Techno-Economic Assessment of Hybrid PV And CST Systems

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Abstract

Detailed network analysis conducted on a comprehensive range of concentrated solar thermal (CST) plants with varying storage sizes for 48 sites in the Australian electricity networks has identified that the most viable option for CST at most locations uses a storage capacity of approximately 15 hours. Subsequently, a more detailed techno-economic study was conducted for several locations that were identified to be viable for CST implementation. A review of the engineering and site practicalities for these sites determined that the optimal plant size for technical and economic implementation was 125 MWe (net) with 15 hours of storage. In an extension to this assessment, this study aims to find the most cost-efficient hybrid CST and PV system that matches the performance of the optimized CST system at one site, Tom Price (Western Australia). This site has annual DNI of 7.50 kWh/m^2/day, with the CST system having an annual generation of 983,120 MWh with the expected LCOE of 9.92 c/kWh. The assessment indicates that use of PV in hybrid systems can offer a more flexible design with potential benefits to land use and technical risk mitigation. Therefore, the criteria for selecting the type of systems and designing the power plant and the operational strategy should not only be based on the financial performance.

Keywords: Concentrated solar thermal, PV, hybridization, techno-economic analysis

1. Introduction

A detailed network analysis to determine the regions where CST technologies were likely to become viable in and the most relevant system designs determined a range of locations in different Australian networks where significant uptake was forecast based on projected future demand profiles and technology costs. All CST systems were based on a 100 MWe (net) power block size, but with varying storage capacities with corresponding field size changes. The preferred storage capacity was found to be either 12 or 15 hours, with the majority at 15 hours, for all sites identified potentially viable for CST operations (Beath et al., 2019). As a continuation in assessing opportunities for CST systems in the Australian electricity networks, technical and financial performance of eight different central receiver plant designs in twelve grid connected locations across Australia were investigated and optimum systems were identified. For each location, solar tower systems with the nominal capacity of 100 MWe (net) and thermal storage capacities from 6 to 18 hours were optimized. Findings of that study indicated that the optimum storage capacity was within the range of 14-16 hours (Meybodi and Beath, 2020), confirming the 15 hours was a suitable capacity.

A review of the central receiver power plants that were in operation, under construction or announced projects indicated that in practice the largest size of plants with a single tower was around 150 MW gross. There are technical challenges associated with larger size plants, with tower height being one of the limiting parameters. The tallest tower proposed is just over 260 m high (including the receiver). Therefore, it appeared that the largest practical size for a standard system to conduct techno-economic analyses of CST systems at different Australian locations was 125 MW net (almost 140 MW gross). This sizing also links to the storage capacity, with this system size allowing a storage of 15 hours. The expected output profile for the standard plant would be near-continuous full-load for the whole year, excepting periods of inclement weather and some reduction in winter due to lower solar availability. This study, by building on previous studies, provides an insight into the cost competitiveness of hybrid CST and PV systems in comparison with the previously optimized standard standalone CST system near Tom Price, WA (annual DNI =7.50 kWh/m^2/day), which is within a zone with high potential CST uptake as identified by previously conducted network analysis. Three operational strategies (i.e. scenarios) are considered and the performances of the hybrid and standard CST systems are compared from a techno-economic point of view. Fig. 1 shows the location of Tom Price, which is within the North Western Interconnected System network.

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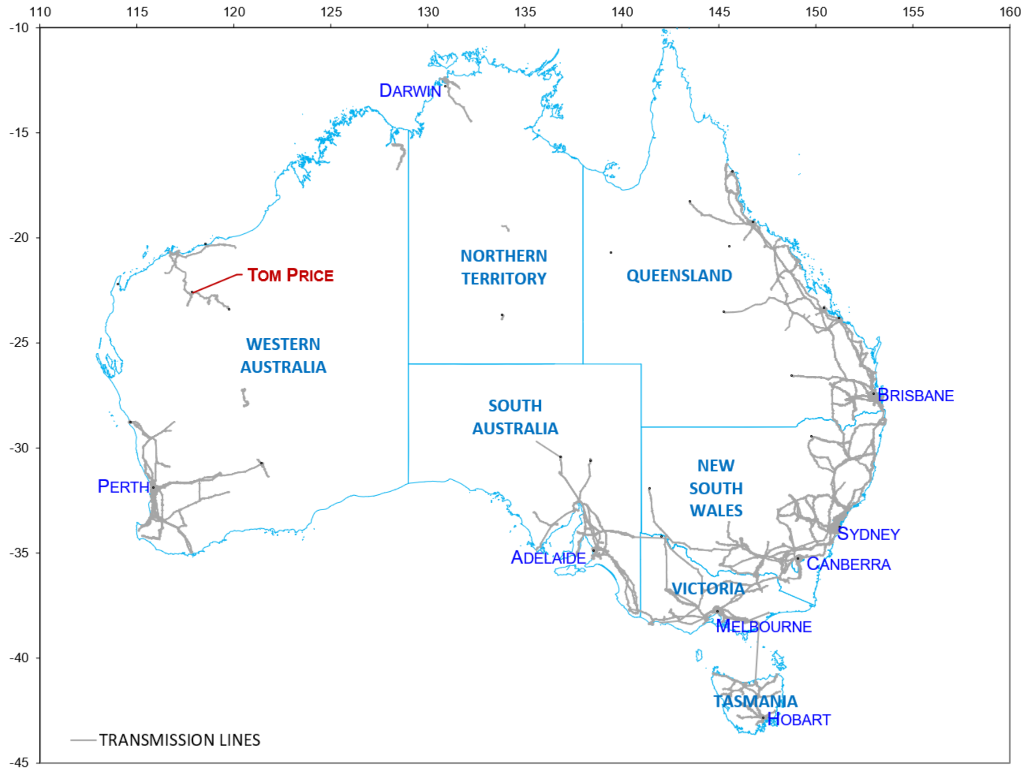

Fig. 1: Location of the Tom Price site

2. Methodology

This study aims to find the most cost-efficient hybrid CST and PV system that matches the performance of the previously optimized standard CST system (i.e. 125 MWe (net) with 15 hours of thermal storage). To achieve this, both technical and financial performances are assessed. Three scenarios are considered. In the first scenario, CST supplements the generation of the PV system and when there is no PV generation (i.e. from late in the afternoon until the next morning) it operates solely to match the standard system's output. It is noteworthy that there is a constraint on the steam turbine's partial load for all scenarios. Working at loads below 30% is not allowed; if supplementing PV output requires operating at below 15% of the nominal capacity, the turbine shuts down. For the partial loads between 15-29%, turbine works at 30% of the nominal capacity. In the second scenario, CST commences shutting down as soon as PV starts generating with only an overlap during the late afternoon, where CST supplements the PV generation for the last 2 hours of PV operation. In the third scenario, CST load drops to 30% as soon as PV system starts generating electricity in the morning. In the late afternoon, for the last 2 hours of PV generation it supplies the difference between PV and standard CST generations only if the shortage is above 30% of the nominal power, otherwise it keeps working at 30% load.

With each scenario, the hybrid system is designed following this procedure: for a given PV capacity solar field, tower and, receiver of the CST component of the hybrid system, which has the same power block and storage system as the standard plant, are optimized considering different solar multiples to minimize the difference between the average monthly generations of the standard and the hybrid systems. Differences between the average monthly generations of the two systems, have to be lower than a certain limit for all months, i.e. lowest possible (5%, 7%, or in few cases 9%). The different hybrid systems are compared based on the actual annual generation and Levelized Cost of Energy (LCOE) values. The system that meets the performance criteria (i.e. matching the annual generation of the standard system as closely as possible) and has the lowest LCOE is selected as the best hybrid system for the scenario.

NREL's System Advisor Model (SAM, version 2018.11.11) was used to model and optimize both PV and CST components of the hybrid system. As noted in the two previously published studies conducted by the authors (Meybodi and Beath, 2016; Meybodi et al., 2017), a thorough analysis of the international as well as Australian studies led to a detailed capital cost and O&M cost breakdown of a molten salt central receiver base case plant

(100 MWe with 4 hours of two-tank molten salt thermal storage). The cost values have been updated to reflect cost reductions in the CST technology in recent years. The previously developed cost model, which allows for estimating capital and O&M costs for other sizes of the system and provides a detailed system cost breakdown, has been used to estimate the costs of the standard system and is used to calculate the costs of CST component of the hybrid system. Table 1 lists the SAM costing data for the standard system. For the capital cost of the PV system, the value of $1463/kW is used (Graham et al., 2019). The O&M cost of the PV system is assumed to be 1% of the capital cost.

Tab. 1: The standard system (125 MWe and 15 h of storage) SAM costing data

Item	Value	Unit
Site improvements	20.1	$/m^2
Heliostat field	140	$/m^2
Balance of plant	277.3	$/kW$_e$
Storage	26.4	$/kWh$_{th}$
Fixed tower cost	3,193,998	$
Tower cost scaling exponent	0.0113	-
Receiver reference cost	61,507,728	$
Receiver reference area	761.121	m^2
Receiver cost scaling exponent	0.7	-
Contingency	7	%
EPC and owner cost	10.3% of the direct capital cost	-
O&M cost	83.7	$/kW-yr

LCOE is defined by Equation (1), where CAPEX is the total capital cost ($), OPEX is the operational and maintenance cost ($/y), n is life of project (years), r is the discount rate, E is the produced electricity (kWh/y), t is the year of the project, and LCOE is in c/kWh. The discount rate is assumed to be 0.07. The project lifetime was considered to be 30 years, comprising of 3 years of construction and 27 years of operation.

$$LCOE = \frac{\sum_{t=1}^{n} \frac{CAPEX_t + OPEX_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \qquad \text{(eq.1)}$$

3. Results and discussion

Table 2 provides the summary of results and Fig. 2 shows the average annual output profiles for the three scenarios at the studied site. It is noteworthy that the generation values for PV and CST components of the hybrid system are the net generated electricity by these systems that is supplied to the grid and excludes any surplus PV generation that would result in the system exceeding the nominal maximum system output. There is also provision in the model for PV output to be used internally to supply the parasitic loads of the CST system, which can result in complicated interpretations of the total system output compared to the sum of the individual CST and PV generation predictions. The hybrid system in the second scenario provides the best match to the standard CST system profile. This is due to that fact that in the first and third scenarios the hybrid CST system increases generation when the storage is filled early in the afternoon. However, selecting the operational strategy (the scenario) for a specific site may require considerations beyond the similarity in output profile to the standard system and instead be based on better economics (i.e. lowest LCOE, as achieved in the second scenario) or closest match to the actual annual generation (i.e. as achieved by the third scenario).

Tab. 2: Summary of results

Scenario	First	Second	Third	Standard System
LCOE (c/kWh)	9.91	9.90	10.05	9.92
Annual generation (MWh)	1,026,199	1,051,524	993,878	983,120
Difference in generation with respect to the standalone system (%)	4.38	6.96	1.09	-

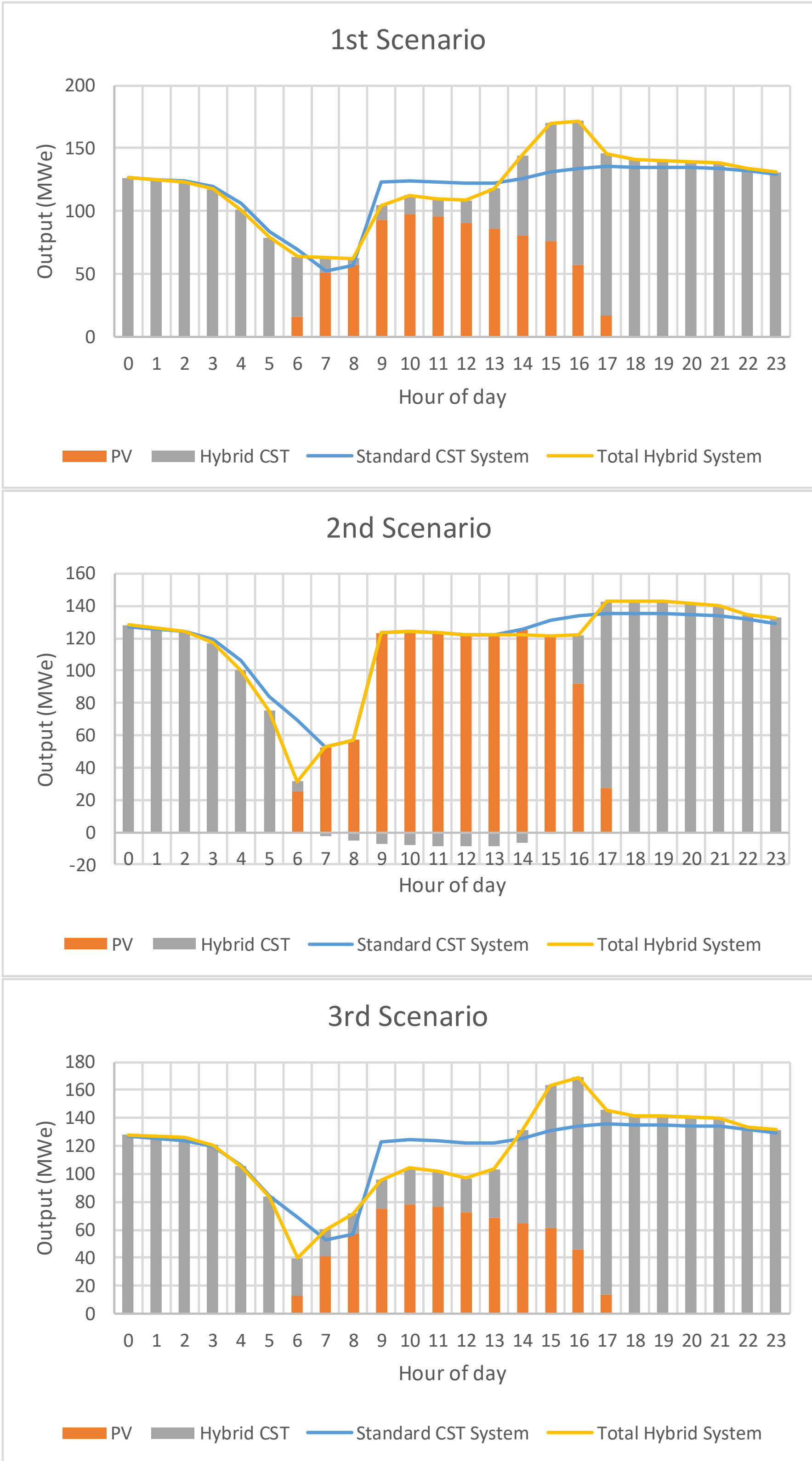

Fig.2: Average annual output for different systems

3.1. Equipment cost comparison and sensitivity analysis

Fig. 3 shows the total equipment cost of the hybrid systems under the three scenarios as well as the standard CST system. The standard system has the lowest equipment cost and the second scenario is the most expensive option but has the lowest CST system cost. To clarify the cost conditions under which the hybrid systems are more cost efficient than the standard system, variations of the total equipment cost with changes in PV and CST solar field cost (including tower and receiver) have been depicted in Fig. 4. The power block and thermal storage are the same for all the systems and therefore have been omitted. Also, minor differences in the total land size and annual generation have been neglected due to the minimal impact on the assessment. Based on this simplification, the capital cost of the system components translates to being representative of the overall LCOE value.

The contour areas represent the total equipment cost of the hybrid system when the corresponding PV and heliostat field costs are used in the costing, with system costs changing between scenarios due to differences in the system designs. The slopes of the contours vary due to the differences in the relative contributions of PV and CST components to the cost of the total hybrid system equipment. The regions of the graph where the standard CST system is cheaper or more expensive than the hybrid system are indicated by color changes, with a diagonal transition line where the system costs are identical. This varies depending on the hybrid system considered, as the cost relative to the standard CST is affected by the different split between PV and CST components in the hybrid system design. This means that for every different way of optimizing a hybrid system there are different costing points that influence whether the standard CST or hybrid systems are the best economic decision. It is evident that the hybrid system design in the third scenario is the more likely to be cost effective compared to the standard CST system, will the hybrid design in the first scenario is least likely to be cost effective.

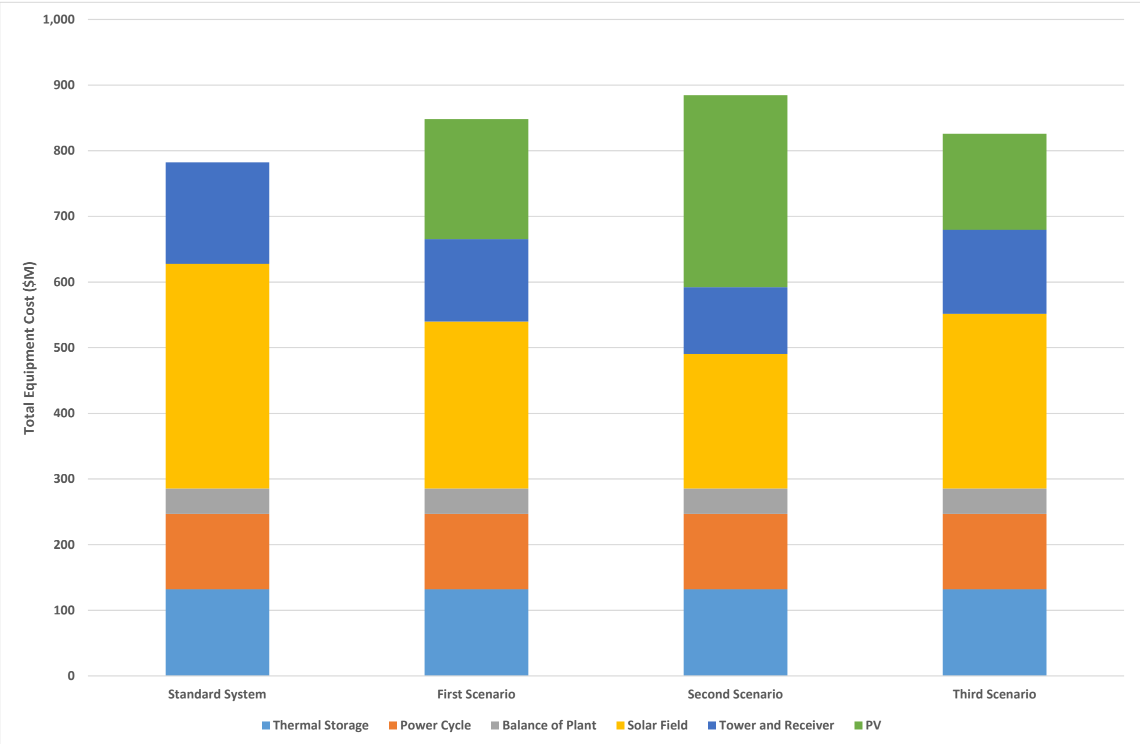

Fig. 3: Total equipment cost

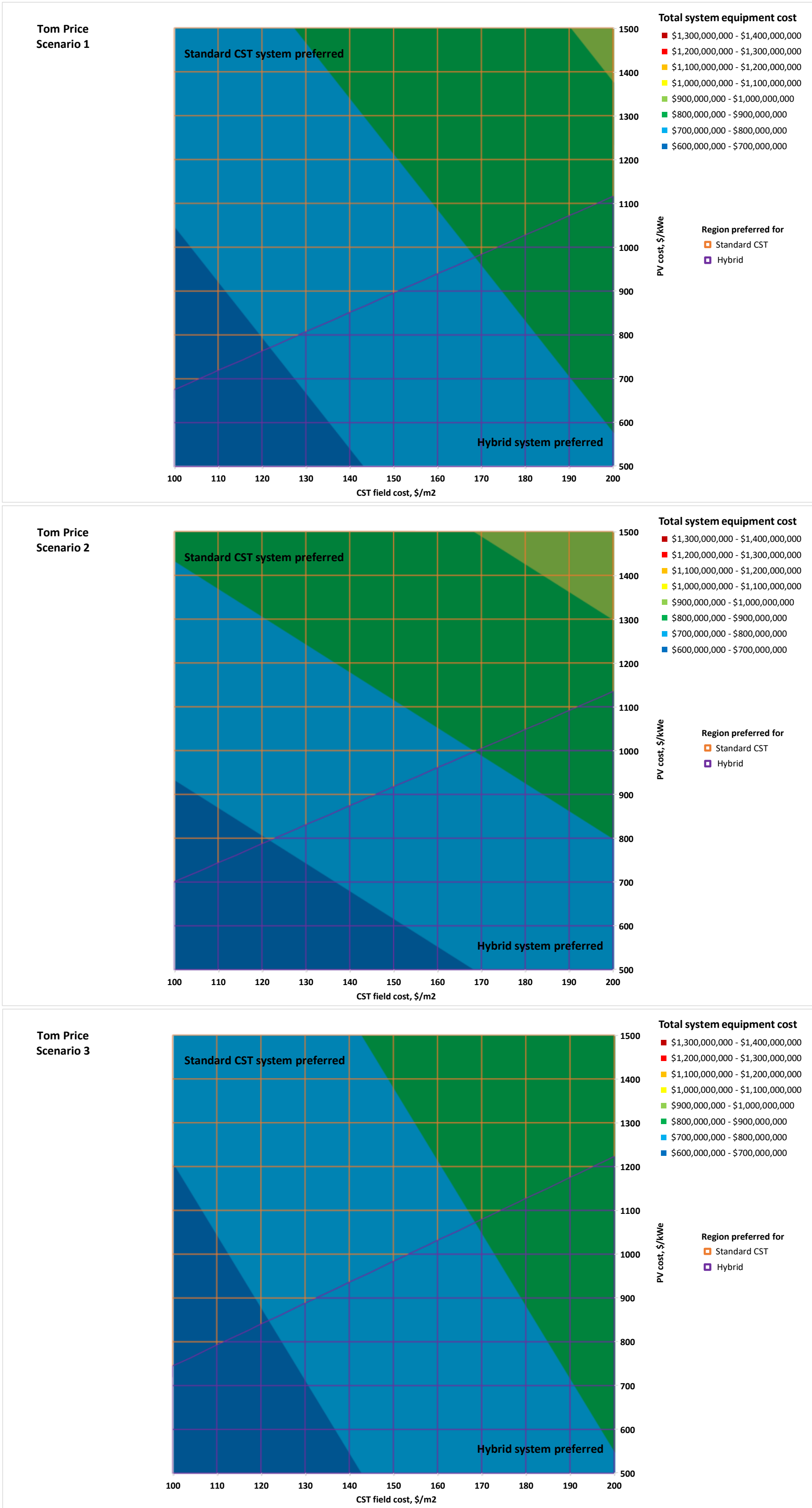

Fig. 4: Impact of PV and CST field cost on the competitiveness of the hybrid system

4. Conclusion

This study considered the potential benefits of incorporating solar photovoltaic systems in hybrid combination with the concentrated solar thermal plants to produce hybrid plants with the same generation profile that has been projected to be desirable in the future electricity networks. A simplified description of the impact of hybridization on the plant design is that the daytime generation from photovoltaic panels will reduce the need for daytime generation from the solar thermal plant, so reduce the heliostat field, receiver, and tower sizes, but the storage system and power block will remain the same size in order to produce the required night-time production. The potential use of battery storage for photovoltaics was not included in this analysis.

As the study was conducted, it became apparent that different design and operational strategies for the hybrid system could achieve similar generation profiles to the CST-only system. Three alternative scenarios were considered for the design of the hybrid systems, all with different outcomes:

- Simple PV replacement of portion of the heliostat field used for daytime operations – Power block was allowed to supplement the PV generation and ramp up when the storage fills, so very high output occurs in the afternoons in summer and may require shedding if the network connection is limited.
- PV for daytime operations, but with operational parameters limiting output of the combined hybrid system to accurately match the target output profile.
- Reduced PV implementation to minimize the intermittent operation of the power block – This approach is intended to both reduce the likelihood of maintenance issues arising from excessive power block starts and to increase the reliability of the system during cloudy daytime operations.

5. Acknowledgments

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6. References

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