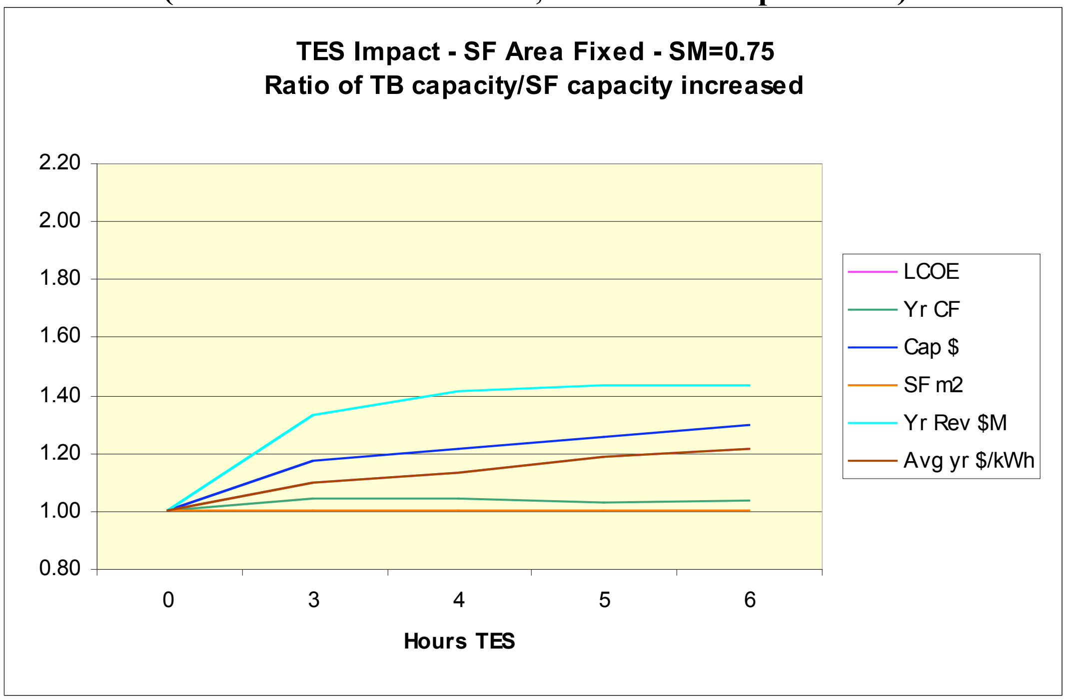


Figure 20 – Effect of Storage Capacity on Plant Capacity Factors in Specific Time of Use Periods

(with a fixed solar field size, at a solar multiple of 0.75)

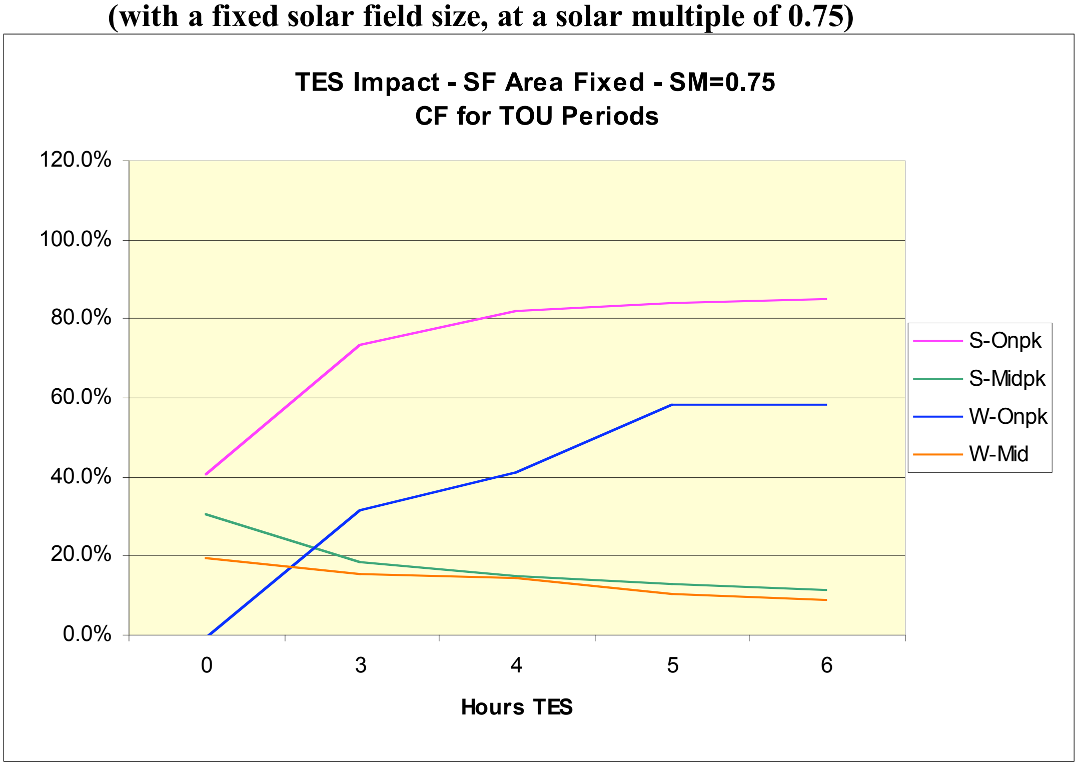


Figure 21 – Relative Effect of Storage Capacity on Selected Plant Metrics

(solar field size increased with storage capacity)

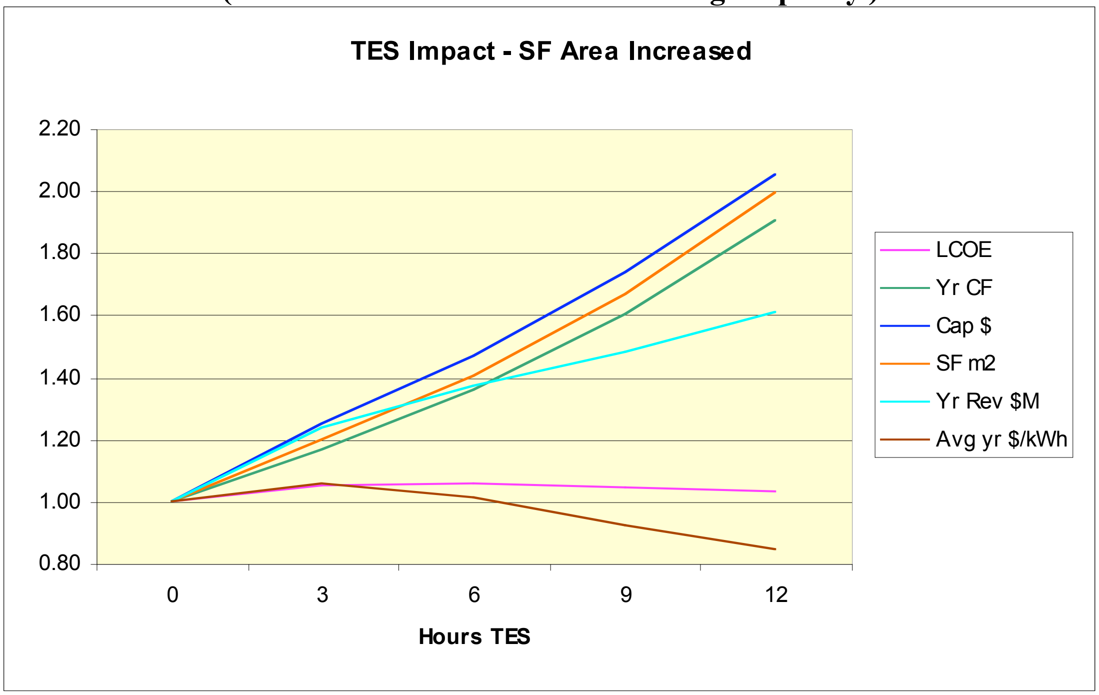


Figure 22 – Effect of Storage Capacity on Plant Capacity Factors in Specific Time of Use Periods

(solar field size increased with storage capacity)

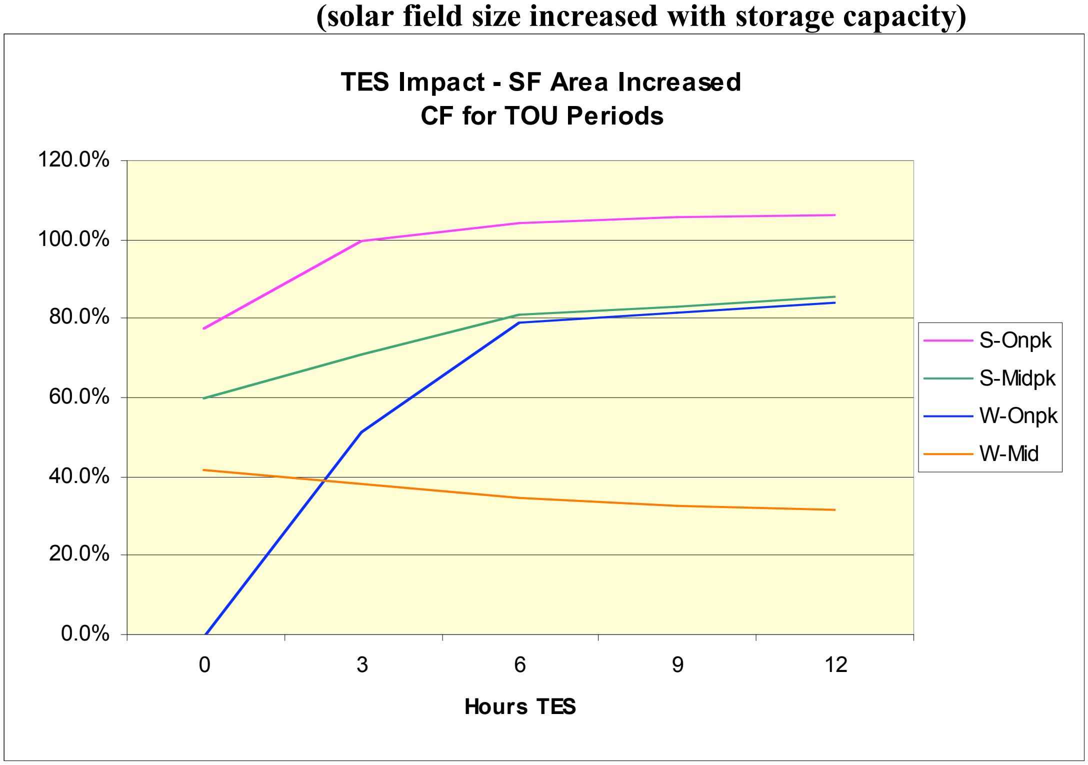


Figure 23 – Effect of Storage Capacity on Capital Costs and LCOE for both near-term and long-term costing assumptions.

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2.4 Parabolic Trough Solar Power Plant Configurations[7]

2.4.1 Introduction

Existing Solar Electric Generating Systems (SEGS) are steam turbine power plants using parabolic trough solar collectors as the primary heat source. Similar to conventional thermal power plants, the primary difference is that steam is generated in these systems by a parabolic concentrating solar collector and heat exchanger sub-system. A significant advantage of this configuration is that the steam turbine can also be driven by supplying fossil-fired supplementary steam in parallel with or in place of solar steam, extending the capacity factor and the period of electricity production.

There are currently nine SEGS plants, with a total capacity of 354 MWe, installed and operating in the Mojave Desert of Southern California. All of these plants have the capability to produce power in several operating modes: either solar-only, fossil fuel boiler, or a mix of the two systems (hybrid).

2.4.2 Solar Thermal Power Plant Technical Descriptions

2.4.2.1 System Overview

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. These plants, developed by Luz International Limited and referred to as Solar Electric Generating Systems (SEGS), range in size from 14–80 MW and represent 354 MWe of installed electric generating capacity. More than 2,000,000 m^2 (21,500,000 ft^2) of parabolic trough collector technology has been operating daily for up to 18 years, and as the year 2002 ended, these plants had accumulated 136 years of operational experience. The Luz collector technology has demonstrated its ability to operate in a commercial power plant environment like no other solar technology in the world. Although no new plants have been built since 1990, significant advancements in collector and plant design have been made possible by the efforts of the SEGS plants operators, the parabolic trough industry, and solar research laboratories around the world. Figure 24 below shows an aerial photo of the Kramer Junction SEGS III – VII site. Each of the five plants located at the Kramer Junction facility generates 30 MWe, with a total capacity of 150 MWe.

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[7] This chapter summarizes the work completed in the task 4.1.4.1 Technical Option Ranking Report, dated February 2004.

Figure 24 – Solar Thermal Power Facilities in the Mojave Desert

(SEGS 3-7 at Kramer Junction, California) (Source: Kramer Junction Company)

Parabolic trough power plants consist of large fields of parabolic trough collectors and a power block. The power block contains a heat transfer fluid/steam generation system, a Rankine steam turbine/generator cycle, and optional thermal storage and/or fossil-fired backup systems. The collector field is made up of a large field of single-axis-tracking parabolic trough solar collectors. Figure 25 below illustrates a trough collector.

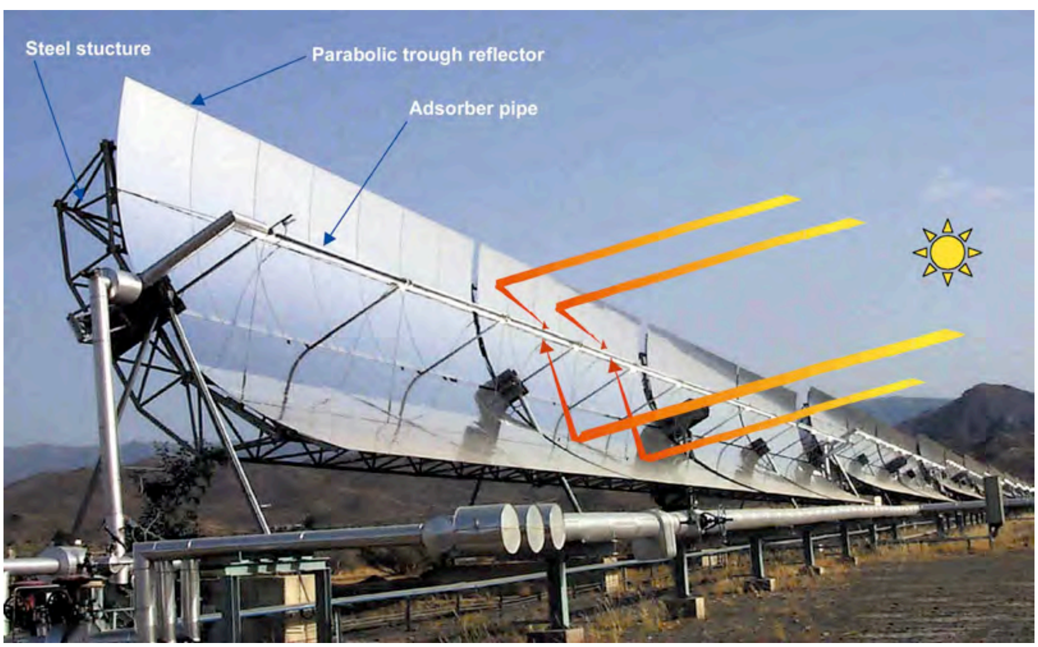


Figure 25 – Trough Principle

The solar field is modular in nature and comprises many parallel rows of solar collectors, normally 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's energy is continuously focused on the linear receiver. A heat transfer fluid (HTF) circulates through the receivers and is heated up as high as 399°C (750°F). The HTF then returns to a series of heat exchangers in the power block, where it is used to generate high-pressure superheated steam (1450 psia/100 bar, 700°F/371°C). 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 feed-water pumps to be transformed back into steam. The condenser is cooled by mechanical-draft wet cooling towers. After passing through the HTF side of the solar heat exchangers, the cooled HTF is re-circulated through the solar field.

The existing parabolic trough plants have been designed to use solar energy as the primary energy source to produce electricity. In summer months, when solar input is high, the plants typically operate for about 10 hours a day at full-rated electric output on solar energy alone. For example, for an average day in August in the Mojave Desert the solar output of a trough plant is at full power from 7 am to 5 pm. During overcast or nighttime periods the plants can achieve rated electric output by operating in a hybrid solar/fossil mode. In hybrid mode fossil-fired capability is used to supplement the solar input during periods of low solar radiation.

Figure 26 shows a process flow schematic for a typical large-scale parabolic trough solar power plant. While the schematic shows both thermal storage and natural gas boiler options, an actual system would include either none or only one of these components. The reference 50 MWe plant is a solar-only configuration, without thermal storage or a fossil fuel boiler.

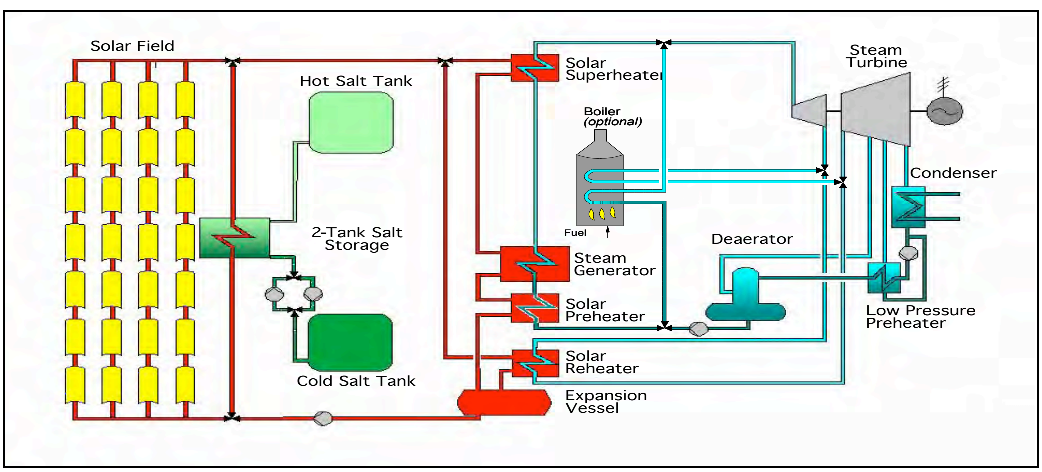


Figure 26 – Process flow Schematic of large parabolic trough solar power plant

(Source: Pilkington Solar International)

2.4.2.2 Major Equipment and Systems

A summary of the major equipment for a 50 MWe SEGS-type plant is shown in Table 6.

Table 6 – Major Equipment for a 50 MWe SEGS type plant

Equipment type	Typical characteristics
Parabolic trough solar field, with control system	1-axis tracking parabolic trough solar system; 300,000 sq. meters of mirror aperture, exit HTF 390ºC (735ºF).
Heat transport system for solar field energy	2700 HP Fluid pumps; rated at 12,000 gpm (757 liters/s); 310 psia (21.4 bar) discharge head; solar steam generator rated at 500,000 lbm/hr (63 kg/s) steam
Power block	Conventional reheat steam Rankine cycle turbine-generator plant; nominal rating 60 MWe gross (maximum continuous rating 63 MWe); 13.8 kV, 3-phase output; steam conditions: superheat and reheat both 1450 psia/ 700ºF (100 bar/371ºC).
Major elements	Condenser; cooling tower and cooling water system; condensate and feed pumps; distributed control system; electrical transformers, switchgear and motor control centers

2.4.2.3 Thermal Storage

One of the advantages of solar thermal power systems is the opportunity to store solar thermal energy for use during non-solar periods. Thermal storage also allows the solar field to be oversized to increase the plant's annual capacity factor. In good solar climates, trough plants without thermal storage can produce an annual capacity factor of approximately 25%. By adding thermal storage, the plant capacity factor can be increased significantly.

The first SEGS plant used a mineral oil HTF and included three hours of thermal storage. The plant used a 2-tank system, one tank to hold the cold oil and a separate tank to hold the hot HTF once it had been heated. This helped the plant dispatch its electric generation to meet the utility peak loads during the summer afternoon and winter evening. The mineral oil HTF is quite flammable and cannot be used at the later, more efficient SEGS plants that operate at higher solar field temperatures. A mineral oil thermal storage system was also use at the Solar One steam central receiver demonstration power plant. This system used a single tank thermocline storage system with rock/sand filler.

Different thermal storage systems are required for the higher solar field operating temperature found in the more efficient steam cycles that are part of the later SEGS designs. For these plants the 2-tank oil storage system used at SEGS I is not feasible because of the higher cost of the synthetic HTF and the high HTF vapor pressure that would require pressurized storage vessels. Several thermal storage options are currently under development and in commercial design for higher temperature parabolic trough plants.

Concrete: A thermal storage system that uses concrete as the storage medium has been proposed. This system would use a heat transfer fluid in the solar field and pass it through an array of pipes imbedded in the concrete to transfer the thermal energy to and from the concrete. Limited prototype testing has been done on the concrete-steel thermal storage concept. During 1991 to 1994 two concrete storage modules were tested at the storage test facility at the Center for Solar Energy and Hydrogen Research (ZSW) in Stuttgart, Germany. The test results confirmed the theoretical performance predictions. The cost for the concrete thermal storage was estimated to be about 50$/kWht. The highest uncertainty is the long-term stability of the concrete material itself after thousands of charging cycles.

Indirect 2-Tank Molten-Salt: A near-term thermal storage option for parabolic trough technology has been developed that uses Therminol VP-1 or Dowtherm A HTF in the solar field and then passes it through a heat exchanger to heat molten salt in the thermal storage system. The molten salt is the same “solar salt” used at the Solar Two pilot demonstration plant, a binary mixture of 60% sodium nitrate ($NaNO_3$), and 40% potassium nitrate (KNO_3) salt. When the power cycle is dispatched, the salt flow is reversed through the HTF/salt heat exchanger to reheat the HTF and use a traditional SEGS type HTF steam generator system. This system has been demonstrated at a 10 MWe pilot-scale demonstration in Solar Two, which showed that the system is feasible and has relatively low risk. Nexant (formerly Bechtel) has conducted a detailed design and safety analysis of the indirect molten-salt thermal storage system. The Nexant study considered a thermal storage design that would provide two hours of full load energy to the turbine of an 80-MWe SEGS plant. Although solar salt has a relatively high freeze point (~437°F/225°C), the salt is kept in a relatively compact area and is easily protected by heat tracing and systems that drain back to the storage tanks when not in use. Based on the experience at Solar Two, the Nexant study concluded that this thermal storage concept has low technological risk. The primary disadvantage of this storage system is its relatively high cost, with a cost of about $30/kWht. Two systems of this type are presently being engineered for two 50-MWe trough plants in Spain.

Thermocline Storage: One of the options for reducing the cost of molten salt thermal storage for trough plants is through the use of a thermocline storage system which has hot and cold fluids in a single tank. The single tank, only marginally larger than either of the tanks in the two-tank system, is partially filled with a low-cost material which acts as the primary thermal storage medium. The filler displaces the majority of the salt used in the two-tank system, thus reducing costs. The remaining volume in the single tank is filled with a heat transfer fluid such as molten salt. Thermal buoyancy keeps the hot and cold fluids separate. The thermocline is the region of the tank between the two temperature resources.

Recent studies and field-testing validated the operation of this type of system. In a test at the National Solar Thermal Test Facility at Sandia National Laboratory (SNL) the filler material - quartzite and silica sand - replaced approximately two-thirds of the salt that would be needed for a two-tank system. With a 140°F (60°C) temperature difference between the hot and cold fluids the thermocline occupied between 1m (3.28 ft.) and 2m (6.56 ft.) of the tank height. For this reason, the thermocline storage system seems to be best suited for applications with a relatively small temperature difference between the hot and cold fluids. The testing at SNL showed that the thermocline maintained its integrity over a three-day no-operation period. Additional analysis of full-scale thermocline storage systems is currently in progress, but initial economic assessments indicate that the thermocline could reduce thermal storage costs by 30% to 45% to below $20/kWht. Technical risk is moderate and large prototype system testing is required at this time.

2.4.2.4 Dry Cooling Systems

Alternatively ambient air can be used for cooling rather than cooling water. A direct air-cooled condenser or a dry cooling tower can perform the function of the wet cooling tower and transfer the heat in the circulating cooling water to the atmosphere with the advantage of greatly reduced water use. The water requirement for dry cooling is approximately 72 gallons/MWh, compared to 905 gallons/MWh for wet cooling. The selection of the appropriate cooling method (i.e. wet or dry) depends on both technical and economic tradeoffs.

Some of the major concerns regarding dry cooling systems include:

- Ambient air generally has higher temperatures than a cooling water source, especially in the hot summer months where desert air temperatures can be well above 100°F.
- Air is a less efficient cooling fluid than water, and typically requires large flow rates and large heat exchanger surface areas.
- High air temperatures and less effective cooling results in a higher steam condensing temperature, which corresponds to a higher turbine backpressure leading to reduced turbine performance.
- Forced draft air fans require high power and increase the plant electrical parasitics significantly.
- Natural draft cooling towers, a viable alternative air-cooling method, eliminate the need for large air fans and reduces parasitic power needs. However, their size and other factors increase costs over a wet cooling tower.

Dry cooling systems can be direct or indirect. The significant difference between the direct dry and the indirect dry systems is the use of different coolants to condense the steam. The coolant for the exhaust steam in a direct dry system is ambient air. The coolant for an indirect dry system is an intermediate water loop, which must then be re-cooled by ambient air to reject the turbine system heat to the atmosphere.

Direct Dry Cooling System

Direct dry cooling systems can utilize mechanical (or forced) draft or natural draft configurations. For this size power plant, were dry cooling to be used, SolarGenix favors the forced draft system consisting of an air-cooled condenser (ACC) in which the turbine exhaust steam is condensed inside air-cooled finned tubes at constant temperature. ACC systems cover the entire range of feasible power plant unit ratings, with steam condensing capacities from below 1 tons/hour up to 1400 tons/hour.

A variation on the ACC is possible for use in a desert climate that experiences very high ambient air temperatures for a limited number of hours of the day during a few months of the year. In this variation, the turbine exhaust steam can be ducted to either an ACC or a wet mechanical draft cooling tower. The turbine exhaust steam is normally cooled in an ACC and cooling water is not used. During high ambient air temperature conditions, when the ACC is not efficient, the steam is ducted to the wet tower cooled in a conventional wet-cooling tower and high turbine performance is maintained. Overall water requirements are then limited to a much lower usage level. Choice of this configuration is a site-specific economic tradeoff based on water availability, ambient air conditions, turbine characteristics and equipment costs.

Indirect Dry Cooling System

In indirect systems, the steam is condensed by cooling water flowing inside finned condenser tubes. In a wet-cooled system, heat is rejected from this closed intermediate cooling water loop via a mechanical draft wet cooling tower or by ocean or river cooling. In a dry system, a large natural draft dry cooling tower is utilized for heat rejection in large plants. Limited natural draft dry cooling towers have been installed worldwide, and typically for large multi-100 MW power plants. While capital costs are high, the parasitic power requirement is markedly reduced. A forced draft air cooler can also be used, and is more suitable for smaller plants.

Comparison between Direct Dry and Indirect Dry Cooling System

The direct dry ACC provides the greater temperature difference between the condensing steam and the cooling air, thus reducing the heat transfer surface area requirement. Elimination of the intermediate cooling water loop reduces capital costs and water pumping parasitics. However, the parasitic power requirement for the cooling air is high. The ACC is usually placed next to the turbine house to keep the length of the steam exhaust duct as short as possible.

The indirect dry cooled system has less favorable heat transfer characteristics but eliminates a high air pumping power requirement by incorporating natural convection in the dry tower. Further, it utilizes a conventional condenser/intermediate cooling loop configuration.

As noted above, SolarGenix has identified the ACC to be most cost-effective dry cooling method for evaluation with the reference plant. For estimating purposes, a cost of $150/kWe is assumed.

2.4.3 Evaluation of Technical Options

2.4.3.1 Procedure

NREL has developed a parabolic trough simulation model[8] that allows a detailed performance, cost, and economic assessment of design and technology variations. This model forms the basis for the SolarGenix model, which was used for all evaluations in this feasibility study along with performance, O&M cost, and capital cost input parameters developed by SolarGenix.

The ranking of technical options carried out here might better be termed a *characterization* of technical options. Specific site and market conditions will dictate the appropriate plant configuration for a particular project development. For example, wet cooling will always be preferred over dry cooling from the viewpoint of obtaining the lowest cost of electricity, but the wet cooling option may not be available at a site that is preferred due to other factors. The analysis presented below characterizes each option with respect to its impact on:

- performance
- investment cost
- annual capacity factor
- dispatchability

[8] Developed by Henry W. Price. Reference: Henry Price, "A Parabolic Trough Solar Power Plant Simulation Model", Proceedings of ISES 2003: International Solar Energy Conference
Hawaii, March 2003.

Further, integrated solar combined cycle systems (ISCCS) are discussed with these same factors in mind.

2.4.3.2 SEGS Analysis

The reference plant used for the evaluation of SEGS technical options is a 50 MWe SEGS plant located at a high insolation site in Southern California. The solar radiation database used for this analysis is the data set for Daggett, California. Performance evaluations were performed for four different plant configurations:

1. 50 MWe nominal output using wet cooling
2. Hybrid solar-fossil fuel operation
3. Use of a dry cooling system
4. Utilization of 6 hours of thermal storage

Summary comparative results are given in Table 7. These are reviewed and discussed in the following paragraphs. The configuration and performance impacts are largely seen in the results for solar field size and annual electricity generation. In addition, the incremental cost impacts due to the technical changes are addressed in the table with normalized (relative) investment costs[9]. Absolute values of investment costs and levelized cost of electricity (LCOE) results are developed and discussed for the SEGS plants in Deliverable 1.4.8.1 (Financial Feasibility Study) of this project.

Table 7 – Summary of Technical Options Analysis for SEGS-type Plants

		Performance Parameters			
Option #	Case	Solar Field Area, 1000 m2	Annual MWh	Annual CF	Dispatch-ability
1	Reference case	301	113648	25.9%	none
2	Hybrid operation	301	175200	40.0%	full
3	Dry cooling	301	106709	24.4%	none
4	Thermal storage	451	169417	38.7%	good

		Normalized Cost Parameters				
Option #	Case	Solar Field Cost	Power Block Cost	Total Cost	O&M Cost	LCOE
1	Reference case	1.00	1.00	1.00	1.00	1.00
2	Hybrid operation	1.00	1.14	1.05	2.01	0.81
3	Dry cooling	1.00	1.11	1.05	0.98	1.10
4	Thermal storage	1.50	1.00	1.48	1.09	0.93

Notes: a) O&M cost for Option 2 includes the fuel cost.
b) Annual plant availability for the reference and hybrid cases is about 95%, including a two-week maintenance outage is winter and a solar field tracking availability of over 99%.

[9] A simplified LCOE was calculated consistent with the IEA method, assuming a discount rate of 5%, 25 year lifetime, and a 0.5% insurance rate, resulting in a before-tax fixed charge rate of 7.6%.

Option 1 – Solar-only 50 MWe nominal output using wet cooling

The reference 50 MWe nominal solar-only plant with wet cooling utilizes a trough solar field with 300,800 m^2 reflector aperture area. Figure 27 shows the monthly solar electricity generation. As can be seen, the monthly output (blue bars) in summer months is up to four times greater than the output in winter. This is a typical characteristic of a north-south single axis tracking system due to geometric effects of the sun position with respect to earth. The yellow line on the graph represents the incoming daily average solar radiation. This also is higher in the summer months, matching (and driving) the peak system loads.

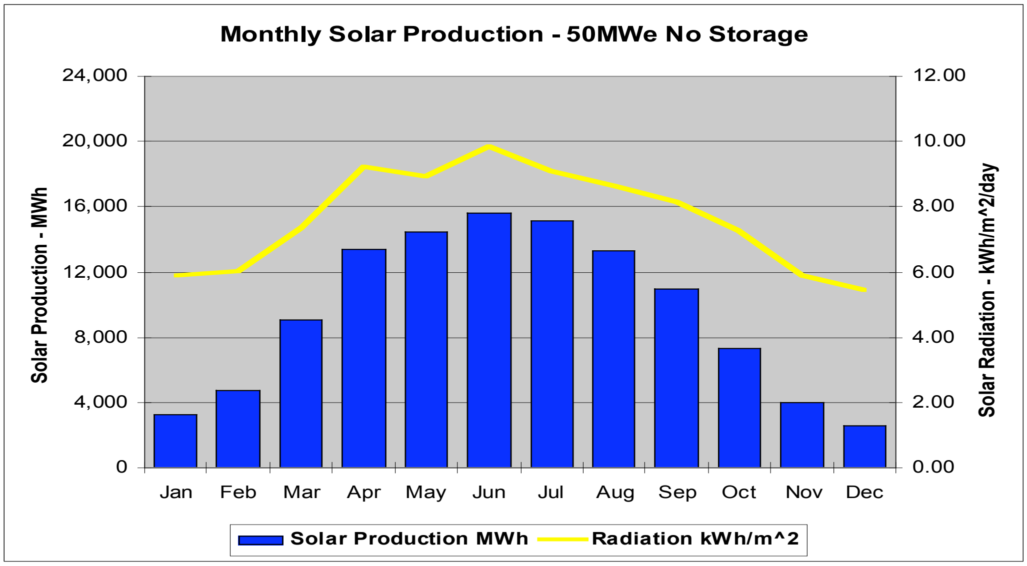


Figure 27 – Monthly Solar Production fo Solar-Only 50 MWe Plant

Table 8 summarizes the technical characteristics of the power plant. The annual net sales of solar electricity are over 113,648 MWh per year, or a 25.9% capacity factor. The solar field reflector aperture is 300,808 m^2. The annual water consumption of over 100 million gallons per year reflects the use of a mechanical draft wet cooling tower. For a SEGS-type plant, the water usage is approximately split as follows: wet cooling 95%, condensate makeup plus demineralizer system blowdown 3%, and solar field mirror washing 2%.

Table 8 – Plant Characteristics

Solar Plant Characteristics			
Site	Location	Southern California	
	Data Source	TMY2 Daggett, CA	
	Longitude	116.8	deg W
	Latitude	34.9	deg N
	DNI	7.65	kWh/m2/day
Collector Field			
	Collector Type	SolarGenix	
	Collector Area	300,800	m2
	Solar Collectors	640	
	Plant Area	300	acres
Power Block			
	Net Output	50	
	Gross Output	55.5	
	Max Gross Output	63.5	
	Turbine Effic	37.7%	
	Water Usage	103	MMgal/year
Storage System			
	Storage size	0	MWht

The projected solar steam system cost, including the solar field and HTF system, constitutes approximately 55% of the total direct costs. Figure 28 shows the breakdown of solar field costs by its major components. The pylon foundations are included in the S*tructure* category. *Tracking* includes the drive, electronics and controls. All roads, buildings and fences are included in *Civil*, while the *HTF* category contains the pumps, expansion vessel and heat exchangers for steam production.

Solar field O&M costs are estimated to be about 35% of the total O&M costs. Of that 25% is for solar field parts and materials. At least one-half of the current projection for parts covers receiver replacement. With the developments in this area noted above, this cost is expected to reduce markedly in the near future. Mirror breakage, also being reduced, is already relatively low, constituting only 15% of the total parts costs.

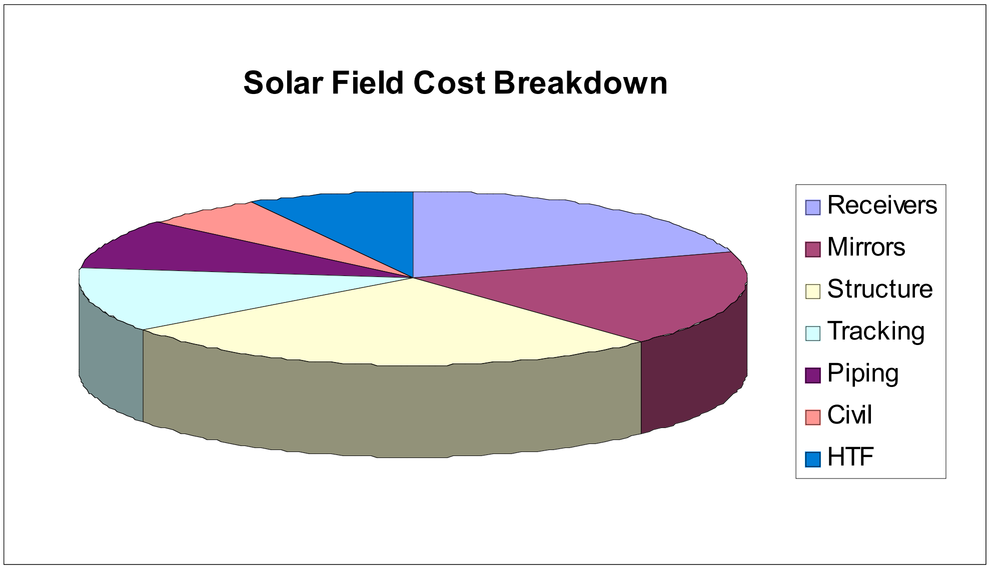


Figure 28 – Solar Field Direct Costs

Option 2 – Option 1 with hybrid operation

Hybrid plants that incorporate a natural gas boiler or oil heater are the most common design of existing SEGS plants. During periods of inclement weather or nighttime, steam can be generated to maintain system output or in general to increase the annual capacity factor. A hybrid SEGS-type plant provides a firm capacity option because the electrical generation is fully dispatchable. Further, the plant can produce during high demand and high value periods as desired. The cost of generating electricity in this mode is dependent on gas prices. Figure 29 shows the relative levelized electricity cost for several different gas price scenarios. Four different gas prices were used ($3, $5, $7 and $9/mmBTU) with the generation cost plotted for different capacities.

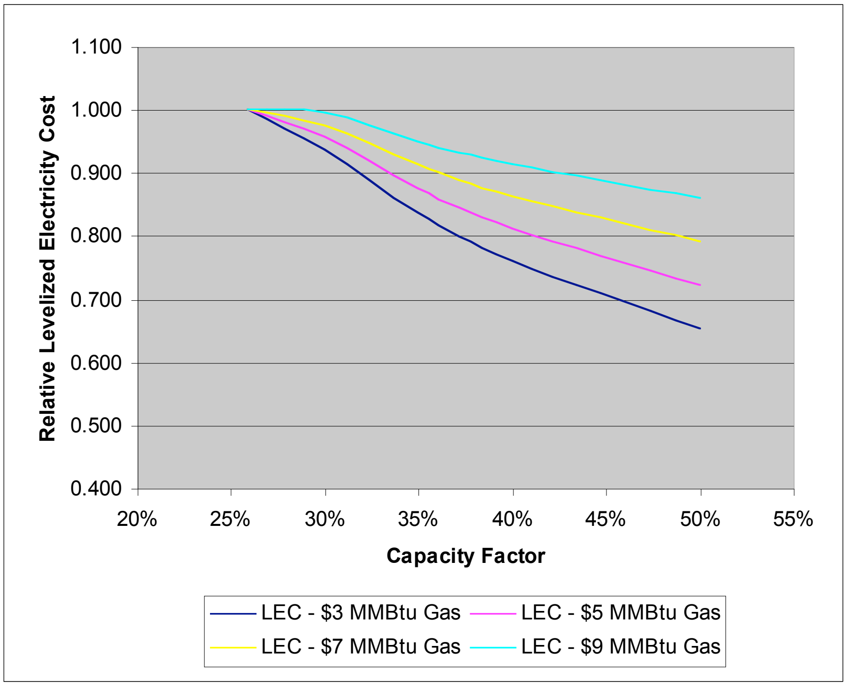


Figure 29 – Effects of Gas Use on Electricity Cost – 50 MWe Hybrid Plant

The solar-only Option 1 plant is the reference configuration with a capacity factor of 25.9%. The existing SEGS operate under a FERC ruling that allows for 25% of the energy into the steam on an annual basis to be admitted via natural gas derived energy, resulting in an annual capacity factor of approximately 39%. As can be seen from Figure 29, the relative levelized electricity cost with a 39% capacity factor and based on $5 gas is about 19% lower than the base case solar plant. The instantaneous price of gas is usually not constant, thus the natural gas generation would be most optimized when gas prices are low and/or energy rates and demand are high.

Cost assumptions for this hybrid analysis include a capital cost increase of $8 million for the additional cost of the natural gas boiler. The O&M portion also increases significantly as seen on Table 7 due to the cost of natural gas. Additionally, 2-3 employees are added to the O&M costs due to the extended hours of operation.

<u>Option 3 – Option 1 with dry cooling</u>
Performance and cost were evaluated for a dry cooling using an air-cooled condenser (ACC). With dry cooling, water usage is reduced significantly from 103 million gallons per year to 8. The remaining water requirement supplies the steam cycle condensate make-up, demineralizer blowdown, reflector cleaning, and miscellaneous minor uses.

Three aspects of the dry-cooled system have an effect on the higher electricity cost compared to the solar-only system. The biggest impact, approximately $7 million, is due to the increased capital cost and installation of the ACC. Performance is reduced by 5.2% due to lower turbine efficiencies because of higher average turbine backpressure associated with this type of cooling.

Finally, forced draft fans in the ACC introduce additional parasitic power penalties, further decreasing the performance to a cumulative 6.1% loss for a total reduction of the plant's electrical output from 113,648 MWh to 106,709 MWh.

Option 4 – Option 1 with thermal storage

Thermal storage provides constrained but important dispatchability without the need for fossil fuel operation. The primary reason for choosing thermal storage is that it can lower the generation cost and better match system loads.

To determine the optimal size of the solar field and storage system it is important to look at both the needs of the demand and the lowest cost of electricity system. An analysis was performed as shown in Figure 30 to select the solar size corresponding to the lowest electricity costs. In general, the electricity cost initially reduces as the solar field (solar multiple[10]) and thermal storage size increase. Six hours of storage has been selected for this evaluation to meet the needs of the system demand[11] based on demand data received from several sources in California. For this storage capacity, a solar multiple of 1.8 resulted in the lowest levelized electricity cost. It is important to note that for a specific plant development the optimization for solar field area, storage capacity, and demand needs should be carried out for the particular requirements of that plant.

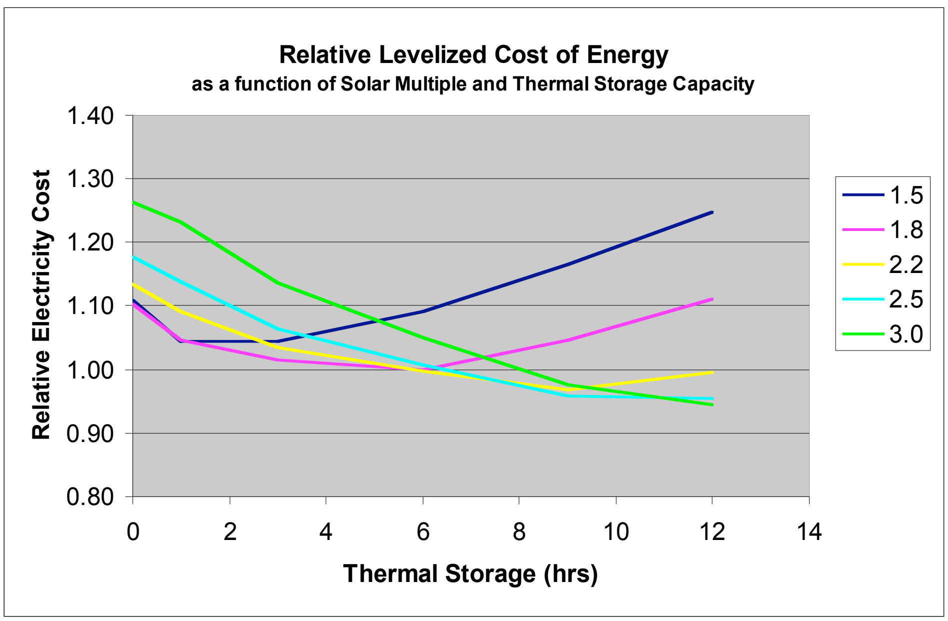


Figure 30 – Optimizing Electricity Cost for 50 MWe Hybrid Plant with Storage

A typical clear summer day is shown in Figure 31 to illustrate the dispatchability available with 6 hours of thermal storage in the plant configuration. The match between plant generation and demand without and with storage can be seen in this figure. Note that the solar production in the non-storage configuration drops off at about 1800, while the system incorporating storage operates until midnight due to the increased energy collection from the larger solar field plus the

[10] A solar multiple of 1 is the solar field size required to make the nominal output rating at peak radiation values.
[11] Further addressed in Deliverable 1.4.2.1.

ability to shift the time of electrical production. The output of the plant with storage can match the demand pattern quite well.

While both of the plants shown in Figure 31 are 50 MWe nominal plants; the solar field is 451,000 m^2 in the storage case compared to 300,800 m^2 in the no-storage case. Figure 32 displays the monthly performance for the storage configuration, which can be compared to the no-storage case shown in Figure 27. The capacity factor of the storage configuration is 38.7%, which is very similar to the 25% hybrid case discussed earlier with its 39% capacity factor.

Another important advantage of the storage system is that it increases the periods during which the turbine capacity remains constant and at full load, offering better turbine efficiencies. Also, the power block configuration and power block costs are identical in both the solar-only and storage cases. The added capital cost of the storage system is just over $25 million. The O&M staff has been increased by two operators due to the added ability to operate into the night, and the materials and services are also increased slightly.

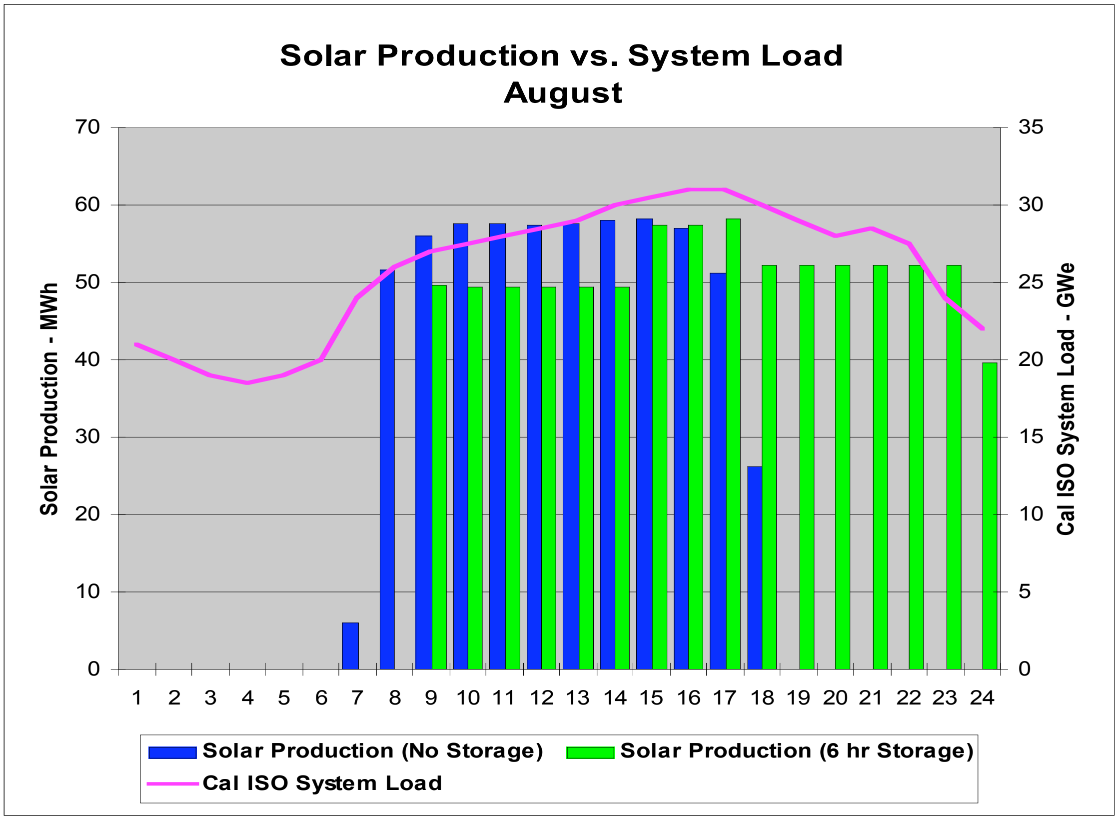


Figure 31 – Solar Production Over 24 Hour Period with Storage

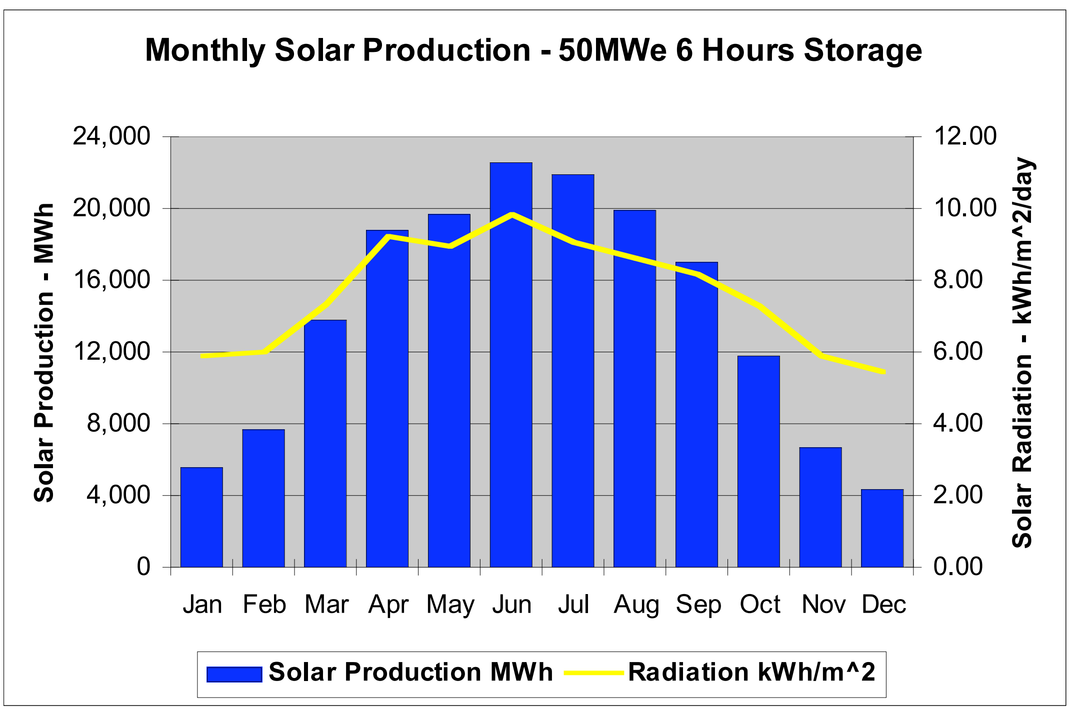


Figure 32 – Monthly Solar Production with Storage

2.4.3.3 ISCCS Plants

In addition to the standard SEGS configuration, a system configuration for a solar field integrated with a gas-fired combined cycle plant is possible and has been extensively evaluated, but not yet built. It has been selected for four large projects for startup grants under the UN/World Bank Global Environment Facility program. This might better be termed a "configuration option" rather than a technical option. It offers quite a different consideration with regards to solar integration and ownership options than does a SEGS-type plant. The following paragraphs discuss several technical aspects of the configuration.

The two alternatives for this concept, known as the Integrated Solar Combined Cycle System (ISCCS), both utilize a solar steam system but in different ways, as shown in Figure 33. The ISCCS is derived from a conventional combined cycle design in which the exhaust heat from the combustion turbine generates steam in a heat recovery steam generator (HRSG) to drive a steam turbine connected to a generator, with supplemental heat input from the solar field to increase the steam to the steam turbine. The ISCCS combines mature gas turbine/steam turbine technology with mature solar parabolic trough technology. This approach may eventually offer a more cost effective and thermodynamically efficient method to utilize solar thermal energy to produce electricity compared to the use of solar energy with a conventional boiler fired (Rankine) cycle plant.

In general, the solar system contributes only a small fraction of the total plant capacity and annual electrical production in an ISCCS plant. In general, one can expect the capacity addition to be in the range of 5-15% and the incremental annual electrical production to be in the range of 4-10%.

<u>Technical Description of a Integrated Solar Combined Cycle System</u>
A combined cycle plant operates on the Brayton cycle, and modern combined cycle plants can achieve thermal efficiencies over 55%. This compares to a fossil-fired project where fuel is fired in a boiler to produce steam to drive a Rankine cycle plant at efficiency on the order of 40%. Cycle efficiencies can be improved by using higher firing temperature gas turbines and using supercritical steam in conventional Rankine cycles. In most combined cycle plants the steam turbine has about half the megawatt capacity of the combustion turbine.

In the ISCCS concept, in which the solar field supplements the steam generation function, the steam turbine capacity needs to be larger, for example, an incremental increase in turbine capacity from about 25% up to 100%. The selection of this incremental capacity is an important consideration in ISCCS design. Crucial issues in the effective utilization of parabolic trough solar fields in combination with combined cycle plants are the ability to achieve a significant reduction in global emissions, the effective annual heat rate of the combined system, and the cost impact on plant output. Previous project feasibility studies and current evaluations have selectively contributed to the improvement of cycle configurations to achieve technical, operational and economic objectives.

While there are several approaches to the integration of the solar field, solar steam can essentially be used in two ways:

1. entry into the HRSG (heat recovery steam generator) to be further superheated and used in the HP inlet of the steam turbine, or
2. direct use at lower pressure in a LP inlet of the steam turbine.

Figure 33 illustrates an ISCCS configuration with these two options.

Impact of Solar Integration

Integration of a solar thermal steam system with a conventional gas turbine combined cycle requires careful system design for optimum operation. Recent work on the most effective integration of the solar field places considerable attention on the mitigation of possible degradation of pure combined cycle performance due to the addition of a solar system.

In general, the capacity of the steam turbine is increased to accommodate the additional steam from the solar field. Therefore, when solar steam is not available the plant operation will be somewhat penalized due to part-load performance of the steam turbine. For Option A in Figure 33, the magnitude of this effect is dependent on the capacity factor and the details of the solar steam integration via the HRSG. It is also possible to utilize the higher capacity of the steam turbine by use of separate fuel (natural gas or liquid fuels) firing of an auxiliary steam source (boiler) or duct firing additional fuel in the HRSG to make up for the lack of solar steam in low insolation conditions. This method, while technically viable, introduces a less efficient use of fuel compared to firing the fuel in the gas turbine (combined cycle operation).

Option B in Figure 33 is less complex in that it requires no re-design of the HRSG, and is favored in that respect. However, this approach is less favorable from a thermodynamic viewpoint.

Design of an ISCCS plant requires a careful analysis of the thermodynamic cycle using a sophisticated power system code such as GateCycle, consideration of the design details of the HRSG, and an annual simulation on at least an hourly basis to understand the tradeoffs between factors such as part-load steam turbine operation, solar contribution during hot summer days when gas turbine operation decreases, duct firing, and other system options.

Operating characteristics of an ISCCS feasibility design developed for a proposed GEF project in Mexico are shown in Table 9. Note that the solar contribution to the overall plant is relatively small compared to total design capacity and annual generation, though reasonably large for a solar system. Other ISCCS configurations have been considered that incorporate a smaller gas turbine and/or a larger solar fractional contributions.

From an investment standpoint, the capital cost increases by the cost of the solar field and an incremental power block cost of approximately $100/kW. The levelized electricity cost can be expected to increase by approximately a fraction of a cent/kWh.

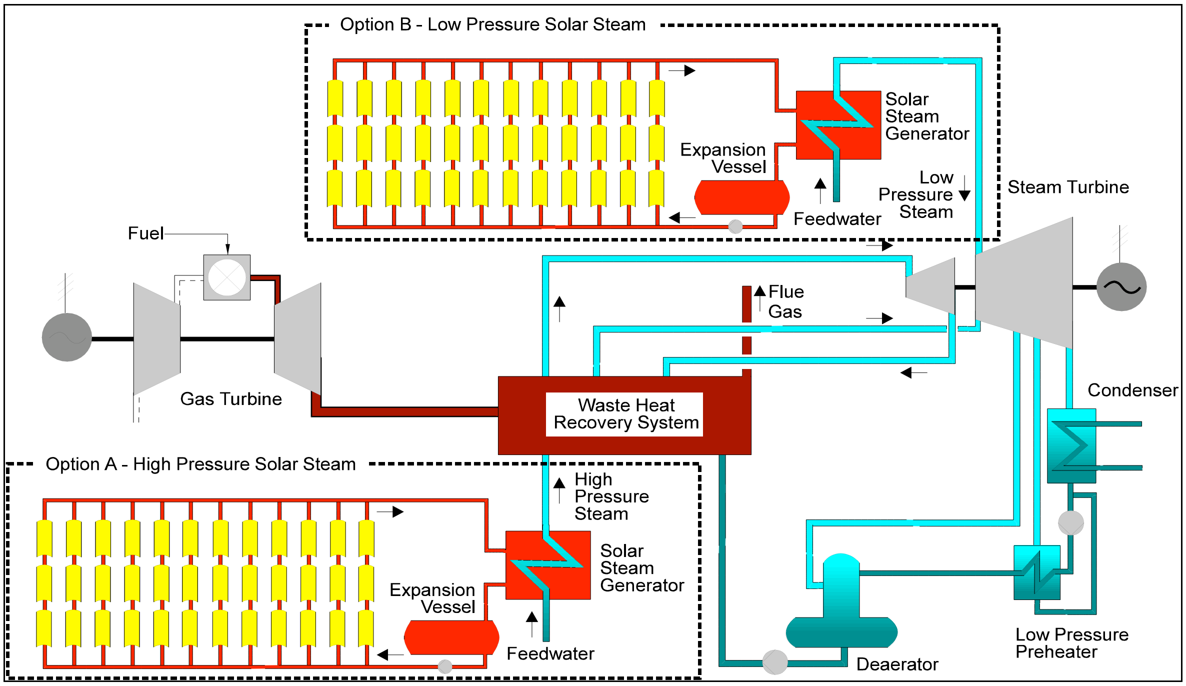


Figure 33 – Two Options for Utilizing Solar Steam in an ISCCS Configuration

Table 9 – Example of Operating Characteristics of an Option A ISCCS Plant

	No Solar Input	**Design Solar Input**
***Design Point** Power Characteristics*		
Solar Power		
Design thermal output	0 MWt	100 MWt
Equivalent electric capacity	0 MWe	41.3 MWe
Parasitic Power Consumption	0 MWe	1.64 MWe
Net Gain from solar power	0 MWe	39.6 MWe
Gas Turbine-Generator		
Type	GE-PG7241(FA)	GE-PG7241(FA)
Number of gas turbines	1	1
Inlet air cooling	Evaporative	Evaporative
Gas Turbine Power Gross Output	162.1 MWe	162.1 MWe
Combustor temperature	2400ºF	2400ºF
Exhaust gas temperature	1137ºF	1137ºF
Heat Recovery Steam Generator		
Type	3 pressure	3 pressure
Steam Turbine-Generator		
Type	Single reheat	Single reheat
Number of steam turbines	1	1
Main steam conditions	1100 lbf/in2/1,050ºF	1815 lbf/in2/918ºF

Reheat steam conditions	272 lbf/in2/1050ºF	400 lbf/in2/972ºF
Steam Turbine Gross Power Output	89.7 MWe	131.0 MWe
Total CC Gross Power Output	251.8 MWe	293.1 MWe
Total CC Net Power Output	**245.5 MWe**	**285.1 MWe**
Net plant heat rate (LHV)	**6331 Btu/kWhe**	**5438 Btu/kWhe**
***Annual* Performance Characteristics**		
Annual DNI (CP-hi value)	540.6 GWh,t	540.6 GWh,t
Solar Thermal Energy Delivery	0	247.2 GWh,t
Net CCGT Share	2,212,910 MWh	2,212,910 MWh
Net Solar Field Share	0 MWh	90,406 MWh
Net Total Electricity Output	2,212,910 MWh	2,303,317 MWh

2.4.4 Observations and Conclusions

The SEGS and ISCCS configurations both offer viable methods of solar thermal electrical generation. Selection of the most appropriate configuration will be based on policy factors, technical performance, cost, and marketplace conditions.

The solar system in the ISCCS approach contributes a fairly small fraction of the energy output of a large plant. The solar-to-electric efficiency of this configuration is improved over a SEGS-type plant, and the incremental power block cost is attractively low.

The SEGS-type system, on the other hand, would likely be deployed in much higher solar capacities and numbers of plants and offers a path for a greater solar contribution to the mix of utility generation resources. Hybrid operation, thermal storage and dry cooling offer a flexibility of implementation to be evaluated and chosen depending on site-specific and utility-specific opportunities.

2.5 Siting Solar Thermal Plants in California[12]

2.5.1 Summary

The siting of solar power plants is dependent on factors that, together, lead to the most suitable locations from technical, environmental and economic perspectives. Many of these factors are similar to conventional power plants. Those that are somewhat unique to solar thermal power plants are largely associated with the land area required for the solar field, the nature of the heat transfer fluid that flows though the solar field to collect heat, and the positive environmental effects, such as lesser emissions due a reduction in fossil fuel use.

The unique aspects of siting solar thermal plants are described in some detail. Next, the results of geographical information system (GIS) analyses with respect to solar thermal power plants are presented for the state of California. The major factors considered in this assessment are solar radiation intensity, land slope, proximity to transmission, and land use. Backed by quantitative

[12] This chapter summarizes the work completed in the task 4.1.3.1 Potential Site Ranking Report, dated March 2004.

performance analysis and a qualitative assessment of other siting factors, as shown in the table below, it is concluded that the preferred siting approach is to locate a plant in the Mojave Desert region and transmit power to users in both southern and northern California. Based on this result, GIS data are shown for the Mojave Desert region in particular, and attention is then focused on the Harper Lake site in that area.

Table 10 – GIS Data for Sites

Site	Bakersfield	Carizzo PL	Harper Lk	Las Vegas	Reno	Sacramento
Radiation (kWh/m^2-day)	5.91	6.72	7.65	7.14	6.39	5.45
Relative Performance[a]	0.86	0.98	1.11	1.00	0.84	0.76
Proximity to CA Load[b]	Excellent	Adequate	Excellent	Good	Poor	Excellent
Transmission Access[b]	Good to Excellent	Good	Good to Excellent	Excellent	Poor	Excellent
Water supply	Site dependent	Site dependent	Excellent	Adequate	Site dependent	Site dependent
Suitable Land[c]	Likely	Likely	Good to Excellent	Lease from Boulder Cty	Likely	Limited

a) Annual solar plant electrical generation in MW_eh/year relative to Las Vegas site
b) At present, the Reno area is electrically isolated from California and southern Nevada. Transmission studies within the Hetch Hetchy PIER Program are evaluating several scenarios for enhancing transmission pathways from Northern Nevada into California. Should those transmission enhancements be developed, the greater Reno area could become an attractive renewable energy region for serving California load centers.
c) Availability of large tracts of suitably flat land at reasonable cost, without other specified land use or environmental barriers

2.5.2 Siting Factors

Siting issues vary broadly in character and importance, and can range from issues that have either a cost impact or a more definitive go/no-go impact on a project. Most requirements fall into the former category, or shift from one to the other in the limit. For example, a terrain with a 3% slope has potential, but grading costs would be much higher than a site with <1% slope. However, a very high slope or hilly topography would be totally unsuitable.

While there are many plant cost and construction issues related to siting, the key top-level siting factors for a solar thermal power plant are:

<u>Technical considerations</u>

- Abundance of the solar resource
- Site topography
- Land ownership
- Proximity to transmission and water

<u>Environmental issues</u>

- Fossil fuel air emissions displaced
- Water usage similar to conventional plants
- Solar field heat transfer fluid (HTF)

- Land usage

These characteristics discussed below are those with the most significant impact on costs.

2.5.2.1 Solar Resource

Parabolic trough solar steam systems require high direct normal insolation (DNI), or beam radiation, for cost-effective operation; the required size of the solar field for a given power plant capacity is in general directly proportional to the DNI level. The solar field cost is a significant factor in the economics of a solar power plant; for a Rankine cycle steam power plant with a solar heat resource, the solar field constitutes about 50% of the total cost. Thus, not only do sites with excellent solar radiation offer more attractive levelized electricity prices, but this single factor normally has the most significant impact on solar system costs.

DNI data are either measured directly or constructed by radiation models from measurements of total radiation (which consists of both direct beam and diffuse components). Satellite data are proving to be an important source of these data. Micro-climate effects, sometimes in relatively small regions, can be quite important. Although constructed data are becoming increasingly accurate and valuable, measured DNI data offer the best assurance that the solar field size is chosen accurately.

Ideally, any site under consideration should have ten or more years of measured solar resource data to indicate the seasonal and annual variations likely to be experienced at the site. Unfortunately, very few sites have solar monitoring stations, and even when they do, the data are often not of sufficiently high quality. This assessment uses a new, high-resolution solar resource data set developed using satellite data and correlated to good ground station data. Annual solar DNI estimates are provided on a grid of 0.1 degree in both latitude and longitude (nominally, 10 km). These estimates were created using the Perez irradiance model.[1] As input, the model uses visible cloud images from the NOAA GOES-10 weather satellite (in California), atmospheric water vapor measured from satellites and radiosondes (balloons), total column ozone measured from satellites, and aerosols (dust and haze) estimated from surface and satellite measurements. This is a third-generation model with substantial improvements to handle cloud detection over desert terrain, a critical problem in the western United States.

The model was used to create hourly estimates of DNI for each hour in a 5-year period, 1998-2002. These results were then averaged to create the annual average direct normal radiation for each grid point. Current results (from June 2003) were then reduced by 7% from the satellite model outputs to correspond with ground measurement data from two desert locations (Kramer Junction, California, and Desert Rock, Nevada). The resulting map agrees in general with previous estimates of DNI for California made using surface measurements and a 40-km grid model. The Perez model provides substantially better resolution and a consistent methodology for all locations. The results in the Mojave Desert should have higher confidence than the prior 40-km grid model. Results from a newer model should be available by March 2004, including more extensive validation at multiple surface locations.

2.5.2.2 Land

A parabolic trough solar power plant requires approximately 5 acres (20,000 m^2) per MW of plant capacity. Plants with thermal storage and higher capacity factors will require proportionally more land per MWe. Siting studies have generally found that a land with an overall slope of less than 1% are the most economic to develop. Potential sites should have reasonable land costs, be generally level, and be close to transmission, water, and natural gas. The specific slope and topography of the land will then determine the comparative acceptability of competing sites through their impact on site costs for grading and preparation. Land characteristics are thus most effectively used as screening tools in selecting acceptable sites for further evaluation.

2.5.2.3 Transmission Access and Interconnection

Transmission line costs can be very high, and access to transmission lines of appropriate capacity is a very important siting factor. Depending on the line voltage level and the length of the transmission line, costs for a 100-MW capacity, for example, can range from $50,000 to $180,000 per mile. Therefore, the proximity of potential solar power plants sites to transmission lines is very important.

Parabolic trough plants use conventional Rankine steam turbine/generator sets, with some performance enhancements such as reheat. The interconnection requirements are similar to those of other steam power plants. The existing 80- MWe trough plants have step-up transformers to supply power at 230 kV and include reactive power control.

2.5.2.4 Water

The primary water uses at a Rankine steam solar power plant are for the steam cycle, cooling, and washing mirrors. Historically, parabolic trough plants have used wet cooling towers for cooling. The cooling tower make-up represents about 95% of the raw water consumption. Steam cycle make-up and mirror washing constitute the remaining approximately 5% of raw water consumption. However, availability of water can be a significant issue in the desert. Many of the flat areas in the desert have underground water. Two of the Mojave Desert trough sites use underground water, and one uses aqueduct water.

Annual water consumption at trough plants is approximately half that of agricultural use for an area the size of the solar field. If sufficient water is not available for cooling, either dry cooling or wet-dry systems are necessary. These options can increase plant electricity costs by 10% or more, indicating the desirability of sites with sufficient aquifer or other water resources. Treatment of raw water is required for plant use.

2.5.2.5 Natural Gas

Solar thermal power plants have the capacity to provide firm power in a hybrid configuration where fossil fuel, preferably natural gas, can supplement the solar energy resource. This is particularly important during peak demand periods where the electricity value is high. Proximity to natural gas pipelines is a very important factor. It is a significant, though usually not critical, determinant in the viability of hybrid operation. Of course, very large distances can make this option economically unacceptable.

2.5.2.6 Geology and Soils

The following data are required or useful to assess flood potential and soil characteristics for grading, foundation design, and flood diversion channels.

- Topography and Surface Hydrology
- Site land area (1.5-3.0 km^2 depending on configuration)
- Topographical maps (1:200,000-1:500,000 for overview, 1:25,000-1:50,000 for site selection) showing slopes as a function of direction; ⟨0.5% slope is preferable; higher slopes up to 3% may be acceptable depending on cost of grading; slope in the north-south direction is preferred)
- 50-year and 100-year flood data; height, duration, and season of flooding
- Aerial photographs (oblique or low-angle views)
- Data on natural drainage and flood runoff flow paths
- Information on streams, ravines, obstructions, or other special features
- Soil Characteristics (at various locations on site)
- Soil type and composition as a function of depth (e.g., sand, clay, loam, sedimentary; grain size, density)
- Water table data (well depths, level of water in wells)
- Resistance to penetration (standard blows per foot)
- Lateral modulus of elasticity
- Minimum stress capacity
- Geology
- Geological formation of the area
- Seismic records (magnitude and frequency data, maximum probable and maximum credible seismic events). This is needed for plant design, including buildings and solar collector field.
- Geological or man-made features that would shadow the solar field in early morning or late afternoon (features lower than 10 degrees above the tangent horizon will not shadow the solar field)
- Additional
- Site elevation and geographic coordinates (longitude/latitude)
- Legal description of property (location, etc.)
- Land ownership and current land use
- Land use priorities or zoning restrictions applicable to this site
- Existing rights of way (water, power line, roads, other access)
- Land cost
- Existence of dust, sand, or fumes carried to site by winds (constituents, quantity or rate, duration, direction, velocity)

2.5.2.7 Heat Transfer Fluid and Waste Products

The heat transfer fluid (HTF) for a parabolic trough solar field is typically a diphenyl/biphenyl oxide. Dowtherm A and Solutia VP-1 are commercial products that have been used in the SEGS plants. These fluids must be handled with care. Although the collector design has advanced to an excellent level of performance and reliability, occasional small spills of HTF do occur, primarily because of equipment failures, and must be handled by prescribed methods. The Solar Electric Generating System (SEGS) plants at Kramer Junction have reduced HTF spills caused by accidents or pipe ruptures to very low levels. Good maintenance practices and the use of ball joint assemblies rather than flexible hoses in the HTF system are the major contributors to this improvement.

If a line worker or other staff member observes a spill or release, the system operators in the power block will be notified and the affected collector loop shut down. An appropriately equipped crew will make any equipment repairs necessary and remove any hazardous wastes to an on-site bioremediation facility that utilizes indigenous bacteria to digest the hydrocarbon contamination. A combination of nutrients, water, and aeration is provided to facilitate bacterial activity where microbes restore the soil to a normal condition in 2-3 months. Figure 34 shows HTF-contaminated soil being aerated with a tractor-drawn plow.

Hazardous waste or other regulated fluids and solids associated with other normal plant maintenance procedures (e.g., chemicals for water treatment; oils; cooling tower and boiler blow down) are the same as those of a conventional power plant, or similar. Fugitive emissions of HTF from valve stem packing and gaskets are very low and difficult to monitor. No recent measurements of fugitive losses from valves and collector field ball joint assemblies have been made at the Kramer Junction site, though this factor appears to be a very minor factor in overall HTF losses.

Figure 34 – Bioremediation of HTF-Contaminated Soil

(Source: KJC Operating Company)

Regarding HTF losses, from 1996-1998 Kramer Junction did not purchase any HTF. Over that 7-year period (1996-2002), an average of about 15,000 gallons per year was purchased or just under 3% of the site inventory of 540,000 gallons.

2.5.2.8 Land Use

Solar thermal power plants require a large area for their solar collector field, approximately 5 acres are required per megawatt of electricity produced in a solar thermal power plant. As a result, the potential for wildlife habitat disruption may be greater than that of a conventional power plant. In desert regions, where a solar thermal power plant would typically be located, protected wildlife such as the desert tortoise and the Mojave ground squirrel could require habitat remediation. The 80-MWe solar thermal power facilities, SEGS VIII and IX, have minimized habitat disruption by being built on sites on former agricultural land. This strategy appears to be successful and is the wisest approach, if feasible, in regions of interest. No strategies have yet been identified for solar thermal fields that encourage dual use of land, for example, wind energy installations that include wind turbines and farming or grazing.

Desert land is valued as an unspoiled resource, but much of this land has been converted to meet human needs. Its use as a solar energy resource should rank high in evaluations. For example, compared with the land areas required for reservoirs for hydroelectric power plants, the amount of land needed for a solar field is smaller by at least an order of magnitude.

Except for the solar field, noise and visual impacts associated with solar plants are similar to those of a conventional power plant. The solar field causes no noise pollution and has minimal visual impact. Parabolic solar fields have a low profile from a normal viewing perspective.

During the certification of the SEGS plants in the Mojave Desert, some concern was expressed about reflected light that could interfere with aircraft flying in the vicinity. This was shown to be of no consequence, since the parabolic mirrors have a focal length of approximately 1 m. The reflection seen by aircraft is one sun, similar to that seen when flying over a lake.

2.5.2.9 Air Quality

Emissions will be present as a result of fossil fuel operation in hybrid mode or in combined-cycle mode, and very low emissions will result from the evaporation of the HTF ullage system and small leaks. Permitting and licensing requirements by the California Energy Commission and the local air quality management district will dictate emissions limits to be met at the plant.

Although parabolic trough technology is the least-cost solar power option, it is at present more than twice as expensive as power from conventional fossil-fueled power plants at today's fossil energy prices in the United States. A number of factors are expected to bring solar thermal plants to a competitive level within the next decade or so. One factor that should be considered when evaluating the economic need for a new solar thermal power plant is the positive effect of emissions reductions. The higher operating cost of a solar thermal power plant can be partially offset by the value of the air quality benefits, according to analysis conducted by California Energy Commission staff (Luz SEGS IX-X AFC [89-AFC-[1]). The staff examined the Luz SEGS IX & X project with respect to air quality attainment plans in Southern California, analyzed system effects, quantified the air quality benefit available to the ratepayers, and presented a social value of emissions reductions. That social value was demonstrated to be positive.

2.5.2.10 Wind

The performance and structural design of the solar field are impacted by high winds. The solar field is not designed to operate at winds of more than 35 mph; consequently, high-wind sites limit the performance potential of the solar plant. Moreover, wind forces dictate the collector structural design. Since the structure constitutes about 40% of solar field costs, it is important to optimize this component. Wind tunnel tests on parabolic trough collectors were conducted recently to provide design data for estimating design wind loads from ambient wind conditions. The solar field is designed to survive wind speeds of 80 mph with the collectors stowed in a non-operating face down position. The solar field can be designed for higher maximum survival wind speeds, but at an increased cost.

2.5.3 Geographical Information System Mapping

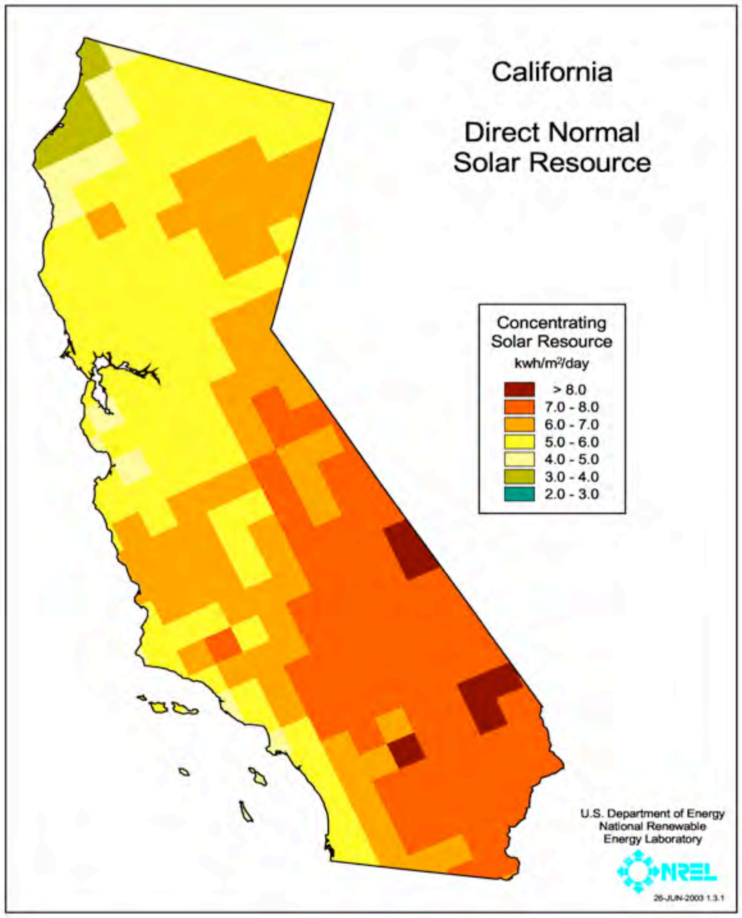
We have utilized data analysis from NREL to examine California sites both generally and in the Mojave Desert region. Specifically, NREL used a Geographic Information Systems (GIS) analysis to identify areas with high potential for development. The GIS analysis evaluated the following factors to determine siting potential: direct normal solar resource level; slope; environmental sensitivity; and contiguous area and distance to transmission.

2.5.3.1 Statewide GIS Data and Performance Analysis

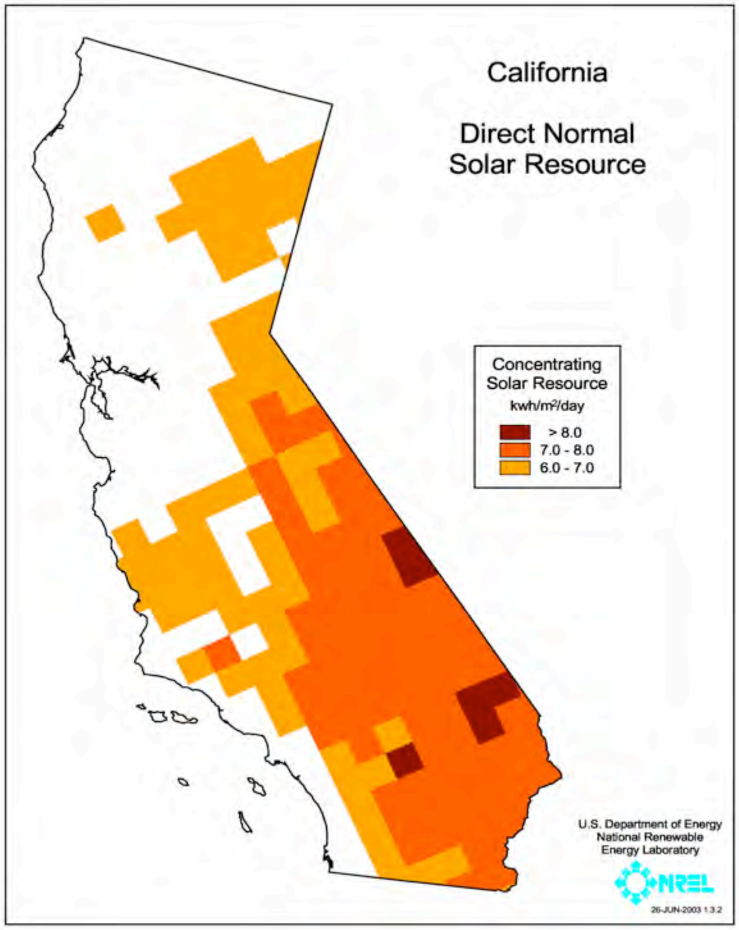
The graphics shown in Figure 35 - Figure 37 were prepared by NREL for the entire state of California. Our purpose in showing these plots is to give a brief overview of the state with respect to a few of the key siting factors. Figure 35 shows the levels of direct normal radiation (also referred to as Direct Normal Insolation, or DNI) throughout the state, and then focuses on the higher levels, that is, over an average daily value of 6 kWh/m^2-day. The significance of the radiation level is quantified in the next section.

As discussed earlier, topography can be an important factor in the siting of a solar thermal power plant. One key topographical feature is land slope. Since topological data is available that allows a rough characterization of land slope, this factor can be considered on a statewide basis. In Figure 36 only land areas with slope equal to or less than 1% have been retained. Further, the California transmission system is overlaid on this map for information.

Figure 37 shows public lands that are not available for power plant development. In the analysis presented later in this report on a smaller area – the Mojave Desert region – all of these factors are combined in a single graphic.



(a) All levels of direct normal radiation



(b) Shows only radiation levels above 6 kWh/m2-day

Figure 35 – California Radiation Resource Applicable to Solar Thermal Power Plants – Yearly Average kWh/m2-day

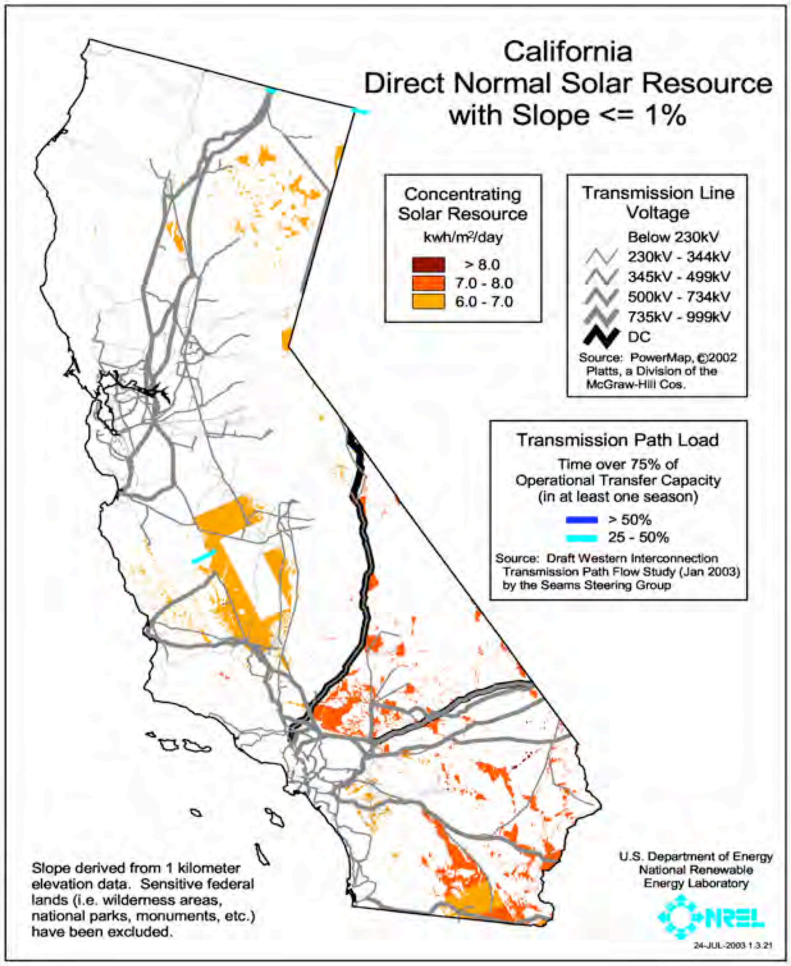


Figure 36 – Similar to Fig. 2 but with land slope> 1% deleted and transmission system overlaid

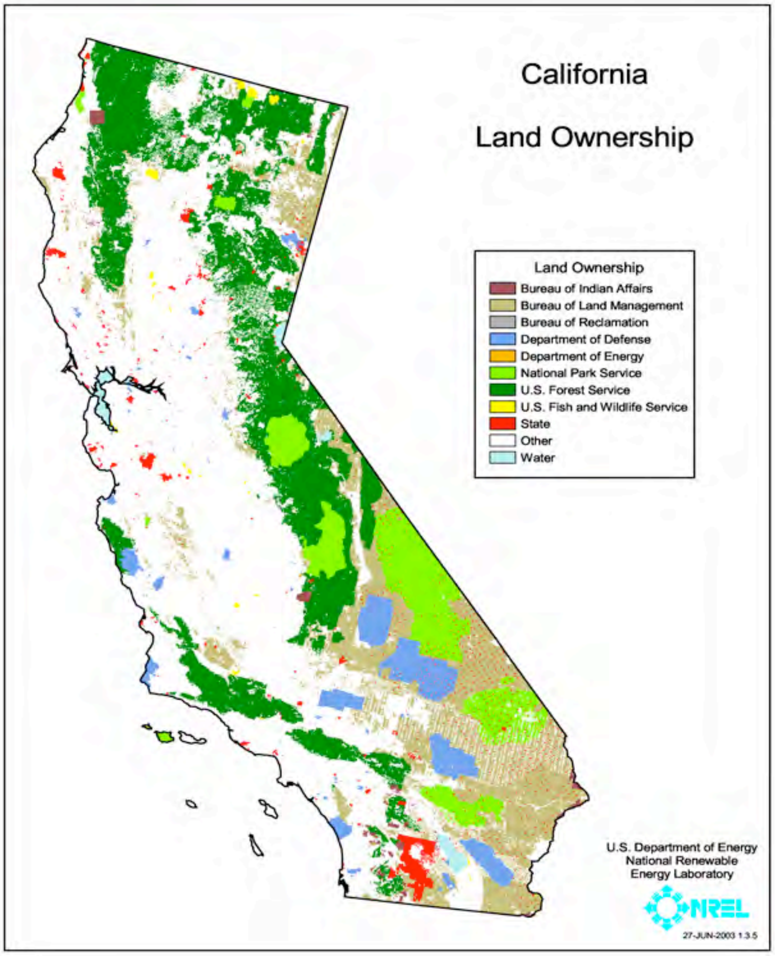


Figure 37 – Government / Public lands identified

2.5.3.2 Performance Comparison at Several Sites

The cost of electricity from a solar thermal plant is directly dependent on radiation level. Consider the electricity capacity factor[13] of the solar power plant, which in turn is directly dependent on the solar resource and the plant efficiency. The plant efficiency is set by the design of the solar field and overall system. The solar resource is set by the site location and, to a lesser extent, site features (e.g., slope, shading).

To examine the electricity production cost for several sites we ran the Solargenix plant performance model[14] for six site areas, selected to give a broad cross-section of the regions of interest:

- Harper Lake, California → Mojave Desert region
- Bakersfield, California → San Joaquin Valley region
- Sacramento, California → Central Valley region north
- Carrizo[15] Plains, California→ West of Central Valley in high hills before coast
- Las Vegas, Nevada → possible site to feed southern California

[13] The annual capacity factor (CF) = net power produced / maximum capacity. Maximum capacity = 8760 h/yr * nominal net power capacity of the plant (e.g., 100 MWe,net).
[14] See deliverable D4.1.4.1 "Technical Options Ranking Report" for information on the performance model.
[15] The spelling "Carissa Plains" is also seen.

- Reno, Nevada → possible site to feed northern California

The results are presented in Table 11 and Figure 38. The relative levels of direct normal radiation for these sites, normalized to the Solargenix project site in the El Dorado valley near Las Vegas, favor the Harper Lake site, both in annual performance factors and monthly performance. Carizzo Plains, in the high coastal plateau between San Luis Obispo and Bakersfield, has good performance, although still over 10% lower than Harper Lake in annual output.

Table 11 – Relative Performance Comparison of Several Regions

Site	Bakersfield	Carizzo Plain	Harper Lake	Las Vegas	Reno	Sacramento
Perf. Factor	0.86	0.98	1.11	1.00	0.84	0.76

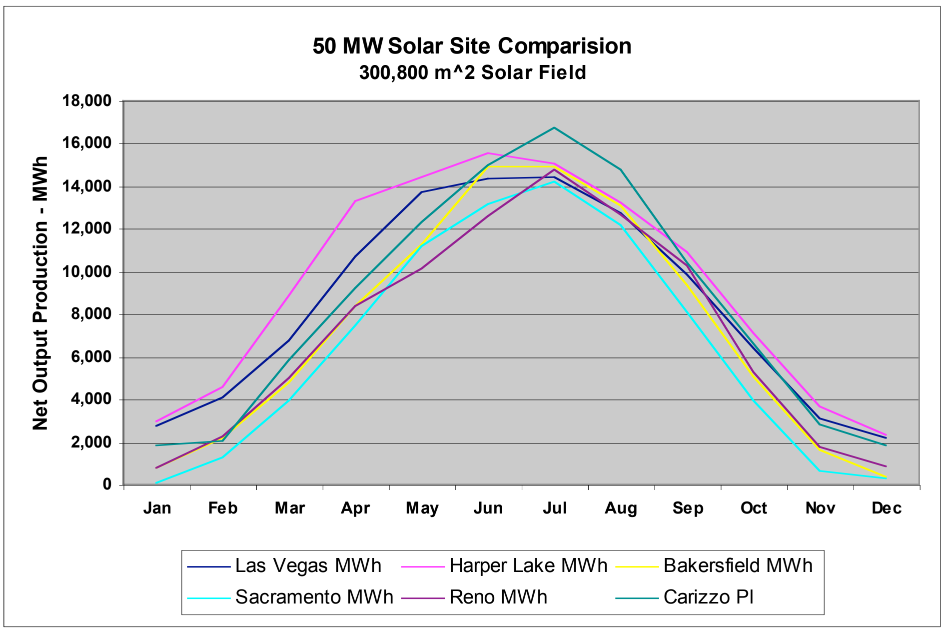


Figure 38 – Annual Performance by Month, at Several Sites

The relative cost of electricity mirrors the performance relationship if no other major factors change. Based on this evaluation, the decision was made to look much more closely at the highest radiation area – the Mojave Desert region.

2.5.3.3 Evaluation of the Mojave Desert Region

The next step focused on the Mojave Desert region north of Victorville, Calif. due its high solar resource and proximity to transmission.

Solar Resource: The Solar resource data developed from satellite information by Perez were used to identify the level of direct normal solar resource. A minimum value of 6.75 $kWh/m^2/day$

of average annual solar irradiance was determined to be suitable for near-term development. There are many areas in this region that exceed this level.

Slope: As noted above, large-scale solar installations require a relatively flat surface (ideally, <1%) for optimal siting. In past siting studies, NREL has used slope data from a 1-km^2 data set. This data set tended to hide surface terrain features; however, for this study, slope data were derived from 30-m elevation data extracted from data made available through NASA's shuttle radar topography mission. Because this results in much more scatter, we have relaxed the slope criteria <3%. In general, the areas identified have slopes that are less than the <1% over the larger area. Gaps in the data were filled by interpolating information from nearby areas.

Land Type and Ownership: The federal government owns the majority of the land in desert areas having a high solar resource. Some of these land areas are incompatible with development, because they are in national parks, national preserves, wilderness areas, wildlife refuges, water, or urban areas. A federal land classification dataset produced by the U.S. Geological Survey (USGS) was used to identify areas that should be eliminated from the analysis because of this incompatibility. Urban areas and water features were identified using a USGS global land cover/land classification dataset and other publicly available data sources. In general, Bureau of Land Management (BLM), National Forrest Service, and Department of Defense lands were assumed to be acceptable for purposes of this screening study.

Minimum Contiguous Area: After the solar resource level, percent slope, and compatibility have been accounted for, an area must be at least 8 km^2 in size. This area would be sufficient for the development of a 400-MW plant. Some developable areas may have been excluded in the analysis because of small gaps that caused the areas to appear discontinuous.

Detail in the Mojave Desert near Harper Lake: Figure 39 shows a close up of the region west and north of the Kramer Substation. The green triangles show substations, and the green squares denote existing SEGS plant sites. The Harper Lake site is just northwest of the Kramer substation (about 10 miles away). A number of good resource regions with low surface slope and proximity to transmission exist in this general region. The thick blue and gray lines are major transmission corridors.

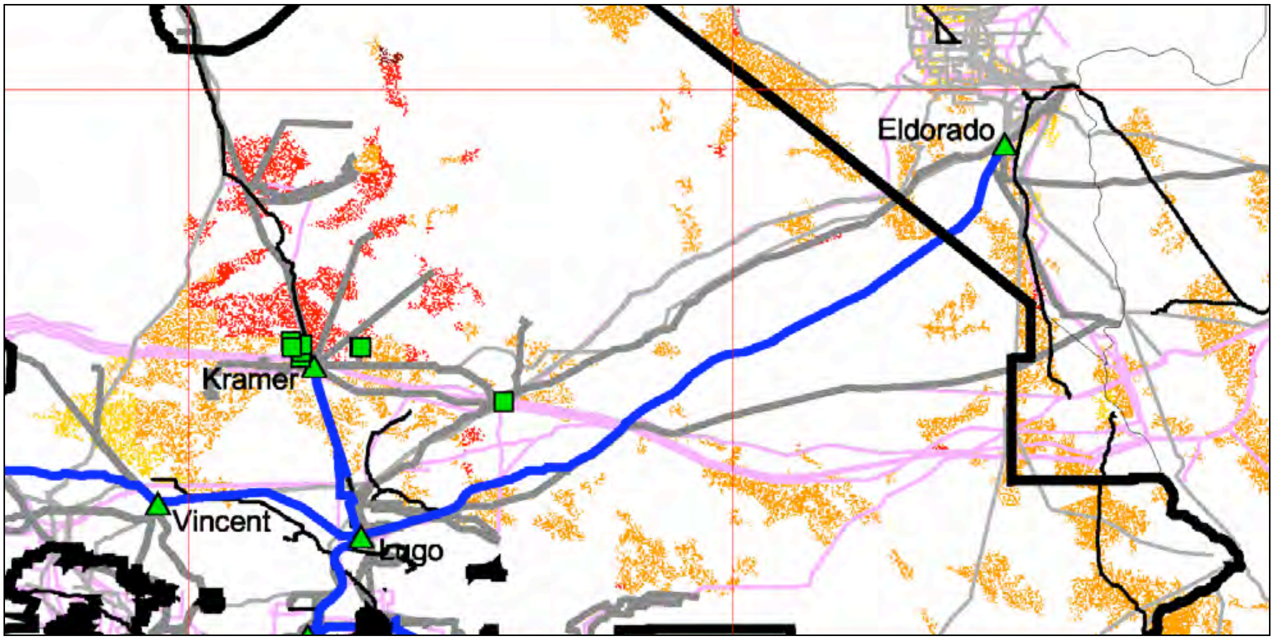


Figure 39 – Close-up of Potential Solar Sites NW of Kramer Substation (NREL 2003)

In general, there appears to be reasonable proximity to natural gas pipelines in the prime solar regions. If a hybrid plant is planned, proximity to natural gas pipelines could be included in a more detailed siting analysis. Propane, oil or compressed natural gas could be alternatives to connecting to natural gas pipeline.

2.5.4 Transmission Issues

Based on the evaluation to this point, we have chosen as a reference case to concentrate on a single solar power plant site or complex at Harper Lake that would supply power to both southern and northern California. Consideration of siting a solar power plant in the Mojave Desert region to provide solar electricity statewide requires a preliminary understanding of the transmission system issues. One is immediate local problem of getting power from the solar plant to a main substation, such as Lugo or Vincent. The other issue is that of connecting to northern California via Path 15.

2.5.4.1 Path 15 Analysis

Electranix Corporation conducted a limited evaluation to determine how much energy from a solar generating plant located in the Mojave Desert, and connected through electric power transmission into the California power system south of Path 15, could be sent to northern California. Path 15 is a transmission bottleneck between the electric power systems of southern and northern California as shown in Figure 40.

The purpose of the analysis was to examine the ability of a solar plant located in the Mojave Desert to transmit energy north via Path 15, and to draw preliminary conclusions.

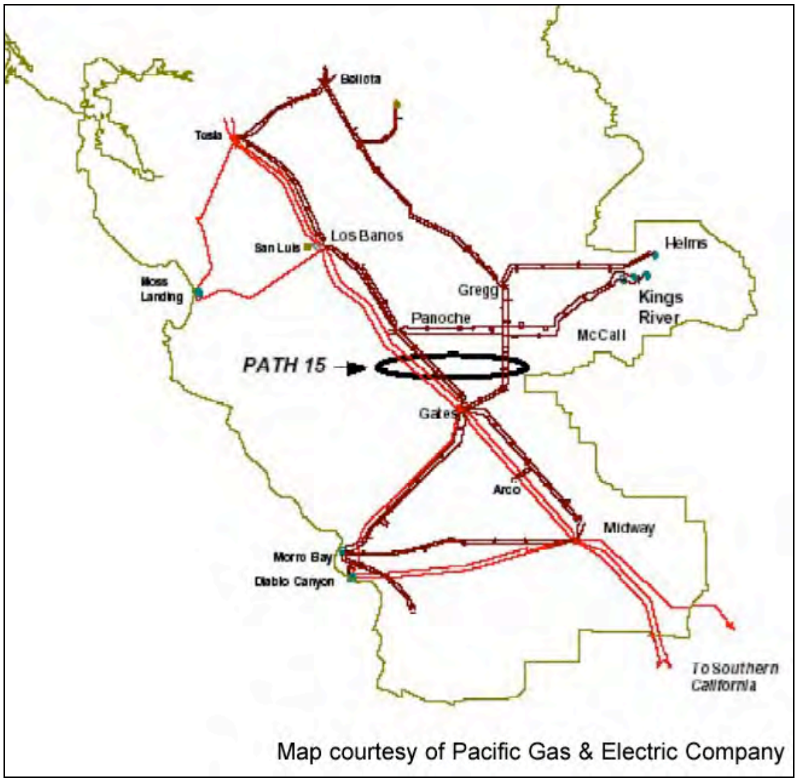


Figure 40 – Path 15

The following data was compiled for this purpose:

- One year of hourly solar energy output from a total 500MW solar plant capacity located in the Mojave Desert, statistically representative of the last 25 years. This data was received from Solargenix Energy LLC, Raleigh NC.
- Hourly zonal average energy prices for SP15, NP15, and ZP26 for the year 2003
- CAISO Transmission Allocation Report for Path 15 for the year 2003. This includes data for flows both North to South and South to North and specifies total hourly flows, available hourly flows, constraints, and other flow data. This data is provided on a day-ahead basis.

In order to evaluate the ability to move solar energy north, it was necessary to compare the hourly Available Transmission Capacity (ATC) through Path 15 to the hourly energy produced by the solar plant. The ATC is a figure provided by CAISO which takes into account the total available capacity, hourly constraints which may be in place, capacity dedicated to existing contracts, spot market usage, and other data. It is the ATC through Path 15 that is available for sending the solar electricity north.

The analysis determined that the energy that cannot be sent north due to insufficient ATC is very low. In fact, less than 2.5% of the total generated energy from a 500 MW solar generation over the course of this one year would be restricted from being transmitted without the Path 15 upgrade and 1.8% with the upgrade. Additionally, the use of a 6 hr storage device in conjunction with the solar generation seems to have a slightly beneficial effect for solar ratings of less than 1000MW.

It is worthwhile noting that through there is reserved transmission capacity on Path 15 that is often not used. Existing Transmission Contract rights (ETC) is capacity reserved for Existing Transmission Contract owners. ETC available reflects the Existing Transmission Contract rights that have not been scheduled for use over the Path. It may be possible to purchase ETC when not being used by the Existing Transmission Contract owners, and this capacity is additional to ATC.

Additionally, it seems from this data that during the hours when solar generation is likely to be at its peak, the ATC also seems to be at peak levels. A seasonal correlation between the ATC and the solar output was also observed, although further study would be required before firm conclusions could be drawn pertaining to this correlation. It could be expected that for different water conditions in the northern California hydroelectric systems and for the Columbia River, the ATC over the season or year may be different than through the year 2003. Likewise, if energy supply to thermal generation in California becomes unavailable or too expensive as it was in 2001, then ATC on Path 15 would be significantly less or congested more frequently.

2.5.4.2 Local Transmission at Harper Lake

The nearest existing transmission is expected to be Kramer substation, which has two 230 kV lines to Lugo. These lines are currently fully loaded at peak time from the hydro (Poole, Rush Creek and Bishop Creek) and geothermal plant (Coso). Thus there would be little daytime/peak time transmission capacity available between Kramer and Lugo. For 500-1000 MW into Lugo or Vincent substations, additional transmission would be required.

Solargenix approached Southern California Edison Company (SCE) to clarify this situation. As a result, in July 2003, SCE and Solargenix Energy executed a Conceptual Transmission Facilities Study Agreement to evaluate the connection of a total of 1,000 MW of new solar generation at the Harper Lake site, about 10 miles northeast of Kramer substation.

The results of the Conceptual Study indicated that new 230 kV lines are needed from Lugo substation to Kramer substation to help deliver the renewable solar generation to the load centers. There will be a need for a total of three 230 kV lines from Lugo to Kramer substation, i.e., Lugo-Kramer No.3, Lugo-Kramer No.4, and Lugo-Kramer No.5.

The Net Present Value (NPV in 2003 Dollars) of these conceptual transmission facilities to be implemented by 2017 to connect 1,000 MW of solar generation is estimated to be $86.8 Million. This cost does not include the cost of the Gen Tie transmission facilities to connect the solar generation project to the Kramer substation.

2.5.5 Summary of Preliminary Site Selection

Based on the information collected at this preliminary stage, a table has been prepared to summarize the issues for general siting areas. Selection of specific sites would require a deeper level of site evaluation, carried out for specifically identified site locations. Certain important issues, such as the availability of water, environmental constraints and local transmission options, can only be identified and/or fully understood at that more detailed level. However, given the highly favorable characteristics of the Harper Lake site, detailed data has been assembled for that location.

Table 12 lists key factors for the sites previously ranked in section 3 from the viewpoint of electricity cost. As noted, Harper Lake is the preferred site based on the information available at this juncture, particularly the very high solar resource (direct normal radiation) at that site. Harper Lake is a favorable site for the following reasons:

1. High solar insolation levels are available
2. Previously disturbed (cultivated farmland) sites with low diversity of biological species and limited aesthetic value are available.
3. An adequate water supply is available
4. An existing transmission-line corridor, natural-gas pipeline, and rail transportation system are nearby
5. The sites are flat, which is important for solar fields
6. No population centers are nearby so impacts on communities will be limited
7. San Bernardino County supports introduction of clean industrial development within its jurisdiction.

Table 12 – Regional Site Comparison

Site	Bakersfield	Carizzo PL	Harper Lk	Las Vegas	Reno	Sacramento
Radiation (kWh/m^2-day)	5.91	6.5	7.65	7.14	6.39	5.45
Relative Performance[a]	0.86	0.98	1.11	1.00	0.84	0.76
Proximity to CA Load[b]	Excellent	Adequate	Excellent	Good	Poor	Excellent
Transmission Access[b]	Good to Excellent	Good	Good to Excellent	Excellent	Poor	Excellent
Water supply	Site dependent	Site dependent	Excellent	Adequate	Site dependent	Site dependent
Suitable Land[c]	Likely	Likely	Good to Excellent	Lease from Boulder Cty	Likely	Limited

a) Annual solar plant electrical generation in MW_eh/year relative to Las Vegas site

b) At present, the Reno area is electrically isolated from California and southern Nevada. Transmission studies within the Hetch Hetchy PIER Program are evaluating several scenarios for enhancing transmission pathways from Northern Nevada into California. Should those transmission enhancements be developed, the greater Reno area could become an attractive renewable energy region for serving California load centers

c) Availability of large tracts of suitably flat land at reasonable cost, without other specified land use or environmental barriers

An alternative to the Harper Lake site lying within the same solar resource region is the site of the High Desert Power Plant located near Adelanto at the site of the decommissioned George Air Force base. It is expected that the size of available acreage or a solar plant is likely restricted either by cost or presently designated use. However, the site would have the advantage of an existing infrastructure, and a jump start on licensing and permitting procedures.

2.6 Permitting of Parabolic Trough Solar Power Plants in California[16]

2.6.1 Summary

The California Energy Commission has exclusive authority to certify power generation projects and related facilities in California. This includes solar energy facilities. In general, the Commission has jurisdiction over thermal power plants with a net generating capacity of 50 MWe or more, modifications that result in a 50 MWe or more increase in generating capacity, and transmission lines that carry the electricity from a power plant with a generating capacity of 50 MWe or more to the interconnected grid.

This section describes the scope, requirements and steps required to certify a trough power plant for municipal or investor-owned utility applications. The complexity and number of steps in the certification process depends primarily on the MWe capacity of the plant and potential environmental impacts of the particular project. Three different certification paths are described for these solar plants.

Next a complete list of the detailed permitting and licensing requirements in the certification process is discussed, including definition of the key agencies involved and the permits or licenses issued by each. These agencies exist at the Federal, State and Local levels.

Finally the California Energy Commission process, or Application for Certification (AFC), is briefly described. This includes a discussion of all the technical and socio-economic areas that enter into the certification, with identification of the appropriate laws, ordinances, regulations and standards. General comments are made on schedule and cost, though these factors can vary widely between projects.

Special attention is paid to the unique aspects introduced by the solar energy component of the power plant. Information on the impact of these systems is presented.

A reference site is introduced into this discussion to better illustrate the types of agencies involved in the certification process. For this report, the area in the vicinity of Harper Lake, California in the Mojave Desert has been selected as the Reference Site.

2.6.2 Unique Permitting Aspects of Solar Systems

The regulatory permitting of solar thermal power plants is similar to conventional thermal power plants in many aspects. However, certain solar system features as described herein may uniquely impact the licensing process. The addition of a solar steam system is clearly the significant unique system compared to conventional plants. Solar energy is a diffuse energy source, and even efficient parabolic trough solar fields must cover a large land area to generate high electrical capacities. Relevant issues in the permitting and licensing process that are introduced

[16] This chapter summarizes the work completed in the task 4.1.5.1 Required Permits Report, dated November 2003.

by the solar steam system include land use, potential spills of heat transfer fluid, and air quality improvement. A hybrid (solar/gas) configuration will add emissions constraints to the plant.

2.6.2.1 Land Use

Solar thermal power plants require a large area for their solar collector field. Approximately 5 acres are required per MWe of electricity produced in a solar thermal power plant[17]. As a result the potential for wildlife habitat disruption may be greater than that for a conventional power plant. In the desert regions where a solar thermal power plant would typically be located, protected wildlife such as the Desert Tortoise and the Mojave Ground Squirrel could require habitat remediation. The 80 MWe solar thermal power facilities SEGS VIII and IX have minimized habitat disruption by choosing sites on former agricultural land. This strategy appears to be successful and is the wisest approach, if possible, in regions of interest. No strategies have yet been identified for solar thermal fields that encourage a dual use of land, e.g., as seen in installations that include wind machines along with farming or grazing.

Desert regions have been managed to allow for multiple uses such as recreation, grazing, and mining. Construction of a solar plant in desert regions to harness a valuable renewable energy resource may be done so without conflicting with these uses and without causing harm to the environment and biological community. As demonstrated by the SEGS projects, such facilities may be constructed to meet all applicable laws, ordinances, regulations, and standards (LORS) and without causing harm to public health and safety. Nonetheless, any proposed new construction must go through close scrutiny by applicable federal, state and local agencies as described in this report.

2.6.2.2 Heat Transfer Fluid

The HTF fluid for a parabolic trough solar field is typically a diphenyl/biphenyl oxide. Dowtherm A and Solutia VP-1 are commercial products that have been used in the SEGS plants. The diphenyl/biphenyl oxide mixture (CAS numbers 101848 and 92524, respectively) is not classified as a hazardous material by the U.S. Dept. of Transportation, nor is it listed under U.S. EPA CERCLA regulations. However, this material when discarded may be a hazardous waste as that term is defined by the Resource Conservation and Recovery Act (RCRA), 40 CFR 261.24, due to its toxicity characteristic. On-site handling of wastes is discussed below.

While the collector design has advanced to an excellent level of performance and reliability, occasional small spills of HTF do occur, primarily due to equipment failures. The SEGS plants at Kramer Junction have reduced HTF spills due to accidents or pipe rupture to very low levels. Good maintenance practices and the use of ball joint assemblies rather than flexible hoses in the HTF system are the major contributors to this improvement.

In addition, safe handling of HTF-contaminated soils from accidental spills has been demonstrated at SEGS facilities. Spill management procedures are in place to report, contain

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[17] While large, this land area is expected for a renewable resource. A large photovoltaic system would require more area because of the lower solar-to-electric efficiency of the system. As another example, compared to land areas required for reservoirs for hydroelectric power plants, the land use for a solar field is smaller by at least an order of magnitude.

and clean up any accidental spills. If a line worker or other staff observes a spill or release, the system operators in the power block will be notified and the affected collector loop shut down. An appropriately equipped crew will make any necessary equipment repairs and remove any hazardous wastes to an onsite bioremediation facility that utilizes indigenous bacteria to digest the hydrocarbon contamination. A combination of nutrients, water and aeration is provided to facilitate the bacterial activity where microbes restore the soil to a normal condition in 2-3 months. See Figure 34, for a picture of bioremediation of HTF-contaminated soil.

2.6.2.3 Air Quality Improvement

If a solar plant has a hybrid configuration, any equipment using fossil fuel for supplementary electrical production, such as the steam boilers at the Kramer Junction plants will be expected to meet current emissions standards using best available emissions control technology or in some cases, lowest achievable emissions control technology.

For now, the hybrid configuration can be desirable for more competitive plant economics. Although parabolic trough technology is the least cost solar power option, it is at present more expensive than power from conventional fossil fueled power plants at today's fossil energy prices in the United States. A number of factors have been identified that are expected to bring solar thermal plants to a competitive level within the next decade or so.

The air quality impacts of the hybrid mode come from the fossil-fuel portion. Air quality improvements from the solar portion may contribute positively to the permitting process. For example, in the permitting of the SEGS plants, when the regulatory process included an analysis of "economic need", the positive effect of emission reductions offset the higher operating cost of a solar thermal power plant. The staff testimony examined the Luz SEGS IX & X project with respect to the air quality attainment plans in Southern California, analyzed the system effects, quantified air quality benefit available to the ratepayers, and presented a social value of emission reductions. That social value was demonstrated to be positive.

Although the economic need analysis is no longer a part of the California Energy Commission process in a merchant plant marketplace, the avoided emissions from the heat generated by the solar portion may be a factor in comparing total emissions of various energy source options for a municipality or utility.

2.6.2.4 Fire Systems

The concern about HTF spills from a catastrophic break in the integrity of the piping system is managed by installing appropriate protective facilities such as berms in the solar fields to isolate spilled fluid, and adequate fire protection equipment such as well-placed fire hydrants, and reserve fire water tanks for fire protection systems.

2.6.2.5 Manufacturing and Jobs

This socio-economic factor is relevant because of the increased fabrication and erection requirements of a large solar field. Figure 41 below illustrates the large construction crew for a solar plant resulting in significant local socioeconomic benefits from new jobs and local spending. O&M requirements are also moderately increased over a conventional plant, though experience at the SEGS plants has seen a marked reduction of O&M labor and costs over time.

2.6.2.6 Other

During the certification of the SEGS plants in the Mojave Desert, some concern was expressed about reflected light that could interfere with aircraft flying in the vicinity. This was shown to be of no consequence, as the parabolic mirrors have a focal length of approximately one meter. The reflection seen by aircraft is one sun, similar to flying over a lake.

As with other projects that may be located within or near a flood-prone zone, flood control measures must be put in place. However, because the land area required by the solar field would be larger, flood control requirements may be more extensive than needed for a conventional power plant. For example, the terrain in the vicinity of the Kramer Junction plants is subject to high flooding potential from 50-year and 100-year floods. A wide channel was constructed through that site for flood control under extreme rain conditions. The terrain at the SEGS Harper Lake sites, on the other hand, did not require this feature.

Should the solar plant configuration include thermal storage, the storage fluid is likely to consist of molten nitrate salts, as used in the 10 MWe Solar Two pilot plant project. While this fluid is relatively benign, its use may require special measures for containment, disposal, or spill monitoring.

2.6.2.7 Construction Schedule

Based on completed solar thermal Rankine cycle power plant projects, an EPC (Engineering, Procurement and Construction) schedule of approximately 18 months is expected from the start of engineering. The controlling lead-time procurement is normally the turbine-generator. The major phases of certification, engineering, procurement, construction, and startup are shown in Figure 42. The construction workforce requirements, anticipated to reach approximately 950 at peak, are depicted in Figure 41. These schedules reflect good construction techniques and past experience on similar projects.

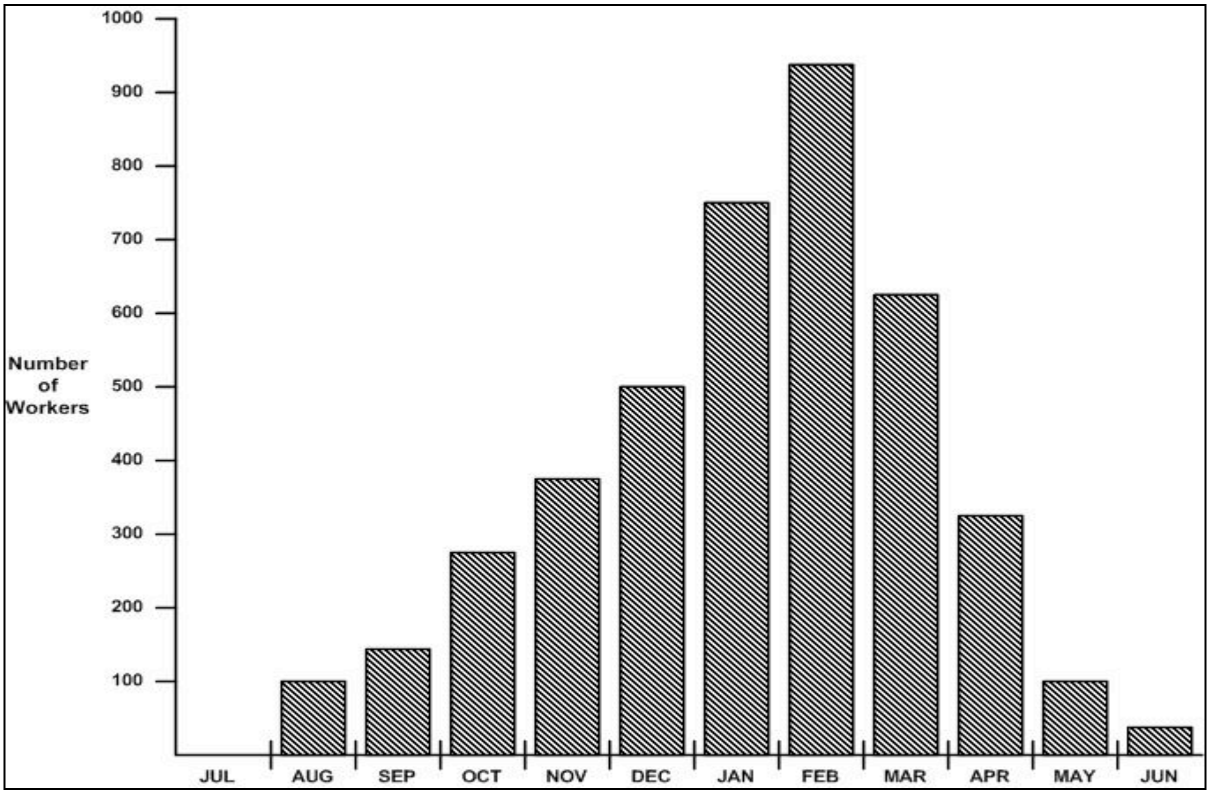

Figure 41 – Construction Manpower Plan

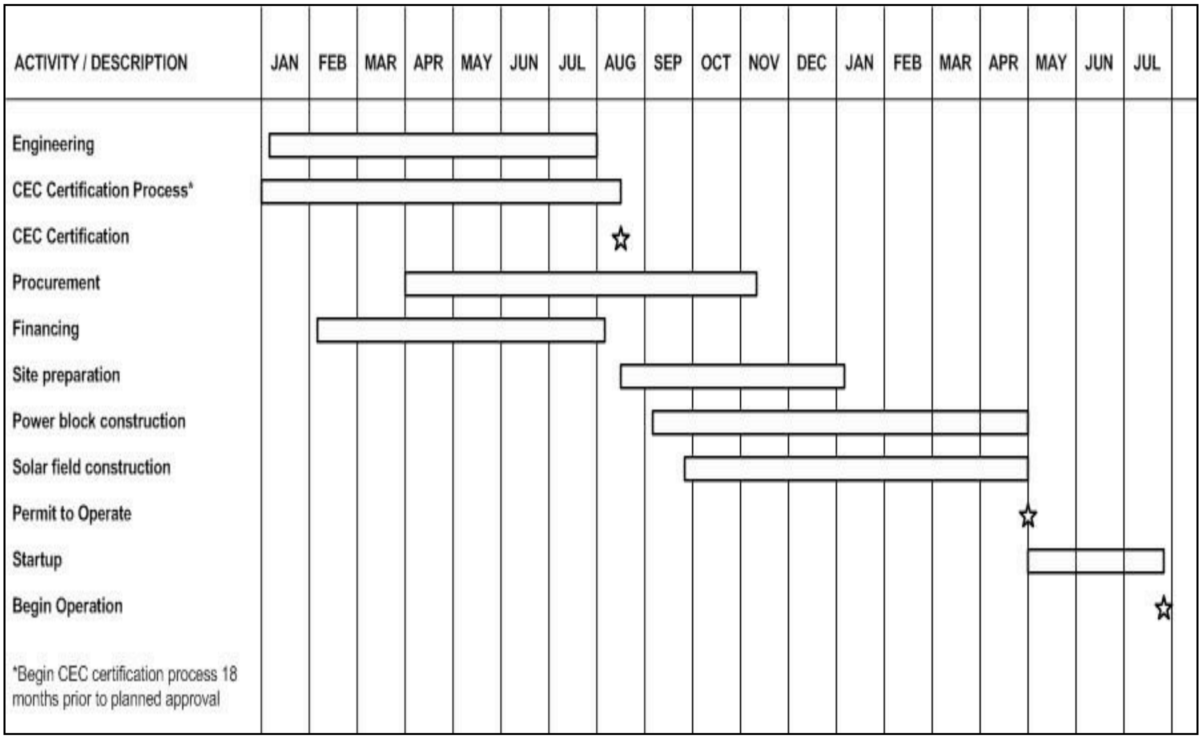

Figure 42 – Example EPC Schedule (SEGS-type plant)

2.6.3 Paths for Licensing a Thermal Power Plant

The California Energy Commission has exclusive authority to certify power plant sites and related facilities. In general, the Commission has jurisdiction over thermal power plants with a net generating capacity of 50 MWe or more, modifications that result in a 50 MWe or more increase in generating capacity, and transmission lines that carry the electricity from a power plant with a generating capacity of 50 MWe or more to the interconnected grid.

The licensing process can follow one of several paths, conditional on net generating capacity and projected impact on the environment and energy resources. For the purposes of licensing, thermal power plant projects can be categorized as:

- net generating capacity of less than 50 MWe
- net generating capacity of 50 MWe or greater
- net generating capacity of less than 100 MWe without unmitigated adverse impacts on the environment or energy resources (Small Power Plant Exemption)

2.6.3.1 Net Generating Capacity of Less Than 50 MWe

Thermal power plants with a net generating capacity of less than 50 MWe do not fall under California Energy Commission jurisdiction. While such projects do not need a permit from the

California Energy Commission, they will likely need permits from other state, local, or federal agencies.

2.6.3.2 Net Generating Capacity of 50 MW or Greater

The California Energy Commission has exclusive jurisdiction over thermal power plants with a net generating capacity of 50 MWe or greater. The standard licensing process is normally conducted in 12 months, starting from the day the Application for Certification (AFC) is deemed data adequate by the California Energy Commission. The AFC process is outlined later. The Energy Commission's siting process has been determined to be a certified regulatory program under the California Environmental Quality Act (CEQA) and the functional equivalent of preparing environmental impact reports. The Commission acts as the lead agency under CEQA. The California Energy Commission process and associated documents are functionally equivalent to the preparation of a traditional Environmental Impact Report (EIR). The Energy Commission staff relies upon CEQA and other applicable LORS for guidance on assessing a project's potential environmental impacts and their significance.

2.6.3.3 Small Power Plant Exemption

Thermal power plants with a net generating capacity of less than 100MWe with no unmitigated adverse impacts on the environment and no unmitigated adverse impacts on energy resources are eligible for the Small Power Plant Exemption (SPPE). Unlike the 12-month licensing/permitting processes, the SPPE is an exemption from the licensing process and is not a permit or license to build the project. The Energy Commission is the lead agency under the California Environmental Quality Act (CEQA) and will prepare an Initial Study and Final Decision. The power plant developer must apply for the various appropriate licenses and permits from local, state and federal agencies. Those local and state agencies will use the Energy Commission's CEQA document when issuing their respective permits.

A SPPE approval process may be completed in about 4½ months. To meet this schedule, the applicant must provide timely responses to data requests, and agencies (local, state, and federal) must provide timely comments. The Committee assigned to the proceeding will determine the actual schedule. There are no specific data adequacy requirements for an SPPE application; however, the more thorough the filing the fewer information requests California Energy Commission staff will have of the applicant, and there will be an improved possibility of meeting the schedule. In practice, the information contained in an SPPE application should follow the format established for a 12-month AFC.

2.6.4 Permitting and Licensing Requirements

The developer-applicant must contact the local or regional air pollution control district and the appropriate regional water quality control board, regardless of whether the project requires participation in California Energy Commission certification process. The developer-applicant should also contact the appropriate city or county planning/community development department to understand the local applicable laws, ordinances, regulations, standards, plans and policies that need to be addressed in the Application for Certification. The city or county government staff can provide a general sense of likely community response to the project. These local government contacts should be made before the Application for Certification is filed, preferably in coordination with the Energy Commission staff's pre-filing meeting.

2.6.4.1 Permits and Approvals Required for a Solar Thermal Power Plant

An extensive and representative list of federal, state, and local permits and/or approvals that may be applicable to a solar thermal power plant is presented in Table 13. The project specifics and site characteristics will determine the actual permits and approvals required. The California Energy Commission may also require, as conditions of approval, compliance monitoring programs for areas such as water, biological, and cultural resources. While the majority of these programs' requirements would apply to the construction phase, additional monitoring may well be required in the power plant operations phase.

Table 13 – Federal, State and Local Agencies and Permits

Agency	Required Permit or Approval	Authority	Applicability to Project
Federal			
Federal Energy Regulatory Commission	Authority to sell electricity at avoided cost as a qualifying cogeneration facility	16 USC 2601 et seq. 18 CFR 292, Subpart B	Sale of electricity
Environmental Protection Agency	Hazardous waste generator permit	Resource Conservation and Recovery Act	Disposal of hazardous waste
Environmental Protection Agency	NPDES – Discharge of point-source waste into U.S.	Clean Water Act	Surface Discharge, storm water permits for construction and operation
Environmental Protection Agency	PSD permit	Clean Air Act 40 CFR 52	Applicable to some major sources located in air districts that do not have PSD delegation
Bureau of Land Management	Operations and rights-of-way on federal land	Federal Land Policy and Management Act of 1976, National Environmental Protection Act	Any facilities on federal land
Federal Aviation Administration	Proposed construction that may affect navigable aerospace	AC No. 701/7460-2H	File endorsement of Form 7460-1 to define longitude and latitude
U.S. Fish & Wildlife Service	Federally listed species of wildlife	16 USC 1531 et seq.	Desert tortoise and any other federally protected species
U.S. Army Corps of Engineers	Section 404 permit	Clean Water Act	Fill or discharge to Waters of the U.S.
State			
State Dept. of Transportation	Overload approvals	Vehicle Code 35780 Streets and Highways Code 117, 660-711, Adm. Code Title 21 1411.1-1411.6	Transportation of excessive loads over state highways
State Dept. of Industrial Relations – Div. of Industrial Safety	Permit to Operate Equipment	Labor Code 7621, 7680, 7683, 7300 et seq.	Plant boilers and other equipment
State Dept. of Industrial Relations – Div. of Industrial Safety	Cal-OSHA Permit	Labor Code 6500	Construction of plant and appurtenant facilities
Dept. of Health Services	Storage and disposal of hazardous wastes	Cal. Admin. Code Title 22, Section 66016 et seq.	HTF-contaminated soil

State of CA Regional Water Quality Control Board	Waste Discharge Requirements	Cal. Admin. Code Title 23, Subchapter 15	Discharge to evaporation ponds
Office of Environmental Health Hazard Assessment	Toxics Inventory	AB2588	Operation of stationary sources of air pollutants (power blocks)
State of CA Dept. of Water Resources	Permit to drill wells	Cal. Admin. Code Title 23, Section 5001	Groundwater wells
State of CA Dept. of Water Resources	Record of water extractions in excess of 25 ft.	Cal. Water Code Sections 4999-5008	Cooling Tower makeup ground water supply
Dept. of Fish and Game	Consultation		Mojave Ground Squirrel, Desert Tortoise, threatened species
Native American Heritage Commission	Consultation		Site-specific cultural resources
Local			
Mojave Desert Air Quality Management District	Authority to Construct Permit to Operate	MDAQMD New Source Review Regulation XIII	Construction and operation of stationary sources of air pollutants (power blocks)
San Bernadino County Land Management Dept.	Building Permits	County Ordinance 2815	Construction of new structures or additions to existing structures
San Bernadino County Land Management Dept.	Grading Permits	County Ordinance	Certain agency-specified excavation and fill activities
San Bernadino County Land Management Dept.	Minor Subdivision Development	San Bernadino County Code Section 84.050(i)	Site development
San Bernadino County Transportation Dept.	Transportation Permit	Division 15 of CA Vehicle Code	Transportation of oversize loads on county roads
San Bernadino County Environmental Health Services	Mobile home installation and temporary occupancy	CA Environmental Quality Act of 1970, Public Resources Code Section 21000 et seq.	Construction and operation
San Bernadino County Forestry and Fire Warden Dept.	Fire protection approval		Facilities and associated pipelines
San Bernardino County Planning Department	Land Use Permit (Special or Conditional)	Local ordinances related to noise, visual resources, zoning, etc.	Facilities must meet local ordinances as applicable

2.6.4.2 Steps in the Certification Process

Developers of power plant projects following the California Energy Commission certification path should plan on these steps in the licensing process:

1. Prepare AFC outline – explained later.
2. Preliminary meeting with Energy Commission licensing staff to discuss project.
3. Contact local or regional air pollution control district, appropriate regional water quality control board, and appropriate city or county planning/community development department to determine relevant laws, ordinances, regulations and standards (LORS). California Energy Commission staff may also offer assistance in this area.
4. Prepare first draft of AFC. It may be necessary to conduct biological, cultural and paleontological surveys of the project site in order to collect sufficient data to complete

the application. Biological surveys may need to be conducted during specific time periods of the year, e.g., nesting seasons for birds and flowering seasons for some plants.

5. Meet with Energy Commission staff informally to review AFC before it is submitted.
6. Make additions and/or corrections as suggested by the California Energy Commission.
7. File AFC.
8. The California Energy Commission determines data adequacy of the AFC within 30 days, or longer if additional information is needed. File supplements if AFC contains inadequate data as judged by the Energy Commission.
9. Data Discovery Phase: Once the AFC is determined to be data adequate, California Energy Commission staff, other responsible agencies, and Intervenors may request additional data. File responses to data requests unless showing can be made that provision of the data would be overly burdensome and/or unnecessary.
10. Public workshops on technical and procedural matters and issues, and informational hearings for the public are held.
11. Analysis Phase: California Energy Commission staff prepares a Preliminary Staff Assessment, which contains the staff's analysis of potential impacts, mitigation requirements, and proposed conditions of certification. Public workshops on the Preliminary Staff Assessment are held. The analysis phase is completed by preparation of a Final Staff Assessment that is the staff's testimony for the hearing phase
12. The applicant, Commission staff and responsible agencies present testimony reflecting the analysis to the Energy Commission Committee (i.e. two Energy Commissioners) assigned to the proposed project. Other interested parties and the public can also testify or provide comments at these hearings.
13. The Energy Commission Committee prepares the Presiding Member's Proposed Decision that is released for public review and comment after the close of hearings.
14. Based on public review and comment, the Presiding Member's Proposed Decision is revised before it is heard by the full Commission (i.e., five Commissioners).
15. The Presiding Member's Proposed Decision is either adopted, modified, or rejected. Depending on the Decision, the Application for Certification is either approved/certified by the full Commission with conditions, or denied. Construction may begin soon after the license is granted.

2.6.4.3 Schedule for Obtaining Approvals

The critical path for permitting a solar power plant is the California Energy Commission process. Other approvals could be applied for in parallel to reduce delays in the start of construction. In previous projects, the Energy Commission has entered into Memorandums of Understanding (MOU) with local agencies for land use entitlements or MOUs with federal agencies for joint CEQA/NEPA review. Through these MOUs, redundant reviews are avoided and streamlining of the processes is possible. It is always prudent to plan ahead and anticipate potential permitting issues before entering the process. The major issues encountered in most permitting include the following:

1. **Local Zoning and Planning Designations.** In order to qualify for the 6-month AFC process the project must be in conformance with all San Bernardino County zoning and planning requirements applicable to the site. These requirements would include a review of the General Plan (and Specific Plans if available), zoning ordinance, Minor Subdivision Map Act, the Williamson Act and any other policies applicable to preservation agricultural land.
2. **Biological and Cultural Reconnaissance Studies.** These studies include data base review and records searches as well as a preliminary visit to the site and locations of the proposed transmission, gas, and water tie-in lines. Surveys of proposed site locations during peak growing or flowering seasons (Spring) should be done in consultation with the agencies to avoid being deemed data inadequate causing lengthy delays in the California Energy Commission permitting process.
3. **Emissions Estimates.** Emissions estimates and control strategies need to be developed and discussed with the MDAQMD to identify all applicable regulations and review requirements. The need for offsets must be evaluated early in the process to allow for planning and sourcing of potential offsets.
4. **Water Supply.** Regional water quality control board review can add six months to a year to the licensing of a project, but could be done in parallel to the Energy Commission process. The project's demand for water and any adverse effects on surface or groundwater supplies must be evaluated.
5. **Wastewater Discharge Characteristics.** All wastewater characteristics and limitations need to be considered early in the permitting phase to identify the most appropriate way of obtaining board approval.
6. **System Impact Study.** It must be shown that there is sufficient transmission capacity available to the project. If a system impact study is needed, it must be contracted to Southern California Edison or the applicable transmission system carrier. These studies can take many months to complete.

Once the key site and project characteristics are identified, discussions can begin with the California Energy Commission to determine the type of process and criteria appropriate to the project.

Studying a broad sampling of power plants constructed in California during the last decade provides a sense of the average duration of key stages in the Energy Commission certification process. Based on this analysis, the timeline depicted in Figure 43 was constructed. Note that this schedule exceeds the stated California Energy Commission guidelines. The actual certification schedule can vary considerably due to project specifics.

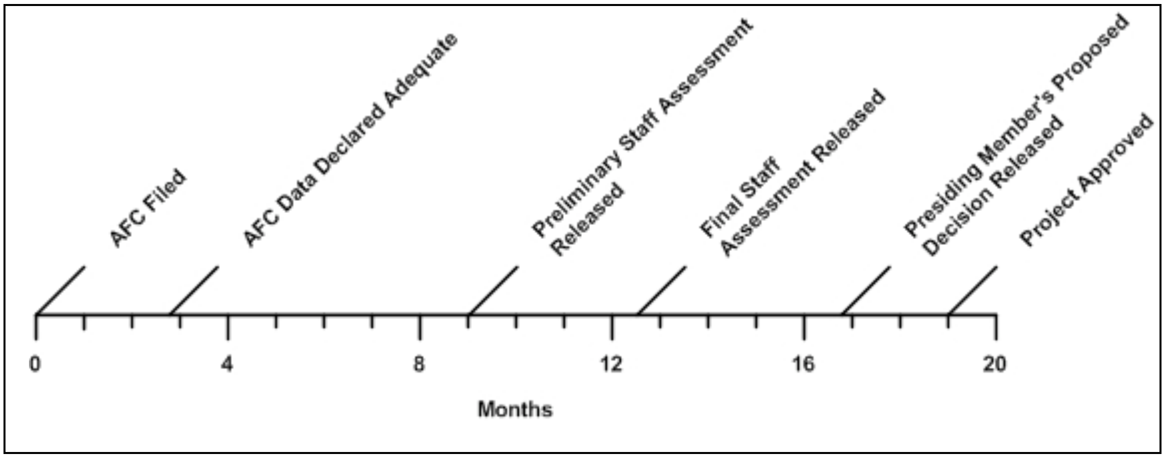

Figure 43 – Typical Power Plant Licensing Timeline

2.6.4.4 Environmental Agencies and Their Jurisdictions

As can be seen from Table 13, the agencies involved in the licensing and permitting process cover a wide range of engineering, safety, socio-economic and environmental responsibilities. Environmental concerns are of particular importance. The key agencies with discretionary environmental approval authority for a solar thermal power plant project located in the Mojave Desert reference site are as follows:

> **California Energy Commission .** The Energy Commission certification process includes the review of all standards, ordinances, regulations, and laws applicable to the project. California Energy Commission certification is typically issued in lieu of all other state and local approvals. Agencies that would normally have jurisdictions over the project, such as San Bernardino County, are consulted during the review process, and the requirements of these agencies are typically included in the Energy Commission conditions of approval.
>
> **Mojave Desert Air Quality Management District (MDAQMD).** As the delegated agency to enforce the non-attainment New Source Review and Title V Operating Permits programs of the Clean Air Act, the MDAQMD will review the application for the proposed project through the California Energy Commission process and issue its Determination of Compliance (DOC). The DOC (the term used for an Authority to Construct if issued within the Energy Commission process) will discuss the ability of the project to conform to all applicable air district rules, including a determination whether the proposed project proposes to use Best Available Control Technology and whether the project will need to obtain offsets. Based on preliminary information, emissions of nitrogen oxides (NOx) from a gas-fired boiler, if present, must be at a minimum controlled with a low NOx burner. Project NOx emissions may be less than the 25 tons/year, which is the threshold for offsets in this district. Since the project will burn natural gas, the emissions of the other criteria pollutants are expected to be low. Particulate impacts will have to be considered, because the air basin has high background particulate levels. If the proposed facility is not a major source (e.g., emissions are less than 25 tons/year of NOx or VOC), no federal Title V permit would be needed. If emissions exceed the applicable major source thresholds, then the project must obtain

offsets and a Title V permit. In some cases, the California Energy Commission may require offsets or other mitigation for emissions that are below the air districts threshold if it is determined under CEQA that there is still the potential for significant environmental impact. This is particularly true for non-attainment pollutants, where any new emissions have the potential to exacerbate an existing exceedance of the ambient air quality standards.

MDAQMD has not been delegated to administer the federal Prevention of Significant Deterioration (PSD) program of the Clean Air Act. A PSD permit is required for certain sources (such as steam-generating units) that will emit more than 100 tons/year of attainment pollutants such as NOx and CO. Applicable sources within the MDAQMD must obtain the PSD permit from the U.S. Environmental Protection Agency, a process than is outside of the Energy Commission certification process and can easily take a year or more to complete.

Lahontan Regional Water Quality Control Board (Lahontan RWQCB). The demineralized wash water from mirror cleaning should not contain substances regulated by the regional board, but will probably require review by this agency. Depending on the volume of the effluent and its characteristics, the regional board may decide that no permit will be needed or it may issue wastewater discharge requirements for the project. Since construction of the project will disturb more than 5 acres, the project will need to prepare a Storm Water Pollution Prevention Plan (SWPPP) and may need a separate SWPPP for operation of the project. An SWPPP provides detailed plans on the measures taken to prevent hazardous materials (oil, cleaning fluids, etc.) from contaminating storm water. As is the case with previous solar thermal projects, evaporation ponds would collect sludge, allowing the project to qualify as a zero surface discharge facility. Waste Discharge Requirements must be approved by the Lahontan RWQCB.

San Bernardino County. If the proposed site's zoning designation does not allow the proposed use, land use approval from the County in the form of a Conditional Use Permit or Rezone is necessary. The county could use the California Energy Commission process as the vehicle for satisfying its CEQA review of the project and can enter into a MOU with the Energy Commission to document the manner of cooperation between the two agencies. While the Energy Commission has the power to override the County's land use decision with adequate justification, this override is seldom used. A cooperative working relationship is preferred and is often the case in most previous siting cases.

Bureau of Land Management. If transmission or other facilities will be located on Bureau of Land Management or other federal agency land, approval will be required for such construction. Federal agencies conduct their environmental review pursuant to the National Environmental Policy Act (NEPA). The California Energy Commission review under CEQA is often adequate to meet NEPA requirements. As with local jurisdictions, the Energy Commission has entered into MOUs with federal agencies to jointly review projects under CEQA and NEPA.

Other agency approvals may be potentially applicable to the project and its related facilities. Site investigations should be performed to identify whether any of the following approvals apply to the proposed project.

US Army Corps of Engineers Section 404 Permit. A Corps permit would be needed if any aspect of the project were to place fill in Waters of the United States, which includes all tributaries, many wetlands, and, potentially, some manmade features.

US Fish and Wildlife Service (USFWS) Section 7 Permit. A "take" permit would be needed if the project were to harm any species protected by the federal Endangered Species Act. Detailed biological studies are needed to make sure that no special status species or its habitat would be affected. The Mojave Desert is within the range of the desert tortoise, the Mojave ground squirrel and protected plant species; the power plant site and the transmission line tap would require review by the USFWS for these species. A Section 7 permit is issued if another federal agency is involved in the permitting process. A Section 10 permit is issued if there is no other federal agency involved.

California Department of Fish and Game (CDFG) Streambed Alteration Permit. This approval would be needed if the project facilities were within the bank of any stream. CDFG review of species protected by the state Endangered Species Act is typically conducted through the CEQA process.

State Historic Preservation Office (SHPO) Section 106 Review. If the project were to affect significant archaeological or historical resources, SHPO could review the project. Most SHPO review is limited to federal land, but the agency can review significant resources located on private land.

Federal Aviation Administration (FAA). If any project facilities were more than 200 feet high or within 20,000 feet of an airport, the FAA would review the effect on navigable air space.

2.6.4.5 Preparation of AFC Data

For projects required to complete the AFC process, an AFC should be prepared that includes the following information required by the California Energy Commission Siting Regulations:

a. Project description
b. Site description
c. Engineering description of proposed facilities
d. Electric transmission lines, system impact study, and any other linear facilities (e.g., natural gas or water pipelines) related to the project
e. Project, site, and linear alternatives
f. Environmental description, including biological surveys conducted at the appropriate time of year, and expected impacts
g. Mitigation measures to reduce potentially significant environmental or transmission system impacts
h. Information necessary for the local/regional air pollution control district to make a determination of compliance with local rules and regulations
i. Information necessary for the regional water quality control board to issue wastewater discharge requirements or a national pollution discharge elimination system permit

j. Compliance with applicable laws, ordinances, regulations, and standards
k. Financial impacts and estimated cost of the project
l. Project schedule
m. Project alternatives.

2.7 Business Models[18]

The high capital cost of solar thermal power plants can be attributed primarily to the cost of the solar collectors required to harvest the sun. However, for summer peaking utilities, the ability to harvest energy from the sun coinciding with the utilities peak load requirements provides much greater value than, say, intermittent energy produced from wind. Accordingly, the value of the electricity product must also be evaluated along with the cost. In addition, while the *cost* of solar thermal power plants will be the result of competitive bidding, the actual *price* of the solar thermal power plant can, to a large degree, be highly dependent on the manner of ownership.

This chapter details the analyses of different ownership/business scenarios where the cost of a nominal 100 MW solar plant of the SEGS type is, essentially, the same; however, the different manner of ownership is shown to significantly impact product price. In adition, for comparison purposes, a solar plant integrated with a conventional combined cycle is also evaluated. Different ownership scenarios produce varying degrees of comparative product price differentials when evaluated against the private ownership scenario (base case at 13.5 cents/kWh); these pricing reductions are tabulated below (these cost figures represent the mid range of each financial scenario; specific ranges and assumptions used are found in this chapter and in the text of the 4.1.6.1 report):

Table 14 – Cost Savings of Different Financial Scenarios

	Levelized Energy Cost ($/MWh)	Actual Cost Reduction ($/MWh)	Percent Cost Reduction
Base Case	135	Baseline	Baseline
Partial Muni Ownership after Debt Repayment	115	20	15%
Muni Ownership	87	48	35%
Muni Pre-payment of PPA	84	51	38%
Hybrid Solar* with Combined Cycle (Muni)	75-80	55	40%
Hybrid Solar * with Combined Cycle (IPP)	115-125	10	7%

*All cost savings attributed to solar

Table 14 shows the impact of the various financial scenarios that may be available to the developers and purchasers of solar thermal power plants. Clearly, the most cost effective scenarios is to use 100% bond financing that is currently available to the Muni's at historically low interest rates. As noted above, Muni financing can reduce the levelized energy costs (LEC)

[18] This chapter summarizes the work completed in the task 4.1.6.1 Business Models Report, dated January 2004.

by ~35% to 40% depending on the scenario and type of technology employed. It should also be noted that the above costs do not consider any Production Tax Credit. (PTC) that could be available nor do the costs show the benefit of Renewable Energy Credits (REC). The PTC, if available, could lower the costs by an additional $15/MWh to $20/MWh. The REC is not yet tradable in California but current efforts by the Energy Commission may make REC trading a reality by early 2006. Currently the REC in other open markets (e.g. ERCOT, NEPOOL) indicates that the REC will be valued at around $15/MWh to $20/MWh (about as much as any PTC). Accordingly, the total cost of solar could be substantially less than Table 14 indicates.

Lastly, the California Public Utility Commission (CPUC) is considering an emissions adder for fossil fuel plants when they are evaluated against renewable resources. While this doesn't lower the cost of solar or other forms of renewables it will make the renewable alternative more attractive during bid evaluation. While the CPUC has no jurisdiction over Muni's, typically, the commission sets the trend and direction that Muni's normally follow.

These analyses are meant to be representative of differential savings that may result from different types of project ownership; the work performed in this Task should not be construed to be a definitive or absolute analysis of any particular ownership structure.

2.7.1 Introduction

The purpose of this chapter is to determine the "sweet spot" for CSP technology. In other words, what ownership structures, operational scenarios and capacity factors produce the greatest cost effectiveness for the Muni's. This investigation develops a methodology that is applicable to both private and municipal ownership for comparative purposes. Comparisons are also made to the cost of the appropriate fossil alternative; this cost is defined as the "pricing proxy" and is more fully described in the Task 4.1.8 report (the Financial Feasibility Study) where operational scenarios are evaluated.

2.7.2 Evaluation Approach

In the case of electricity, the actual real time market is not an accurate barometer of the true value of the product. This is because electricity is a unique product that has to be used the instant it is produced; storage is normally impractical and is seldom used. Real time market pricing, hedging costs and bilateral contracts all have certain limitations that may impact the long- term cost of electricity. The California Public Utility Commission (CPUC) has recently completed a long and comprehensive process (through testimony and evidentiary hearings) to determine the benchmark or "price proxy" that should be used when comparing solar and other renewable electricity costs to conventional fossil alternatives. In a recent CPUC decision[19], the Commissioners ruled that:

> *"The use of a proxy generating plant provides an allowable and usable basis for establishing the market price referent".*

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[19] CPUC Decision 03-06-071 "Order Initiating Implementation of Senate Bill 1078 – Renewable Portfolio Standards Program", June 19, 2003

The Commission further stated that to establish the market price referent for the delivery of on-peak energy, a combustion turbine should be used as the plant proxy and that a combined cycle facility should be used for base-load energy. The CPUC therefore has concluded, after much study and investigation, that the only true market referent is the appropriate greenfield (i.e. newly constructed) facility that allows direct and true comparison of similar electricity products. In this manner, the incremental cost of generation has been identified as an appropriate benchmark to evaluate solar and other renewable generation. Accordingly, the evaluation used in this investigation to determine the value of CSP electricity to the California Muni's under various ownership scenarios, is based on the following:

- Use of the appropriate price proxy generation technology;
- Determination of product as a function of use and capacity factor;
- Use of common economic and financial assumptions; and
- Use of common assumption on gas price and operations.

For low capacity factor use (peaking and shoulder loads), the CSP solar plant can be compared against two combustion turbines, a "heavy frame" and an "aeroderivative". The heavy frame machine is normally less expensive than an "aero" but is less efficient. The heavy frame is therefore used for pure capacity, i.e. standby, or for anticipated low capacity factor use. However, as the forecasted use (capacity factor) rises, the lower cost but less efficient heavy frame machine looses its economic attractiveness to the aeroderivative CT that, while more expensive, is justified by its higher efficiency when used at a higher capacity factor. CSP is ill-suited to supply pure capacity or for use in low capacity applications, under this scenario the appropriate "price proxy" is the aeroderivative combustion turbine. For intermediate and high capacity factor (base-load) price comparisons, the combined cycle can be used as the price proxy. As part of the business evaluation, the "crossover" point of economic operation based on capacity factors is presented later in this analysis.

2.7.3 Ownership Scenarios

An important criterion in determining the value of CSP produced electricity to the California Muni's is the plant ownership. Due to the influence of various economic and financial aspects and of various federal incentives that may be available to both private and public entities, the structure and manner of ownership can have significant impact on the cost of CSP power production. In this analysis, five different ownership scenarios are investigated. Some of the scenarios are specific to the plant owner and all of the scenarios are not necessarily available to all types of owners. The investigated ownership cases are as follows:

1. Private Ownership with Conventional Financing (i.e. Independent Power Producer used as the "base case");
2. Muni Ownership with Debt Repayment;
3. Muni Ownership;
4. Private Ownership with Muni Pre-Paid PPA; and
5. Ownership of Hybrid Solar-Combined Cycle Plant

All of the five case are initially examined with no federal incentives, then a summary analysis with the Investment Tax Credit (ITC) is made and finally an assessment is made with both the ITC and a production tax credit (as appropriate).

For comparison purposes, a brief description of past and forecast solar energy prices is presented after the ownership scenarios are discussed. These data and prices are from previously published work and represent base case pricing history.

2.7.4 Evaluation of Ownership Scenarios

2.7.4.1 Scenario 1: Private Ownership with Conventional Financing (base case)

In the Private Ownership case (base case), we assume that the CSP power plant is constructed by an Independent Power Producer (IPP) with a combination of owner equity and debt. The purpose of the base case is to establish a baseline or benchmark for comparison and not necessarily to establish a firm absolute energy pricing. Certainly the energy pricing for each case is representative, but these costs should not be construed as definitive and specific to each case. Each solar plant must be evaluated based on an exact site and financial/economic assumptions.

The cost of energy will vary significantly based on the financing that can be arranged and is highly dependent on the debt/equity ratio as well as the cost and length of debt.

In performing the analysis, the following parameters were considered and assumed.

- Plant size is nominal 100 MW;
- Plant cost is $270 million ($2,700/kW representing the next generation plant);
- Electricity escalates at 3%;
- Insurance requirements at ½% of project value per year;
- Tax rate (third party private entity) at 41% (state and federal); the assumption is made that the tax write-off available in the first few years of operation can be applied to other operations of the owner);
- Property Taxes at 0.6% of project value (note this is a levelized value since the equipment will decrease over time consistent with depreciation; the increased in land/property value is considered inconsequential);
- Maintenance is at 2 cents/kWh and escalates at 3% per year;
- Double declining balance method is used for depreciation;
- Depreciation life is 20 years;
- Fuel cost is $5.00 per million BTU and escalates at 3% per year;
- Heat rate of plant (EPGS) is 8,500 BTU/kWh (this heat rate is the conversion efficiency of both the solar and gas input into the cycle to produce one kWh);
- Project life is 30 years;
- Debt life is 25 years;
- Cost of debt is 7.5%;
- Cost of equity is 12.50%;
- Debt to equity ratio is 70/30;
- Fuel use is consistent with PURPA 25% rule;
- Overall capacity factor is 39% (with PURPA gas usage);

- Solar capacity factor is 27%; and
- Levelized carrying charge is 13% (used for comparison only).

Due to the capital nature of CSP plants, the economics are extremely sensitive to the financial conditions at the time of plant financing. The assumptions are considered to be "realistically" conservative and are used to provide a basis for comparison to other ownership scenarios.

The base case and the other ownership cases are based on a 100 MW plant located at the Harper Lake site which was identified as the most cost effective location for development of California's solar resources to serve both Muni's and the independently owned utilities (IOU's). The plant location will significantly impact plant cost due to the amount of solar insolation available at each specific site, infrastructure requirements and land and water availability.

The base case assumptions produced a cash flow over the 30 year plant life resulting in a internal rate of return of approximately 12.5% when electricity is sold at a levelized electricity cost (LEC) of 13.5 cents. This rate of return assumes no investment tax credits (ITC), production tax credits (PTC), renewable energy credits or any other incentives or credits that may be applicable to a CSP plant.

Using the Excel spreadsheet, various sensitivity analyses were performed to determine the key components that produce the lowest LEC. For example, the cost of the debt and the debt to equity ratio has a large impact on the overall product economic viability due to the high capital cost of solar thermal power plants. These two key components are the primary reason why there is a significant reduction in the levelized energy cost when municipal financing is assumed: municipal financing is essentially 100% debt and is normally procured at a tax exempt rate that is usually 30 to 35% lower than commercial rates.

It is interesting to note that when compared to a conventional fossil plant, a lower debt to equity ratio has a more pronounced impact on the rate of return than for a CSP plant. Contrarily, the impact of low cost financing has a more pronounced impact on the rate of return of a solar plant. High debt to equity ratio benefits the fossil plant since much of the net present value of the plant is dependent on the payment for gas usage and this payment is expensed. In other words, greater leverage is achieved since the overall capital component of a fossil plant is a much lower proportion of the overall net present value. For example, a combustion turbine's net present value is approximately 1/3 capital and 2/3 fuel cost. Accordingly, the total net present value can be leveraged by a smaller contribution to equity when compared to a solar plant whose net present value is predominantly all capital. However, as shown below, high leverage becomes extremely beneficial to the owners of solar plants in any case. Since the internal rate of return is based on the return of only the equity invested, as the amount of equity approaches "zero" then the internal rate of return approaches infinity.

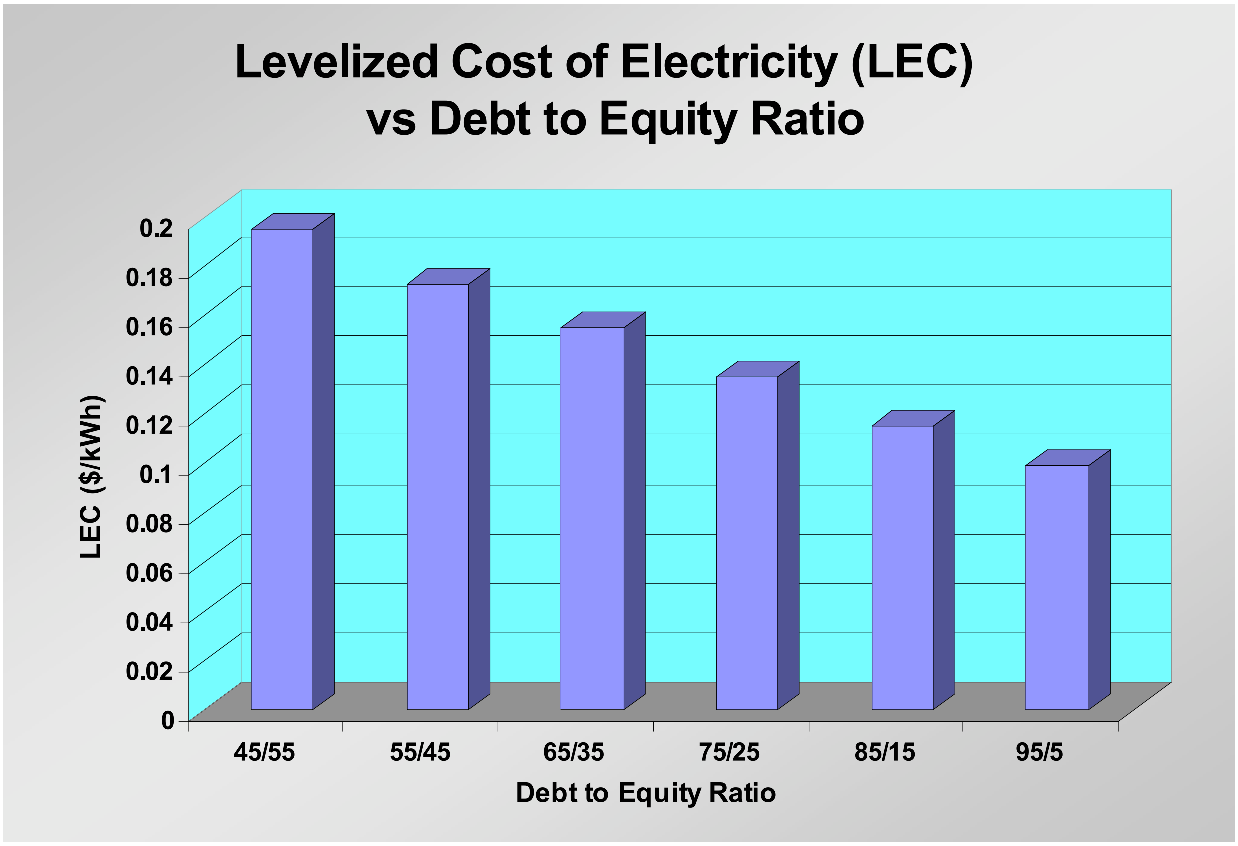

Figure 44 – LEC vs. Debt to Equity Ratio

Figure 44 was developed to show sensitivity to the debt to equity ratio. The graph is based on the assumptions and estimates previously presented in this section and the only variable is the debt/equity ratio. The graph depicts significant impact to the levelized energy costs based on the debt to equity coverage. From a practical standpoint, however, financing above a 75/25 ratio, while producing attractive rates of return, is difficult and somewhat unrealistic due to the assumption of risk that must be borne by the bank or financier of the project. High debt to equity leverage produces attractive rates of return but there is a risk apportionment issue that must be considered.

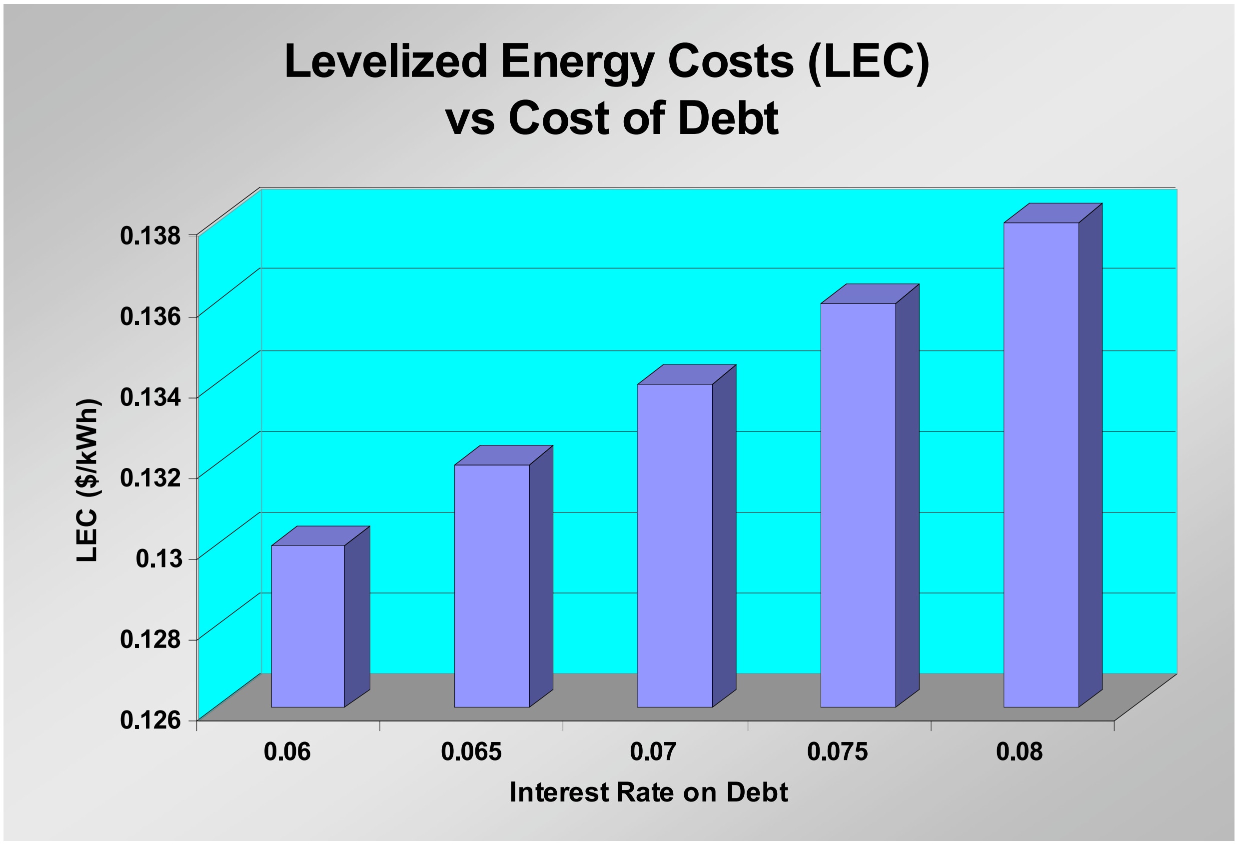

Figure 45 – Levelized Energy Costs (LEC) vs. Cost of Debt (constant 2003$)

Figure 45 shows the impact of the cost of debt which is the other highly sensitive financial parameter impacting the economics of solar thermal power generation. Low cost financing is a greater benefit to a solar plant than to a fossil plant simply because nearly all of the net present value of the plant is capital, i.e. capital cost represents a much higher proportion of the net present value. As shown, however, the impact is not as significant as variations in the debt to equity ratio. This is because in the financial analysis, the economic impact of high debt cost is somewhat mitigated because the interest is deductible which tends to minimize the effect of high debt cost. In addition, even if the debt burden were financed at a zero rate of interest, the principle would still have to be paid back. Accordingly, there is never a situation akin to an infinite return as in the 100% debt to equity case discussed above.

> Scenario No. 1 "Private Ownership with Conventional Financing" shows a Levelized Electricity Cost (LEC) of 13.5 cents/kWh with an IRR to the plant owner of approximately 12.5%. This estimate is based on realistic performance and assumptions as listed and with no tax credits or subsidies of any kind.

2.7.4.3 Scenario 2: Muni Ownership after Debt Repayment

A distinction can be made between the price and cost. The seller performs financial and economic analysis to determine the necessary cost of the product to the customer. The customer performs financial and economic evaluation to determine the price it is willing to pay. The evaluation by the two different parties, the seller and buyer, usually results in different criteria and assumptions to determine the respective price and cost. Due to these different criteria and assumptions, cash flows and net present values vary in worth to each party. In particular, the discount rates that the seller and buyer use will vary. Consequently, the lower discount rate used by a Muni will result in greater value assessed to a future asset when compared to a private party's value of the same asset at the same future date.

Accordingly, value to both parties, seller and buyer, can be substantially different based on the same cash flows but by assigning different value to the cash flows. This phenomenon creates the opportunity for the Muni's to be ceded a part of the plant by the owner at some future date with the plant value evaluated differently by each party. The value of the solar plant at the time of turnover can be measured against the projected value of energy at the time the turnover is affected. In other words, the "paid-up" solar plant is assumed to sell energy at a more competitive price when measured against the future price of energy. With the solar power plant life estimated at 35 years (based on extrapolated life of existing SEGS units) the projections are obviously long term. However, the accuracy of the forecast is less problematic because the capital asset, the solar power plant, is a fixed cost investment at the time of the evaluation. Only the cost of energy and normal maintenance need to be estimated over the long term. While even these long-term projections still entail risk, conservative estimates on the meaningful parameters will still produce strong incentives for the Muni to purchase CSP energy plants.

An analysis was made based on the following concepts:

- Determining the remaining life of the plant at the time of turnover;
- Determining the competitive or fair market pricing at the time of turnover;
- Escalating the cost of energy over the plant life;
- Finding the net present value today at the time of turnover based on the remaining performance life of the plant and energy worth; and
- Determining the present value of plant today and levelizing the energy costs based on the discount rate furnished by the Muni.

The premium paid by the Muni and the price they pay for electricity that can be applied to the solar plant purchase at an agreed upon date in the future was computed. In other words, the small increase in the cost of solar produced electricity over that of a combustion turbine is essentially a pre-payment for future part ownership in the solar plant, i.e. this concept is a form of "lease to own". The cost analysis that follows assumes that 50% of plant ownership is deeded to the Muni after 20 years and that the plant uses natural gas no more than 25% of the time under PURPA rules. The values shown below are slightly different than from the base case determined above to reflect different assumptions used by the Muni and other tax considerations available to the Muni's.

Table 15 – Assumptions for Muni Ownership After Debt Repayment

Solar Plant Cost =	2,600	$/kW	Gas Rate of Inflation =	3.0%
Solar Plant CF =	0.39	yearly fraction	O&M Rate of Inflation =	2%
Solar Plant Output =	100,000	kW	Market Rate of Inflation =	2.0%
Total Plant Output =	341,640,000	kWh/yr	MUNI Discount Rate =	5.50%
Solar Plant O&M Cost =	0.020	$/kWh	Market Costs ($/kWh) =	0.07
Equivalent Heat Rate =	2,850	BTU/kWh	Current Gas Cost =	$5.00
Ownership Fraction =	0.5		Years to transfer Assets =	20
Operational Life =	35	years		

Note: The equivalent Heat Rate of 2,850 BTU/kWh is the fossil heat rate of cycle with the solar input included; if there was only pure solar heat used to generate electricity then the equivalent heat rate shown above would be zero.

Using the developed Excel program, sensitivity analyses were performed based on variations in the:

a. Initial market price;
b. Escalation rate of electricity; and
c. Discount rate used by the Muni's.

The full analysis is presented in Appendix B of the Task report and shows the evaluated case based on the assumptions used in Table 15. The analysis first determines the market price value of electricity at the future date when the plant will be ceded to the Muni (in the evaluated case the assumption was made that the current market price of 6 cents is escalated at 4%). This future electricity price is then escalated over the remaining solar plant life and the net present value is then determined at the future date the plant is ceded to the Muni. This future net present value is then discounted back (at the Muni discount rate) to determine today's net present value and is then levelized over the life of the solar plant to ascertain the premium paid. In similar fashion, adjustments are made for O&M and fuel. No government adders or adjustments were made for solar generated power. However one (1) mill per kWh were assigned for each of the following:

- Customer value (value that the customer will attach to environmentally friendly generated electricity);
- Fuel diversity;
- Transmission constraint reduction; and
- Pricing stability.

Cumulatively, these subjective values of solar generated electricity only add approximately 8% to the total price reduction (or prepayment) resulting from a future plant ownership transfer. Accordingly, these added values can easily be subtracted out of the final price reduction described in the following figures.

The pre-payment premium or price reduction as shown on the following figures represents the portion of the overall price paid to the solar developer/owner that can be applied towards purchasing the plant over a 20 year period. For example, if the contract between the solar developer and the Muni is for $125/MWh and the price reduction is at $20/MWh, then the Muni's "True Cost" of the power purchase is $105/MWh. This is because the price reduction of $20/MWh is construed to be pre-payment for half ownership in the power plant that is ceded to the Muni at the agreed upon date at no cost. The exact amount or portion of the power plant ceded to the Muni is a negotiated item determined during contract discussions. The price reduction is therefore defined in the following figures as that amount of the levelized energy cost (LEC) that can be allocated to the future purchase of the plant. The generator still receives the full payment for his plant but then cedes the negotiated part of the plant to the Muni at the agreed upon future later date.

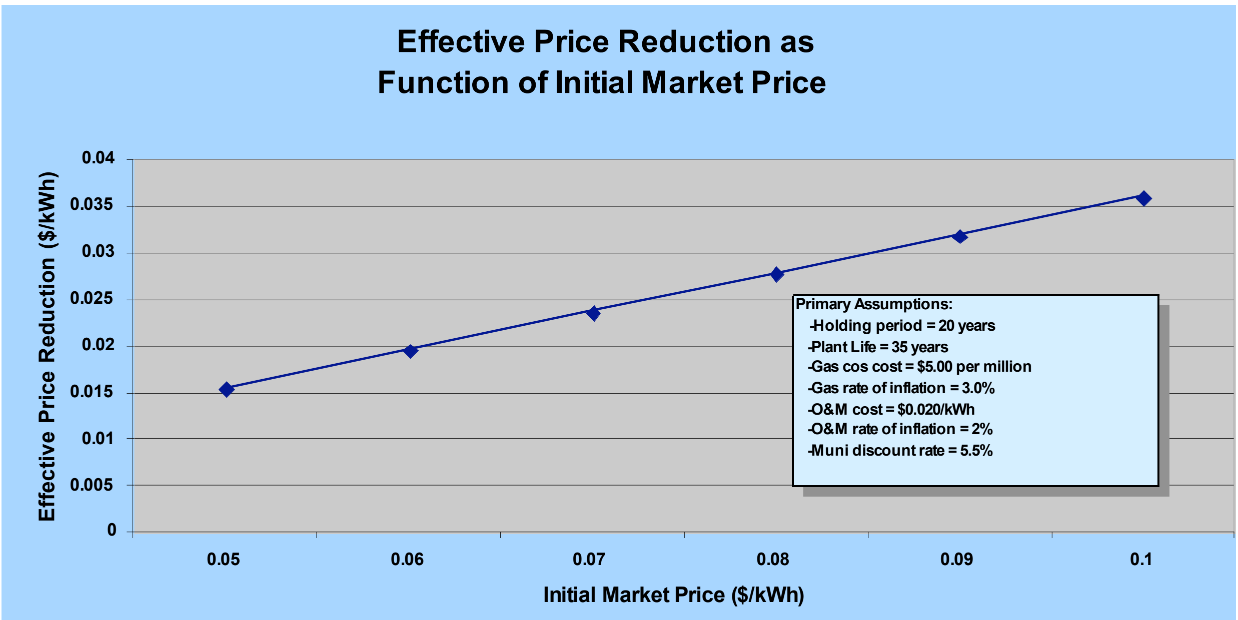

Figure 46 – Sensitivity to Market Price (constant 2003$)

Figure 46, "Price Reduction as a Function of Initial Market Price," shows the amount of the price paid to the generator that can be counted towards ½ ownership in the plant after debt repayment of 15 year. If the plant owner is getting, say, $125/MWh for his product then the true price paid by the Muni would be 12.5 cents/kWh less 2.4 cents/kWh (from the figure based on an initial market price of 7.5 cents/kWh) for a true price of 10.1 cents. At the end of the holding period, the Muni would receive ½ ownership of the plant. The net present value of the initial market price (or proxy plant) is shown as a range from $.05 to $.10 per kWh to illustrate sensitivity. If the initial market price or price proxy is higher then there is a greater price incentive. The initial market price is used as an indicator of future value since this is the "benchmark" to escalate electricity pricing and to determine the cost of electricity in the future at an assumed escalation rate. For the sensitivity analysis shown in Figure 46, the electricity price was assumed to rise at the natural gas cost escalation of 4.1% (approximately 1.1% over the rate of assumed inflation).

Likewise, sensitivity analysis can also be made for the escalation rates of electricity (Figure 47) to ascertain the projected market price at the time of turnover. This figure shows that for higher rates of electricity escalation, the greater the price reduction and the greater value received by the Muni.

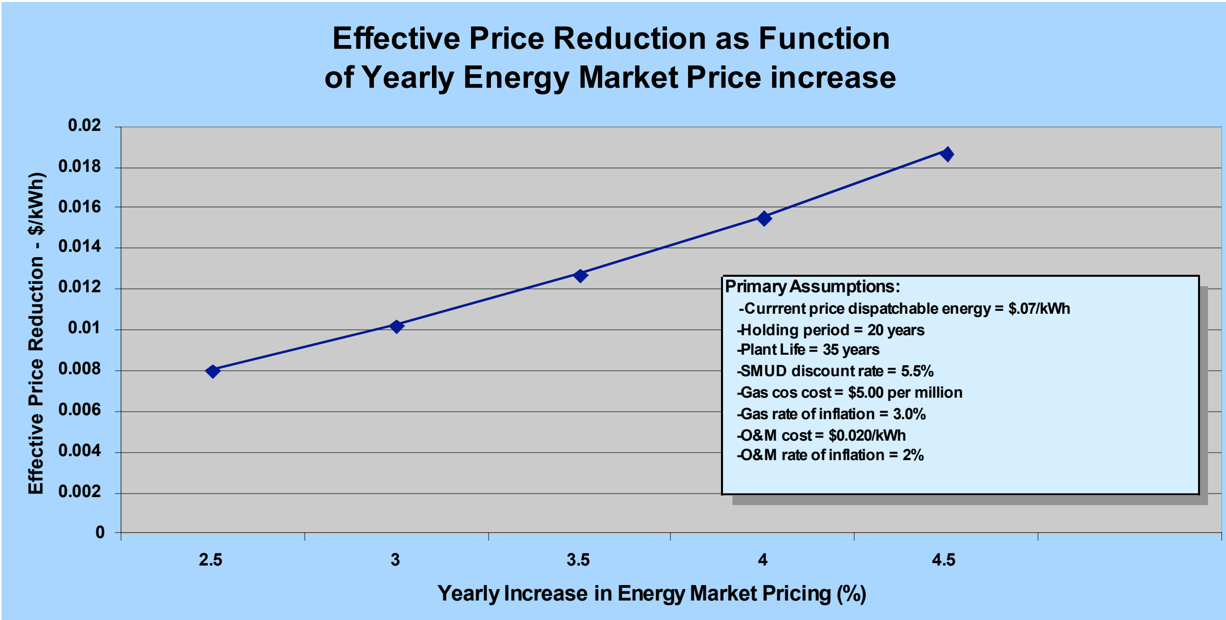

Figure 47 – Sensitivity to Energy Market Pricing (constant 2003$)

Finally, an analysis was made that shows the sensitivity to the Muni discount rate. As the discount rate is raised, the value of any future asset becomes less attractive on a net present value basis. Since the investor owned utilities (IOU's) use higher discount rates than Muni's, any future asset ceded to the IOU becomes less valuable to them. In other words, the future acquisition of an asset at a high discount rate is worth less than a future acquisition at a lower discount rate. In addition, since the IOU discount rates are similar to that of the solar owner/developer then this results in the future plant value being the same to both parties. Only in the instance where there is a difference in the discount rate can there be differential value of a future asset. Figure 48 shows the declining value of the price reduction as the discount rate is raised.

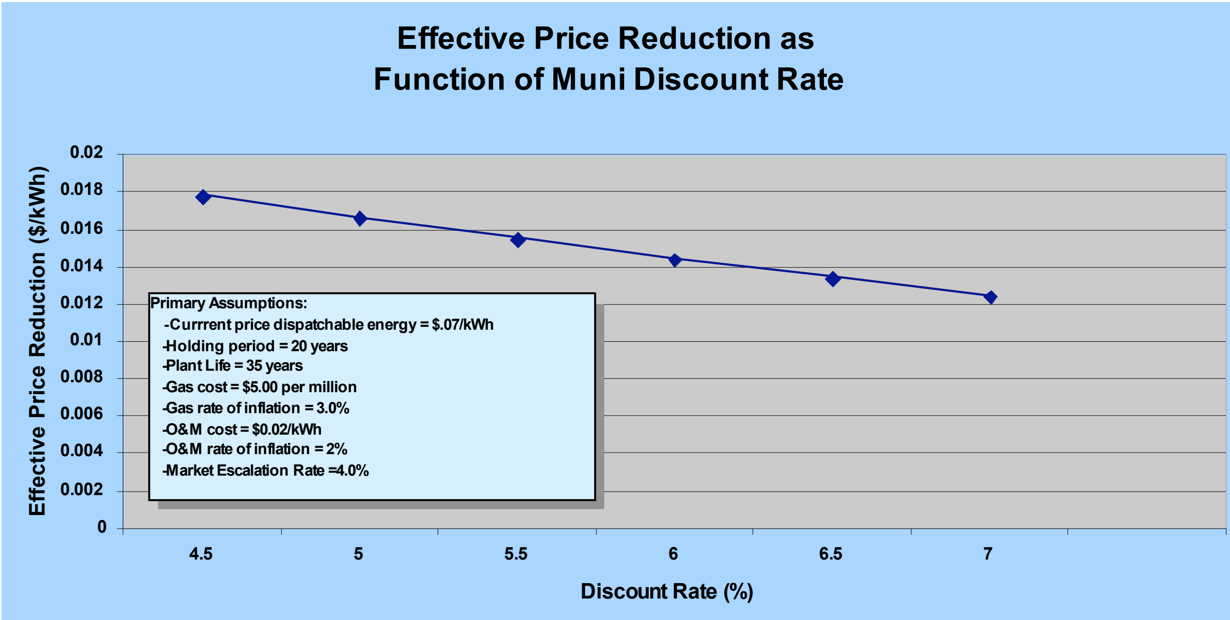

Figure 48 – Sensitivity to Discount Rate (constant 2003$)

The concept of prepayment similar to a "lease to own" financial arrangement is highly contingent upon the assumptions made by the Muni to determine the future value of the solar plant (based on a proxy price or market price of the future value of a combustion turbine plant). The determination of this value represents a form of risk that must be evaluated by the Muni. However, this risk is prudent given that the type of fossil plants that are approved today are based on long term fuel cost forecasts.

> Scenario No. 2 "Muni Ownership After Debt Repayment" represents a "lease to own" concept that reduces the effective cost of solar thermal plant to the Muni's to ~11.5 cents/kWh (LEC).

2.7.4.2 Scenario 3: Muni Ownership

Since the capital cost of a CSP plant is high compared to a fossil fueled equivalent plant, e.g. combustion turbine, the cost and amount of debt are highly critical in determining the cost of electricity produced by the plant. Muni ownership allows for 100% debt financing at tax-exempt bond rates that are typically 30 to 35% less than investment grade bonds afforded to private parties.

Sensitivity studies related to the "base case" have already shown the large economic advantages that can result from 100% debt financing. Analyses of the "base case" have also shown that cost of the debt is less significant to the economics of CSP plants when compared to the amount of leverage. Accordingly, 100% debt financing scenario offers the best form of financing available to CSP. The economics of a Muni are quite simple since there are no tax consequences and no depreciation to take into consideration. Assuming the cost of administration and bond risk mitigation to the Muni represents 1/2 % per year of capital invested, then the cost to the Muni is primarily based on:

a. The amortization of the bonds used for financing;
b. Operation and maintenance costs; and,
c. Gas usage consistent with PURPA requirements.

The governing criterion for the cost of Muni ownership is the cost of the bonds. A sensitivity analyses was made that showed the lower cost resulting from the lower bond cost at 100% debt. The results show significant reductions in the levelized cost of electricity due to current low bond costs; there are obviously lower LEC costs associated with a lower cost of 100% debt. Using the operational assumptions from the base case (scenario no. 1), the levelized cost of electricity based on a 25-year bond term is expressed as a function of the bond interest in Figure 49.

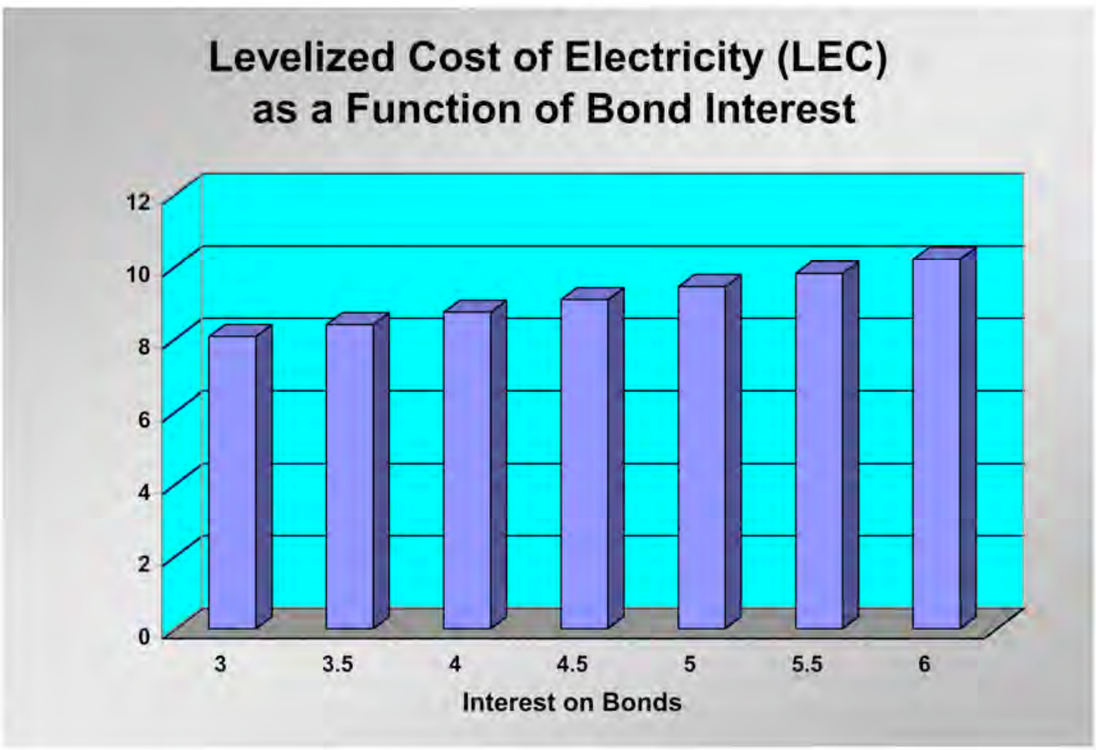

Figure 49 – Sensitivity to Bond Interest (constant 2003$)

Significant advantage over the private party ownership is shown when compared to the base case (scenario no. 1). This is, of course, due not only to the lower cost of interest, but more significantly to the 100% debt financing since the cost of equity ranges anywhere from 3 to 4 times more than the cost of municipal bonds. The high cost of solar thermal can best be financed through the use of municipal financing.

Scenario No. 3 "Muni Ownership" shows significant improvement in the LEC when compared to private ownership. Approximately ~30%-35% cost reductions result from low cost 100% debt financing resulting in a Muni LEC of approximately 8.7 cents/kWh.

2.7.4.4 Scenario 4: Private Ownership with Muni Pre-payment

Recent rulings from the Internal Revenue Service (IRS)[20] now allow a Muni to pre-pay for the power plant instead of paying for the electricity upon receipt. The Final Regulations on this ruling is shown in Appendix C of the Task Report. This, in effect, allows the private developer to build the power plant using de facto Muni financing since upon plant completion, the Muni would pay the full the value of the plant. The builder/developer of the plant would be responsible for the construction loan that would be paid off, in full, after the plant is completed with the pre-payment received from the Muni. While there are certain risks involved, the risks are essentially equal to signing a Power Purchase Agreement (PPA) for a long-term commitment to purchase electricity from a plant. In both scenarios, certain performance bonding will be required to ensure performance by the private developer.

The pre-payment option allows for the private party to take advantage of the 10% investment tax credit that is worth approximately 6 to 12 mills off of the levelized cost of electricity. The value or worth of the investment tax credit is very sensitive to the amount of equity invested in the plant. Higher leverage, i.e. lower amounts of equity investment makes the investment tax credit worth considerably more. While the rules are in flux and the US congress has not yet agreed on the exact form of incentive, the 10% investment tax credit has been used in the past for incentives on renewable energy and it can be reasonably assumed that this form of subsidy will continue. Accordingly, the impact of the investment tax with de facto Muni financing would reduce the cost of ownership (Muni finances but private ownership) resulting in a lower levelized cost of electricity when using prudent financing assumptions. There is some concern with regard to the appropriateness of the ownership option as it seems to suggest "double dipping". Further clarification of the tax rule changes is required prior to establishing the legitimacy of this financial option.

> Scenario No. 4 "Private Ownership with Muni Pre-payment" relies on a recent IRS ruling allowing the Muni to prepay the private developer for the plant. This concept allows for the developer to take advantage of the investment tax credit and de facto Muni financing and reduces the LEC to ~8.4 cents/kwh.

2.7.4.5 Scenario 5: Ownership of an Integrated Solar Combined Cycle System (ISCCS)[21]

The Task 4.1.6 Business Model Report includes a fifth scenario that investigates an integrated conventional combined cycle with a CSP plant.[22,23] Past studies indicate significant savings in capital cost and increased performance for the ISCCS/hybrid plant when compared to either a

[20] Treasury Decision 9085 (68 FR 45772-45777, August 4, 2003), 26 CFR, Part 1 "Arbitrage and Private Activity Restrictions Applicable to Tax-Exempt Bonds"

[21] See Task 4.1.4 Report, Section 2 of this project for a more detailed description of the solar hybrid power plant.

[22] "Optimization Studies for Integrated Solar Combined Cycle Systems", presented by the National Renewable Energy Laboratory (NREL) at the ASME 2001 Forum

[23] "Mexico Feasibility Study for an Integrated Solar Combined Cycle System (ISCCS)", Spenser Management Associates, June 2000

combined cycle or solar plant built and operated independently. A particular concern regarding this plant configuration is the apportionment of ownership. Solar generated capacity and energy, as shown in this analysis, becomes highly competitive to the fossil alternative and appears to be the most cost effective form of CSP generation. However, the solar energy of the hybrid plant will be limited to somewhere between 7 to 12% of the overall hybrid plant output depending on the capacity factor of the combined cycle (which, of course, can be operated independently of the solar plant).

The cost savings associated with this ownership configuration can be estimated to about 10 mills/kWh (the details are shown in the Task 4.1.6 report).

Scenario No. 5 "Hybrid Configuration" represents more of an economic and cost reduction scenario rather than an ownership scenario. Either a privateer or Muni can take advantage of this configuration, which will reduce the cost of solar by approximately 1 cent/kWh.

2.7.5 Summary of Ownership Scenarios

The attractiveness of the above ownership scenarios will vary greatly based on:

- Tax status of ownership parties;
- Current debt and bond market conditions;
- Current and expected pricing of electricity;
- Risk apportionment between the parties;
- Status of federal and state incentive plans; and
- Status of Renewable Portfolio Standards (RPS) in California and other states.

The analyses performed within this investigation should be interpreted as a representation of possible financial and economic scenarios. *As the analysis was based on a generic CSP plant, the assumptions and methodologies presented herein should not be construed as a definitive assessment of any particular plant configuration or ownership arrangement*. The various ownership scenarios can be shown to have cost advantages and disadvantages specific to each type of financing and to each type of incentives that may be available.

The Production Tax Credit (PTC) is expected to be 1.8 to 2.0 cents for probably no more than five years. In addition, there has been little discussion on the Renewable Energy Credit (REC) that can also produce an additional cash flow depending on how the REC is treated.

When the potential of the PTC and the REC are included in the financial evaluation of CSP, the value of CSP is significantly enhanced. A range of Levelized Energy Costs has been compiled for the five ownership scenarios. There are an infinite number of values for debt to equity, debt cost and duration, project duration, etc. Case no. 1 (ownership by the private developer with no subsidies) has been quantified in this analysis as a benchmark to compare the other case scenarios. Using the aforementioned assumptions to evaluate the five scenarios, the cost reductions associated with the various subsidies and ownership cases are shown in Figure 50.

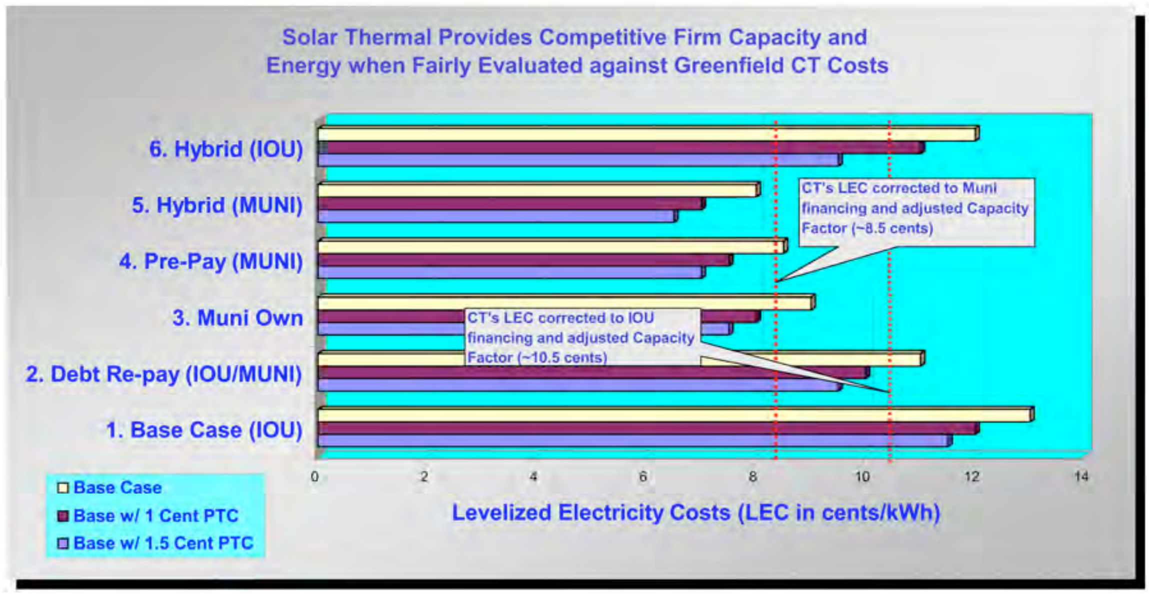

Figure 50 – Solar Pricing Against Fossil Competition (constant 2003$)

Figure 50 shows that the commercially available CSP can be competitive against the fossil alternative today. The Levelized Electricity Costs for the CT's shown in the above figure are based on the analysis shown in a later section (See "Development Cost of the Pricing Proxy") and are presented in this chart as benchmarks. The levelized energy costs of the CT's (both privately owned and municipal owned) have been estimated at the same capacity factor (compared to the solar only portion of the gas assisted solar thermal plant) for comparison purposes. The two LECs for the combustion turbine (shown as "notes" within the graph) represent the differences in cost that result from private financing or financing available with Muni ownership.

2.8 Incentives Report[24]

2.8.1 Summary

2.8.1.1 Objective

The Incentives Report is a review of the incentives suitable and available for large-scale CSP projects built by one or more California Municipal utility companies (Muni's) or built by an independent power producer (IPP) under a long-term power purchase agreement with one or more California Muni's.

The availability of incentives depends on the nature of the CSP plant ownership and the location of the plant. The ownership options are IPP or Muni ownership and the location options are in California or out of state yet within the Western Electric Coordination Council (WECC) system. The three near-by states, with the excellent solar radiation required for CSP, are Arizona, New Mexico and Nevada.

[24] This chapter summarizes the work completed in the task 4.1.7.1 Incentives Report, dated January 2004.

2.8.1.2 Purpose of Incentives

The purpose of incentives is to cover and reimburse the developer for the variety of benefits resulting from the greater use of renewable energy technologies, including energy portfolio diversity, electricity price stability as well as socio-economic and environmental benefits. Incentives reduce the price that must be charged for power generated by a CSP plant and make it more competitive with the price of fossil fuel power. This can be accomplished in two ways. The first is to reduce the net capital cost of the plant and the second is to cover a portion or all of the gap between the cost of competition power and that from the CSP plant. The real purpose of incentives, when viewed from a macro-perspective, can be characterized as putting renewables on the same economic basis as the fossil fuel alternatives.

2.8.1.3 Available Incentives for CSP[25]

Incentives that would reduce the capital cost of the plant include the 10% Federal Investment Tax Credit (ITC) and the federal accelerated depreciation credit (MACRS) and any available state and/or local property tax exemptions. This will result in reducing the price gap between CSP power and conventional power. To reduce the remaining price gap, the first step would be to use the federal PTC, if and when it exists and the Renewable Energy Production Incentive (REPI), if and when that becomes available again, each depending on plant ownership. The remaining gap would have to be covered by public benefit charge funds or by absorbing the additional cost into the utilities rate base, either of which generally are related to the renewable portfolio standards (RPS) available in California and the three near-by states. In the case of the Muni's, emission credits that are acquired when CSP technologies are used and these, even without other incentives, are worth 1 – 2 cents.

Federal Incentives

Federal incentives for an IPP regardless of locations are:

1. 10% ITC
2. MACRS
3. Possibly some MACRS bonuses
4. PTC the existence and specifics of which are still uncertain (at the time of report)
5. Profit tax exemption on portion of plant covered by grants

Federal incentives for a Muni regardless of location are the REPI (if it is renewed).

State Incentives

State incentives for an IPP regardless of which state are:

1. RPS and associated PBC or rate-base
2. Property tax exemptions are possible
3. Bond financing may be possible
4. Renewable Energy Credits

[25] Since the research for the Incentives Report was conducted in late 2003 and the submission of the report in February 2004, legal and legislative changes have occurred which may impact both the federal and state incentives described herein.

5. California has a program that could provide up to 1 c/kWh
6. New Mexico has a state production tax incentive of 1 c/kWh

There are no State incentives for Muni-owned CSP plants or for CSP plants whose power is purchased by Muni's above Muni financing rates and normal Muni tax exemptions. Most of the California Muni's have adopted a voluntary RPS and would presumably rate base the cost gap. Most of these incentives are limited in amount, duration and how they can be used in combination with other incentives.

At its present level of development and deployment, and given the methodology for economic evaluation used by the Muni's, CSP is a more expensive technology than those using fossil fuels. This cost difference has prevented the necessary market expansion that would drive down the price of the technology and make it cost-competitive with other energy sources. Utilization of available incentives will facilitate expanding the market for CSP in the United States.

2.8.2 Incentives Overview

The federal government and the states have numerous reasons to offer incentives to encourage the use and expansion of renewable energy technologies. There are environmental reasons such as reduction of climate changing emissions caused by conventional energy production and the improved health of citizens who are exposed to less of the unhealthy bi-products of this production. The public continues to show support renewable energies and many are willing to voluntarily pay higher electricity premiums for the purchase of renewable energy. The use of renewable energies reduces environmental damage by preserving the environment, conserving water and conserving non-renewable resources. The creation of new renewable energy producing facilities also serves to stimulate the economy and creates new and lasting job opportunities. For many of the states another benefit of renewables is that it helps provide diversity in their energy supply which helps with production and price stability. This is especially important to the southwestern states following the problems of California's deregulation which resulted in wide-spread brown and black outs and extreme increases in the cost of electricity. Incentives help pay for, and reimburse the developer for, the numerous benefits received by the increased and expanded use of renewable energy technologies.
For example, in response to the problems of deregulation, California has created a public benefits fund specifically to fund renewable energies in the state.

Very few renewable incentives are available for these purposes. Most state incentives are aimed at end-use consumers or residential customers and have been omitted from this report. However, some consumer incentives may be used to indirectly help in negotiating with the Muni's. For example "green" power purchasing agreements allow consumers to volunteer for increased electricity prices that helps the power producer purchase more expensive renewable energy. This incentive could help bridge the cost gap between fossil fuel and CSP prices. Other incentives are aimed at the commercial and industrial sectors but for projects of limited size that are too small for CSP bulk power producers.

With these limitations in mind, the best incentives for large CSP power plants are California's Renewable Portfolio Standards. While other incentives may also apply, it should be noted that most of these incentives cannot be used, or cannot be fully used, together. Some states, including California, also have a Systems Benefits Charge (SBC), or Supplemental Energy

Charge (SEP) that is used to support renewable energy. The following summary describes the incentives and the table following the summary gives a general overview of the incentives and contact information.

2.8.3 Existing Federal Incentives

Federal Investment Tax Credit for Commercial Solar Energy Property

The Federal Investment Tax Credit is a 10% investment credit for companies, including IOUs and independent power producers (IPPs) that invest in or purchase solar energy property. However, if the property is financed by either Federal or state subsidized energy financing or by a private activity bond, the credit will be reduced. The investment must be subject to depreciation or amortization and must conform to any quality regulations and standards. This Investment Tax Credit has no expiration date, as per the Energy Policy Act of 1992.[26]

The credit cannot be used by governmental entities or Public Utility Companies. All equipment must be installed and operating in the year that the credit is taken and other incentives reduce the eligible amount. To claim the credit, a specific IRS form must be filed with income taxes. The necessary form to apply for the credit is IRS Form 3468.

Modified Accelerated Cost Recovery System (MACRS)

Section 168 of the IRS code contains a system for accelerated depreciation. The Modified Accelerated Cost Recovery System (MACRS) allows business to recover investments through depreciation deductions. Solar properties have a "class life" of 5 years during which they can use the depreciation deductions. Solar properties that are eligible for the 10% investment tax credit are also eligible for this incentive.

In addition to this, the "Job Creation and Worker Assistance Act of 2002" allows businesses an additional 30% of depreciation on solar property for the first year. The "Jobs and Growth Tax Relief Reconciliation Act of 2003" increased this extra depreciation to 50%, in the first year, for equipment purchased and in service. However, to qualify for the 50% bonus the property must be purchased between May 6, 2003 and December 31, 2005.

Many states have either not adopted the federal bonus depreciation or have separated the state tax depreciation schedules from the federal ones.

Federal Tax Exemption for Nontaxable Energy Grants or Subsidized Energy

Subsidized energy financing and energy grants from federal, state or local government organizations may be exempt from federal taxes. The financing and/or grants must be for the purpose of energy conservation or energy production. The financing or grant administrator is responsible for submitting the necessary IRS Form 6497 in order to use this.

[26] Please see the 4.1.7 Task Report titled "Incentives for Large-Scale CSP Projects for the California Municipal Utilities" for all end notes, references and detailed appendices.

2.8.4 Pending Federal Incentives[27]

Renewable Energy Production Incentive (REPI)

The Renewable Energy Production Incentive (REPI) provides for incentive payments to owners of qualified energy facilities. This program was in operation between October 1993 and September 2003. Though this program is no longer taking applications, it is still important to consider this incentive because both the Senate and House Energy Policy Act of 2003 contain new versions of this incentive.

CSP qualifies as an eligible renewable energy for this program. Facilities that are eligible are state and local government-owned facilities, including municipal utilities and non-profit electric cooperatives. Those that qualify are eligible for annual incentive payments of 1.5 cents per kilowatt-hour (indexed for inflation.) These funds are available for a ten year period of operation, though they are subject to availability of annual appropriations.

Production Tax Credit

The Federal Production Tax Credit (PTC) has been included in the Energy Bill 2003 that is currently stalled in the Legislature. In the pending bill, the PTC has been expanded to include solar facilities sited prior to the end of 2006 and includes 1.8 cents kWh for five years of production. Unfortunately, this PTC may not be used with the 10% ITC which generally yields a greater benefit.

2.8.5 State of California Incentives

California Property Tax Exemption for Solar Systems

California Revenue and Taxation Code, section 73, allows active solar energy systems an exemption from property taxes. These active solar systems must be installed between January 1, 1999 and January 1, 2006 to receive this exemption, unless another statues changes or extends the ending date. This property tax exemption is for 100% of the project value and has no maximum limit. However, the system must be operational, not under construction, to receive the exemption.

California Renewables Portfolio Standard

The California Renewables Portfolio Standard Program (RPS) requires retail suppliers of electricity to increase their procurement from eligible renewable energy sources at least 1% per year so that at least 20% of their retail sales are from renewable energies by 2017. The RPS applies to statewide Investor Owned Utilities (IOUs), Community Choice Aggregators (CCA), Electric Service Providers (ESP) and Municipal Utilities. The California Public Utilities Commission (CPUC) and the California Energy Commission are responsible for working collaboratively to implement the RPS. Supplemental energy payments will be provided by the California Energy Commission, if funds are available, to cover the cost difference between conventional and renewable energy sources. These funds come from the Public Goods Charge affixed to the IOU's ratepayer bills. The Energy Commission does not cover the cost-gap for Muni's but, where they voluntarily implement the RPS, they will most likely cover this cost-gap via the ratepayers.

[27] These were pending at time of report submission (February 2004).

The CPUC and the Energy Commission are currently working on implementation of the RPS for IOUs and will later do the same for CCAs and ESPs. Municipal Utilities are to implement the RPS for themselves and their compliance is not mandated. CPUC will set the annual goal for the amount of renewable energy to be procured by the utilities. IOU compliance starts with submitting a procurement plan to CPUC. CPUC then reviews and approves this plan. An IOU must be proven creditworthy and will then issue a solicitation to procure the necessary renewable energy. CPUC will approve standard contracts for the eligible renewable energy products and will generally require a contract term of at least 10 years. Responses to the solicitation are to be ranked looking at "least cost" and "best fit" for the long-term needs of the IOU. Transmission charges are to be ranked in the evaluation of the renewables but the actual charges incurred for transmission will be borne by the ratepayer.

The CPUC will compare the bids to the market price referent it establishes for each of the eligible renewable products. This referent estimates the amount that would be paid for energy if renewable power were not being purchased. This referent is not revealed until all bids have been submitted. To compensate for the higher costs of renewable power, when compared to non-renewable energy sources, the cost difference will be paid back to the energy purchaser. The difference will be paid by a Public Goods Charge from the California Energy Commission in a Supplemental Energy Payment (SEP), which is subject to availability of the funds to pay it. If funds are not available or are insufficient to cover the difference, the energy purchaser can limit its annual procurement to the amount which can be supported by SEPs.

It is worth noting that the California Energy Commission, in defining eligibility requirements for IOU renewable power purchasing, has addressed RPS eligibility for out of state power. An out of state power generator can deliver electricity to California, meet the RPS requirements and be eligible to receive SEPs if it meets one of the following requirements. The first requirement is that the renewable generation facility is located near the border of California, with the first interconnection point to the WECC transmission system located within California or, the second requirement, it is eligible for SEPs because the facility is located so it is, or will be, connected to the WECC transmission system and has guaranteed contracts to sell its power to California customers in IOU service territories during the time it is receiving the SEPs. If the California Muni's voluntarily adhere to the rules set out in SB 1078, which seems likely, then they also will be limited to locating any out of state site so that the first point of interconnection is located within California.

The CPUC adopted rules for IOUs in June 2003. These rules address determining market price referents from non-renewable energy sources, and that bids above these referents may be eligible for SEPs, subject to availability of funds. The process to determine the market price referent for base load and peaking renewable power has been created. SEPs will bridge the cost-gap so electricity supplies do not have to purchase renewables over the market price. The actual market price referent will not be known until after bids are received, which means that the portion of each successful bid above the referent, and eligible for SEPs, will not be know ahead of time.

CPUC addresses the issue of winning selections based on "least cost" and "best fit" for the IOU. Each IOU will be required to provide CPUC with a procurement plan that allows bidders to develop their plans to fit the needs of each IOU. The rules note that "for the short-term, renewable generation that can operate as dispatchable or peaker power may possibly fall slightly higher on the 'procurement hierarchy." The Edison Electric Institute Master Agreement will be the basis of standard terms and conditions that the CPUC is instructed to use, per SB 1078, and the groups involved must negotiate more detailed terms. Further, utilities are asked to seek bids for 10, 15 and 20 year contracts. Bilateral contracts are allowed only if they will not receive any SEPs.

California Energy Action Plan & CPU Energy Resource Investment Plan
Though it cannot be considered a true "incentive," an Energy Action Plan was developed in Spring 2003 by the Consumer Power and Conservation Financing Authority (CPA), Energy Resources Conservation and Development Commission and Public Utilities Commission (CPUC). The adopted plan hopes to ensure adequate, reliable, available reserves and reasonably priced power for California. This plan specifically accelerates the 20% target date of the California RPS from 2017 to 2010. Actions intended to achieve the goals set by the plan include: optimize energy conservation and efficiency, thereby reducing demand, build sufficient new generation, upgrade and expand the electric transmission and distribution infrastructure and bring new facilities on-line faster. The three agencies have committed to provide assessments of energy needs, resources, and prices and to license and fund construction of new energy facilities, where necessary. Decisions that are made by the agencies are put into a "loading order" by the plan. First, the agencies will optimize all strategies for increasing conservation and promoting energy efficiency. Second, necessary new generation will be met first by renewable energies and distributed generation. And third, they will support additional "clean" fossil fuel, central-station generation. While following this plan the agencies will, at the same time, be improving the electricity transmission and distribution infrastructure to support growing demand and for interconnection with new generation facilities.

The CPA may issue bonds for up to $5 billion to help with financing the creation of, among other things, renewable energy projects. These bonds, if borrowers are private parties, must be taxable bonds as stated by the IRS. They are also currently exploring bulk power procurement that include multi-year, higher-volume supply contracts. They also will consider CPA ownership in certain, critical areas. Possibilities of financing through the CPA include via the RPS using long-term agreements with IOUs or by CPA being the developer/owner of a renewable energy resource at-cost to benefit the public – including the use of tax-exempt debt. The CPA also has the option of providing turn-key financing to the Muni's in privately owned projects with long-term PPA agreements with the Muni.

2.8.6 State of Nevada Incentives

Nevada Renewable Energy Portfolio Standard
The Nevada Renewable Energy Portfolio Standard (REPS) was originally established in 1997. In 2001, the Nevada legislature revised the REPS requiring more aggressive goals. The REPS applies to IOUs and to providers of electricity to large retail access customers. Currently, there are no large retail access customers and the only two IOUs in Nevada are Nevada Power and Sierra Pacific Power. The REPS requires that each electricity provider must derive a minimum amount of its power consumed in Nevada from renewable energy resources, including solar. The minimum percentage is to increase 2% every two years until 2013 and the final minimum set for

2013 is 15%. The REPS specifically states that no less than 5% of the REPS must be derived from solar energy, though there is nothing that specifies which type of solar energy must be used. While there is a solar set aside, it does not specify an amount requirement for CSP.

Nevada Renewable Energy Credits

Nevada, as a part of its REPS has included a program for Renewable Energy Credits (RECs). RECs are divided into solar and non-solar categories, consistent with Nevada's statute. Solar energy may be provided by residential and business customers, Muni's and other retail energy suppliers, as long as the energy provided is consumed in Nevada. These RECs can be sold to utilities to meet the Nevada REPS. Energy systems for all providers must be certified by the PUCN. It is important to note that PV has been given a distinct advantage over the other renewable resources, including CSP, when it comes to generating RECs because each PV-generated kWh equals 2.4 kWh as RECs.

2.8.7 State of Arizona Incentives

Arizona Environmental Portfolio Standard

Arizona's Environmental Portfolio Standard (EPS) was implemented by the Arizona Corporations Commission in Rule R14-2-16-18 and included an EPS surcharge. Any Load-Serving Entity (LSE) selling electricity must, under the Article, derive at least 0.2% of total energy sold from renewable energy technologies, whether the energy is purchased or generated by the seller. Electric Service Providers (ESPs) are exempt from the EPS requirements until 2004. Utility Distribution Companies (UDCs) recover part of the costs of EPS implementation by current System Benefit Charges, where available. Additional costs are to be recovered by a customer surcharge, which appears on the customers' monthly bill. The charge will be either $0.000875 per kWh (or $.35 for residential customers, $13 for non-residential customers, or $39 for demand greater than 3,000 kWh whichever is less.)

For 2001 – 2003 the renewable technologies making up the EPS must be at least 50% solar. For 2004 – 2012 the renewable technologies making up the EPS must be at least 60% solar. If the annual percentage increase continues, the EPS will produce almost 100 MW of solar power by 2007.

2.8.8 State of New Mexico Incentives

New Mexico Renewable Energy Production Tax Credit

The New Mexico Renewable Energy Production Tax Credit (PTC) states that any qualified taxpaying energy generator that is certified by the NM Energy, Minerals and Natural Resource Department is eligible for a tax credit on the energy produced. The tax credit equals one cent per kWh for the first 400,000 MW hours of electricity produced for 10 consecutive years, beginning when the generator begins producing electricity.

To be qualified as an energy generator, the facility must have at least 10 MW generating capacity and be located in New Mexico. This generator must use a qualified resource (CSP is included) and sell the energy to an unrelated person.

To receive the PTC an energy producer must be certified. The energy producer may be certified only if the electricity produced by all of the qualified energy generators in a given year does not exceed 2 million MW hours. It is up to the IRS to decide whether or not this state PTC can be used in conjunction with any federal incentives. However, at an AWEA annual conference in Austin 2003, one of the speakers noted that the IRS had issued a "letter ruling" indicating that a state PTC does not reduce the federal PTC. In New Mexico, a federal PTC would not reduce the state PTC.

New Mexico Renewables Portfolio Standard

The New Mexico Renewables Portfolio Standard (RPS) requires IOUs produce 5% of their energy generation from renewable resources by 2006 and increase this amount by 1% each year until 2011 when 10% of energy generation will be produced by renewable sources.

Utility RPS compliance is recorded using renewable energy certificates which equal kilowatt hours of electricity. Different renewable technologies are weighted differently for the purposes of determining the number kilowatt hours generated for the RPS. Solar is most heavily favored and one kWh of solar power is worth 3 kWh for the RPS. The certificates may be traded, transferred or sold to other parties. Unused certificates may be carried forward up to four years from their issuance.

New Mexico Mandatory Utility Green Power Option

The New Mexico Public Regulation Commission (NMPRC) renewable energy rule is a part of the same authority as the New Mexico RPS. This new rule requires IOUs (and electric cooperatives, to the extent that their supplier makes renewables available) to offer voluntary renewable energy tariff programs, also known as green pricing programs, to their customers who wish to purchase additional renewable energy. This is not, in itself, a good incentive for CSP, however the additional energy tariffs will be used to purchase renewable power and that power can come from a CSP plant.

2.8.9 Conclusion

In conclusion, the excellent direct normal solar radiation found in California, Arizona, Nevada and New Mexico is ideal for Concentrating Solar Power projects. CSP has a number of unique economic, environmental and health benefits relative to fossil-based power projects, but CSP-generated electricity is currently more expensive. Federal and state incentives can bridge the cost-gap between the cost of fossil-based and CSP-generated electricity.[28]

Incentives that would reduce the capital cost of a CSP plant include the federal 10% ITC and accelerated depreciation credit (MACRS) as well as available state and local property tax exemptions. To further reduce this gap, the federal PTC, the REPI (if it exists) may be used and the remainder may be covered by public benefit charge funds or be absorbed as an additional cost to the electricity ratepayers.

There are few incentives currently available for the development of large-scale CSP projects in these states and the incentives that are available depend on project location and ownership. Most

[28] Appendix B is a Table of Incentives for CSP.

state renewable energy incentives are aimed at consumers and end-users. However, by using the best incentives or combination of incentives available, CSP project developers and purchasers can produce a product that is more cost-competitive with non-renewable power sources and has important environmental and socio-economic benefits.

2.9 Economic Assessment of CSP[29]

2.9.1 CSP Pricing History and Forecast

Price reductions associated with the production of electricity from CSP generation are predicated on the amount of capacity installed and the resulting energy sales, that is, larger plants and increased output result in investment cost economies and more megawatt-hours sold, thus lowering the expected cost of electricity. One-of-a-kind type generation facilities, regardless of size or type, will nearly always remain expensive. In order to justify the investment in production facilities to manufacture the solar plants and, in particular, the solar collectors, these production facilities must be used in order to recoup the capital investment. In general, the investment cost of CSP plants can be lowered in three ways:

- Economies of scale,
- Economies of production; and,
- Technology improvements.

The economies of scale results in high manufacturing facility use simply because large CSP plants will require a large number of collectors and associated solar equipment. The economies of production can also be achieved by producing high numbers of smaller CSP facilities. Both methods can produce an equal amount of capacity but the economics strongly favor the larger solar plant due to cost considerations of the other equipment in the power plant, e.g. the electric power generating system (EPGS) and auxiliary systems. As the solar plant is reduced in size, the proportional cost of the non-solar equipment rises significantly on a per unit bases. Small plants also suffer large non-recurring costs such as A&E charges, permitting costs, generation tie-in costs, etc. Accordingly, greater economy of scale is achieved by building larger solar thermal plants. In addition, the maintenance and operational requirements of small plants can be unusually high due to the inefficiency of the multi-tasks required when applied on a small scale. Therefore, the focus for the industry is to build large solar plants in the 100 MW –200 MW and above range.

Technology improvements that decrease capital costs and improve efficiency result in a learning curve that is remarkably similar in shape for nearly all generation technologies though not necessarily in time. The similarity of these curves produce confidence in future pricing, and extrapolation of the costs can give a strong indication of the capital and operating costs of the "next" plant. Cost trends represent the maturing of the technology, and as the technology is more fully understood, greater size and extrapolation of the technology results in ever-lowering costs for as long as its market continues to expand with healthy competition.

The cost trend for CSP is illustrated in the NREL-generated cost curve[30] show in Figure 51.

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[29] This chapter summarizes the work completed in the task 4.1.8.1 Economic Analysis Report, dated March 2004.

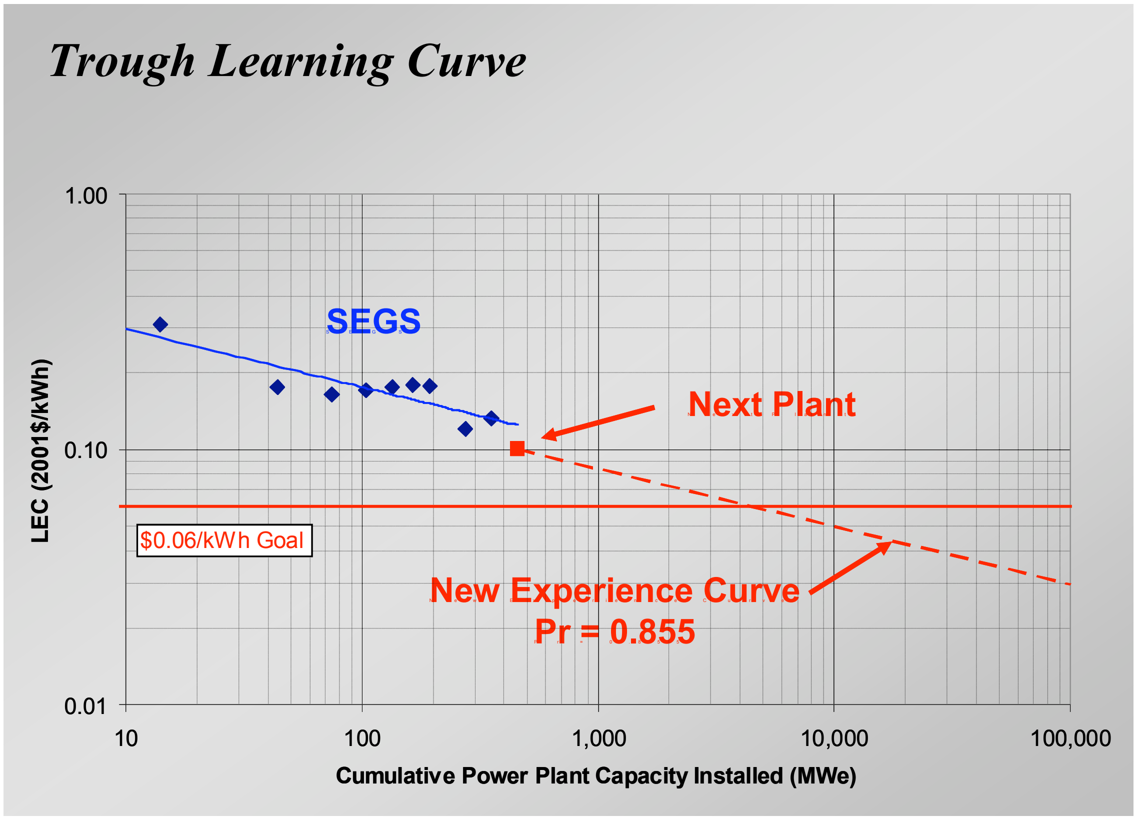

Figure 51 – Levelized Cost of Electricity as a Function of Installed Capacity

This graph shows the declining cost of CSP plants as a function of MW installed. As noted, the early plants produced electricity at a Levelized Energy Cost (LEC) in the 30 cents per kW range. The next plant constructed is expected to produce energy at approximately 10 cents per kW. At the 2,000 MW level, the price is predicted to be approximately 8 cents. It is noted that the extrapolated curve for SEGS results in more capacity requirements to achieve the same goals illustrated in the "New Experience Curve". This can be explained by the regulatory/legal impairments that prevailed at SEGS; the 30 MW size limit impaired the normal downward cost progression but when the two larger 90 MW sizes were constructed, further cost reductions were realized. However, Figure 51 should be viewed as a "trend" chart and should not be taken as absolute. There is insufficient empirical evidence, at this time, to verify the New Experience Curve. While it is expected that the learning curve should be quicker now that certain legislative encumbrances restraining size of CSP plants have been removed, further capacity installation is required to increase cost forecast accuracy.

Figure 52 illustrates the path of cost reductions for CSP as compared to other technologies. The chart was also originally prepared by NREL using published data. As noted, the downward trend line for solar thermal is not as pronounced as other technologies. The lack of a steeper

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[30] Sargent and Lundy's "Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts", May 2003

declination of the CSP line can most likely be attributed to the relative lack of subsidy and R&D investment provided to solar thermal when compared to other technologies such as Photovoltaics (PV), Wind and Combustion Turbines (CT).

While solar is shown to be relatively expensive compared to gas turbines in Figure 52, it should be noted that the fuel consumption is not considered in the "Capital Cost Learning Curve" and care should be exercised not to equate bus bar energy costs with the graph lines that represent only the capital component. In addition, the graph does not represent the value of the products. For instance, wind is shown as having a much lower capital cost that solar and while both forms of generation do not have fuel components (assuming a pure solar only plant), wind is an "energy" only generator and does not provide the full capacity credit. Solar produced electricity, on the other hand, would essentially follow the sun and load demands of the utility and would be more highly valued in the electricity market.

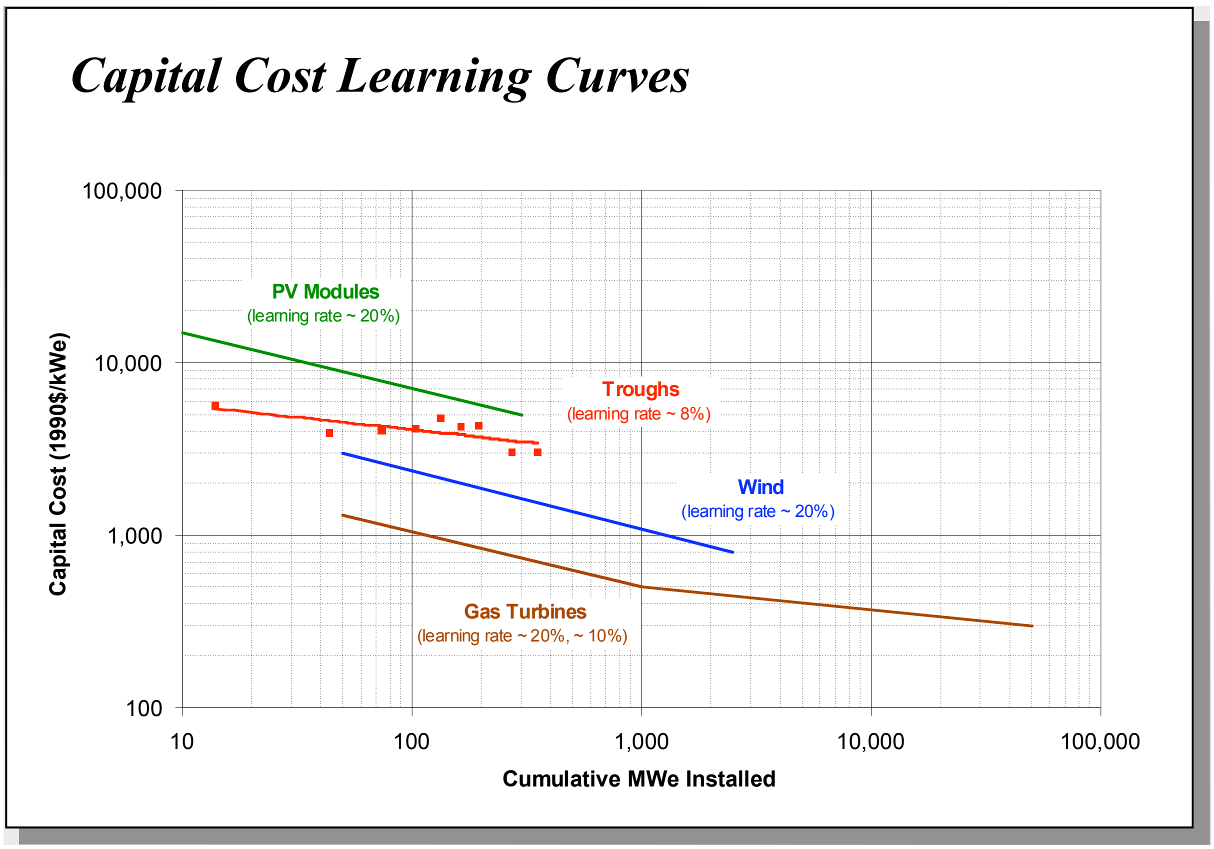

Figure 52 – Comparison of CSP Troughs to Other Generation Technologies

The continuance of CSP cost reduction is predicated on an ever developing market. This market must be defined and served in order to promote the development of the infrastructure and manufacturing facilities. The cost analyses in this investigation shows that the principle market to be served is "peaking power" as this market is the high valued market especially for those IOU's and Muni's that are summer peaking utilities.

Following is the development of the "pricing proxy" for a combustion turbine that is, for all intents and purposes, the fossil alternative to solar thermal power plants. It is this price proxy that must be matched or exceeded in order for solar thermal to be considered a competitive alternative to fossil fuels.

2.9.2 Development of the Pricing Proxy

In the past, CSP plants have been an "economically challenged" product for the IOU's and Muni's to purchase. Previous CSP "all-in" plant costs have resulted in electricity prices in the $0.15 to $0.18/kWh range. Technology enhancements and improvements have significantly reduced this price to approximately $0.10/kWh to $0.13/kWh or lower depending on size, financing, configuration and costs associated with siting and infrastructure. With different ownership structures previously discussed in chapter 6, and with certain tax advantages, the price can be significantly lower.

However, before any direct product pricing comparisons are made, the price determination of the "competition" must first be determined. The "greenfield" pricing structure of a combustion turbine has been determined by the California Public Utilities Commission[31] (CPUC) to be the appropriate "pricing proxy" for comparison of energy costs.

<u>Current Pricing of Dispatchable Peak and Shoulder Power (CF ~25%)</u>
The current pricing of dispatchable energy can be found on the CAISO[32] web site at a level of approximately $45-60/MWhr, varying with the season. The OASIS site, which also lists post pricing details, indicates that this range might actually be high as even last summer's pricing rarely went above $60/MWh on an average peaking/shoulder hour basis. However, this cost is not necessarily indicative of the true incremental "spot" pricing that a Muni or IOU will pay. Given the melt down of energy trading in California (and elsewhere) and the fact that many energy traders are currently "upside down" in pricing, it is doubtful that this pricing structure will or can be sustained. In addition, for the near term, the possible deficiency in energy production for the state of California in 2006-2008 may result in higher spot market pricing. The only accurate method of projecting a true energy price is to estimate the levelized cost of a new "greenfield" generation unit to serve the dispatchable peak and shoulder market.

An analysis using utility economic assumptions and methodology shows the lowest *<u>idealized</u>* levelized cost of production at 25% capacity factor (using baseline assumptions as modified for a combustion turbine, see chapter 6 and "Determining the Pricing Proxy" later in this chapter) to be approximately:

[31] CPUC Decision 03-06-071 "Order Initiating Implementation of Senate Bill 1078 – Renewable Portfolio Standards Program", June 19, 2003

[32] Energy prices are available at the CAISO web site [www.caiso.com] under OASIS

$.08/kWh - Based on the installation of a General Electric LM 6000 at quoted heat rate and $495/kW total installed cost and baseline $3.50 fuel

In order to ascertain the relative accuracy and volatility of the greenfield combustion turbine costs, a sensitivity analysis using the two most volatile components of the analysis (fuel cost and capital cost) was run, showing the following results:

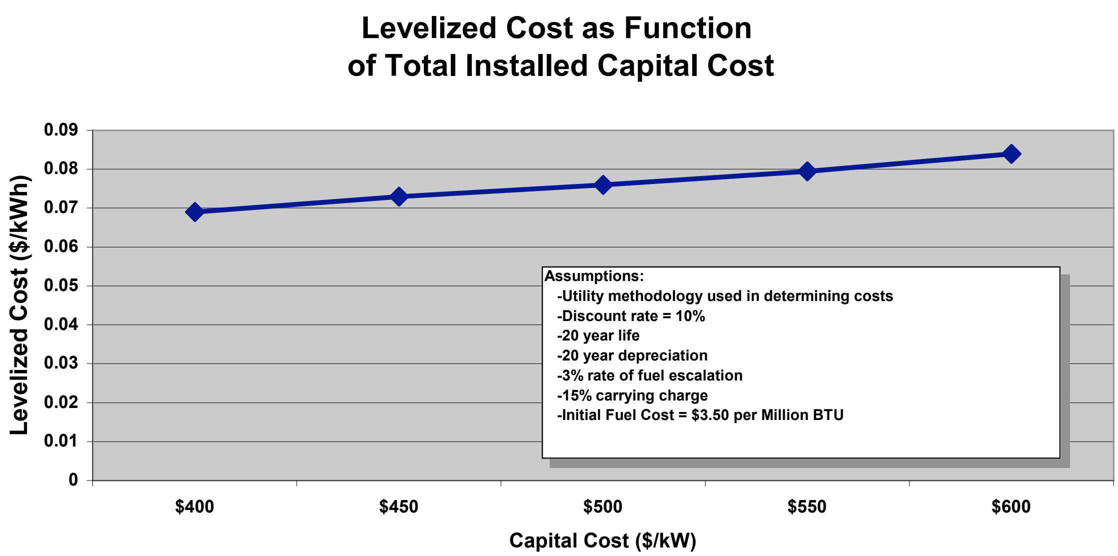

Figure 53 – Levelized Cost as Function of Total Installed Capital Cost

Figure 53 shows that only modest changes in the levelized costs occur with the change in capital costs (total Installed costs). The assumptions shown on the graph, primarily the year and depreciation schedule minimizes the impact of capital cost changes. If the unit was installed by an Independent Power Producer (IPP), the capital cost volatility could be expected to increase. This is due to the IPP requiring a quicker return on their investment and the capital cost would have an increased sensitivity than for an utility owned machine. The volatility would be based on the type of depreciation schedules used and the discount rate used by the IPP. The chart below (Figure 54) shows a modest correlation of pricing to fuel costs. As the asset is used more, i.e. a higher capacity factor, there would be no increase in the cost in $/kWh for fuel since fuel is a variable cost dependent o asset use. However, the levelized costs would be expected to go down due to lower capital amortization required.

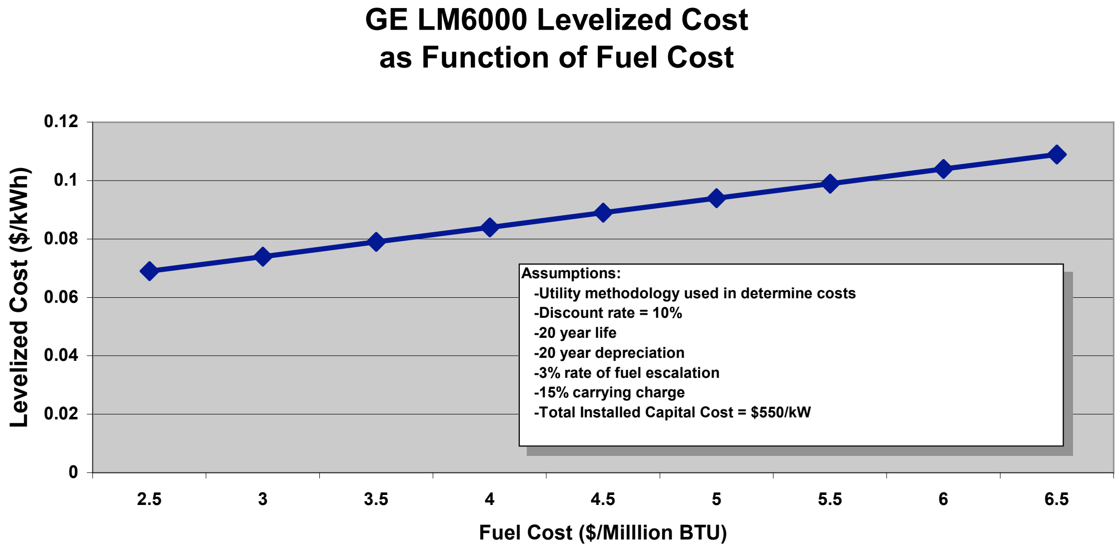

Figure 54 – GE LM6000 Levelized Cost as Function of Fuel Cost

The gas cost estimate is shown in Figure 55. At the time of the development of this price comparison, the EIA cost estimate was considered to be accurate and a common industry benchmark for gas costs. It is interesting to note that the California Energy Commission's cost estimate[33] for gas pricing and escalation is approximately the same. Given the recent stubborn resistance of natural gas to go below even $4.00 or $4.50 at the hub, it is difficult to believe that the EIA forecast or the California Energy Commission forecast are accurate; however, this analysis did not attempt to independently estimate gas pricing and forecast and leaves the estimating to those skilled in this art. For all practical purposes, gas pricing forecasts remain in the realm of uncertainty; however, for purposes of comparison, the estimates provided by the EIA are an easily accessible source of consistent information.

[33] California Energy Commission's "Natural Gas Market Assessment", August 2003

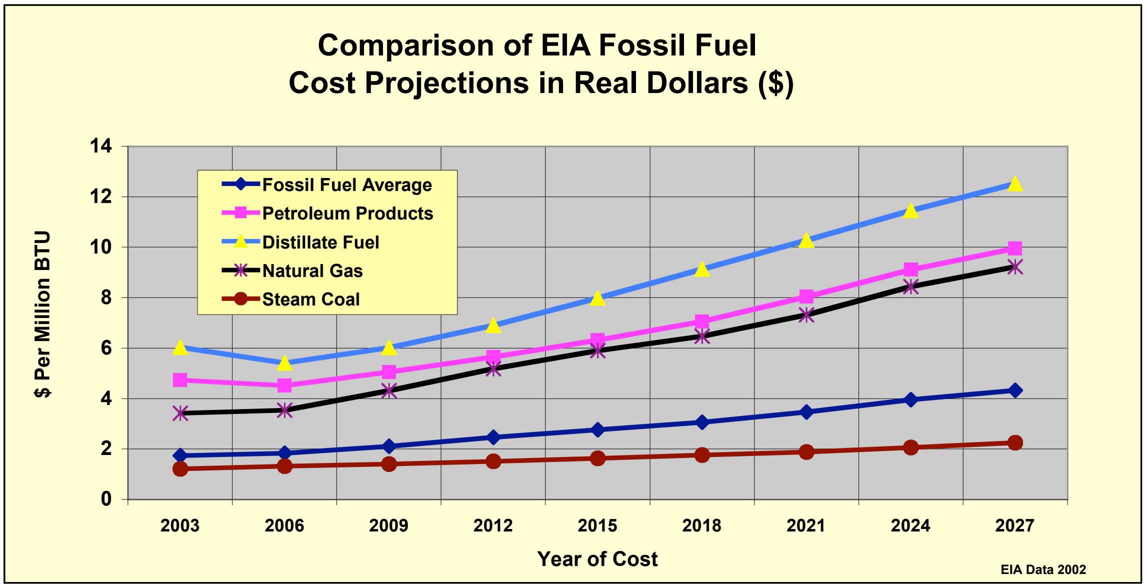

Figure 55 – Comparison of EIA Fossil Fuel Cost Projections in Real Dollars ($)

Referring back to Figure 53 and Figure 54, these charts should be construed as "idealized" graphs since the calculated costs do not include utility specific "adders". These "adders" can vary significantly from utility to utility and from project to project. Although each "adder" by itself does not necessarily result in significant changes in the "pricing proxy", in total, these adders play a very significant role in the overall pricing proxy. In order to simply this analysis, these adders were assumed to include:

- Hedging costs for natural gas procurement are sometimes difficult to identify and are specific to each IOU (estimated adjustment of $7/MWh)[34];
- Start-up and ramping rates add to fuel cost and are dependent on the type of product operation (estimated adjustment of $4/MWh);
- Environmental and mitigation costs which are site specific (estimated adjustment of $0.5 to $3/MWh- high end reflects reclaim costs if generation is located in the South Coast Air Quality Management Division);
- Ambient derates which are also site specific (estimated adjustment of $6 to $8/MWH assuming high desert location in southern California); ambient derates are due to temperature and elevation changes form the standard rating at 59F and sea level conditions;
- Gen-Tie costs to utility substation ($5/MWh); these are the costs required to connect the generation plant to the utility grid. It will normally include a substation nad may require a substantial transmission tie to the utility's substation;
- Network changes (transmission upgrades) that may be required ($6-$8/MWh); and,
- Imbalance charges that may be incurred by the plant owner/operator ($2-$4/MWh); imbalance charges result when the plant's scheduled delivery changes resulting in certain costs, primarily gas costs to be incurred by the plant's owner.

[34] San Diego Gas and Electric has estimated hedging costs of $5 to $8 per million BTU in their Opening Brief, Exhibit A, Section VI of the SB 1078 CPUC evidentiary hearings held in San Francisco June 2003

Accordingly, the costs shown in the above Figure 53 and Figure 54, when adjusted for the specific IOU adders, can be expected to be approximately $25 per MWh ($.025/kWh) higher than the idealized values when all cost considerations have been included. For example, a true cost to the IOU for a firm 25% capacity product (roughly a 5x8 "product", i.e. a contract that provides capacity and energy five days a week for 8 hours a day) would be the calculated $80/MWh (idealized value from graphs) plus the utility adjustments of, say, $25/MWh ($.025/kWh) for a total cost of $105/MWh ($.105/kWh).

Based on incremental "greenfield" pricing, the true benchmark levelized pricing for on-peak and shoulder dispatchable energy (25% capacity factor) is in the range of $105/MWH ($.105/kWh) based on using a GE LM 6000 combustion turbine.

2.9.3 Optimal Sizing to Maximize Solar Thermal Value

CSP plants are ideally suited to provide on-peak capacity and energy to summer peaking utilities. Where there is an abundance of sun and high corresponding temperatures there is also high utility load. Typically, combustion turbines (CT) provide the peaking service to satisfy load in critical summer times for those utilities that are summer peaking; CT's are also used by winter peaking utilities to satisfy winter peaks.

2.9.3.1 Determining Plant Operational Characteristics

When planning and evaluating the cost effectiveness of a power plant, the system planner ranks the plant's performance against other alternatives based on the following criteria:

- Capital costs
- Operating costs (inclusive of O&M, fuel)
- Operational limitations (e.g. ramp times, minimum load, regulation requirements, start up and shut down costs, transmission constraints, etc)

Once the plant has been sized and the type of generation selected with all operational characteristics, the expected performance is "loaded" into a system simulation program. The system simulation program then determines the operating cost of the new addition and comparison analyses can be made that show the differential operating costs between alternatives. In this manner, an evaluation of the plant's total cost effectiveness can be determined by how the plant is loaded by the system and the known capital costs.

Once the plant is built, however, the planning and economic evaluations may no longer be valid as actual and needed operation may differ from the planned operational scenario. All that matters, once the plant is built and operating, is the cost of operation, i.e. fuel, operations and maintenance.

For simplification, the method of determining the most cost effective or "best fit" technology as a function of use is illustrated in Figure 56.

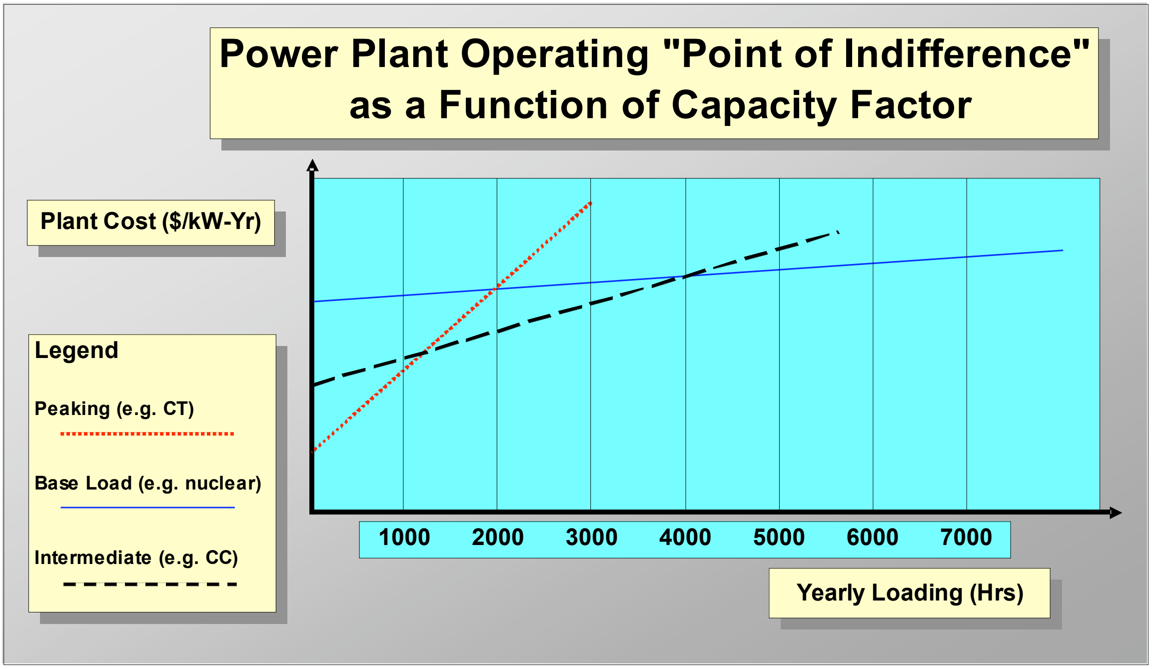

Figure 56 – Methodology of Evaluating Type of Plant vs. Operating Time

In Figure 56, the plant cost in $/kW-yr is the ordinate and the number of hours in a year the plant is used is the abscissa. There is a "Point of Indifference" that is reached when other lower capital cost generation technologies with higher operating costs are evaluated against a base load facility. For example, at approximately 2,000 hours of operation, the low capital cost peaker (combustion turbine) reaches a point of indifference with a base load facility; at approximately 1,200 hours, a point of indifference is reached with an intermediate generation facility (combined cycle). At any time period less than 1,200 hours, the combustion turbine is the most cost effective choice over a combined cycle or nuclear power plant. These points of crossover determine the type of generation planned to meet a defined system need. In similar fashion, a comparison can be made with the combined cycle. In the planned operation of a combined cycle between 1,200 and 4,000 hours, the combined cycle is shown to be the most cost effective. However, if the operational time is planned to be less than 1,200 hours, then the combustion turbine is the best choice and if the planned operational hours exceed 4,000 hours, then the nuclear plant is the best choice.

In order to fully "value" the electricity product produced by CSP plants, the "sweet spot" must be determined. In other words, at what capacity factor does solar thermal power plants produce the greatest value when compared to the fossil alternatives.

As illustrated in Figure 56, increasing the capacity factor in the fossil alternative results in substantially higher $/kW-yr due to additional fuel use and increased costs in operation and maintenance; however, the principle change in energy costs from the solar plant is the change in capital costs and the change in capital amortization on a per kWh basis resulting from a change in capacity factor.

2.9.3.2 Optimization of CSP Plant Operation

Pure solar CSP plants in Southern California, have a "natural" capacity factor somewhere around 25% to 27%. A typical set of southern California load curves served by the utilities as a function of time of day, along with corresponding energy costs of typical August and December days, is shown in Figure 57[35]. The California utilities peak in the summer and, roughly, the peaks follow the sun.

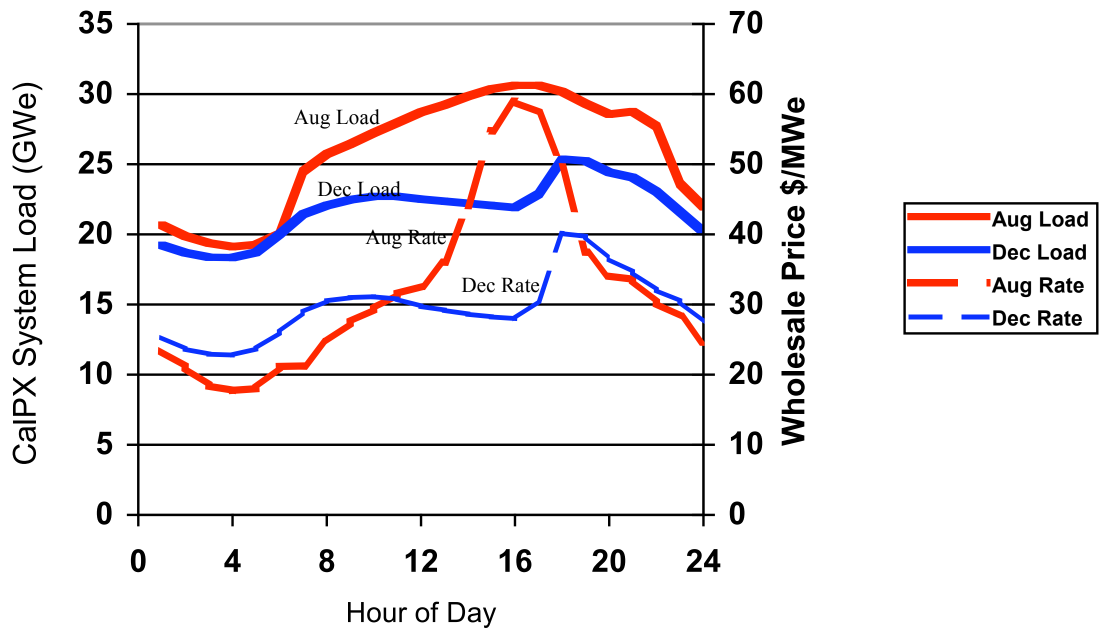

Figure 57 – Load Profiles and System Costs

It can be surmised from this graph that if a CSP plant has, for example, 100 MWh to sell into the grid, the best time from an economic perspective would be the hours between 3 pm to 5 pm in the summer, as this is the time region that returns the maximum value; the winter maxim time value would be shifted be a few hours towards the evening and would last a little longer. Assuming that the plant is needed for about 3 hours a day (about 1100 hours) on average, this correlates to a capacity factor of about 12.5%. Accordingly, the time period providing the maximum value is inconsistent with the natural solar thermal capacity factor of approximately 26% (about 2400 hours). Consequently, a CSP plant with a natural capacity factor of 26% and selling 100 MWhr into the grid is forced to sell its product at less than maximum value since it selling its product over 2400 hours and not over a 1100 hour period. Greater income would be received for the plant's product if the 100 MWhr could be sold over a shorter period.

Previous studies[36] have shown that a higher capacity solar thermal plant will have a lower levelized cost. However, studies to date have not evaluated the consequences of this lower cost

[35] Curve produced from CAISO 1999 data

[36] Sargent and Lundy "Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts", May 2003

since the CSP plant would now compete against a different product, e.g., a combined cycle. Consequently, CSP would be competing against a different pricing structure that would have a lower levelized energy cost (LEC) than a combustion turbine. However, a significant advantage of a lower LEC CSP plant operating at a higher capacity factor is the proportional increase in the value of existing subsidies; the actual dollar amount would remain the same, but the subsidy would represent a greater portion of the total costs. Accordingly, by lowering the solar thermal LEC, greater proportional subsidies will result in an improved cash flow balance as compared to higher valued and higher priced solar products with a lower capacity factor.

2.9.3.3 Determining the Pricing Proxy

The value of capacity and energy will vary over time depending on the region where it is sold and on the generation mix that serves the region. However, a generic approach to determine the optimized (maximized) value of a CSP plant is to evaluate the varying cost of a combustion turbine as a function of capacity factor and then compare these costs with a CSP plant that also has the same capacity factor. In performing this analysis, the CSP plant can be evaluated based on a variable capacity factor through the use of thermal storage to vary the hours of operation.

The same economic, financial and fuel cost assumptions described in the "Evaluation of Ownership Structure – Base Case No. 1" (see chapter 6, Section 5 Private Ownership with Conventional Financing) are used for the combustion turbine evaluation except for the following changes:

- 48 MW's with a varied capacity factor (13%, 26% and 39%) to match the analysis with the solar thermal capacity factor (see discussion below);
- Heat rate is 10,500 BTU/kWh to adjust the 41% efficiency to higher heating value, fuel gas compression requirements and ambient adjustments for elevation and temperature; and,
- O&M is $0.004/kWh.

A General Electric LM 6000 (used in the "Development of the Pricing Proxy" see Figure 53 above) was also used for this analysis. For evaluation of the combined cycle, the same economic, financial and fuel cost assumptions used in the evaluation of the combustion turbine were used except for the following changes:

- 750 MW at a capital Cost of $750/kW (total installed including owner's cost)
- Capacity factor is varied (26%, 39%, and 52%);
- Heat rate is 6,500 Btu/kW; and
- O&M is $0.006/kWh.

2.9.3.4 A Determination of CSP LEC as a Function of Capacity Factor

For the evaluation of the CSP plant and its fossil competitors, four points are evaluated for the development of the cost curves. These points correspond to capacity factors of 13%, 26%, 39% and 52%. In order to ensure an "apples to apples" comparison, each evaluated capacity factor assumes the same amount of energy produced. In other words, each case produces the same amount of energy but at different capacity factors; consequently, each case has a different capacity rating. A description of each of the four capacity factors used for the solar unit is as follows.

- The 13% capacity factor (300 MW output) requires a storage capability that equals 200% of plant energy output when compared to the 39% capacity factor option.
- The capacity factor of 26% (150 MW) assumes a solar power plant that operates corresponding to the sunlight but with storage assist to produce additional capacity.
- The 39% capacity factor (100 MW) corresponds to a solar plant that uses the 25% gas to boost capacity factor (operating time) without storage; and,
- The 52% % capacity factor (75 MW) corresponds to a solar plant that uses storage and the 25% gas to boost capacity factor (operating time) to compete against combined cycle power plants.

To be consistent, all cases assume natural gas at 25% of total heat input and the total amount of energy produced is the same in all four cases. The storage cost is based on a nitrate salt system and is extrapolated from data supplied by the SunLab evaluation for Sargent & Lundy.

The balance of plant cost differences among the four capacity factors (CF), principally the sizing of the EPGS (300 MW at 13% CF and 75 MW at 52% CF), is varied according to a 0.66 scaling factor. Basic cost component estimates are derived from the previously cited Sargent and Lundy (S&L) report. In the S&L report (page 5-21, Section 4.3) the proportional costs of the solar thermal major components are shown in Figure 58.

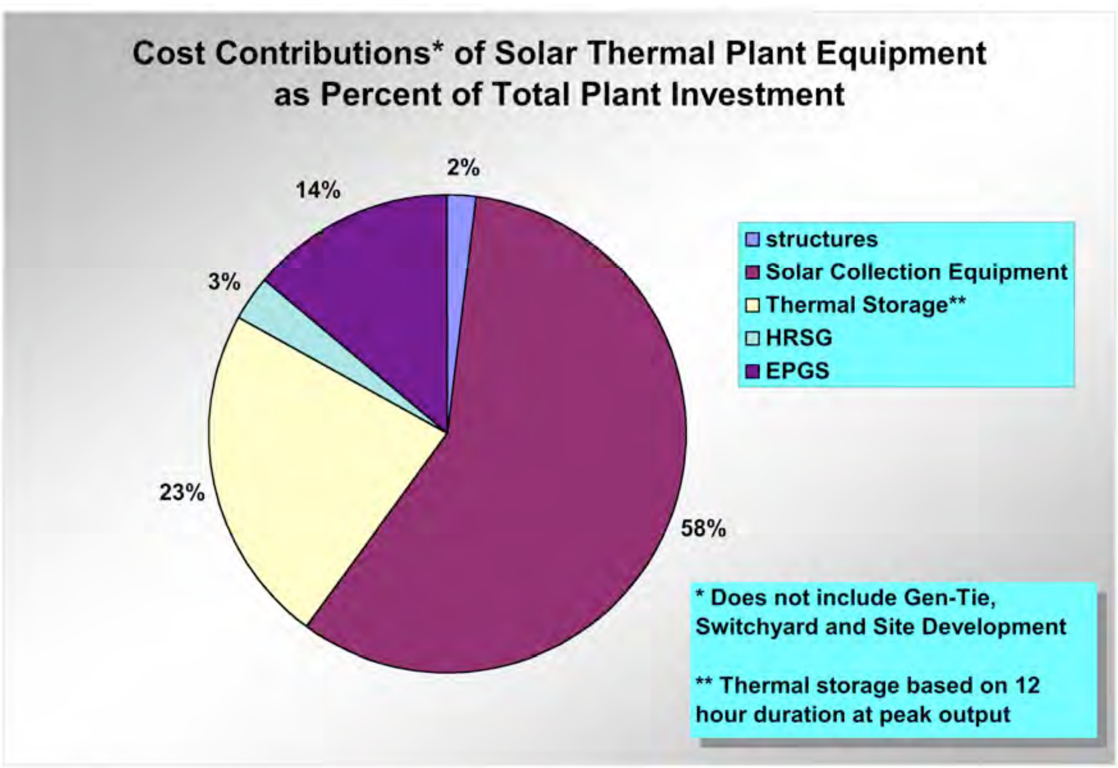

Figure 58 – Pie Chart of Solar Plant Costs

Using the percentages above and correcting for the reduced amount of thermal storage required, the changes in the EPGS sizes and costs, and adding in the requisite site related costs, a cost summary was prepared and is presented in Table 16.

Table 16 – Cost Summary

Next Generation Total Cost with Base Case of 100 MW (@39% CF) and No Storage

	Base Case - 39% CF 100 MW No Storage	300 MW - 13% CF w/ Storage	150 MW - 26%CF w/ Storage	75 MW - 52% CF w/ Storage
Structures	6,000,000	6,000,000	6,000,000	6,000,000
Solar Collectors	156,000,000	156,000,000	156,000,000	156,000,000
Thermal System	0	35,000,000	17,500,000	17,500,000
HRSG	18,000,000	37,200,000	23,500,000	16,200,000
EPS	60,000,000	124,000,000	78,400,000	54,000,000
Total $	240,000,000	358,200,000	281,400,000	249,700,000

For the base case of 39% capacity at 100 MW (no storage), a total plant cost of $240,000,000 was assumed (plus infrastructure costs of $30,000,000 for a total costs of $270,000,000). Care should be exercised in interpreting the results; the costs and economics should not be construed on an absolute basis but rather as differences among alternatives.

Figure 59 shows the cost of the two price proxies, i.e. the combustion turbine and the combined cycle, and the CSP at various capacity factors. As noted in Figure 59, the cost of CSP becomes economically competitive when compared to the combustion turbine only when compared at a very low capacity factor (~13%) with incentives/subsidies included; combined cycle at about a 38% to 44% capacity factor. Although solar also appears to be competitive against the CT at around 40% capacity factor, this is a non-realistic comparison as the combined cycle would then be the logical fossil alternative. At approximately 40% capacity factor, solar thermal appears to be about 2 cents out of the market. The small "dip" in the CSP costs shown on the graph (from ~25% to ~40% and then back up again at ~52%) is the result of not having thermal storage when the plant is sized at 39% capacity factor. In the other three capacity factors shown, thermal storage costs were incurred and were sufficiently significant to make the solar thermal plant more uneconomical when compared to the fossil alternatives (the combustion turbine and the combined cycle). The incentives for the solar thermal plant above were considered to be conservatively valued at $25/MWH (total) and essentially consisted of the production tax credit, investment tax credit and the value of a renewable energy credit.

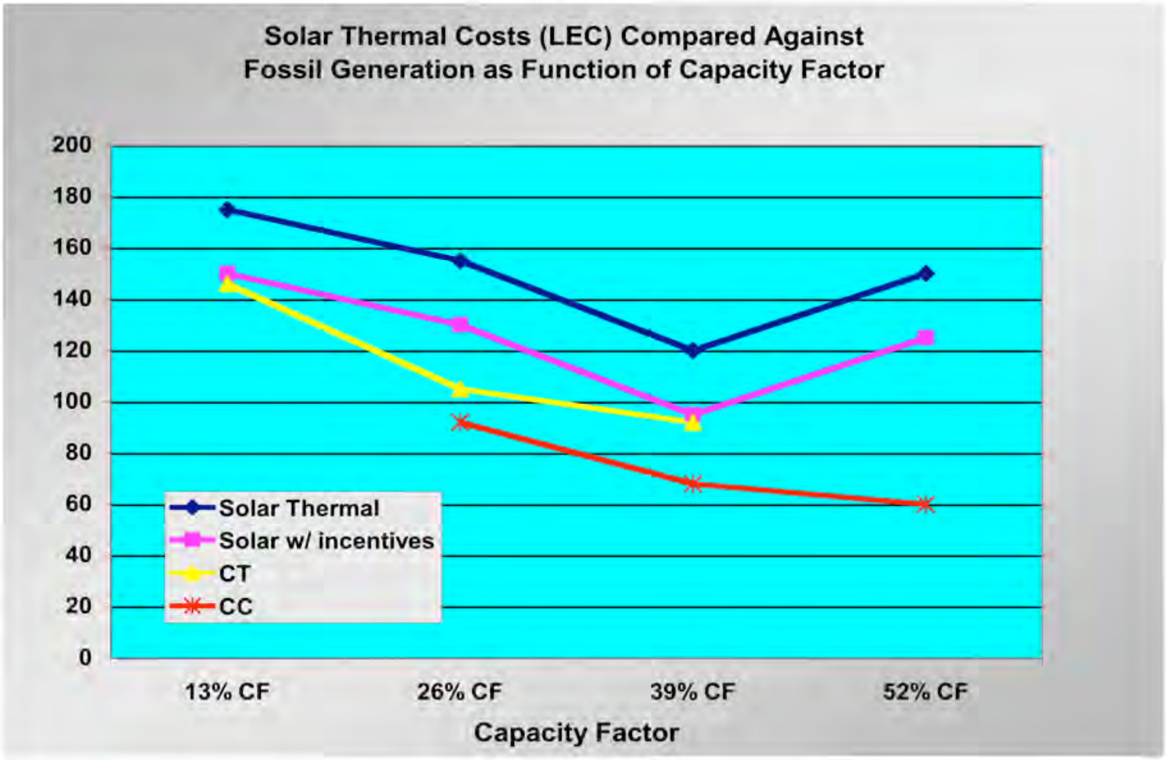

Figure 59 – Cost Variance Resulting from Capacity Factor Changes

2.9.3.5 Additional Pricing Considerations

As noted, with incentives, the CSP plant still remains slightly above the costs of the fossil competition. However, full value analysis would also result in several cost advantages to the CSP plant. Among these are:

- Property tax consideration – The high property tax generated by the CSP plant is approximately 4 times that of a comparable fossil alternative.
- Employment increases – It takes 2 or 3 times the construction labor force (local) to erect a solar plant and approximately 3 times more personnel on a MW basis to maintain the plant. These increased jobs can be of vital importance to the local economy;
- Protection from electricity price volatility – The price of the plant remains fixed and the low amount of gas used is only 25% of a comparable fossil plant. This results in price stability for the plant's product.
- Although the emission credits were assumed in the overall incentive allocation (see Figure 57), the actual credits, after establishment of a trading desk in California, could be substantial higher and actually equal the entire $25/MWH as indicated in other Renewable Energy Credit (REC) markets.

2.9.4 Conclusion and Summary

Economic incentives received by other renewable technologies, principally wind and photovoltaic, have not been applied to CSP. Wind and photovoltaic technologies have received substantial federal and state incentives in both tax relief and direct subsidy. By comparison, the CSP industry has received much less in these types of subsidies. In addition, the CSP industry and government have also spent less money on research and development compared to other generation alternatives. The combination of:

- lower subsidies and incentives compared to other technologies;
- low expenditures on research and development (both private and government); and,
- lack of large scale deployment

have resulted in CSP price reduction that have been significantly less than the alternatives. Thermal storage lowers the cost of CSP generation but, at this time, based on the projections of natural gas prices, does not appear to add value to the competitive cost of electricity in this analysis since lower price options would be available to the utilities at higher capacity factors, i.e. combined cycle. The analysis shows the most significant savings resulting from CSP plants operating at higher capacity factors is the reduction in the overall costs of the EPGS; this reduction does not appear to be cost effective when evaluated on an overall cost perspective. The cost of storage does not appear to be cost effective at current thermal storage system costs[37] and current gas estimates compared to a gas-assist option, as the natural gas fired boiler can substitute for storage to ensure capacity delivery at less cost.

As important as the CSP price is, the concept of merely lowering the LEC of CSP does not address the overall issue of cost competitiveness. The value of the product produced by CSP, when compared to other fossil alternatives, must also be taken into account. Solar, by nature, is a peaking resource and a high value product. Efforts to reduce the price by extending the capacity factor should be carefully scrutinized from an overall competitive market perspective. Given the finite limitation of fossil fuel (natural gas) and the inherent emission problems, solar thermal with storage will eventually become more competitive and, at some point, become more cost effective than using gas assisted solar thermal technology.

2.10 Draft Power Purchase Agreement[38]

2.10.1 Summary

The objective of Task 4.1.9 was to develop a draft model power purchase agreement (PPA), and its key terms, to be used for the aggregated municipal utility market. The Model Power Purchase Agreement and the related Term Sheet[39] are intended to provide a template that the municipal utilities of California can use for purchasing the electrical output of a Concentrating Solar Power plant. This Model is proposed from the perspective of the Seller, as a starting point for negotiations with one or more municipal utilities or with a consortium, such as the Northern California Power Authority or the Southern California Public Power Authority. The Model PPA presupposes the municipal utility or utilities purchase the power from a Seller that owns and operates the CSP plant. However, different ownership scenarios are possible including power plant owner ship by the Muni(s) or plant ownership by both the Muni(s) and Seller (See Task 4.1.6 Business Models Report).

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[37] Thermal storage development for trough power plants is part of the SunLab solar thermal electric R&D program, with a goal of reducing storage investment costs by a factor of 3 by about 2015.
[38] This chapter summarizes the work completed in the task 4.1.9.1 Model Power Purchase Agreement and Report, dated September 2004.
[39] The Term Sheet is Appendix C of this report.

2.10.2 Methodology

Numerous renewable energy power purchase agreements were carefully reviewed and, of those, three became the focus of this Task. These PPAs and their influence on the Model PPA is described below.

2.10.2.1 The Example PPA[40]

The first PPA reviewed was one that was proposed by an Independently Owned Utility (IOU) for the purchase of electricity from a CSP plant. This was a highly detailed PPA that raised many issues which, while perhaps appropriate in a negotiated contract, added unnecessary complications for a model agreement. These issues included a complicated pricing structure that was accompanied by complex formulas for energy and capacity payments, capacity performance factors and replacement damage amounts. These, and other issues, led us to seek out a more appropriate PPA to serve as a model that included all of the elements necessary for a CSP PPA, was less complicated, fair to both parties and allowed for greater flexibility in negotiations. This rejected Example PPA, is included in the original report as a reference. Additional comments regarding various issues the Example PPA are noted within the included text.

2.10.2.2 The WSPP Agreement[41]

The second PPA reviewed was the Western Systems Power Pool (WSPP) Agreement. According to private communication with Michael Small, the WSPP manager and attorney who drafted the agreement, over 220 members of this power pool use this contract, as do almost all of the California municipal utilities. It is a multilateral agreement, approved by the membership and filed with FERC. The non-utility members (not public IOU's or municipalities) are predominantly energy brokers. This contract is the basis for well over 10 thousand, primarily short-term, transactions. This agreement was not designed for long-term projects. There are too many changes that may occur over a 20 to 30 years period that must be covered in a long-term contract that were not dealt with when creating the WSPP contract. The longest-term use of this agreement was a 10-year contract written by Enron. This contract was for a block of power at a fixed price. It was not a "unit commitment service" that would be required for a CSP project.

Most short-term transactions in the west use the WSPP contract and then add a "Confirmation Agreement" which is a bilateral agreement that overrides some of the terms in the main agreement but does not legally amend the agreement.

Although most municipalities are comfortable with the WSPP contract, it seems that this contract has not been used for any Unit Commitment Service (e.g. for CSP) for a long term, although there in no technical reason why it could not be used for CSP projects. For the above as well as other reasons, it was decided that this Agreement was not an appropriate example for the Model PPA.

2.10.2.3 The Model PPA[42]

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[40] The Example PPA was modified from a Southern California Edison power purchase agreement.
[41] The Western Systems Power Pool Agreement issued by Michael E. Small on November 19, 2003.

The best PPA example that was found was a contract used by the Bonneville Power Administration for renewable projects and was used as the basis for the Model PPA. This Model PPA for CSP projects has been modified to conform to the technical requirements of a CSP plant and may easily be modified to allow for different ownership scenarios (single owner or aggregated ownership), various CSP technologies and different configurations of CSP plants described below. The Term Sheet for the Model PPA is Appendix C of this report and the entire Model PPA is included in the Task 4.1.9 report.

2.10.3 Contract Considerations for CSP

The Model PPA provides guidance by addressing the major contracting issues that are unique to CSP power purchase and those that are common to all power plants. These issues include CSP plant design, construction, configuration, power purchase formulas and power distribution. It should be kept in mind that, because of the large up-front cost of constructing a CSP power plant, a long term PPA of a minimum of 20-30 years is preferred. Also, unlike other PPAs, the contract is based on energy generated (i.e. number of Megawatt hours per year) and not Nominal Capacity. The Seller should provide a long-term generation production forecast based on solar radiation available by season and time-of-day using the Typical Meteorological Year (TMY) as a reference.

Each of the three possible CSP power plant configurations (solar-only, storage or hybrid) will require separate considerations. For example, the capacity factor of the plant can be greatly increased if the generating facility is able to produce power beyond the daylight hours as is the case with plants that incorporate thermal storage or hybrid capabilities. For a hybrid plant, the seller can offer guaranteed capacity and, therefore, the contract should be based on nominal capacity as well as energy.

Numerous price structures were examined. It is recommended that a series of prices for energy and capacity (in the case of storage and hybrid plants) based on time of use be determined and an annual average calculated. Once the Buyer and Seller mutually agree on an average energy price per kilowatt hour, the parties can agree to refine the payment structure for various time of use periods (by hour, day and/or by season). Because the solar radiation varies, a CSP plant is capable of producing more than the projected amount of electricity in a given year. Therefore, a separate reduced price should be negotiated for purchase of any excess energy produced by the plant. Power Purchase Agreements for hybrid plants should state a mechanism by which the price of utilized fossil fuels may be adjusted based on fluctuations in the public market.

An important consideration for the municipal utility may be the availability of additional funds to bridge the gap between the cost of CSP generated electricity and that from conventional fossil fuels. Public Goods Charge or similar funding and/or other federal and state incentives that help defray the cost of CSP may be written into the contract. For example, availability and approval of the use of Public Goods Charge or similar funding may be stated as a necessary condition precedent to the Agreement. In this way it is possible for a Buyer to contract only on the condition that certain funds or benefits are available and can be used.

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[42] The Model PPA is based on a modified version of the Power Sales Agreement used by Bonneville Power Administration for wind projects.

2.10.4 Summary of the Model Power Purchase Agreement

The Term Sheet provides a short description of key elements of the Power Purchase Agreement. The Power Purchase Agreement is divided into sections that are described below. The Term Sheet and Exhibits are considered to be a part of the Model PPA as are any additional agreements that may be required for interconnection to the grid, fossil fuel purchase for hybrid plants, etc.

The body of the Model PPA provides the template that details all of the essential elements of the contract. The introduction to the model PPA lists the Parties and their intent to sell and purchase the electric output of the CSP plant.

The Articles of the Model PPA may be summarized as follows:

- Article 1 is a list, including definitions, of contract specific terms.
- Article 2 describes the term of the Agreement.
- Article 3 references the exhibits that are incorporated into the Agreement.
- Article 4 describes the CSP power production facilities including the site, design, construction and the expected capacity and output of the plant.
- Article 5 describes the Interconnection Facilities Agreement, which should be a separate document that will be negotiated between the Seller and the Transmission System Operator and Transmission System Owner and shall include switching, metering, testing, maintenance and other procedures necessary to the successful delivery of electricity from the Seller to the Buyer. This article also describes the separate agreement(s) (Delivery Arrangements Agreement) that the Buyer will be required to enter into with the Transmission System Operator, Transmission System Owner and, perhaps, others to provide for the acceptance of the electricity generated by the Seller. The other important subject covered in this article relates to metering devices to measure the energy output and adjustments for inaccurate meters.
- Article 6 describes the obligation to sell and purchase the electricity produced by the CSP plant, the point of delivery and exceptions and exclusions to purchase.
- Article 7 describes the energy price. Two prices are listed. The first is the price of energy produced prior to the agreed Completion Date and the second is the price, after completion, for both the first 20 years of the contract (i.e., the debt period) and for the remaining years of the contract.
- Article 8 discusses billing and payment for the energy output. The billing is based on data provided by the meters. Invoicing, payment dates, late payments and billing disputes are detailed in this section.
- Article 9 describes the operation and maintenance of the facility. This includes conditions that must be satisfied prior to the facility Completion Date such as insurance, interconnection agreements, permitting, use of good utility industry practices and compliance with the model PPA. The standards for Good Utility Industry Practices are defined here as well. Standards for the maintenance of the facility, including maintenance schedules, records, reports is stated as is the creation of an Operating Committee to act on matters regarding facility operation.
- Article 10 details acts which constitute Events of Default for both the Seller and Buyer and describes Termination for Cause following an Event of Default.

- Article 11 designates who represents each Party, means of communication and record keeping requirements.
- Article 12 examines Dispute Resolution and the necessary steps required in Arbitration.
- Article 13 discusses Force Majeure events that are beyond the control of the parties.
- Article 14 discusses the Representations and Warranties of both the Seller and Buyer.
- Article 15 requires evidence of insurance from Seller both for construction of the facility and liability insurance.
- Article 16 addresses governmental jurisdiction and regulatory compliance required by each party. This section also requires Seller to make available to Buyer any personnel and records that may be required to fulfill Buyer's legal and reporting requirements.
- Article 17 states that the assignment of rights or obligations cannot be transferred without the other party's consent. The article further states that the Seller will enter into agreement with financial lenders and that automatic assignment to lender will be allowed in certain conditions.
- Article 18 describes how confidential information will be handled by and between the two parties as well as limited exceptions to confidentiality.
- Article 19 covers a variety of topics such as: waivers, the relationship of the parties, tax issues, severability and choice of law.

In addition to the Term Sheet and the Model PPA, the following Exhibits should be included:
- Facility Description
  - Map
  - Substation Diagram
- Form of Invoice
- Sample of Methodology to be used in determining the Average Annual Incremental Energy Rate

Though not included here, other provisions could be included in a contract if desired by the Buyer and the Seller. For example: a predetermined mechanism for allowing the buyer to acquire the project at any time; guarantee or payment provisions required by a lender depending on the credit quality of the buyer, etc. The model PPA presupposes the construction of a new CSP power plant, however, this model may also be adjusted to accommodate existing power plants. Adjustments are necessary where one is purchasing power from a hybrid plant that uses both solar and fossil fuels. In this case, additional capacity issues as well as pricing issues of the fossil fuel must be added to the PPA.

2.10.5 Conclusion

The benefits of renewable energy are various and important, especially as consumers and states continue their support of them. Federal and state governments continue their development and support of renewable portfolio standards and renewable energy incentives and the market for CSP continues to grow. This growth will make CSP cost competitive with conventional and other renewable energy sources. These conditions make large-scale CSP both economically feasible and an increasingly better option for power purchasers, including municipal utilities. The ability to aggregate the purchase of CSP lowers the price while it helps utilities diversify their energy portfolios and meet peak power needs.

The Model PPA is intended to help municipal utilities negotiate and purchase power from a CSP Plant. This Model PPA may be adjusted, as necessary, to accommodate different CSP technologies (trough, central receiver or dish), power combinations (solar-only, hybrid or storage) and purchase options (sole buyer or aggregated power purchases).

3.0 Project Outcomes

The cost of electricity from a CSP power plant depends on many parameters, including plant ownership, the details of such ownership, the specifics of the financing of the plant and the available incentives. The impact on the cost of electricity of five ownership/ business scenarios was investigated for a nominal 100 MW trough plant of the SEGS type. The base case was private ownership with conventional financing (the IPP model). The other ownership models explored were (1) Muni ownership, (2) Muni ownership after debt repayment, (3) Private ownership with Muni pre-paid PPA, and (4) Muni ownership of a hybrid solar-combined cycle plant.

Of the various ownership scenarios compared against the base case (#1), the most cost effective was private ownership with Muni prepayment of the PPA (#4). In this scenario, the project is conventionally financed with any and all tax incentives applied to the private ownership. After the plant is built, the Muni pre-pays for the energy to be delivered over the life of the contract. In its purest form, this scenario only requires the private owner to pay for the construction loan as the long term financing is de facto 100% Muni debt financing. This ownership is similar to the privateer owning the plant for a set period and then selling the plant, at an appropriate time, to the Muni. The next most cost effective scenario is simply straight ownership by the Muni (#3). These ownership scenarios allow an energy cost reduction from the IPP conventional financing of approximately 35% to 40% for scenario #4 (Muni pre-payment) and approximately 30% to 35% for scenario #3 (Muni ownership).

The LCOE also depends on the investment cost of the CSP plant, which can be lowered by building larger plants, building more of them, and by incorporating technology improvements. Taken together, it is expected that the LCOE will reach 7 c/kWh after an additional 1000 MW of CSP capacity is installed. This will drop the cost of electricity below that of a new combustion turbine.

Incentives are offered to cover and reimburse the developer for the variety of benefits from the greater use of renewable energy technologies. Currently the incentives available for CSP plants include the federal 10% investment tax credit (ITC) and the federal accelerated depreciation credit plus any applicable state credits. The 1.8 c/kWh production tax credit (PTC) that was granted last year is "either/or" with the 10% ITC, which makes it irrelevant from a practical view. There are currently no California state incentives for Muni-owned CSP plants, or for CSP plants whose power is purchased by Muni's above the normal Muni tax exemptions.

4.0 Conclusions and Recommendations

4.1 Conclusions

The direct normal solar radiation in specific areas in southern California is large enough to generate thousands of GW using CSP technology. Although currently limited by transmission availability, this still represents a very large and attractive resource for the California Muni's. Trough technology is proven and commercial, but its current cost makes selection difficult for the cost-conscious Muni's; however, as the cost of natural gas continues to rise and fluctuate significantly, and as the costs of CSP technologies fall, Muni's may find that now is the time to include CSP in their renewable energy portfolio. When the added costs of future fuel price volatility and environmental regulations are considered, the near-term costs of CSP appear close to fossil-fueled alternatives. Furthermore, the long-term trend suggests a crossover between CSP and fossil-fueled generation costs within about 5 to 10 years.

Opportunities are certain to be created by the growing interest of the California independently owned utilities in CSP, as well as the interest embodied in the Western Governors' Association 1000 MW CSP Initiative. Taken together, the California Muni's should find a growing number of opportunities to own or contract for CSP generated power.

4.2 Recommendations and Benefits to California

CSP power plants can only be built on land that is un-used for any other activity, that receives a high-level of direct solar radiation and that has a slope of about 1% or less. Taking this into account, if just the area in California with the very best direct normal solar radiation (that greater than 8 $kWh/m^2/day$) is considered, 6,731 MW could be deployed. If a slightly lower, but still very good solar radiation level of 7 $kWh/m^2/day$ is used, this potential increases more that a hundred-fold to 742,305 MW. From the viewpoint of raw potential, California has ample land to produce as much electricity from CSP as needed to fulfill its current and future energy needs. The current voluntary Muni renewable portfolio standards could provide the stimulus to tap this potential, provided the cost issues can be resolved.

Development of the state's solar energy resource will bring significant economic benefits to the state. While not quantified yet for California, economic impact studies performed in New Mexico have shown, for example, that building 500 MW CSP in that state adds $2.25 billion to the state's economy, increases the states tax revenues by $1.23 billion and adds 1,696 construction and 397 permanent jobs. Given California's greater economy and greater solar resource, the economic impact will be significantly greater. CSP provides firm dispatchable power which can help meet the states summer peaking needed and peak reserve margins. While clearly the "best fit" renewable options for peak power, the future will likely show that CSP power is the lowest cost option as well.

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Appendix A
Project 4.1 Task List

The separate Tasks to accomplish the objectives of the 4.1 Solar Thermal Parabolic Trough Power Plant Project were:

Task 4.1.1	Seminars and Site Visits
Task 4.1.2	Data Collection and Assessment
Task 4.1.3	Potential Plant Site Evaluation
Task 4.1.4	Pre-Feasibility Studies
Task 4.1.5	Determine Site Needs
Task 4.1.6	Business Models
Task 4.1.7	Incentives Report
Task 4.1.8	Financial Feasibility Study
Task 4.1.9	Draft Power Purchase Agreement
Task 4.1.10	Final Project Report

Appendix B
Table of Incentives for CSP

PROGRAM TITLE	INCENTIVE TYPE	APPROVED SECTORS	EFFECTIVE DATES	SUMMARY	CONTACT
Federal Incentives					
Federal Investment Tax Credit for Commercial Solar Energy Property	Tax Incentive	Commercial	1992 – permanent	10% investment tax credit for investment or purchase. No public utility property.	IRS and MDV-SEIA
Modified Accelerated Cost Recovery System (MACRS)	Tax Incentive	Commercial		Can recover investment in property through depreciation deductions. 5 year term. Same eligibility standards as 10% tax credit.	IRS
Federal Tax Exemption for Nontaxable Energy Grants or Subsidized Energy Financing	Tax Incentive	Energy producers		Federal tax-exemption for subsidized energy financing and energy grants from federal, state and local organizations. Main purpose of grant/financing must be conservation or energy production.	IRS
Renewable Energy Production Incentive (REPI) [Pending]	Production Incentive	Muni State & city owned and non- profit energy producers	1993-2003 (should be reintroduced in next energy bill)	Financial incentive payment for producers of renewable energy and sellers.	US DOE EERE IRS
Production Tax Credit [Pending]	Production Incentive		Pending energy bill	New energy bill extends the PTC to solar but can't be used with ITC. 1.8 cents per kWh for five years.	
State of California Incentives					
CA Property Tax Exemption for Solar Systems	Property Tax Exemption	Commercial, Industrial, Residential	1/1/99-1/1/06	CA tax code, section 73 – when assessing property for prop tax purposes, active solar systems are not subject to property taxes	Tax specialist – CA Franchise Tax Bd. 800-852-5711 www.ftb.ca.gov http://www.dsireusa.org
CA Renewables Portfolio Standard	RPS	IOUs, later: ESPs and CCAs. Muni's implement themselves on a voluntary basis	1/1/03 -	From legislation SB1078. Requires retail sellers of elec. to purchase 20% from renewables by 2017. Increase 1% per year. Allocate & award supplemental energy payments to eligible renewables to cover above-market costs.	Heather Raitt, California Energy Commission 916-654-4735 hraitt@energy.state.ca.us www.energy.ca.gov/portfolio/index.html
CA Energy Action Plan and Energy Resource Investment Plan	Accelerates RPS targets, financing plans	Same as RPS	2003 -	Agencies plans accelerate the RPS from 2017 to 2010. Plans to help with financing and with transmission and	California Energy Commission, CPA, PUC www.energy.ca.

				distribution infrastructure.	gov/2003_energy_action_plan/ www.capowerauthority.ca.gov/EnergyResourceInvestmentPlan/default.htm
State of Nevada Incentives					
NV Renewable Portfolio Standard	RPS	IOUs	1997 – 2001 – 2013 -	Utilities must derive a minimum % of total electricity from renewables. In 2001 minimum amts to increase by 2% every two years. Starting with 5% requirement in 2003 (15% by 2013). At least 5% solar . Temp provision allows buying/selling of renewable energy credits	Mark Harris 775-687-6065 mpharris@puc.state.nv.us or Anne-Marie Bellard 775-687-6035 abellard@puc.state.nv.us www.puc.state.nv.us
NV Renewable Energy Credits Program	Production Incentive	Commercial, Industrial, Gov't, Muni, Retail, etc.	Permanent rules currently being developed	1 kWh = 1 REC to be sold to utilities trying to meet RPS.	Same as NV RPS
State of Arizona Incentives					
AZ Environmental Porfolio Standard	RPS	Utilities	2001 – 2012 a	Regulated utilities must a % of renewable energy. Started at 0.2% in 2001 and will top out at 1.1% 2007-2012. 60% solar requirement 2004-2012	Ray Williamson 602-542-0828 rwilliamson@cc.state.az.us www.cc.state.az.us
State of New Mexico Incentives					
NM Renewable Energy Production Tax Credit	Tax Incentive	Energy generator and seller of >10 MW capacity located in NM	2002 -	Tax credit of $0.01 kWh applies to corporate income tax. For first 400,000 MWh of electricity for 10 consecutive years. Energy generators cannot exceed 2 million MWh of production annually.	Harold Trujillo 505-827-7804 hjtrujillo@state.nm.us www.emnrd.state.nm.us/ecmd
NM Renewables Portfolio Standard	RPS		2003 – 2011 and on.	RPS of 10% by 2011. Uses certificates. Favors solar. Also requires voluntary green pricing program.	John Curl 505-827-6960 john.curl@state.nm.us www.nmprc.state.nm.us

Appendix C
Term Sheet for the Model PPA

TERM SHEET
FOR THE
CONCENTRATING SOLAR POWER
MODEL POWER PURCHASE AGREEMENT

BETWEEN

[SELLER]
AND

[BUYER]

This term sheet summarizes the principal terms with respect to a potential transaction between (the "Buyer ") and (the "Seller"). This term sheet is intended solely as a basis for further discussion and is not intended to be and does not constitute a legally binding obligation. No legally binding obligations will be created, implied, or inferred until a document in final form is executed and delivered by all parties. Without limiting the generality of the foregoing, it is the parties intent that, until that event, no agreement shall exist among them and there shall be no obligations whatsoever based on such things as extended negotiations, "handshakes," oral understandings, or courses of conduct (including reliance and changes of position).

Description	The Seller plans to construct, own and operate a Facility that generates electricity via direct solar radiation captured in an array of concentrating solar collectors. The Facility will consist of a generating plant (consisting of concentration solar collectors, heat exchangers(s), steam turbine(s), generator(s), step-up transformer(s), a control room and electrical safety and disconnect devices). In addition, the Facility will include an Interconnection Facility that will deliver the electric energy at the appropriate voltage to a Grid (transmission line). The Facility will be located in (city), (state).
Interconnection Facility	Interconnection Facility is the power line interconnecting the generation plant to the Grid. The Seller will have the sole responsibility to arrange with both the Transmission Owner and Transmission Operator for the necessary, studies, engineering, construction, acquisition of Rights of Way and easements and delivery of energy onto the Grid.
Delivery Location	Energy will be delivered onto the transmission line located between (substation) and (substation). The Buyer will have the responsibility to transport energy to his customers at his cost.
Metering	Metering will occur at the Delivery Location. Meters will be owned, installed, operated and maintained by Seller and will meet all technical and reliability requirements of the

	Transmission Operator and Transmission Owner. Metering will be in kilowatt-hours and will incorporate recording devices. Buyers may also want to install their own metering devices at the Delivery Location.
Product sold	The Facility is selling energy only (no ancillary services such as spinning reserve, reactive power, black starting, etc.). Buyer will be responsible to purchase all energy generated from Facility except during Emergencies and in cases of Force Majeure. All environmental attributes that exist or may exist in the future (excluding Renewable Energy Certificate's) will remain with the Seller.
Energy	The Facility will sell energy measured in kilowatt-hours (kWh).
- Capacity	The Facility is capable of generating kilowatts of energy for one hour assuming the design level of solar radiation is available.
- Average Annual Output	The expected total generation per year based on historical solar radiation is kWhs per year.
- Maximum Annual Output	The maximum total generation per year based on historical solar radiation is kWhs per year.
- Minimum Annual Output	The minimum total generation per year based on historical solar radiation is kWhs per year.
- Availability Factor	The Facility will take the equipment risk and will guarantee an Availability Factor of 80%. This will be based on the percent of hours the Facility is available to produce energy during a year.
Term	The contract will remain in effect for 30 years.
- Completion Date	The Term of the contract begins at the Completion Date. Completion Date occurs after Commercial Operations Date has occurred, all perfunctory testing and regulatory compliances have been met and testing proves that the plant is capable of generating the entire Capacity.
- Commercial Operation Date	Commercial Operations Date will occur no later than . This is when the Seller first starts delivering energy onto the grid based on Good Utility Industry Practices.
- Proviso for delayed Commercial Operation date	Excluding delays resulting from Force Majeure, the Seller will be giving up to an extra year to meet the Commercial Operation Date but will accept a 2% lower price.
Energy Pricing - first 20 years	The Average Annual Energy Price during each year will consist of the sum of two components. The first component is fixed at $/kWh. The second component starts out at $/kWh and annually escalates with inflation as indexed by GPDID.
Energy Pricing - last 10 years	The price received for energy will be 100% of the Wholesale Spot Market Price for each hour of generation.
- Breakdown by Time-of-Day &	The Buyer will have the right to break down the Average Annual Energy price in up to 4 different time-of-day increments

Season	and up to 3 seasonal adjustments such that the expected annual revenue to be received by the Seller does not change.
- Energy Pricing before Commercial Operations Date	For energy delivered onto the Grid before the Commercial Operating Date, the Seller shall receive a payment based on 90% of the Average Annual Energy Rate.
- Payment for Excess Energy	If the Seller delivers more than the Maximum Annual Output for any one year period, the Buyer can request a refund to be paid by the Seller that equals the amount of excess energy delivered times the difference between what was actually paid and the Wholesale Spot Market Price.
- Refund if less than guaranteed Availability Factor	The prices paid for future energy will be decreased by 5% if the average Availability Factor is not achieved. This will last until the average Availability Factor exceeds the guarantee.
Billing	Seller will issue monthly bills and seller will pay within 30 days or be subject to late fees.
Meteorological Solar Data	Meteorological Solar Data will be recorded and used in determining the breakdown of time-of-day and seasonal energy rates and for capacity testing. The historical data and future data will be measured by an agency of the National Renewable Energy Laboratory. The weather station used for measuring will be located at . The solar radiation will be measured in terms of kWh/m2 and will be recorded on a direct beam, one-axis tracking parabolic trough with east-west horizontal axis using a Normal Incidence Pyrheliometer (NIP) or equivalent.
<u>Representations and Warranties</u>	Both the Seller and Buyer will make similar representations and warrantees as to the organizational structure, legal and regulatory rights to enter and perform under this Agreement.
Insurance & Indemnification	Seller will be obligated to maintain the appropriate insurance throughout the term of the contract with the Buyer as a named insured. Insurance shall consist of general liability insurance of no less $5 million per incident plus all-risk property insurance for the entire Facility. Each party will provide the appropriate indemnification to the other party.
Disputes	Most disputes will be resolved by predetermined arbitration procedures although Seller reserves the right to seek judicial resolution for certain conditions such as terminating the contract without cause.
Event of Default by Buyer	No cure period will be given to Buyer if they liquidate, assign assets to creditors or fail to purchase all the energy. A 90 day cure period will be given to Buyer if they assign the agreement without prior approval, cause energy not be able to be put on the Grid and failure to make payments. If Default is not cured in the time period, the Seller can terminate the Agreement.
Event of Default by Seller	No cure period will be given to Seller if Completion Date is not met after extension period, company is liquidated or construction is abandoned. A 90 day cure period will be given

	if bankruptcy occurs, tampering of meter occurs, power is sold to anyone other than Buyer without prior permission, failure to maintain key agreements and permits. If default is not cured in the time period, the Buyer can terminate the Agreement.
Confidentiality	Buyer and Seller will maintain the confidentiality of this term sheet, the terms and payments of the final agreement and any other specified information. Special steps will be take if and when information is required to be shared with regulatory agencies or legal institutions