SolarPACES 2022, 28th International Conference on Concentrating Solar Power and Chemical Energy Systems
Analysis and Simulation of CSP and Hybridized Systems
https://doi.org/10.52825/solarpaces.v1i.683

Published: 16 Apr. 2024

CSP Design Study for Sandia National Laboratories and Kirtland Air Force Base

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Abstract. This report provides a design study to produce 100% carbon-free electricity for Sandia NM and Kirtland Air Force Base (KAFB) using concentrating solar power (CSP). CSP plant designs of 50 MW and 100 MW are assessed to meet the electricity needs of Sandia NM and/or KAFB. Probabilistic modeling is performed to evaluate inherent uncertainties in performance and cost parameters on total construction costs and the levelized cost of electricity. Estimated annual electricity production was ~200 – 300 GWh for the 50 MW plant and ~400 – 700 GWh for the 100 MW plant. The overnight construction costs ranged between ~$300M - $400M for the 50 MW CSP plant and between ~$500M - $800M for the 100 MW CSP plant. The heliostat field was the most significant subsystem cost, followed by the thermal energy storage, power cycle, and fixed operation and maintenance costs. Other considerations such as land availability and permitting, funding options, and interconnections are discussed.

Keywords: CSP, Kirtland Air Force Base, Sandia

1. Introduction

The U.S. Department of Energy's Sandia National Laboratories is located in Albuquerque, New Mexico, and resides on land leased by the Department of Defense's Kirtland Air Force Base (KAFB). Both Sandia NM and KAFB are interested in pursuing sustainable energy sources and reducing their carbon footprint. Another goal is to increase resilience and reliability of their electrical supply to maintain critical operations if the grid goes down.

The annual electricity requirements for Sandia NM are expected to increase from current values of ~300 GWh to just over 400 GWh by 2040, much of the increase due to expected data-center growth in the next few years. The combined electricity requirements for Sandia NM and KAFB are expected to grow from ~400 GWh to just over 600 GWh by 2040 (Figure 1). Peak loads range from 30 – 40 MW for Sandia NM and 50 – 70 MW for Sandia NM and KAFB. To offset these energy requirements, both 50 MW and 100 MW molten-salt power-tower CSP plants were evaluated. The objective of this study was to develop a conceptual design of a CSP plant that can provide clean electricity for Sandia NM and KAFB. The annual energy needs of both Sandia NM and KAFB were considered, along with other factors such as land and siting requirements, interconnections, partnering, costs, and funding.

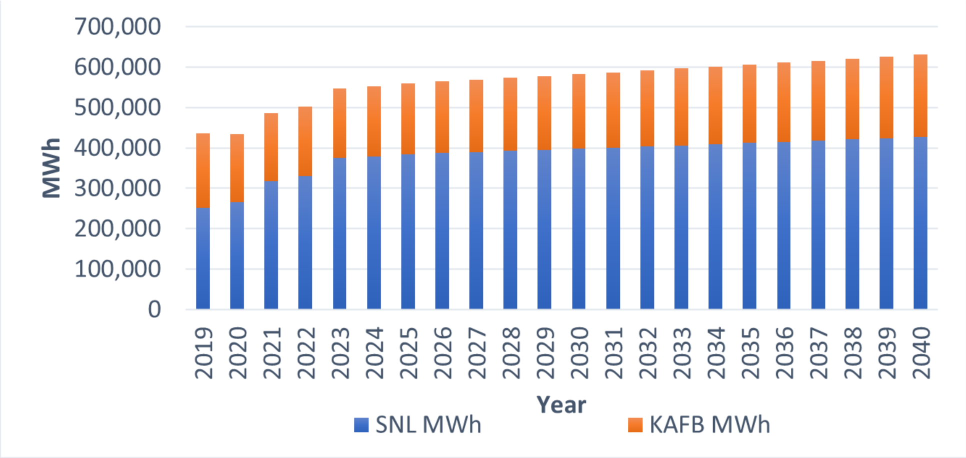

Figure 1. Projected electrical demand for Sandia NM and KAFB.

2. CSP Plant Design

Component sizing and subsystem costs in a molten salt CSP plant are dependent on three key parameters: rated capacity, hours of storage, and the solar multiple. The rated capacity is the nominal power output of the turbine, the hours of storage is the ratio of the total thermal energy that can be stored in the hot storage bin to the rated capacity of the turbine, and the solar multiple is the ratio of the power delivered to the molten salt in the receiver to the rated capacity of the turbine. The solar multiple describes the amount of excess thermal energy supplied by the heliostat field during nominal conditions which can be stored for later electrical generation. A solar multiple of 1 indicates a plant can generate electricity at its rated capacity during the day when the solar resource is present but is unable to produce additional thermal energy to charge the storage. A solar multiple of 3 indicates that a plant can generate three times the thermal energy required to power the turbine, allowing the additional thermal energy to be stored for later electrical generation when the solar resource is not present.

The solar multiple and storage bin size are related in that increased thermal generation requires increased storage to fully utilize the collected energy. In general, a plant with a high solar multiple has a commensurately sized thermal-energy storage system. On days with low solar irradiance, such as days with cloudy or hazy conditions, a plant with a high solar multiple will produce more thermal energy than a plant with a low solar multiple due to its larger heliostat field area, allowing for greater resilience to varying weather conditions. With greater resilience to weather and additional thermal capacity to charge the thermal energy storage, a plant with a higher solar multiple can produce electricity for a larger portion of the year. This resilience leads to a higher capacity factor, defined as the percentage of the year the plant produces its rated output.

Increasing the heliostat field area relative to the rated capacity of the turbine (paired with a larger receiver to transfer the solar input to the molten salt) provides a higher solar multiple, but also increases the plant capital costs. “Downstream” components of the receiver, such as the molten salt pumps, piping, and heat tracing, are also scaled, further contributing to an increase in the capital costs of the system. The levelized cost of energy (LCOE) has a more complicated relationship with the solar multiple. The minimum LCOE can be determined by optimizing the solar multiple and the hours of thermal energy storage to increase the capacity factor without incurring unnecessary capital and operating costs due to oversizing components. However, to increase the reliability and energy security of a plant, a higher solar multiple and increased storage size may be considered at the expense of the LCOE (and capital costs).

Two baseline CSP plant scenarios, summarized in Table 1, were considered for supplying electricity to Sandia NM: a 50 MW nameplate capacity scenario capable of offsetting anticipated future average demand at Sandia NM, and a 100 MW scenario capable of approaching or meeting the total anticipated average future electricity demand. Each system included consideration of 15 hours of energy storage from a molten salt thermal energy storage system. Two scenarios for the solar field size were considered for each system: a more typical field scenario with a solar multiple of 2.4, and a solar field sized to produce a solar multiple of 3.0 and take greater advantage of the system thermal energy storage capacity. The larger solar multiple enabled higher receiver thermal power and therefore greater annual energy production, but at the cost of increased capital costs due to the larger scale of the tower, receiver, and heliostat field. These relationships are studied in greater detail in Section 0.

Table 1. Major plant operating parameters and size metrics for 50 MW and 100 MW baseline simulations in the System Advisor Model. Median predicted annual energy production is reported with the 95% confidence interval in brackets.

Parameter	50 MW Baseline Value		100 MW Baseline Value	
Solar Multiple [-]	2.4	3.0	2.4	3.0
Receiver Thermal Power [MW_t]	297	371	594	743
Heat Transfer Fluid Max Temperature [°C]	574			
Total Land Area [acres]	965	1240	1892	2350
Total Heliostat Reflective Area [m^2]	562629	717254	1147635	1449523
Tower Height [m]	120	132	167	187
Storage Tank Volume [m^3]	9422		18844	
Annual Energy [GWh]	275 [233 - 318]	308 [259 - 338]	522 [414 - 608]	621 [521 - 678]

2.1 Baseline Modeling

The System Advisor Model (SAM) [1], developed at NREL, was used for simulations of plant production and economics. Weather conditions were taken from TMY (typical meteorological year) data for Albuquerque, NM with the design point direct normal irradiance (DNI) of 950 W/m^2. The key parameters for the scenarios, summarized in Table 1, were supplied to the model. Values such as the heat transfer fluid temperature were defaults defined by SAM for a prototypical power tower system. Some parameters, including the storage tank volumes, were calculated based on the specified nameplate capacities. Finally, parameters such as the heliostat field and tower size were calculated based on the nameplate capacity and solar multiple using an optimization procedure within SAM. For each simulation, the plant nameplate capacity and solar multiple were defined, and then the heliostat field layout was calculated via SAM's heliostat layout and tower dimension optimization tool. The annual energy production is reported as the median and 95% confidence values from the probabilistic study.

Figure 2 shows the month-averaged hourly power generation from the plant for each month of the year for the 50 MW, solar multiple of 2.4 plant scenario in blue, compared to the plant with the same nameplate capacity but a solar multiple of 3.0 in red. Peak generation approached the nameplate capacity of 50 MW during summer months and approached 40 MW during the winter. The dip in production in the early morning hours for each profile resulted from depletion of the thermal energy storage during off-sun hours. The effect was most significant in winter months of Nov – Jan but impacted generation year-round, particularly for the blue curve, suggesting that the default solar multiple of 2.4 did not take sufficient advantage of the 15 h storage system. These effects are also captured in Figure 3, which represents the same data as an hourly heat map of generated energy and depicts how increasing the solar multiple from (a) 2.4 to (b) 3.0 partially “filled in” the early morning generation gaps in winter months.

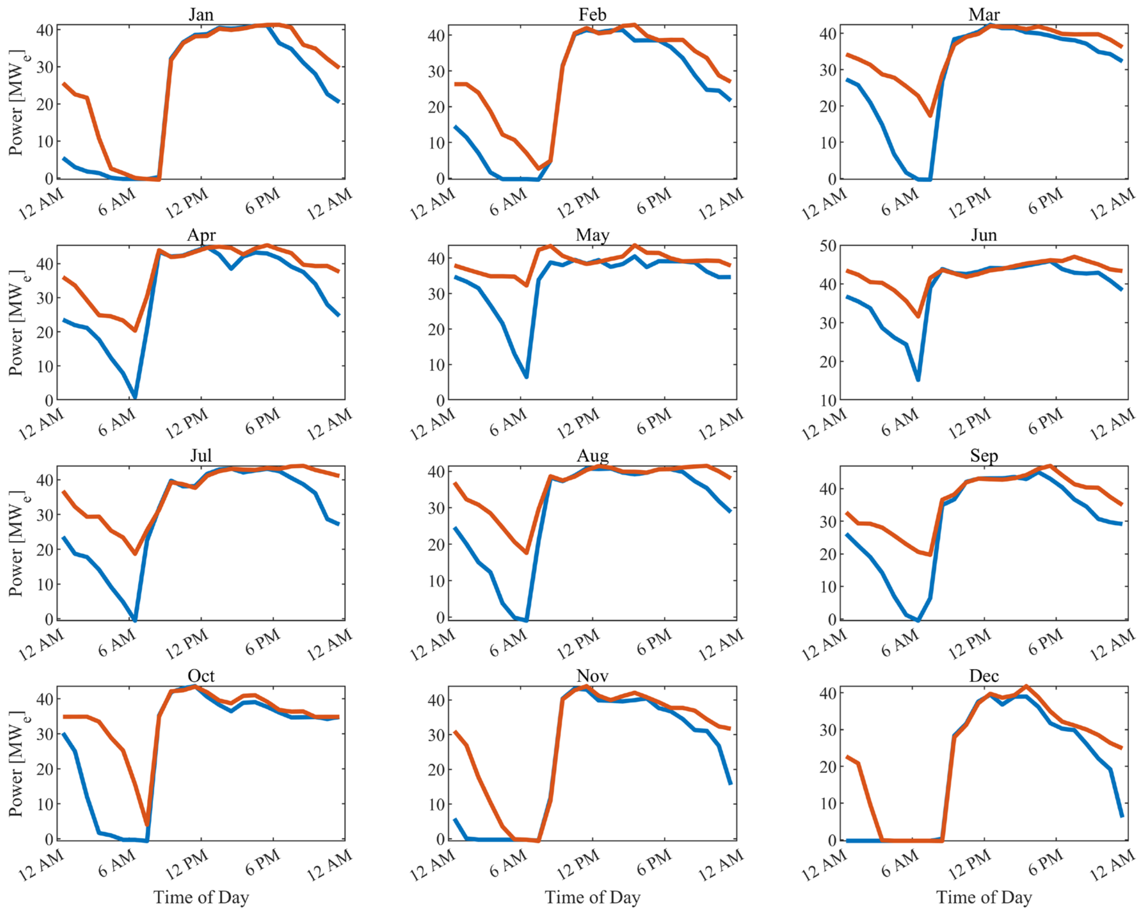

Figure 2. Month-averaged hourly power production for the 50 MW plant scenario with solar multiples of 2.4 (blue) and 3.0 (red).

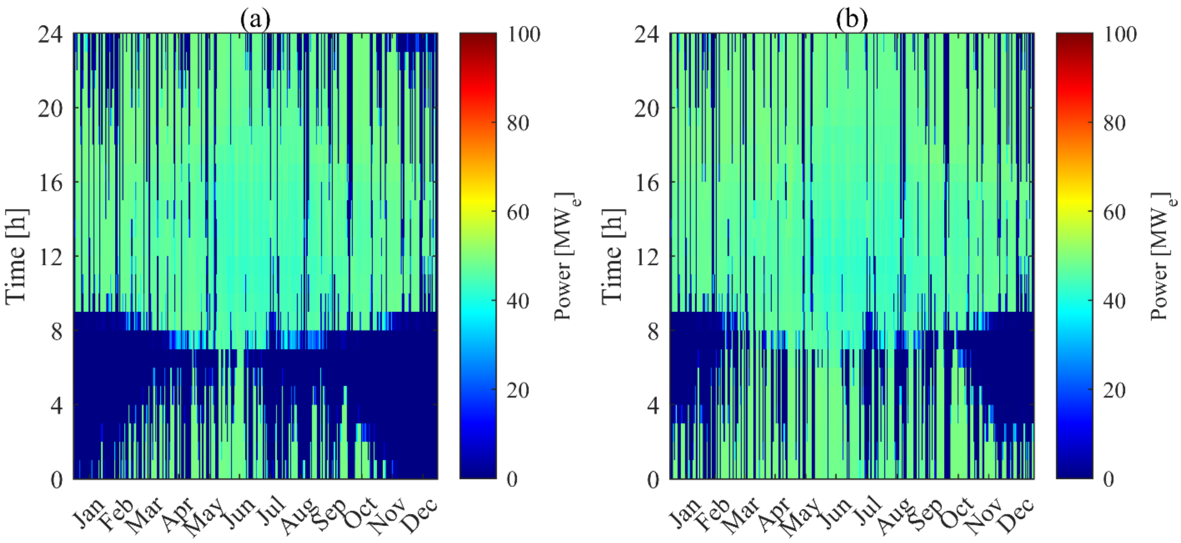

Figure 3. Heat map of month-averaged hourly power production, reported in units of kW, for the 50 MW plant case with solar multiples of (a) 2.4 and (b) 3.0.

Figure 4 and Figure 5 depict the production metrics for the 100 MW plant, which were similar to the 50 MW cases and also suggested a higher solar multiple to increase wintertime generation.

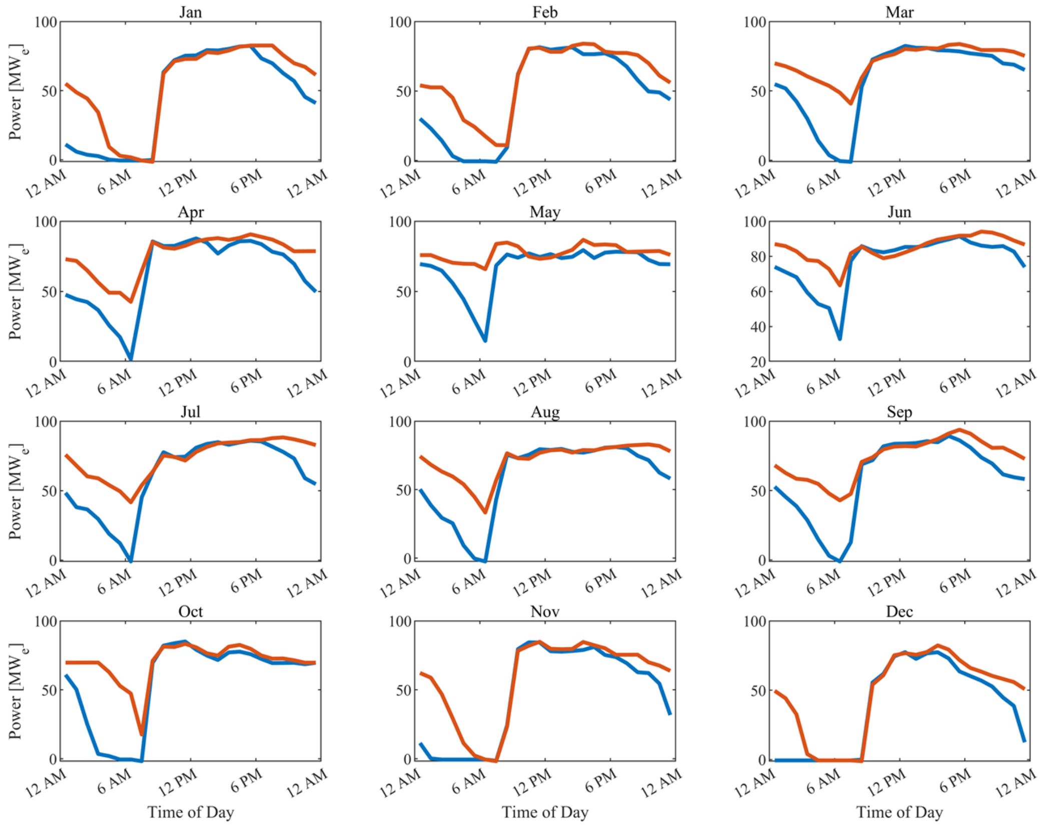

Figure 4. Month-averaged hourly electricity production for the 100 MW plant scenario with solar multiples of 2.4 (blue) and 3 (red).

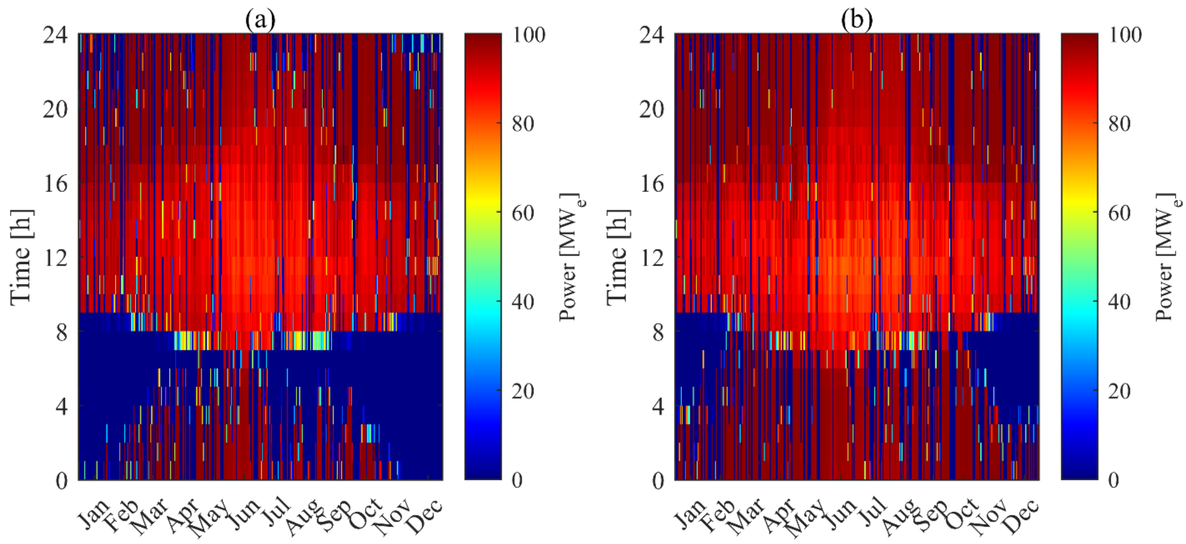

Figure 5. Heat map of month-averaged hourly power production, reported in units of kW, for the 100 MW plant case with solar multiples of (a) 2.4 and (b) 3.0.

2.2 Probabilistic Modeling

Plant economics are a function of the estimated costs of the plant subsystems (heliostat field, solar tower and receiver, thermal energy storage) and the expected O&M costs for electricity production. Probabilistic studies were performed in SAM for both the 50 MW and 100 MW scenarios to estimate variability in levelized cost of electricity and net capital costs due to subsystem cost uncertainties. Like in the base studies, solar multiples of 2.4 and 3.0 were considered for the analyses.

A single owner, power purchase agreement (PPA) was selected as the system financial model for each plant scenario, which allowed projections of plant economics in terms of common metrics including 25-year LCOE and net capital costs. Inflation and real discount rates of 2.5% and 4.4% per year, respectively, were assumed, which results in a nominal discount rate of 7.01% per year. The project LCOE was the inflation-adjusted total project lifecycle cost in terms of dollars per kWh, accounting for construction costs, O&M costs, and project financing. The net capital cost was defined as the summed total installed costs (i.e. “overnight” construction cost) and financing costs.

Major subcomponent costs and performance metrics were considered for the study and are defined in Table 2. Baseline values were those recommended by SAM for the power tower CSP system. Uniform distributions were selected for the analysis due to the varied range of historic and predicted data upon which the bounds were based, as well as to produce more conservative estimates of the overall certainty. Cost parameter upper bounds were defined as 115% of the 2017 baseline values as defined by an NREL study [2] and lower bounds were informed by DOE 2030 cost targets for CSP field and subcomponent costs.

The SAM stochastic simulation capability was used for the analysis, in which iterations of the four base SAM models (one for each nameplate capacity and solar multiple) were run with values of the inputs perturbed based on their defined uncertainties. The perturbed input values were generated via Latin Hypercube Sampling and the STEPWISE packages developed at Sandia and implemented within SAM. A total of 100 model iterations were performed to ensure iteration independence, which was verified by comparing mean output values for a range of simulations between 10 and 200 iterations. System performance was evaluated by the LCOE and net capital cost, which purposely did not account for policy incentives or financing impacts on plant economics. As parameters of the solar field and tower were not included in the probabilistic study as independent variables, the receiver heights and heliostat arrangements optimized for each of the four base cases were used without iterative recalculation within the respective probabilistic studies.

Table 2. Input variables for probabilistic cost study. Baseline values were drawn from the default System Advisor Model values and uncertainty ranges were defined as uniform distributions.

Parameter	Baseline Value	Uncertainty Distribution	Basis
Heliostat Field Cost [$/m^2]	70.0	[50.0 - 167]	Range between 2017 baseline value and DOE 2030 cost target
Fixed O&M Cost [$/kW-yr]	66.0	[40.0 - 76.0]	Range between 2017 baseline value and DOE 2030 cost target, informed by JEDI model inputs for construction, O&M
Power Cycle Cost [$]	1300	[900 - 1660]	Range between 2017 baseline value and DOE 2030 cost target
Receiver Reference Cost [$]	10.0 E6	[6.67 - 11.5] E6	Range between 2017 baseline value and DOE 2030 cost target
Thermal Energy Storage Cost [$/kWh$_t$]	30.0	[15.0 - 45.0]	Symmetric range about default value; lower limit based on DOE 2030 cost target

Parameter	Baseline Value	Uncertainty Distribution	Basis
Fixed Tower Cost [$]	8.00 E6	[5.33 - 9.20] E6	Range between 2017 baseline value and DOE 2030 cost target
Cycle Thermal Efficiency [%]	40.4	[35.0 - 50.0]	Range encompassing typical and state-of-the-art CSP power cycle performance [3]
Receiver Heat Loss [kW_t/m^2]	30.0	[29.2 - 190]	Receiver efficiency range between 80% and 96% (blackbody efficiency) [4]

The resulting plant economics from the probabilistic studies were characterized in terms of their Cumulative Distribution Functions (CDFs). Figure 6 depicts the CDF of the LCOE for the (a) 50 MW and (b) 100 MW scenarios with solar multiples of 3.0, along with the median value from the model runs (solid vertical line) and dashed lines representing the error margins at the 95% confidence level. The values are also presented numerically in Table 3. The median LCOE of the 50 MW case was determined to be $0.078/kWh with a 95% confidence interval of [0.058 - 0.101]. The LCOE for the 100 MW case was roughly the same. Compared to the cases with solar multiples of 2.4 (not plotted), increasing the solar multiple slightly decreased the LCOE, although not to a statistically significant degree, highlighting that a larger heliostat field can increase generation without necessarily increasing the levelized cost of generation.

Table 3. Median levelized cost of electricity and construction costs for nameplate capacities of 50 and 100 MW and solar multiples of 2.4 and 3.0, including the 95% confidence intervals from the probabilistic study.

Parameter	50 MW Plant		100 MW Plant	
Solar Multiple [-]	2.4	3.0	2.4	3.0
Levelized Cost of Electricity (LCOE) [$/kWh]	0.080 [0.065 - 0.111]	0.078 [0.058 - 0.101]	0.083 [0.060 - 0.113]	0.076 [0.059 - 0.097]
Overnight Construction Costs [$]	318 E6 [263 - 389] E6	340 E6 [263 - 416] E6	613 E6 [479 - 748] E6	666 E6 [528 - 833] E6
Net Capital Costs (includes financing and fees) [$]	352 E6 [291 - 430] E6	376 E6 [291 - 459] E6	678 E6 [530 - 826] E6	736 E6 [586 - 920] E6

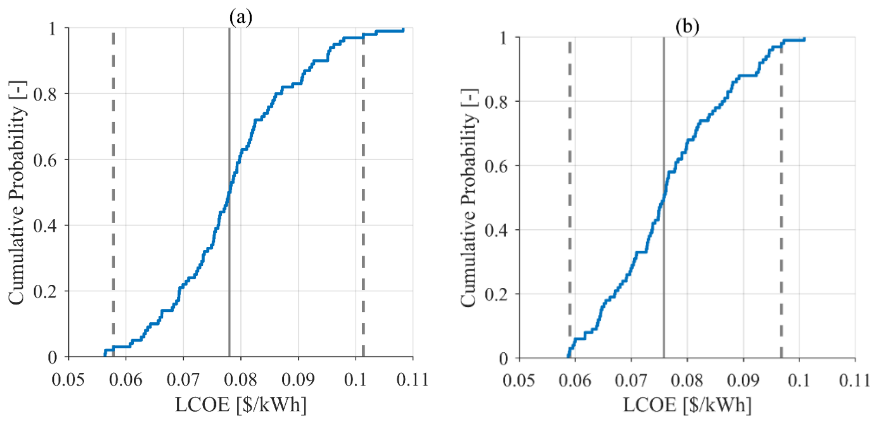

Figure 6. Levelized cost of electricity from the System Advisor Model probabilistic study for the (a) 50 MW and (b) 100 MW plant scenarios with solar multiples of 3.0. Cost is represented in terms of the cumulative probability, median value (vertical line), and 95% confidence values (vertical dashed lines).

Figure 7 depicts the CDF of the nominal plant capital costs, again for (a) 50 MW and (b) 100 MW scenarios with solar multiples of 3.0. The results are also included in in Table 3. For the 50 MW case, a median cost of approximately $376 million [291 - 459] was determined, while for the 100 MW simulation the cost was $736 [586 - 920]. On a per MW generation basis, the capital costs for the 50 and 100 MW cases were $7.52 and $7.36 million per MW, respectively, revealing a modest scaling benefit to the construction economics. Unlike for the LCOE, increasing the solar multiple produced significant cost increases due to the increased construction costs of the taller tower and larger heliostat field. Increasing the solar multiple from 2.4 to 3.0 produced additional costs of approximately $0.5 to 0.6 million/MW nameplate capacity.

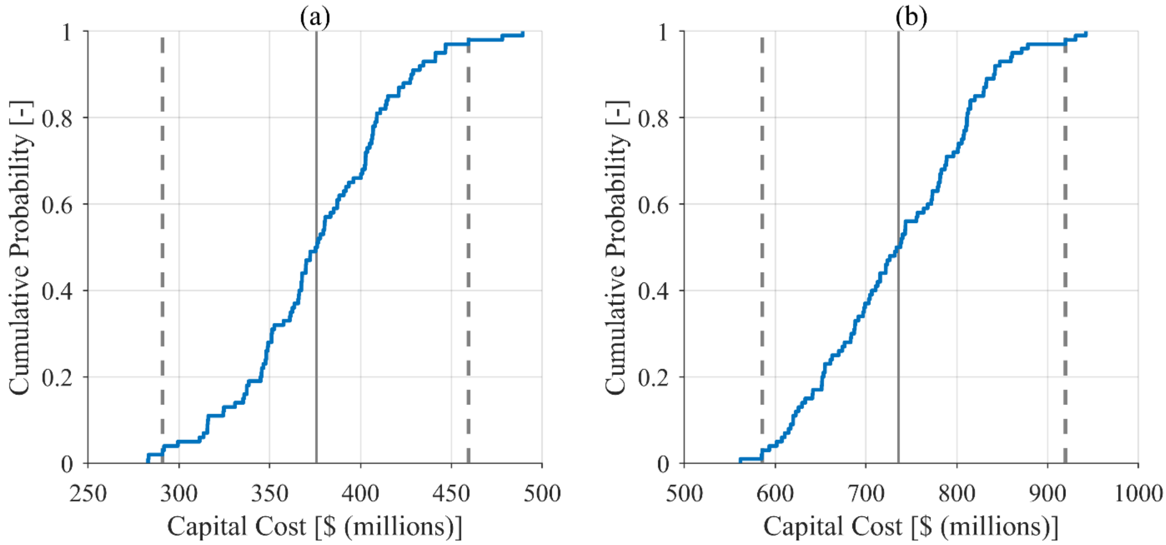

Figure 7. Net plant capital cost from the System Advisor Model probabilistic study for the (a) 50 MW and (b) 100 MW plant scenarios with solar multiples of 3.0. Cost is represented in terms of the cumulative probability, median value (vertical line), and 95% confidence values (vertical dashed lines).

To understand the relative importance of the component cost variations, rank regressions of the LCOE and capital costs versus the eight independent variables defined in Table 2 were performed. All independent and dependent variables were rank-ordered ascending and fit using a stepwise regression procedure to determine significant parameters. The variables were assumed to be linearly related without significant interactions. Entrance and removal p-values of 0.05 and 0.10, respectively, were used for the stepwise regression. The model coefficients β for all statistically significant input variables were recorded as measures of the parameter sensitivity.

Figure 8 contains the regression coefficients for the 50 MW, 3.0 solar multiple plant scenario for (a) LCOE and (b) net capital cost (similar results were obtained for the 100 MW and 2.4 solar multiple plant scenarios and are therefore not shown). For LCOE, cycle thermal efficiency was the most significant and only negatively correlated parameter versus plant economics. The heliostat field was the most significant subsystem cost, followed by the thermal energy storage, power cycle, and fixed O&M costs. The tower cost was the least significant parameter, while the receiver heat loss and receiver reference costs were not significant predictors and were therefore omitted. The cycle thermal efficiency effect on the capital costs was significant but relatively less so than for the LCOE. The subsystem costs followed the same relative trends as for the LCOE, except that the fixed O&M costs were insignificant as they did not factor into the initial construction costs.

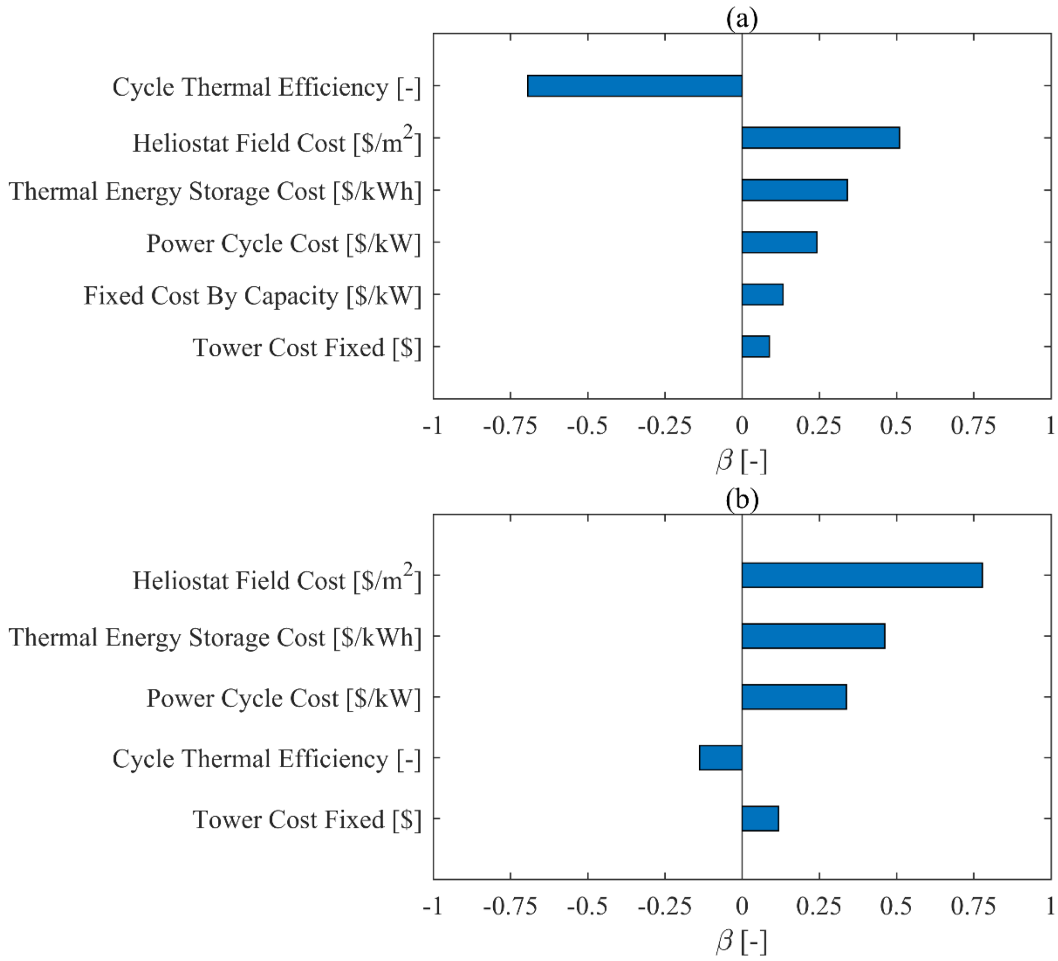

Figure 8. Rank regression coefficients from the System Advisor Model probabilistic study for the 50 MW, 3.0 solar multiple plant scenario for (a) levelized cost of electricity and (b) net plant capital cost.

3. Siting and Funding Considerations

Figure 9 and Figure 10 show potential locations for siting either a 50 MW or 100 MW CSP plant, which would require approximately 1000 and 2000 acres, respectively. Recent discussions with stakeholders from KAFB, Federal Aviation Administration (FAA), and Sandia NM have revealed that the ~1000-acre site just northeast of the KAFB golf course is the most viable based on operational and mission considerations at the other sites. Gaining approval for the use of specific land will involve many stakeholders and ecological considerations. Another concern for any of these sites is the proximity of the power tower to the runways used by the airport and KAFB. Constraints for FAA requirements still need to be assessed, as well as interconnection requirements and operations with Public Service Company of NM (PNM) to ensure sustained electricity service to the base if the main grid goes down.

Funding for construction of a CSP plant on KAFB is being considered through several options, including public-private partnerships (PPP), power purchase agreements (PPA), and direct capital funding through DOE. Of these options, a PPP appears to be the most promising to take advantage of recent funding opportunities through DOE, DoD, and the Bipartisan Infrastructure Law. Private investment and partnerships with CSP companies are also being considered. Operation of the plant would likely be performed by the developer or PNM, and the cost of operations and maintenance needs to be negotiated with the operator.

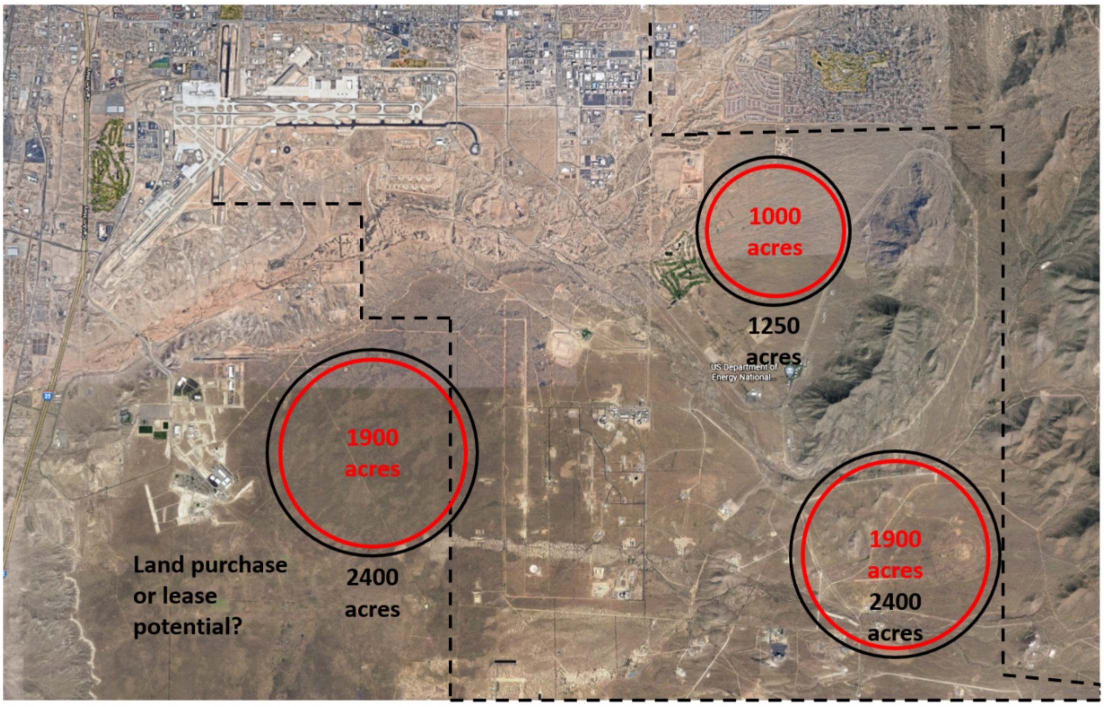

Figure 9. Three potential sites for 100 MW (1900-2400 acres) and 50 MW (1000-1250 acres) CSP plants with 15 hours of storage. The KAFB boundary is depicted by dashed lines.

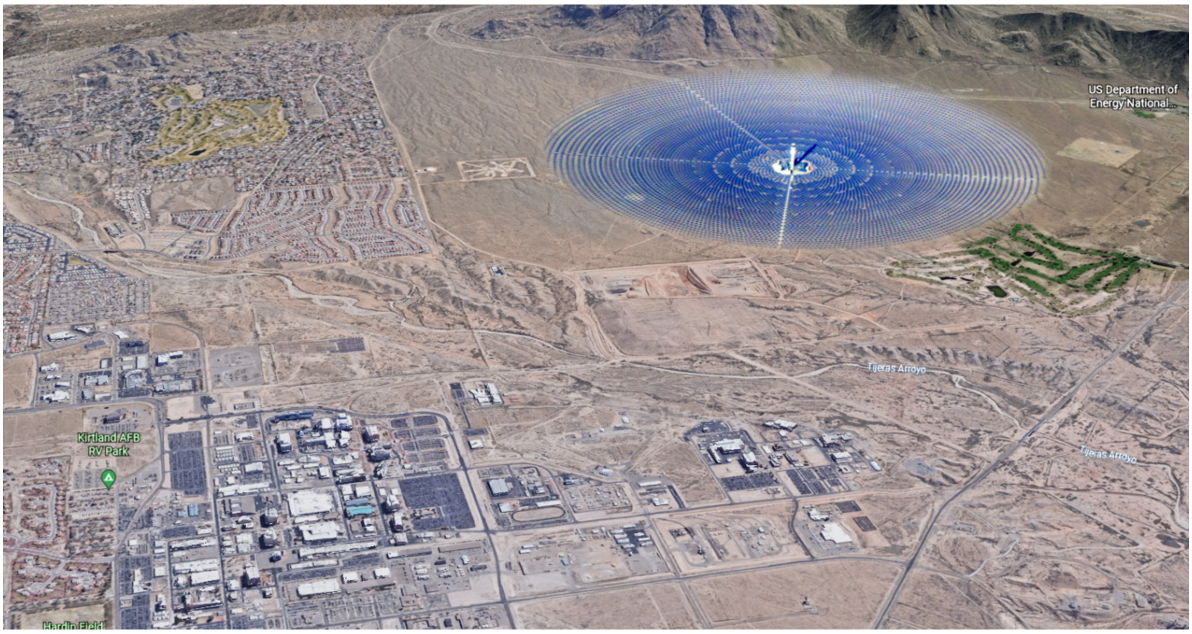

Figure 10. Potential site for a 50 MW power tower CSP installation covering between 965 to 1240 acres (looking east). The image depicts the Crescent Dunes facility in Nevada overlaid to give perspective on appearance of the installation (Wikimedia Creative Commons license).

A payback analysis was performed using the net-present-value method. The projected number of years to achieve a net present value of zero depends on interest rates and avoided costs. The avoided electrical costs are ~\$14M/year for the 50 MW plant and ~\$24M/year for the 100 MW plant. Future avoided costs of carbon ranged from ~\$7M - \$11M per year for the 50 MW plant and ~\$13M - \$22M per year for the 100 MW plant assuming proposed initial carbon pricing by the 117th congress ranging from \$15/ton to \$59/ton. Maintenance and operations costs are ~\$2M - \$4M per year for the 50 MW plant and ~\$4M - \$8M per year for the 100 MW plant. Assuming a real interest rate of 4%, the payback period was estimated to be ~14 - 35 years for the 50 MW plant and ~14 - 41 years for the 100 MW plant assuming the low-end of the construction and O&M costs with and without carbon pricing. Assuming a worst-case scenario with the highest costs and no avoided carbon costs, the payback period was infinite for both plants. It should be noted that additional revenue (e.g., from selling electricity back to the grid, arbitrage, and other resilience cost savings) was not considered in the payback period analysis.

4. Conclusions

CSP plant designs for construction and operation of 50 MW and 100 MW molten-salt power towers with 15 hours of storage were developed to offset the electricity requirements of Sandia NM and/or KAFB. Estimated annual electricity production was ~200 – 300 GWh for the 50 MW plant and ~400 – 700 GWh for the 100 MW plant. The overnight construction costs are expected to range between ~$300M - $400M for the 50 MW CSP plant and between ~$500M - $800M for the 100 MW CSP plant. The heliostat field was the most significant subsystem cost, followed by the thermal energy storage, power cycle, and fixed operation and maintenance costs. Payback periods were estimated to be ~14 – 41 years assuming low-end costs. Payback period was infinite assuming high-end costs and no avoided carbon costs. Benefits and impacts of the CSP plant include job creation, reductions in CO_2 and greenhouse gas emissions, and increased energy resilience and security. The plant, sited on or near KAFB, would provide energy to Sandia and KAFB, increasing the energy security and resilience of the site while avoiding the buildout of vulnerable and costly high-voltage transmission.

Data availability statement

The models in this paper can be reproduced using the data provided and cited in this paper.

Underlying and related material

The System Advisor Model is free to the public and available from the National Renewable Energy Laboratory website [1].

Author contributions

Dr. Ho led the overall project, coordinated efforts, and directed the modeling; Dr. Bush led the SAM modeling; Mr. Villa performed the payback and siting analyses; Ms. Rinaldi provide data on energy requirements; Mr. Schroeder assisted with the modeling; and Mr. Sment assisted with the modeling.

Competing interests

The authors declare no competing interests.

Funding

Funding was provided through Sandia's climate change and net zero programs (project/task 278/40.02.01.04.02.01.06 and 278/40.02.02.11.01).

Acknowledgement

Sandia National Laboratories is a multimission laboratory managed and operated by National Technology and Engineering Solutions of Sandia, LLC, a wholly owned subsidiary of Honeywell International, Inc., for the U.S. Department of Energy's National Nuclear Security Administration under contract DE-NA0003525. SAND2022-12306 C

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