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Estimating the Value of Utility-Scale Solar Technologies in California Under a 40% Renewable Portfolio Standard

J. Jorgenson, P. Denholm, and M. Mehos

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List of Acronyms

CAISO	California Independent System Operator
CO_2	carbon dioxide
CPUC	California Public Utilities Commission
CSP	concentrating solar power
ELCC	effective load-carrying capability
IID	Imperial Irrigation District
LDWP	Los Angeles Department of Water and Power
LOLP	loss-of-load probability
Munis	local municipal and cooperative utilities
NREL	National Renewable Energy Laboratory
PG&E	Pacific Gas and Electric
PNNL	Pacific Northwest National Laboratory
PV	photovoltaic
REPRA	Renewable Energy Probabilistic Resource Adequacy tool
RPS	renewable portfolio standard
SAM	System Advisor Model
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SM	solar multiple
SMUD	Sacramento Municipal Utility District
TES	thermal energy storage
TIDC	Turlock Irrigation District
VO&M	variable operation and maintenance
WWSIS-2	The Western Wind and Solar Integration Study: Phase 2

Executive Summary

This analysis is follow-on work to a previous study of the value of concentrating solar power (CSP) with thermal energy storage (TES) in the state of California. As in the previous study, it analyzes the value of both CSP-TES and utility-scale photovoltaics (PV), with the following additions:

1. This analysis uses the October 2013 database of the California grid as prepared by the California Independent System Operator (CAISO). This version of the database includes reductions in fuel costs and prices of carbon dioxide emissions, among other updates.
2. In the base case, this analysis assumes that California adds 1,175 MW of energy storage to reflect policy targets. This analysis also evaluates sensitivities to this assumption.
3. This analysis evaluates both the base 33% renewable portfolio standard (RPS) released by the CAISO, and a 40% RPS scenario created by NREL. The additional renewables are based on an assumed 75%/25% split between solar PV and wind, with no changes to the non-RPS resources.
4. This analysis considers multiple CSP-TES configurations, starting with a base assumption of a solar multiple (SM) equal to 1.3 with 6 hours of storage but also with solar multiples up to 2.7 with 15 hours of storage.
5. As in the previous study, the base case considers no export limits from California to neighboring states beyond inherent transmission capacity. However, this analysis also considers the impact of restricting California net exports to 0 MW and 1,500 MW.

This analysis includes two sources of value for either solar technology: operational value and capacity value. Operational value represents the avoided costs of conventional generation, which includes fuel costs, start-up costs, variable operation and maintenance costs, and emission costs. Capacity value reflects the ability of PV or CSP-TES to avoid the costs of building new conventional thermal generators in systems that need capacity in response to growing energy demand or plant retirements. Table ES-1 quantifies the operational value of CSP-TES and PV, and compares the potential value of providing firm system capacity.

Table ES-1. Total Value (Operational Value Plus Capacity Value Range) in Two RPS Scenarios

Value Component	33% RPS		40% RPS	
	CSP-TES Value ($/MWh)	PV Value ($/MWh)	CSP-TES Value ($/MWh)	PV Value ($/MWh)
Operational	46.6	31.9	46.2	29.8
Capacity	47.9–60.8	15.2–26.3	49.8–63.1	2.4–17.6
Total	**94.6–107**	**47.1–58.2**	**96.0–109**	**32.2–47.4**

The totals in Table ES-1 represent the highest value configurations for CSP-TES plants. Larger CSP-TES solar multiples tend to reduce the average value because more energy is produced during times of lower value, resulting in a flatter output shape. Reducing export capacity changes the value of CSP-TES very little but somewhat increases PV curtailment, slightly lowering the PV system value. Eliminating 1,175 MW of energy storage increases the relative flexibility benefits of dispatchable CSP-TES and results in higher value.

Table ES-1 also indicates that a large fraction of the value of CSP-TES appears to be derived from its ability to provide firm system capacity. The range of values is based on significant uncertainty of the capacity value of PV at increased renewable energy penetration as well as a range of estimates of the cost of new conventional thermal capacity. More robust estimates of the impact of increased penetration of PV on its capacity value are needed. The capacity value analysis shows an interaction between the capacity value of PV and CSP that warrants further analysis.

Additionally, while this analysis provides insight into the value of CSP-TES providing grid flexibility it does not examine the role of such flexibility in enabling greater penetration of wind and solar PV. Further analysis is needed to examine the portfolio benefits of CSP in meeting higher penetrations of variable generation resources.

Finally, this analysis compares only the relative *value* of CSP-TES in various situations and configurations and does not indicate the capital cost of building a plant. Further analysis will examine the trade-off between CSP-TES capital costs and total value provided to the power system.

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1 Introduction

With growing interest in renewable energy, the penetration of solar photovoltaics (PV) and wind generation is likely to rise. Accommodating the time-varying and uncertain output of these resources will be a challenging aspect of integrating large-scale renewable energy into the electric power system. Concentrating solar power (CSP) with thermal energy storage (TES) is a unique source of solar energy in that its output can be shifted over time and also controlled in response to system operator signals, allowing for provision of a wide range of grid services. The ability of CSP-TES to be a flexible source of renewable generation may be particularly valuable in regions with high overall penetration of solar energy, such as the state of California.

California's renewable portfolio standard (RPS) requires the state to increase electricity generation from eligible renewable energy resources to reach at least 33% of total retail sales of electricity per year by December 31, 2020. Beyond 2020, California targets a further reduction in greenhouse gas emissions to 80% of 1990 emission levels by the year 2050 (Brown 2013). To help reach this ambitious goal, current California governor Jerry Brown has stated that a higher 40% RPS might be reachable in the near term (Brown 2011).

In this report, we evaluate the value of adding an additional PV or CSP-TES plant to the base case 33% RPS scenario using a grid model developed by the California state energy agencies and maintained by the California Independent System Operator (CAISO). To examine changes in value at higher levels of penetration, we also assess the value of both PV and CSP in a 40% RPS scenario. We compare the technical and economic aspects of both solar technologies under various constraints and sensitivities, including limits on exporting renewable energy from California to surrounding regions, as well as the configuration of the CSP plant.

2 Simulating CSP in a Production Cost Model

2.1 CAISO Database for PLEXOS

The modeling framework utilized in this study is based on the one developed by the California state agencies for 10-year ahead resource planning in jurisdictional utilities. CAISO produces and maintains a database for PLEXOS, a commercially-available production cost modeling software used to simulate the power grid in California for planning purposes. Production cost modeling software allows grid planners and operators to assess many aspects of power generation, including system costs, reliability, and emissions. The database contains generator-level details of California's electricity sector as well the rest of the Western Interconnection because California is highly interconnected with several western states and historically imports a significant amount of power from neighboring regions. CAISO has utilized the database in analyses of the original 20% RPS as well as the 33% renewable integration study for the California Public Utilities Commission (CPUC) (CAISO 2011 and CAISO 2012).

Production cost models such as PLEXOS are formulated to minimize the total cost of generating electricity to serve energy demand in every time step by committing (determining whether a generator is on or off) and dispatching (adjusting the output of the committed generators). However, unit commitment and dispatch is complicated by many system constraints. For example, balancing authorities in the United States must maintain a given level of operating reserves. In functional power systems, reserves ensure reliable power delivery in case of rapid changes in energy supply or demand. As modeled, operating reserves represent partially-loaded generators with the ability and necessary capacity to change their output. In addition, the model has simplified transmission constraints that enforce the minimum and maximum allowable power flow into or out of a region. Finally, the model specifies constraints on the individual generators, which include ramp rates, minimum generation levels, outage profiles, heat rates, and many more.

Table 1 describes the three aggregated regions represented in the model. For consistency with the database, the CAISO footprint is modeled as the area served by the three largest investor-owned utilities in the state of California: Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), and Pacific Gas and Electric (PG&E). This represents approximately 80% of the total load in the state, as shown in Table 1, with the remainder served by local municipal and cooperative utilities (Munis), which include the Los Angeles Department of Water and Power (LDWP), Imperial Irrigation District (IID), Turlock Irrigation District (TIDC), and Sacramento Municipal Utility District (SMUD). Figure 1 provides a map of the study area, including the location of the added CSP plant discussed in Section 2.2.

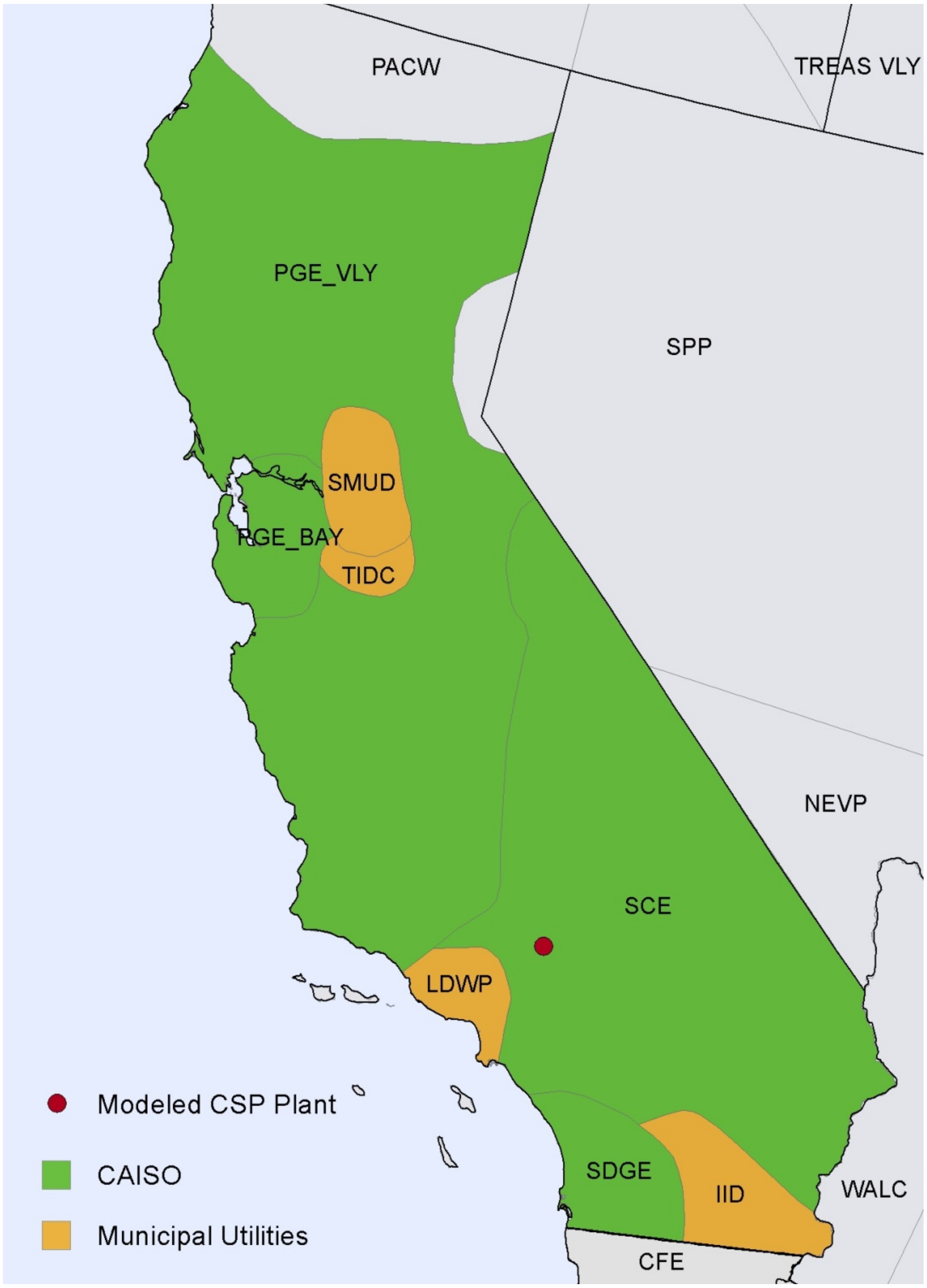

Figure 1. Map of the California study area.[1]

The base case formulation includes the RPS generation necessary to exceed the 33% RPS mandate for 2020 given the forecasted load for that year. Overall, the total RPS energy in the database (87.8 TWh) represents approximately 34.6% of CAISO's annual demand, or approximately 28% of California's total annual demand[2]. The model includes generator-level

[1] This map is used only as an illustration. The boundaries of the utility service territories are approximate.
[2] The CPUC calculates renewable energy to meet the 33% RPS goal based on retail sales, which includes transmission and distribution losses, not the modeled load.

detail for the entire Western Interconnection and solves an optimal least-cost dispatch for the entire geography, with defined flow limits and wheeling charges for interchanges between regions. In reality, many individual utilities outside CAISO operate their power systems individually, subject to various agreements with their neighbors, and hence the actual dispatch may not be least-cost for the region.

Table 1. Characterization of the Regions Modeled in the Database

2022	CAISO	Munis	Rest of the West
Peak Load (GW)	54.3	12.0	122.9
Annual Demand (TWh)	254	58.0	753
CA RPS Energy (TWh)	60.4	9.2	18.2
Other Wind and Solar Energy (TWh)[3]	6.4	0	69.4
Annual Net Imports (TWh)	46.2[4]	29.6	-75.8
Areas Served/ Balanced By	SCE, SDG&E, PG&E	LDWP, IID, TIDC, SMUD	Rest of the West (includes areas in CO, AZ, WY, NM, AZ, WA, OR, NV, ID, UT, MT, Alberta, and British Colombia)

Table 2 describes the installed capacity in the CAISO region for the base 33% RPS scenario, with the RPS-eligible generators separated. The assumed generation-averaged fuel prices are $1.71/MMBtu for coal and $4.38/MMBtu for natural gas. The fuel prices vary by region, and the natural gas prices also vary by month to reflect seasonal demand. In addition, carbon dioxide (CO_2) emissions within California cost $21.9/ton. Carbon dioxide emissions outside of California have no modeled cost, though energy imported to California has a small added cost to reflect the incoming cost of carbon.

[3] This category contains California generation that does not satisfy the RPS (e.g., 6.4 TWh of distributed PV in CAISO) or wind and solar in other states that may satisfy other RPSs, such as Arizona's.
[4] For comparison, in 2012 the state of California (CAISO plus Munis) imported approximately one-third of its total annual demand (CEC 2014).

Table 2. Description of the Installed Capacity of the CAISO Region in the 33% RPS Scenario

	Capacity Installed (MW)	
	Non RPS[5]	RPS[6]
Biomass	-	1,080
Coal	138	-
CSP[7]	-	1,400
Demand Response	2,730	-
Gas Combined-Cycle	17,900	-
Gas Combustion Turbine	7,430	-
Geothermal	-	2,460
Hydropower	7,350	1,380
Nuclear	2,240	-
PV	2,080	9,950
Steam/Other	615	-
Storage	3,025	-
Wind	-	10,400
Total	**42,300**	**26,600**

We use the model discussed above as a starting point for the analysis, but we include one major deviation, shown in Table 2. The 3,025 MW of CAISO storage shown above includes 1,850 MW of existing pumped hydropower storage as well as an assumed additional 1,175 MW of battery storage. This addition represents the procurement of energy storage mandated by the CPUC by the end of 2020 in accordance with Rulemaking R.10-12-007 (CPUC 2013). Although the rulemaking requires the procurement of 1,325 MW, 150 MW of this storage is already reflected in the database as a CSP plant. The additional 1,175 MW of storage is divided among the three investor-owned utilities as detailed in R.10-12-007 and represents a long-duration battery with 8 hours of energy storage capacity and a round-trip efficiency of 70%. In reality, short-duration storage may largely comprise the new storage procurement, thus Section 3.3 provides additional details and addresses alternatives to this assumption.

In addition to committing and dispatching the generators shown in Table 2, the model also ensures a supply of operating reserves. In functional power systems, reserves ensure reliable power delivery in case of changes in energy supply or demand. As modeled, operating reserves represent committed generators with the ability and necessary capacity to change their output upward or downward. Table 3 describes each of the six types of operating reserves enforced in the model. The table describes the name of the product, magnitude of the requirement, and the amount of time it takes for each generator to respond. The CAISO used a tool developed by the

[5] Only small hydropower plants contribute to the RPS, which means that a significant portion of hydropower is not eligible. In addition, distributed demand-side PV is not eligible for RPS status.

[6] The RPS category also includes out-of-state generators that contribute to the RPS procurement. Specifically, 183 MW of biomass capacity, 215 MW of geothermal capacity, 7 MW of hydroelectric capacity, 486 MW of PV capacity, and 4,180 MW of wind capacity are located out of state. The overall penetration of PV in CAISO, including non-RPS PV, is 10.9%.

[7] This represents three existing solar thermal generators in the database. Two of them have fixed output with no storage. The third has six hours of storage and a maximum capacity of 150 MW. The representation of the 150-MW plant allows for the co-optimization of dispatch and operating reserves, but its characterization is much simpler than that of the CSP-TES plant modeled here, as discussed in Section 2.2.

Pacific Northwest National Laboratory (PNNL) to calculate the regulation and load-following requirements for the 33% RPS database (Makarov et al. 2010).

Table 3: Description of the Reserve Requirements Enforced in the Database

Reserve Product	Time to Respond	Annual Req. (GW-h)	Mean Hourly Req. (MW-h)
Load-Following Up (LFU)	10 min.	10,960	1,254
Load-Following Down (LFD)	10 min.	10,790	1,235
Regulation Up	5 min.	3,700	424
Regulation Down	5 min.	3,800	440
Spinning Contingency	5 min.	7,500	860
Non-Spinning Contingency	5 min.	7,500	860

Figure 2 shows the hourly dispatch of the generators located physically within the CAISO region for two contiguous days in spring, summer, and winter for the base 33% RPS case. The difference between the total CAISO load, shown by the black line, and CAISO generation represents energy that must be imported from outside the region. In this 33% case, CAISO is still a net importer of energy for almost every hour of the year. However, excess generation associated with high solar output in the spring and early summer combined with relatively low load causes CAISO to export energy 61 hours of the year in the amount of 35 GWh (only 0.02% of energy produced within CAISO), with a maximum hourly flow of 1,730 MW exported power. Because of the technical and economic implications of exporting energy out of CAISO, in Section 3.2 we evaluate scenarios with constrained export capabilities.

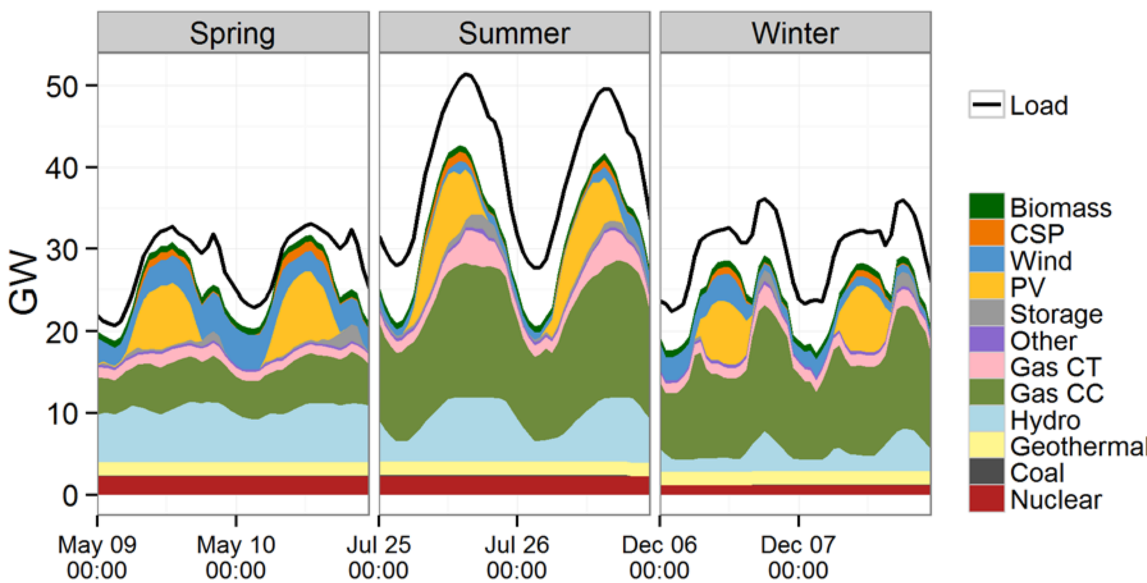

Figure 2. Dispatch of CAISO generator fleet for two days in spring, summer, and winter in the 33% RPS case. The black line shows total load.

2.2 Incremental PV and CSP-TES Generation in the 33% RPS Case

In this analysis, we first compare the system above with and without the addition of incremental PV or CSP-TES with equal annual energy. Denholm et al. provided a detailed report on adding incremental PV or CSP-TES to an earlier version of this 33% RPS system (2013). For comparison, we first evaluate the value of incremental PV or CSP-TES in the current 33% RPS system before implementing the 40% RPS scenario. We calculate the difference in total production cost (which includes fuel costs, variable operation and maintenance, or VO&M, costs, and start-up costs) between the two runs and attribute the marginal system savings to the new solar plant. To correctly capture the dispatch and value of CSP-TES, we must integrate and connect the three aspects of a solar thermal plant to the storage depicted in Figure 3: the solar field and receiver, the storage tank, and the power block. Jorgenson et al. (2013) describe the methodology in detail.

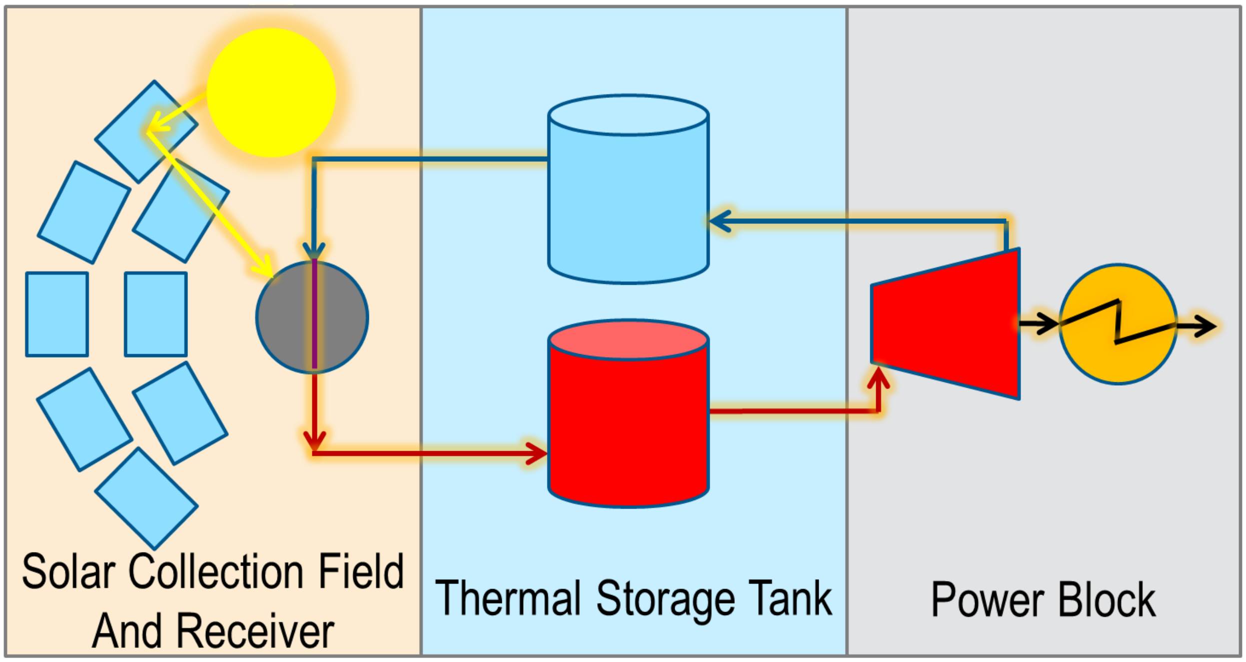

Figure 3. Three major operations within a CSP-TES plant: the solar field and receiver, the thermal storage tank, and the power block.

Firstly, we quantify the solar resource of a typical good solar resource location in California. Meteorological data for the site chosen, located near Daggett, California, originates from the National Solar Radiation Database for the year 2006. This data is an input to the National Renewable Energy Laboratory's (NREL's) System Advisor Model (SAM) version 2013-1-15 (Gilman et al. 2008; Gilman and Dobos 2012). The molten salt power tower model within SAM converts hourly irradiance into thermal energy and then into net electrical energy based on the rated gross thermal-to-electric efficiency of the dry-cooled turbine. Downtime, outages, start-up energy, and part-load efficiency decrements were neglected in SAM to be taken into account during dispatch modeling. The electrical equivalent energy then served as a dispatchable resource in PLEXOS within the constraints of the thermal power block characteristics of the CSP-TES plant discussed by Jorgenson et al. (2013). Figure 4 describes the modeling flow.

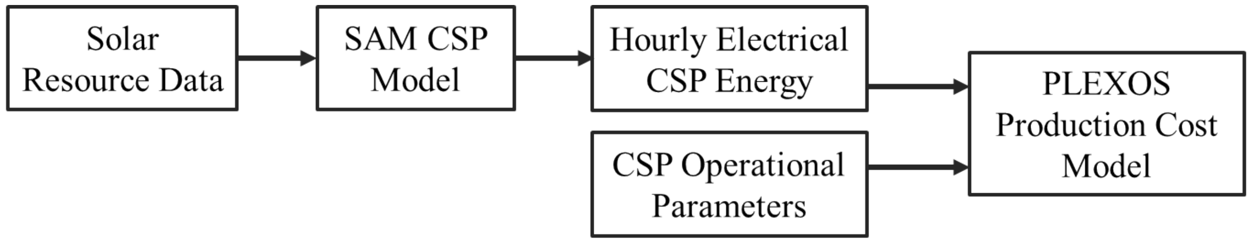

Figure 4. Process of simulating CSP in a production cost model

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, immediately 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. This framework accounts for three types of losses within the plant: start-up losses incurred when warming up the plant, part-load efficiency losses resulting from operating below the design point, and storage losses that result from transferring and storing heat. In addition, the plant has operational parameters, such as a ramp rate and minimum generation level similar to conventional steam turbine generators. Incorporating the CSP-TES plant into PLEXOS allows the model to optimally schedule both the output of solar energy and co-optimize the plant’s capacity to provide operating reserves. Previous findings indicate that reducing the ratio of the solar collection field size to the power block capacity (a design parameter often called the SM) in combination with sufficient thermal storage provides the most benefit to the power system per unit of energy produced (Jorgenson et al. 2013).[8] Thus, we use a plant that has an SM equal to 1.3 and enough thermal storage to operate the plant at rated capacity for six hours. Section 4 addresses the sensitivity to these configuration parameters.

Adding the same annual energy output from PV and CSP-TES (approximately 3,400 GWh, which represents an approximate increase of 1% solar penetration relative to total load) requires 1,172 MW of CSP-TES and 1,576 MW of PV. The new PV capacity was implemented by linearly scaling existing RPS PV located in existing locations above the 33% case. After implementing either solar technology into the model, we observe a reduction in overall total production cost and attribute the savings to the addition of the incremental PV generation or the new CSP-TES plant. Total production costs fall into four categories: fuel costs, VO&M, start-up costs, and emissions costs. Table 4 shows the breakdown of these cost savings. In this 33% case, the addition of CSP-TES results in an additional reduction of $14.7 per MWh of energy delivered compared to the addition of PV. The difference in displaced fuel costs between these two technologies results from the ability of CSP-TES to shift solar energy to replace the more costly generators, which run on natural gas, shown in Table 5. The operational value of CSP-TES, $46.6/MWh, is lower than previously reported values using earlier versions of the same database. Previously, Denholm et al. reported an operational value of $83/MWh (2013). Appendix A details the sources of this deviation.

[8] This finding only indicates a higher value provided to the power system in terms of reduced operational costs of conventional thermal generators, not necessarily reduced capital costs.

Table 4. Marginal Operational Value of Two Solar Technologies Added to the 33% RPS Case in California

	Marginal Operational Value in 33% RPS Case ($/MWh)	
	CSP-TES (SM = 1.3, 6 hrs TES)	PV
VO&M	1.6	1.2
Start-up and Shut-down	2.5	-0.9
Fuel	34.4	27.9
Emissions	8.1	3.7
Total	**46.6**	**31.9**

Table 5. Avoided Fuel by Generator Type per Unit of Energy in the 33% RPS Case

	Avoided Fuel per Unit Energy (MMBTu/MWh)	
	CSP-TES (SM = 1.3, 6 hrs TES)	PV
Biomass	0.2	0.5
Coal	0.3	0.9
Gas Combined Cycle	6.8	6.0
Gas Combustion Turbine	0.7	0.1
Total	**7.9**	**7.5**

3 Implementation and Discussion of 40% RPS

Next we assess a scenario in which PV or CSP is added to a 39% portfolio, resulting in a total renewable penetration of approximately 40% within CAISO. To create a 39% scenario, we scale the hourly profiles of new wind and PV RPS generators in the 33% scenario with an incremental ratio of 25% wind to 75% PV in the assumed existing locations. This ratio reflects various incentives within California to promote distributed PV generation from the California Energy Commission (2011) and increases the overall PV penetration (including RPS and non-RPS PV) in CAISO from 10.9% to 14.1%. Figure 5 and Table 3 show the breakdown of RPS energy for both the original 33% and the scaled 39% case before the addition of incremental CSP-TES or PV.

Table 3. Annual Generation From RPS and non-RPS Renewable Energy Sources for the 33% RPS and the 39% RPS in Gigawatt Hours Before Incremental PV or CSP-TES

GWh	33% RPS	39% RPS
Biomass	9,400	9,400
Geothermal	21,500	21,500
Small Hydropower	7,200	7,200
Wind	25,100	27,800
PV	21,200	29,300
CSP	3,400	3,400
Total RPS	**87,500**	**98,600**
Non-RPS PV	6,400	6,400
Total RE	**94,200**	**105,000**

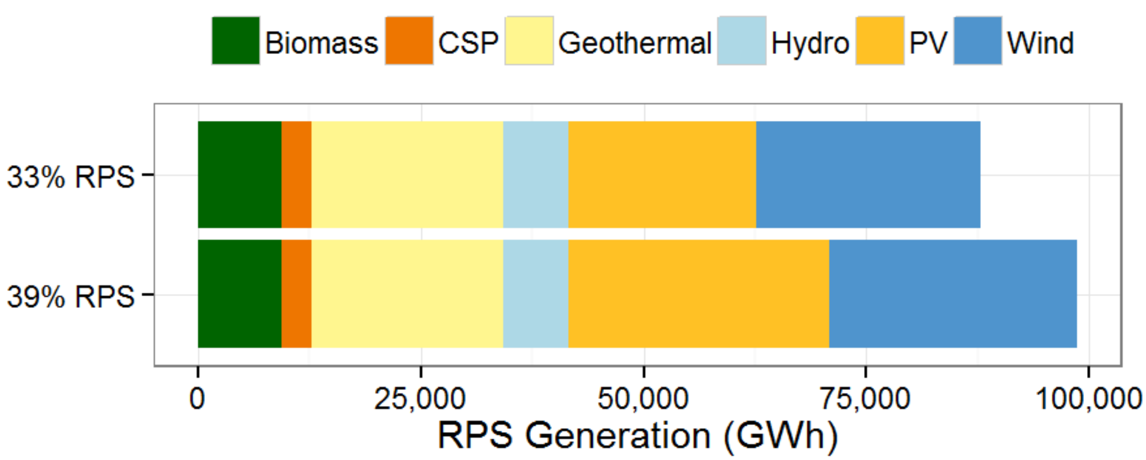

Figure 5. Annual generation from RPS sources for the base 33% RPS case and the 39% RPS

Integrating these additional variable generation resources incurs a change in operating reserve requirements. We do not have access to the PNNL/CAISO methodology for calculating these new reserves requirements, so we evaluate an alternate method utilized in the Western Wind and Solar Integration Study: Phase 2 (WWSIS-2) (Ibanez et al. 2012, Lew et al. 2013). The calculation assumes the procurement of adequate reserves to meet 70% of forecast errors in the 1-hour time frame and 95% of 10-minute forecast errors. The additional reserves are calculated based on the difference between these forecast errors in the 39% and 33% cases and then added to the original reserve requirements in the 33% RPS database. The results of this method are shown in Table 6. Note that the reserve requirements increase only slightly, by approximately 1%, compared to those shown Table 3. The reserves requirements of wind and solar energy have not been definitively determined and are an area of active research. Further analysis will be required to understand the impact of wind and solar on both regulation and load-following or flexibility reserves requirements and associated system costs. Spinning and non-spinning reserves, which are defined as 3% of hourly load, do not change.

Table 6. The Application of Incremental WWSIS-2 Reserves Methodology to the Reserves Products Modeled in the Database

Reserve Product	Time to Respond	Annual Req. (GW-h)	Mean Hourly Req. (MW-h)
Load-Following Up (LFU)	10 min.	11,027	1262
Load-Following Down (LFD)	10 min.	10,853	1242
Regulation Up	5 min.	3,748	429
Regulation Down	5 min.	3,878	443
Spinning Contingency	5 min.	7,500	860
Non-Spinning Contingency	5 min.	7,500	860

After implementing the additional PV and wind resources as well as the new reserve profiles, we observe some significant operational changes to the system, shown regionally in Table 7. First, the higher levels of RPS generation within CAISO lead to lower levels of energy imports from surrounding regions. In addition, the number of hours in which CAISO is a net energy exporter increases from 61 hours in the 33% RPS case to 342 hours in the 39% RPS case. The amount of energy exported increases from 35 GWh to 313 GWh (approximately 0.2% of total energy generated within CAISO), with an hourly maximum of 3,240 MW exported. Figure 6 shows the duration curve of hourly CAISO inflows throughout the year. Negative inflows represent a net flow of energy from CAISO into the neighboring regions. Figure 7 indicates the location and quantity of generation displaced by the new RPS generation. Although most RPS generation is located within the boundaries of CAISO, a reduction of out-of-state imports means that displaced generation is largely located outside of CAISO in regions such as the Pacific Northwest and Arizona. The additional wind and solar largely displaces gas combined-cycle generation, which is typically the marginal resource in much of the Western United States. The assumed ability of the neighboring regions to accept this new RPS energy and the modeled flexibility of these generators lead to very low curtailment (or overgeneration) in the 39% scenario. Approximately 0.01% of the incremental RPS energy added to the 33% case to reach the higher RPS is curtailed.[9]This curtailment rate is lower than shown in previous analysis of a CAISO 40% RPS scenario and driven largely by the different mix of wind and solar (Energy and Environmental Economics, Inc. 2014). Previous analysis has shown that curtailment rates of solar are highly nonlinear, which demonstrates the need to evaluate many scenarios of renewable penetration to determine the relative value of different generation mixes (Denholm and Mehos 2011).[10]

[9] In this document, we use the term *curtailment* to represent energy from renewables that could have been delivered to the grid (i.e., the resource was available) but was not delivered because of any system constraint. These constraints include generator flexibility, low demand, and regional transmission limits.
[10] For example, in this study the penetration of solar PV was approximately 14% on an energy basis, whereas the Energy and Environmental Economics study used a PV penetration of approximately 20% (2014). Previous analysis

Table 7. Characterization of the Regions Modeled in the Scaled 39% Case

2022	CAISO	Munis	WECC
Peak Load (GW)	54.3	12.0	122.9
Annual Demand (TWh) (% of total Western Interconnection)	254 (23.8%)	57.9 (5.4%)	754 (70.7%)
CA RPS Energy (TWh) (% of total CA RPS)	68.9 (69.8%)	10.1 (10.2%)	19.7 (20.0%)
Other Wind and Solar Energy (TWh)	6.4	0	69.4
Net Annual Imports (TWh)	41.2	29.8	-71.0
Incremental CA RPS Energy (TWh)	8.5	0.9	1.5
% of CA RPS Generation Displaced in Region (%)	32.7	11.5	55.8

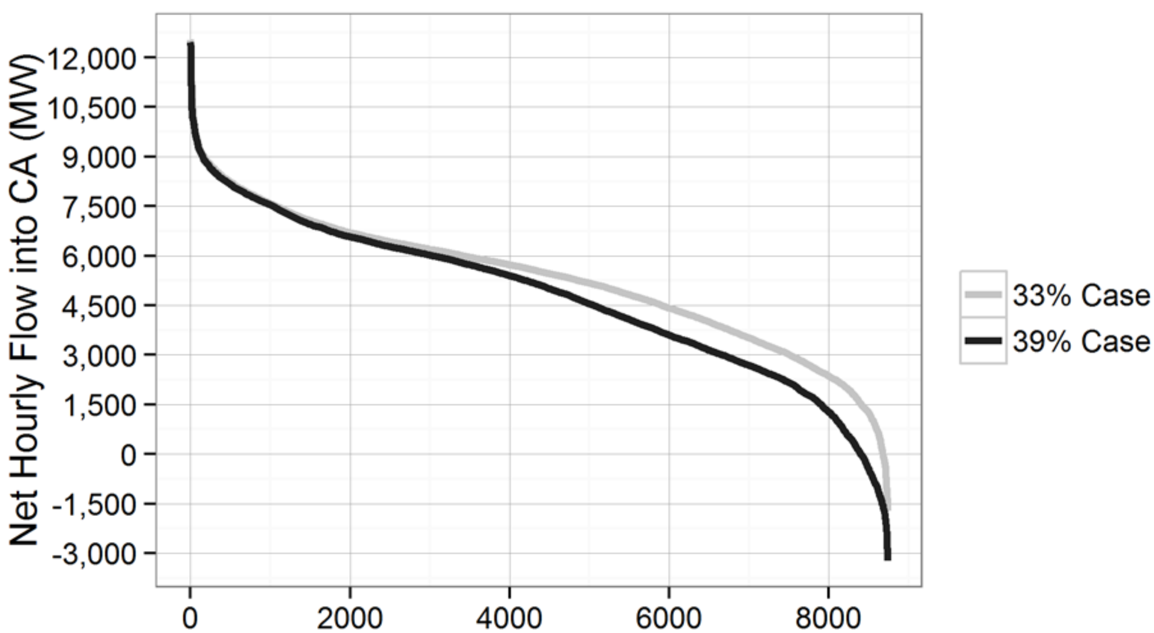

Figure 6. The hourly duration curve for net CAISO inflows in the 33% RPS case compared to the 39% case. Negative inflows represent energy exported out of CAISO.

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has demonstrated that this relatively small difference can produce a difference of more than 20 percentage points in the marginal curtailment rate (Denholm and Mehos 2011). In addition, this analysis makes different assumptions about energy storage capacity, generator must-run status, and export limitations.

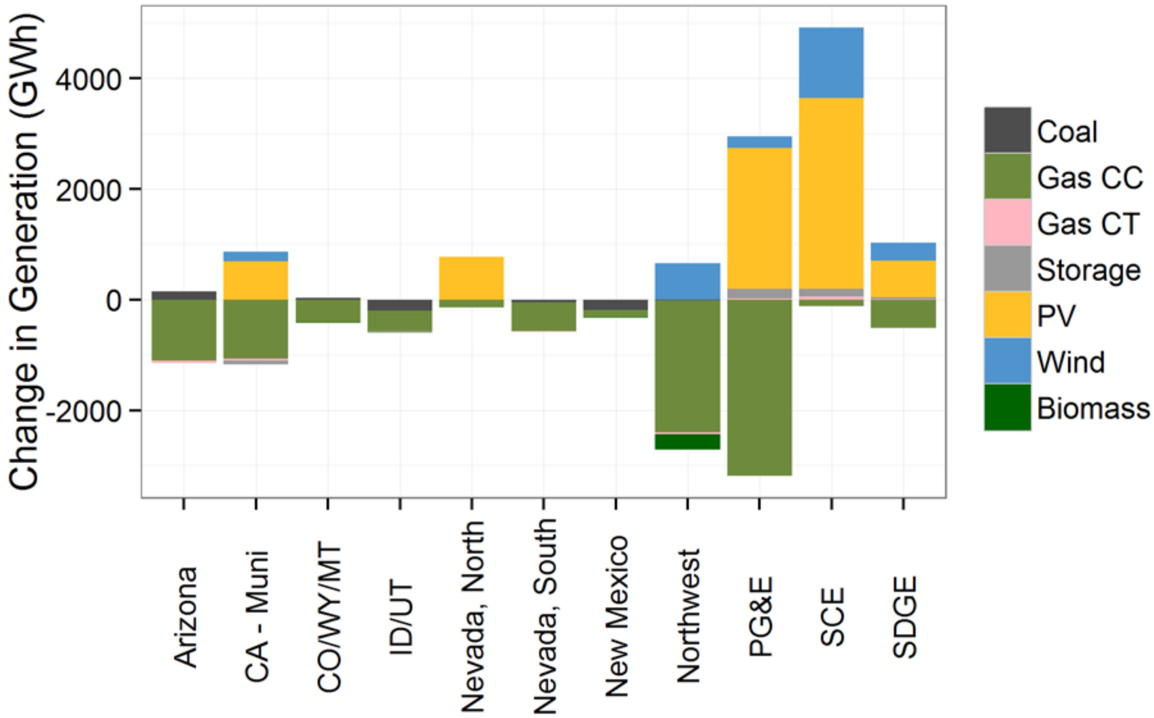

Figure 7. Displaced energy in the Western Interconnection as a result of an increase from 33% RPS energy to 39% RPS energy in CAISO

3.1 Integration of Incremental PV or CSP-TES

Using the same methodology presented in Section 2.2, we first compare the 39% system described above to a system with and without the addition of this incremental PV or CSP-TES (to achieve a 40% RPS) and attribute the cost savings to the new plant. Adding the same annual energy output from PV and CSP-TES (approximately 3,400 GWh) requires 1,172 MW of CSP-TES and 1,576 MW of PV,[11] as before.

Table 8 shows the change in total production costs, normalized by the total MWh of energy produced by either plant. First, the value of both CSP-TES and PV declines slightly in the 40% scenario because of the presence of new zero-marginal-cost generation (PV and wind). However, CSP-TES avoids $16.4/MWh more than PV, which is slightly higher than the $14.7/MWh in the 33% case. Thus, the value of PV declines at a faster rate than the value of CSP-TES. Additionally, as in the 33% case, the CSP-TES plant displaces roughly the same quantity of CO_2 emissions as PV, but avoids more emissions costs. As discussed further below, this results from the fact that CO_2 has a cost of $22/ton inside California but $0/ton in the rest of West, indicating that the PV plant is displacing generation largely outside California.

[11] The incremental PV in this 40% RPS case resulted in very low marginal curtailment (0.1%).

Table 8. Marginal Operational Value From a CSP-TES Plant and a PV Plant Implemented in a 40% RPS Case

	Marginal Operational Value in 33% RPS Case ($/MWh)	
	CSP-TES (SM = 1.3, 6 hrs TES)	PV
VO&M	1.5	1.2
Start-up and Shut-down	2.9	-0.4
Fuel	33.9	25.8
Emissions	7.9	3.2
Total	**46.2**	**29.8**

Figure 8 shows the difference in displaced generation for PV and CSP-TES. Both plants displace the same amount of energy, but the majority of the CSP-TES generation (60%) displaces energy within CAISO, whereas only 30% of the generation from the PV plant displaces other CAISO generation. Adding incremental PV generation also leads to an increase in utilization of storage within CAISO. Output from all existing storage devices increases slightly in the PV case, but the co-optimized flexible battery output increases by 16% overall. This indicates that the co-optimized battery is using more of its capacity to shift energy instead of to providing reserves.[12] The importance of the assumed flexibility and configuration of the battery is evaluated in Section 3.3.

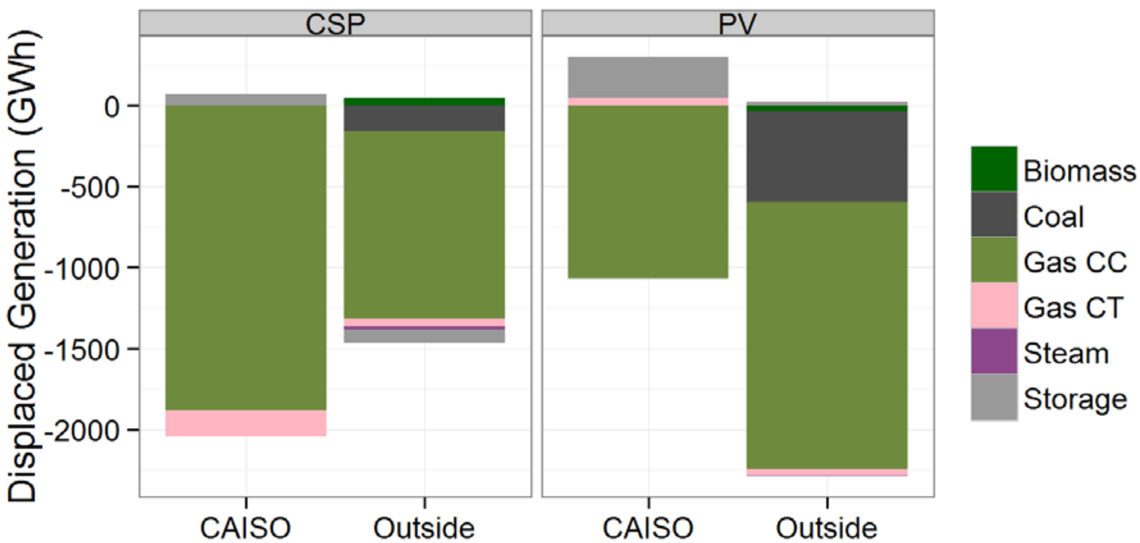

Figure 8. Difference in displaced generation for PV and CSP-TES in the 40% RPS case

As shown in Figure 8, a reduction in conventional generation due to the presence of additional solar energy leads to a reduction in CO_2 emissions. Although both technologies displace a similar amount of emissions per MWh produced (484 lbs./MWh for CSP-TES and 507 lbs./MWh for PV)[13], CSP-TES displaces more emissions within CAISO compared to PV. This

[12] Increased battery output results in increased charging demand as well, meaning that overall system load increases.
[13] PV displaces slightly higher amounts of CO_2 per MWh produced since it displaces a higher proportion of coal generation, shown in Figure 8.

causes CSP-TES to displace more than twice the emissions cost than does PV, since CO_2 outside of California has no modeled cost.

For explanation, Figure 9 shows the net imports for the base 39% case as well as the cases with additional PV and CSP-TES. The original 39% case results in a severe dip during midday when solar output is high, which causes CAISO to reduce imports. Adding PV makes this dip more defined, especially in the spring when load is relatively low. CSP-TES also slightly reduces imports during the middle of the day, but it also notably reduces the import peak late in the day when PV output drops as a result of sunset. The ability of CSP-TES to decrease the evening peak is an important source of value to the power system; this is indicated by the higher value for CSP-TES shown in Table 8. However, the value of providing dispatchable energy during the highest net load hours (net load being defined as system load minus contributions from zero-marginal-cost wind and solar) is only partially captured in the marginal operational value. This issue is addressed in Section 5.

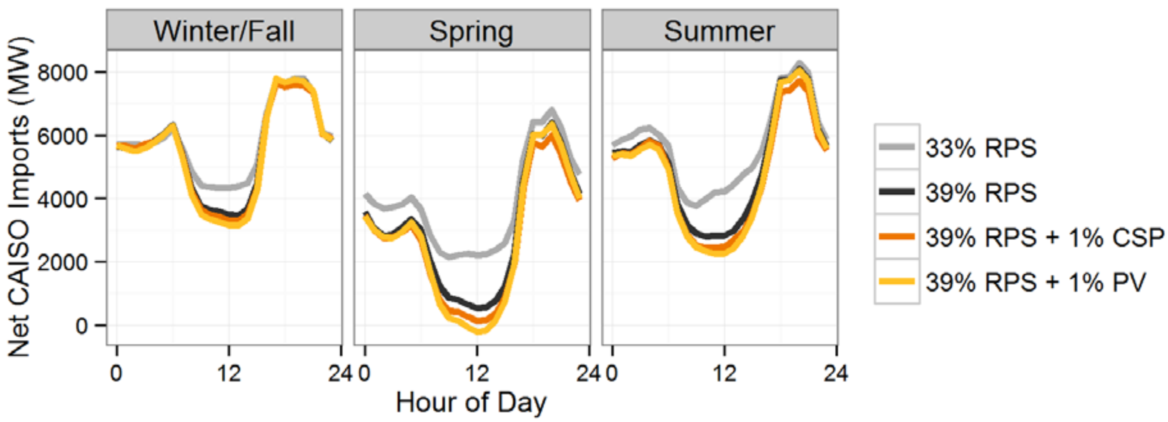

Figure 9. Net imports (representing load minus generation in CAISO) for the 33% RPS case, 39% RPS case, and the cases with added PV or CSP-TES to reach 40%

3.2 Constraining CAISO Exports

As mentioned previously, the implications of assuming that other regions can accept RPS energy from CAISO represents a large shift in current operations. Therefore, we examine two scenarios with export restrictions: capping net hourly exports from CAISO at 1,500 MW and 0 MW. The base 39% case with unlimited export ability results in negligible (0.01%) marginal curtailment compared to the base 33% case.[14] With constrained exports, the marginal curtailment increases to 0.1% in the 39% RPS case with 1,500 MW of exports (making overall curtailment 0.02%) and 1.4% in the case with 0 MW of exports (making overall curtailment 0.1%).[15]

Table 9 shows the value of 1% additional PV and CSP-TES in reducing operational costs for the two limited exports cases. The relative value of CSP-TES over PV rises from $16.4/MWh in the

[14] Marginal curtailment represents the curtailment of the incremental resource. Here, the marginal curtailment is the percent of added energy curtailed when increasing from 33% to 39%.
[15] The export constraint is binding for 80 hours of the year in the 1,500-MW case and 326 hours of the year in the 0-MW case.

40% case with unlimited exports to $17.4/MWh in the 1,500-MW limit case and $17.7/MWh in the 0-MW limit case. The 1,500-MW case shows 1.7% marginal curtailment of incremental PV, whereas the 0-MW case shows 7.3% marginal curtailment of the incremental PV.[16] In addition, system constraints cause the CSP-TES plant to curtail 0.2% more of its energy in the 1,500-MW exports case and 0.6% more energy in the 0-MW exports case compared to the case without export constraints. The operational values in Table 9 are normalized by MWh of uncurtailed energy (i.e., how much energy the plant would produce before curtailment), which explains in part why the value of PV decreases slightly in the cases with constrained exports. This in part helps explain the increasing relative value of CSP-TES to PV, because PV curtails more energy than does CSP-TES. The value of CSP-TES remains high in the export-constrained case because the plant is still able to generate during the highest-cost hours.

Table 9. Marginal Operational Value of PV and CSP-TES in a 40% RPS Case With Export Limitations

	Base Case		1,500-MW Export Limit		0-MW Export Limit	
Marginal Operational Value ($/MWh)	CSP-TES	PV	CSP-TES	PV	CSP-TES	PV
VO&M	1.5	1.2	1.6	1.2	1.3	0.9
Start-up and Shut-down	2.9	-0.4	3.4	-0.5	3.5	-0.4
Fuel	33.9	25.8	34.6	26.2	35.1	21.6
Emissions	7.9	3.2	8.3	2.8	6.7	1.3
Total	**46.2**	**29.8**	**47.1**	**29.7**	**46.2**	**28.5**

3.3 Sensitivity to Existing Energy Storage

As mentioned previously, we modified the existing CPUC database with the addition of energy storage capacity to represent the procurement mandated by the end of 2020 (in accordance with Rulemaking R.10-12-007). The presence of this existing storage capacity has an effect on subsequent storage value, such as CSP-TES. This value is also dependent on the type of device implemented. To demonstrate this effect, we introduced a highly flexible, long-duration battery with the ability to immediately switch between charging and discharging. However, Rulemaking R.10-12-007 presents guidelines for eligible storage technologies that include short-duration storage devices that provide operating reserves and other grid services instead of energy arbitrage.[17] First, we examine the value-suppressing effect of existing storage on CSP-TES by removing the 1,175 MW of storage associated with Rulemaking R.10-12-007. In addition, we

[16] Although marginal curtailment is higher in the 0-MW case, both cases still show less than 0.5% curtailment of overall RPS energy.

[17] The mix of storage types and attributes is expected to evolve in response to utility and state agency determinations. In addition, the storage mandate is divided among transmission-interconnected, distribution-interconnected and customer-side storage projects. At present, the CPUC is expecting customer-side projects to act as load modifiers but not provide grid services. The distribution-interconnected projects are currently expected to have some capability to provide grid services, but the proportion is not yet known. Hence, our decision to use 1,175 MW of storage as providing grid services is potentially an over-estimate of the actual utilization of these resources, and should be understood as one scenario for further refinement.

analyze a scenario in which the 1,175 MW of storage is assumed to operate as a short-duration device, providing only ancillary services with no energy-shifting capabilities.[18]

To understand the relative value of storage in each of these cases, we first calculate the value attributed to the new storage in the 39% case before adding additional CSP-TES or PV. The operational value of the new storage capacity is calculated using the same method—attributing the reduction in production costs to the new devices. Because the total capacity of the storage (1,175 MW) is held constant rather than the amount of energy (or reserves) provided, the value is instead normalized by capacity, shown in Table 10. Table 10 also shows the highest system value for a co-optimized storage device in which the model is allowed to decide between energy arbitrage and holding reserve capacity.[19] The value of the reserves-only device is slightly lower, which indicates a high value in holding reserve capacity and allows for a more optimal dispatch of the rest of the thermal generator fleet.

Table 10. Annual Operational Benefit of Two Types of Storage Evaluated in the 39% RPS Scenario

1,175 MW of New Storage	Annual Operational Benefit of Storage ($/kW storage capacity)
Co-optimized Storage (Base Case)	59.1
Reserves-Only Storage	56.0

Considering the relative benefit that the existing storage capacity above provides to the system, we now evaluate the additional CSP-TES or PV generation to reach a 40% RPS. Figure 10 shows the comparative value of CSP-TES and PV added to the system. CSP-TES is worth $3.7/MWh more in a system with no additional storage than with the co-optimized storage device assumed in the base case. Table 11 shows the relative value of CSP-TES over PV in the three cases. The relative values show that as CSP-TES provides more services that are not already being performed by the existing storage, its value over PV rises. Note that the value of PV and CSP-TES is the highest in the case with no additional storage because storage provides a more optimal dispatch of thermal generators that reduces the value of either technology and lowers the cost of the energy being displaced.

[18] This represents a fly-wheel device or similar technology.
[19] This scenario is noted as the base case in Table 10 because all the results presented this far have included this device.

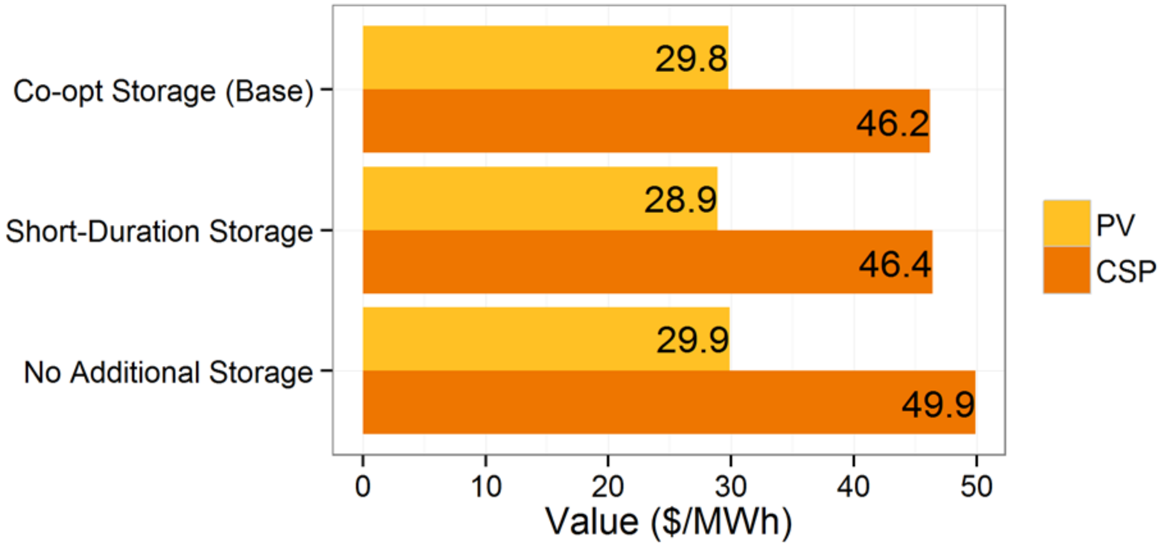

Figure 10. The operational value of a CSP-TES and PV plant added to a system with varying configurations of existing storage

Table 11. Relative Value of CSP-TES Compared to PV Under Various Assumptions Regarding Existing Storage

	Relative Value of CSP-TES Compared to PV ($/MWh)
Co-optimized Storage (Base)	16.4
Reserves-Only Storage	17.5
No Additional Storage	20.0

4 Impact of Plant Configuration on Value of CSP-TES

The configuration of a CSP-TES plant has significant impact on its ability to provide value to the power system (Jorgenson et al. 2013) beyond its interaction with electricity demand patterns and penetration of variable generation technologies such as PV. We examine the effect of the configuration by varying the size of the power block and thermal storage tank while holding constant the size of the solar collection field. As discussed previously, the SM normalizes the size of the solar field with respect to the power block. A system with a SM of 1 is sized for the solar field to provide the power block with exactly enough energy to operate at its rated capacity in reference solar conditions. A larger SM implies a larger solar collector area. For example, Figure 11 depicts two days of solar inflow for a CSP plant with a power block rating of 300 MW and a SM of 2. Any electrical energy delivered from the solar field that exceeds the maximum thermal rating of the power block must be stored—or curtailed for systems without storage.[20] As the diagram indicates, excess energy (in yellow) from an oversized field (a SM greater than 1) can be sent to thermal storage and subsequently delivered to the power block, resulting in a higher plant capacity factor. However, plant configurations with a very high capacity factor produce a fairly flat output. This requires a large fraction of solar energy to be stored during the day when electricity costs are the highest and then discharged during off-peak periods of low value. Sioshansi and Denholm previously analyzed different configurations using a simple "price-taker" model and demonstrated how lower SMs may provide the highest value considering the time-varying value of electricity (2010). Detailed dispatch modeling in a small test system supported this idea (Jorgenson et al. 2013).

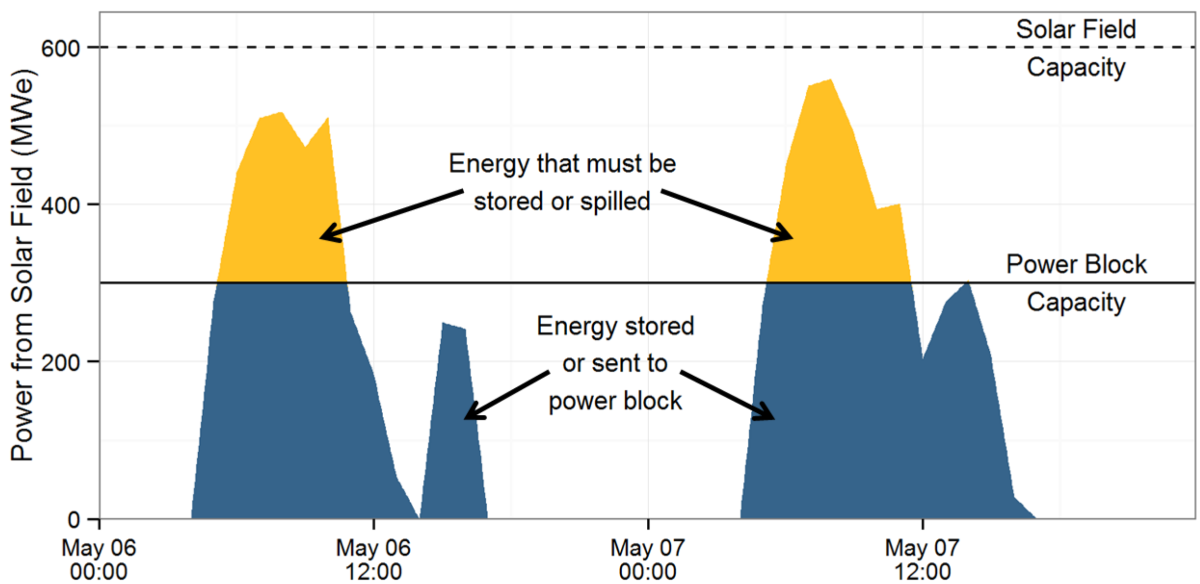

Figure 11. Impact of the solar multiple parameter on the energy flow of a CSP plant

To evaluate the operational value of different SMs, we change the rated capacity of the power block instead of 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

[20] Energy from CSP plants may be curtailed by defocusing some of the mirrors and reducing the amount of thermal energy delivered from the solar field.

varies. We also increase the storage capacity to quantify the additional system benefit provided by increased storage capacity.

Table 12 shows the studied parameters. As previously described, we calculate the system benefits by calculating the avoided production costs as a direct result of adding the CSP-TES plant to the system discussed earlier, and then we normalize by the amount of energy produced, shown in Figure 12.

Table 12. The SMs and Corresponding Plant Characteristics of CSP-TES Plants Modeled

Solar Multiple	Rated Capacity of Plant (MW)	Electrical Equivalent Inflow from Field (GWh)	Hours of TES Capacity Tested[21]
1.3	1,172	3,667	0, 3, 6
1.7	896	3,667	3, 6, 9
2	762	3,667	6, 9, 12
2.3	663	3,667	9, 12, 15
2.7	564	3,667	12, 15

Figure 12 indicates two trends that have been previously reported (Jorgenson 2013). First, the value of CSP-TES energy per unit produced generally increases with thermal energy storage capacity. Each of these plants has a SM greater than 1, meaning that the solar field is oversized compared to the power block. Therefore, during hours with high insolation and with insufficient (or no) thermal storage capacity, some solar energy must be curtailed. Increasing the storage capacity reduces the amount of energy that must be curtailed. In addition, thermal energy storage allows the energy to be shifted to periods with higher energy prices. Figure 13 shows the marginal energy price in the base case 40% RPS case on an average day during three seasons in CAISO as modeled. The highest-priced hours occur in the evening after or during sunset. Figure 14, which shows the average daily dispatch of CSP-TES during different seasons, indicates the time-shifting ability of TES. With no storage, the plant must be dispatched during the day. With increasing energy storage, the plant dispatch follows CAISO's marginal energy price.

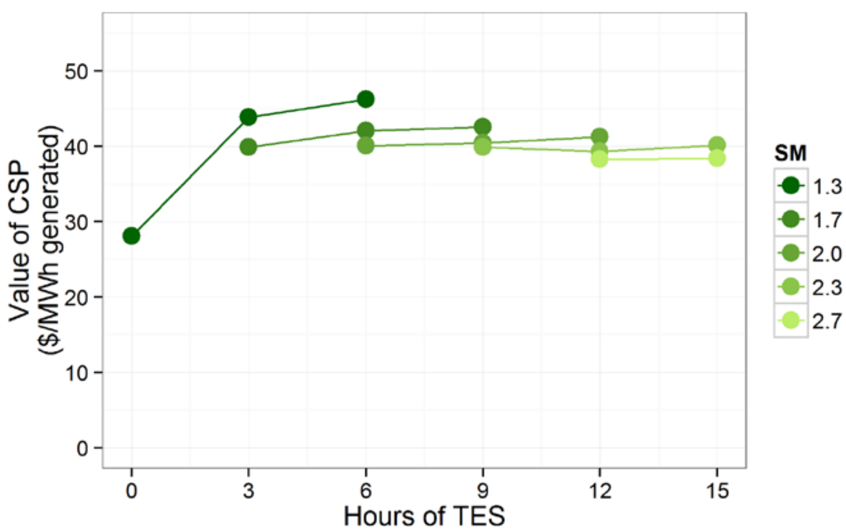

Figure 12. Marginal operational value of tower CSP-TES plants in the 40% RPS scenario with varying configurations

[21] Generally, storage capacity is measured in terms of hours of output at rated capacity.

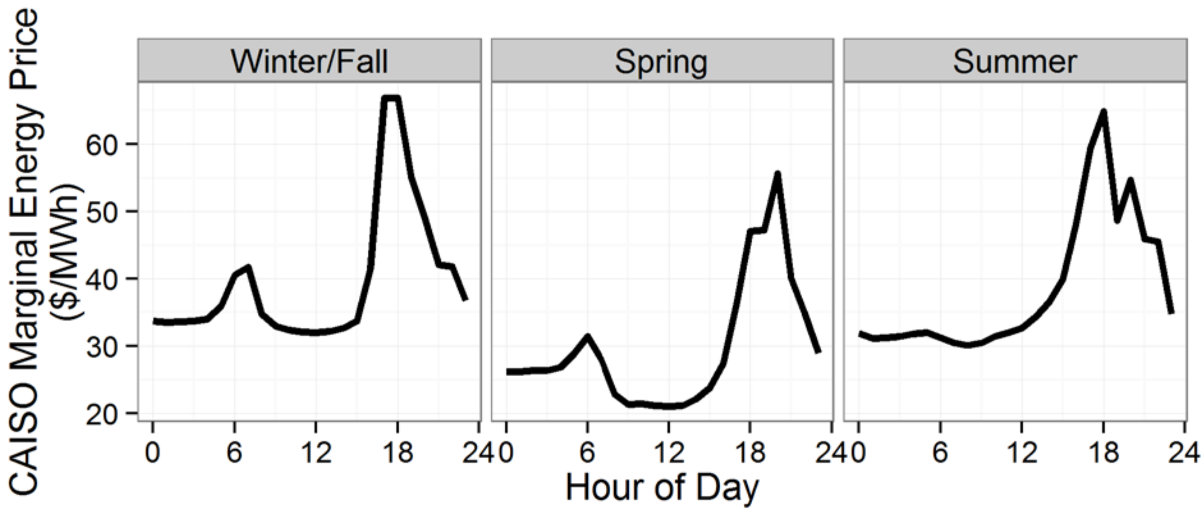

Figure 13. Average daily marginal energy prices for three major seasons in the 40% RPS scenario in CAISO

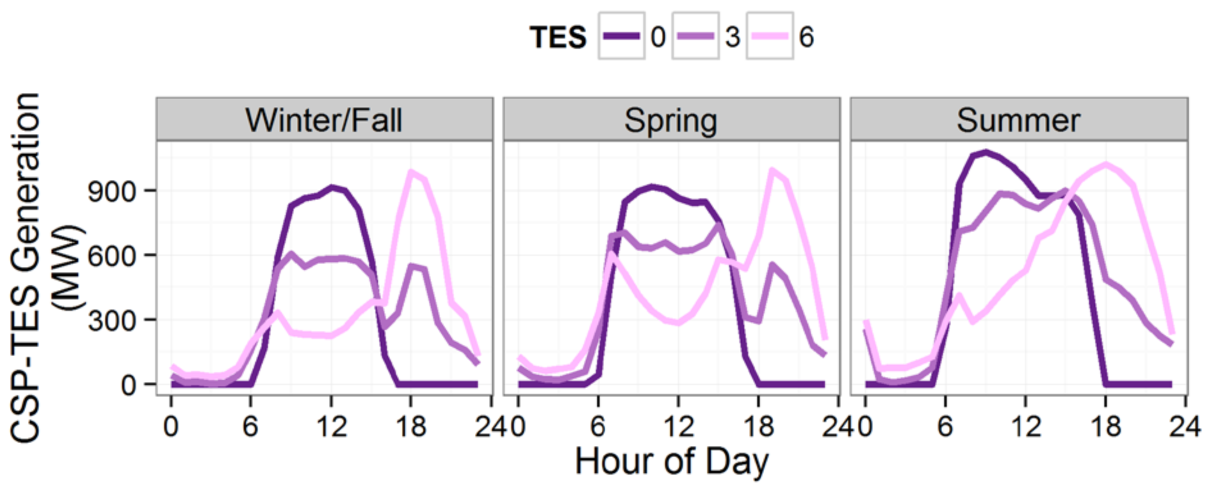

Figure 14. Average daily dispatch of a tower CSP-TES plant in a CAISO 40% RPS scenario with a SM of 1.3 and with 0, 3, and 6 hours of TES

Second, Figure 12 shows that the marginal value of plants with lower solar multiples is generally higher than plants with higher SMs per unit energy delivered. Because power block size decreases as SM increases, plants with higher SMs are forced to store an increasing fraction of solar energy, even during periods of high energy prices. In this case, the size of the power block limits the amount of energy that can be generated during the highest-priced hours of the day, which generally occur after sundown. Figure 15 shows the average daily dispatch for three CSP-TES plants with six hours of thermal storage capacity and varying SMs. As SM increases, the plant is forced to flatten its output and behave more like a baseload power plant that exhibits a relatively flat output profile. Because they are dispatchable over additional hours, the plants with smaller SMs act as peaking plants that displace more expensive generation sources during the highest-priced hours.

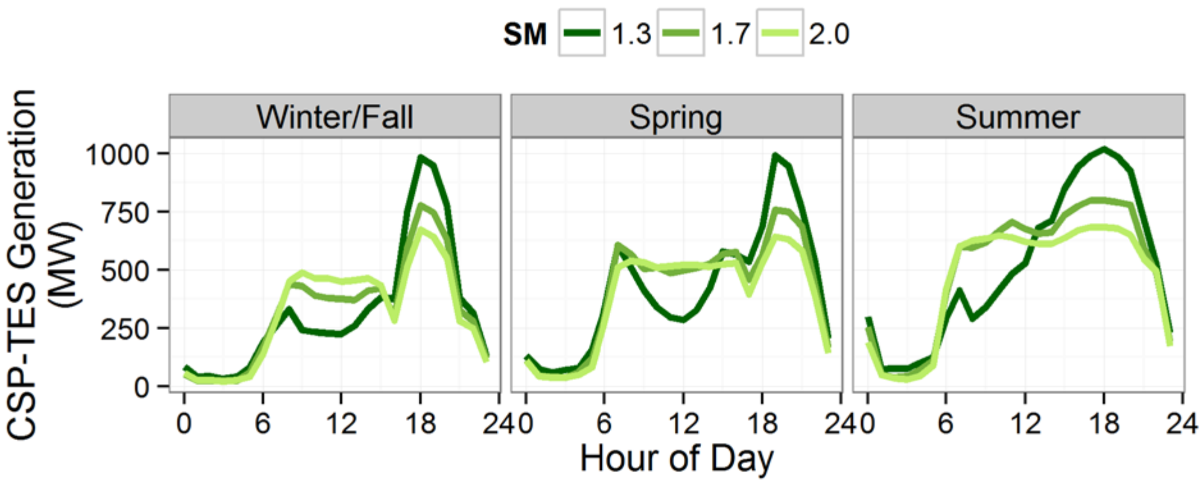

Figure 15. Average daily dispatch of a tower CSP-TES plant in CAISO with 6 hours of TES capacity and SMs of 1.3, 1.7, and 2.0

Figure 16 further explains the trends shown in Figure 12 by showing the restrictions on incoming solar energy. The incoming energy can be divided into three categories, before any losses: (1) energy that must go directly to the power block, (2) energy that must be stored, and (3) dispatchable energy. The first category represents energy that cannot be stored because the storage tank is finite in size. The second category arises from the fact that all plants modeled here have an undersized power block relative to the solar field. During high insolation, the solar field will collect more energy than can be used in that hour, which results in energy that must be sent to storage or be curtailed if the tank is full. The rest of the energy is classified as dispatchable because the model can choose to either send it to storage or generate power immediately. Plants with more dispatchable energy provide the most benefit to the system because fewer constraints on the incoming energy allow its output to be more fully optimized.

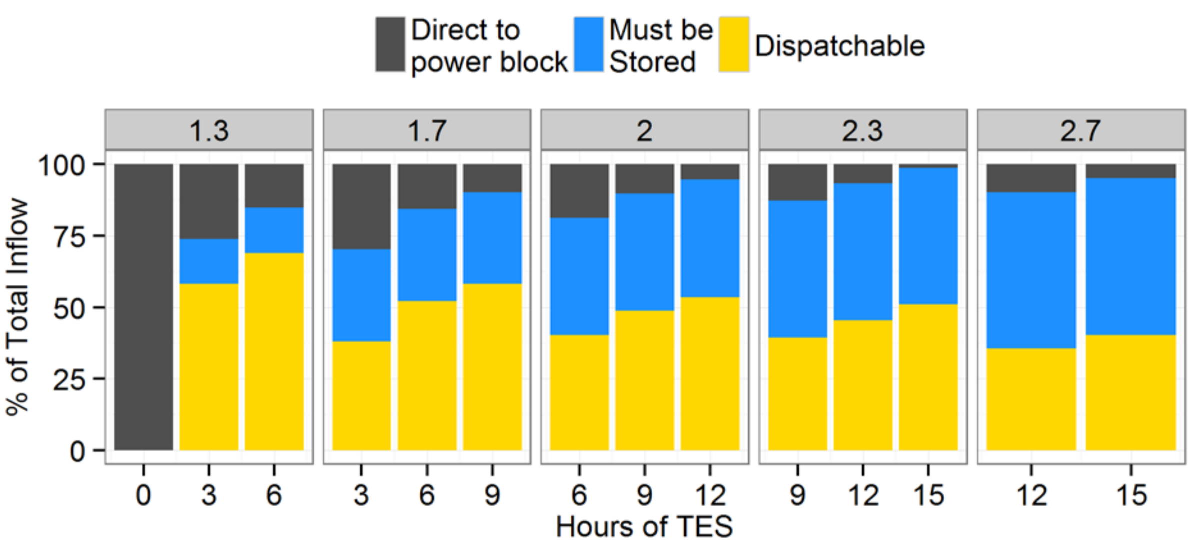

Figure 16. Breakdown of the limitations of incoming solar energy for solar multiples varying (across) from 1.3 to 2.7 with increasing amounts of thermal storage

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

The results of this analysis indicate that CSP-TES has a higher marginal operational value than PV, and that the relative value may increase slightly with increased PV penetration. However, calculating the avoided operational costs captures only one source of value. Next, we examine another source of potential value: firm capacity. The capacity value reflects the ability of PV or CSP-TES to avoid the costs of building new conventional thermal generators to meet demand. Note that firm capacity has value only in systems that need capacity to respond to growing energy demand or plant retirements. Capacity value in overbuilt systems with large amounts of excess capacity is essentially zero.

In this system, we add either 1,172 MW of CSP-TES or 1,576 MW of PV. However, these are the plants' rated, or nameplate, capacity, and do not necessarily reflect the generator's availability during periods of peak demand. The actual effective load-carrying capability (ELCC) for a generator is the amount of load that could be added to the system with the presence of a new generator while still meeting a reliability target. Historically, the reliability is measured using a loss-of-load expectation metric and a targeted reliability such as of 1 day of unserved energy every 10 years.

To estimate the capacity value of PV, we used the Renewable Energy Probabilistic Resource Adequacy tool (REPRA) tool that conducts a full ELCC calculation to determine how non-dispatchable sources of power such as PV can contribute to the reliability of a power system (Ibanez and Milligan 2012, Sigrin et al. 2014). This model uses the effective forced-outage rate for conventional plants and profiles of renewable generators to calculate loss-of-load probability (LOLP) and ultimately the ELCC of additional generation types such as solar PV.

The application of the REPRA tool to the additional PV plant in the 33% RPS and the CAISO projected load for 2022, with an overall PV penetration of 10.9%, gives an ELCC of 346 MW for the incremental PV (which is equal to a capacity credit of 22.0% given the plant capacity of 1,576 MW). The 40% RPS case, with an overall PV penetration of 14.1% in CAISO, gives an ELCC of 53.2 MW for the incremental PV (which is equal to a capacity credit of 3.4% given the plant capacity of 1,576 MW). Note that high PV penetration continues to shift the daily peak net load until later in the evening, when PV output drops. The hours with the highest LOLP generally occur during hours of highest net load. This indicates that as PV penetration increases, PV is less able to contribute in the peak net load hours. This very low value may be the result of the single year of data or other uncertainties in the data set. Because of this, we use a range of estimates with an upper value derived from Mills and Wiser, who calculated an approximate 30% capacity credit for a PV penetration of 10.9% and a 20% capacity credit for a PV penetration of 14.1% (2012a, 2012b).[22]

The traditional ELCC calculation becomes more complicated for CSP-TES because of the presence of dispatchable thermal storage. Similar to PV, we use an approximation method for estimating capacity credit for CSP-TES and thus the actual capacity value that a plant may earn. First, we examine the solar resource and dispatch of the CSP-TES plant during the hours with the

[22] This high value includes single-axis tracking with latitude tilt.

highest net load, which is used as a proxy for the hours with the highest LOLP.[23] The actual contribution of CSP-TES to the load-carrying capacity of the system should include not only its output during the 100 hours with the highest net load but also the availability of thermal energy to increase its output upward during those hours, as discussed by Tuohy and O'Malley (2011). For example, if the CSP-TES plant was dispatched below its full capacity during hours with high net load but has enough energy stored to increase its output, then it would receive a full capacity credit in this method. However, if the CSP-TES plant were forced to increase its generation over subsequent high-load hours, the available output could not exceed the thermal energy in reserve. That is, the calculation must reflect the energy limitations on the CSP-TES plant. The base configuration CSP-TES plant (with a SM of 1.3 and six hours of TES) earns a capacity credit of 92.8% in the 33% RPS case and a credit of 96.6% in the 40% RPS case using this method. This counterintuitive result in which the capacity credit of CSP-TES increases at a higher solar penetration is due to the "narrowing" of the daily peak resulting from the increased penetration of solar PV, demonstrated further in Appendix B. This complicates the allocation of capacity credit to differing technologies, because although PV appears to enable a slightly increased capacity credit of CSP, it receives very low capacity credit due to its non-coincidence with the shifted peak. It also demonstrates another element of the potential co-benefits of deploying both solar technologies in high renewable scenarios.[24]

Applying the annualized capacity cost of a new combustion turbine in California ($150/kW-y or $190/kW-y)[25] to the effective capacity of each plant, or the rated capacity adjusted by the capacity credit, and then normalizing by the amount of energy produced leads to a range of capacity values measured in terms of $/MWh. For PV, the capacity value is $15.2/MWh to $26.3/MWh in the 33% case and $2.36/MWh to $17.6/MWh in the 40% case[26]. For CSP-TES, the capacity value is $47.9/MWh to $60.8/MWh in the 33% case and $49.8/MW/h to $63.1/MWh in the 40% case. To quantify the total value of each technology, we add the operational value (presented in Section 3) and the range of capacity values. This results in a range of total values for PV and CSP-TES in the two RPS scenarios, depicted in Table 13 and Figure 17.

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[23] For more information about this approach and its limitations, see Sioshansi et al. (2013).
[24] Another benefit not analyzed here is the ability of CSP plants to replace less flexible units with higher minimum turndown ratios. This would enable greater penetration of PV by reducing overgeneration events, as discussed by Denholm and Mehos (2011).
[25] Lower estimate from Pfeifenberger 2013, upper estimate from CAISO 2012.
[26] The range of capacity values reflects the low capacity credit and low capacity value bound and the high capacity credit and high capacity value bound.

Table 13. Total Value (Operational Value Plus Capacity Value) Range in Two RPS Scenarios

	33% RPS	
	Lower Estimate ($/MWh)	Upper Estimate ($/MWh)
PV	47.1	58.2
CSP-TES	94.6	107
	40% RPS	
	Lower Estimate ($/MWh)	Upper Estimate ($/MWh)
PV	32.2	47.4
CSP-TES	96.0	109

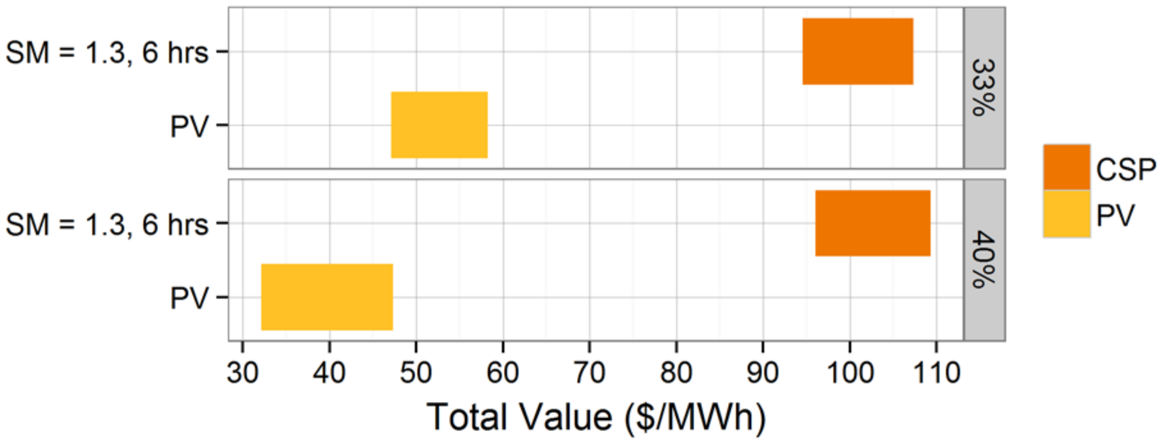

Figure 17. Total value range, which includes operational and capacity value, of CSP-TES and PV in two RPS scenarios

Applying the annualized capacity cost ($150/kW-y or $190/kW-y) to the various configurations of CSP-TES plants in the 40% RPS, as discussed in Section 4, leads to different overall values for various configurations. First, we calculate capacity credit as discussed above, shown in Table 14. The plants with higher solar multiples have higher capacity credits because of their surplus of solar energy relative to rated capacity, and plants with more thermal storage capacity have higher capacity credits because of their ability to shift solar energy to the hours of highest net load. However, combining operational value with total value indicates that low SM plants (with thermal storage) have the highest overall value but also the largest ranges for overall value. This is shown in Figure 18.

Table 14. Capacity Credit Assigned to Various Configurations of CSP-TES Plants in the 40% RPS Scenario Using Two Methods

	Capacity Credit Including Dispatch and Useable Storage				
Hours of TES	SM				
	1.3	1.7	2	2.3	2.7
0	0.092				
3	0.946	0.979			
6	0.966	0.989	0.999		
9		0.995	1.00	1.00	
12			1.00	1.00	1.00
15				1.00	1.00

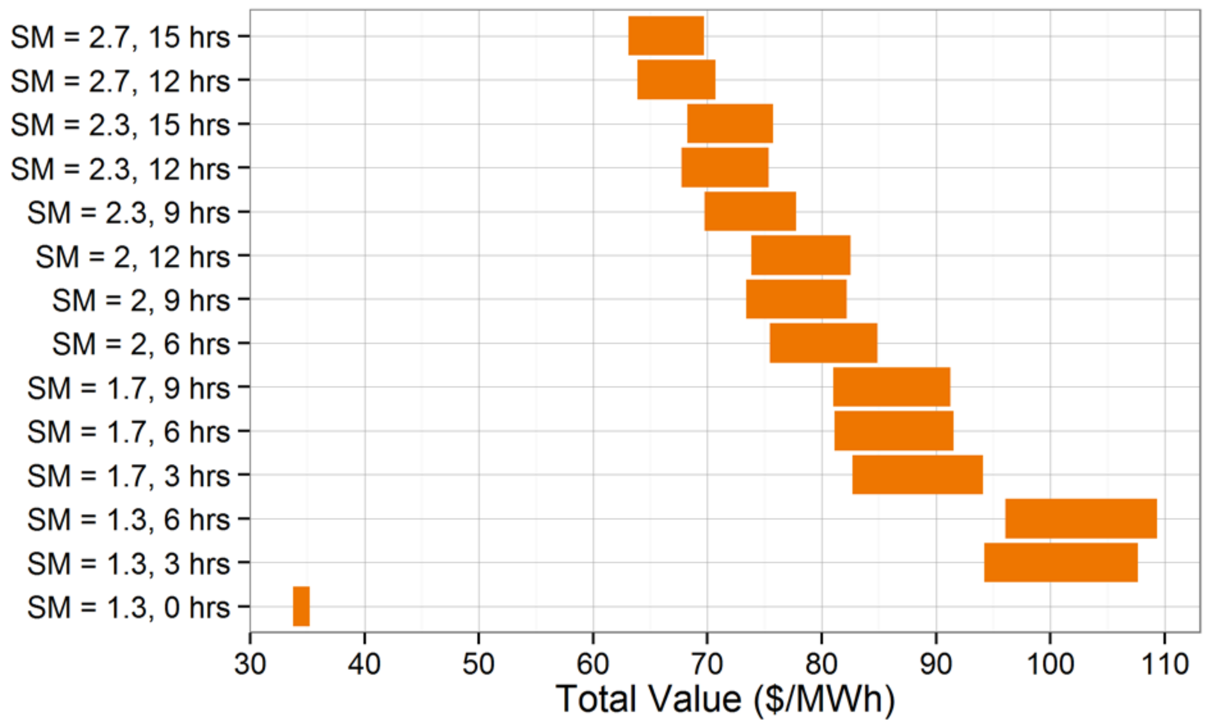

Figure 18. Total operational and capacity value of several configurations of CSP-TES in the 40% RPS scenario

6 Conclusions

We evaluated the relative value of PV and CSP-TES in the California grid system with two levels of assumed RPS-mandated renewable penetrations: 33% and 40%, which have PV penetrations of 10.9% and 14.1%, respectively. In the 33% case, we found an operational value of $46.6/MWh for our base CSP-TES configuration and $31.9/MWh for PV. These values are lower than a previous 33% RPS study based largely on the assumed reduction in cost of natural gas and CO_2 emissions. In the 40% case, we estimated an operational value of $46.2/MWh for CSP and $29.8/MWh for PV. Several sensitivities to these cases were also evaluated. Larger CSP solar multiples tend to reduce the value of CSP because the plant produces a more base-load output, producing more energy during times of lower value. However, plants with smaller solar multiples may be significantly more expensive to build per unit of energy produced; this warrants future analysis. Reducing export capacity increased PV curtailment somewhat, slightly lowering its value to the system. Eliminating 1,175 MW of energy storage increases the flexibility benefits of dispatchable CSP and results in higher value.

The value of CSP appears to be largely derived from its ability to provide firm system capacity. Depending on the assumptions used, the capacity value (expressed in terms of $/MWh of generation) for the CSP plant was estimated from $47.9/MWh to $60.8/MWh in the 33% case and $49.8/MWh to $63.1/MWh in the 40% case. This produced a total value for the base CSP configuration of $94.6/MWh to $107/MWh in the 33% case and $96.0/MWh to $109/MWh in the 40% case. Although we observed a relatively small drop in CSP value between the scenarios, a greater reduction was observed for PV, largely because of the reduction in capacity value. We estimated total values for PV from $47.1/MWh to $58.2/MWh in the 33% case and $32.2/MWh to 47.4/MWh in the 40% case. This produced a relative value of CSP of about $47/MWh to $49/MWh greater than PV in the 33% case and $62/MWh to $64/MWh greater in the 40% case.

The steep decline in capacity value for PV has been observed before, but the results presented here utilized only one year of data. Because the value of both PV and CSP are highly dependent on their ability to provide firm capacity, a more robust capacity value calculation could provide valuable insight. In addition, further analysis will determine the system needs at shorter timescales as VG integration continues to influence sub-hourly system operations. Finally, this analysis compared only the relative value of CSP-TES in multiple scenarios and configurations and did not consider upfront cost. The capital costs are highly dependent on many assumptions, including the solar resource and achievement of cost-reduction goals. Future work should analyze the trade-off between value to the grid and required costs.

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Appendix A: Changes in CSP Value Relative to the 2013 CSP Value Study

As reported in Section 2.2, the operational value of CSP-TES in the 33% RPS case, $46.6/MWh, is lower than previously reported values in the same database. Denholm et al. reported an operational value of $83/MWh (2013). This produces a decrease in value of approximately $36.4/MWh. Table A-1 summarizes the sources of this difference.

Table A-1. Sources of Value Reduction in This Study Compared to a Previous NREL Study of CSP in CAISO

Change	Decrease in Value in This Study
Reduced natural gas prices. This study assumes an average of $4.4/MMBtu compared to the assumptions in the previous iteration of the database (between $5.6 and $6.3/MMBtu). This results in a $13/MWh to $15/MWh direct difference and acts as a multiplier on several other costs.	$13–$15
Reduced CO_2 costs. This study assumes that a cost of CO_2 is $22/ton in California and $0/ton outside of California, down from $36/ton in all of the Western Interconnection in the previous analysis.	$10–$12
Reduced reserve provision due to the introduction of storage. This issue is discussed in Section 3.3 and produces a difference of $4/MWh to $5/MWh after considering the impact of fuel prices and CO_2 costs.	$5–$6
More conservative CSP assumptions. This study includes more realistic (and conservative) part-load heat rate and start costs for CSP-TES plants.	$2–$4
General database updates. This includes assumptions about VO&M costs of conventional generators, heat rates, ramp rates, and other operational parameters and costs.	$3–$4
Use of tower plant. The previous study used a trough plant. For more explanation about the difference in operational value, see Jorgenson et al. (2013).	$2–3
Use of reduced solar multiple. The operational value presented here analyzes a SM of 1.3, whereas the previous analysis utilized a SM of 2. For more information about the drivers of this deviation, see Section 4.	-$6 to -$7
Total	**$29–$38**

Appendix B: How PV Can Increase the Capacity Value of CSP-TES

Section 5 demonstrates a slight increase in capacity credit for the CSP plant when increasing the RPS penetration from 33% to 40%. This result appears counter to previous analysis that demonstrated a decreasing capacity credit for PV or CSP-TES when analyzed independently (Mills and Wiser 2012a, 2012b). The explanation for our counterintuitive result is based on the fact that we are considering the combined impact of both PV and CSP. Figure A-1 illustrates the load and contribution from PV and wind (labeled as RE Gen) to net load for July 22 in both the 33% and 39% scenarios. This is one of the days of peak net demand that drives the capacity credit measurement.

The 40% scenario demonstrates two important factors. First, the addition of PV effectively shifts the hour of peak demand on this day from 4 p.m. to 6 p.m. During this hour, the capacity credit of any incremental PV is very small. However, the large amount of PV also reduces the duration (number of hours) of the peak period, meaning fewer hours of storage may be needed to meet this shorter peak. In the 33% case, the natural inflow of solar energy and 6 hours of storage capability is enough to cover approximately 10 of the 12 peak hours in this period, or run at approximately 85% of rated capacity during the entire peak period. However, in the 39% case, the reduced peak duration allows the plant to operate at rated capacity during approximately 9.5 of the 10 hours at full capacity, or approximately 95% of rated capacity during the entire period.

Overall, this issue demonstrates the complementary nature of PV and CSP and adds difficulty in "allocating" the value of different technologies.

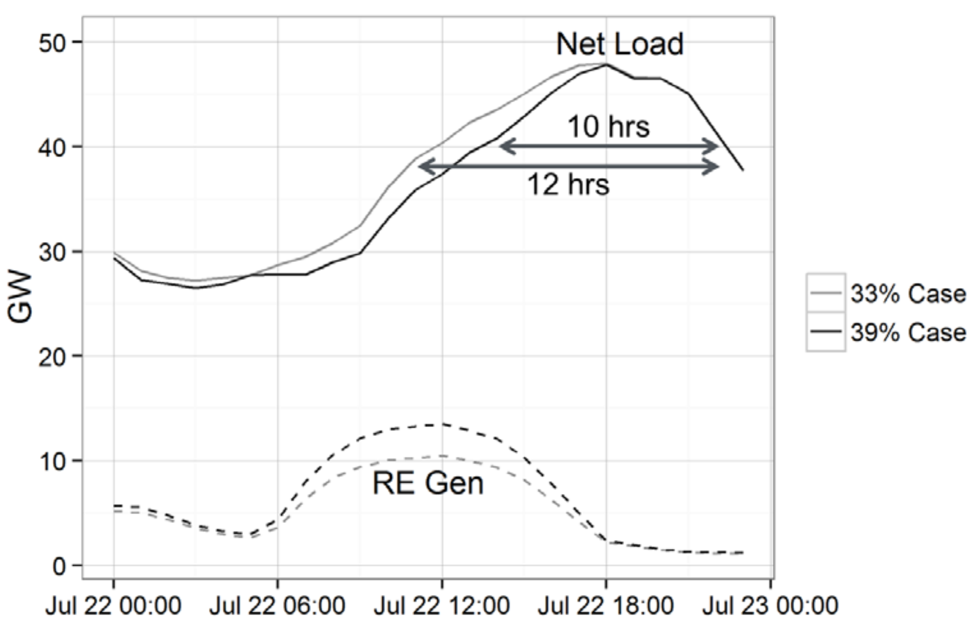

Figure A-1. Change in peak demand period resulting from the deployment of PV on July 22