Estimating the Performance and Economic Value of Multiple Concentrating Solar Power Technologies in a Production Cost Model

Jennie Jorgenson, Paul Denholm, Mark Mehos, and Craig Turchi

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Technical Report
NREL/TP-6A20-58645
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Prepared under Task No. SS13.3060

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List of Acronyms

AGC	automatic generation control
CC	combined cycle
CSP	concentrated solar power
CT	combustion turbine
EIA	Energy Information Administration
LCOE	levelized cost of energy
NG	natural gas
PSCo	Public Service Company of Colorado
PV	photovoltaic
SAM	System Advisor Model
SM	solar multiple
TEPPC	Transmission Expansion Planning Policy Committee
TES	thermal energy storage
TRC	technical review committee
VG	variable generation
VO&M	variable operation and maintenance
WACM	Western Area Colorado Missouri
WECC	Western Electricity Coordinating Council

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1 Introduction

Dispatchable power plants provide multiple services to the electricity grid, including the ability to respond to changes in supply or demand. Concentrating solar power (CSP) with thermal energy storage (TES) is a unique source of renewable energy in that the solar thermal energy can be dispatched similarly to conventional thermal generation. However, CSP-TES plants are an energy-limited resource, meaning that their response might be restricted by solar availability. Therefore, the use of this solar energy must be optimally scheduled to provide the greatest value to the system. The timing of CSP-TES dispatch depends on a variety of factors, including electricity demand patterns, the penetration of variable generation (VG) sources, and the configuration of the CSP plant itself.

Recent studies have identified the value of CSP-TES in not only shifting energy over time but also in providing ancillary services and serving as a source of firm capacity (Denholm and Hummon 2012; Denholm et al. 2013; Denholm et al. 2012). However, previous analysis simplifies several operational parameters of CSP as a thermal power plant and does not consider multiple CSP technologies and configurations now being deployed.

We use an established CSP modeling framework in a commercially available production cost model to compare the operation and value of two CSP technologies: molten salt towers and parabolic troughs. In addition, we consider a range of configuration parameters, such as solar multiple (SM) and storage size, to evaluate how the operational and capacity value varies with plant configuration.

2 Implementing CSP Technologies in Production Cost Models

Previous analysis details the methodology of implementing a parabolic trough CSP plant with TES into the PLEXOS production cost model (Denholm and Hummon 2012; Denholm et al. 2013). This section first summarizes earlier work and then describes the implementation of a power tower CSP generator with TES, which is less well represented in the literature.

Both parabolic trough and power tower CSP-TES plants consist of the same basic technology. Initially, the reflective solar field directs solar radiation to a heat transfer fluid. The heated fluid can either be stored or sent to the power block, which converts thermal energy to electricity.[1] In combination with the solar resource (energy coming from the sun), the relative sizing of these three components (the solar field, storage tank, and power block) determines the capacity factor of the plant. A smaller solar field results in reduced thermal energy delivered to the power block and a lower capacity factor. An undersized power block relative to the solar field, in the absence of sufficient thermal storage, can result in wasted energy during hours of high solar irradiance.

A design parameter called the solar multiple (SM) normalizes the size of the solar field with respect to the power block. A system with an SM of 1 is sized for the solar collector to provide the power block with exactly enough energy to operate at its rated capacity under reference solar conditions. A larger SM implies a larger solar collector area. For instance, Figure 1 depicts a CSP plant with a power block rating of 300 MW and an SM of 2. Any electrical energy delivered from the solar field that exceeds the maximum thermal rating of the power block rating must be stored—or dumped for systems without storage. As the diagram indicates, excess energy (in yellow) from an oversized solar field (an SM greater than 1) can be sent to thermal storage and subsequently delivered to the power block resulting in a higher plant capacity factor.[2]

[1] Trough and tower systems can either have direct or indirect storage. For direct storage configurations, the storage medium is the same as the heat transfer fluid. Indirect storage configurations use an intermediate heat exchanger to transfer thermal energy from the heat transfer fluid to the storage medium. For more detail on CSP technologies, see DOE (2012).

[2] Capacity factor is the ratio of the actual output of a power plant with respect to the maximum possible output if it operated at its rated power block capacity during some amount of time.

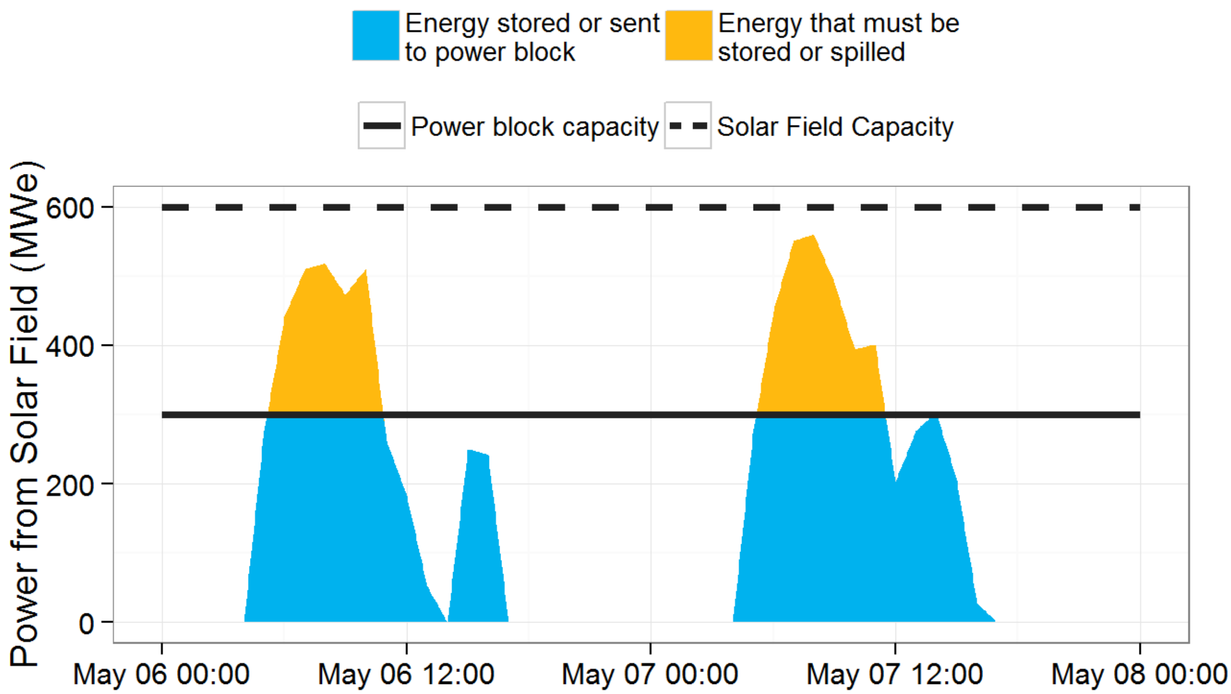

Figure 1. Impact of the solar multiple on the energy flow of a CSP plant

2.1 Production Cost Modeling

Production cost models are used by utilities, system planners, and researchers to evaluate the operation of power systems. Specifically, the model determines the dispatch of each generator to minimize production cost in each interval while still retaining sufficient operating reserves. The optimal dispatch must consider the physical limitations of each generating unit. For instance, each unit has a given minimum and maximum generating capacity, efficiency curve, up- and down-time, and ramp rate. Production cost modeling provides a methodology to evaluate the operational impact and value of integrating CSP with TES into a power system. This study used the PLEXOS production cost model, simulating one full year of hourly operation (8,760 hours).[3] The simulations co-optimize energy and ancillary services over a sliding 24-hour dispatch window (with an additional day of look-ahead for a full 48-hour window of perfect forecast) to simulate hourly operation of the day-ahead electric power system.[4]

2.2 Characterization of the Colorado Test System

NREL has developed a test system derived from a subset of the Western Electricity Coordinating Council (WECC) Transmission Expansion Policy Planning Committee (TEPPC) model and other publicly available datasets. The system is large enough to be realistic but small enough to isolate changes associated with the addition of CSP. Many recent NREL studies focus on

[3] All PLEXOS simulations used version 6.207 R08 using the Xpress-MP 23.01.05 solver with the model performance relative gap set to 0.5% and a time horizon of one chronological year, 2020.

[4] While additional look-ahead may increase the apparent value of thermal storage, it also assumes perfect future knowledge of both load and solar. In addition, large look-ahead windows increase computational burden. For more discussion about energy storage and foresight, see Sioshansi et al. (2009).

evaluation of this test system due to its size and relative isolation from the rest of the Western Interconnection (see Denholm and Hummon 2012; Denholm et al. 2013; Hummon et al. 2013a; Hummon et al. 2013b).

The test system consists of two balancing authorities—Public Service Company of Colorado (PSCo) and Western Area Colorado Missouri (WACM). Multiple individual utilities operate within this region, which is referred to in this study as the Colorado test system. These vertically integrated utilities balance their own operation and interact with their neighbors under confidential bilateral agreements. Because the bilateral contracts are not publicly available, this analysis assumes an optimal, least-cost dispatch. Hourly load profiles were scaled from 2006 data to match the projected TEPPC 2020 forecast for annual load (TEPPC 2011). The peaking demand is 13.7 GW with an annual energy demand of 79.0 TWh. Conventional coal-fired generators comprise the majority of installed thermal generation capacity (6.2 GW). Natural gas-fired combined cycle (CC) and combustion turbine (CT) plants make up 3.7 GW and 4.0 GW of capacity, respectively. The system has 773 MW of hydroelectric generation capacity and 560 MW of pumped storage hydro capacity. The base case assumes a photovoltaic (PV) and wind penetration of 16% on a total energy basis,[5] which equates to 878 MW installed PV capacity and 3.3 GW installed wind capacity. The total system capacity for the Colorado test system is 15.9 GW, which includes an additional 513 MW of capacity from oil- and gas-fired internal combustion generators and demand response. Figure 2 shows the breakdown of total generation in the base case, which assumes no existing CSP-TES capacity.

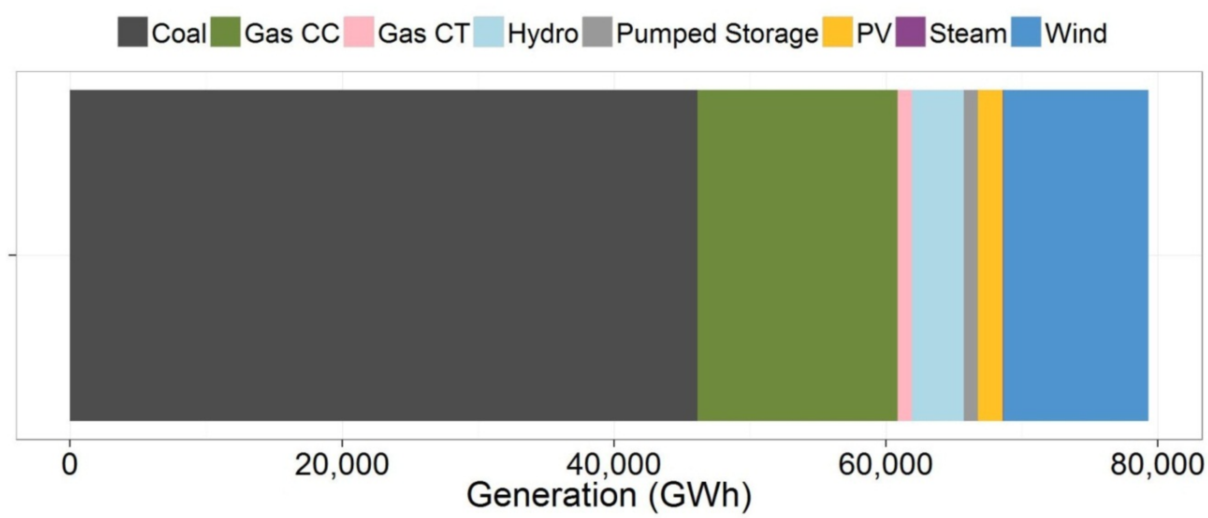

Figure 2. Base case Colorado test system generation breakdown by generator type

Fuel prices come from the TEPPC 2020 database. Coal price is constant at $1.42/MMBtu for all coal-fired units. Natural gas (NG) prices vary by month (between $3.8/MMBtu and $4.5/MMBtu) to capture changes in seasonal demand, as shown in Figure 3. The generation-

[5] This is about 2.3% from PV and 13.4% from wind. For comparison, Colorado received about 11% of its electricity from wind generation in 2012. EIA "Electric Power Monthly with Data for December 2012." The relatively low penetration of PV is significant because the solar resource availability of CSP and PV are largely coincident. Future analysis will evaluate the impact of PV and wind penetration on the value of CSP-TES.

weighted average NG price is $4.1/MMBtu. The fuel prices are slightly lower than $2.9/MMBtu and $5.1/MMBtu, which is the U.S. Energy Information Administration's (EIA's) 2013 Annual Energy Outlook[6] projection for coal and NG, respectively, to the Mountain region power sector in 2020. Section 3 addresses the sensitivity of CSP operation to NG prices.

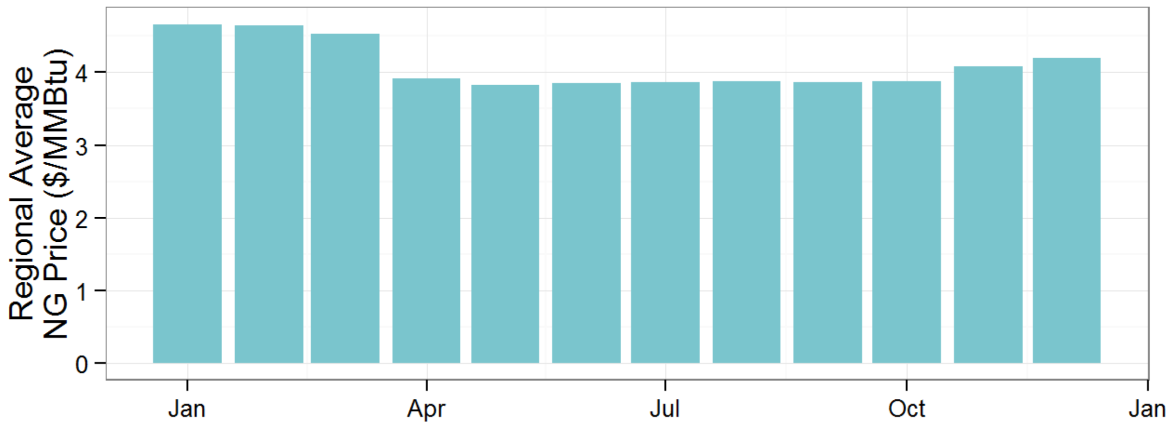

Figure 3. Seasonal change in gas prices for the Colorado system

This test system models three classes of operating reserves: contingency, regulation, and flexibility reserves. The contingency requirement is based on the ability to ensure stability in the event of the loss of the largest system power supplier—in this case, an 810-MW supercritical coal plant.[7] Of this 810-MW requirement, 50% must be met by spinning units. Any partially loaded generator, constrained by its ramp rate, can hold spinning contingency reserves. Further references to contingency reserves refer only to the spinning portion of this requirement.[8] While the requirement for spinning contingency reserves remains constant at 405 MW, regulation and flexibility reserves are both time-dependent and based on the statistical variability of load, wind, and PV.[9] Only a subset of generators can provide regulation and flexibility reserves based on the lack of operational practice or control equipment. Table 1 shows a summary of the characteristics of the three modeled operating reserve services.

[6] U.S. Energy Information Administration's Annual Energy Outlook 2013, www.eia.gov/oiafaeo/tablebrowser.
[7] The largest contingency on a system can be a power plant (as in this case) or a transmission line. For further reading, see Kirby 2007.
[8] Historical market-clearing prices for non-spinning contingency reserves are very low because there is often little opportunity cost.
[9] Flexibility and regulation reserve requirements used the methodology detailed in Ibanez et al. 2012. For a more comprehensive discussion of operating reserves in this system, see Hummon et al. 2013.

Table 1. Summary of Operating Reserves Modeled in the Test System

Operating Reserve Service	System Drivers to Service Requirement	Time to Response (Minutes)	Requirement as Percentage of Load Mean (Min/Max)	Generators Eligible To Provide Service
Regulation	PV, wind, load	5	1.33 (1.00/1.71)	60% of dispatchable generators (omitting gas combustion turbines[10]), constrained by ramp rate
Spinning contingency	Largest generator	10	4.54 (2.97/5.95)[11]	Any partially loaded plant, constrained by ramp rate
Flexibility	PV, wind	20	0.64 (0.13/1.07)	60% of dispatchable generators, constrained by ramp rate

Holding regulation reserves incurs extra costs due to rapid and frequent change in output. This cost results from non-steady-state wear and tear as well as heat rate degradation. In a restructured market, a generator will "bid" its assumed cost for holding regulation (PJM 2013). In a vertically integrated utility, the additional cost of regulation reserves is folded into each generator's total production cost. Table 2 shows the assumed additional cost for units holding regulation reserves by generator type used in this analysis.

Table 2. Assumed Additional Operating Costs for Units Providing Regulation Reserves in This Analysis

Generator Type	Cost ($/MW-h)
Supercritical Coal	15
Subcritical Coal	10
Combined-Cycle	6
Gas/Oil Steam and CSP	4
Hydro	2
Pumped Storage Hydro	2

The unit "MW-h" represents a unit of capacity (MW) held for 1 hour.

2.3 CSP Technology Implementation in the Model

Production cost modeling provides several valuation techniques for analyzing specific technologies, such as CSP. In this analysis, we compare the system described above as modeled with and without the addition of one CSP-TES plant. We calculate the difference in total production cost (which includes fuel costs, variable operating and maintenance costs, and start-up costs) between the two runs and attribute the marginal system savings to the CSP plant. We also observe the dispatch and utilization of the CSP-TES plant. To correctly capture the dispatch and value, we must integrate and connect the three aspects of a CSP-TES plant: the solar field, the storage system, and the power block. Denholm and Hummon (2012) and Denholm et al. (2013) describe this methodology in detail. Firstly, we quantify the solar resource. Meteorological data for the site chosen for this analysis, located in the San Luis Valley of

[10] CTs are omitted from holding regulation reserves in the test system based on feedback from various utilities and system operators. This omission serves to further restrict generator availability for holding regulation reserves given the lack of information regarding exactly which generators are equipped with automatic generation control (AGC).
[11] The spinning contingency requirement is constant at 405 MW, meaning that it varies as a percent of load.

southern Colorado, originates from the National Solar Radiation Database for the year 2006 to match the TEPPC load assumptions (NREL 2007).

This meteorological data is an input to NREL's System Advisor Model (SAM) version 2013-1-15 (Gilman et al. 2008; Gilman and Dobos 2012). The CSP models within SAM convert hourly irradiance and meteorological data into thermal energy and model the flow through the system components, accounting for various losses, and then convert the thermal energy into net electrical energy. The trough CSP simulations used the physical trough model, and the tower CSP simulations used the molten salt power tower model (Wagner and Gilman 2011). Down-time, outages, start-up energy, and part-load efficiency decrements were neglected in SAM so as to be taken into account during dispatch modeling. The turbine was allowed to operate anywhere between zero and its maximum output. All other performance settings remained at default. Thermal energy from SAM is converted to an electrical equivalent based on the rated gross thermal-to-electric efficiency of the turbine in the model. Unless noted otherwise, the plants were assumed to use dry cooling and gross turbine efficiency was determined as per SAM's default dry-cooled conditions. The electrical equivalent energy then served as a dispatchable resource in PLEXOS within the constraints of the thermal power block characteristics of the CSP plant. Figure 4 describes the modeling flow.

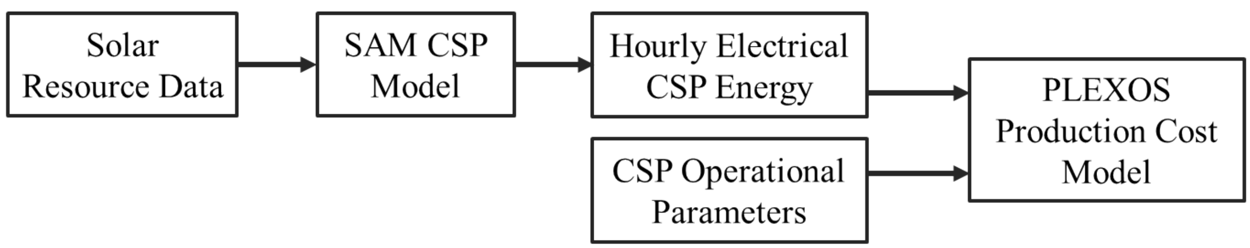

Figure 4. Process of simulating CSP in a production cost model

The "raw" electrical energy flow from SAM is applied to a modified hydropower algorithm in PLEXOS to simulate dispatched storage and CSP-TES generator operation. Specifically, in each hour the model can send electrical energy into storage, directly into the grid through the CSP power block, or a combination of the two. The model can also choose to draw energy from storage to feed the power block. Figure 5 illustrates the flow of energy through the CSP plant. As mentioned above, all parameters that may affect, or be affected by, plant dispatch were neglected in SAM and accounted for in PLEXOS. Figure 5 also shows (in dashed lines) three types of losses within the plant: start-up losses incurred when warming up the plant, part-load efficiency decrement resulting from operating below the design point, and storage losses that result from transferring and storing heat either directly or indirectly.

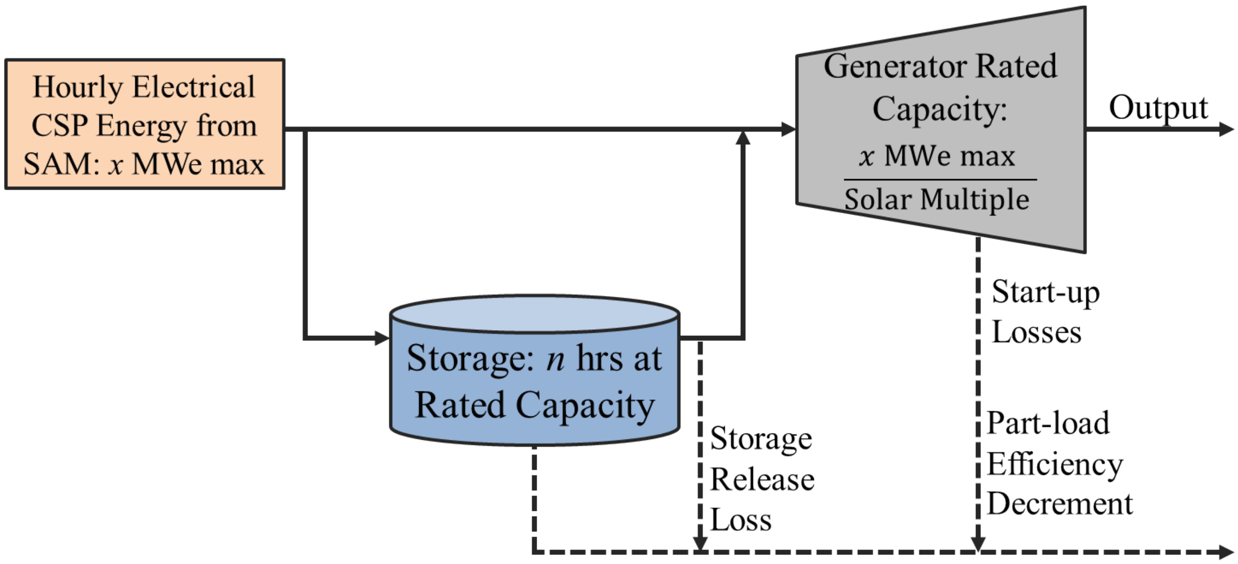

Figure 5. Flow of energy through a CSP plant

Figure 5 illustrates another concept discussed here—the effect of the SM. As discussed earlier in Section 2, increasing the SM of a CSP plant represents either decreasing the size of the power block or increasing the size of the solar collection field. Here, we adjusted the SM by changing the size of the power block, or rated capacity, of the system. Note that changing the rated capacity of the system also affects the size of the thermal storage tank, which is measured in hours of operation at the rated power block capacity. Section 4 offers a discussion of the sensitivity of plant operation to the SM and thermal energy storage capacity.

3 Relative Performance of Dry-Cooled Troughs and Towers

Both trough and tower CSP plants convert sunlight to electricity via steam turbines and can make use of TES. Although the governing steam turbine parameters are largely the same for trough and tower configurations (though tower turbine efficiencies are typically greater than the efficiency for troughs due to higher operating temperatures for towers), the hourly electrical energy from each system may be substantially different due to differences in the solar collection method. Figure 6 depicts the seasonal and daily variations of solar resource availability for trough and tower plants providing an equal amount of energy on an annual basis. The solar resource availability for the tower field is relatively constant throughout the year, while the trough resource exhibits a strong seasonal dependence. This is due primarily to the seasonal "cosine" effect due to low sun elevation angle in winter, which is more pronounced for single-axis tracking parabolic trough collectors versus two-axis tracking heliostats used for tower configurations.[12]

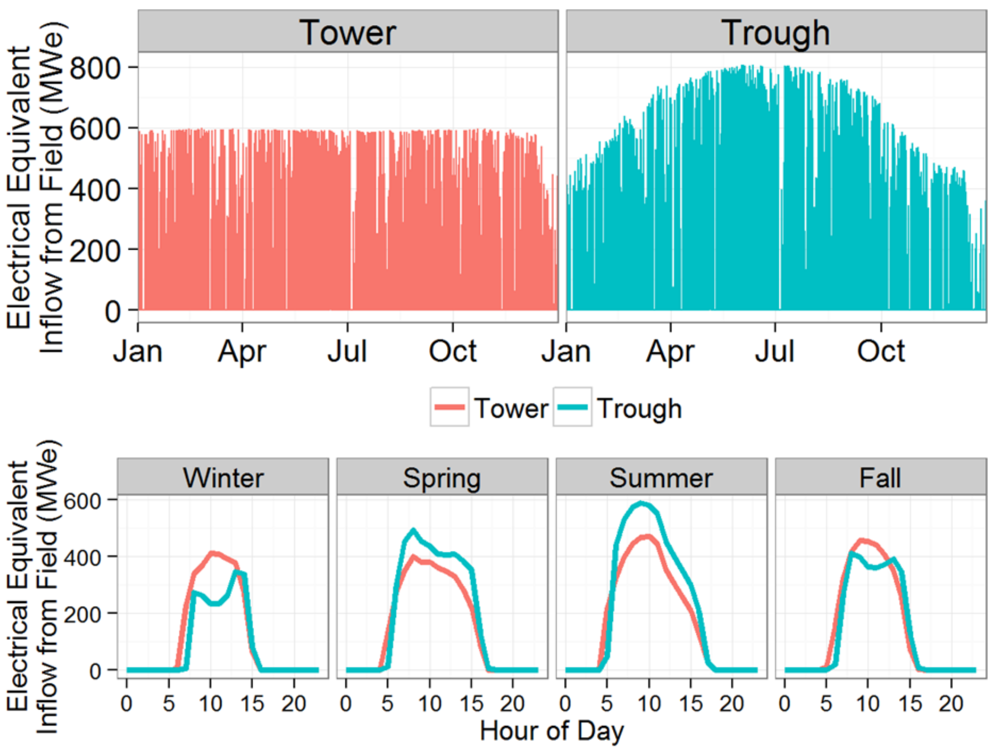

Figure 6. The seasonal (top panel) and average daily (bottom panel) variation in solar resource availability for trough and tower CSP plants[13]

[12] For additional reading, see EASAC (2011).

[13] The midday dip in output for trough plants in the winter, spring, and fall months is due to a geometrical effect characteristic of single-axis tracking collectors that follow the sun from sunrise to sunset. Early and late in the day, the vector normal to the collector aperture points nearly directly toward the sun. As the sun rises in the sky toward noon, the collector faces upward while the sun remains low in the sky. This "cosine" effect, which is most

We use the presented methodology to implement both technologies in a production cost model to compare the dispatch and system value of the two types of plants. The hourly solar energy availability shown in Figure 6 serves as an energy inflow into a power plant that can either choose to store the energy or generate through the power block. Table 3 shows the operational constraints of the power block in the base case dry-cooled trough and tower systems.[14] We assume tower and trough plants largely have the same operational parameters; however, troughs are assumed to use indirect storage. Indirect storage requires a transfer of heat from the solar collector fluid to the storage medium, which incurs additional heat exchanger losses.[15] Therefore, indirect storage plants (in this case, the trough plant) lose an additional 5% of stored energy compared to direct storage plants, such as power towers. Towers, as modeled here, use direct storage but still experience a loss of stored energy in the form of heat decay.

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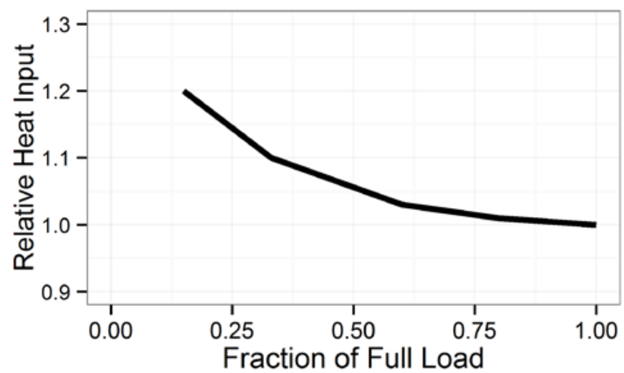
pronounced during the winter months, results in a decrease of the effective aperture available for concentrating the incoming sunlight.

[14] The TEPPC-generated PLEXOS database contains operational information for all generators in the western United States. As a guideline for CSP plants, we examined existing gas-fired steam plants above 50 MW and submitted for review from a Technical Review Committee (TRC). For the analysis of another, less flexible set of generator parameters, see Hummon et al. (2013c).

[15] Current parabolic trough systems with indirect storage typically size the heat exchanger to accommodate only that energy delivered that is in excess of the design point thermal rating of the generator. This constraint has not been implemented in this study with the understanding that future systems could be designed to maximize operational flexibility.

Table 3. Operational Parameters of the Base Case Dry-Cooled CSP Tower and Trough Plants

<table>
<tr><th>Parameter</th><th>Base Case Scenario</th></tr>
<tr><td>Minimum Up-Time</td><td>1 hour</td></tr>
<tr><td>Minimum Down-Time</td><td>1 hour</td></tr>
<tr><td>Number of Starts per Day</td><td>Unconstrained</td></tr>
<tr><td>Ramp Rate</td><td>10% of capacity per minute</td></tr>
<tr><td>Minimum Generation Point</td><td>15% of capacity</td></tr>
<tr><td>Enabled to Hold Regulation, Contingency, and Flexibility Reserves</td><td>Yes</td></tr>
<tr><td>Heat Rate Curve</td><td>


<table>
<tr><th>Fraction of Full Load</th><th>Ratio of Relative Heat Input</th></tr>
<tr><td>0.15</td><td>1.2</td></tr>
<tr><td>0.33</td><td>1.1</td></tr>
<tr><td>0.60</td><td>1.03</td></tr>
<tr><td>0.8</td><td>1.01</td></tr>
<tr><td>1</td><td>1.0</td></tr>
</table>
</td></tr>
<tr><td>Cost of Providing Regulation Reserves</td><td>$4/MW-hr</td></tr>
<tr><td>Regulation Range[a]</td><td>60%–100% of rated capacity</td></tr>
<tr><td>Start-Up Energy</td><td>20% of rated output for 1 hour</td></tr>
<tr><td>Start-Up Cost</td><td>$10/MW/start</td></tr>
<tr><td>Variable Operation and Maintenance</td><td>$1.1/MWh</td></tr>
<tr><td>Average Storage Loss Rate[b]</td><td>2% (direct molten salt tower)
7% (indirect trough)</td></tr>
<tr><td>Maintenance Rate</td><td>0%</td></tr>
<tr><td>Forced Outage Rate for Unscheduled Maintenance</td><td>4%</td></tr>
<tr><td>Hours of Thermal Storage</td><td>6</td></tr>
<tr><td>Solar Multiple</td><td>2 (direct molten salt tower)
2.2 (indirect trough)</td></tr>
</table>

[a] This parameter requires that the generator is operating within the specified range in order to hold regulation reserves. Because the modeled regulation requirement encompasses both “up” and “down” regulation, the service is net-zero energy over a small period of time. Therefore, the generator must be above its minimum generation point to ensure that it can ramp up (and subsequently down) to achieve net-zero energy output.

[b] This loss applies to all energy sent to storage. This represents about a 5% loss for indirect troughs in the heat exchanger and an additional loss of 2% for heat decay in storage for both types of plants. In reality, the decay losses would be represented using a percent loss per unit time. Future analysis will determine if this simplification is problematic.

For direct comparison, we added a tower and trough plant that each provided an equal amount of annual energy. However, this approach results in CSP plants of different size, in terms of rated capacity. Furthermore, the “optimal” plants may have a different SM due to their seasonal profiles and assumptions regarding component costs for each technology. For this base case, we used SAM to determine the corresponding SM (and thus, nominal size of plant) by optimizing the levelized cost of energy (LCOE) with respect to amount of thermal storage.[16] Production cost models such as PLEXOS, by definition, do not consider the capital cost of new technologies. In this case, the optimal SM for towers and troughs with 6 hours of storage is different—2.0 and 2.2, respectively. Given the solar energy input under reference conditions and scaling to achieve matching annual energy outputs, we model a base case tower plant of 300 MW net and a base case trough plant of 367 MW net, each with annual output of 1.2 TWh. The larger capacity of the trough plant for an equivalent annual generation is the result of several factors. SAM’s trough plant sizing routine uses the solar field performance for the hypothetical situation with the sun directly overhead to size the solar field for the specified SM. This represents the best possible performance point for the solar field. Consequently, the solar field is smaller than if the design point was selected for any specific time of year. SAM’s sizing routine for the power tower selects the spring equinox as the design date; however, this selection is less important given that the tower exhibits less variation over the course of the year. This sizing convention will result in a larger SM for a trough plant compared to a power tower with the same storage capacity at the same site when optimized for annual performance. The seasonal differences of the two technologies create this difference in SM sizing convention and accounts for most of the disparity in trough and tower capacity. Other factors that necessitate a larger trough capacity to attain equivalent annual generation include the lower gross power cycle efficiency of the trough plant, greater losses from the indirect thermal storage system, and slightly greater plant parasitic losses.

Both plants produce about 1.2 TWh of energy annually as dispatched by PLEXOS. Table 4 shows the results from the dispatch modeling of the two technologies. The tower has a higher capacity factor due to its lower rated capacity. However, the trough plant provides more regulation, spinning, and flexibility services in the form of reserve capacity on an annual basis due in part to its greater capacity. Both plants utilize about 70% of their total capacity throughout the year, when considering the allocation of the plant’s capacity to providing either energy or holding reserves. In addition, both plants spend more than 6,000 hours of the year online, at or above the minimum generation level. The tower plant is online more hours of the year due largely to a better solar resource in the winter and fall months.

[16] Unless noted otherwise, this analysis was based on default performance and cost parameters available in SAM version 2013-1-15. Cost models used in support of SAM’s default trough and tower configurations can be downloaded at https://sam.nrel.gov/cost.

Table 4. Simulation Results for Dry-Cooled Tower Versus Dry-Cooled Trough CSP-TES With 6 Hours of Thermal Storage

	Capacity (MW)	Electrical Equivalent Inflow From Field (GWh)	Annual Generation (GWh)	Annual Reserves Provision (GW-h)	Capacity Factor (%)	Annual Hours On
Dry-Cooled Tower	300	1,264	1,190	650	45.3	6,958
Dry-Cooled Trough	367	1,321	1,183	721	36.8	6,347

Figure 7 depicts the difference in average daily dispatch for the two plants. In the spring and summer, the dispatch shape is similar. In both cases, the system optimizes the solar energy to serve load when it peaks and has sufficient solar resource to do so, which can be seen in the lower pane of Figure 6. Though the shapes are similar in the spring and summer, the output of the trough is higher due to the increased plant capacity and high solar resource (recall that the trough electrical inflow is scaled to result in similar annual output, so the trough solar resource is higher relative to the tower in the spring and summer and lower in the winter and fall). The tower plant, however, exhibits flatter output during the winter and fall mornings because it has more solar energy available during those periods relative to the trough plant due primarily to the pronounced cosine effect exhibited by trough systems during winter months as described previously (see Figure 6).

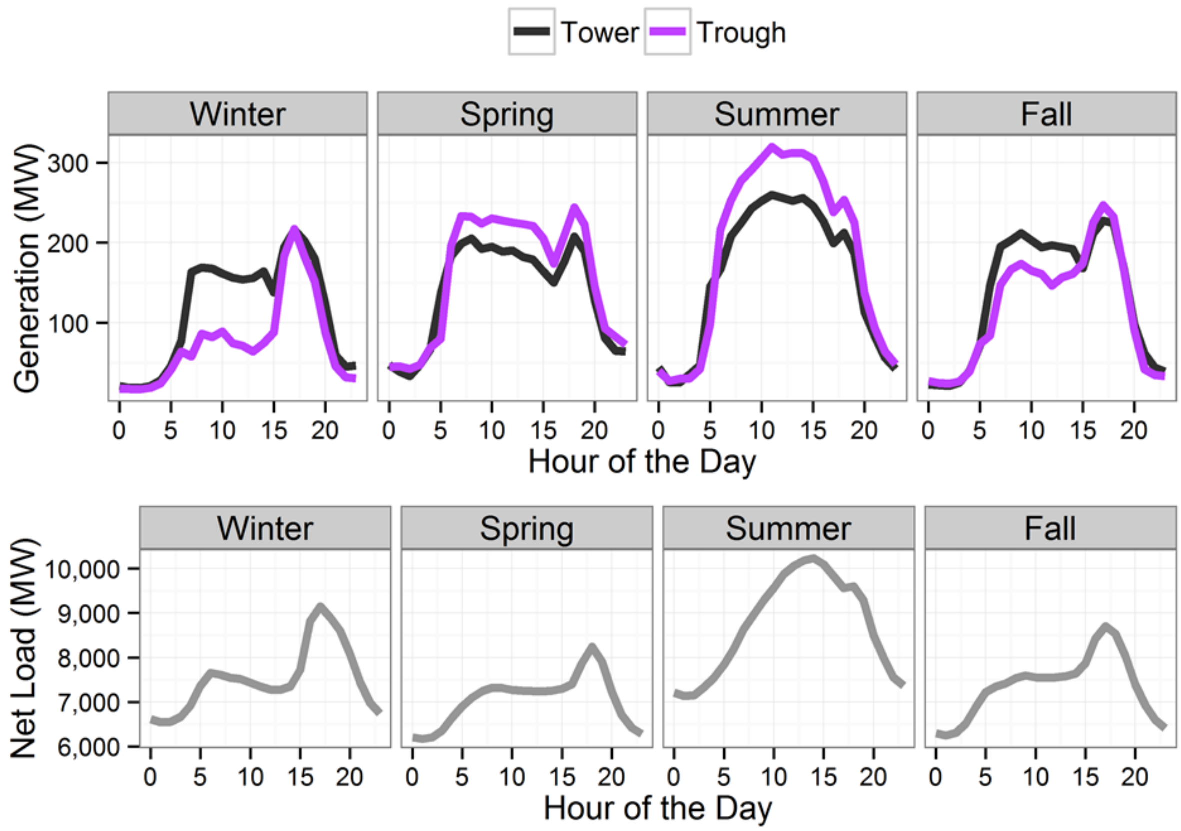


Figure 7. Top panel: Average daily dispatch for a tower and trough CSP-TES plant in each season of the year; bottom panel: Average daily net load (system load minus wind and PV) in each season

Although the dispatch of troughs and towers are slightly different, they provide similar value to the system in the form of a reduction in total generation cost: by displacing fuel, operating and maintenance costs, and start-up costs for more expensive generators. The tower plant reduces the total generation cost $51.9 million annually, while the trough reduces the total generation cost by $53.2 million. This represents a reduction of 3.6% and 3.7% from the base case production cost, respectively. The trough shows a more seasonal reduction in cost. From March through the end of August, the trough plant shows an average cost savings of 4.2% compared to 3.0% savings in the other half of the year. The tower reduces costs by 3.7% from March through August and 3.4% in the winter months.

The savings attributed to either CSP plant can be normalized by the amount of energy produced (in MWh), which produces a value per unit energy, expressed as dollars per megawatt-hour. This value can be compared to the LCOE from the plant and also forms a basis to compare the value of energy produced by CSP to other types of generation. As will be discussed in Section 4, this metric has certain limitations and should not be the sole basis for comparing different generation technologies; however, it does form a useful starting point for our analysis. Therefore, we first describe the marginal system value in terms of dollars per unit energy produced by CSP and then discuss other valuation methods in Section 4.

Table 5 provides the marginal system value for the simulated tower and trough plants in each of the three fuel price scenarios: with monthly NG prices as depicted in Figure 3, with a constant NG price of $4.1/MMBtu, and with the monthly NG prices doubled. It includes the source of value for each case, dominated by the avoided fossil fuel. Table 6 provides a summary of the avoided fuel by generator type. Natural gas is the marginal source of generation during most hours of the year, and both troughs and towers tend to displace mostly gas-fired generation. However, the trough displaces slightly more fuel than the tower because it has higher output in the summer when the lower efficiency CTs are online to serve the peak summer load. The trough displaces more starts for the same reason and also because it displaces more reserve capacity than the tower due to its larger capacity, which allows the rest of the conventional generators to be operated more optimally.

When the marginal operational value for the two CSP-TES plants is instead normalized by installed plant capacity, the tower has an operational value of $184/kW, and the trough has an operational value of $162/kW. The dollar-per-kilowatt metric leads to a higher apparent value for the tower plant because of its smaller capacity (300 MW compared to 367 MW), telling a different story than the dollar-per-megawatt-hour value depicted in Table 5. This illustrates a challenge in this analysis, which strictly evaluates the value of each technology but not the costs (which will depend on configuration and capacity).

Table 5. Difference in Marginal Operational Value Between Simulated Tower and Trough CSP-TES Plants With 6 Hours of Thermal Storage

	Marginal Value ($/MWh)				
	Variable Operations and Maintenance	Start and Shutdown	Fuel	Reserves Operations and Maintenance	**Total**
Dry-Cooled Tower	1.0	4.5	36.6	1.5	**43.6**
Dry-Cooled Trough	1.0	5.4	37.5	1.1	**45.0**
Dry-Cooled Tower, Const. NG Prices	1.0	5.0	36.5	1.4	**44.1**
Dry-Cooled Trough, Const. NG Prices	1.0	5.6	37.6	1.2	**45.5**
Dry-Cooled Tower, 2x NG Prices	1.1	5.4	73.6	1.5	**81.5**
Dry-Cooled Trough, 2x NG Prices	1.1	6.5	74.4	1.2	**83.1**

Table 6. Difference in Marginal Fuel Savings Between Simulated Tower and Trough CSP-TES Plants With 6 Hours of Thermal Storage

	Marginal Fuel Savings (MMBtu/MWh)			
	Coal[17]	Natural Gas (CCs)	Natural Gas (CTs)	**Total**
Dry-Cooled Tower	(0.1)	6.6	2.3	**8.9**
Dry-Cooled Trough	(0.2)	6.5	2.8	**9.2**
Dry-Cooled Tower, Const. NG Prices	0.0	6.7	2.2	**8.9**
Dry-Cooled Trough, Const. NG Prices	(0.1)	6.3	2.8	**9.1**
Dry-Cooled Tower, 2x NG Prices	0.1	6.6	2.3	**9.1**
Dry-Cooled Trough, 2x NG Prices	0.1	6.3	2.8	**9.3**

Denholm and Hummon (2012) report a similar marginal value, \$42.1/MWh, for a trough CSP plant in the same system with 6 hours of thermal storage but unable to provide reserves. Table 5 indicates a similar, but slightly higher, system value for a trough CSP plant with an added ability to provide reserves. For this analysis, we imposed operational constraints and costs (start-up costs, variable operation and maintenance (VO&M) costs, and regulation VO&M costs) to the plant not modeled previously with CSP. These additional costs imposed on CSP-TES reduce the marginal value in Table 5 by \$2.3/MWh for the tower and \$2.0/MWh for the trough. The comparable marginal value (computed by adding the previously reported value of \$42.1/MWh for a trough with the new additional costs, \$2/MWh) in this analysis is within 2% of the marginal value presented previously.

We also compare the operational value of CSP-TES to a fixed-output PV plant with similar annual energy output (1,255 GWh) to both CSP-TES plants, which corresponds to a higher rated capacity of 584 MW. The requirements for both regulation and flexibility reserves are dependent on PV penetration; therefore the additional PV capacity imposes a slightly higher reserve burden on the system.[18] The marginal value of the PV plant is \$33.6/MWh. The marginal value of either base case CSP-TES plant is about 30% higher than PV. The marginal fuel savings of the PV plant is 8.2 MMBtu/MWh, which is only 10% lower than the marginal fuel savings of both CSP-TES plants. The similar marginal fuel savings between PV and CSP-TES, but higher discrepancy in overall marginal value, indicates that CSP-TES displaces more high-cost fuel by storing solar energy to be used at a time of higher marginal price when the sun is not shining.

[17] A small increase in coal offtake in two cases results from the fact that the CSP-TES is not only providing energy but also holding reserves. When CSP-TES holds reserves, another generator is free to use its capacity for energy rather than reserves. In this case, coal plants that are already online, but only partially loaded to hold reserves, may increase their energy output by consuming fuel.
[18] The new PV plant increased total PV generation by 68% and the flexibility and regulation requirements increased by 6% and 4%, respectively.

4 Solar Multiple Configuration for CSP Plants

As discussed in Section 2, the SM is an important design concept of CSP plants. Increased SM, particularly with the addition of energy storage can increase the utilization of the power block, thus increasing capacity factor, which acts to reduce the LCOE of the plant as a whole. However, increasing the SM and storage capacity also increases capital costs. This tradeoff between solar field size, energy storage, and capacity factor represents an optimization problem, and tools like SAM can be used to estimate the configuration with the lowest overall LCOE.[19] Figure 8 provides an example for the default molten salt power tower configuration in SAM.

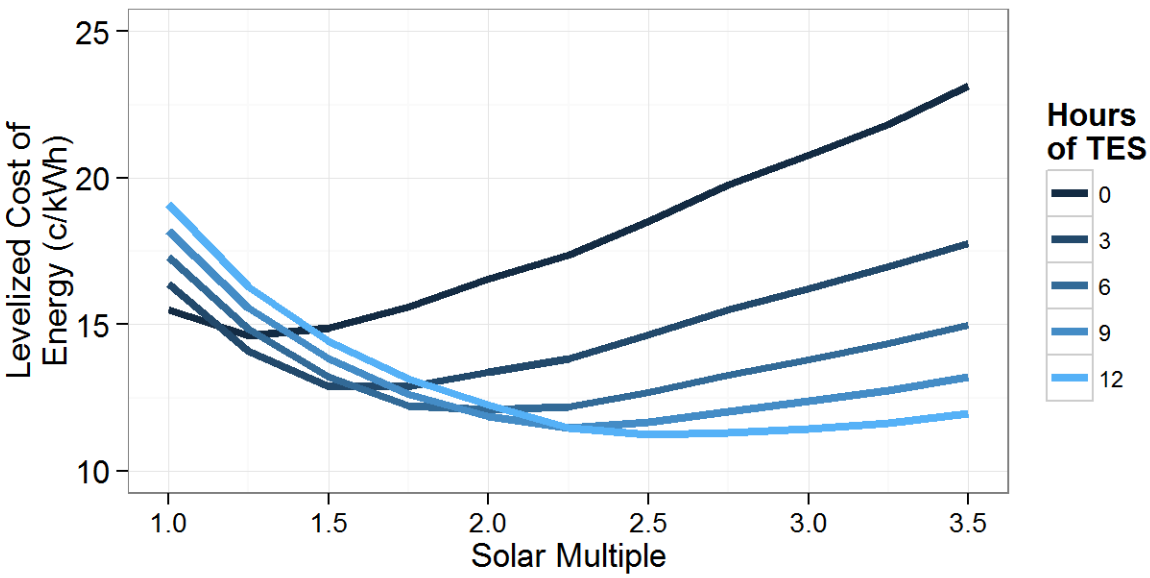


Figure 8. Calculated over the lifetime of the plant, the LCOE of a CSP project is dependent on the relative size and cost of the solar field and the power block[20]

While Figure 8 indicates the lowest LCOE configuration (under the default set of assumptions), it provides no indication of the actual system value of these configurations. Figure 8 indicates that the lowest overall LCOE would be for a plant with a high SM and many hours of storage. This configuration would likely have a very high capacity factor but produce a fairly flat output, requiring a large fraction of solar energy to be stored during the day, which are the periods of highest energy value, and requiring this energy to be discharged during off-peak periods of low value. Sioshansi and Denholm (2010) previously analyzed different configurations using a

[19] Larger plant capacity may present an additional capital cost barrier not evaluated here: higher capacity transmission lines. This cost may be especially relevant because CSP plants are often geographically isolated. For more information, see Sioshansi and Denholm (2012).

[20] LCOE is typically measured in units of cents per kilowatt-hour produced. We preserve these units to differentiate between the LCOE, calculated using SAM, and marginal system value (with units of dollars per megawatt-hour produced), which is calculated in the production cost modeling. The LCOE from SAM incorporates all CSP costs (both capital and operating costs) and uses a simplified dispatch approach to calculate the plant output, which gives an LCOE for the lifetime of the plant. For comparison, production cost models include only operating costs and will dispatch the CSP plant optimally for the one-year horizon, considering avoided fuel costs, starts, and VO&M. Thus, the two valuation methods are not directly comparable.

simple “price-taker” model and demonstrate how lower SMs may provide the highest value considering the time-varying value of electricity.

To evaluate the system value of different SMs, we start with the optimum pair depicted above and change the rated capacity of the power block rather than the size of the solar field. Therefore, the electrical equivalent solar energy available for use in each scenario remains constant, but the rated capacity of the power block varies. Because trough and tower plants appear to provide similar operational value to the system, based on the results in Section 3, we evaluate only tower systems in this analysis for simplicity.

Table 7. The Base SM/Hours of TES Pairs Used for the Dry-Cooled Tower CSP Plants in This Sensitivity

Base Hours of Thermal Storage	“Optimal” Solar Multiple (From Figure 8)	Rated Capacity of Plant (MW)	Electrical Equivalent Inflow from Field (GWh)
0	1.3	462	1,264
3	1.7	353	1,264
6	2	300	1,264
9	2.3	261	1,264
12	2.7	222	1,264

Table 8 illustrates the operational differences as dispatched by the production cost model for the different plant configurations. While the inflow remains the same for all configurations, the addition of storage decreases spillage and increases energy output by as much as 11% between the no storage plant and the plant with SM = 2.3 and 9 hours of storage, as explained below. The capacity factor increases by about 40%, driven by the reduction in plant rating as a function of increased SM. This also causes the annual reserve provision to generally decrease with increasing SM because the plant must use more of its capacity to deploy energy.

Table 8. Simulation Results for the Annual Output, Capacity Factor, Reserve Provision, and Utilization Factor of Dry-Cooled CSP Towers With Varying SM/TES Configurations

	Dry-Cooled Tower						
Hours of Thermal Storage	SM	Capacity (MW)	Annual Inflow (GWh)	Annual Output (GWh)	Capacity Factor	Annual Reserve Provision (GW-h)	Utilization Factor
0	1.3	462	1,264	1,072	26.5%	0[21]	26.5%
3	1.7	353	1,264	1,156	37.4%	633	57.8%
6	2	300	1,264	1,190	45.3%	678	71.1%
9	2.3	261	1,264	1,205	52.7%	617	79.7%
12	2.7	222	1,264	1,197	61.5%	460	85.1%

Utilization factor is the sum of energy output and reserve provision and represents the fraction of time that the plant capacity is being used for either energy or reserves.

Using the "optimal" SM and hours of TES combinations shown in tower systems in Table 7 as a basis, we further increase the storage capacity to quantify the additional system benefit of more storage, bearing in mind that increasing the storage capacity also increases the initial capital costs.[22] Figure 9 shows the reduction in generation costs due to the CSP plant as a function of SM and hours of TES. This is the total value of avoided production costs, not normalized to a value per unit of energy, which is discussed later in this section. This figure shows two major trends. Firstly, adding storage capacity increases value for the smaller SMs (larger plants) but only up to a certain point. The increase in system value with storage capacity results from reduced energy spillage, occurring when the incoming solar resource exceeds the thermal storage limits, as well as from the time-shifting value of storage. However, beyond a certain point, additional storage adds little value, as there is sufficient capacity to store nearly all the incoming thermal energy, and there is no additional value in energy shifting because the plant already has sufficient storage capacity to displace energy in the highest cost hours. The second major trend in this figure is the continually decreasing value for the higher SMs. This is due to the fact that the lower power block size associated with higher SMs forces the plant to store energy, even during periods of high value.

[21] The CSP plant with no thermal storage was not allowed to hold reserves due to its decreased dispatchability. The reserves provision (in GW-h) only includes the modeled "up" reserves which require a plant to be able to increase energy output. Modeling "down" reserve products slightly increases the value of the CSP-TES plant, but increases computational burden. Future work will examine the implications of CSP-TES providing down reserves as well.

[22] Increasing the storage capacity allows the plant to dump less solar energy at a given SM and optimize its dispatch of stored energy over more hours of the day. Decreasing the storage capacity only increases dumping at the given SM and, thus, we only analyzed additional storage scenarios.

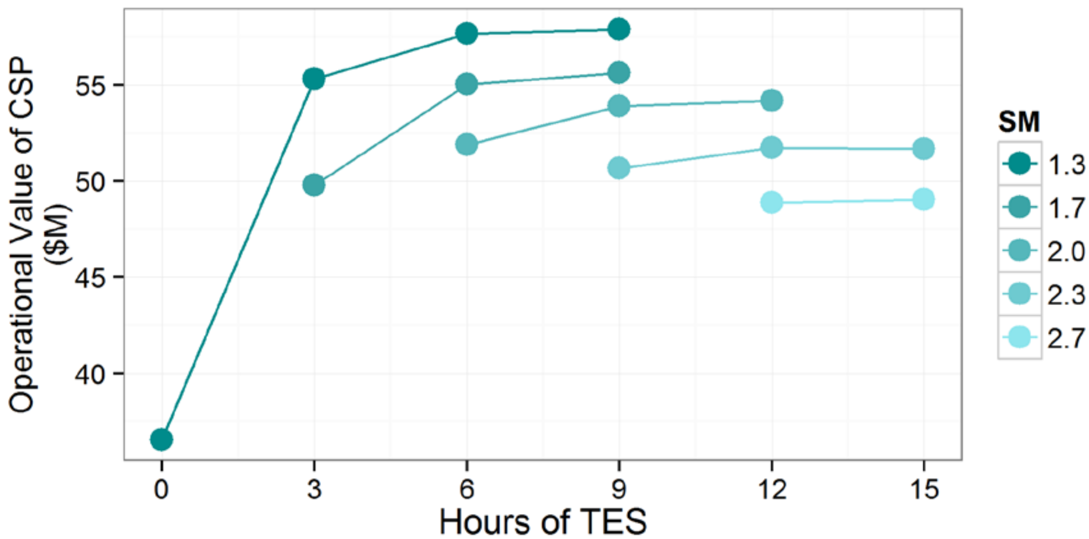


Figure 9. Operational value of tower CSP-TES plants with varying configurations

To help explain the difference in value between the cases, recall that the CSP plant losses as modeled can be categorized into start-up losses, heat exchanger losses, part-load heat rate decrement, and “spill” occurring when incoming solar resource exceeds the thermal storage limits. Generally, the plant output (and value) increases with increasing storage capacity due to decreased spillage as thermal storage capacity increases, as shown in Figure 10. The figure also illustrates diminishing returns for additional storage for each given SM. The CSP plant with no storage must spill about 12% of the energy delivered by the solar field because it is oversized relative to the power block by a factor of 1.3. Start-up losses also decrease with increasing CSP-TES storage capacity because the plant operates longer on its stored energy and has to shut down and start up less often, and because plant size is smaller, less start-up heat is necessary. Heat rate losses stay relatively constant while storage losses increase as more solar energy must be sent to storage rather than directly to the power block.

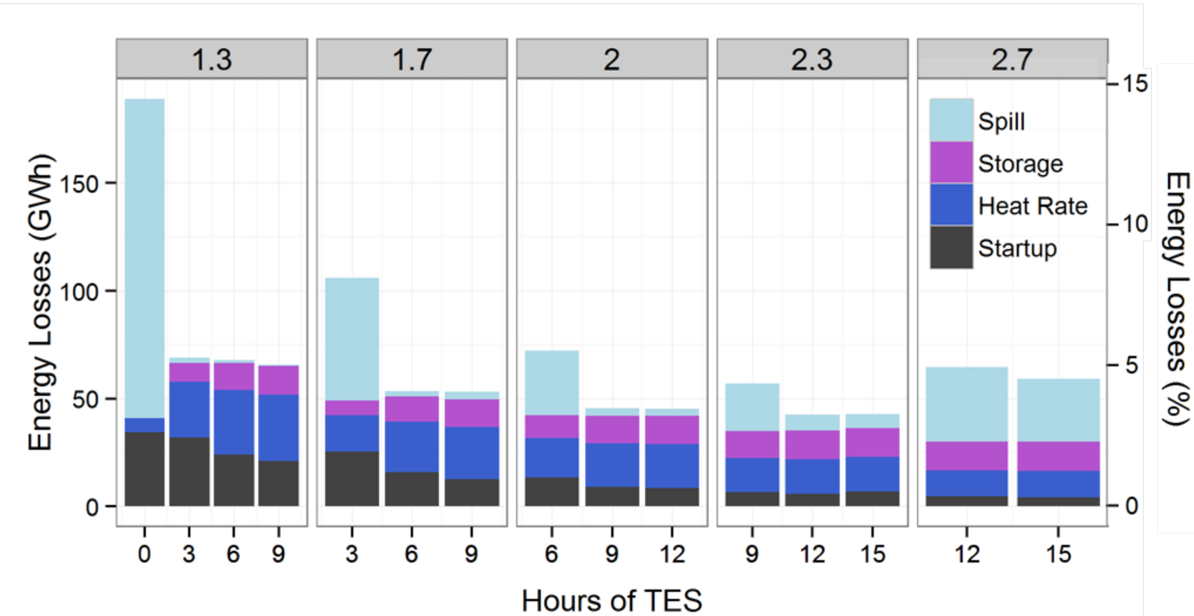


Figure 10. Annual energy losses for modeled CSP plants by SM 1.3 to 2.7 categorized into start-up losses, heat exchanger losses, part-load heat rate losses, and spillage due to thermal storage limits, shown as both a percent of total electrical equivalent inflow from the field and electric equivalent energy in gigawatt-hours

Figure 11 provides an additional example of the impact of SM on value showing the average daily operating profiles for the SM = 1.3 configurations with increasing storage. The top panel depicts the average daily solar inflow from the field. With zero hours of storage, the plant must dispatch the solar energy as it comes, so the daily profile looks similar to the inflow from the field. However, with more storage capacity, the plant shifts energy toward the evening or late afternoon when the peak net load occurs (shown in the bottom panel).

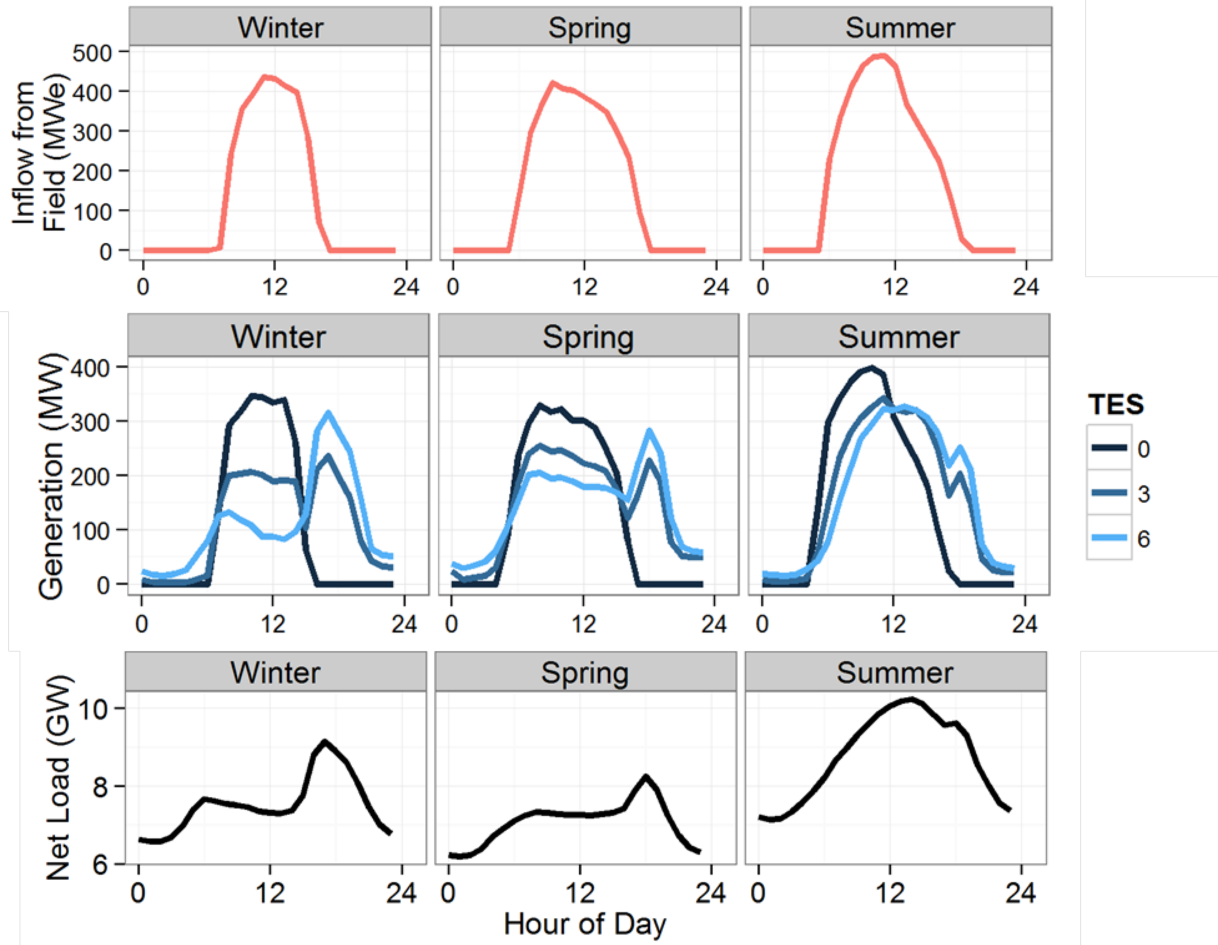


Figure 11. Middle panel: The average daily operating profile of a CSP plant with SM = 1.3 and 0, 3, and 6 hours of storage. For comparison, the top panel shows the hourly solar inflow from the field, and the bottom panel shows the system net load.

As the SM of the plant rises (and the rated capacity decreases), the plant produces less energy during the peak periods, particularly in the summer when electricity prices are greatest. Furthermore, the higher SM plants are forced to generate a greater fraction of their output during off-peak periods of low value, as shown in Figure 12 for the "optimal" plant configurations shown in Table 8. Plants with higher SMs begin to resemble base load plants with flatter output and lower ability to meet the demand for peaking energy.

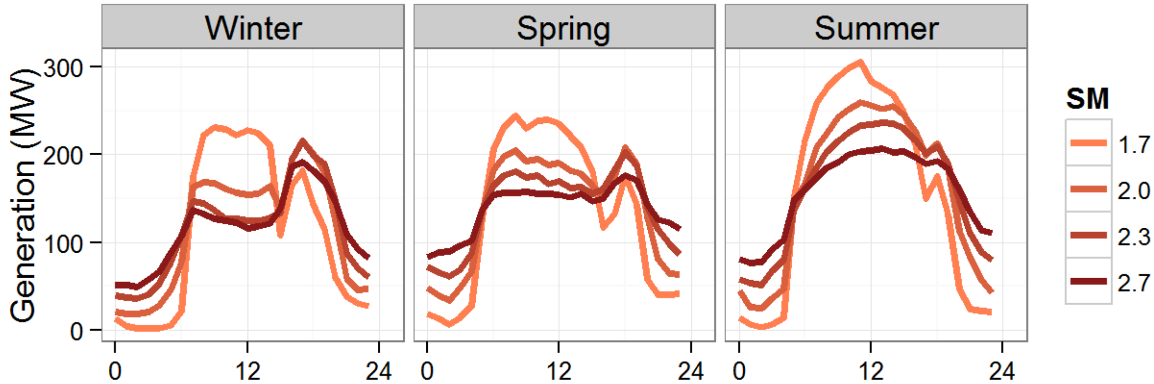


Figure 12. The average daily dispatch of four CSP-TES plants with varying solar multiples and corresponding hours of TES, as shown in Table 8.

Figure 13 translates the total savings into the value per unit of energy-delivered metric ($/MWh) in the same manner as shown previously in Table 5. The general trends in this figure are similar to those in Figure 9. The differences reflect the challenges in using the normalized dollar per megawatt-hour as a single performance metric, which is attributing the same value to each megawatt-hour of energy produced. In general, adding additional storage increases the total system value of the plant, often by decreased spillage resulting in the steeper upward slope in Figure 9 for configurations with the first three additional hours of storage. However, the additional generation enabled by additional storage may be of lower-than-average value. This results in a shallower slope for additional storage in Figure 13, as compared to Figure 9.

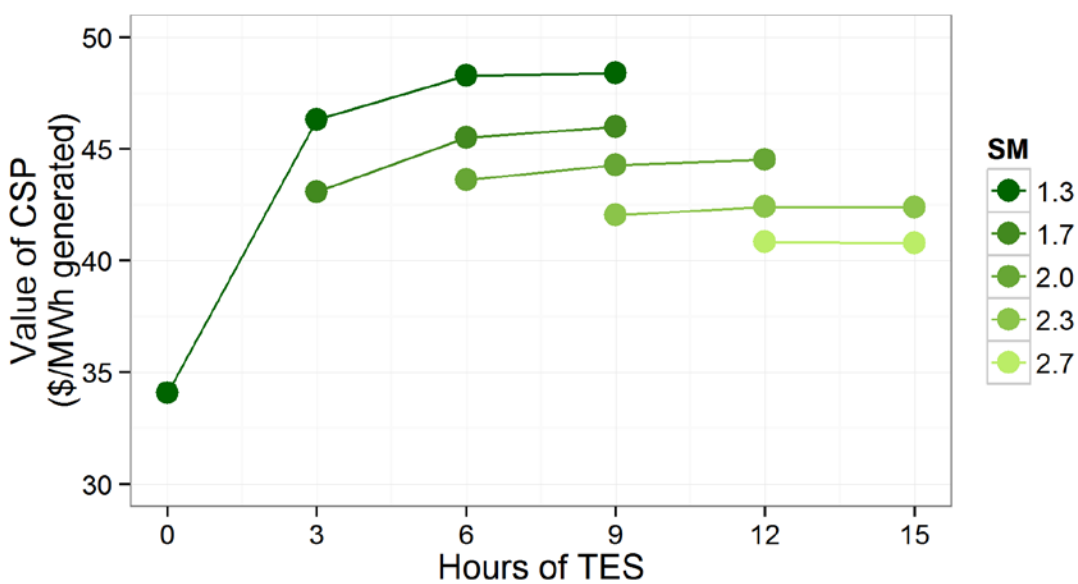


Figure 13. The marginal system operational value ($/MWh) of a dry-cooled tower CSP plant with various configurations of SM and TES capacity

The decrease in value for the plants with higher SM can be further explained by the avoided fuel mix. Figure 11 indicates that the larger plant begins to resemble a base load plant with flatter output. During off-peak periods, lower-cost generators, including more efficient CC units and coal generators are displaced by the CSP plants with higher SMs. Table 9 illustrates this by showing less fuel displacement for these CSP plants.

Table 9. Simulation Results for the Fuel Avoided by Dry-Cooled Tower Plants With Varying Amounts of Thermal Storage

	Avoided Fuel (MMBtu/MWh)			
Hours of Thermal Storage	SM	Coal	Natural Gas	Total
0	1.3	1.0	7.1	8.1
3	1.7	0.2	8.8	9.0
6	2	(0.1)	8.9	8.9
9	2.3	0.1	8.6	8.7
12	2.7	0.3	8.3	8.6

Figure 13 indicates relatively small differences in the simulation results for plants with storage with an operational value of between $41/MWh and $48/MWh in the base fuel price scenario. The overall system value and the total avoided fuel vary little between the plant configurations. All of the plants displace mostly NG because, at $4.12/MMBtu, it is the marginal fuel. However, with increasing SMs, CSP displaces off-peak generation (due to the effect of flatter output), meaning the avoided coal offtake generally increases relative to NG, as shown in Table 9. Overall, the difference in value and fuel displacement between the configurations is small.

5 Impact of Capacity on the Overall Value of CSP-TES

The calculated value for the various configurations of tower CSP-TES presented up to this point considers only operational value and does not consider the ability of CSP-TES to displace new conventional thermal generation. The actual capacity value for a VG resource depends on the coincidence of resource availability with net load. For CSP-TES we use an approach from Tuohy and O'Malley (2011) for estimating capacity value from devices with storage. This approximation considers the stored energy available for dispatch during hours with the highest probability of unserved load. For instance, if the CSP-TES plant is dispatched below capacity but has enough stored energy to generate at full output during that hour, the device earns a 100% capacity credit during that hour.[23] In this simulation, we consider the 88 hours (or 1%) with the highest net load (equal to load minus the contribution of wind and solar PV). The capacity credit, determined with this "maximum generation" approach, is 100% for all configurations with storage. Additional discussion of the capacity value of CSP plants is provided by Madaeni et al. (2012).

The corresponding monetary value of this capacity can be based on the cost of comparative conventional plant. We use a range of values with a low annualized cost of new capacity equal to $77/kW-yr and a high value of $144/kW-yr (Xcel 2011). This capacity value is contingent on a system actually needing additional capacity to provide an adequate planning reserve margin—for example, to replace a retiring generator or to meet growth in demand. A system with an adequate planning reserve margin would have essentially zero capacity value for a new resource.

Table 10 shows the capacity value for each CSP-TES plant for the year of operation. The first column shows the rated capacity of the plant, assuming equal energy production. Because all plants with storage are assumed to have a 100% capacity credit, their capacity value is simply proportional to their size. This produces the result that the lower SM will inherently be worth more as a system resource because lower SM plants have larger megawatt capacities in this analysis. The size of the plant, multiplied by the assumed cost of new capacity (either $77/kW-yr or $144/kW-yr) produces an annualized capacity value in the third results column. Finally, this value is divided by the annual energy production to derive a capacity value per unit of energy ($/MWh) in the last column. The annualized capacity value will be the same for all plants with the same SM regardless of storage size. However, the capacity value per unit of energy will actually decrease for the plants with more hours of storage due to their slightly greater energy production resulting from lower spillage. This demonstrates another limitation of using the value per unit energy performance metric.

[23] This actually corresponds to an "equivalent conventional power" capacity, or the capacity credit of the CSP plant relative to a conventional plant with an equivalent forced outage rate. For further discussion of this approach, including limitations, see Sioshansi et al. (2013).

Table 10. Capacity Value for the Various SM Configurations of a Tower CSP Plant

	Capacity (MW)	Hours of TES	Capacity Credit	Annualized Capacity Value, Low/High ($M/yr)	Capacity Value, Low/High ($/MWh)
Tower, SM = 1.3	462	3	100%	35.6 / 66.5	30.3 / 56.6
Tower, SM = 1.7	353	3	100%	27.2 / 50.8	23.5 / 44.0
Tower, SM = 2	300	6	100%	23.1 / 43.2	19.4 / 36.3
Tower, SM = 2.3	261	9	100%	20.0 / 37.6	16.7 / 31.2
Tower, SM = 2.7	222	12	100%	17.1 / 32.0	14.3 / 26.7

The full value of each plant is the sum of its operational value and its ability to offset additional new capacity (capacity value). Figure 14 adds the operational values in Figure 13 with the capacity values measured in dollars per megawatt-hour from Table 10. Because the operational values in Figure 13 are relatively flat for each SM, we only use the "base" configurations described in Table 10, which includes the SM = 1.3 with 3 hours of storage case. It includes four values for each configuration—combinations of low and high operational value using the base and double NG price case (2x NG), and the low and high capacity value from Table 10. Figure 13 and Figure 14 indicate that smaller SMs may provide more system value.[24]

[24] However, capital costs will also increase with power block size (smaller SM) and with thermal storage capacity. The trade-off between value the evaluated this report and capital cost (which is not evaluated here) must be studied in future work.

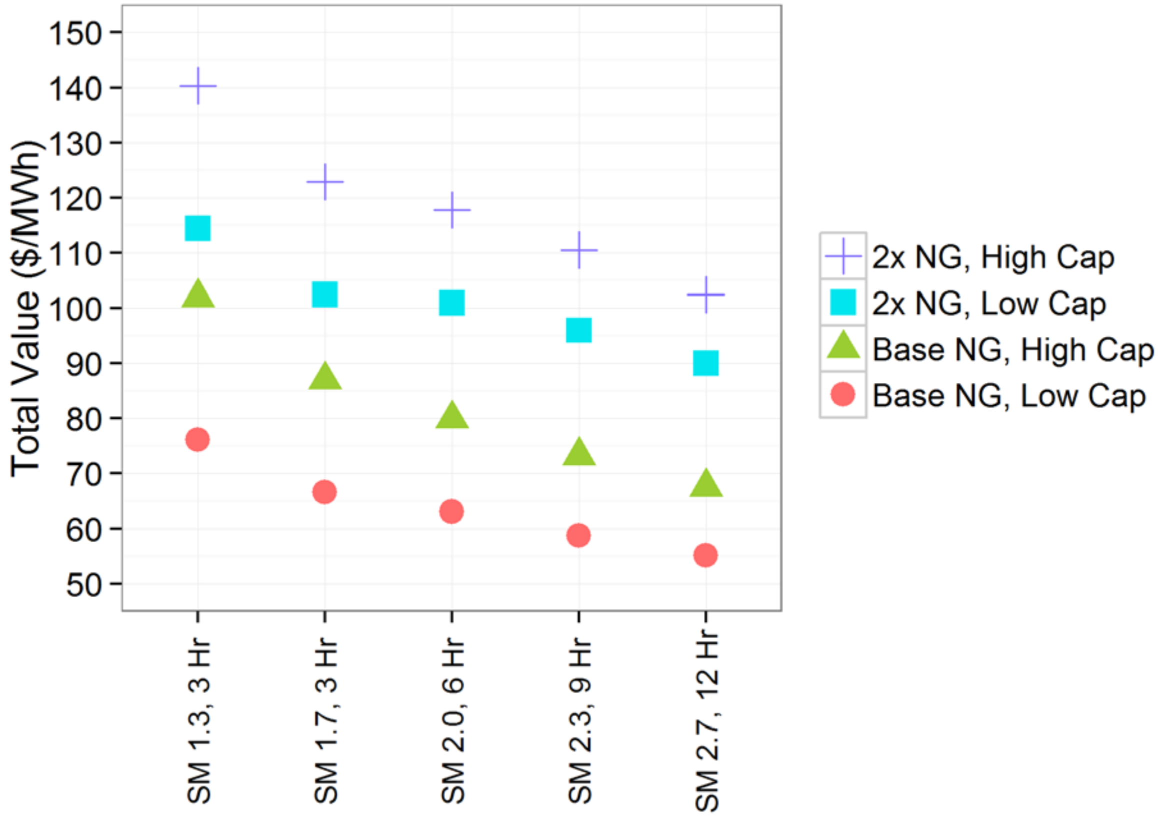


Figure 14. Total value of CSP plants with TES, which is the sum of the operational value and the capacity value; the points represent possible combinations of high/low fuel prices and high/low capacity values

6 Conclusions

The ability to vary both SM and hours of storage is an important aspect of CSP plant design. Adding energy storage enables reduction in LCOE due largely to decreased spillage. However, the optimum CSP design should consider not only cost but also the value of energy and capacity CSP delivers to utilities and system operators. This analysis demonstrates that multiple CSP technologies (both troughs and towers), as well as plant configurations, can be analyzed using traditional planning tools such as production cost models.

We find that a parabolic trough CSP-TES plant may require a higher capacity, at a greater expense, than a similar molten salt power tower to achieve the same annual output largely due to a larger seasonal variation in output, lower thermal efficiency, and greater storage losses. However, we find that the system value as measured by their value per megawatt-hour of delivered energy of dry-cooled tower and parabolic trough CSP-TES plants are similar despite their different solar resource profiles.

We also analyzed various configurations of SM and thermal storage capacity. We found that lower SMs (with correspondingly larger rated plant capacity) had the largest marginal system value and benefitted from some additional storage to prevent spilled energy. However, for all SMs, we found only a small benefit to storage from 6 to 9 hours of rated plant capacity and less benefit beyond 9 hours. Plants with smaller SMs shifted energy more effectively to periods of high load due to their increased capacity, acting as “peaking” units, while plants with higher SMs acted more like base-load plants, generating at a constant output for more hours of the day. Plants with smaller SMs incur additional capital costs for a larger power block but may also be able to earn more capacity value. Capacity is likely an important source of value for CSP plants, which appear to offer a capacity value similar to conventional thermal plants if properly scheduled and utilize accurate forecasts of solar availability.

Further analysis will examine the role of energy-limited resources such as CSP-TES in providing ancillary services under current and alternative sets of regulation and markets. The relative value in CSP-TES, and the capacity factor of the CSP-TES plant, is dependent on renewable energy penetration (including existing CSP-TES plants). For instance, this system has a relatively low penetration of PV generation, which is largely coincident with CSP solar resource availability. In addition, further analysis will determine the system needs at shorter timescales as VG integration continues to influence sub-hourly system operation.

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