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Expanding the Western U.S. Grid With CSP

An Update on the Findings of the CalCSP Study

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Abstract. As states within the United States respond to future grid development goals, there is a growing demand for reliable and resilient nighttime generation that can be addressed by low-cost, long-duration energy storage solutions. This paper summarizes the findings of a study for the state of California that evaluated how molten-salt tower concentrating solar power (CSP) plants with thermal energy storage (TES) can be utilized to address the goals within the state established by Senate Bill 100. The study found that CSP exhibits deployment potential both in California and in the rest of the Western Interconnection and is utilized primarily to serve nighttime load. The plants are designed to collect and store energy during the day and then are dispatched to produce power at night. The paper presents a technoeconomic analysis that compares the cost of CSP to photovoltaics (PV) plus battery energy storage systems (BESS), provides an overview of capacity expansion modeling performed by NREL, and a screening analysis that identifies CSP siting potential in the U.S.

Keywords: Concentrating Solar Power, California, Power Market, SB 100, Renewable Portfolio Standard, Molten Salt Tower, Thermal Energy Storage

1. Introduction

In the United States, many states are implementing goals to achieve 100% renewable power generation by 2050 or sooner. California has one of the more aggressive goals to source 100% of its end-use electricity generation from renewable energy resources by 2045. California has excellent solar resources, but to accomplish this goal, California's power utilities will need new renewable resources that can replace the natural gas units that they currently rely on to supply power at night. Appropriately configured CSP plants with thermal energy storage (TES) are an option to serve this nighttime load. These plants would be designed to take advantage of CSP's low-cost TES and collect and store energy during the day and then be dispatched to produce power at night. The U.S. Department of Energy has funded a study to identify the design of a CSP plant that optimally meets the evolving California grid needs. The objective of this study, reported in [1,2], is to take a fresh look at how CSP technologies can best be designed to meet the emerging nighttime market for firm, renewable power generation. This paper provides an overview of some of the findings of the study focusing on the technoeconomic of CSP and the market and siting potential for CSP projects in the U.S. southwest with an emphasis on the molten-salt tower technology.

2. Technoeconomic Analysis

The study initially considered different parabolic trough and central tower CSP technologies for providing nighttime renewable power. The molten-salt central tower (MST) technology quickly emerged as the preferred CSP alternative to use in the study, due to its low-cost direct two-tank TES and its commercial maturity. Conventional parabolic trough technology fell out of consideration due to the high cost of its indirect TES. Several other distributed tower and even parabolic trough plants using molten salt as the heat transfer fluid have the potential to be competitive alternatives to MST technology but are not as commercially proven at this point. Although many competing technologies provide renewable generation, long-duration Li-ion batteries being charged by PV are viewed as the primary competition for baseload or night-dispatched CSP projects in the near term. This study compares the cost of a 100 MWe CSP plant to the analogous PV + BESS alternative. It is particularly important to define an appropriate, consistent comparison for evaluating costs between CSP and PV + BESS technologies. For example, it is not relevant to compare the cost of PV only, or PV with 4 hours of BESS, directly with a baseload or nighttime-dispatched CSP plant. For the comparison shown here we compare baseload CSP and a hybrid CSP + PV configuration with PV + BESS options. The standalone baseload CSP plant is a 75% capacity factor plant. CSP + PV hybrid is the baseload CSP plant with PV added to it to achieve a 90% overall capacity factor. These are compared to PV + BESS plants that achieve 75% and 90% capacity factors. PV and BESS pricing is derived from data from the NREL 2023 Annual Technology Baseline (ATB) [3]. The battery and PV pricing is based on the NREL ATB assuming the moderate forecast cost scenario for these technologies in 2025. CSP cost assumptions were sourced from data on recently constructed molten-salt tower plants.

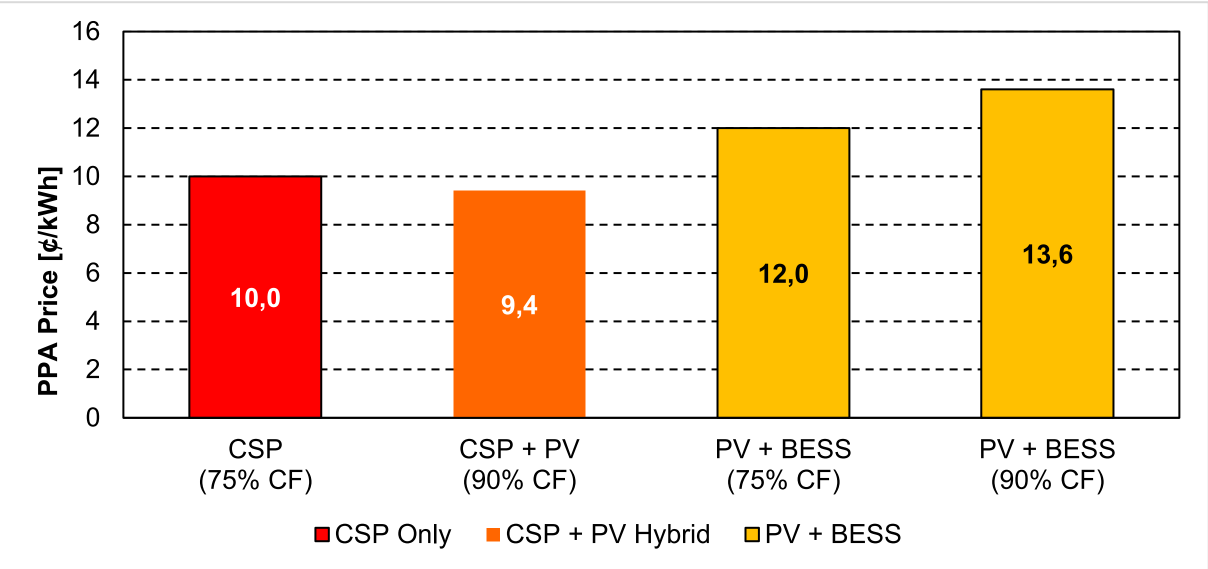

Figure 1. *LCOE of CSP vs. PV+BESS baseload Plants as a function of capacity factor (CF)*
Assumptions: *30-year Flat PPA, 30% ITC, Harper Lake (CA) site, DNI 2950 kWh/m2, 2021$.*
CSP (75%CF): *70 MW gross power cycle, 600 MWt receiver, 13 hours of TES.*
CSP+PV (90%CF): *105 MW gross power cycle, 600 MWt receiver, 13 hours of TES,130 MW_{DC}.*
PV+BESS (75% CF): *100 MW_{AC}, 350 MW_{DC} PV, 12 hours BESS.*
PV+BESS (90% CF): *100 MW_{AC}, 500 MW_{DC} PV, 16 hours BESS.*

CSP is currently found to have a competitive advantage over PV + BESS with respect to levelized cost of energy (LCOE) when designing a system to have a capacity factor of 75% or greater, but the rapid decrease in the cost of battery and PV technology requires that CSP finds ways to reduce the cost of generation. Development of a competitive domestic CSP supply chain, development of larger power park projects such as the DEWA projects in Dubai that can benefit from leaning and economies of scale, and development of projects that maximize the tax incentives available for CSP projects in the U.S. may be important factors in achieving these cost reductions.

3. Capacity expansion with CSP for California SB100

In 2021, the California Energy Commission (CEC) released a joint agency report [4] that included a study of potential capacity expansion pathways to achieving the renewable portfolio standards (RPS) goals established in SB100 which excluded CSP as an option. However, the dispatchability of CSP's power cycles and low cost of TES compared to batteries makes CSP a cost-competitive option for complementing variable generation and provision of ancillary services to the grid [5]. This section details the study we conducted to assess the deployment potential of CSP in future capacity planning to meet the revised California RPS.

3.1 Resource planning model

We employ the Resource Planning Model (RPM), a utility-scale capacity expansion model developed at NREL [6]. The main advantage that RPM has over other capacity expansion models is that it can model the region of interest at nodal fidelity rather than zonal. Figure 2 displays the Western Interconnection as a nodal and zonal representation; our study includes the nodes inside the shape on the left-hand side, connected to the zones outside the black shape on the right-hand side. This adds high-fidelity modeling of transmission and distribution within California and incorporates connections to generators outside the state while maintaining tractability.

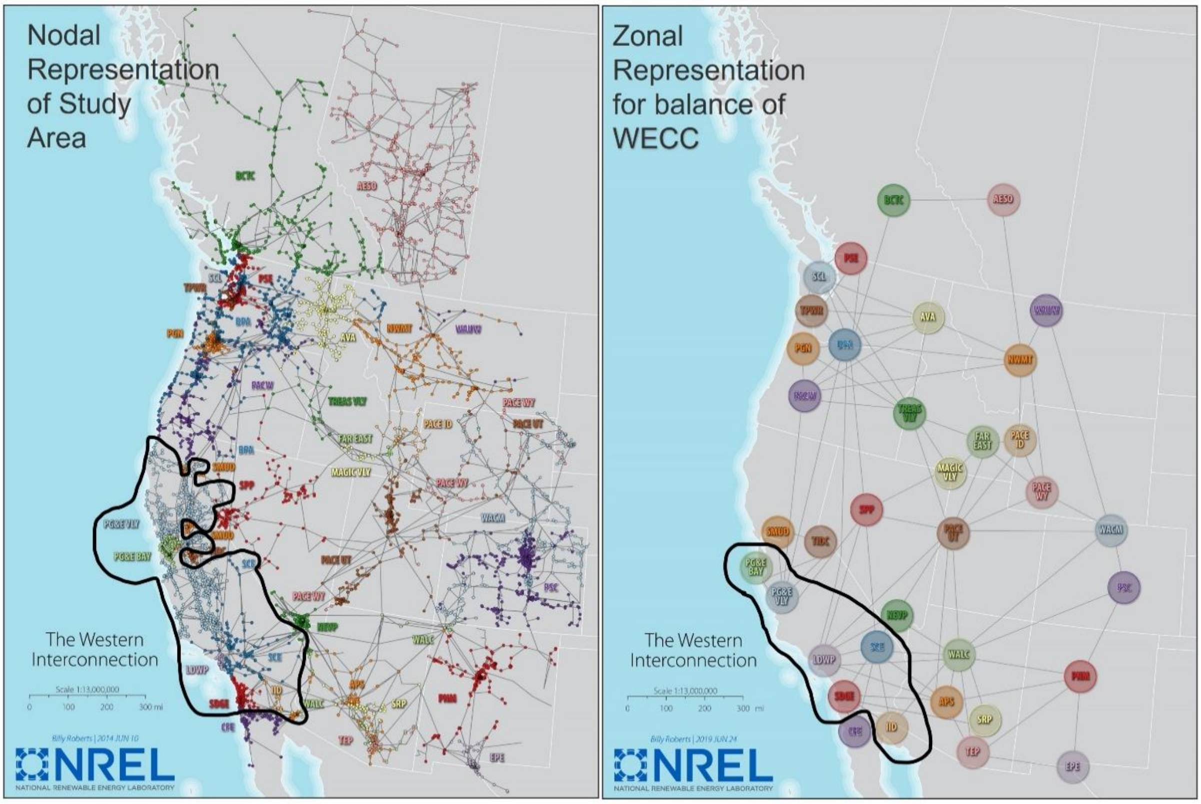

Figure 2. *Nodal and zonal representations of the Western Interconnection. The model instance of RPM used in this study includes the nodes inside the shape on the left-hand side, connected to the zones outside the black shape on the right-hand side.*

The model solves in five-year increments from 2025 to 2045 to find the lowest-cost system expansion (i.e., capacity, transmission and reduced-order dispatch decisions) at annual fidelity. New generation prescriptions by the model (along with known projects under construction) start in 2025 for generation and energy storage technologies except for fossil-based, nuclear, and hydropower technologies to be consistent with assumptions in the joint agency report [4]. We obtain variable generator profiles (i.e., wind, solar PV and CSP) from the Renewable Energy Potential Model (reV) using meteorological data from 2012, aggregated to a regional level [7]. The fuel prices are sourced from the U.S. Energy Information Administration (EIA)'s Annual Energy Outlook (AEO) 2022 Reference case [8]. NREL's 2022 Annual Technology Baseline (ATB) [9] is used for technology cost assumptions. RPM also includes a production tax credit (PTC) that aligns with the Inflation Reduction Act (IRA) and the 2022 Standard Scenarios [10]. Statewide RPS guidelines were taken from the DSIRE database (https://www.dsireusa.org/).

3.1.1 Case study description

We compare a model instance of RPM without CSP to one with CSP as an option, in which new CSP installations are assumed to be 100 MWe capacity plants with multiple options for solar multiple (1-3) and hours of TES (6-18). We also perform a sensitivity analysis in which we increase the technology cost of CSP by 10% and 20% to determine the elasticity of CSP installations to currently forecasted cost trends.

3.2 Results

Table 1 summarizes the deployment of CSP to the grid when it is included as an option and shows that RPM selects deployment of more than 13 gigawatts of CSP capacity by 2045 across the Western Interconnection; in this scenario, the technology generates about 15% of in-state electricity production for California in 2045. Comparing to the scenario without CSP, the new deployments displace wind, PV and batteries, which is consistent with the technoeconomic analysis in Section 2 suggesting that CSP is a more economical option to replace fossil-fueled, net-load-following plants with nighttime dispatch capabilities. Dispatch results indicate that the deployed CSP plants, which mostly have a 2.0 solar multiple and 12 hours of TES, operate like load-following plants that maximize output in the late afternoon and early evening hours in the summertime when net load is highest. However, Table 1 shows that the deployment of CSP is highly elastic to technology cost, highlighting the potential benefit of goals such as the SunShot 2030 target from the U.S. Department of Energy to the CSP industry.

Table 1. *Summary of CSP Deployments in 2045 from RPM Results to meet the California RPS established by SB100.*

CSP Installations	Baseline (MWe)	+10 % (MWe)	+20% (MWe)
California	9,072	3,880	2,223
Western Interconnection	4,519	3,241	1,416
Total	13,590	7,121	3,639
% of Baseline	100%	52%	27%

The results showed that outside of California, CSP deployments were well-distributed in the Western Interconnection except for Arizona, which has a relatively permissive RPS target in 2045 of 8.8%, and New Mexico, which has access to low-cost wind resources. In addition to the higher-than-expected CSP deployment in the Western Interconnection, a surprising finding was the lack of installation of hydrogen combustion turbines, a part of the future asset mix in the joint report which used the RESOLVE model. Future work may include an investigation of more aggressive RPS targets, including removing the ability of natural gas or other fossil-fueled sources to offset system losses. We may also leverage the insights of RPM's higher-fidelity information about nodal system deployment to determine future transmission and distribution needs that would be coupled with a capacity expansion plan for California.

4. Siting Potential of CSP

A detailed screening study has looked at the potential for siting of CSP in the western US. Due to land use constraints, many areas that might be good sites for CSP plants are not available for development. Even so, the potential land available for CSP development is significant. The screening analysis conducted in this study shows where there is excellent resource potential for CSP development in the US southwest.

4.1 CSP Siting Assessment.

The CSP siting assessment generally follows a similar approach to the one used by the CEC in its recent staff report "Land-Use Screens for Electric System Planning" [11]. The CEC process uses graphical information systems (GiS) data and analysis to identify areas with renewable energy resource technical potential after considering technical and economic criteria commonly applied in energy infrastructure development, legal restrictions, and planning considerations for biodiversity, lands used to produce crops, terrestrial landscape intactness, and terrestrial climate resilience. The CEC assessment looked at the resource potential for wind, geothermal, and photovoltaic technologies.

The CEC approach was adapted to identify land that is potentially available for siting CSP plants. CSP projects have significant economies of scale, making larger projects and the construction of multiple projects sequentially in a single location desirable to drive costs down. Additionally, the intent of this effort is to identify the potential for the siting of large amounts of CSP for California. Thus, the study did not look to identify the best site for a single plant, but rather areas where multiple CSP plants could be developed. Since the current CEC methodology virtually eliminates all desert regions in California for development, including the area around all existing CSP plants, some of the CEC criteria were relaxed. The following describes the process followed.

Gridding of land area: To classify land into parcels that can be developed for CSP, the land area needs to be broken down into individual parcels that can be independently evaluated. To do this, grids of 800 meters by 800 meters were created that covered the entire land area in the states of interest.

Land Screening: The next step is to filter out land area that is not appropriate for use as a CSP plant. The approach was similar to but slightly less restricrtive than the CEC's. We went back to some of the underlying screening data to selectively choose which locations would be screened. The following describes our screening process (i.e., land grids that are excluded from consideration).

- Screened federal land: The US government owns a significant portion of the land area in the western states. The federal land ownership is defined by the agencies that manages the land. Land managed by the National Park Service, Fish and Wildlife Service, US Forest Service, and Department of Defense were screened out. Lands managed by the Bureau of Land Management (BLM) were not initially screened out.
- General land exclusions: Land was excluded if it had a slope greater than 3 percent, it was an established body of water, it had a population area (populations of 2500 or greater) plus an 8-kilometer buffer, or it was within 8-kilometers of an airport.
- Infrastructure filters: Any grids with the following infrastructure were excluded: Grids including major roads with 100-meter buffer; natural gas pipelines with 50-meter buffer; railroads with 250-meter buffer; transmission lines greater than 100 kV with 100-meter buffer; and, airports with a 1000-meter buffer.

Environmental and land use exclusions: Environmental and land use restrictions were then applied. We used screens from the Bueuro of Land Management (BLM) 2012 PEIS ROD [12] and California 2016 DRECP [13] to conducted screening of BLM lands to excluded lands from solar development for environmental and land use reasons. The DRECP includes variance lands and a process to permit solar projects on other BLM managed lands. For this project, we felt it was important to reassess the land screenings used in the original BLM PEIS and DRECP assessments to evaluate potential new opportunities for CSP development. In our assessment we evaluated two cases, one that included all original BLM PEIS/DRECP screens, and one with a reduced set of environmental and land use screens. Most of the screens were very specific, but some were very general. Our reduced screens eliminated several of the more generalized screens that eliminated large swaths of land. Using the original screens we find that there are almost no BLM lands available for CSP (or solar) development that are outside the existing BLM solar enterprise zones. However, when we use the reduced set of environmental and land use screens, many potential new sites emerge for siting of CSP plants including in the western Mojave Desert, the desert areas around the Imperial Valley, and the eastern California desert areas.

Molten-salt Tower Specific Screens: A number of specific screens were included for molten-salt tower plants, including an 8-kilometer buffer around airports and plant height restrictions for military aviation training routes.

Parcel Size: Finally, any grouping of parcels of land that are not a minimum size of 2.4-kilometers by 2.4-kilometers are screened. This is assumed to be the minimum size for a molten-salt tower plant.

4.2 Economic Assessment of Sites

The next step was to assess the economic potential of different sites. A simplified LCOE model was used to estimate the cost of a molten-salt tower constructed at each location. To calculate the LCOEs, GIS data is exported for locations of interest, run through a Python script to generate the LCOEs for varioius scenarios, then the LCOEs are uploaded to the GIS system so that the results could be analyzed. This section describes the LCOE methodology used.

Levelized Cost of Energy (LCOE): We used the LCOE calculation from the NREL 2023 ATB [3] to compare the cost of energy producted at different sites. The LCOE can account for differences in CAPEX or OPEX, different performance, or different financial assumptions that may apply at individual sites. We calculated a real LCOE based on the economic assumptions used in the NREL 2023 ATB. The LCOE calculation allows either the production tax credit (PTC) or the investment tax credit to be accounted for. For CSP systems, given the high capital cost of current systems, using the ITC provides a better incentive to the project.

Table 2. *Molten-salt Tower Reference Baseload Plant Configuration*

Turbine size	100 MW gross
Receiver size	600 MW net
TES	14 hours
CAPEX	$7,000 /kW
FOM	$150 /kW-yr
VOM	$0.003 /kWh
Plant lifetime	30 years
Construction time	36 months

Reference Plant Configuration: The capital cost, O&M cost, and the performance were taken from the Solar Dynamics reference baseload molten-salt tower plant design for a location in Arizona.

The LCOE calculation is corrected for the following locational factors:

- Solar resource at the site: Hourly direct normal insolation (DNI) data was used in the analysis comes from the NREL NSRDB 2k dataset for 2019-2022. This dataset only relies on four years of data. We decided that a more accurate spatial distribution of the DNI was important rather than using the longer term 4km x 4km typical meteorlogical year dataset that has 25 years of data from 1998 to 2022. For tower plants, latitude and ambient air temperature were found to have a second order influences on performance, thus the DNI is the primary influence on the plant performance. The performance for a particular site was calculated using a curve fit of annual net generation for each location in the region of interest.
- Regional cost differences: We used the Faithful & Gould construction cost location indices to scale costs for each state [14]. Note, this data is for major cities, which may not be fully reflective of the cost of construction in rural and remote locations.
- Single plant vs. power parks: Cost reduction factors were used to scale costs for multiple plants constructed at the same site. Separate scaling factors were used for CAPEX and OPEX costs. The scaling factors were developed as part of [15]. The scaling cost reduction was limited to a maximum of four plants in the analysis.
- Remoteness of site for labor and transportation: experience from existing plants has shown that the remoteness of the site can have a significant impact on the cost of construction and operation of a plant. We have estimated this impact by determining the distance to the nearest large urban population center greater than 250,000 residents.
- Transmission interconnection costs: The analysis evaluated the cost of building a transmission line from each location to the nearest substation (230kV or higher) or building a transmission line to the nearest transmission line and adding a new substation.
- Transmission wheeling charges: We assumed a cost adder for wheeling power into California from an interconnection point in surrounding states.
- Seismic loading: California has regions with high probability of seismic events. Costs were adjusted by location to account for sizemic loading variations.
- Energy communities 10% ITC adder: The inflation reduction act included a 10% adder to the ITC for projects constructed in qualifying Energy Communities. A location qualifies as an energy community if it is a Brownfield site, a census tract (or adjoining sensus tract) in which a coal mine or coal power plant that has closed, or a metropolitan or non-metropolitan statistical area with employment related to the extraction, processing, transport, or storage of coal, oil, or natural gas and an unemployment rate below the national average.
- Other cost factors: development, permitting, and land costs vary depending on the state where projects are being sited and depending on the type of land that is being used (federal, private, state, or tribal). These factors may also affect the project timeline as well. It should be noted that no learning curve cost reduction has been included in this analysis unlike the RPM study. Costs represent current technology costs.

4.3 LCOE Results

Figure 3 below shows the LCOE results for molten-salt tower projects in the western U.S. The circles on the figure show the location of the sites considered for CSP. The size of the circle defines the resource potential at the site, in terms of megawatts of baseload CSP plants that can be sited in that location. The color of the dot indicates the estimated levelized cost of the plants at that location, green indicating the lowest LCOEs, and red indicating the highest LCOEs. Sites with more siting potential are assumed to benefit from cost savings associated with building solar power parks (i.e., two or more plants developed at the same site). The LCOE color grouping in Figure 3 each represent 100 GWe of the CSP siting potential.

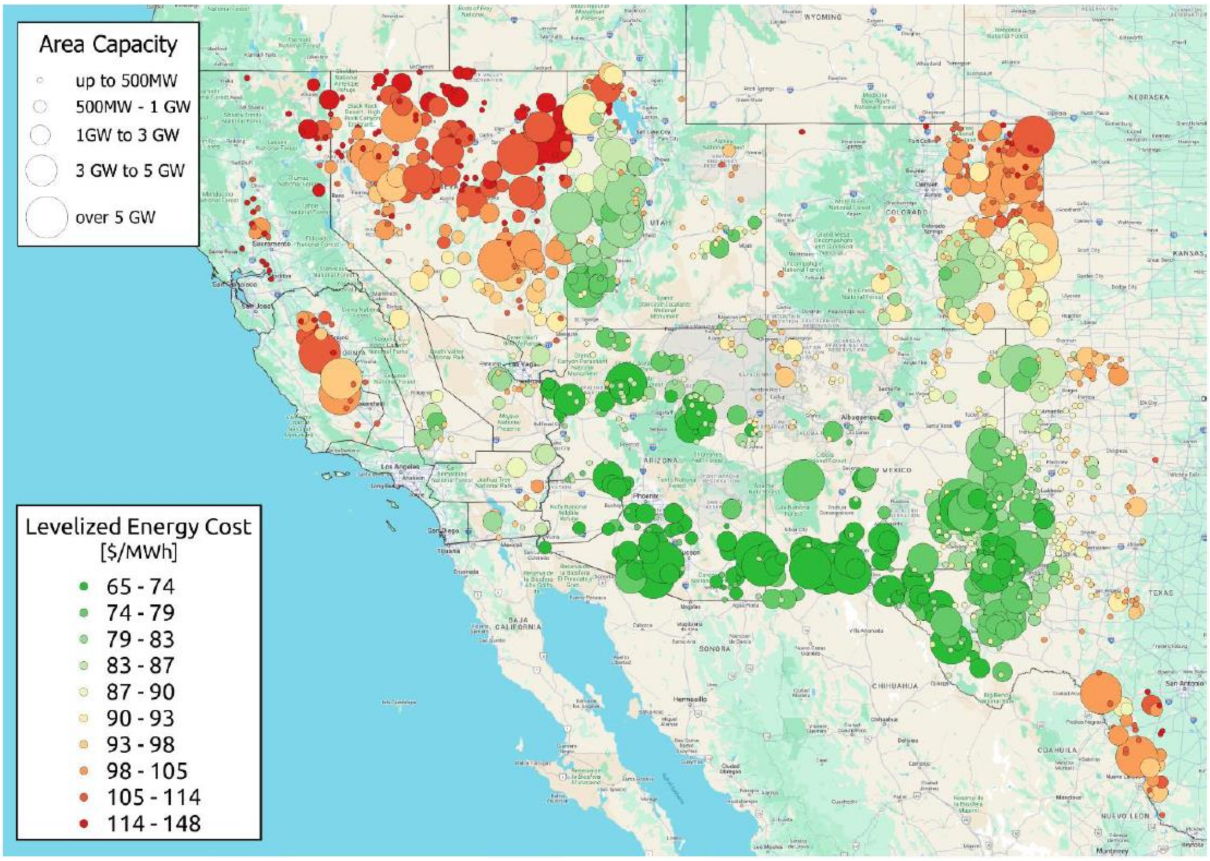

Figure 3. *Screening Study of Molten-Salt Tower Sites in the Western United States, Shows siting potential and economic assessment by location.*

The results in Figure 3 are unlikely to accurately represent future deployment of CSP projects. In practice, only a small fraction of the areas shown in Figure 3 will be practical for the deployment of a commercial-scale CSP project because most locations will not be economically attractive. The figure highlights the relative cost-effectiveness of CSP by region.

5. Conclusion

CSP paired with TES has the potential to be an important resource to help the US southwest (and other regions in the world) achieve capacity expansion goals by providing a low-cost, dispatchable, reliable resource for nighttime generation. This study found that:

- MST technology provides a lower cost option for nighttime generation compared to PV and Batteries.
- NREL's RPM capacity expansion model predicts 13 GW of CSP would be built in the western U.S. to meet California SB100 and regional goals when included in the analysis.
- Primarily baseload CSP configurations are deployed to meet nighttime demand.
- CSP capacity offsets the building of three times as much PV, wind, and battery capacity.
- Locations for many GW of CSP have been identified if siting challenges are overcome.

Although it is unlikely that any CSP-specific procurement opportunities will occur as have been implemented in other countries, as many U.S. states implement specific targets for electric generation, CSP exhibits potential to compete against other technologies for providing nighttime renewable generation with the integration of long-duration TES.

Data availability statement

Data and information on the CalCSP study can be requested from the authors.

Author contributions

Hank Price performed writing – original draft of the paper, and conceptualization and supervision of the CalCSP project. Kyle Kattke performed performance modeling of CSP and other technologies. Keith Boyle and Devon Price conducted the GIS conceptualization and analysis for the CSP screening analysis. Ryan Shininger conducted CSP siting studies. Dr. Frederick Morse performed interaction with California stakeholders and edited the draft. Chad Augustine performed writing – original draft, led the NREL RPM modeling effort. Sarah Awara ran the NREL resource planning model (RPM), summarized results, and prepared graphics. Alexander Zolan performed writing – review and editing of the NREL RPM work and editing of the paper.

Competing interests

The authors declare no competing interests, except to encourage the development of CSP in the United States.

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Legal disclaimer

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