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SUMMARY OF THE SOLAR TWO TEST AND EVALUATION PROGRAM

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Abstract - Solar Two was a collaborative, cost-shared project between eleven U. S. industry and utility partners and the U. S. Department of Energy to validate molten-salt power tower technology. The Solar Two plant, located east of Barstow, CA, was comprised of 1926 heliostats, a receiver, a thermal storage system and a steam generation system. Molten nitrate salt was used as the heat transfer fluid and storage media. The steam generator powered a 10 MWe, conventional Rankine cycle turbine. Solar Two operated from June 1996 to April 1999. The major objective of the test and evaluation phase of the project was to validate the technical characteristics of a molten salt power tower. This paper describes the significant results from the test and evaluation activities.

1. PROJECT BACKGROUND

The 10-MWe Solar One Pilot Plant, which operated from 1982 to 1988 near Barstow, California, was the largest demonstration of first-generation power-tower technology (Radosevich, 1988). During operation of Solar One and after its shutdown, significant progress was made in the United States on more advanced, second-generation power tower designs. The primary difference between first- and second-generation systems is the choice of receiver heat-transfer fluid: Solar One used water/steam, while the second-generation systems in the U. S. used molten nitrate salt.

U. S. industries currently prefer molten-salt power towers because the design decouples solar collection from electricity generation better than water/steam systems, and it allows the incorporation of a cost-effective energy storage system. Energy storage allows the solar electricity to be dispatched to the utility grid when the power is needed most, increasing the economic value of solar energy. A team composed of utilities, private industry, and government agencies joined together to demonstrate molten-salt power towers at the 10-MWe Solar Two plant, which was constructed by retrofitting Solar One with new molten-salt systems.

Converting Solar One to Solar Two required a new molten-salt heat transfer system (including the receiver, thermal storage, piping, and a steam generator) and a new control system. The Solar One heliostat field, the tower, and the turbine/generator required only minimal modifications. A schematic of the plant is shown in Figure 1.

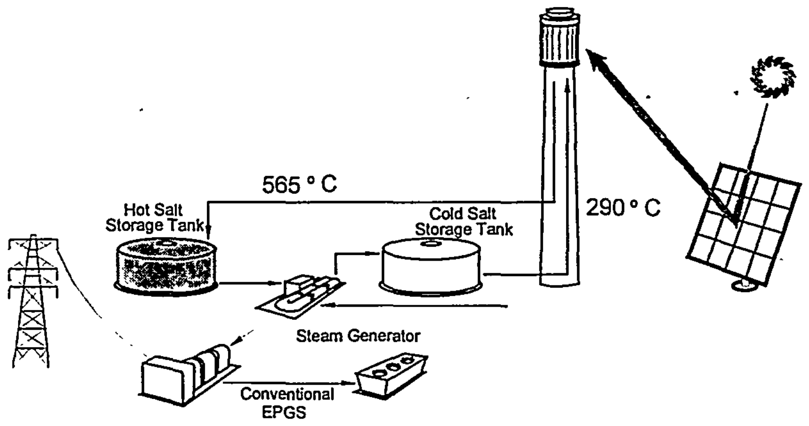

Fig. 1: Schematic of a molten-salt power plant. Molten salt is pumped from the cold tank, heated to 565°C in the receiver, and flows to the hot storage tank where it can be used to make steam. After making steam, molten salt at 290°C is returned to the cold tank to be pumped back to the receiver.

DISCLAIMER

Table 1: Design Ratings and Description of Major Systems

Major System	Design Rating	Description
Heliostat Field	48 MW_t incident on receiver	1818 original Martin Marietta (39.1 m^2 each) plus 108 Lugos (95 m^2 each)
Molten Salt Receiver	42 MW_t absorbed by nitrate salt	24 panels arranged in a cylinder, 5.1 m diameter by 6.2 m high
Thermal Storage	107 MWh thermal capacity	1400 tonnes nitrate salt; stainless steel hot tank: 11.6 m diameter by 8.4 m tall; carbon steel cold tank: 11.6 m diameter by 7.8 m tall; hot pump sump and cold pump sump.
Steam Generator	35.5 MWt (100 bar steam at 538°C)	Salt-in-shell superheater; salt-in-tube kettle boiler; salt-in-shell preheater
Electric Power Generation	12.0 MWe gross, 10.4 MWe net	Non-reheat Rankine cycle turbine, 100 bar, 510 °C

The Bechtel Group, Inc. designed and constructed the new salt system. They developed the plant layout, sized much of the salt handling equipment, and developed specifications for the receiver, storage tanks, steam generation system, and the master control system (Kelly and Singh, 1995). The design was based on experience gained from molten-salt receiver and system experiments conducted at Sandia National Laboratories' National Solar Thermal Test Facility (Smith and Chavez, 1992). Bechtel also installed all of the salt piping (except piping in the receiver system), pumps, sumps, instrumentation and controls. In addition, Bechtel was responsible for plant start-up and acceptance testing. The major Solar Two systems are described in the section that follows and are summarized in Table 1.

2. SYSTEM DESCRIPTION

The Solar Two receiver was designed and built by Rocketdyne (now part of The Boeing Company). It was rated to absorb 42 MW of thermal energy at an average solar energy flux of 430 kW/m^2, while accommodating peak fluxes up to 800kW/m^2. The receiver consisted of 24 panels forming a cylindrical shell around internal piping, instrumentation, and salt holding vessels. Each panel consisted of 32 thin-walled, stainless steel tubes connected on either end by flow-distributing manifolds called headers. The external surfaces of the tubes were coated with a black Pyromark paint that was resistant to high temperatures and thermal cycling, and absorbed 95% of the incident sunlight. The receiver was designed to change temperature rapidly without being damaged. For example, during a cloud passage, the receiver could safely change from 565 to 290 °C in less than one minute (Kolb and Saluta, 1999). The salt fed to the receiver was split into two flow circuits.

The thermal storage tanks were fabricated on-site by Pitt-Des Moines. All pipes, valves, and vessels for hot salt were constructed from stainless steel because of its corrosion resistance in molten-salt at 565 °C. Lower cost carbon steel was used for cold-salt containment because of the salt's lower corrosivity at 290 °C. Solar Two was designed with a minimum number of gasketed flanges; most instrument transducers, valves, and fittings were welded in place to minimize salt leaks.

The thermal storage medium consisted of nitrate salt composed of 60 wt% $NaNO_3$ and 40 wt% KNO_3, provided by Chilean Nitrate Corporation (New York). This salt melted at 220 °C and was thermally stable to about 600 °C.

ABB Lummus designed the steam generation system (SGS). It consisted of shell-and-tube super- and pre-heaters and a kettle evaporator. Stainless steel cantilever pumps transported salt from the hot sump through the SGS to the cold tank. Salt in the cold tank flowed to the cold sump and was pumped with multi-stage turbine pumps up the tower to the receiver.

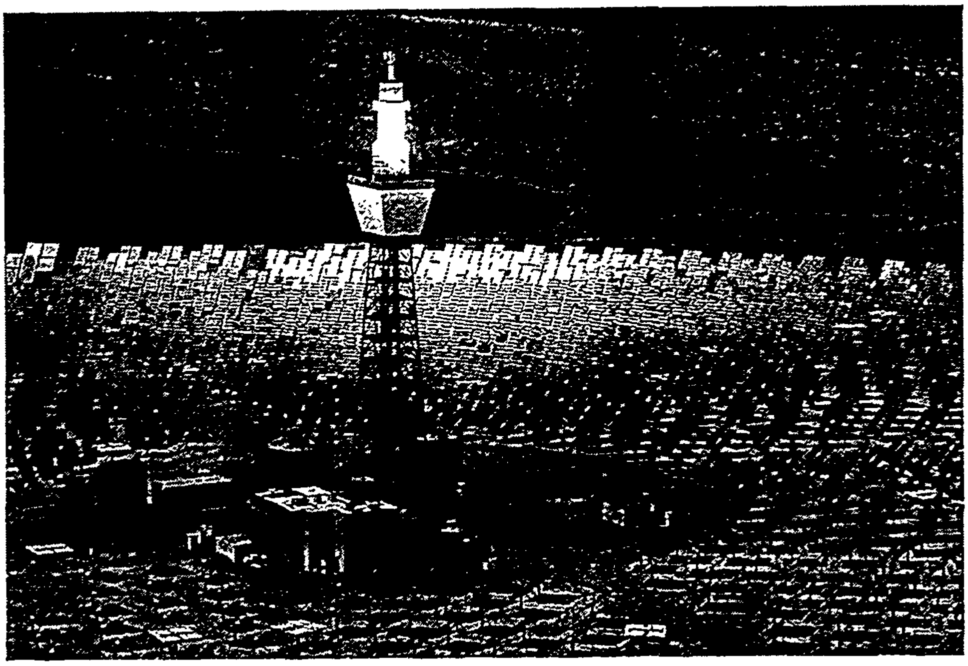

Fig. 2. Photograph of the 10 MWe Solar Two power plant in operation.

The Rankine-cycle turbine was refurbished from the Solar One project. It was rated for 12.4 MWe gross generation. It accepted steam from the steam generator at 100 bar and 510 °C.

The original 1818 Martin Marietta heliostats from Solar One were reused, with the inner 17 rows of heliostats refocused for the smaller Solar Two receiver. The area of each of these heliostats was 39.1 m^2. Damaged or missing facets on these heliostats were replaced with mirrors from a defunct photovoltaic power plant. Also, 108 large-area (95 m^2) Lugo heliostats (so named because many of their parts were salvaged from the defunct Lugo photovoltaic plant) were added to the south part of the field to improve the flux profile of the receiver. Figure 2 is a photograph of the Solar Two plant in operation.

3. TESTS AND EVALUATIONS RESULTS

The objectives of the Solar Two Test and Evaluation (T&E) program were to gather data and information, and perform analyses to:

1. Validate the technical characteristics (reliability, annual net electric performance, environmental impact, and capability for dispatch) of the nitrate salt receiver, storage system, and steam generator technologies.
2. Improve the accuracy of economic projections for commercial projects by increasing the database of capital, operating, and maintenance costs.
3. Distribute information to U.S. utilities and the solar industry to foster wider interest in the first commercial plants.

Originally, the T&E program was planned to run for a period of one year after final plant acceptance (Bechtel, 1995). During this period, the entire plant and the operations and maintenance (O&M) crew were to be devoted exclusively to T&E with no emphasis on power production goals. However, the startup and acceptance phase of the project took much longer than expected – nearly 2½ years, with the plant being turned over to the operating and maintenance company in mid-February 1998 (Reilly, Pacheco, 2000). Consequently, the T&E phase was integrated into the power production phase and reorganized. Special tests that required the plant to be in a non-

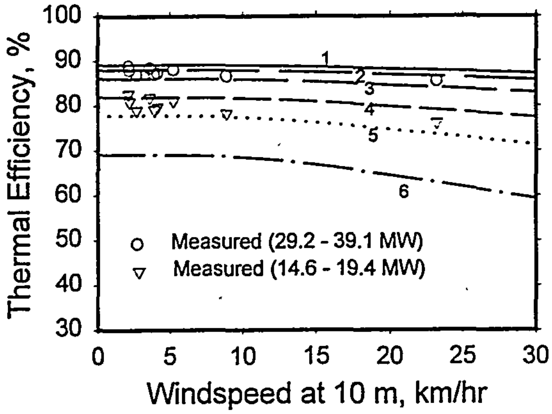

Fig. 3: Measured and modeled (lines) receiver efficiency as a function of wind speed and incident power. Line numbering refers to: 1) 48.6 MW (design), 2) 40 MW, 3) 30 MW, 4) 20 MW, 5) 15 MW, 6) 10 MW.

standard configuration were accommodated during power production. Because of the compressed project schedule, the test plan was revised, with some tests eliminated and others combined or re-scoped to fit into the new objectives. The following sections describe results from tests on the receiver efficiency, steam generation and electric power generation system characterization, thermal storage, dispatchability, and plant performance. The primary objectives of these tests were to characterize each major subsystem relative to design predictions and to characterize the overall plant performance.

3.1 Receiver Efficiency Test

The primary objective of the receiver efficiency test was to map the receiver efficiency as a function of operating temperature and wind speed. The receiver efficiency, η, is defined as the ratio of the average power absorbed by the working fluid, P_{abs}, to the average power incident on the receiver, P_{inc}, evaluated over a defined period under steady-state conditions.

Since the incident power cannot be measured directly on this size of receiver, the efficiency has to be obtained by eliminating incident power from the heat balance equation and by estimating the thermal losses from other measurements. The power-on method was designed for this type of measurement (Baker, 1988).

The heliostat field was divided into two groups of equal numbers of heliostats, symmetrically dispersed about the receiver. Group 1 contained every other heliostat. Group 2 contained the heliostats not in Group 1. The test was conducted symmetrically about solar noon between 11:00 AM and 1:00 PM solar time to minimize cosine effects on the heliostat field. By dividing the heliostat field into two symmetric groups, the power on the receiver can be halved independent of field cleanliness, mirror corrosion, and (to some extent) heliostat availability.

The receiver was operated at full power (both groups) with the outlet temperature fixed (e.g., 565°C ±14°C) during period A, which ran between 11:00 AM and 11:30 AM (solar time). Then, for period B, which ran between 11:30 AM and 12:00 PM, group 2 heliostats (half the field) were removed (put in standby) and the flow was adjusted so the same outlet temperature was achieved. At 12:00 PM, period C started. The flow was increased and the full field tracked the receiver again. The flow rate was again adjusted to maintain the same outlet temperature as for the previous periods. At 12:30 PM, period D began. Group 1 heliostats were removed. Again, the flow rate was adjusted to maintain the desired salt outlet temperature. The test ended at 1:00 PM.

The power-on method of determining efficiency is based on following assumption: under steady-state conditions with constant inlet and outlet salt temperatures and wind velocities, the temperature distributions on the receiver surface and throughout the receiver were independent of power level. Therefore, the thermal losses, $L_{thermal}$, were independent of the incident power and were a function of the absorbed power.

With constant thermal losses, the thermal loss was found by eliminating the incident power from the heat balance equation and determined only in terms of the absorbed power and receiver measured absorptivity, α. The efficiency can be expressed as in Eq. 1.

$$\eta = \frac{\overline{P}_{abs}}{\overline{P}_{inc}} = \frac{\overline{P}_{abs}}{\dfrac{\overline{P}_{abs} + \overline{L}_{thermal}}{\alpha}} = \frac{\alpha}{1 + \dfrac{\overline{L}_{thermal}}{\overline{P}_{abs}}} \tag{1}$$

On September 29, 30, and October 1, 1997, the power-on method was used to measure receiver efficiency during low wind speeds (≤3.0 km/h). The same method was used in March 1999 to measure efficiency in higher wind conditions. For the first set of tests (low wind speeds), the outlet salt temperature was set to 552 °C instead of 565 °C because there was some concern that the outlet temperature would overshoot the set point when the receiver went through a severe transient. However, the control system responded well and did not overshoot its set point. The higher wind speeds efficiency tests were conducted with an outlet temperature of 565 °C. At full power, the receiver efficiency was measured to be a weak function of wind velocity, being 88% with low wind velocities and 86% in high wind speeds. These data agree well with results from the calculated (modeled) efficiency at low wind speeds as shown in Figure 3. At higher wind speeds, the measured efficiencies were actually slightly higher than predicted.

One significant issue with the receiver was the difficulty in filling it with salt in windy conditions. To avoid freezing salt in the receiver during start-up, the receiver operating procedures called for warm-up of the receiver, using portions of the heliostat field, to bring the tubes close to the salt freezing temperature (about 220°C) prior to initiating salt flow. Those portions of the receiver not exposed to the field were heated with electric heat tracing. Because of a simple design flaw in the receiver, one small region of the tubes was difficult to heat, especially in windy conditions when losses were highest, and would occasionally cause salt freezing in a short portion of tube. This would delay plant operation (in the worst cases, for several hours) until the salt plugs would melt. The impact on daily energy collection is discussed later with overall plant performance. Although a long-term fix for the Solar Two receiver was not possible, the design flaw is well understood and easily corrected in the next receiver.

3.2 Steam Generation / Electric Power Generation System Characterization

The purpose of the Steam Generation / EPGS Characterization Test was to measure the steam generation system (SGS) and electric power generation system (EPGS) performance over a range of power loads and two inlet salt temperatures. Testing was done under steady-state conditions where the unit was held at the required conditions for a minimum of two hours, but typically three to eight hours. For the steady state operations test, the SGS and the EPGS were operated together to measure the gross thermal conversion efficiency at the various loading conditions.

We were not able to achieve the desired 565 °C salt at the inlet to the steam generator because, in addition to thermal losses, some of the molten salt valves in the receiver and steam generation system leaked, causing cold salt to be mixed with hot salt. Salt entering the steam generator was thus typically 14 to 27 °C cooler than design. This problem would be resolved in future designs by using gate valves. This, however, has only a minor impact on the gross output of the SGS/EPGS as shown by the gross electrical power output plotted against salt flow rate in Figure 4. Also shown in the figure are the design values calculated by Bechtel during the design phase of the project. The measurements agree well with the design calculations. The SGS was designed to deliver steam temperatures required by modern turbines, but the steam was attemperated to accommodate the Solar One turbine. In a new plant, a state-of-the-art turbine with reheat capability would be used, dramatically improving the conversion efficiency (greater than 40% for a modern turbine versus 34% for the Solar Two turbine).

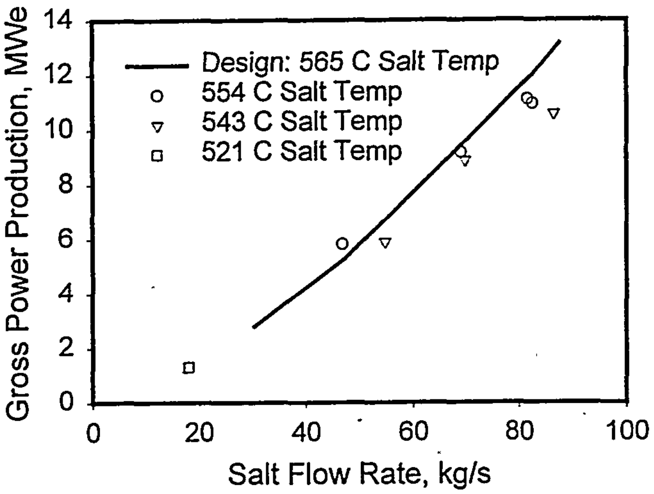

Fig. 4: Measured and design gross electrical power output versus salt flow rate.

At full flow (82.5 kg/s) and at the design inlet and outlet salt temperatures of 565 and 290°C, respectively, the steam generator was designed to transfer 35.5 MW_t for a gross turbine output of 12 MW_e. We were unable to reach the design gross turbine output for several reasons, including salt inlet temperature degradation discussed above, increased feedwater temperatures necessitated by SGS design issues, and fouling in the SGS. After these tests, in August 1998, the flange on the preheater was removed and the tubes were found to be fouled and plugged. After cleaning, the performance improved dramatically, yielding a gross turbine output of 11.6 MW_e, much closer to the design point. The water chemistry was monitored more closely after the cleaning and adjusted to reduce the rate of scaling on the water side of the SGS.

3.3 Thermal Storage Performance

The thermal storage system provides a reservoir of hot salt that the steam generation and electric power generation systems use to dispatch electricity. The efficiency of the thermal storage system is a direct result of the thermal losses. To measure the thermal storage performance, we quantified the thermal losses of the hot tank, cold tank, steam generator sump, and receiver sump and compared the values to predictions. We also determined the actual thermal capacity of the thermal storage system based on the operating temperatures and delivered salt inventory.

There are two methods of measuring the thermal losses in the tanks and sumps. One method is to turn off all auxiliary heaters and track the rate of decay of the average tank or sump temperature. By knowing the salt level, and thus the mass of salt in the vessel, an estimate of the heat loss can be made. Another method is to have the heaters energized and regulate the inventory at a set temperature. Once the vessel is at steady state, the power consumption of the heaters is measured over a long period of time. The electrical power consumption is assumed to be equal to the heat loss. Both methods were employed for these tests.

A summary of the measured and design thermal losses is shown in Table 2. The thermal losses for the tanks and sumps are similar to the design values except for the steam generator sump. The

Table 2: Design and Actual Thermal Losses of Major Equipment

Major Equipment	Calculated Thermal Loss, kW	Measured Thermal Loss, kW
Hot Tank	98	102
Cold Tank	45	44
Steam Generator Sump	14	29
Receiver Sump	13	9.5

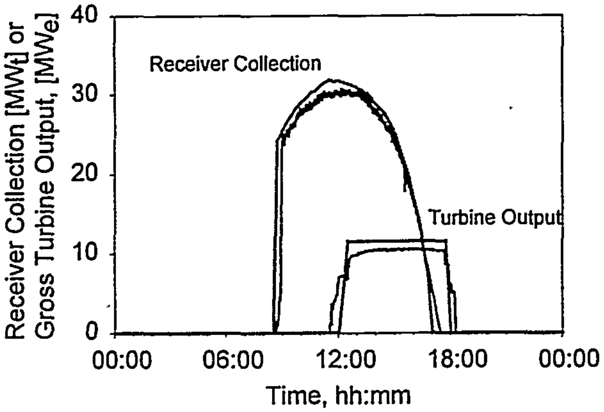

Fig. 5: Measured receiver thermal collection and turbine output (lower curves) for September 30, 1998 along with predicted collection and turbine output (upper curves) from a SOLERGY model under similar conditions.

losses for the steam generator sump were higher than predicted possibly because the insulation degraded over the course of the project. Salt had leaked out of the sump and into the insulation on the sump which significantly affected its insulating properties.

The actual thermal capacity of the thermal storage system was estimated to be 107 MWh based on the delivered amount of salt in the storage system, accounting for the mass of salt in the heels of the tanks and in the pump sumps and accounting for the actual attainable salt temperatures delivered to and returning from the steam generation system. The thermal storage system was designed to deliver thermal energy at full-rated duty of the steam generator for three hours at the rated hot and cold salt temperatures of 565°C and 288°C, respectively. The amount of salt in the system was estimated to be 1380 tonnes, which was somewhat less than design specified 1490 tonnes because approximately 100 tonnes of salt were not delivered to the site. In addition, the maximum attainable hot salt temperature from thermal storage delivered to the steam generation system (before the salt mixer) was typically 554°C (as discussed above). Despite the slightly lower-than-specified salt inventory and decreased hot-salt temperature, the storage system still had the capacity to deliver the full-rated steam generator duty for three hours (35.5 MW x 3 h=106.5 MWh).

3.4 Dispatchability Test

The objective of the dispatchability test was to demonstrate the ability to dispatch electricity during the day, evening and night – independent of energy collection. The plant was designed to operate at full turbine output for three hours after shutdown. Figure 5 shows the receiver thermal collection and turbine output for September 30, 1998 along with predicted collection and turbine outputs from the SOLERGY model (Stoddard, 1987) under similar conditions. Note how electricity was produced into the evening after collection had stopped.

In another test, the objective was to generate uninterrupted grid-connected electricity for as long as possible. To conduct this test, the steam generation and electric power generation system were operated with the receiver such that by the end of the day the hot salt tank was full. The operators derated the turbine input (to about 8 MWt) such that the inventory of salt would last through the night and into the morning, when the receiver could be restarted. This test was conducted in June and July of 1998. During one stretch, the plant produced electricity 24 hours-a-day for nearly a week (153 hours total) by using stored energy at night and recharging the inventory during the day.

3.5 Overall Plant Performance

A measurement of the daily performance of a solar power plant is how well it can collect energy relative to what is predicted. The daily thermal collection is a function not only of the incident energy, but also on several factors including the plant availability, heliostat field availability, mirror cleanliness, heliostat optical performance, and wind effects.

Table 3. Solar Two Peak Efficiencies (Goal and Achieved) Along with Those Expected for a Commercial Plant

Parameter	Solar Two Goal	Solar Two Achieved (July 4, 1998)	Commercial Plant Predictions
A. Mirror Reflectivity	90%		94%
B. Field Efficiency	69%		74%
C. Field Availability	98%	94%	99%
D. Mirror Cleanliness	95%		95%
E. Receiver	87%		87%
F. Storage	99%		>99%
G. Overall Collection (Product of Above)	50%	43%	57%
H. EPGS	34%	34%	43%
I. Parasitics	88%	87%	93%
J. Overall Peak Efficiency (G*H*I)	15%	13%	23%

One of the performance goals of Solar Two was to demonstrate a 15% overall peak efficiency. The overall peak efficiency can be broken down into efficiencies of each major step in the conversion from sunlight to grid-connected electricity as shown in Table 3. The table shows the project goals, along with what was achieved at Solar Two and what would be expected in a commercial plant with improvements implemented into the design. The project efficiency goals were meant to be achieved in the third year of operation, after the two-year test and evaluations phase where the optimum operating conditions were to be determined. As stated earlier, project delays severely compressed the testing schedule. Consequently, Solar Two was not fully optimized. The shortfalls in the actual peak performance can be attributed primarily to the under performance of the heliostat field (caused by low availability, excessive corrosion, delamination of the facets, poor canting, and high tracking errors of the old Solar One heliostat technology).

Figure 6 shows the daily thermal energy collected as a function of daily incident insolation for non-outage days. The figure also includes a curve fit of SOLERGY predictions for 90% heliostat field availability, and 90% cleanliness, when the receiver was operated for the full day. With typical heliostat availability between 88 and 94% and the known mirror degradation, the daily performance approaches the predicted SOLERGY curve for 90% field availability/90% cleanliness on many days when the receiver operated for the full day. Issues with receiver start-up (as discussed previously), partial operation during testing, and system debugging account for much of the remaining difference, i.e., those points fall well below the predicted curve. We are continuing our analysis of these effects.

Another measure of the daily plant performance is how well the daily energy that is sent to the steam generator is converted into electrical energy. This data is shown in Figure 7. As can be

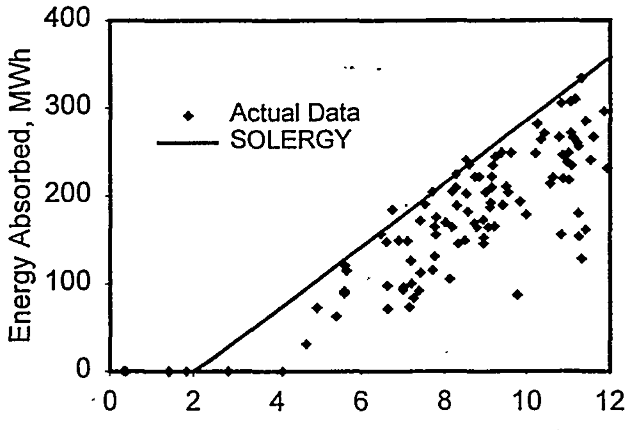

Fig. 6: Daily Collection as a Function of Insolation on Non-Outage Days.

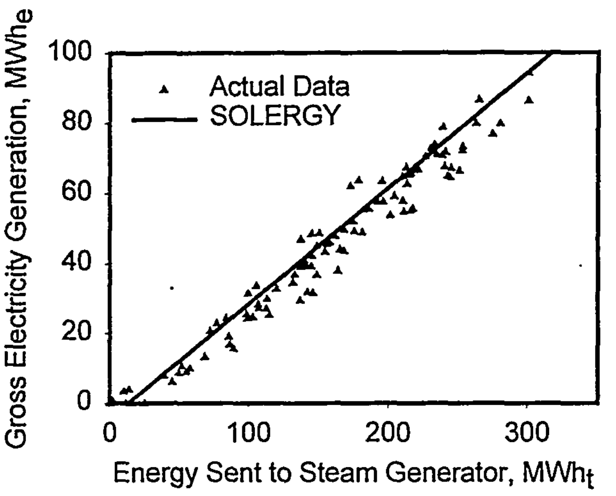

Fig. 7: Measured daily gross electrical output versus daily energy sent to the steam generation system.

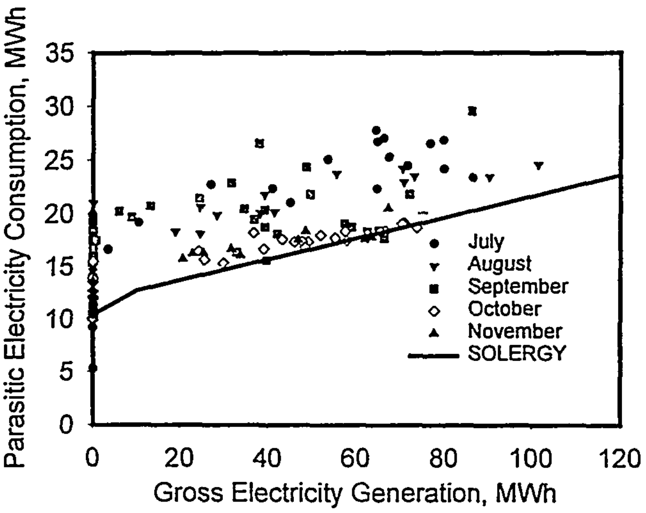

Fig. 8: Parasitic-energy consumption as a function of gross-generation for the months July through November 1998. The SOLERGY goal is also shown in the plot.

seen in the figure, a certain amount of energy is required to startup the steam generation system and keep the system warm at night and on cloudy days as indicated by the non-zero intercept. The data agree well with the SOLERGY curve.

The final measure of daily plant performance is how well Solar Two met its parasitic power consumption goal. In Figure 8, we compare the daily plant parasitics with the SOLERGY goals. It can be seen that our daily goals for parasitic power consumption were met after we implemented parasitic reduction methods in late September, October, and November of 1998. The goal was accomplished by turning off unnecessary cooling water pumps, plant lights, and altering the set-points and operating procedures of the heat trace circuits within the plant. Heat trace consumption was ~3 MWh/day after implementing the parasitic reduction methods [Kolb, 2000]. It should be noted that parasitics were generally high at Solar Two, even after achieving the goal (e.g. shown as 25% on an 80 MWh day in Figure 8), because the plant was designed to have a low annual capacity factor (only 20% because Solar Two was a non-commercial plant). In commercial plants that are designed to have high annual capacity factors (40 to 70%), parasitic-consumption is predicted to be about 10%.

4. PLANS FOR COMMERCIAL POWER TOWER PLANT

In addition to validating the design and technical characteristics of molten-salt receiver and storage technology, Solar Two was also successful in fostering commercial interest in power towers. Two of the project's key industry partners, The Boeing Company and Bechtel Corporation, have joined forces with the Spanish corporation Ghersa to pursue commercial solar power tower plant opportunities in Spain. The first commercial molten salt power tower plant, called Solar Tres, is planned for deployment in southern Spain. The commercial interest in Solar Tres was sparked by the enactment of the Spanish Royal Decree, on January 1, 1999, which specifies that 36 pesetas/kWh (~24 U.S. cents) shall be paid for solar-generated electricity[1].

The decree is similar in nature to the PURPA law that launched the renewable electricity industry in California in the 1980's. Solar plants in Spain are to be built by Independent Power Producers (IPP) and the electricity generated must be purchased by the local utility company at a rate of 36 pesetas/kWh via a long-term (≥ 5 years) power purchase agreement. Plant size must not exceed 50 MW_e. The decree was issued to help Spain achieve their commitment to the Kyoto Protocol to obtain 12% of the primary energy needs from renewables.

Unlike the USA PURPA legislation, the Spanish Royal Decree stipulates that plants must be solar only. This requirement should favor a solar technology with a relatively inexpensive energy storage system, like molten-salt power towers, because these plants will have a high annual capacity factor and much-improved economic utilization of the power block equipment than a solar technology without inexpensive storage. The plan is to first build the sub-optimal 10 MW_e Solar Tres plant (in order to fully debug the system and to minimize financial risk) followed by an optimized 50 MW_e plant. These plants will likely have 12 or more hours of storage so they can operate nearly 24 hours/day and achieve a ~60% annual capacity factor.

Although Solar Tres will incorporate a 10 MW_e steam turbine, the same size as Solar Two, the preliminary design calls for a heliostat/receiver system that is 2 to 3 times larger than Solar Two and a thermal storage system that is 5 times larger (nominally, 100 MW_t receiver and 500 MWh_t storage systems). Solar Tres will incorporate several design improvements based on the lessons learned from Solar Two. Furthermore, it will not be hindered by some of the old heliostat and steam-turbine technology employed at Solar Two and should achieve a significant improvement in the solar-to-electric conversion efficiency. If all goes according to plan, Solar Tres could be operating within 2 to 3 years.

U.S. industry views this project as a springboard to near-term opportunities for numerous full-scale (greater than 50 megawatts) commercial power tower plants in Spain, in other worldwide markets, and eventually in the southwestern U.S. This dispatchable, utility-scale solar power could be a major source of clean energy worldwide, offsetting as much as 4 million metric tonnes of carbon equivalent (MMCTE) over the next 10 years.

5. CONCLUSIONS

The Solar Two Test and Evaluation program has successfully quantified the performance of the receiver, steam generation system, electric power generation system, and heliostat field on an instantaneous and daily basis. Despite its short test and evaluation phase, Solar Two demonstrated the unique features of a molten salt power tower and will hopefully lead to the first commercial deployment of this technology in Spain.

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[1] At the time of this writing, there was some question whether the definition of "solar" in the Royal Decree applies only to photovoltaics. While many Spanish authorities insist that solar thermal is included, clarifying language may be necessary in a future amendment.

6. ACKNOWLEDGEMENT

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