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100% Carbon-Free Electricity for Sandia NM and KAFB Using Concentrating Solar Power (CSP)

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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). Annual electricity requirements for both Sandia and KAFB are presented, along with specific load centers that consume a significant and continuous amount of energy. CSP plant designs of 50 MW and 100 MW are then discussed to meet the needs of Sandia NM and the combined electrical needs of both Sandia NM and KAFB. Probabilistic modeling is performed to evaluate inherent uncertainties in performance and cost parameters on total construction costs and the levelized cost of electricity. Total overnight construction costs are expected to range between ~\$300M - \$400M for the 50 MW CSP plant and between ~\$500M - \$800M for the 100 MW plant. Annual operations and maintenance (O&M) costs are estimated together with potential offsets in electrical costs and CO_2 emissions. Other considerations such as interconnections, land use and permitting, funding options, and potential agreements and partnerships with Public Service Company of New Mexico (PNM), Western Area Power Administration (WAPA), and other entities are also discussed.

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EXECUTIVE SUMMARY

This report presents a concentrating solar power (CSP) design study to produce carbon-free electricity for Sandia NM and KAFB. Table ES-1 summarizes the key parameters and findings from this study. The following sections provide additional details regarding the key findings.

CSP Plant Design

The annual electricity requirements for Sandia NM are expected to increase from current values of ~300 GWh to just over 400 GWh by 2040. The combined electricity requirements for Sandia NM and KAFB are expected to grow from ~400 GWh to just over 600 GWh by 2040. 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. Probabilistic analyses were performed to quantify uncertainties in both performance and cost. Results showed that the 50 MW CSP plant is expected to produce ~200 – 300 GWh of annual electricity, and the 100 MW CSP is expected to produce ~400 – 700 GWh.

Costs and Financing

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 (O&M) costs. The projected number of years to achieve a net present value of zero (payback period) 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 could be up to $11M per year for the 50 MW plant and up to $22M per year for the 100 MW plant assuming congressionally proposed initial carbon pricing up 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. See Table ES- 2 for additional details regarding avoided carbon costs and payback periods. Financing of the project may come from state and/or federal funding opportunities or venture capital (see Table 12). Agreements would be needed regarding responsibility for annual costs of maintenance and operations and use/resale of electricity generated from the CSP plant.

Siting, Construction, and Operation

Construction of a CSP facility on KAFB land would require coordination with Sandia Field Office/NNSA, KAFB Civil Engineering Division, and Sandia to obtain all necessary permits and approvals. Land and siting requirements on and near KAFB were evaluated. Three locations were identified that could host the 50 MW and 100 MW CSP plants, which would require ~1000 acres and ~2000 acres of land, respectively. Operation of the plant would likely be through a third-party CSP developer or PNM contractor. Table 12 summarizes these entities and roles.

Benefits and Impact

Benefits and impacts of the CSP plant include job creation, reductions in CO_2 and greenhouse gas emissions, and increased energy resilience and security using innovative technologies developed, in part, at Sandia. Construction of a 100 MW CSP plant is expected to create nearly 2,000 jobs related to construction and supply chain. Nearly 100 permanent jobs would be created to operate and maintain the facility and provide necessary services and supplies. A reduction of ~300,000 tons of CO_2 per year (or 10 million tons of CO_2 over a 30-year period) is expected based on a 100 MW CSP plant producing ~500 – 600 GWh of clean electricity annually. This is equivalent to the annual carbon emissions of ~60,000 passenger vehicles. The annual CO_2 offset is also equivalent to at least 2% of the remaining fossil-fuel generation (~25,000 GWh) that would need to be replaced to achieve NM's 50% carbon-free electricity generation goal by 2030. 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.

Another benefit is the commercial deployment of innovative technologies at Sandia and KAFB. Sandia has led the development of next-generation particle-based CSP technologies. DOE recently awarded Sandia $25M to build a Gen 3 Particle Pilot Plant (G3P3) to de-risk particle-based technologies. A comparison of conventional molten-salt and particle-based CSP systems and components is provided in Section 4.5. Although no commercial particle-based CSP plants have been deployed, studies have shown particle systems have the potential to improve performance and reduce the levelized cost of electricity (LCOE) to less than $0.06/kWh, about the same or lower than fossil-fuel-based thermoelectric power plants providing baseload power. In addition, particle-based CSP technologies can increase temperatures for next-generation power cycles and decarbonization of high-temperature industrial processes such as cement and steel production.

Finally, this study has investigated only the costs of the proposed CSP projects (e.g., LCOE, construction, and O&M). Revenue potential for selling electricity back to the grid or utilities was not considered. Additional benefits of deploying a carbon-free electric generating system at KAFB to provide additional security and resilience were also not quantified. A centralized CSP plant with long-duration storage may complement distributed microgrids and provide additional resilience and security at lower costs.

Table ES-1. Summary of key parameters and findings from the CSP design study.

Parameter/ Finding	Option		Notes
	Sandia NM	Sandia NM + KAFB	
Annual energy required	~300 - 400 GWh	~400 - 600 GWh	Based on actual and projected energy consumption for Sandia NM and KAFB from 2019 – 2040 (Section 2)
Peak load	~30 – 40 MW	~50 – 70 MW	Peak loads are greater in the summer and less in the winter.
CSP plant capacity	50 MW	100 MW	Nameplate capacity exceeds average power requirement of ~30 MW (Sandia) and ~50 MW (Sandia + KAFB) to simultaneously charge storage
Thermal storage capacity	15 hours (750 MWh)	15 hours (1.5 GWh)	Occasional periods with multiple days of cloudiness may yield energy deficits (Section 3.1)
Estimated annual electricity produced	~200 – 300 GWh	~400 – 700 GWh	Predicted using probabilistic model in System Advisor Model (SAM) (Section 3.2)

Parameter/ Finding	Option		Notes
	Sandia NM	Sandia NM + KAFB	
Land and siting requirements	~1000 acres	~2000 acres	Calculated in SAM (Table 1). See Section 3.3.2 for 3D renderings of potential siting locations.
Overnight construction cost	~\$300M - \$400M	~\$500M - \$800M	Calculated in SAM (Section 3.2)
Annual electricity cost avoided	~\$14M	~\$24M	Based on actual cost for electricity consumed by Sandia NM in 2019; total cost of electricity consumed by Sandia NM + KAFB calculated from ratio of annual electricity consumed
Potential annual carbon costs avoided	Up to \$11M	Up to \$22M	Based on existing bills proposed by the 117th congress ranging from \$15 - \$59 per ton of carbon emitted; price escalation not included. See Table ES- 2 for more details.
CO_2 Offsets	~200,000 tons/yr	~300,000 – 400,000 tons/yr	Based on carbon intensity of ~0.6 tons CO_2/MWh for fossil-fuel-based electricity
Annual O&M	~\$2M - \$4M	~\$4M - \$8M	From SAM and JEDI models.
Payback Period	14 – ∞ years	14 – ∞ years	Assumes 4% real interest rate and avoided annual costs of carbon emissions. See Table ES- 2 for more details.
Jobs Created	~1,000 (construction) 60 (operation)	~2,000 (construction) ~100 (operation)	From JEDI

Table ES- 2. Summary of cases for payback period analyses for 50 MW and 100 MW CSP plants.

Parameter	50 MW			100 MW		
	Best Case (with carbon tax)	Best Case (no carbon tax)	Worst Case (no carbon tax)	Best Case (with carbon tax)	Best Case (no carbon tax)	Worst Case (no carbon tax)
Overnight Construction Cost (\$M)	263	263	416	479	479	833
O&M Costs (\$M/yr)	0	0	3.8	0	0	7.6
Avoided Energy Costs (\$M/yr)	14	14	14	24	24	24
Avoided Carbon Tax (\$M/yr)	10.8 (182,400 tons/year avoided at \$59/ton)	0	0	21.7 (376,800 tons/year avoided at \$59/ton)	0	0
Payback period at 4% IRR (yr)	14.1	35	∞	13.9	41	∞

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1. INTRODUCTION AND OBJECTIVES

1.1. Background

Concentrating solar thermal power (CSP) is a renewable energy technology that can provide clean electricity, heat, and long-duration energy storage for utility-scale applications. Unlike solar photovoltaics (PV), CSP uses an array of mirrors and concentrated sunlight to heat media (e.g., molten salt, particles) to high temperatures of ~400 – 600 °C (emerging CSP technologies are achieving even higher temperatures for next-generation power cycles). The heated media can be stored for use at night or when the sun is not shining. When needed, heat is extracted from the stored media via a heat exchanger to heat steam or other working fluids (e.g., supercritical CO_2) to spin a turbine/generator for electricity production. Over six gigawatts of CSP plants are in operation globally, and over three gigawatts are either under construction or in development. Figure 1 provides an illustration of a typical CSP power-tower plant and its major components.

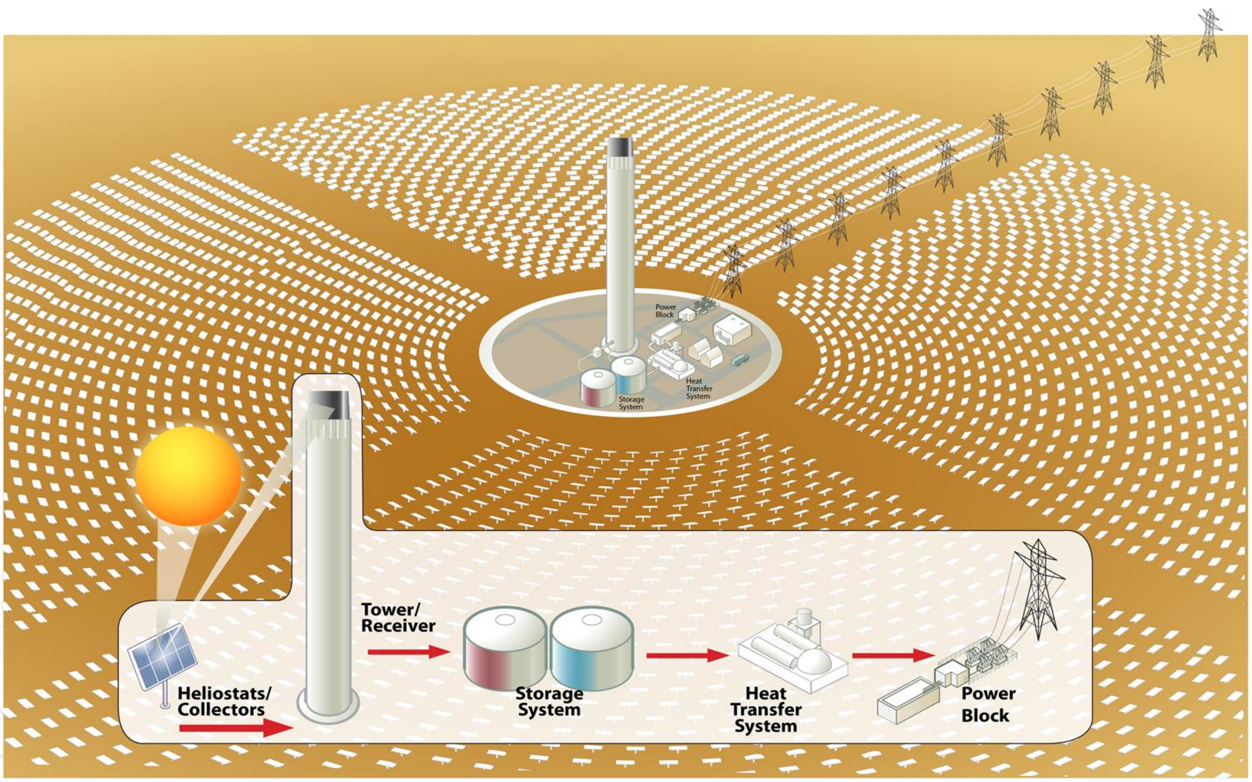

Figure 1. Illustration of a power-tower CSP facility.

Commercial CSP systems were first deployed in the United States in the 1980s (354 MW Solar Energy Generating Systems parabolic trough CSP), including more recent CSP plants with at least 1 GWh of energy storage (Solana Generating Station in Arizona and Crescent Dunes Solar Energy Project in Nevada). Despite these pioneering efforts, no new CSP plants have been under construction or in development in the United States in recent years. The market requirements and policy drivers vary by region and have changed over time, resulting in sporadic development and growth in CSP. Recent market drivers and renewable portfolio standards in the U.S. have favored lower cost solar PV or wind energy. However, as renewable energy penetration onto the grid increases, the need and value for large-capacity, longer-duration storage is being recognized. Studies have shown that for longer-duration storage requirements (> ~6 hours), CSP and thermal energy storage is less expensive than PV plus battery storage [1, 2]. In addition, CSP provides synchronous turbine-based generation for the electrical grid, which can be advantageous over asynchronous inverter-based generation for increased grid stability. Hybridization of CSP with natural gas can also provide increased peaking capacity while drastically reducing reliance on fossil fuels [3]. In other countries, these findings and additional market drivers (e.g., the need to replace expensive and polluting diesel generators) have enabled additional opportunities and deployment of CSP globally.

Recent research and studies demonstrate the feasibility of using CSP to also produce high-temperature process heat (~300˚C – 1000˚C) for industrial and manufacturing applications such as cement and steel production, and solar fuels for heavy transportation. Heavy-duty transportation (e.g., ships, trains, planes) and industrial heating contribute to over a third of global energy consumption [4-6]. Decarbonization of the entire energy sector will be required to reduce greenhouse-gas emissions and achieve climate-change goals set forth in the international Paris Agreement. Through continued advancements in materials, components, and systems integration, CSP technology can be used together with other renewable and carbon-free energy technologies to meet these targets.

1.2. Objectives

The objective of this study was to develop a conceptual design of a CSP plant that can provide clean electricity for Sandia National Laboratories and Kirtland Air Force Base (KAFB) in New Mexico, where Sandia is headquartered. 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.

1.3. Overview of Report

This report first introduces the annual energy requirements of Sandia NM and KAFB in Section 2, with a detailed evaluation of key load centers at Sandia. Section 3 provides a detailed design analysis of a 50 MW and 100 MW CSP plant; a 100 MW plant would be required to offset the electrical energy requirements of both Sandia NM and KAFB, while a 50 MW plant would offset a significant fraction of energy requirements for Sandia NM. A probabilistic model was developed to quantify the uncertainty in both plant performance and costs. Section 4 includes a discussion of other factors such as partners and funding, job creation, payback period, CO_2 offsets, emerging CSP technologies, and increased resilience. Findings and conclusions are summarized in Section 5.

2. ENERGY REQUIREMENTS FOR SANDIA NM AND KAFB

2.1. Annual Load Requirements

In 2019 Sandia's electrical demand ranged from 30 to 40 MW, while the combined Sandia/KAFB demand was between 50 and 70 MW. New high-performance computing capabilities are forecasted to increase Sandia's electrical demand by 12MW before 2023. KAFB has not indicated any substantial future increases in energy demand. Historically Sandia has consumed an average of 250 GWh annually while the combined Sandia/KAFB consumption averages 440 GWh. Sandia's energy forecasts also depict an increase in energy consumption due to new facility additions, aging infrastructure, and high-performance computing demands as represented in Figure 2**.**

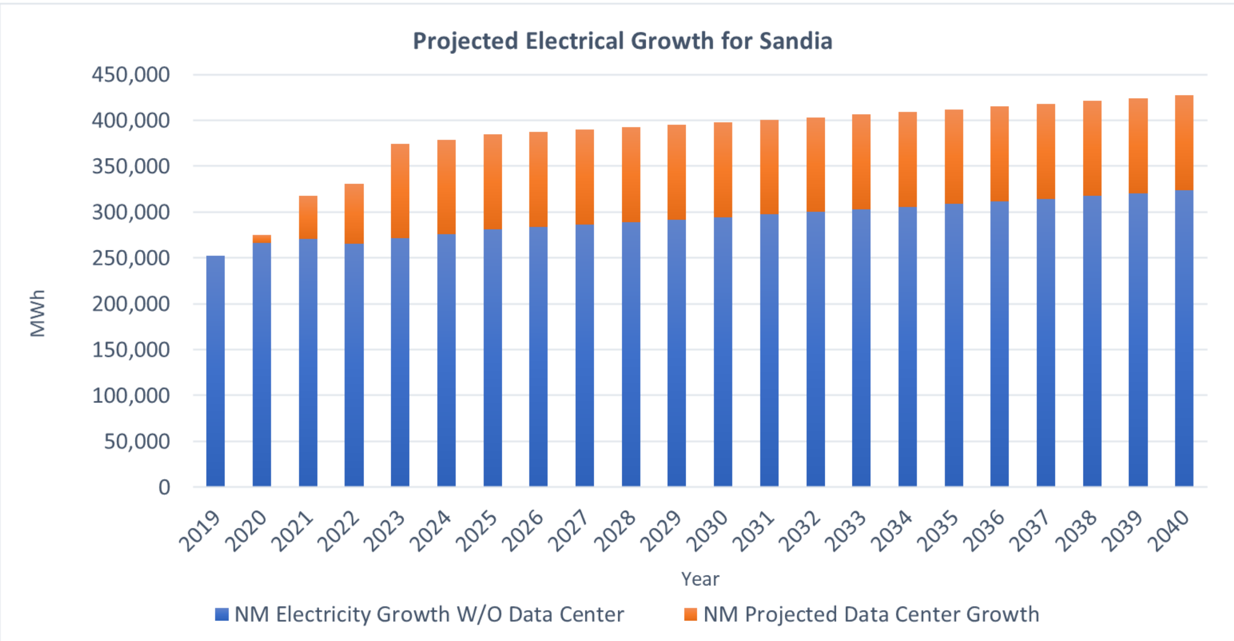

Figure 2. Sandia's forecasted energy consumption. Significant increases in electricity consumption due to data center growth is expected by 2023 (orange bars).

Figure 3 shows the forecasted energy consumption for both Sandia and KAFB to 2040. The combined energy consumption is expected to be just of 600 GWh by 2040.

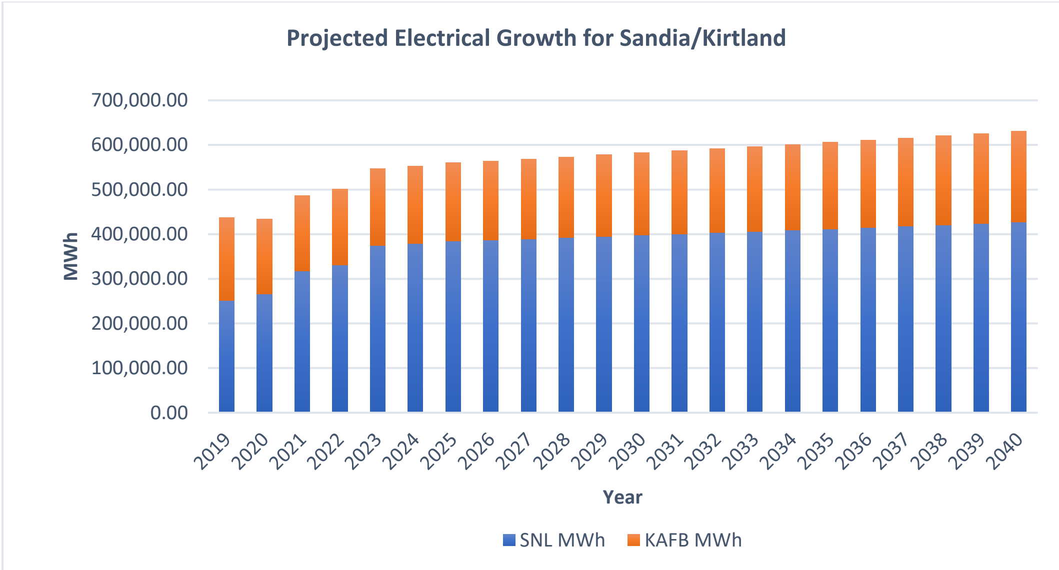

Figure 3. Sandia (blue) and KAFB (orange) forecasted energy consumption.

Sandia NM and KAFB are served by the same utility contract. The sites procure their base power needs from the Western Area Power Administration and procure delivery services from the Public Service Company of New Mexico. Excess power procurement and resale is managed by the Los Alamos County Merchant Desk. The contract structure for Sandia/KAFB is represented in Figure 4. In 2020 the contracted rate for the 35MW Base Block was \$41.40 per MWh, the additional 10MW block had a cost of \$54.85 per MWH and the additional 5MW block had a contracted cost of \$44.50 per MWh. As seen in Figure 4 these block procurements do not provide enough power to meet the Sandia/KAFB demand. Therefore, power must be procured on the open market to make the sites whole.

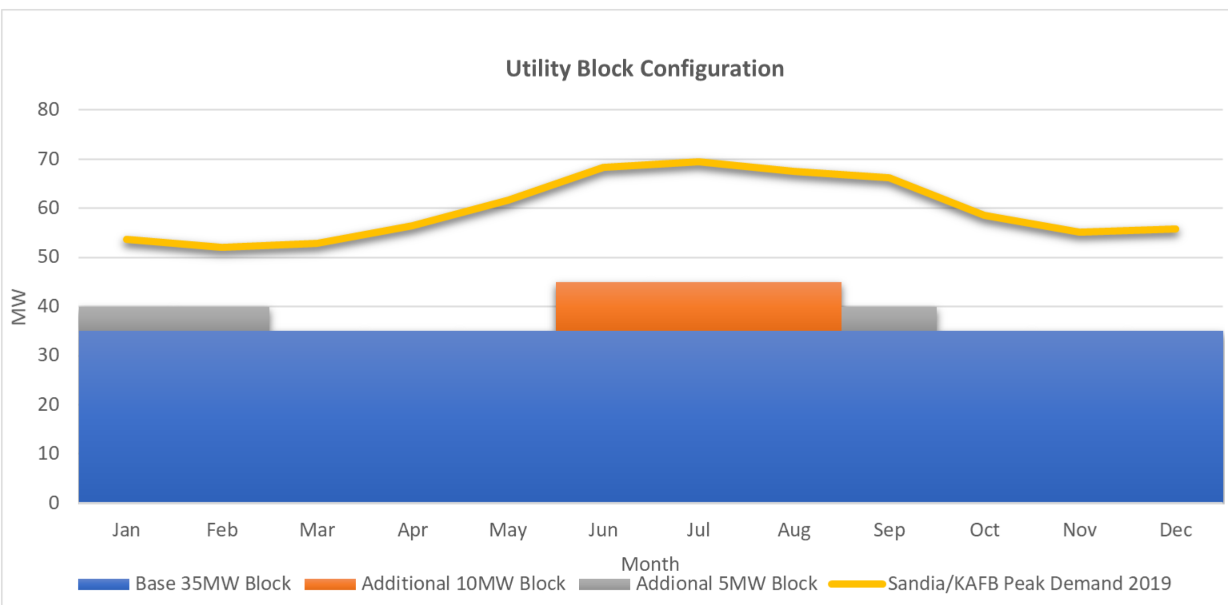

Figure 4. Sandia/KAFB block power procurement structure.

Power that is procured on the open market has variable costs and is dependent on weather and other system conditions. In 2020, Sandia/KAFB experienced market rates as high as $120 per MWh, which is approximately three times more per MWh than average market rates as represented in Figure 5. If Sandia/KAFB had a production source that was able to meet the total demand of the site at a consistent utility rate the sites could be insulated from these extreme situations. The current electrical contract for Sandia and KAFB is up for renewal in 2023.

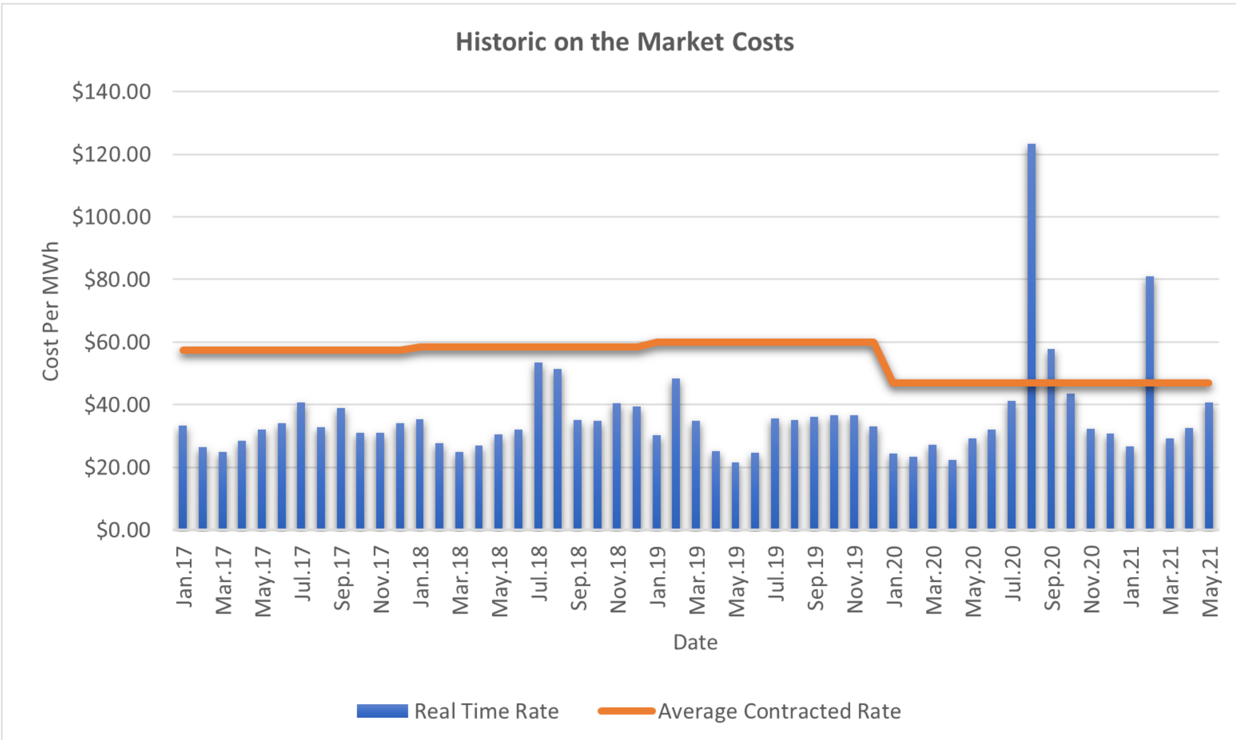

Figure 5. Sandia/KAFB historical market costs and occasional spikes.

2.2. Characterization of Load Profiles

Energy demand at the Sandia National Laboratories site has many complex aspects that will require consideration in an optimal design for a site-wide CSP system. There is a strong base load (constant load) carried by super-computing, industrial processes, and 24-7 lab ventilation that constitutes more than 67% of the site's total electrical energy use[1]. Of the more than 700 buildings owned by Sandia NM, more than 55% of the electric energy for the site (250 GWh/yr) is used by 20 buildings as seen in Figure 6 and Figure 7. Buildings 880A and 725 contribute 22% due to super-computing while 11% is due to the 858 complex of buildings that house industrial silicon manufacturing equipment. Most of the other buildings in the first 55% of power consumption are light or heavy labs with high ventilation requirements.

[1] The numbers provided here are based on energy use in 2017, 2018, and 2019

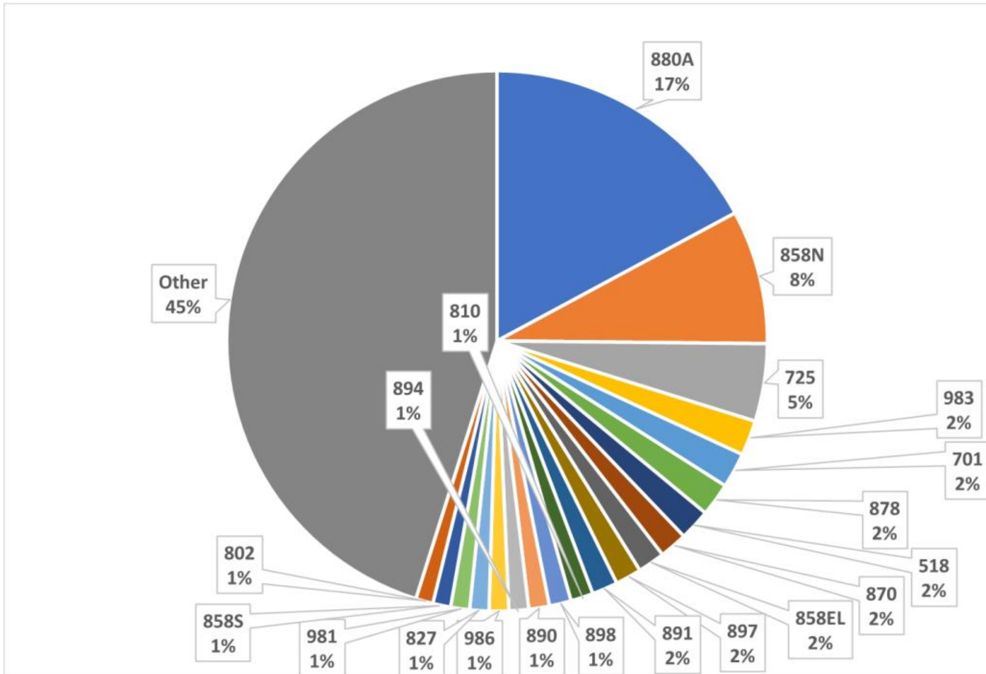

Figure 6. SNL NM site electric energy use by building

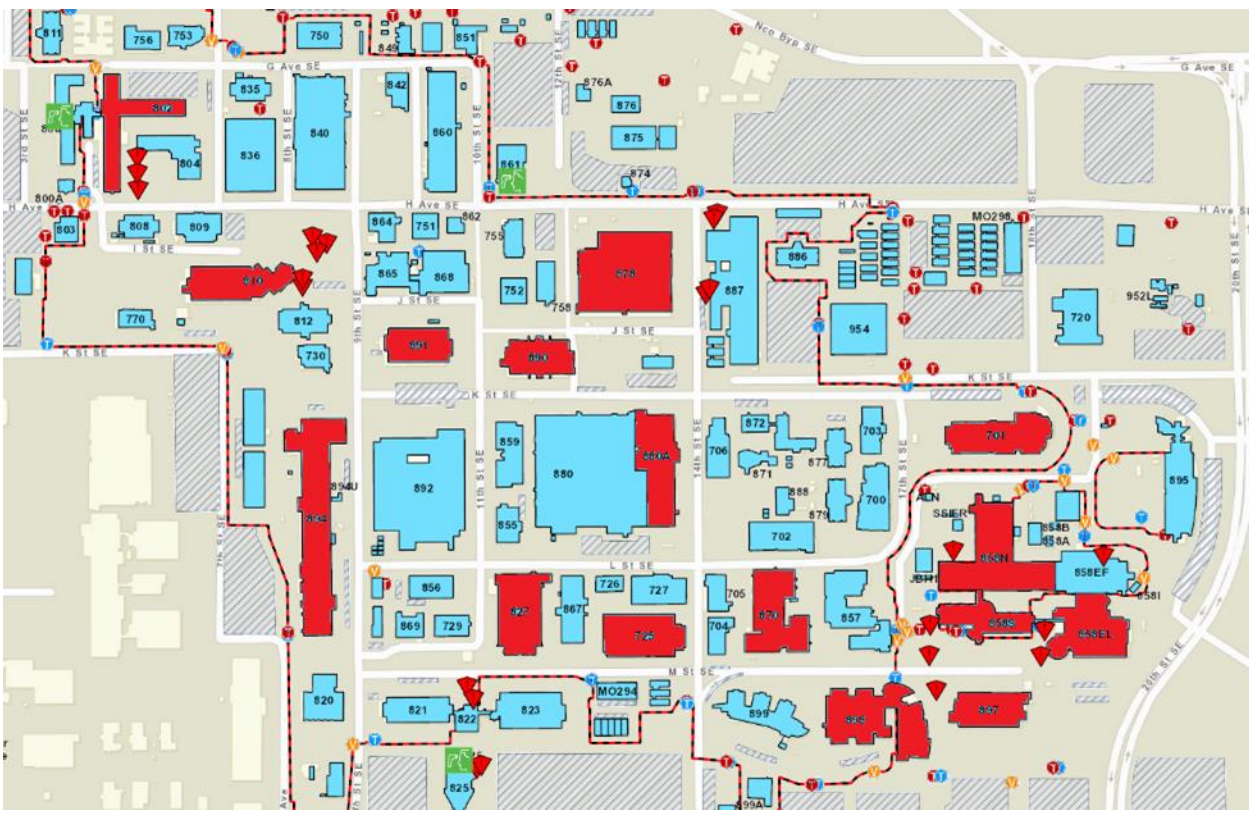

Figure 7. Tech Area I primary energy consuming building locations highlighted in red (983, 986, 981, and 518 are to the south and north).

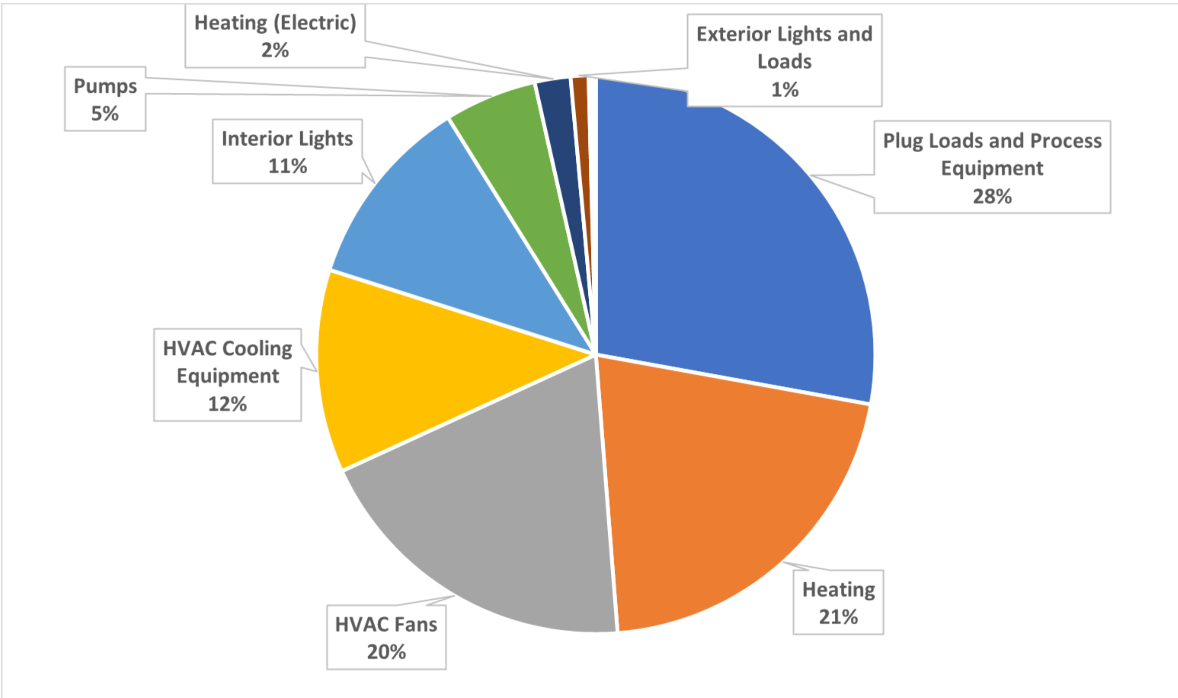

Figure 8. Total energy end use loads as estimated by 96 building energy modeling of the NM site

In addition to electric loads, the natural gas load account for about 23% of site-wide energy (~75 GWh) adding 14.9 kton (13.5 metric kton) of CO_2 emissions per year in addition to the 281 kton attributable to offsite electricity generation and transmission losses. Natural gas is primarily used for heating with the largest consumer, building 878, at around 8% of natural gas use.[2] On an hourly scale, the site power varies significantly with Fridays, holidays, and weekends having much lower peak loads than workdays.

The entire NM site receives power from 16 substations[3] that reduce 115kV high voltage lines to 46kV for further distribution to buildings. The study by Villa (2021) estimated the losses from substation to buildings to have a monthly average of 5.34% for 2019 with a standard deviation of 5.11%. This leads to losses of up to 15.5% for a 95% confidence interval. In addition to this, estimates of the peak load can only be made using partial representation of the site. Only approximately 69% of the yearly site load had reliable 15 min data from 242 building meters as seen in Figure 9. Finally, the site peak load is dependent on temperature and the heat wave study by Villa (2021) quantified near-future heat waves to be expected to reach 43.1°C. All of these factors lead to a site peak load estimated 95% confidence interval at the substation level of 40.13 MW to 75.21 MW with a mean maximum peak load of 53.43 MW. The 50% confidence interval is 49.01 MW to 58.6 MW. The thermal effect of peak load on the site only consists of 1.8 MW increase in peak load due to the 43.1°C heat-wave.

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[2] The mismatch between the building energy modeling and meter are significant for natural gas. The meters for individual buildings are not always reliable but the models often do not contain correct on the ground configurations making this number fairly uncertain. The building energy modeling predicts 878 uses 27% of onsite natural gas

[3] See Villa, Daniel. 2021. "Institutional Heat Wave Analysis by Building Energy Modeling Fleet and Meter Data." *Energy and Buildings*. https://doi.org/10.1016/j.enbuild.2021.110774

Potential load reduction strategies can be envisioned through supercomputing queue managers that allow continuous quantification of load reduction potential based on queue urgency parameters.

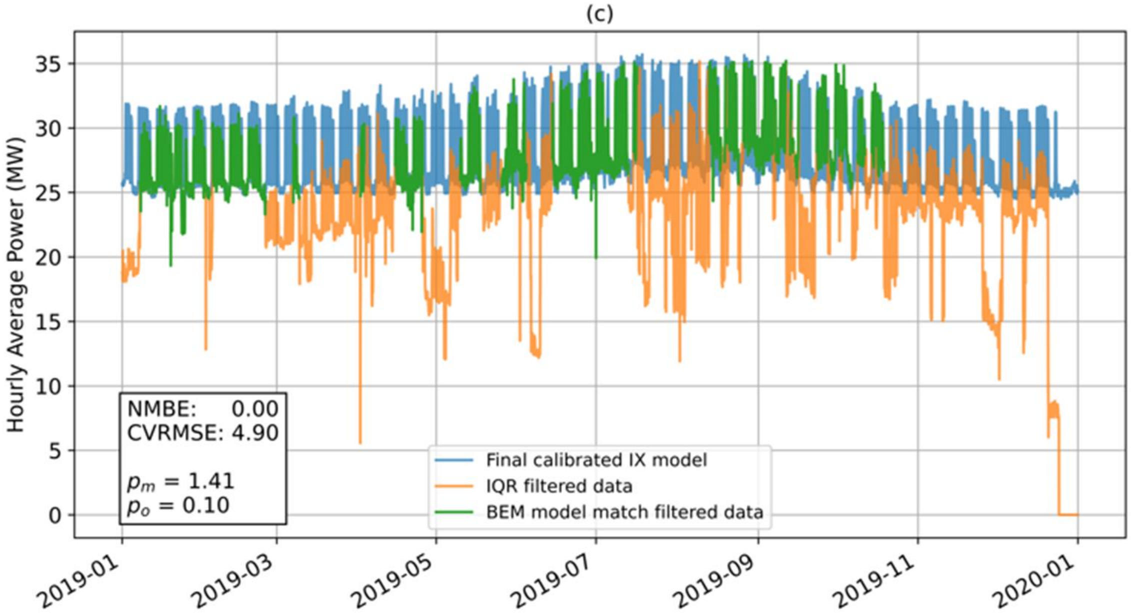

Figure 9. Energy signal for 242 buildings meters (orange) representing 69% of the site-wide load (used with permission from Villa (2021). The meter data has many interrupts or glitches that are better represented for "normal" conditions by 96 building energy models whose aggregate has been calibrated to match the site signal.

3. CSP PLANT DESIGN

3.1. System Overview and Baseline

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 smoky 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 3.2.

The System Advisor Model (SAM), 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 described in Section 3.2.

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]

Figure 10 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 11, 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.

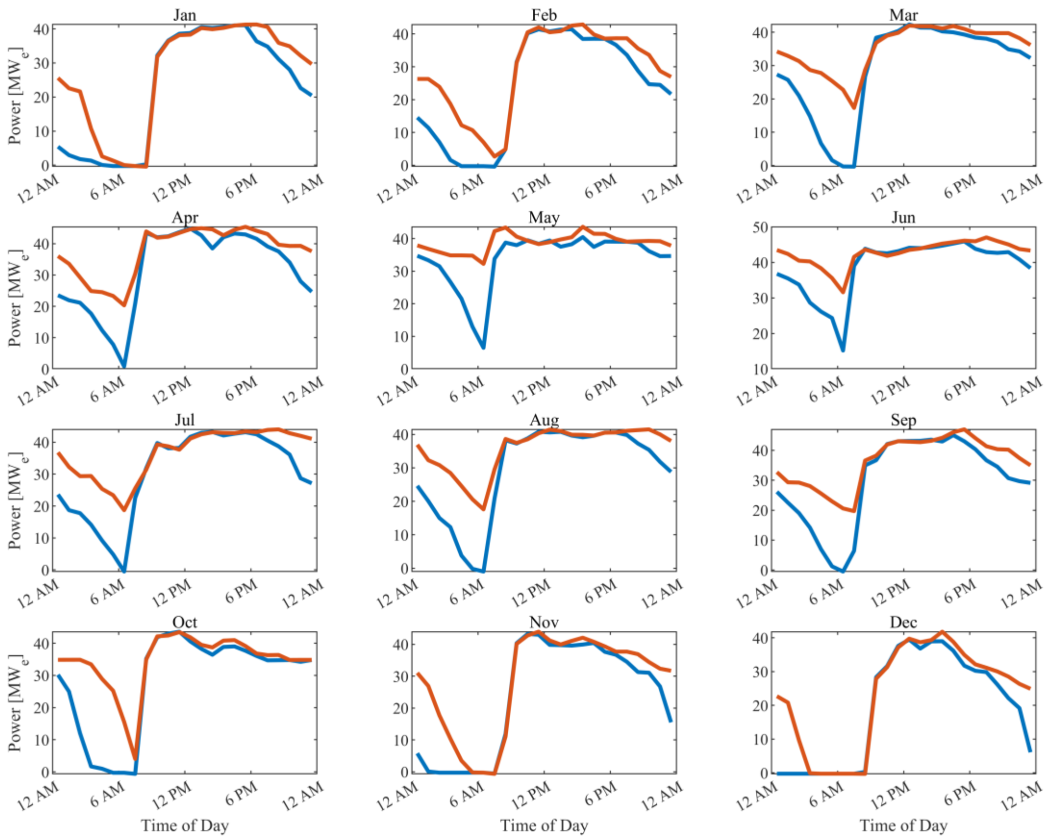

Figure 10. Month-averaged hourly power production for the 50 MW plant scenario with solar multiples of 2.4 (blue) and 3.0 (red).

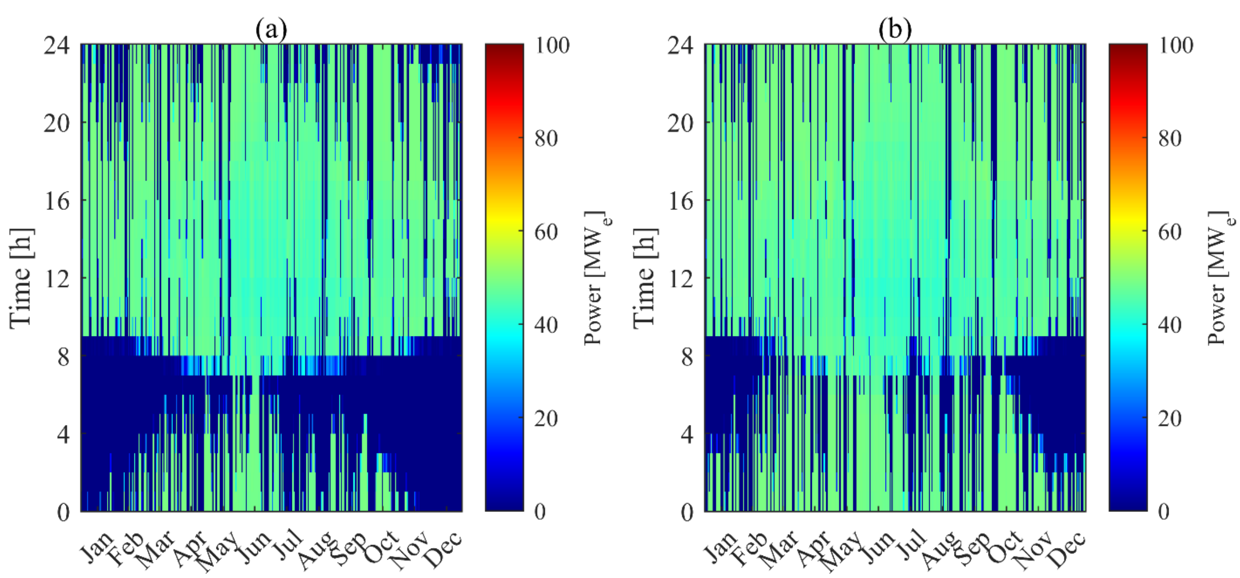

Figure 11. Heat map of month-averaged hourly power production, reported in units of kW, for the 50 MW plant case with solar multiples of (a) 2.4 and (b) 3.0.

Figure 12 and Figure 13 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.

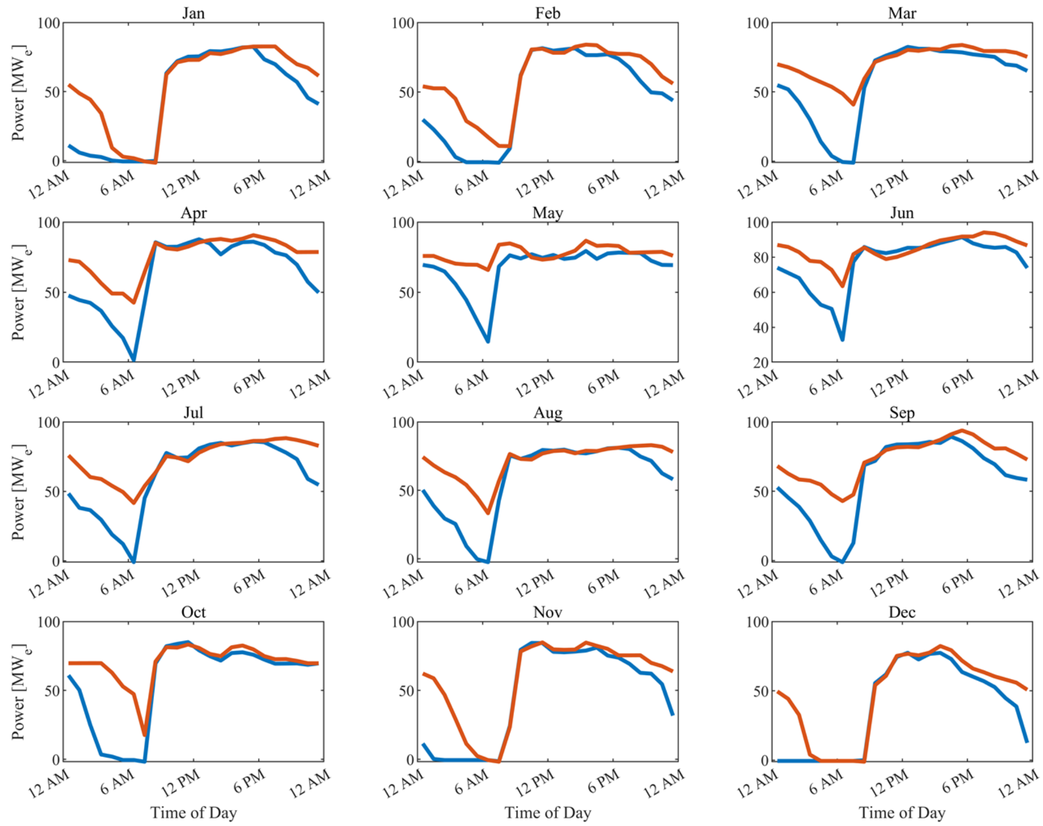

Figure 12. Month-averaged hourly electricity production for the 100 MW plant scenario with solar multiples of 2.4 (blue) and 3 (red).

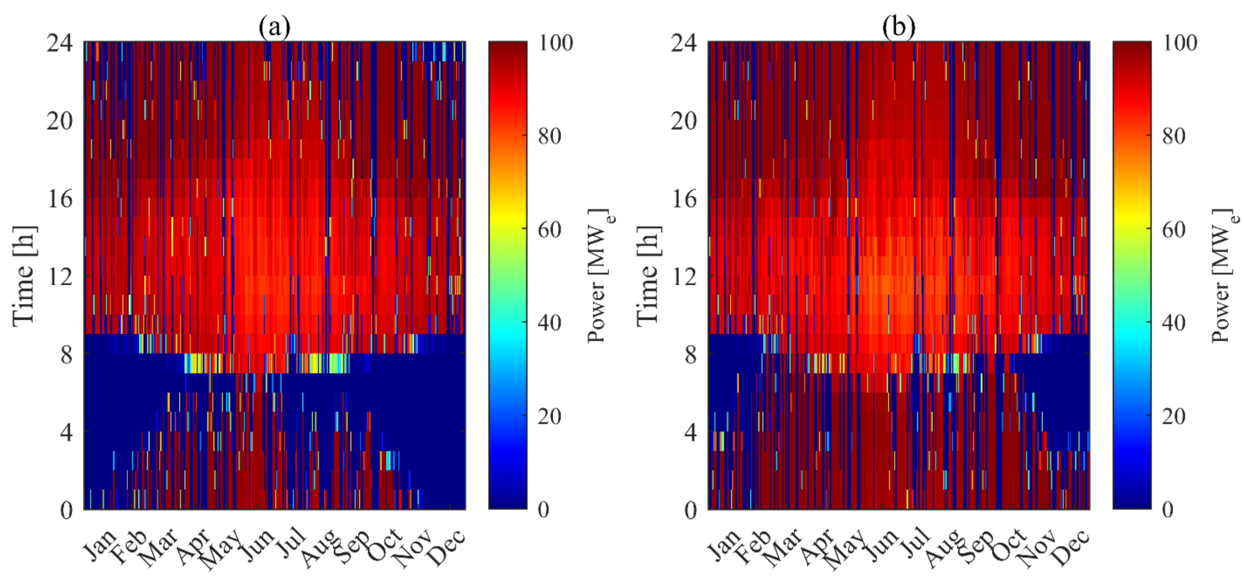

Figure 13. Heat map of month-averaged hourly power production, reported in units of kW, for the 100 MW plant case with solar multiples of (a) 2.4 and (b) 3.0.

3.2. 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 systems defined in Section 3.1. 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 [7] 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

Parameter	Baseline Value	Uncertainty Distribution	Basis
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$]	30.0	[15.0 - 45.0]	Symmetric range about default value; lower limit based on DOE 2030 cost target
Fixed Tower Cost [$]	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 [8]
Receiver Heat Loss [kW$_t$/m^2]	30.0	[29.2 - 190]	Receiver efficiency range between 80% and 96% (blackbody efficiency) [9]

The resulting plant economics from the probabilistic studies were characterized in terms of their Cumulative Distribution Functions (CDFs). Figure 14 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]

Parameter	50 MW Plant		100 MW Plant	
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

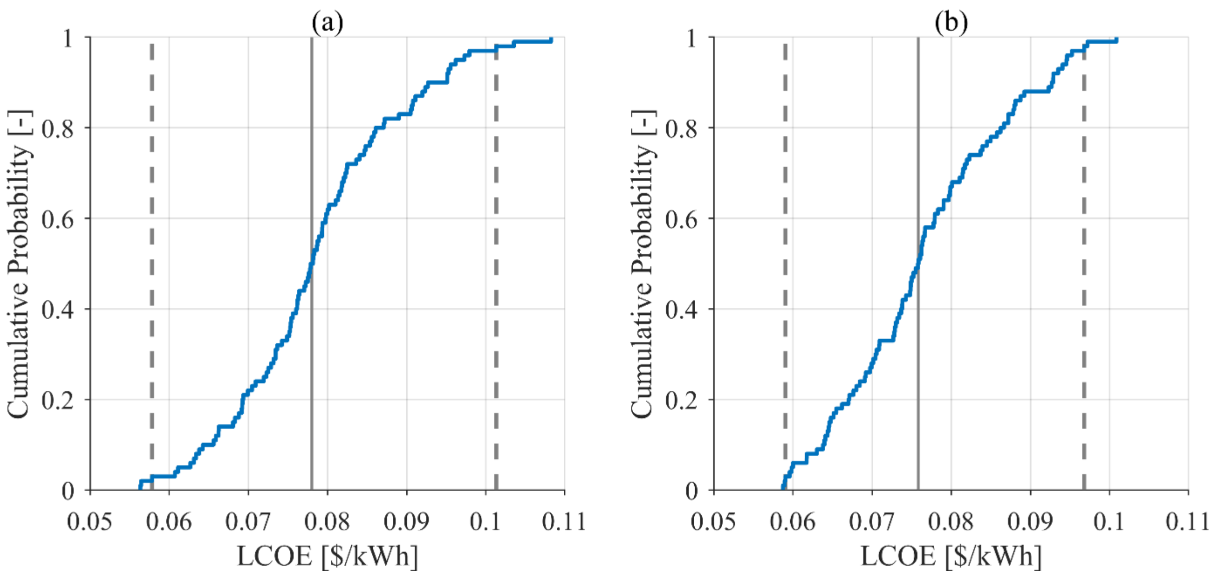

Figure 14. Levelized cost of electricity from the System Advisor Model probabilistic study for the (a) 50 MW and (b) 100 MW plant scenarios with solar multiples of 3.0. Cost is represented in terms of the cumulative probability, median value (vertical line), and 95% confidence values (vertical dashed lines).

Figure 15 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.

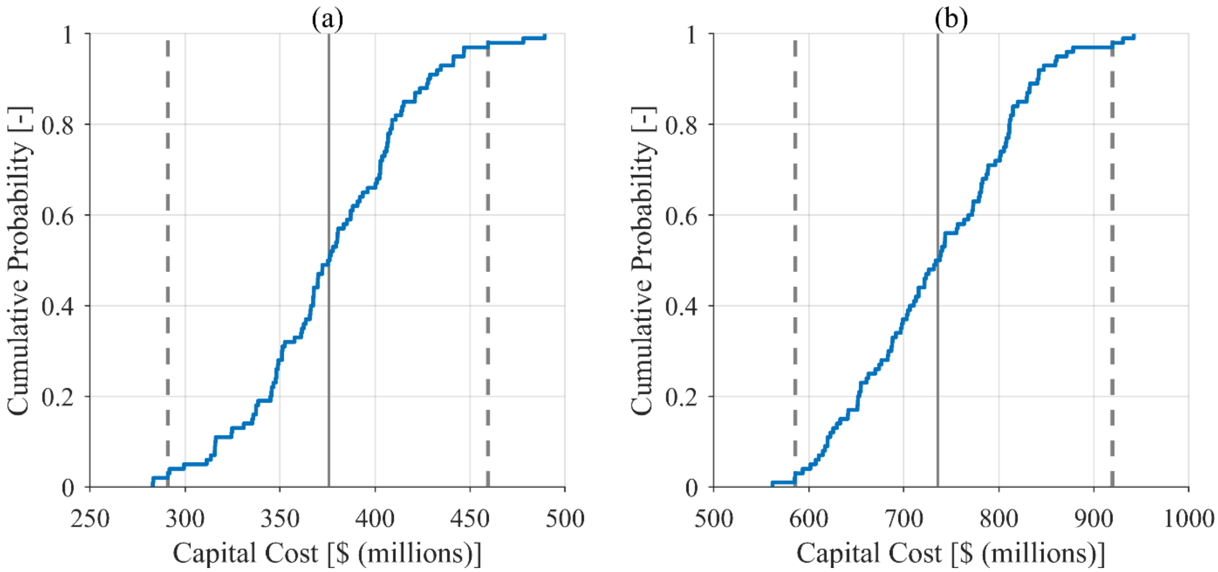

Figure 15. Net plant capital cost from the System Advisor Model probabilistic study for the (a) 50 MW and (b) 100 MW plant scenarios with solar multiples of 3.0. Cost is represented in terms of the cumulative probability, median value (vertical line), and 95% confidence values (vertical dashed lines).

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 16 contains the regression coefficients for the 50 MW, 3.0 solar multiple plant scenario for (a) LCOE and (b) net capital cost. 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.

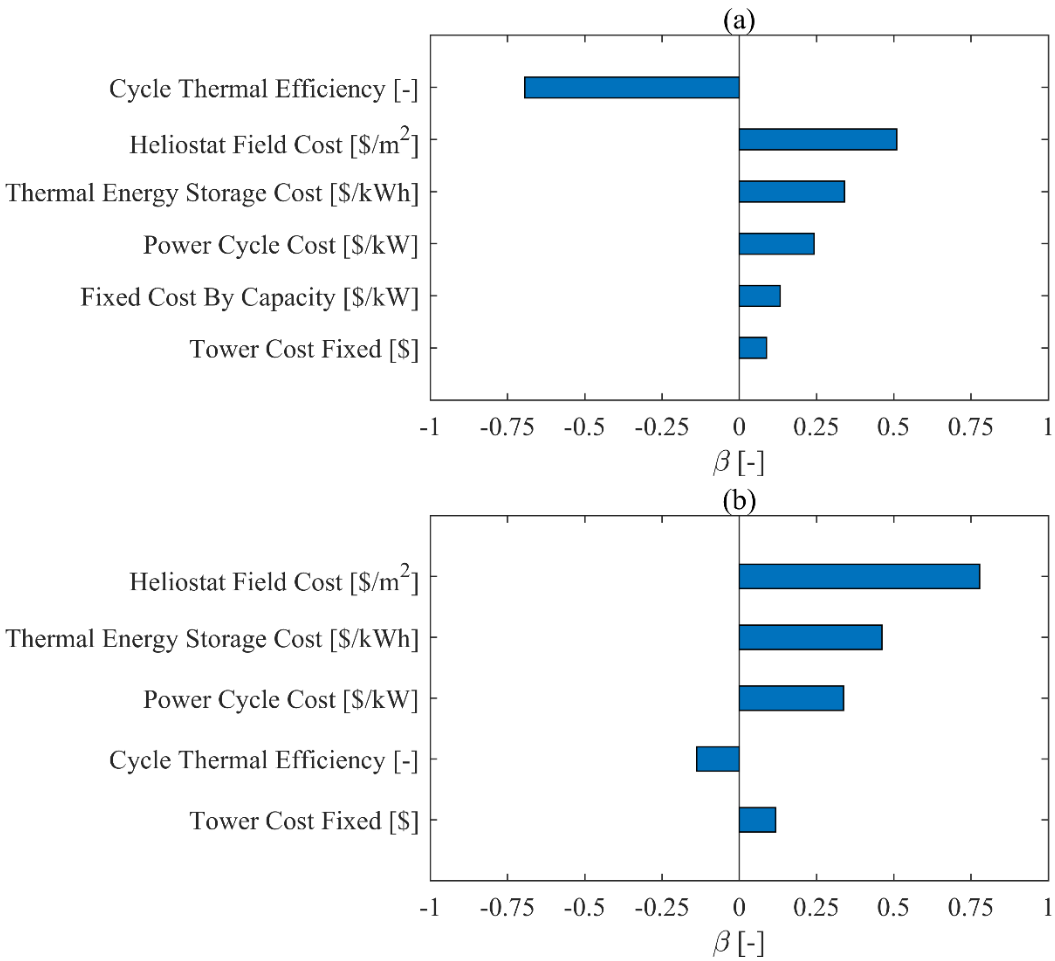

Figure 16. Rank regression coefficients from the System Advisor Model probabilistic study for the 50 MW, 3.0 solar multiple plant scenario for (a) levelized cost of electricity and (b) net plant capital cost.

Figure 17 includes equivalent plots of the regression coefficients for the 100 MW, 3.0 solar multiple plant. The trends in LCOE and capital cost dependence upon the study inputs were highly consistent with the 3.0 solar multiple, 50 MW case. The ranked regression coefficients calculated for the 2.4 solar multiple scenarios were qualitatively the same as those for the 3.0 cases, and therefore are not shown.

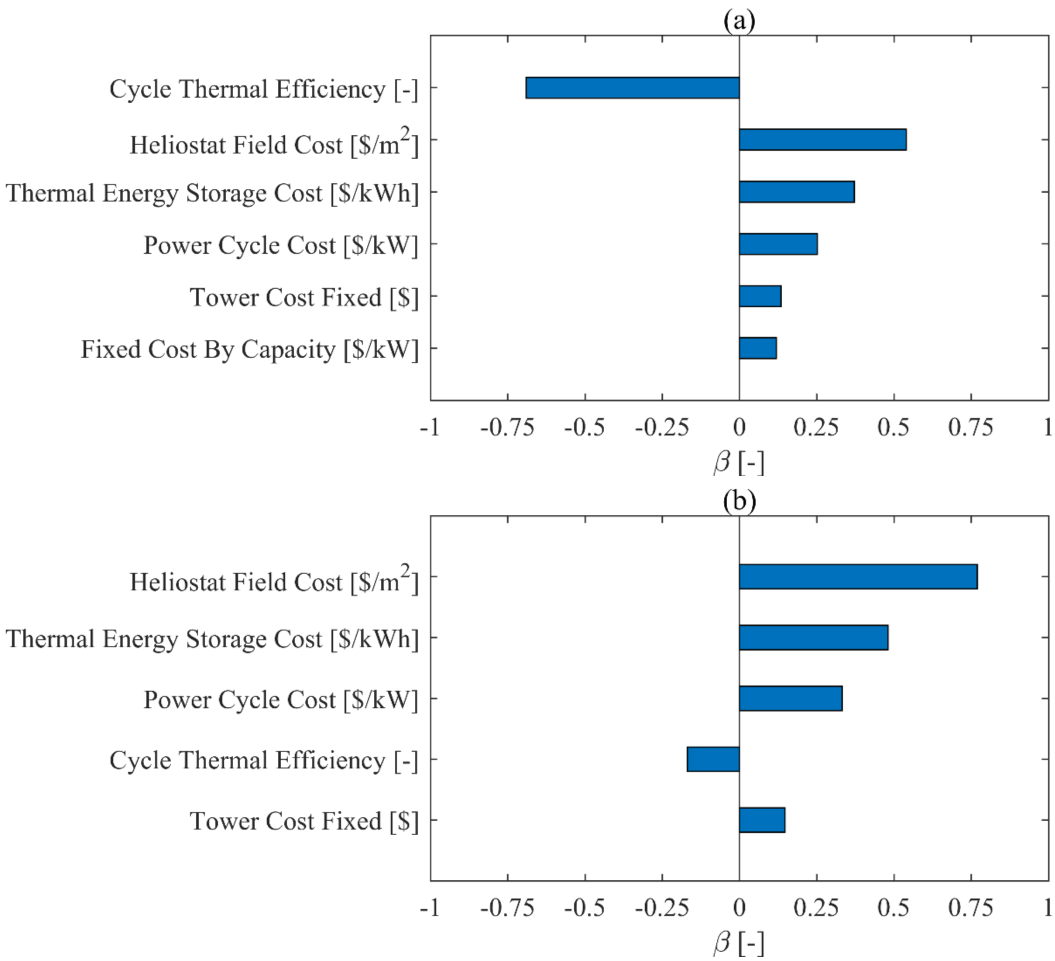

Figure 17. Rank regression coefficients from the System Advisor Model probabilistic study for the 100 MW, 3.0 solar multiple plant scenario for (a) levelized cost of electricity and (b) net plant capital cost.

3.3. Siting Considerations

3.3.1. Environment and Solar Resource

Sandia NM and KAFB are in proximity to the Sandia and Manzano mountains which lead to reductions in the amount of direct solar radiation received for specific locations. Using direct normal radiation data obtained from Sandia's own solar PV weather station with details in Villa (2021) [10], significant reductions in Direct Normal Irradiance (DNI) were calculated for weather years 2017-2020 and TMY3 data [11]. The TMY3 data, used in the analysis outlined in section 3.1, are for a different station at Albuquerque International Sunport.

Table 4. Average daily irradiance over several years [10, 11].

Dataset	DNI ($kWh/m^2/day$) (yearly average)
2017	7.13
2018	7.24
2019	6.80
2020	7.27
TMY3	6.72

These observations are in good agreement with the National Solar Radiation Database (NSRDB) where values of 7.0-7.2 $kWh/m^2/day$ were queried [11]. There are significant variations in the local DNI close to the mountains ranging from 6.5-7.0 $kWh/m^2/day$ near the mountain and 7.0-7.5 $kWh/m^2/day$ away from the mountains as seen in Figure 18.

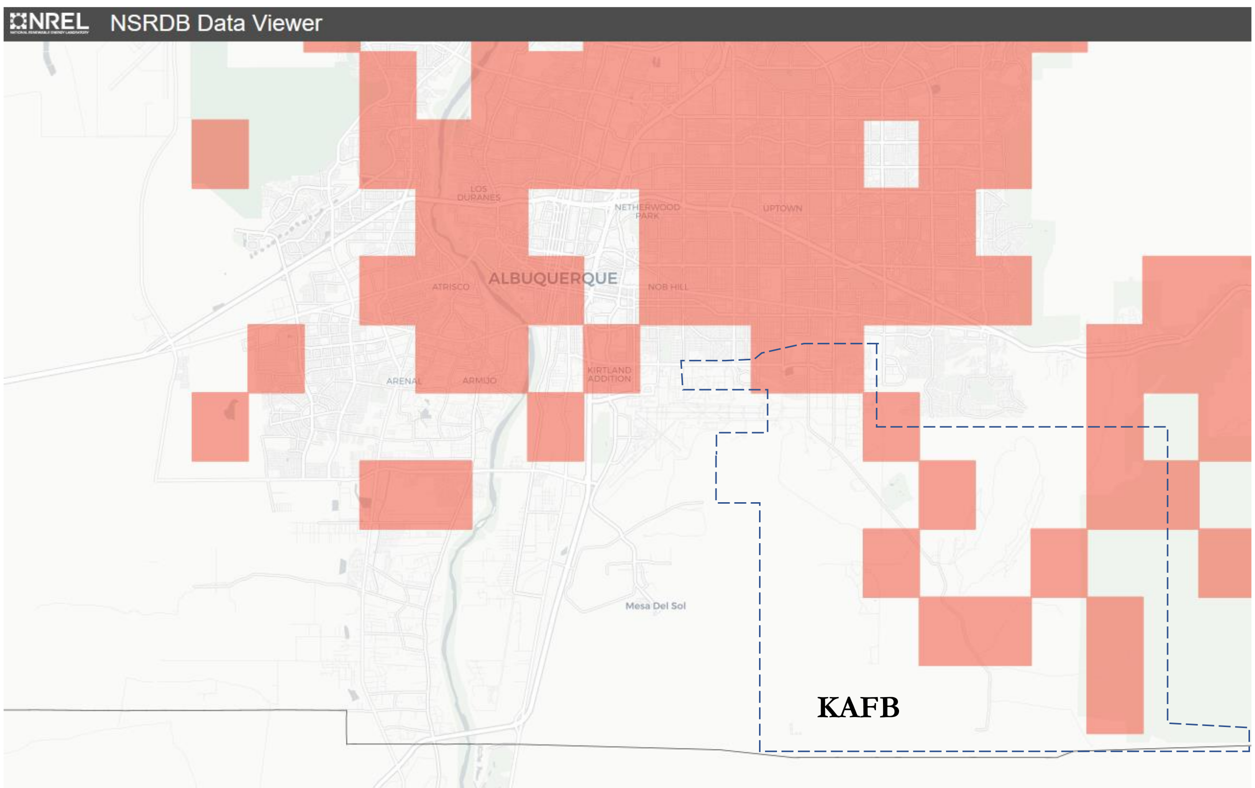

Figure 18. NSRDB regions where DNI ranges from 6.5 - 7.0 $kWh/m^2/day$ in red. All other regions are 7.0 - 7.5 $kWh/m^2/day$. Approximate boundary of KAFB is shown by dashed lines.

3.3.2. *Land Availability*

Figure 19 - Figure 23 show potential locations for siting either a 50 MW or 100 MW CSP plant, which would require approximately 1000 and 2000 acres, respectively (see Table 1). Depending on the location and size of the plant, some existing assets of SNL or KAFB will likely need to be relocated. Also, some of the best space for higher DNI values is just outside the KAFB fenceline (Figure 18). Further research will be needed to determine if this land could be acquired or leased in some way. Gaining approval for the use of specific land will involve many stakeholders and ecological considerations, and the sites shown in the below were only chosen to minimize existing asset displacement. The lower left site in Figure 19 is off of KAFB while the lower right site is on KAFB but has more interference with existing roads and facilities. The site with the least interference is the ~1000 acre (~50 MW) option, which is also very close to the Eubank substation that feeds SNL. A downside to this site might be increased shading from the mountains to the southeast. 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 Federal Aviation Administration requirements have not been considered in the placement of each of these sites.

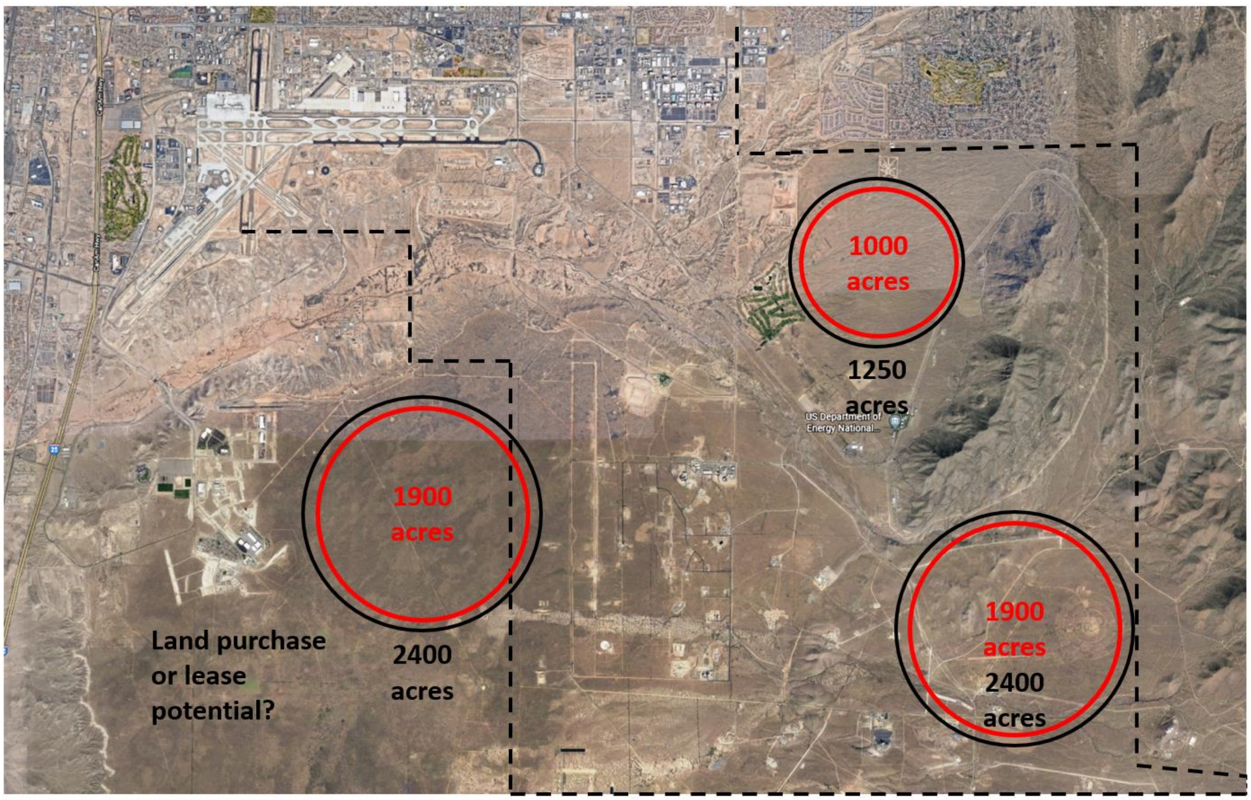

Figure 19.Three potential sites for 100 MW (1900-2400 acres) and 50 MW (1000-1250 acres) CSP plants with 15 hours of storage. The KAFB boundary is depicted by dashed lines.

Figure 20. A potential 1900-2400 acre site off of KAFB for a 100 MW CSP plant (looking SW from Sandia NM).

Figure 21. Second potential 100 MW site on KAFB between mountains (looking SE).

Figure 22. 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]).

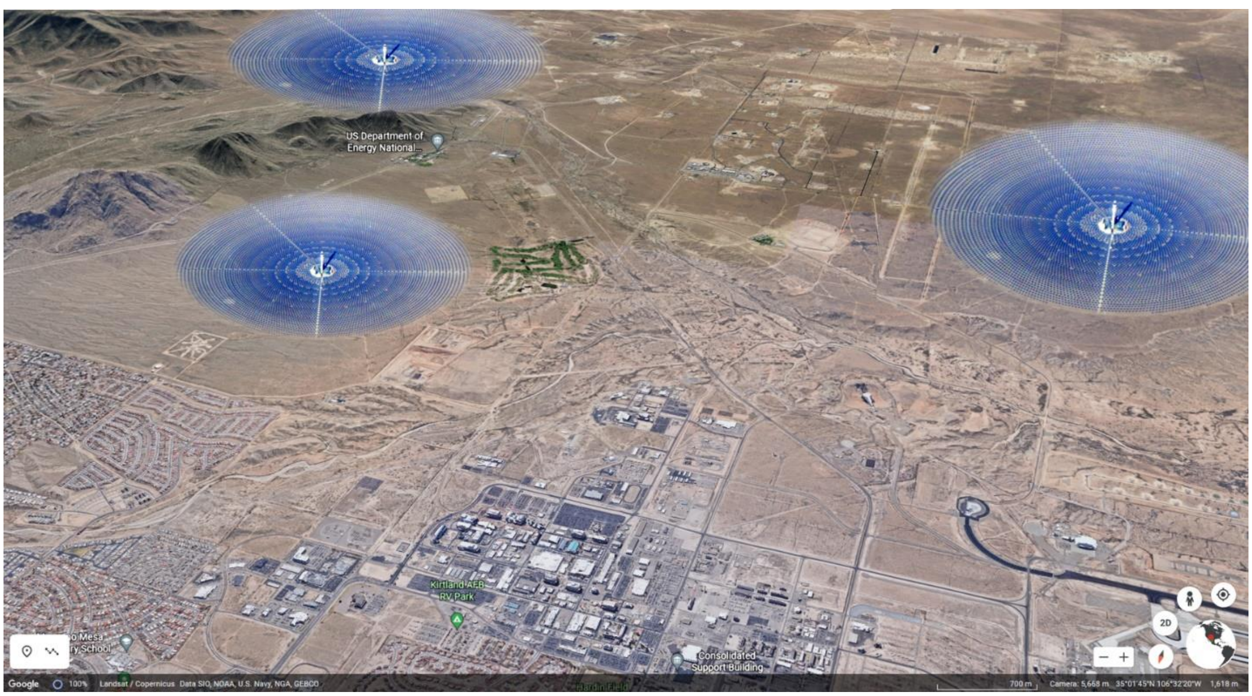

Figure 23. All three prospective sites. Perspective is making the 100 MW facilities look slightly smaller due to parallax

3.3.3. *Additional Siting Considerations*

Additional factors and considerations would need to be assessed when siting a power plant on KAFB, such as security requirements and access. Unique requirements for operating on KAFB may pose additional challenges, but additional security may be beneficial as well.

3.4. Interconnections and Logistics

Siting and interconnecting a system on the Sandia/KAFB campus will require coordination with the Public Utility Company of New Mexico (PNM), the Western Area Power Administration (WAPA), the National Nuclear Security Administration (NNSA), KAFB's 377th Civil Engineering Division (CE), and Sandia. A high-level description of this coordination is being provided as a reference; however, requirements are subject to change and many unknowns exist due to the uniqueness of this project. Table 5 lists some relevant stakeholders at NNSA and KAFB that we will be meeting with to discuss the conceptual project. Meetings with PNM and WAPA will be held separately.

Table 5. List of relevant stakeholders at NNSA and KAFB.

Name	Organization	Job Description
Sheila Rednose	DOE/NNSA/SFO	Disposition, Real Estate, and Utilities
Wayne Evelo	DOE/NNSA/NA-50/NA-533	NNSA Corporate Utilities Program Manager
Mathew OGrady	DOE/NNSA/NA-50/NA-533	General Engineer
Mike Myers	Contractor to DOE/NNSA	Sustainability Specialist
Manny Gabaldon	KAFB 377th CE	Chief, Operations Engineering
Ron Chavez	KAFB 377th CE	Operations Engineer
Cliff Richardson	Contractor to KAFB 377th CE	Base Energy Manager

Coordination with KAFB CE should start with the Infrastructure Operations, Real Property, and Environmental groups. This project will likely require AFCEC involvement and approval. This should be done during the preliminary design phase. An AF Form 332 (Base Civil Engineer Work Request) will need to be submitted to CE. The results of that from will determine all siting and permitting documentation required for the project. Due to the scope of this project, it is expected that the following will be required as a result:

- Approval of proposed location by the KAFB siting team including a review of potential archeological, historical, hazard, ecological and other siting concerns.
- NEPA Review which will likely trigger an Environmental Impact Assessment
- Real Property lease agreements
- Permitting for a Storm Water Pollution Prevention Plan
- Permitting for dig permits
- Permitting for any welding related activities
- Permitting for Fugitive Dust

If the systems evaluated in this study are ever conceptualized, coordination with local utilities will be a critical. The following is a summary of the processes required for interconnection of a power generating station at Sandia. This process was defined in the Brayton Cycle Generation Units Report on Interconnection Process, Cost and Time Schedule prepared by Montech Inc. (Technical Direction #FA1-SNL-2019-02).

1) Complete design of system to include distribution interconnection specification, operating procedures, net output of the system and the scheduling of unit output.
   a) Provide specifications for the generator, inverter, and interconnection facilities.
   b) Design must meet PNM interconnection and safety standards for customer owned generation facilities.
   c) Design and specification shall define:
      i) schedule for when the unit(s) will be online
      ii) how far ahead the schedule can be determined
      iii) reliability of the system
2) Submit a completed PNM interconnection application. Complete and file an interconnection application with WAPA. (note: fees may apply)
   a) File and interconnection application with WAPA
      i) Http://www.oasis.oati.com/wapa/wapadocs/wapa-oatt-sgip-application-effective-2019-0603.pdf
3) WAPA and PNM will review the interconnection application. PNM will perform a system impact study.
   a) WAPA has a network operating agreement with PNM.
   b) WAPA will file an interconnection request with PNM.
   c) PNM will review the application in accordance with NM public regulatory commission rule 17.9.568. This review will include a system impact study to determine impact on the existing power system and potential operating restriction and additions to and/or modifications of the system.
4) Negotiations will be held with PNM and WAPA until an interconnection agreement is agreed upon and executed.
   a) PNM, WAPA and other involved partied will sign an agreement that defines the terms of the interconnection.
5) Designs may need to be revised in order to comply with the executed interconnection agreements.
   a) Systems interconnected with the grid will be
      i) Tested in accordance with industry standards for continuous utility interactive operation, and
      ii) Be labeled and publicly listed by the NRTL at the time of the interconnection appliance
6) Order long lead time equipment and issue bid packages for construction.
7) Construction and interconnection.

It should be noted that if the CSP plant were built and operated as an islanded system, an entirely new electrical contract structure would have to be developed. In addition, in order to provide energy to Sandia NM and KAFB when islanded generation and storage were depleted, or for black start capabilities, interconnections with the grid would still be required. Communicating and coordinating with PNM, WAPA and/or the Los Alamos County Merchant Desk may provide additional insight and options.

4. DISCUSSION

4.1. CO_2 Offsets

Data from the Energy Information Administration and Environmental Protection Agency were used to estimate the carbon intensity of the electricity produced in New Mexico in 2019, which was approximately 0.6 tons of CO_2/MWh [12, 13]. For 2019 electricity consumption levels of 250 GWh by Sandia NM and 440 GWh by Sandia NM and KAFB combined, the annual carbon emissions were therefore approximately 150,000 tons and 260,000 tons, respectively. The total annual carbon emissions of Sandia NM and KAFB combined are equivalent to the annual carbon emissions of ~50,000 – 60,000 cars [14]. The estimated avoided carbon emissions over a 30-year lifetime of a 100 MW CSP plant producing between 500 – 600 GWh of electricity annually (see Table 1) is ~9 – 11 million tons of CO_2.

The production and consumption of energy in New Mexico in 2018 are shown in Figure 24. The end-use applications for consumption include electricity (~40%), heating (~30%), and transportation fuels (~30%). Nearly 80% of New Mexico's electricity was generated with non-renewable resources that contribute to the state's carbon emissions. New Mexico's Energy Transition Act requires 50% of the electricity generation in New Mexico to be carbon free by 2030 [15]. Assuming the total average annual electricity consumption in NM through 2030 remains at ~90,000 GWh (~300 trillion BTUs per year), half of the electricity consumed, or ~45,000 GWh, would need to be from carbon-free sources. Solar photovoltaics, wind, and hydro-electricity already provide ~20,000 GWh (~70 trillion BTUs) of clean electricity. A CSP plant that produces ~500 GWh per year in Albuquerque would offset ~2% of the remaining ~25,000 GWh required to achieve NM's 50% carbon-free goal by 2030. In addition, a CSP plant in Albuquerque would avoid extensive high-voltage transmission infrastructure that may be required if alternative renewable energy plants were sited far from Albuquerque.

Currently, carbon emitted in the US does not have an associated cost, but several bills proposed in the current 117th congress seek to impose a price on carbon [16]. Each bill would impose an initial price per ton of carbon emitted followed by an increase in price for each subsequent year, outlined in Table 6. The price escalation clauses contained in the bills are dependent on the rate of inflation and contain stipulation which vary the rate of price increase based on emission targets.

An analysis of the potential costs of carbon avoided through the consumption of electricity generated by CSP is summarized in Table 7. For simplicity, the stipulations are ignored and the inflation is assumed at the 2% average yearly rate measured since 2000 [17].

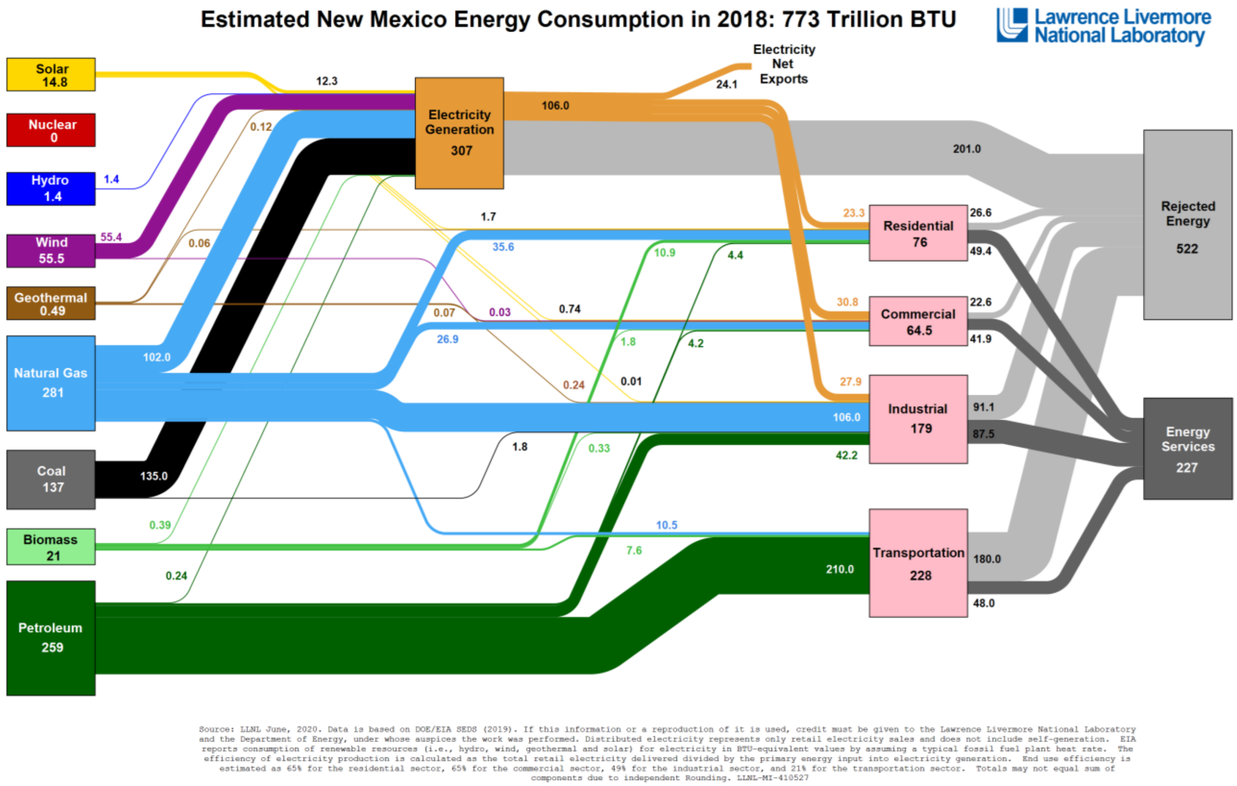

Figure 24. New Mexico energy consumption by source [18]. The end-use applications include electricity (~40%), heating (~30%), and transportation fuels (~30%).

Table 6. Bills proposed for the implementation of a price on carbon in the 117th congress [16].

Bill	Initial Price ($/ton)	Year Initiated	Annual Rate of Increase
Energy Innovation and Carbon Dividend Act	15	2023	$10 above inflation
America's Clean Future Fund Act	25	2022	$10 above inflation
MARKET CHOICE Act	35	2023	5% + inflation
Save Our Future Act	54	2023	6% above inflation
America Wins Act	59	2022	6% + inflation

Table 7. Carbon avoidance of 50MW and 100 MW CSP systems.

Parameter	50 MW Baseline Value		100 MW Baseline Value	
Solar Multiple [-]	**2.4**	**3.0**	**2.4**	**3.0**
Annual Energy [GWh]	275	304	518	613
Carbon Offset [tons/year]	165,000	182,400	310,800	367,800
Avoided cost of carbon [$M/year][1]	2.5-9.7	2.7-10.8	4.7-18.3	5.5-21.7
Portion of NM 50% Carbon Free Goal	1.1%	1.2%	2.1%	2.5%

[1] These values are representative of the initial price on carbon and do not reflect the price escalation clauses.

4.2. Payback Period

A payback period analysis was conducted in coordination with the SAM and CO_2 offset analyses in Sections 3.2 and 4.1. The payback period was estimated with: 1) The overnight cost of construction in Table 3 as a single negative payment in year 1, and 2) The balance of energy costs avoided plus potential carbon taxes avoided (Table 8) minus operations and maintenance costs as an annually compounded amortized yearly payment with specified Internal Rate of Return (IRR). This structure is shown in Figure 25.

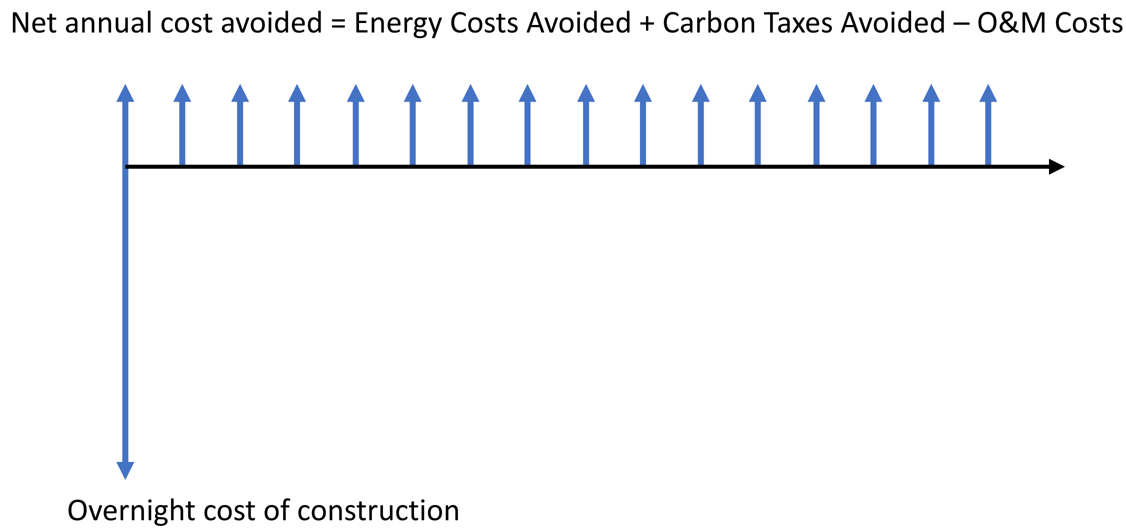

Figure 25. Payment structure for payback period.

The payback period is the time it would take to reach a Net Present Value (NPV) of zero with the payment structure in Figure 25 for a given IRR. The equation to find the number of years at which Net Present Value (NPV) equals zero is:

$$P(construction) - P(A, IRR, N_y) = 0$$

$$P(A, IRR, N_y) = A\frac{(1 + IRR)^{N_y} - 1}{IRR(1 + IRR)^{N_y}}$$

Here P is present cash value operator, A is the yearly net cost avoided, and $P(A, IRR, N_y)$ is the transformation of A into present value. For a given IRR, the integer number of years after construction, N_y, can be found with a nonlinear solver. For the fixed P and A in this analysis the IRR has an upper limit:

$$IRR_\infty \geq \frac{A}{P(construction)}$$

The time to NPV=0 for a given IRR for both plants is highly dependent on the cost of maintenance and of energy for the site. The highest and lowest values from other parts of this report for each cost are recorded in Table 8.

Table 8. Costs (and avoided costs) for payback period assessment.

Parameter	50 MW			100 MW		
	Best Case (with carbon tax)	Best Case (no carbon tax)	Worst Case (no carbon tax)	Best Case (with carbon tax)	Best Case (no carbon tax)	Worst Case (no carbon tax)
Overnight Construction Cost ($M)	263	263	416	479	479	833
O&M Costs ($M/yr)	0	0	3.8	0	0	7.6
Avoided Energy Costs ($M/yr)	14	14	14	24	24	24
Avoided Carbon Tax ($M/yr)	10.8 (182,400 tons/year avoided at $59/ton)	0	0	21.7 (376,800 tons/year avoided at $59/ton)	0	0
Payback period at 4% IRR (yr)	14.1	35	∞	13.9	41	∞

Table 8 contains six cases (best case with carbon tax, best case without carbon tax, and worst case without carbon tax) for the 50 MW and 100 MW plants using estimated construction costs, operations and maintenance (O&M) costs, avoided electricity costs, and avoided carbon costs that were solved over IRR from $\frac{IRR_\infty}{100}$ to $IRR_\infty - \frac{IRR_\infty}{100}$. The best case assumes the low end of the construction and O&M costs, which the worst case assumes the high end of the construction and O&M costs. The results are shown below in Figure 26 for an assumed real IRR of 4%. The dashed lines represent the best case, which yields a payback period of ~14 years for both the 50 MW (black line) and 100 MW (red line) plants. The solid lines represent the best case without carbon taxes, with payback periods of ~35 and 41 years for the 50 MW and 100 MW plants, respectively. For the worst-case scenario, the payback period is infinite. If the construction costs are in the mid to high range of the cost estimates, a carbon tax would need to exist for either 50 MW or 100 MW project to have a finite payback period.

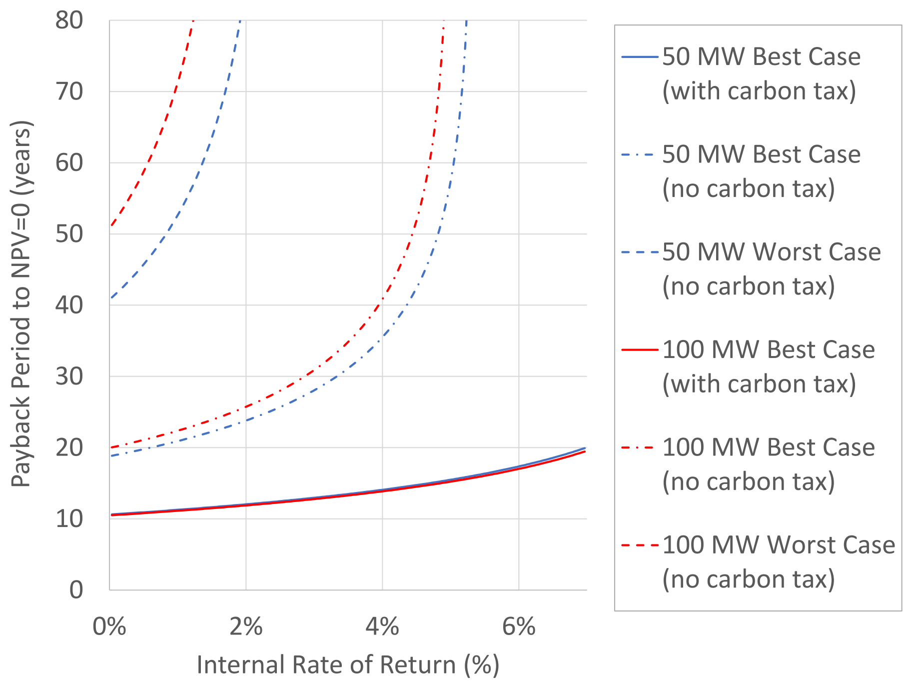

Figure 26. Payback time to NPV equal to zero.

4.3. Job Creation

An analysis was conducted to understand the local benefits of construction for jobs for the proposed 50 MW and 100 MW plants for average cost conditions using the Jobs and Economic Development Impact (JEDI) tool developed by NREL [19, 20]. JEDI was used with many of the cognizant input parameters changed for power tower applications [20], but many of the internal economic parameters for JEDI's defaults are based on trough CSP technology which may lead to inaccuracies in the JEDI estimates. Regardless, the results of this analyses are still the best estimates available for existing CSP cost and job benefit tools.

Table 9. JEDI inputs for 100 MW and 50 MW plants with 15 hours of energy storage

Input Description	100 MW values	50 MW values
Project Location	NEW MEXICO	NEW MEXICO
Solar Field Area (m^2/MW)	11,325*	11,253*
Solar Direct Normal Resource (kWh/m2/day)	7.0	7.0
Year of Construction	2014	2014
Project Size - Nameplate Capacity (MW)	100	50
Solar Field Aperture Area (square meters)	1,132,500*	562,629*
Plant Capacity Factor	70.0%	70.0%
Construction Cost ($/KW)	$6,274**	$6,274**
Annual Operations and Maintenance Cost ($/kW)	$58.00**	$58.00**
* Value is the same as a constant input to the SAM analysis ** Value is the average cost in the SAM stochastic simulations plus some factors unique to JEDI		

Creating the CSP projects will create jobs in Albuquerque during several years of construction and will also create permanent jobs for CSP installation maintenance and operation. The JEDI default data indicate that up to 1,050 full-time equivalent jobs will need to be filled during construction for the 50 MW plant and 2,099 jobs for the 100 MW plant. In the long term, 55 jobs for the 50 MW plant and 88 jobs for the 100 MW plant are expected to be created in order to run the plant and to provide ancillary services in the surrounding Albuquerque area. Table 10 and Table 11 provide estimates of the job types and other economic sources of cash flow due to the project as calculated by JEDI. The columns in the table are explained as follows: 1) Jobs are the number of jobs during construction or during operating life of the plant, 2) Earnings are the yearly wages (or wages for construction) of workers in the local economy expected, 3) Output indicates how much total economic activity is generated by the plant creation per year, and 4) Value Added is the Gross Domestic Product (GDP) added to the U.S. economy from jobs for construction or per year for plant operations and maintenance. The impacts are also divided into direct, indirect, and induced categories: 1) Direct impacts involve jobs created for the purpose of creating the plant; 2) Indirect impacts involve jobs that are necessary as a result of the plant creation such as legal services, equipment suppliers, and more; 3) Induced impacts are for other kinds of businesses that will grow because of the presence of direct and indirect jobs created. Caveats of the JEDI outputs are further elaborated in the JEDI user guide [19].

Table 10. Jobs impact for an average 50 MW plant (JEDI).

Description	Jobs	Earnings ($M)	Output ($M)	Value Added ($M)
During construction period				
Project Design and Onsite Labor Impacts	473	$52.46	$74.15	$60.70
Construction and Interconnection Labor	319	$46.59		
Construction Related Services	153	$5.86		
Equipment and Supply Chain Impacts	373	$16.80	$90.28	$47.95
Induced Impacts	204	$8.13	$28.27	$29.38
Total Impacts	**1,050**	**$77.39**	**$192.70**	**$138.03**

Description	Jobs	Earnings ($M)	Output ($M)	Value Added ($M)
	Annual Jobs	**Annual Earnings ($M)**	**Annual Output ($M)**	**Annual Output ($M)**
During operating years (annual)				
Onsite Labor Impacts	38	$2.37	$2.37	$2.37
Local Revenue and Supply Chain Impacts	11	$0.47	$2.09	$1.37
Induced Impacts	6	$0.23	$0.81	$0.92
Total Impacts	**55**	**$3.08**	**$5.28**	**$4.66**

Table 11. Jobs impact for an average 100 MW plant (JEDI).

Description	Jobs	Earnings ($M)	Output ($M)	Value Added ($M)
During construction period				
Project Design and Onsite Labor Impacts	945	$104.92	$148.31	$121.39
Construction and Interconnection Labor	639	$93.19		
Construction Related Services	306	$11.73		
Equipment and Supply Chain Impacts	746	$33.60	$180.57	$95.90
Induced Impacts	407	$16.27	$56.53	$58.76
Total Impacts	**2,099**	**$154.78**	**$385.41**	**$276.05**
Description	**Jobs**	**Earnings ($M)**	**Output ($M)**	**Value Added ($M)**
During operating years (annual)				
Onsite Labor Impacts	56	$3.29	$3.29	$3.29
Local Revenue and Supply Chain Impacts	22	$0.99	$4.28	$2.57
Induced Impacts	10	$0.39	$1.37	$1.52
Total Impacts	**88**	**$4.67**	**$8.94**	**$7.38**

4.4. Partners and Financing

In order to construct and fund a CSP plant on or near KAFB, coordination with a number of entities will be required. In addition to the entities described in Section 3.4, to obtain necessary approvals and permits, additional entities and partners will be needed to construct, finance, and operate the facility. Table 12 summarizes identified partners and their roles. Although not exhaustive, this summary provides a starting point to coordinate the development and construction of a CSP plant in Albuquerque.

Table 12. List of entities for approvals, construction, financing, and operation of a potential CSP plant in Albuquerque.

Entity	Role	Notes
Permitting and Approvals		
Sandia	Permitting and approvals	Approvals needed from Sandia Facilities and Environmental Safety & Health. Congressional notification and approval may also be necessary.
Sandia Field Office/NNSA	Permitting and approvals	Approvals needed from disposition, real estate, and utilities group.
KAFB	Permitting and approvals	Approvals required from KAFB civil engineering division (infrastructure operations, real property, environmental groups); AF 332 and 813 required.
PNM	Approval for grid interconnection	PNM will review interconnection requirements and impact on existing power system; possibly contract operations and maintenance
WAPA	Approvals for interconnection and operation	The Western Area Power Administration (WAPA) currently contracts with Sandia and KAFB to provide base power
Financing		
Venture Capital	Investment	Potential venture capital investment for the developer could include Breakthrough Energy Ventures (Bill Gates) and NM Angels
State of NM	Investment	NM State Investment Office and Permanent Fund may provide funding. As of 2020, the Permanent Fund has invested "$400 million in power generation, of which, roughly two thirds is invested in renewable energy."
Federal Government	Funding/loans	Developer may be eligible for the DOE Loan Guarantee Program; House Bill 3684 (bipartisan infrastructure bill) includes funding for renewable energy, including $355M for Energy Storage Demonstration Pilot Grant Program
Construction and Operation		
EPC	Construction	Engineering, procurement, and construction contractor may be hired by Sandia Facilities or third party, depending on who owns and operates the facility.
CSP Developer	Construction and operation	Facilitates financing, construction, and operation of CSP facility. Potential options in the U.S. include Heliogen and NRG Energy, which developed the existing Ivanpah CSP plant.
PNM, WAPA, Los Alamos County Merchant Desk	Operation	These entities may establish contracts for operation, maintenance, and resale of electricity produced by the CSP plant

4.5. Molten-Salt vs. Particle Based CSP

Next generation CSP tower systems have the potential to lower the LCOE of solar thermal generation by utilizing an alternative high temperature heat transfer and storage medium to provide increased thermal-to-electric efficiency. The DOE recently provided Sandia National Labs $25 million to construct and demonstrate a particle-based pilot plant utilizing black, ceramic, sand-like particles to gather and store thermal energy at temperatures >700 °C for use in a more efficient supercritical CO_2 closed-loop Brayton power cycle. Sandia conducted extensive research and testing on particle-based subcomponents to demonstrate their feasibility and combined ability to deliver dispatchable solar thermal generation paired with long-duration, 14+ hour storage, at an LCOE of ~0.06 $/kWh. The Generation 3 Particle Pilot Plant (G3P3) will begin construction in early 2022 and will be commissioned and testing in 2023 - 2024. In addition to the particle pilot plant constructed at Sandia, a second, pre-commercial particle-based CSP plant sponsored by Saudi Electricity Company will be built in Saudi Arabia.

4.5.1. LCOE Comparison

Gonzales-Portillo et al. [21] developed a technoeconomic model to predict the LCOE for a commercial-scale particle-based CSP plant as part of the DOE funding for G3P3. The LCOE model for the particle-based CSP plant utilized the same input variables as the SAM model described in Sections 3.1 and 3.2. Figure 27 provides a comparison of the projected LCOE for a particle-based, 100 MW power plant with a solar multiple of 3 and 14 hours of thermal energy storage versus a molten salt-based, 100 MW power plant with a solar multiple of 3 and 15 hours of thermal energy storage. The ranked regressions of the key factors contributing to the LCOE of each plant are provided in the figures on the right. The median value for the predicted LCOE for the molten salt based CSP plant was 0.076 $/kWh with a 95% confidence interval of [0.059,0.097], while the LCOE of the particle based CSP plant was predicted to be 0.058 $/kWh with a 95% confidence interval of [0.055,0.061]. The increased plant efficiency together with the decreased receiver costs and parasitic loads of the particle-based CSP plant produced an LCOE that was significantly lower (by 24%) than that of a traditional molten salt-based system. With the successful demonstration of particle-based CSP technology by G3P3 USA and G3P3 KSA in the coming years, the generation 3 technology may provide the energy needs of Sandia NM and KAFB at a substantially lower cost than traditional molten-salt CSP while showcasing Sandia-developed technology as a forerunner in solar thermal generation and research.

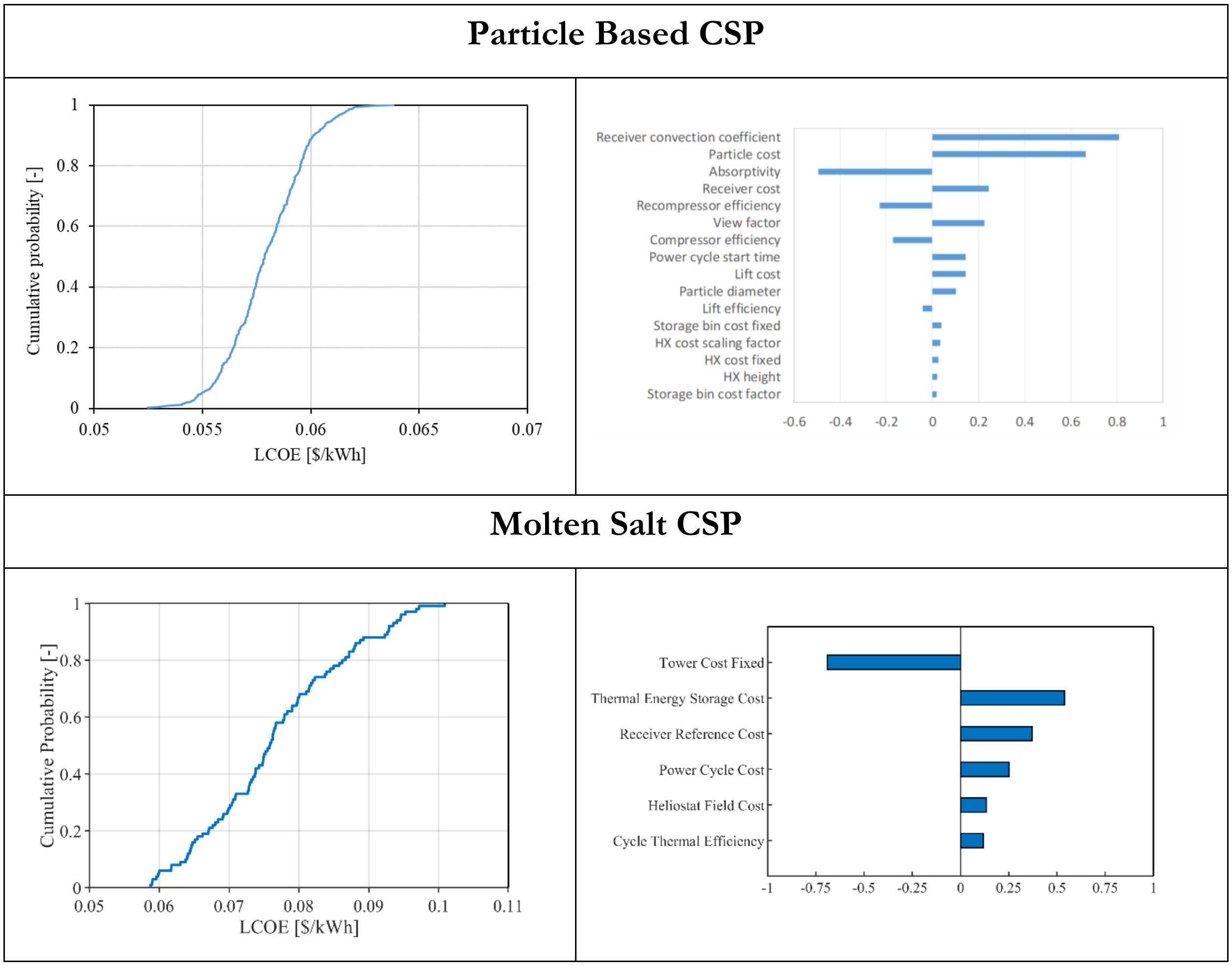

Figure 27. Comparison of LCOE distributions and important parameters from the probabilistic analyses for a 100MW particle-based (top) and molten salt-based (bottom) CSP plant.

4.5.2. Component Comparison

Costs of CSP components for molten-salt and particle-based plants were compared. Figure 28 summarizes the major components that were evaluated: heliostat field, tower/receiver, thermal energy storage, balance of plant, and power cycle. Table 13 describes the components for particle-based systems that were included in an equivalent model using the Energy Equation Solver (EES*)* software [22]. Major differences occur in the tower structure because it must be taller to accommodate a polar heliostat field (vs. surround field) and the particle storage and conveyance system. Instead of pumps and pipes, the particles are handled with skips and chutes. The particle-based storage is assumed to be integrated within the tower, and all particles flow by gravity and conveyors. The cycle efficiency difference reflects the difference between Rankine and Brayton cycles used by molten salt and particle-based systems, respectively. Table 14 summarizes advantages and disadvantages of each of the molten-salt and particle-based components.

Despite the comparable total capital costs of the two systems, results show that 3rd generation particle-based CSP tower plants capable of heating particles to a high enough temperature to achieve Brayton cycle efficiencies ~0.5 may be able to produce more overall power and thus have lower LCOEs than 2nd generation molten salt plants with efficiencies ~0.4 due to the limited upper temperature bound of the salt-based heat transfer material. While overall costs were similar, significant cost differences exist at the component level. The cost of particle-based receivers were found to be much lower than its molten salt counterpart, but these cost savings were offset by higher tower and heat exchanger costs.

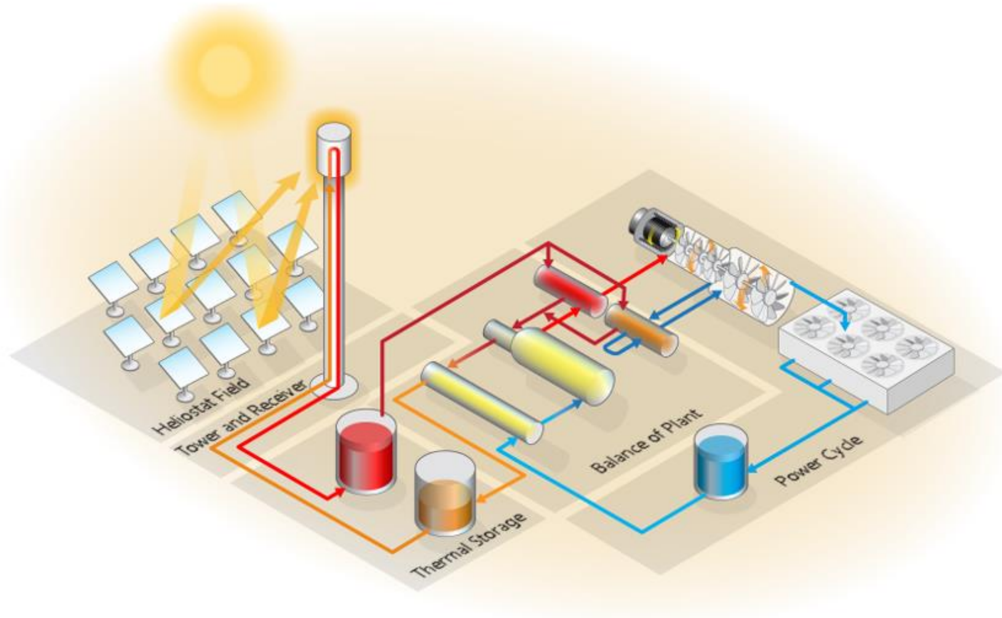

Figure 28. Schematic of CSP plant in SAM with major sub-systems labeled [23].

Table 13. Categories of molten-salt components and equivalent particle-based components

DESIGN CONFIGURATION	Salt (SAM)	Particle (EES)			
Net Output (nameplate) (MWe)	100	100			
Solar Multiple	3	3			
Receiver Height (m)	193	250			
Storage Capacity (hr)	15	15			
Cycle Thermal Efficiency	0.412	0.511			
Cycle Thermal Power (MWt)	269	218			
Receiver Thermal Power (MWt)	808	653			
Heliostat Reflective Area (m^2)	1536000	1536000			
Net energy produced in year (GWh)	686	693			
LCOE (real) ($/kWhe)	$0.067	$0.062			
LCOE (nominal) $/kWhe	$0.084	$0.080			
	Total Cost		Specific Cost		
SUBSYSTEM	**Salt (SAM)**	**Particle (EES)**	**Salt (SAM)**	**Particle (EES)**	**Unit**
Heliostat Field	$131M	$131M	85.00	85.00	$/m^2 reflective area

Tower	\$25.3M	\$96.3M	131K	385K	\$/m height
Receiver	\$85.2M	\$46.4M	105.44	71.00	$\$/kW_t$ receiver
TES	\$88.9M	\$64.7M	22.00	19.81	$\$/kWh_t$ stored
HX	\$32.2M	\$55.8M	119.49	256.46	$\$/kW_t$ HX
Power Cycle	\$115M	\$82.7M	1154.40	827.20	$\$/kW_e$
Total capital costs	\$478M	\$476M	0.70	0.69	\$/kWh produced
	Total Cost		**Specific Cost**		
COST SUMMARY	**Salt (SAM)**	**Particle (EES)**	**Salt (SAM)**	**Particle (EES)**	**Unit**
Contingency (7%)	\$33.4M	\$33.4M	\$334	\$334	$\$/kW_t$
Total Direct Costs	\$511M	\$510M	\$5,110	\$5,098	$\$/kW_e$
Total Indirect Costs	\$106M	\$99.7M	\$1,058	\$997	$\$/kW_e$
Total Installed Costs	\$617M	\$609M	\$6,168	\$6,095	$\$/kW_e$

Table 14. Comparison of molten salt and particle-based CSP subsystems

Component	Molten-Salt CSP		Particle-Based CSP	
	Advantages	Disadvantages	Advantages	Disadvantages
Receiver	Molten salts can be contained in piping	Heat must transfer through containing media such as piping. Receiver piping is expensive. Radiative losses due to reflectance.	Direct irradiance on particles Faster start-up times in early morning	Particle loss through open apertures Wind can disrupt particle curtain and decrease efficiency
Storage	Thermal characteristics are well understood Commercial vendor supply chain exists	Salt is corrosive to bin foundation and small leaks have been difficult to detect or repair.	Lower cost, does not require airtight liner made of high-temperature alloy steel. Particles are non-corrosive	New technology has yet to be tested. Increases cost of towers.
Heat Exchanger	Shell and Tube designs are well established for air or steam cycles.	Viscous salt clogging in microchannels. Tube thickness required for high-pressure sCO2 containment increases thermal resistance.	Can be scaled up modularly.	Particle to sCO2 heat exchange coefficient is low given the capital costs. High stress fields in diffusion-bonded plates during start-up. Flow uniformity requires gaps between plates that reduce heat transfer effectiveness

Component	Molten-Salt CSP		Particle-Based CSP	
	Advantages	Disadvantages	Advantages	Disadvantages
Conveyance	Liquid media can be pumped	Molten salt pumps and pipes use expensive materials to resist corrosion	Sand is non-corrosive Lower routine maintenance due to fewer high-stress welds and immersed pumps. Tower-integrated components for gravity-driven conveyance	Mechanical conveyance is temperature limited. Conveyance systems require housing for large hoist machines Rooftop handling adds height to receiver towers.
Media	Liquid media can be pumped and handled easily.	Forced outages due to leaks and freezing Media is corrosive if spilled Maximum temperatures <600° C for molten nitrate salts. Required parasitic heat tracing to prevent freezing	Media does not freeze and therefore does not need electrical trace heating and can be more modular Media is inert and poses no environmental hazard if spilled	Granular material can abrade containment structures Particle abrasion can contribute to mass loss

4.5.2.1. Receiver

Current molten-salt receiver designs have exhibited radiative heat losses due to reflection and thermal radiation. Cavity receiver designs may mitigate these losses but also limit the energy that reaches the media which must be compensated with more heliostats in a directional (polar) field. In particle-based cavity receivers, the aperture may need to be small in order to protect the curtain from winds or other environmental effects. Losses due to wind have been modeled with CFD for particle systems and the findings show losses in thermal efficiency are in an economically acceptable range. Wind may also affect the uniformity of the particle curtain. Methods of mitigating the impacts of wind and stabilizing the particle curtain are being studied. Particle receiver designs tend to be limited in the height over which particles can fall. A multi-receiver system configuration such as that used at Khi Solar One (Figure 29) has been studied as a means to reduce risk in large scale particle-receiver designs.

Figure 29. Left: Multi-cavity molten-salt receiver at Khi Solar One. Right: Particles falling over catch-and-release troughs in a cavity receiver during testing at Sandia.

4.5.2.2. Storage

Molten-salt storage bins are designed to protect against leakage which can occur from moving parts in thermal expansion events. Newer storage bins may be similar to the cross section shown in Figure 30. The foundation is built upon a concrete pad with a water-cooled reinforced concrete foundation. The bin is comprised of firebrick walls with a steel-tank shell and protective liner. The entire bin is then wrapped in ceramic insulation. The liner must be made of alloy steel materials that are formed in a manner that allows for expansion in all directions.

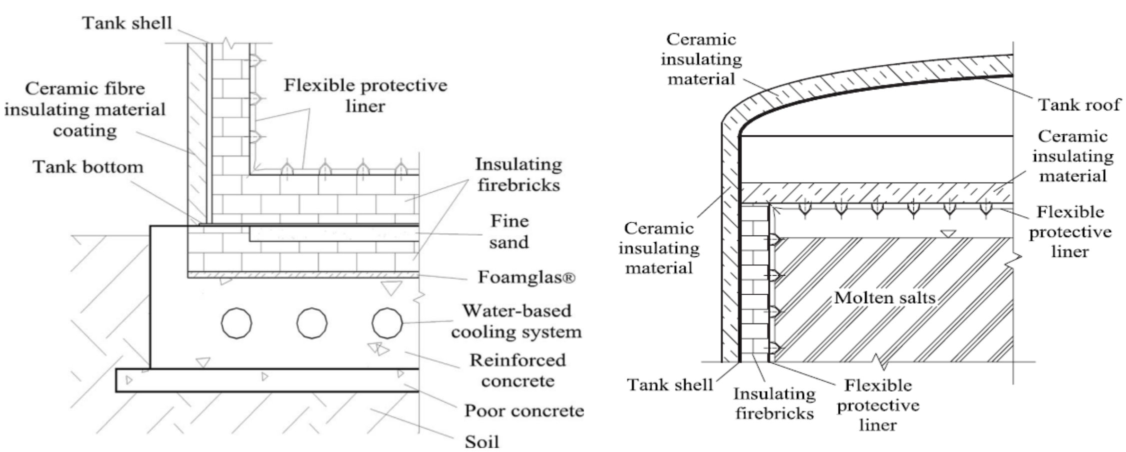

Figure 30. Molten salt tank cross-sectional view. [24]

Particle-based storage systems may use ground-based tanks that are similar to the molten-salt tanks above, but there may be opportunities to reduce costs in the following ways:

- Formed alloy steel liners may not be necessary as particles can be in direct contact with the brick without spillage or corrosion.
- Simplified foundations may be possible as particles form a non-flowing insulative bid that conforms geometrically to evolving ground conditions and as a solid will not leach into the ground.

- Reduced heat losses as the bulk thermal resistance of particles near the wall insulates particles at the central core of the bin.
- Eliminate storage bin structures and use receiver tower walls to contain hot particles.

A novel system design being tested in the G3P3 project integrates the storage system under the receiver so that particles flow by force of gravity to the primary heat exchanger and eventually to cold storage without requiring pumps or mechanical conveyance. In large commercial-scale systems, such as those shown in Figure 31, tower-integrated storage is still feasible but riskier given the need to enhance tower structures to provide support for the particle storage bins which can weigh more than 50 metric kilotons.

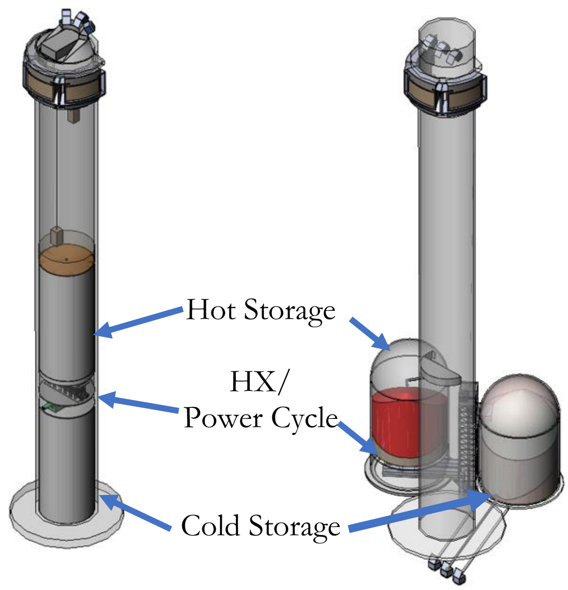

Figure 31. Particle-based CSP tower system with tower-integrated (left) and ground-based (right) storage.

Another key difference between liquid and particle storage media is that salt systems have relatively uniform temperature throughout the bin while stored particles maintain a nearly constant inner core temperature with cooler gradients near the walls and top of the bed (Figure 32). Bins can be designed as mass flow hoppers which require elongated flow cones and exhibit a uniform decreasing particle level, or lower cost flat-bottomed bins which discharge in a funnel-flow in which particles flow from the cool wall region into the hot central flow channel.

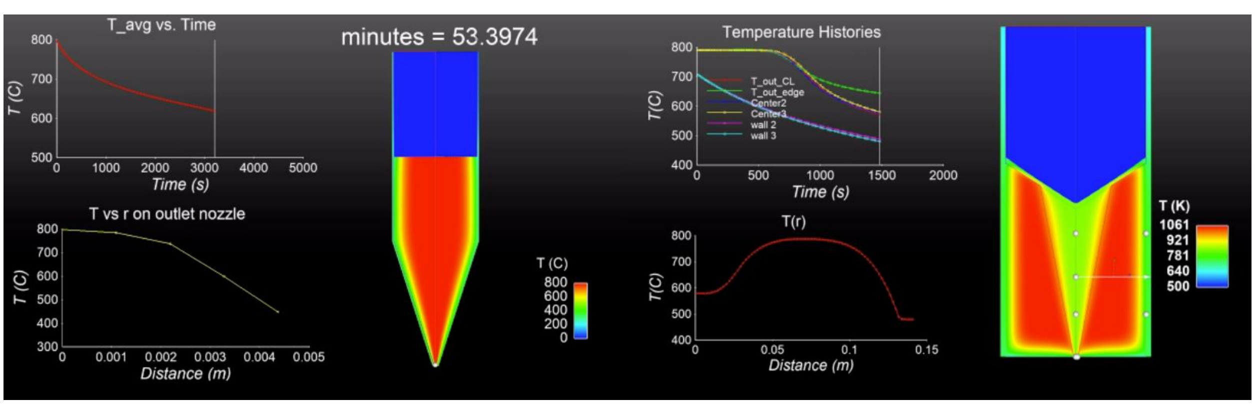

Figure 32. (Left) thermal contours of particles in mass flow hopper. (Right) thermal contours in funnel flow hopper.

4.5.2.3. Conveyance

Molten salts can be pumped throughout the system through large vertical turbine pumps (Figure 33). Pipes and valves must be insulated and wrapped with trace heating so that salts remain fluid and do not freeze in the ducts, or pumps. The high temperature pumps are one of the most expensive components as they are made to be submerged in corrosive salts up to 600° C and must be able to pump high-density molten salt to a height of nearly 200 m.

Particle-based conveyance systems can employ existing skip-hoist technology common in the mining industry (Figure 34) but will require higher temperature payloads than previously demonstrated. High-temperature bucket lift and screw elevators currently in use at the NSTTF can also be used, but these systems increase heat losses and suffer from lower lift efficiencies than skip hoists. In addition, bucket and screw elevators are limited in height, and several in series would be needed for commercial-scale systems.

Figure 33. Molten salt pumps (Flowserve.com).

Skips reduce thermal losses by keeping the particles in large bulk volumes on route to the top of the tower and achieve higher efficiencies >85% due to the counterweight of the return skip. Overturning skips are preferred in order to minimize spillage, but are size limited which may need to be operated in parallel to meet capacity requirements. Skips work in conjunction with chutes or belt conveyors to move particles horizontally (Figure 34). For a 100 MW_e capacity single tower plant, overturning skips may need to be very tall and narrow.

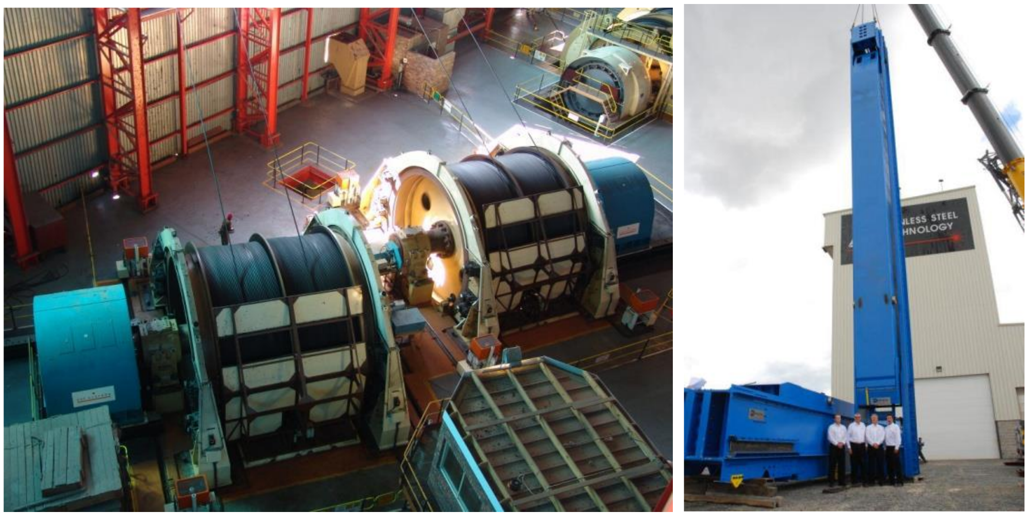

Figure 34. (Left) Large scale hoists and motors. (Right) Elongated skips with large capacity. (Images provided in project proposal by FL Smidth Mine Shaft Systems

4.5.2.4. Heat Transfer Medium

Molten salts and particles are comparable in heat capacity (1300 J/kg/K and 1200 J/kg/K respectively) and price with sodium and potassium nitrate salts ranging between \$0.7/kg and \$1.5/kg and ceramic particles ranging from \$0.6/kg to \$2/kg. Sand could also be used at a much lower cost, but with concerns such as lower optical absorptance and silica inhalation hazards. For sCO_2 Brayton cycles, high-side temperatures of the heat transfer media should be >700° C to achieve peak efficiencies. Particles can be heated to >1000° C before sintering occurs while KNO_3 and $NaNO_2$ salts have an operating ranges between ~200-540° C. Next generation molten salt formulations that operate up to 800° C have been extensively researched but have not been used in a commercial setting.

Figure 35. (Right) test apparatus for falling particle curtain. (Left) closeup of particles used in CSP

4.6. Thermal Energy Storage for Increased Resilience

To increase the resilience of power delivered to Sandia NM and KAFB, additional thermal energy storage may be considered by increasing the size of the storage bins and including either particle or molten salt resistive heater banks. The heaters would provide additional energy to the thermal energy storage via either electricity taken from the grid or alternative renewables on site such as wind or photovoltaics. The incremental cost of the additional thermal energy storage may be lower than tradition lithium-ion battery storage. The incremental levelized cost of storage for lithium-ion battery systems as a function of storage hours is linear with each additional hour of storage costing the same as the previous hour. Thermal energy storage has a high initial cost due to the price of the major components such as the turbomachinery, heat exchanger, and particle/molten-salt heater but each additional hour of storage only requires additional storage volume and the additional relatively inexpensive heat transfer fluid. With the initial capital costs covered by the existing plant additional thermal energy storage could be added at a dramatically lower incremental cost that an independent system.

The ENDURING particle based thermal energy storage developed by NREL provides 26,000,000 kWh of thermal energy storage at a LCOS of 2-4 $/kWh [25]. The additional thermal energy storage can be charged before anticipated periods of low solar irradiance to provide improved resilience to extreme weather that may impact both loads and resources.

5. CONCLUSIONS

This report provided a CSP design study to produce carbon-free electricity for Sandia NM and KAFB. The annual electricity requirements for Sandia NM are expected to increase from current values of ~300 GWh to just over 400 GWh by 2040. The combined electricity requirements for Sandia NM and KAFB are expected to grow from ~400 GWh to just over 600 GWh by 2040. 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. Probabilistic analyses were performed to quantify uncertainties in both performance and cost. Results showed that the 50 MW CSP plant is expected to produce ~200 – 300 GWh of annual electricity, and the 100 MW CSP is expected to produce ~400 – 700 GWh. The cost of construction is 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 O&M 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 could be up to $11M per year for the 50 MW plant and up to $22M per year for the 100 MW plant assuming congressionally proposed initial carbon pricing up 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. See Table 8 for additional details regarding avoided carbon costs and payback periods.

Construction of a CSP facility on KAFB land would require coordination with Sandia Field Office/NNSA, KAFB Civil Engineering Division, and Sandia groups such as Facilities and Environmental Safety & Health to obtain all necessary permits and approvals. Land and siting requirements on and near KAFB were evaluated. Three locations were identified that could host the 50 MW and 100 MW CSP plants, which would require ~1000 acres and ~2000 acres of land, respectively. Financing of the project may come from state and/or federal funding opportunities or venture capital (see Table 12). Operation of the plant would likely be through a third-party CSP developer or entity contracted by PNM. Agreements would be needed regarding responsibility for annual costs of maintenance and operations and use/resale of electricity generated from the CSP plant. The payback period in Section 4.1 assumes that annual avoided electricity costs are offset by operations and maintenance costs. If O&M costs can also be avoided, this would reduce the payback period.

Benefits of the CSP plant include job creation and reductions in CO_2 and greenhouse gas emissions. Construction of a 100 MW CSP plant is expected to create nearly 2,000 jobs related to construction and supply chain. Nearly 100 permanent jobs would be created to operate and maintain the facility and provide necessary services and supplies. A reduction of ~300,000 tons of CO_2 per year (or 10 million tons of CO_2 over a 30-year period) is expected based on a 100 MW CSP plant producing ~500 – 600 GWh of clean electricity annually. This is equivalent to the annual carbon emissions of ~60,000 passenger vehicles. The annual CO_2 offset is also equivalent to at least 2% of the remaining fossil-fuel generation (~25,000 GWh) that we need to replace to achieve NM's 50% carbon-free electricity generation goal by 2030.

Finally, Sandia has led the development of next-generation particle-based CSP technologies. DOE recently awarded Sandia $25M to build a Gen 3 Particle Pilot Plant (G3P3) to de-risk particle-based technologies. A comparison of conventional molten-salt and particle-based CSP systems and components is provided in Section 4.5. Although no commercial particle-based CSP plants have been deployed, studies have shown particle systems have the potential to improve performance and reduce the LCOE to less than \$0.06/kWh. In addition, particle-based CSP technologies can increase temperatures for next-generation power cycles and decarbonization of high-temperature industrial processes such as cement and steel production.

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