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Simulating the Value of Concentrating Solar Power with Thermal Energy Storage in a Production Cost Model

Paul Denholm and Marissa Hummon

NREL is a national laboratory of the U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, operated by the Alliance for Sustainable Energy, LLC.

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Executive Summary

Concentrating solar power (CSP) deployed with thermal energy storage (TES) provides a dispatchable source of renewable energy. The value of CSP with TES, as with other potential generation resources, needs to be established using traditional utility planning tools. Production cost models, which simulate the operation of grid, are often used to estimate the operational value of different generation mixes. CSP with TES has historically had limited analysis in commercial production simulations. This document describes the implementation of CSP with TES in a commercial production cost model. It also describes the simulation of grid operations with CSP in a test system consisting of two balancing areas located primarily in Colorado.

CSP was implemented in the PLEXOS model, which is a security-constrained unit commitment and dispatch model. CSP both with and without storage was implemented and compared to solar photovoltaics (PV) and to a “flat block” resource equivalent to a baseload generator with zero fuel costs. The CSP plant with storage was modeled as a trough-type plant with a solar multiple of 2.0 and 6 hours of storage. The test system consisted of two balancing areas located in Colorado and Wyoming—Public Service of Colorado (PSCO) and Western Area Colorado Missouri (WACM), simulated using publicly available data. The generation characteristics and fuel prices were based on a 2020 scenario and included two renewable energy cases—a low RE scenario where wind and solar provide 13% of the annual generation and a high RE scenario where wind and solar provide 34% of generation, including 8% from PV.

In each scenario, a small amount of a new generator type (CSP, PV, or flat block resource) was added to determine its value to the system. The operational value of the different generation sources is based on which power plant types they displace as calculated by the least-cost dispatch within the model. In the low RE case, gas-fired generators are on the margin most of the time, so all generators displace mostly gas. However, the dispatchability of CSP allows it to time its output to periods when the most expensive gas units are on the margin.

Figure ES-1 shows how CSP with TES dispatches energy during periods of highest price, compared to a CSP plant without storage. During this 3-day period in January, CSP produces energy during periods of peak demand in the morning and evening, both periods without significant solar availability.

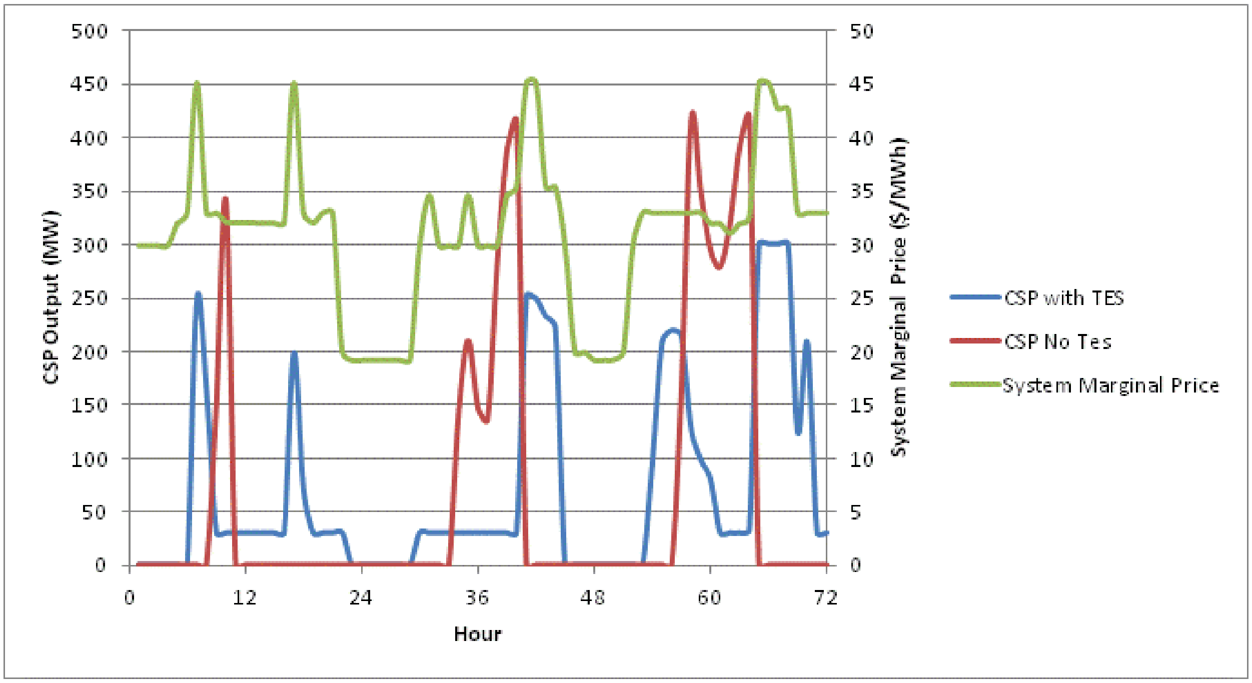

Figure ES-1. System marginal price and corresponding CSP generation on January 22–24 (low RE case)

CSP with TES displaces more fuel and higher-cost fuel than the flat block or solar generation without storage. Table ES-1 shows the avoided fuel per unit of generation (MMBTU/MWh). It also shows the impact of the high RE case, where much of the gas is displaced and coal is the marginal generator for many hours of the year. Generators without storage increasingly displace lower value coal generation, and curtailment of variable generation sources begins to occur due to system flexibility constraints. CSP with TES continues to displace mostly gas generation due to its dispatchability.

Table ES-1. Avoided Fuel

	Avoided Fuel (MMBTU/MWh)							
	Low RE Scenario				High RE Scenario			
	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)
Coal	1.1	-0.7	-0.7	-0.9	5.8	5.2	5.4	1.9
Gas	7.4	8.9	8.9	9.7	3.5	3.6	2.9	7.1
Total	**8.5**	**8.2**	**8.2**	**8.8**	**9.3**	**8.8**	**8.3**	**9.0**

The avoided fuel, as well as plant start costs and operations and maintenance (O&M) were translated into an avoided operational value, as shown in Table ES-2. (This does not include value of system capacity or other potential benefits such as ancillary services.) Key drivers behind these results are the assumed cost of natural gas ($4.1/MMBTU) and coal ($1.4/MMBTU) in 2020.

Table ES-2. Operational Value of Simulated Generators

	Marginal Value ($/MWh)							
	Low RE				High RE			
	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)
Fuel	31.7	35.2	33.9	37.7	22.6	21.2	18.7	31.1
Variable O&M	1.2	1.0	1.0	0.8	2.1	2.0	1.9	1.4
Start	0.4	0.4	0.6	3.5	0.5	-0.9	-1.7	3.1
Total	**33.3**	**36.6**	**35.5**	**42.1**	**25.2**	**22.3**	**18.9**	**35.6**

In the low RE scenarios, the operational energy value of CSP with TES is about $8.8/MWh higher than the flat block (constant output) resource and $5.5–$6.6/MWh higher than the solar technologies without storage. The relatively small difference between solar technologies with and without storage is largely due to the natural coincidence of solar generation with periods of high demand and price. At higher RE penetrations the value of all generation decreases due to the reduced amount of gas on the system. In addition, the solar resource is no longer correlated with net load. As a result, the value of CSP with TES increases relative to the other generation technologies with a difference of $10.4/MWh relative to the flat block and $13.3–$16.7/MWh relative to the non-storage solar technologies.

The operational energy value can be combined with capacity value to get an estimate of the overall system value of the different generation sources. Combining operational benefits and capacity benefits requires summing an energy value (typically expressed in $/MWh) and a capacity value (often expressed as $/kW of installed capacity, or $/kW-year). To perform this calculation first requires an estimate of capacity credit of each plant, or the fraction of nameplate capacity that contributes to reliably meeting peak demand. Capacity credit was calculated by examining output during periods of high net demand (and highest risk of generation shortfall). This capacity credit is then multiplied by an annualized value of an equivalent resource, such as a combustion turbine or combined cycle gas generator. This annualized value can then be divided by annual energy production to derive a capacity value per unit of generation. Table ES-3 summarizes the results of this study, which uses two values for the cost of capacity: $77/kW-year and $147/kW-year. The results show that at low penetration, solar technologies have high capacity value, and non-storage solar technologies can actually have higher capacity value than CSP with TES on a per-unit of energy basis. At high penetration of solar, the highest net load hours shift to periods of low solar availability. This substantially reduces the incremental capacity value of solar technologies without storage.

Table ES-3. Capacity Value Estimates

	Low RE Scenario				High RE Scenario			
	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)
Capacity Credit (%)	100	70	75	98	100	13	3	78
Capacity Value (Low/High) ($/kW)	77/147	54/103	58/110	76/144	77/147	10/19	3/5	60/115
Capacity Value (Low/High) ($/MWh)	8.8/ 16.8	29.7/ 56.6	29.1/ 55.3	21.2/ 40.4	8.8/ 16.8	5.3/ 10.1	1.3/ 2.4	17.1/ 32.6

The total value in the test system is summarized in Figure ES-2. This shows that the dominant source of value is avoided fuel and the potential of these technologies to avoid new capacity. The low-cost capacity case assumes replacement of combustion turbines, while the high-cost case is the replacement of combined cycle units, which may be a more appropriate comparison to the flat block case and the higher capacity factor CSP with TES generator.

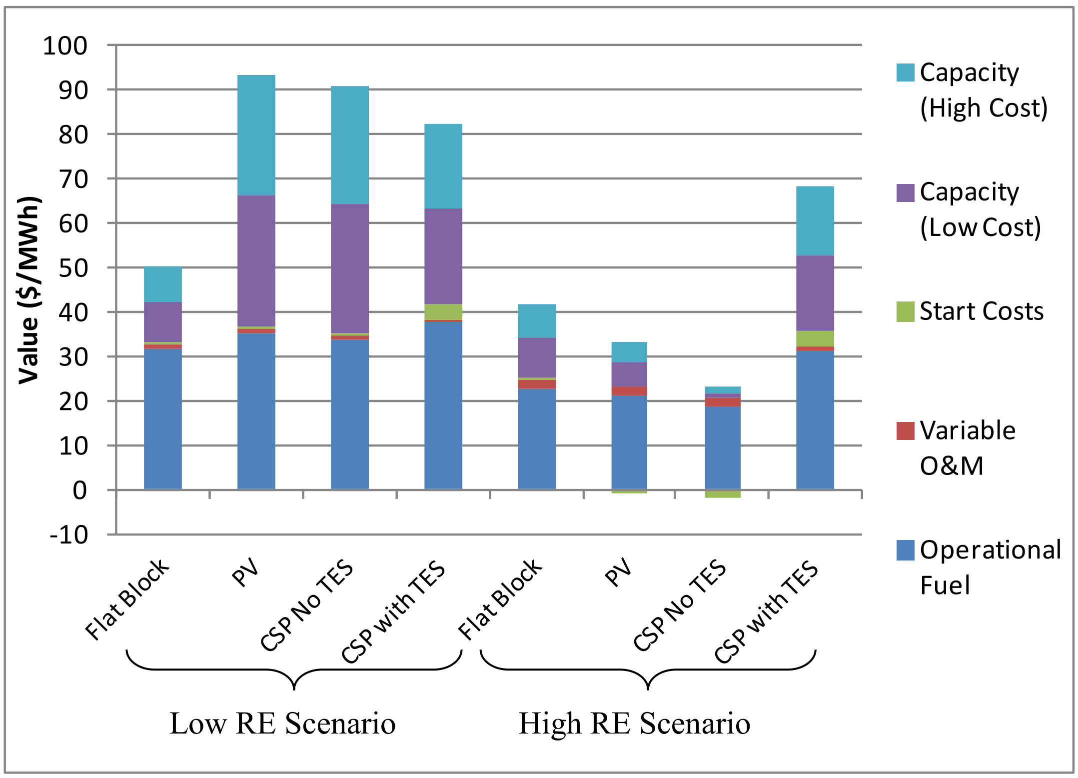

Figure ES-2. Total value of generation sources in the test system

Several sensitivities to these scenarios were performed. The strongest driver behind value is the price of natural gas, and adjusting the price of natural gas to historic levels results in operational values similar to previous studies of the value of CSP. Additional analysis is required to evaluate the other potential benefits of CSP, including provision of ancillary services and intra-hour dispatch flexibility.

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1 Introduction

Concentrating solar power (CSP) becomes a dispatchable source of renewable energy by adding thermal energy storage (TES). There have been a limited number of analyses that examine the value of this energy source and how this value varies as a function of grid configuration and fuel prices.

Challenges of properly valuing CSP include the complicated nature of this technology. Unlike completely dispatchable fossil sources, CSP is a limited energy resource, depending on the hourly and daily supply of solar energy. This supply of energy is both variable and not entirely predictable. This requires the limited energy available to be optimally dispatched to provide maximum value to the grid. The actual dispatch of a CSP plant, including its ability to provide ancillary services, will vary as a function of generator mix, the penetration of variable generation (VG) sources, such as wind and solar photovoltaics (PV), and the amount of storage deployed with CSP.

The ability to evaluate CSP under multiple scenarios requires the use of detailed grid simulation tools, such as a production cost model. A number of commercial production cost models exist, and these are routinely used by utilities, system operators, and researchers to evaluate the impacts of various generation sources. However, there have been limited studies of CSP with TES in the United States using commercial production cost models. Several studies that included CSP assumed that the dispatch of CSP is fixed and did not evaluate the complete benefits of this dispatchable resource (CAISO 2011; GE 2010). Other studies that have included dispatchable CSP made no attempt to isolate the value proposition for CSP or how that value proposition changes with increased levels of wind and solar generation (US DOE 2012; Mai et al. 2012; Denholm et al. 2012).

To completely identify the benefits of CSP and perform analysis in a framework accepted by utilities and system operators, CSP with TES needs to be incorporated into commercially available software. This document describes the methodology of implementing CSP with and without TES into the PLEXOS production cost model. It also provides a preliminary analysis of CSP with TES in a test system, based on two balancing areas located largely in the State of Colorado. It compares the dispatch of systems with CSP and TES to systems with only variable solar generation and examines several performance metrics, including avoided fuel and total system production cost.

2 Production Cost Simulations

A number of commercial production cost models are available to utilities, system operators, and planners to evaluate the operation of the grid. These models are used to help plan system expansion, evaluate aspects of system reliability, and estimate fuel costs, emissions, and other factors related to system operation.[1] The models have the primary objective function of committing and dispatching the generator fleet to minimize the total cost of production while maintaining adequate operating reserves to meet contingency events and regulation requirements. Modern production cost models often include transmission power flow simulations to ensure basic transmission adequacy for the generator dispatch. These models are increasingly used to evaluate the impact of incorporating VG sources, such as wind and solar. Integration studies evaluate the impact of VG on power plant ramping and reserve requirements and explore changes to grid operations needed to incorporate increasing amounts of VG (GE 2010).

As the penetration of VG increases, studies have found an important role for grid flexibility techniques and technologies, including new market structures, flexible generators, demand response, and energy storage. One option for flexible renewable generation is CSP with TES. This dispatchable energy source can provide grid flexibility by shifting energy over time, providing ancillary services, and ramping rapidly on demand, enabling a greater penetration of VG sources, such as wind and solar PV (Denholm and Mehos 2011). Several previous studies have included CSP to various degrees. The Western Wind and Solar Integration Study (WWSIS) (GE 2010) included CSP with TES but assumed CSP was dispatched in fixed schedules. Integration studies by the California Independent System Operator have included CSP but assumed very little storage (CAISO 2011).[2] Two more recent studies, the SunShot Vision Study (U.S. DOE 2012) and the Renewable Electricity Futures Study (Mai et al. 2012) incorporated CSP with TES into a commercial production cost model (Brinkman et al. 2012) and allowed the model to dispatch the TES resource. These studies demonstrate qualitatively the value of dispatchable solar but did not attempt to isolate the value of CSP with TES or compare how the value of CSP changes as a function of storage or other grid components. Alternatively, there have been studies that focused on the value of CSP with TES but were limited in modeling resolution. An example is a study that used a “price-taker” approach to dispatch a CSP plant against historic prices, assuming these prices (and solar availability) are known with varying degrees of certainty (Sioshansi and Denholm 2010). This type of study can identify some of the additional value that TES adds in terms of energy shifting and ancillary services; however, the value of this analysis is limited because it cannot examine the impact of different fuel prices, grid mixes, or the ability of CSP to interact with variable renewable sources, such as wind and PV.

A more comprehensive 2012 study evaluated CSP using a reduced form commitment and dispatch model and quantitatively identified a number of benefits of TES (Mills and Wiser 2012). This study evaluated changes in the long-run benefits of CSP with and without TES in California using an investment model that included a “fleet-based” commitment and dispatch component for conventional generators. The study also isolates the value proposition for CSP with TES, including energy, day-ahead forecast error, ancillary service requirements, and

[1] These models are also used by wholesale market participants. In regions with wholesale power markets, production cost models can also be used to predict market clearing prices on a short-term or long-term basis.
[2] Some scenarios included a small amount of CSP with storage but assumed flat block dispatch.

capacity value, although the simplified commitment and dispatch component of their model did not have the fidelity to represent detailed individual unit commitment and dispatch decisions.

Several studies initiated in 2011, including the second phase of WWSIS (Lew et al. 2012), examine CSP in greater detail. These studies use the PLEXOS production cost model and simulate the operation of the Western Interconnection in the United States. Simulation of the grid over large areas is important because of its interconnected nature and the corresponding ability of utilities to share resources over large areas. The Western Interconnection consists of thousands of generators, each of which must be simulated in detail.

Given the complexity of a large grid, it can be difficult to validate proper operation of a new generator type and isolate the cost impacts of a relatively small change in the system. As a result, to evaluate the performance of CSP, we began with a test system within a subsection of the Western Interconnection. This test system was used to evaluate the performance of CSP and the incremental value of TES under various grid conditions, including penetration of renewable generators, and compare CSP with storage to other generation sources.

3 Implementation of CSP in a Production Cost Model

3.1 Characteristics of CSP Plants

Two common designs of CSP plants—parabolic troughs and power towers—concentrate sunlight onto a heat transfer fluid (HTF), which is used to drive a steam turbine.[3] An advantage of CSP over non-dispatchable renewables is that it can be built with TES, which can be used to provide multiple grid services, including shifting generation to periods with reduced solar resource.

A CSP plant with TES consists of three independent but interrelated components that can be sized differently: the power block, the solar field, and the thermal storage tank. Figure 1 illustrates the main components of a trough-type CSP plant incorporating a two-tank TES system.

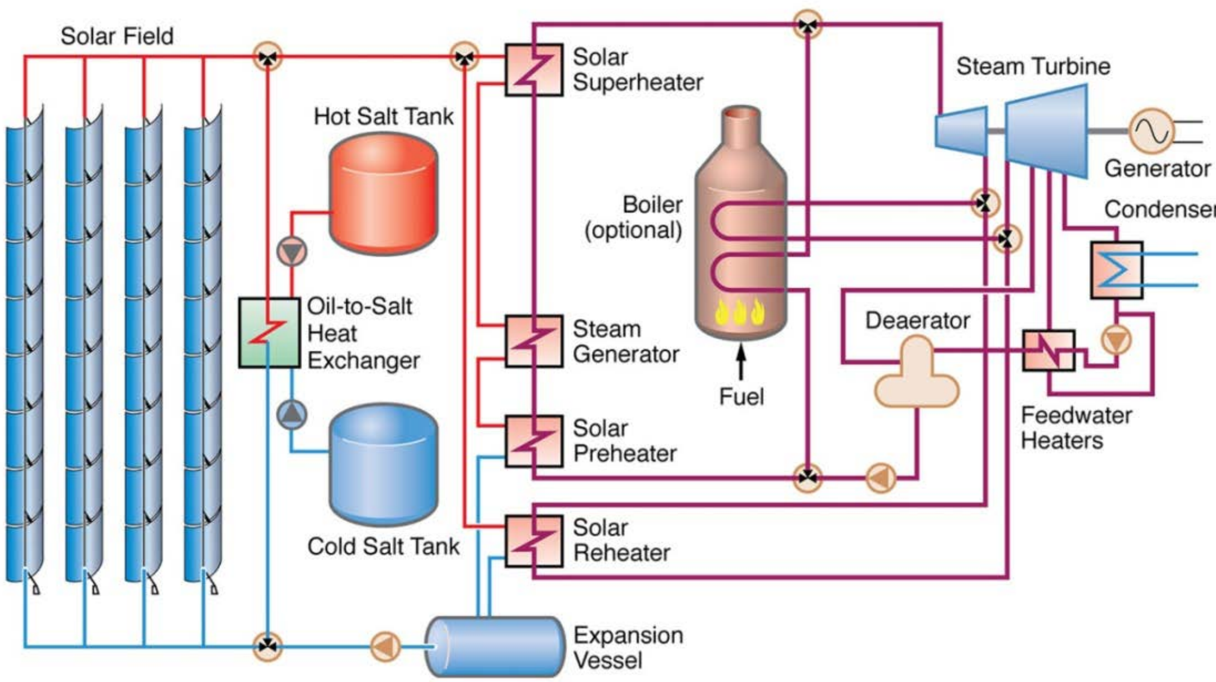

Figure 1. Components of a trough-type CSP plant with TES

Source: EPRI (2010)

The size of the solar field, in conjunction with solar irradiance, determines the amount of thermal energy that will be available to the power block. The sizing of the solar field is important because the relative size of the solar field and power block will determine the capacity factor of the CSP plant and the extent to which thermal energy will be utilized. Undersizing the solar field will result in an underused power block and a low capacity factor for the CSP plant because of the lack of thermal energy during all hours except those with the highest solar resource.[4] However, an oversized solar field, when deployed without storage, can result in wasted energy because the production from the solar field may exceed the power block capacity during many

[3] This is an oversimplification. For a more complete description of CSP technologies, see DOE (2012).
[4] A CSP plant can be designed with a fossil-fueled backup system.

hours. The size of the solar field can either be measured in the actual area of the field or by using the concept of a solar multiple, which normalizes the size of the solar field in terms of the power block size. A solar field with a solar multiple of 1.0 is sized to provide sufficient energy to operate the power block at its rated capacity under reference conditions (in this case 950 W/m^2 of direct solar irradiance at solar noon on the summer solstice).[5] The collector area of a solar field with a higher or lower solar multiple will be scaled based on the solar field with a multiple of one (i.e., a field with a solar multiple of 2.0 will cover roughly twice the collector area of a field with a solar multiple of 1.0).[6]

The size of storage is measured by both the thermal power capacity of the heat exchangers between the storage tank and the HTF (measured in MW-t) and the total energy capacity of the storage tank. The power capacity of the thermal storage will equal some fraction of the maximum solar field output. The energy capacity of the storage tank is commonly measured in terms of hours of plant output that can be stored. Thermal storage allows an oversized solar field and a higher plant capacity factor than a plant without storage.

The concept of solar multiple, and its relation to the role of energy storage, is shown in greater detail in Figure 2, depicting the hourly flow of energy from a plant with a solar multiple of 2.0. The maximum thermal output from the solar field during any hour is 100 MWe, but the power block rating is 50 MW, meaning that energy that exceeds the power block rating must be stored for use at a later time regardless of the instantaneous demand for electricity or other grid conditions.

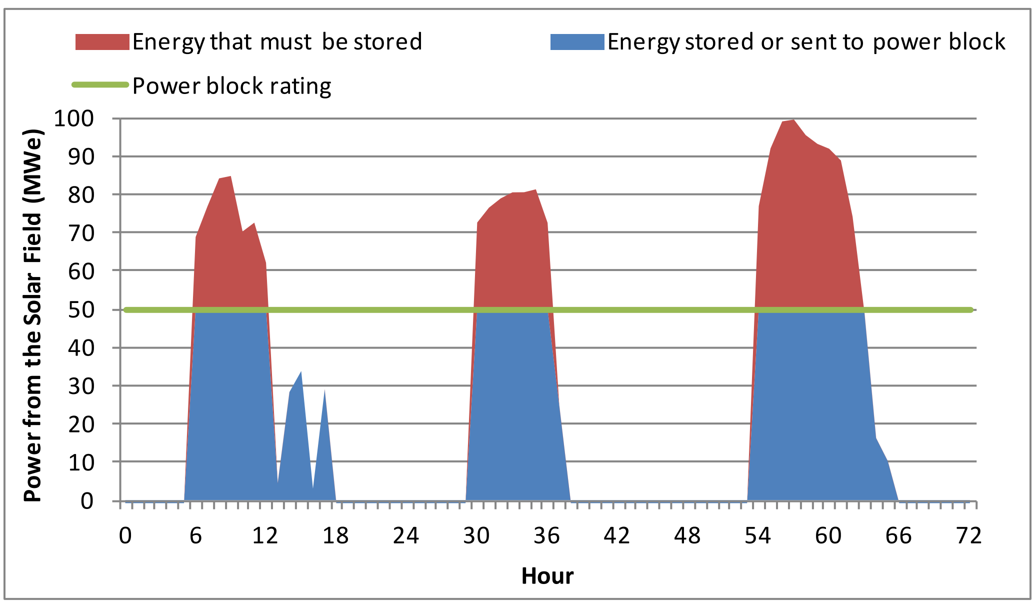

Figure 2. Impact of solar multiple on energy flow in a CSP plant

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[5] This is not a universal definition. Different CSP technology developers use different reference conditions.
[6] This is an oversimplification because there will be some variance in the relationship between collector area and solar multiple based on CSP technology type.

3.2 Implementation of CSP in PLEXOS

The primary function of a production cost model is to determine which generators must be committed and dispatched during each interval of the simulation and the associated cost of operation. Simulation intervals are typically 1 hour (as performed in this analysis), but there is increased interest in sub-hourly simulations, especially in scenarios of increased VG penetration where sub-hourly net load variability can require increased dispatch flexibility (CAISO 2011). A simple dispatch is determined by "stacking" generators in order of production cost (from lowest to highest) until the sum of the individual generator output is equal to load in each time interval. The actual dispatch is complicated by the many additional constraints imposed by individual generators, such as minimum up and down times and ramp rates. The actual dispatch also depends on the need for system security, including spinning reserves, which consist of partially loaded generators with the ability to rapidly ramp in response to a generator outage or unexpected increase in demand. To determine the optimal dispatch requires detailed information for each generator. Primary characteristics include maximum capacity, minimum stable output level, plant heat rate (ideally as a function of load), fuel cost, ramp rates, start time, and minimum up and down time. The software then co-optimizes the need for energy and reserves subject to the various constraints and finds the least-cost mix of generators in each time interval.

VG plants with little or no variable cost are typically placed into production cost models as a fixed hourly generation profile. Because they have no variable cost, and may also have production incentives, they are typically dispatched first but may be curtailed when operational constraints do not allow the system to accept their output.[7] These constraints might occur when the VG exceeds the local capacity of the transmission network or during periods when conventional generators have reduced output to their minimum generation levels. This second phenomenon can be referred to as a "minimum generation" problem (Rogers et al. 2010) or an "over generation" problem (CAISO 2010). CSP plants without storage can be placed into the model in the same manner as a wind or PV plant, using the hourly output from a CSP simulation model.

For this study, trough CSP plants (both with and without storage) and PV were simulated using the System Advisor Model (SAM) (Gilman et al. 2008; Gilman and Dobos 2012) version 2012-5-11. The CSP simulations used the wet-cooled empirical trough model (Wagner and Gilman 2011). The model converts hourly irradiance and meteorological data into thermal energy and then models the flow of thermal energy through the various system components, such as losses in the HTF, finally converting the thermal energy into net electrical generation output. The CSP plant without storage assumes a solar multiple of 1.3, the SEGS VIII default power block with turbine over-design operation allowed at 105% and used default settings for all parameters, such as parasitics. Meteorological data was derived from the National Solar Radiation Database from 2006 (NREL 2007).

CSP with TES was implemented in this study using a two-step process. First, hourly electrical energy from the CSP plant was simulated using SAM, and then the electrical energy was dispatched in PLEXOS using a combination of algorithms that largely existed within that model. This process is illustrated in Figure 3 and described in more detail in the following sections.

[7] Wind and solar may also be modeled as "must-take" resources due to contractual obligations to produce.

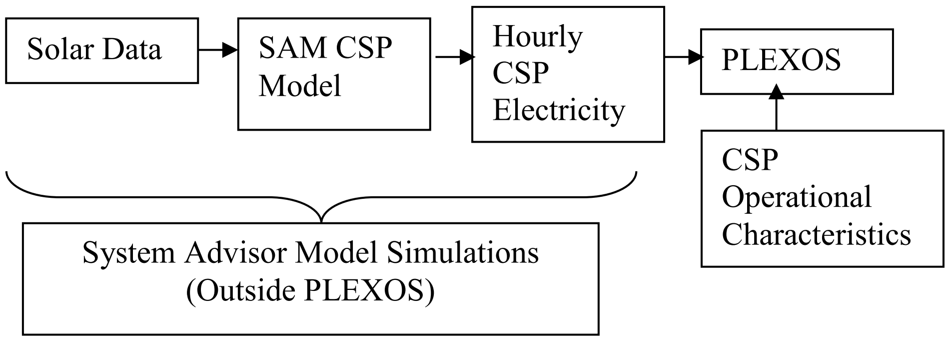

Figure 3. General process of implementing CSP

The first step (hourly electrical energy) was created using SAM in a manner similar to the case without storage with several important differences. Essentially all parameters that are affected by plant dispatch were moved out of SAM and into the PLEXOS framework. First, the solar multiple was set to 1; a larger solar multiple and storage was implemented in the PLEXOS model as described later in this section. Second, the minimum generation levels and start-up energy requirements were set to 0 and also accounted for in PLEXOS. Parasitics were removed from the gross CSP generation to derive a net hourly generation. Operational parasitics calculated by SAM were subtracted from the electrical profile in a manner similar to other thermal power stations. We also considered the constant parasitic loads (e.g., associated with fluid pumps) that occur even when the plant is not operating. This means that the CSP plant will draw a small amount of energy from the grid and incur a small associated cost. This constant load was calculated separately based on SAM CSP simulations.

The product of the SAM simulation is "raw" electrical energy output, which is then processed in PLEXOS using a modified form of the PLEXOS hydro algorithm to simulate storage, generator operation, and the effect of an oversized solar field. In each hour, the model can send the electrical energy from the SAM simulations directly to the grid via a simulated power block, to storage, or a combination of both. The model can also choose to draw energy from storage. The simulated power block includes the essential parameters of the CSP power block, including start-up energy, minimum generation level, and ramp-rate constraints. The model considers start-up losses in the dispatch decision by assuming a certain amount of energy (equivalent to 20 MWhe for a 100-MW power block) is lost in the start-up process.

In CSP plants that use indirect storage, the additional efficiency losses in the storage process are also simulated. The storage losses are set to 7%, which capture both the efficiency losses in the heat exchangers and the longer-term decay losses.[8] Constant parasitics were added by placing a constant load on the same bus as the CSP plant. The general implementation is illustrated in Figure 4, representing a 200-MW CSP plant with a solar multiple of 2.0 and 6 hours of storage.

[8] Longer-term decay losses could theoretically be modeled separately; however, they are relatively small and each new parameter in the model introduces complexity and increases run time. To consider decay losses, we reduce the total round-trip efficiency slightly to represent the "average" losses associated with both the heat transfer process and losses over time.

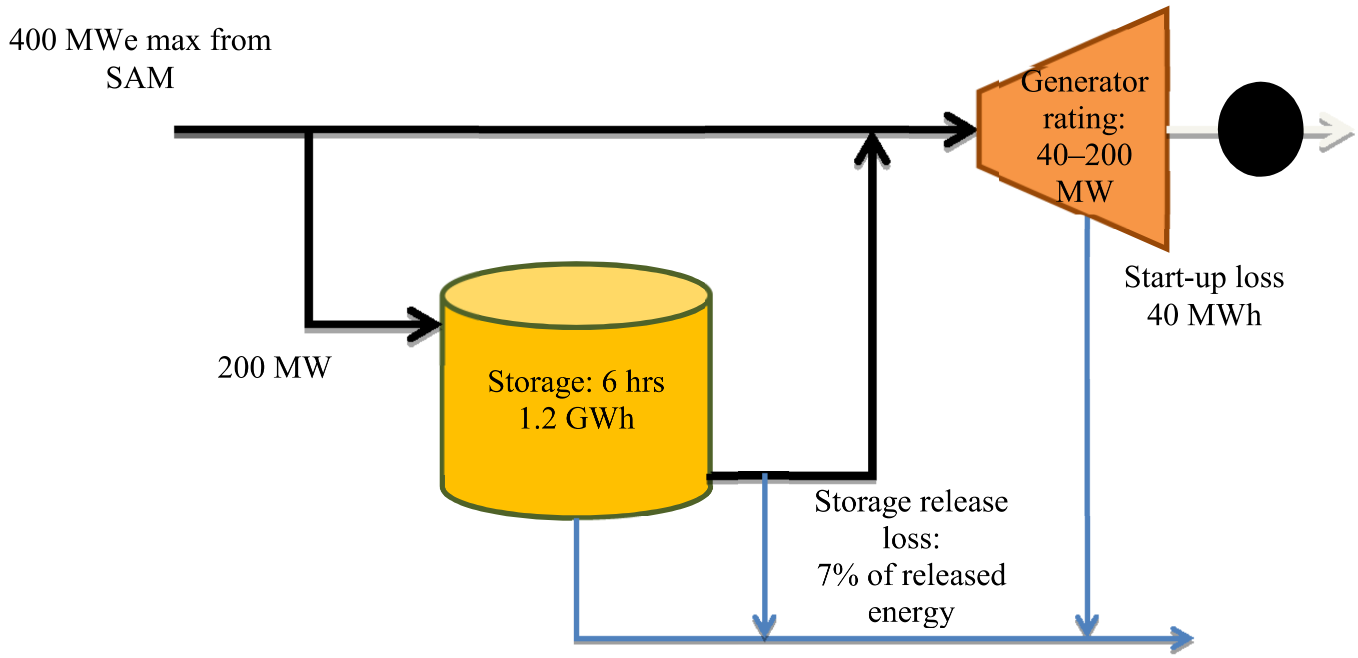

Figure 4. The flow of energy through a trough CSP plant with TES in PLEXOS

Figure 4 also shows the effect of solar multiple, which is captured in the sizing of the power block and storage components. For example, a solar multiple of 2.0 can be simulated by setting the maximum size of the power block to 50% of the maximum output from the CSP simulations from SAM. Likewise, the storage system can be sized to accommodate some fraction of the maximum CSP output. The storage energy capacity (hours of storage) can be set independently.

4 Test System

CSP was implemented in a test system to better verify the basic performance of this dispatchable energy source and to more easily isolate the relative value of TES under various scenarios.

The best locations for CSP in the United States are in the desert southwest within the Western Interconnection. Simulating the entire interconnection makes it difficult to isolate the performance of CSP, so a smaller test system was created to develop and validate the modeling approach. Most of the existing and proposed CSP is in California; however, simply running the California system in isolation ignores the substantial interconnections between the California and bordering states. As an alternative, we developed a system composed of two balancing areas largely in the State of Colorado: Public Service of Colorado (PSCO) and Western Area Colorado Missouri (WACM). These balancing areas consist of multiple individual utilities and this combined area is relatively isolated from the rest of the Western Interconnection. In addition, Colorado has sufficient solar resource for CSP deployment in the San Luis Valley in the south-central part of the state, and there have been proposals for large-scale solar development in the area (Xcel 2011). The test system also has sufficient wind resources for large-scale deployment, which makes evaluation of high renewable scenarios more realistic.

The Colorado test system was isolated by physically "turning off" the generation and load and aggregating the transmission outside of the PSCO and WACM balancing areas.[9] Transmission was modeled zonally, without transmission limits within each balancing authority area. It is very difficult to simulate any individual or group of balancing authority areas as actually operated because the modeled system is comprised of vertically integrated utilities that balance their system with their own generation and bilateral transactions with their neighbors that are confidential. Not having access to that information, we modeled the test system assuming least-cost economic dispatch. We based our inputs and assumptions as much as possible on the Western Electricity Coordinating Council (WECC) Transmission Expansion Policy Planning Committee (TEPPC) model and other publicly available datasets. Projected generation and loads were derived from the TEPPC 2020 scenario (TEPPC 2011). Hourly load profiles were based on 2006 data and scaled to match the projected TEPPC 2020 annual load. The system is a strongly summer peaking system with a 2020 coincident peak demand of 13.7 GW and annual demand of 79.0 TWh. The system load duration curve for 2020 is shown in Figure 5.

[9] This simplification effectively allows the two simulated balancing areas to use the transmission system in the rest of the Western Interconnection to share energy. As discussed later, transmission constraints between the two areas were not binding, and the analysis assumes sufficient additional transmission is constructed to access new renewable resources including both wind and new CSP. The costs and challenges of constructing the required new transmission are not considered in this analysis.

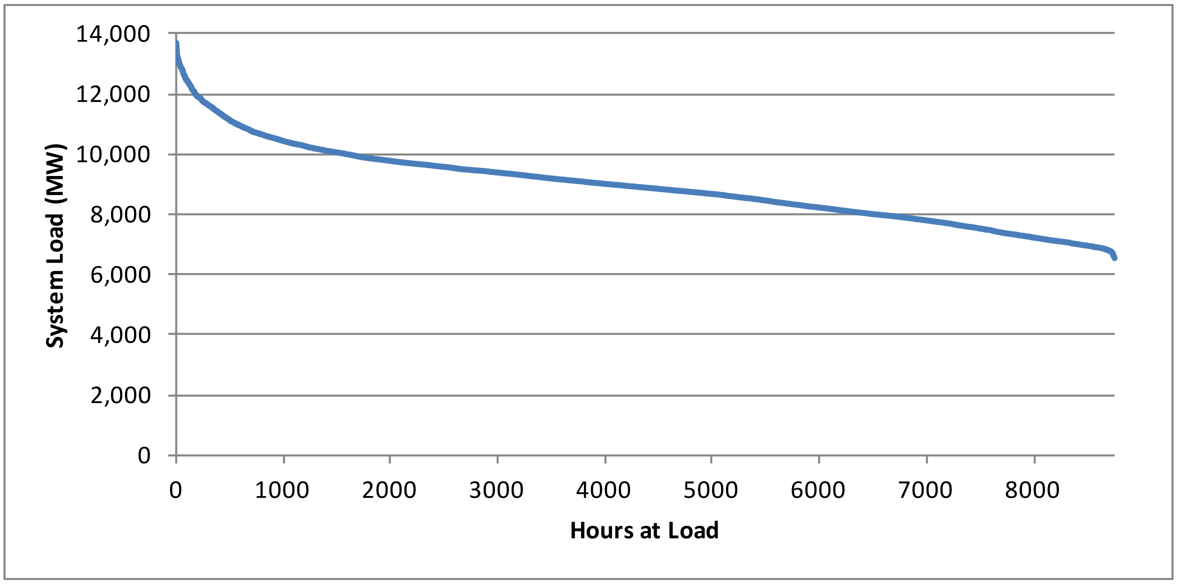

Figure 5. Load duration curve in 2020 for the PSCO/WACM test system

The generation dataset was derived from the TEPPC 2020 database and included plant capacities, heat rates, outage rates (planned and forced), and several operational parameters, such as ramp rates. A total of 201 thermal and hydro generators were included in the test system, with total capacities listed in Table 2. The generator database was modified to include part-load heat rates based on Brinkman et al. (2012). Start-up costs were added using the start-up fuel requirements in the generator database plus the operations and maintenance (O&M) related costs based on estimates prepared for the WWSIS II study (Intertek/APTECH 2012). We adjusted the generator mix to achieve a generator planning reserve margin of 15% by adding a total of 1,450 MW (690 MW of combustion turbines and 760 MW of combined cycle units).

Table 1. Characteristics of the Test System Conventional Generators in 2020

System Capacity (MW)	
Coal	6,178
Combined Cycle (CC)	3,724
Gas Turbine/Gas Steam	4,045
Hydro	773
Pumped Storage	560
Other[a]	513
Total	**15,793**

[a] Includes oil and gas-fired internal combustion generators and demand response.

Two renewable energy scenarios were created by adding wind and solar generation. PV profiles were generated using the SAM model with 2006 meteorology. Wind data was derived from the WWSIS dataset.[10] A low renewable energy (RE) case was created by adding wind and solar to

[10] All generation profiles were adjusted to be time synchronized with 2020, which is a leap year.

achieve a penetration of about 13% on an energy basis. This is a relatively small increase over the renewable penetration in 2011; Colorado received about 12% of its electricity from wind in the year ending June 2012 (EIA 2012).[11] We also considered a high RE case where wind and solar provide about 35% of the region's energy. In each case, discrete wind and solar plants were added from the WWSIS data sets until the installed capacity produced the targeted energy penetration. The sites were chosen largely based on capacity factor, and do not necessarily reflect existing or planned locations for wind and solar plants. Table 2 lists characteristics of the system in the two cases, while Table 3 provides additional details of the renewable and conventional generation mix.

Table 2. Renewable Scenarios in the Test System in 2020

System Capacity (MW)		
	Low RE Scenario	High RE Scenario[a]
Wind Capacity (MW)	3,054	6,489
Wind Energy (GWh)	9,791	20,210
Solar Capacity (MW)	395	3,630
Solar Energy (GWh)	625	6,493

[a] This is the potential generation and does not include curtailment that results in actual dispatch. About 31 GWh of wind and 23 GWh of solar were curtailed in the base high RE scenario.

Three classes of ancillary service requirements were included. The contingency reserve is 810 MW based on the single largest unit (Comanche 3). This reserve is allocated with 451 MW to PSCO and 359 MW to WACM, with 50% met by spinning units.[12] Regulation and flexibility reserve requirements were calculated based on the statistical variability of net load described by Ibanez et al. (2012). Reserves were modeled as "soft constraints," meaning the system was allowed to not meet reserves if the cost exceeded $4,000/MWh. This high cost could result during periods where a power plant would need to start up for a very short period of time just to provide reserves. Load was also modeled as a soft constraint, with a loss-of-load cost of $6,000/MWh (though the reserve margin was adequate to avoid lost load).

Fuel prices were derived from the TEPPC 2020 database. Coal prices were $1.42/MMBTU for all plants. Natural gas prices varied by plant, and for most plants were in the range of $3.9/MMBTU to $4.2/MMBTU, with a generation weighted average of $4.1/MMBTU. This is slightly lower than the EIA's 2012 Annual Energy Outlook projection for the delivered price of natural gas to the electric power sector in the Rocky Mountain region of $4.46/MMBTU in 2020 (EIA 2012). Sensitivity to natural gas price was also analyzed.

Both cases were run for 1 full year (2020, with 2006 meteorology and load pattern). The model run begins with two scheduling models to determine outage scheduling and allocate certain

[11] Colorado generated 3,070 GWh from wind in the year ending June 2012 compared to total generation of 25,614 GWh. EIA "Electric Power Monthly with Data for June 2012" August 2012.
[12] The PSCO and WACM balancing areas are part of the Rocky Mountain Reserve group, which shares contingency reserves based on these values.

limited energy resources.[13] The model then performs a chronological hourly security-constrained unit commitment and economic dispatch to minimize the overall production cost under operational and system constraints. The model performs a 24-hour ahead commitment with an additional 24-hour look-ahead period, allowing the model to effectively optimize storage utilization over a 48-hour period.[14] The analysis in this report was performed using PLEXOS version 6.207 R01, using the Xpress-MP 23.01.05 solver, with the model performance relative gap set to 0.5%.

Table 3 provides a summary of the operational results for the two base simulations. This represents on the variable cost of system operation, dominated by the cost fuel for thermal power plants. There was no loss of load and a small number of reserve violations (less than 40 hours per year in both cases).[15]

Table 3. Base Case Results

	Low RE	High RE
Total Production Cost (M$)	1,491.37	1,024.38
Average Production Cost ($/MWh)	18.9	13.0
Total Generation (GWH)[a]	78,957	79,098
Generation Mix		
Coal	58.8%	52.0%
Gas Combined Cycle (CC)	20.7%	7.2%
Gas Combustion Turbine (CT)/Gas Steam	1.4%	1.1%
Hydro	4.8%	4.8%
Wind	12.4%	25.5%
Solar PV	0.8%	8.2%
Other	1.1%	1.2%
Fuel Use (1,000 MMBTU)		
Coal	490,923	434,426
Gas	140,447	53,928

[a] While the load is the same, the total generation is slightly different (by about 0.2%), due primarily to different operation of the pumped hydro units.

[13] Within PLEXOS, maintenance outages are scheduled in the "Projected Assessment of System Adequacy" model, which generally assigns planned outages to periods of low net demand. This is followed by the "mid-term" scheduling model, which uses monthly load duration curves to assign limited energy resources, such as certain hydro units. The resulting allocation of resources from these two models is then passed to the chronological commitment and dispatch model. The model also includes random forced outages based on plant-level outage rates. The random number seed used to generate forced outages was kept the same throughout the various simulations for consistent treatment of these outages and associated cost impacts.

[14] Without a look-ahead period, production cost models see no value in carrying energy in storage across commitment intervals.

[15] In the low RE scenario there were a total of 39 hours of violations between the two systems. Of these, 31 were of contingency reserve violations. The violations were partial violations meaning that most of the contingency reserve requirements were met but there was some shortfall. The overall shortage represents about 0.14 GWh of the 5,839.4 GWh reserve requirement, or about 0.002%. There were a total of 17 hours of reserve violations in the high RE case.

System dispatch stacks can provide additional insight into system operation. The generation mix and dispatch was as expected, with coal units operating as baseload units, and CC and CT units operating as mid-merit and peaking units as needed. Figure 6 shows the dispatch stack for the low RE case during the week of peak demand in the summer. This figure demonstrates the opportunity for mid-day solar generation to reduce the use of the highest cost generators.

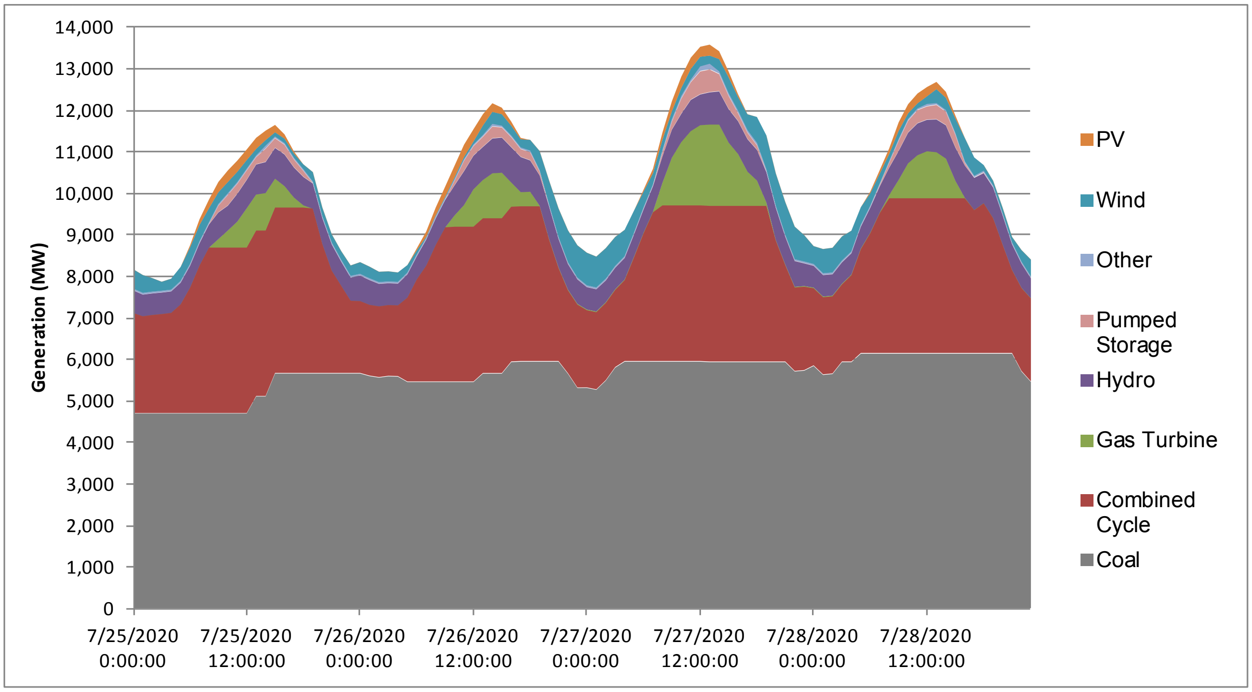

Figure 6. Dispatch stack during the period of July 25–28 in the low RE Case

The high RE case removes much of the gas generation from the system and leaves coal on the margin for a large number of hours. Figure 7 shows a four-day period in February, which includes the day of the lowest net demand on the system in the high RE scenario. In the first two days, coal generators reduce their output to minimum levels and renewable generation is curtailed. Any additional renewable generation from 1 p.m. to 3 p.m. on February 8 and from 11 a.m. to 2 p.m. on February 9 will be unusable in this scenario, and likely curtailed. Generation during many other periods will offset mainly lower-cost coal generation. Also of note is the rapid increase in net demand that occurs after 3 p.m. when the decrease in solar output and increase in electricity demand require large ramps of the coal units, use of higher-cost combustion turbines, and dispatch of the pumped storage plants.[16] Previous integration studies such as WWSIS have found significant increases in ramping requirements of coal units, and a major focus of the second phase of WWSIS is to examine the potential cost implications of increased unit cycling.

[16] The large amount of solar energy creates a new "off-peak" period in the middle of the day. Among the interesting system changes resulting from large mid-day solar generation is the extensive use of the pumped hydro units to absorb otherwise curtailed solar energy during this period.

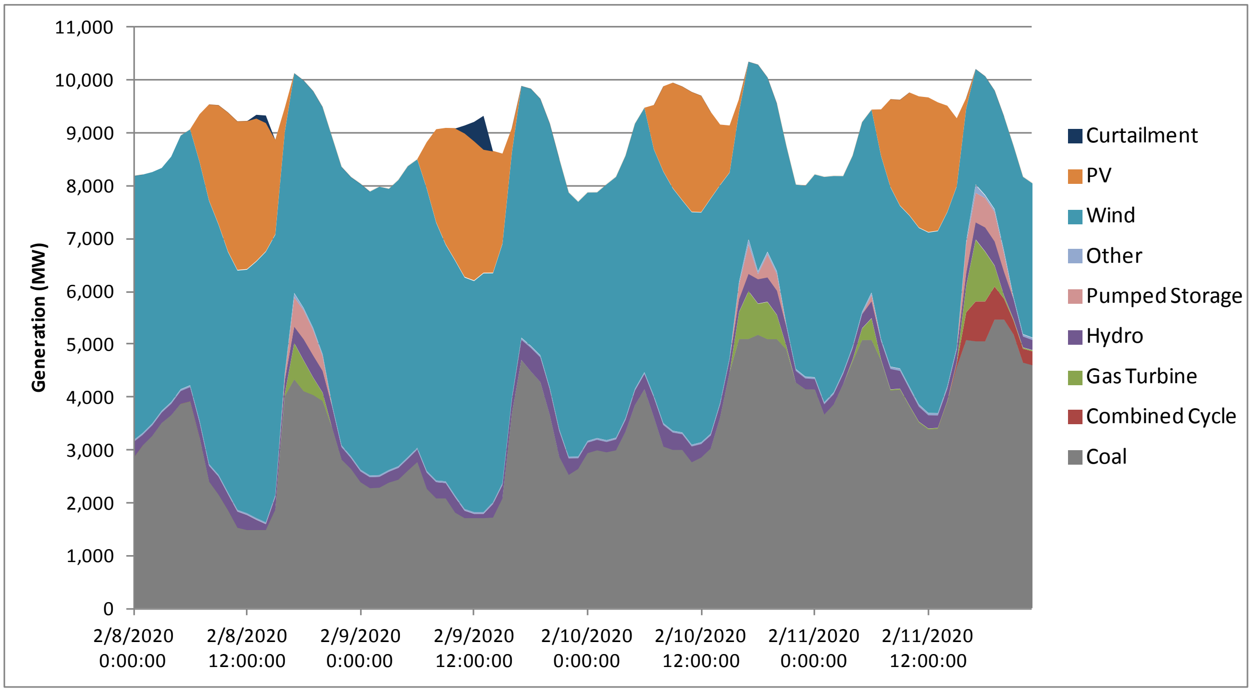

Figure 7. Dispatch stack during the period of February 8–11 in the high RE Case

In any hour of the year, the value of solar or other incremental generation in this system is determined by the marginal generators and associated price. Figure 8 is a price duration curve for the test system showing system marginal cost for the PSCO balancing area. The marginal prices for the WACM balancing area were almost identical because transmission constraints between the PSCO and WACM system were not binding; only very small price differences occurred in a few hours due to different reserve requirements. The price duration curve shows three main "zones" of prices, based on the marginal generators: coal at about \$17–\$20/MWh, combined cycle units at about \$25–\$35/MWh, and combustion turbines at about \$38–\$45/MWh. In the low RE case, coal is on the margin about for about 1,600 hours, while in the high RE case, coal is on the margin for over 5,000 hours. In addition, renewable energy is effectively on the margin for about 100 hours of the year in the high RE case; additional renewable generation during these hours would likely be curtailed and provides no incremental benefit to the system.[17] There are also a small number (less than 40 hours per year) of extremely high prices, set by the reserve violation conditions.

[17] Because this system is isolated from the rest of the Western Interconnection, it does not consider the opportunity for this energy to be exported to neighboring systems.

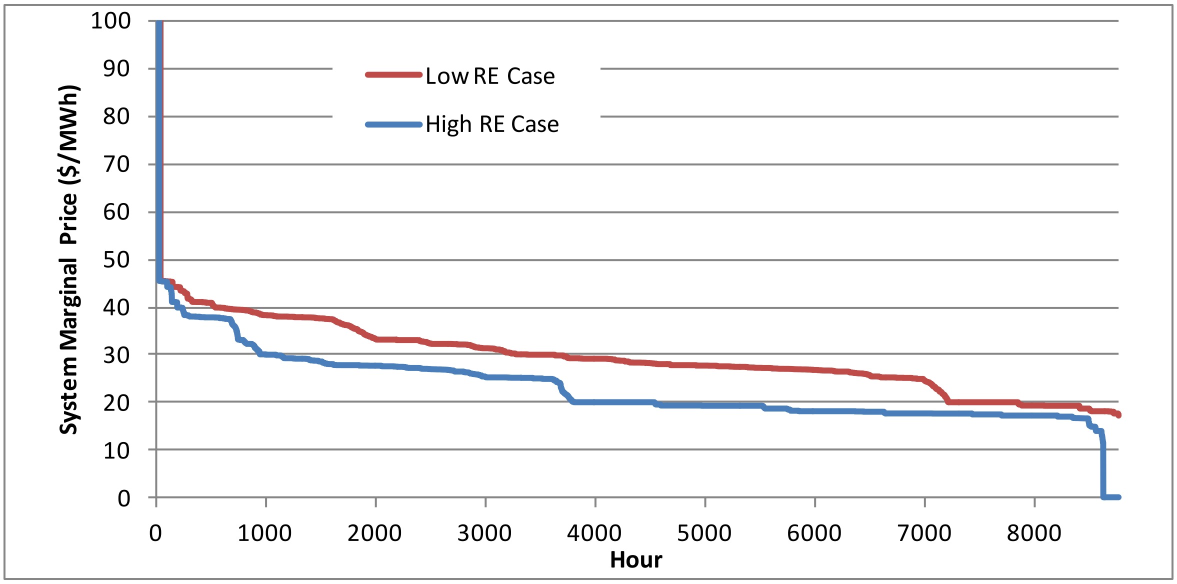

Figure 8. System marginal price duration curve in the PSCO balancing area for the two cases

5 Value of CSP

The value of CSP was determined by adding a relatively small amount of generation to the base system and evaluating the change in production costs and the value of system capacity. We also examined the operation of CSP with TES, including how energy was shifted over time. Several technologies were evaluated; for uniform comparison, each technology provided an approximately equivalent amount of energy, based on the annual production of a 300-MW CSP/TES plant with a solar multiple of 2.0. This is about 1,070 GWh, or enough to provide about 1.4% of the test system demand.[18]

5.1 Solar Scenarios Evaluated

Four main cases were added to the test system, each providing an approximately equal amount of energy.[19]

1. A flat block of zero-cost energy. This provides a point of comparison to examine how the temporal characteristics of solar energy compare to a constant or "baseload" resource. To provide an equal amount of energy, the capacity of this block was set to 123 MW.
2. Solar PV. Discrete-sized 1-axis tracking PV plants generated for the WWSIS project were added in each case until the generation equaled about 1,070 GWh, with a total installed capacity of about 580 MW.[20] The total operating reserve requirement was also increased due to the additional short-term variability.[21]
3. CSP no storage. A single 568-MW plant with a solar multiple of 1.3 was added to the San Luis Valley in southern Colorado. This plant produced 1,130 GWh.
4. CSP with 6 hours of storage. This case adds a 300-MW CSP plant with a solar multiple of 2.0, as discussed previously. The actual amount of energy delivered to the system varied slightly in each scenario based on the amount of energy stored (due to storage losses).

Each of the cases was simulated in both the low and high RE scenarios. Several sensitivity scenarios were considered, as discussed in Section 5.4.

5.2 Operational Value

The operational value of each technology represents its ability to avoid the variable cost of operation. These costs were tracked in three cost categories—operating fuel, variable O&M, and start-up costs. Operating fuel includes all fuel used to operate the power plant fleet while

[18] The potential generation was about 1,100 GWh, but the actual delivered energy was determined by the plant dispatch, considering a net storage loss of 7%.
[19] While each technology produced a slightly different total amount of energy, value of each was calculated on a per megawatt-hour basis as opposed to total system value. This normalization eliminates any effect caused by the small differences in annual generation.
[20] The total amount of capacity added was actually 591 MW in the low RE case and 578 MW in the high RE case. The difference is due to the selection of discrete plants. The slightly different energy production is accounted for by dividing changes in production cost by total solar generation in each scenario.
[21] The additional reserve requirement was about 74 GW-h of additional reserves (51 GW-h of flexibility reserves and 23 GW-h of regulation reserves). This additional reserve requirement should decrease the overall benefits of PV slightly; however the inherent flexibility of generators in the TEPPC database resulted in very little reserve costs. This issue is discussed in more detail in section 5.6.

generating and includes the impact of variable heat rates and operating plants at part load to provide ancillary services. Start-up costs include both the start fuel, as well as additional O&M required during the plant start process. In each case the operational value was calculated by dividing the total avoided generation cost in each cost category by the total potential solar generation.

Table 4 summarizes the results from the production simulations.

Table 4. Operational Value of Simulated Generators

	Marginal Value ($/MWh)							
	Low RE				High RE			
	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)
Fuel	31.7	35.2	33.9	37.7	22.6	21.2	18.7	31.1
Variable O&M	1.2	1.0	1.0	0.8	2.1	2.0	1.9	1.4
Start	0.4	0.4	0.6	3.5	0.5	-0.9	-1.7	3.1
Total	**33.3**	**36.6**	**35.5**	**42.1**	**25.2**	**22.3**	**18.9**	**35.6**

Table 4 demonstrates three significant findings: (1) at low penetration, the value of solar generation technologies is greater than the constant (flat block) resource; (2) the value of all generation decreases as a function of renewable penetration, but the value of non-dispatchable solar resources decreases at a greater rate than the flat block or dispatchable CSP; (3) the value of CSP with storage is higher than solar technologies without storage. The range of values for different generation technologies largely can be explained by understanding the avoided fuel mix in the two different scenarios.

In the test system, the added generators (flat block or solar) reduce the output from a mix of generator types and with different efficiencies, depending on the time of day and season. Figures 9–16 illustrate how the relative value of a renewable generator is affected by the varying marginal generators and the dispatchability of the resource.

Figure 9 illustrates the relationship between price and net load for a 3-day period starting on January 22. The net load is the normal load minus wind and solar PV generation and reflects the load that must be met by other (mostly fossil fueled) generators with non-zero generation cost. The figure illustrates three zones of prices, which are seen earlier in the price duration curves in Figure 8. The lowest price occurs in the overnight periods at the beginning of days 2 and 3 when coal is the marginal generator with total incremental cost of about $20/MWh. During much of the middle of the day, combined cycle units are the marginal generators, with variable costs of about $30–$35/MWh. In several periods in the morning and evening, there is an increase in net demand, where the high ramp rate or the relatively short period of increased demand requires the use of combustion turbines, resulting in a price spike to about $45/MWh. Any renewable generator added to this mix will offset energy within these three price zones but with a value depending on the temporal pattern of its output.

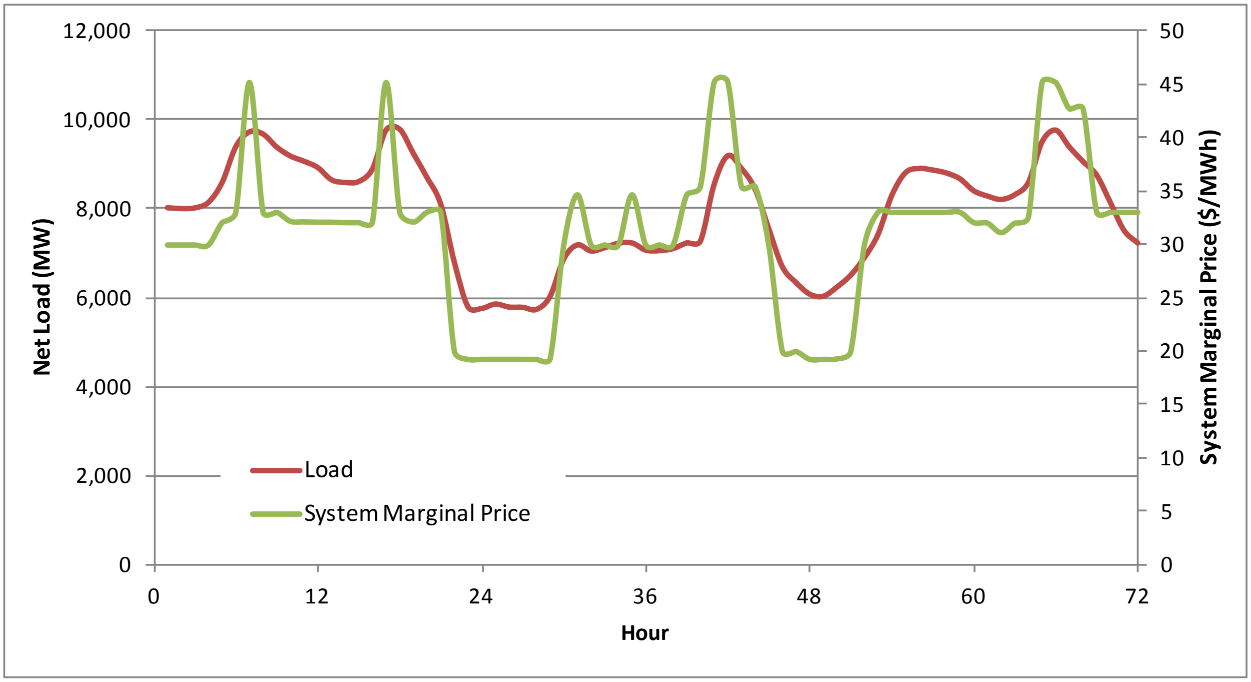

Figure 9. System net load and marginal price for January 22–24 (low RE case)

Figure 10 keeps the marginal price curve but adds the generation profile for CSP with and without storage. The CSP dispatch is isolated from cases where CSP is added.[22] The total generation by these two plants is very similar, but CSP with storage is dispatched during the highest cost periods. In much of the winter, the price of electricity peaks in periods where solar output is low or zero (the morning and evening). This corresponds to when higher-cost gas-fired units are started and ramped to meet peak demand. PV and CSP without storage are unable to generate during this period and typically offset more efficient gas-fired units. Alternatively, CSP with TES is able to shift generation to the evening and carry over energy to start and pick up the morning load ramp that occurs before significant solar energy is available. As a result, CSP avoids the use of higher-cost and lower-efficiency gas-fired units, producing overall higher value to the system.

[22] Figure 10 combines the system marginal prices from the base case dispatch with the CSP results isolated from the two runs with CSP. Because CSP itself affects the entire system dispatch, the actual system marginal prices from the CSP cases are slightly different. Also it should be noted that the simulated dispatch represents a least cost dispatch based on the various generator characteristics and constraints, and does not necessarily represent the dispatch that would occur under wholesale market conditions, which would have additional operating parameters and constraints such as conditions of power purchase agreements.

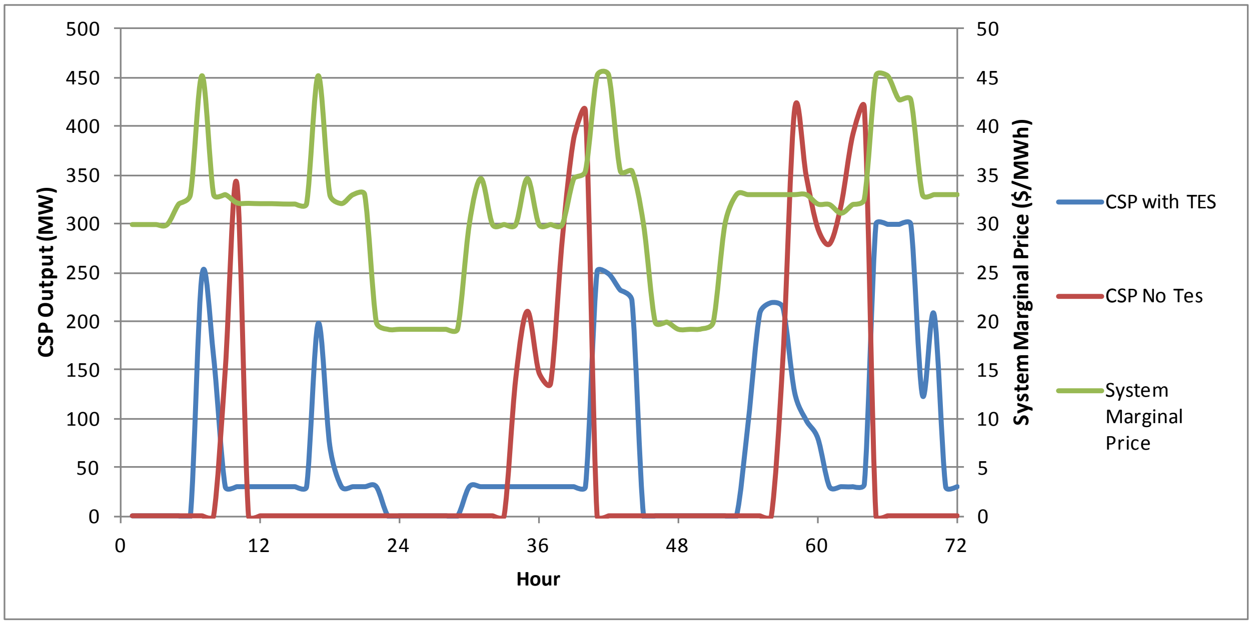

Figure 10. System marginal price and corresponding CSP generation on January 22–24 (low RE case)

During the summer, operation of CSP with storage is more continuous due to higher solar output and a different load and price profile. Figure 11 shows the relationship between net load and system marginal price for a 3-day period starting on July 14.

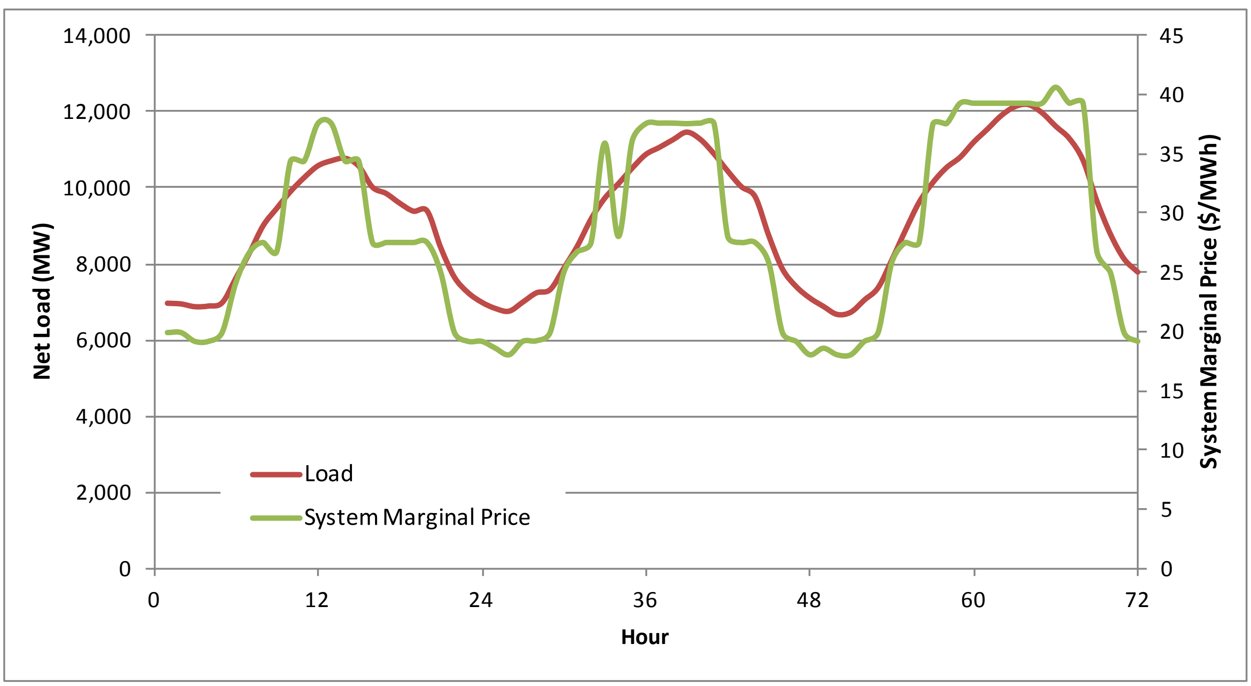

Figure 11. System net load and marginal price for July 14–16 (low RE case)

The corresponding CSP operation is shown in Figure 12. There are several operational issues that affect the overall and relative value of CSP with TES. First, CSP with TES is able to operate more continuously and avoid the impact of cloud cover that reduces output and increases the variability of the plant without TES.[23] Second, CSP is able to start earlier in the day and help pick up the early morning load ramp. Finally, CSP is able to continue operation longer into the late afternoon and early evening. This is particularly important for the plant capacity value discussed in Section 5.3.

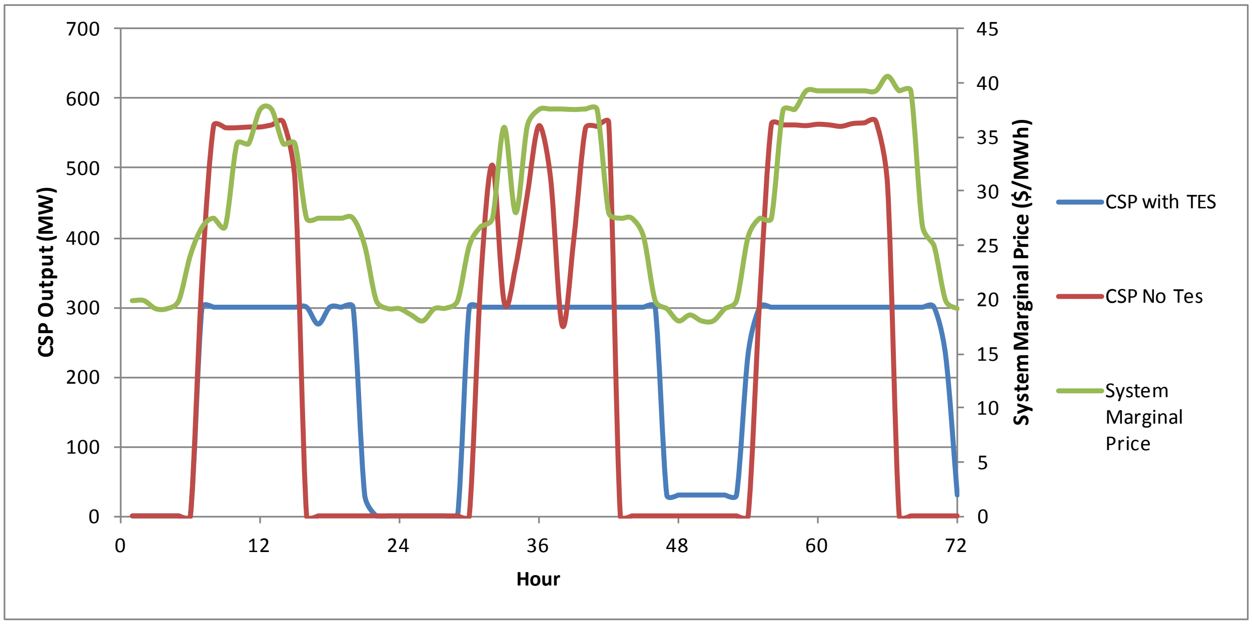

Figure 12. System marginal price and corresponding CSP generation on July 14–16 (low RE case)

Figure 12 shows the impact of the solar multiple, which can provide some disadvantages at low solar penetration. At low penetration of solar, PV and CSP without storage are largely coincident with demand (and relatively high prices) during the summer. As illustrated in Figure 2, whenever the thermal output of the solar field exceeds the power block capacity, energy must be stored, regardless of the system demand for energy or price. As a result, the plant is forced to store this energy and generate at a later time, even if this later time has a lower demand or lower cost of energy. This is shown in Figure 12 on the first and second day, when during some hours, CSP without storage sells more energy at periods of high prices than CSP with TES. CSP with storage is forced to shift some energy to the evening when prices are slightly lower.[24]

The value of solar and dispatchable CSP is strongly dependent on the mix of generator types and amount of renewable energy. As the penetration of renewables increases, the patterns of net demand for electricity change, and different mixes of generation are needed to address the increasing variability and uncertainty of the wind and solar supply. Figure 13 is a duplication of Figure 9, showing price and load during 3 days in January, except for the high RE case. The large amounts of wind and solar PV have suppressed the marginal price, and coal is on the

[23] Note that this only considers hourly operation.
[24] This result is due in large part to the combination of solar multiple and amount of storage. A lower solar multiple and few hours of storage would reduce this effect but would be need to be analyzed on a case-by-case basis.

margin for more hours. The load shape (and price) is also much more volatile, with operation of combustion turbines to address the shorter peaks.

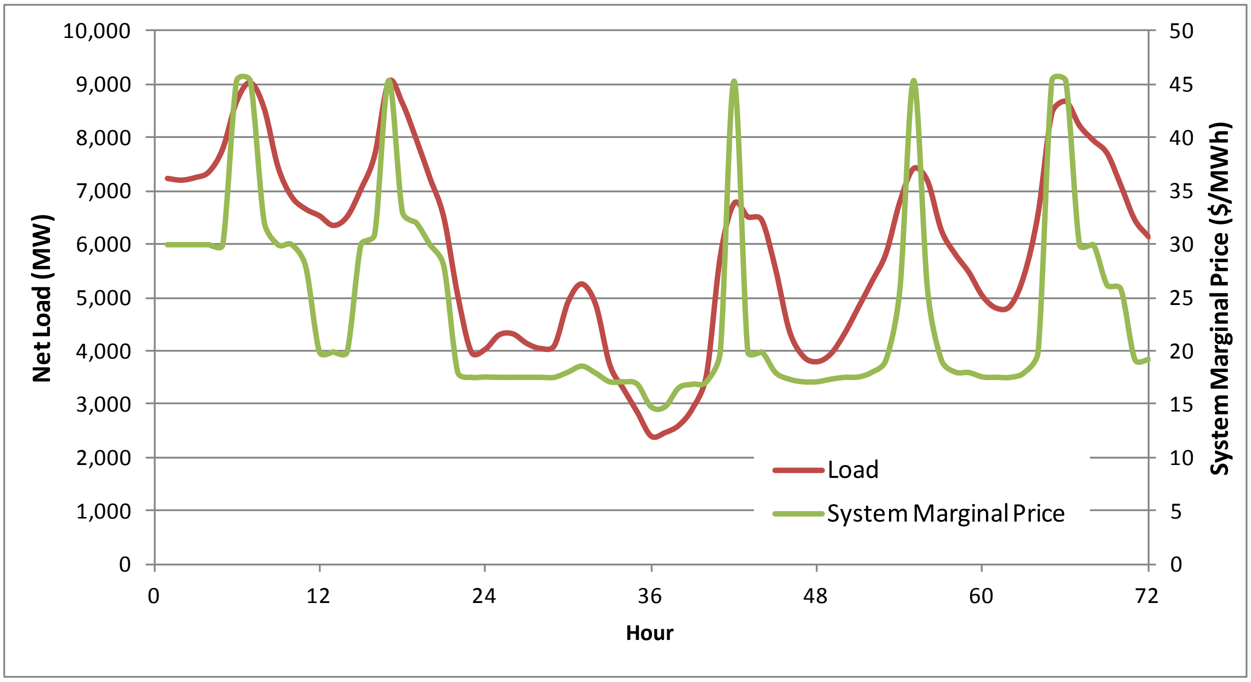

Figure 13. System net load and marginal price for January 22–24 (high RE case)

In the high RE scenario the absolute value of all energy sources drops due to lower system marginal prices. However, the value of variable energy sources drops at a much faster rate than dispatchable sources, as a plant with TES is able to change output to capture the remaining periods of high prices. Figure 14 shows how CSP with TES is able to generate during the hours of highest price during this period in January.

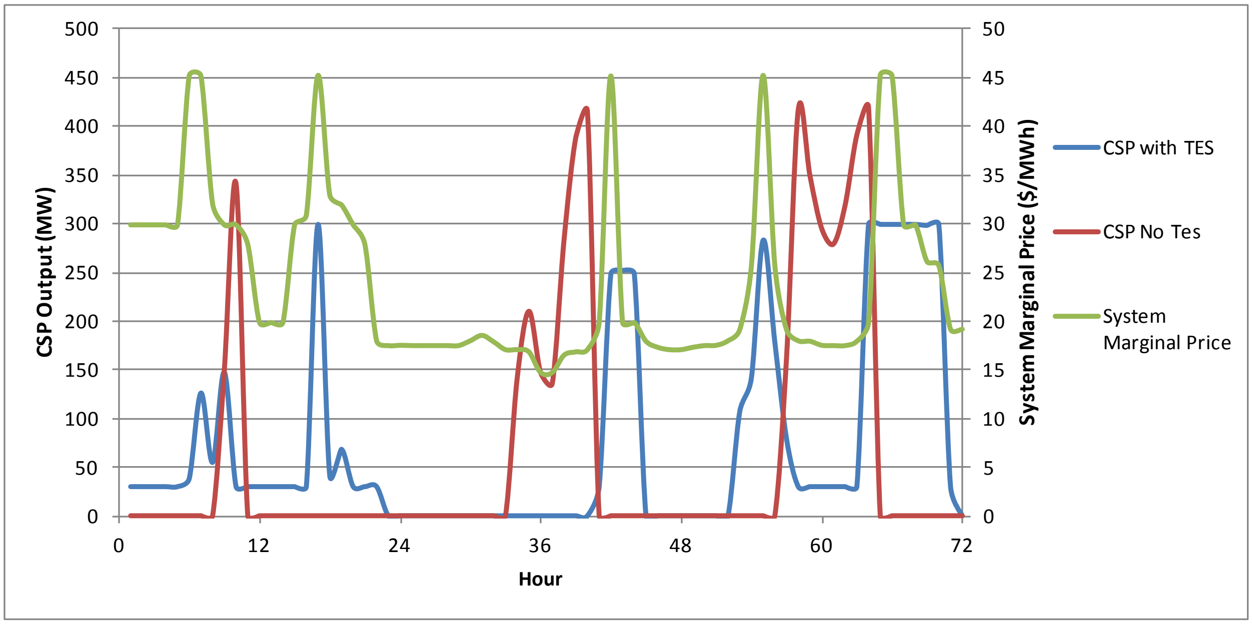

Figure 14. System marginal price and corresponding CSP generation on January 22–24 (high RE case)

Dispatchability becomes increasingly important during periods of very high renewable output to avoid generating during periods of zero value and associated renewable curtailment.[25] Figure 15 shows a period of low net demand due to high solar (and wind) output during the middle of the day. During the first 2 days shown shortly after noon, the net load drops to the point where all thermal generators have reduced output to their minimum. This is the same period as the first 3 days in Figure 8, where during the middle of the day all coal plants in the system cannot reduce output further without incurring a costly shut down. Any additional zero-cost renewable energy generated during these hours cannot be used by the system so have zero value, and the system marginal price is $0/MWh.

[25] In locations with wholesale energy markets, periods of curtailment are often associated with negative prices, driven by wind units bidding negative values to capture the production tax credit and large thermal plants bidding negative to avoid shut down.

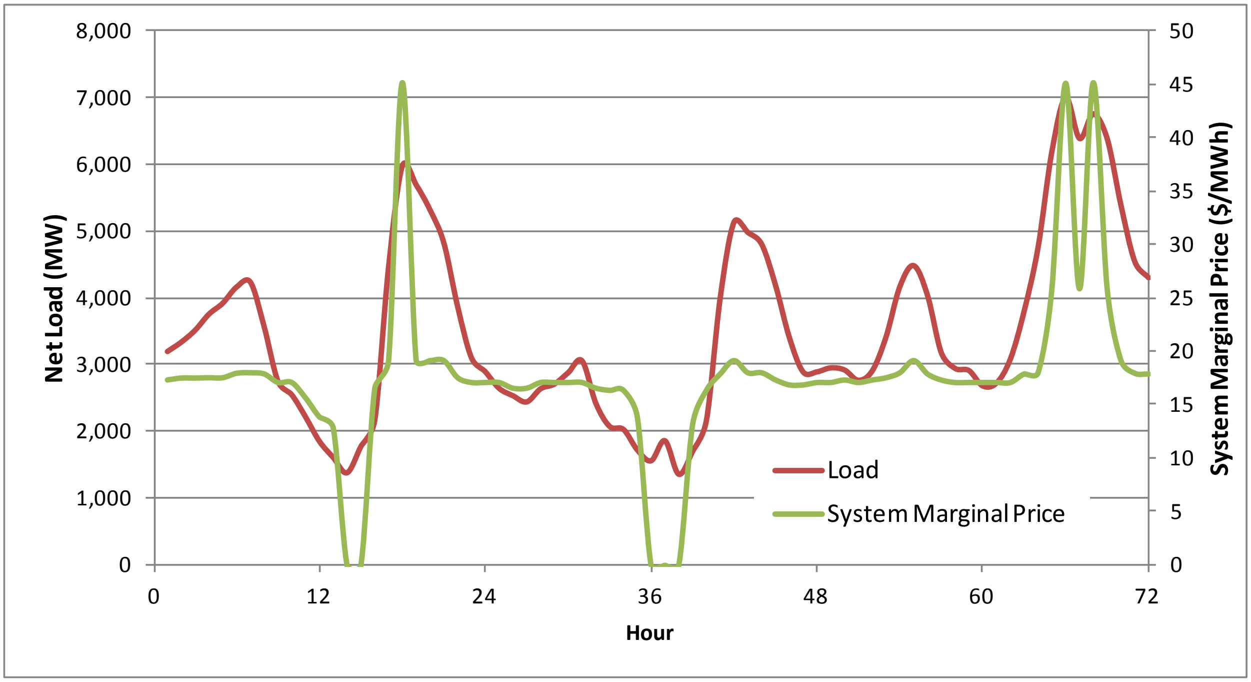

Figure 15. Net load and price for a 3-day period starting February 8

Figure 16 shows the operation of CSP plants in these three days. CSP without storage generates in the middle of the day, producing some output that provides zero incremental value (when the system marginal price is zero). During these periods, CSP with thermal storage generates at low output, or shuts down, avoiding curtailed energy and maximizing value by shifting energy to periods of higher net demand and providing potentially valuable ramping services.[26]

[26] As discussed later, the value of ramping is not quantified in this analysis. While most production cost models can consider the impact of ramping constraints, they do not calculate a cost of plant ramping. WWSIS II will evaluate the cost impact of ramping in high RE scenarios.

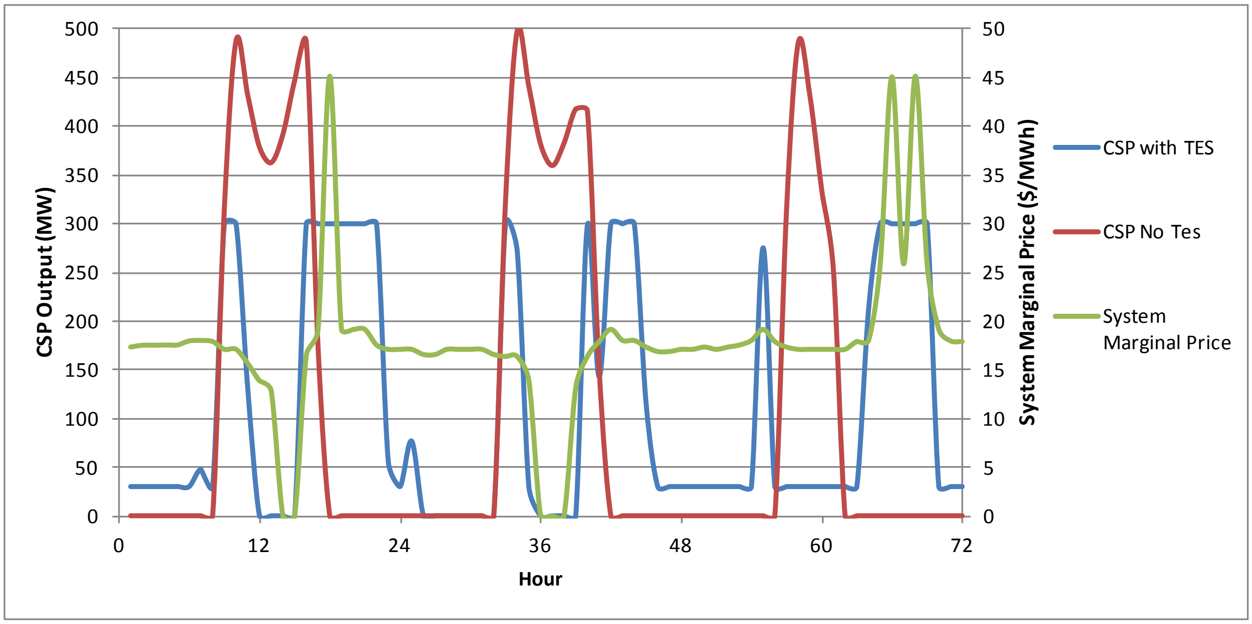

Figure 16. System marginal price and corresponding CSP generation on February 8–10 (high RE case)

The ability to avoid renewable generation during periods of low or zero value will be an increasingly important source of value as renewable penetration increases. In the high RE scenario, about 5% of the additional PV and about 6% of the CSP without storage has zero value and is effectively curtailed.[27] The number of hours of zero value generation (resulting in renewable curtailment) is highly non-linear as a function of renewable penetration and would be expected to increase without additional measures to increase system flexibility (Denholm and Margolis 2007).

The sum of these factors, including the mix of generation, fuel cost, and curtailment can be translated into the source of avoided fuel costs in Table 4. Tables 5 and 6 further explain the source of avoided costs for the different generator types. Table 5 indicates the type of generation avoided by each unit of generation. In the low RE case, each kilowatt-hour of CSP without storage avoids 0.9 kWh of combined cycle generation and 0.1 kWh of combustion turbine generation. In some cases, the smoothing of the load can actually increase the use of some lower-cost generator types; in the low RE case, CSP with storage and PV can improve the system dispatch and increase low-cost coal generation slightly. The flat block results show a greater displacement of coal because it generates at constant output, including at night when coal is often on the margin.[28] Table 5 demonstrates how, in the high RE scenario, much of the gas generation

[27] In reality, PLEXOS assigned most of the incremental curtailment associated with the addition of PV or CSP in the base case to the existing mix of renewable generators, including wind, solar, and hydro (see Table 5). This is because these sources have no variable cost, so there is no difference in production cost regardless of which renewable generator is curtailed. If we assign all the incremental renewable curtailment that occurs with the addition of PV or CSP to the incremental solar generator, we arrive at the 5% PV and 6% CSP (no storage) numbers cited above. This analysis makes no recommendations regarding actual allocation of curtailment. For additional discussion, see Fink et al. (2010).

[28] The fraction of displaced generation from the flat block resource is not exactly equal to the marginal fuel mix shown in Figure 8. This is partially due to the operation of pumped hydro plants.

has been removed by the system, and coal is on the margin for more hours. Both PV and CSP without storage remove similar amounts of combined cycle and coal; however, CSP with storage continues to avoid mostly gas generation due to the dispatchability of the resource.

In some cases, each unit of generation removes more or less than 1 unit of thermal generation. This is due to two factors: pumped storage operation and curtailment. The flat block in the low RE case frees up coal generation to displace more costly gas plant operation via the use of pumped storage. However, because storage incurs losses, this results in a small increase in thermal generation. The opposite occurs in the low RE PV case and the CSP with storage cases. The displacement of higher-cost generation in these cases reduces the economic operation of pumped storage, decreasing storage losses and resulting in more than 1 unit of avoided generation per unit of solar generation. At higher RE penetration, solar without storage displaces less than 1 unit of thermal generation due to curtailment of renewable generators.

Table 5. Avoided Thermal Generation

	Avoided Thermal Generation (kWh/kWh)							
	Low RE Scenario				High RE Scenario			
	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)
Coal	0.09	-0.06	-0.03	-0.08	0.55	0.50	0.52	0.17
Gas Combined Cycle	0.78	0.99	0.91	0.79	0.39	0.50	0.39	0.72
Gas Turbine/Steam	0.10	0.09	0.11	0.27	0.05	-0.02	-0.01	0.11
Total	**0.98**	**1.03**	**1.00**	**1.02**	**0.99**	**0.97**	**0.90**	**1.04**

While Table 5 is a useful illustration of the type of generation avoided, the ultimate cost driver is the type and amount of fuel actually displaced. Table 6 provides the actual avoided operational fuel in each scenario (in MMBTU per MWh of solar generation). Of note is the fact that the avoided fuel rate increases in the high RE scenario. This is due to the displacement of lower cost, higher heat rate coal units compared to more efficient, higher-cost gas generators. The product of the avoided fuel in Table 6 and fuel costs produce the fuel value ($/MWh) in Table 4.

Table 6. Avoided Fuel

	Avoided Fuel (MMBTU/MWh)							
	Low RE Scenario				High RE Scenario			
	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)
Coal	1.1	-0.7	-0.7	-0.9	5.8	5.2	5.4	1.9
Gas	7.4	8.9	8.9	9.7	3.5	3.6	2.9	7.1
Total	**8.5**	**8.2**	**8.2**	**8.8**	**9.3**	**8.8**	**8.3**	**9.0**

An additional important secondary source of value for CSP with TES is the ability to avoid thermal plant starts and associated fuel use and maintenance. Even at low penetration, PV and CSP without storage tends to increase the variability of the net load, increasing the number of plant starts but decreasing the total amount of energy produced by the generation fleet. Table 7 provides the estimated number of avoided starts and percentage reduction. Consistent with the previous tables, a positive number represents actual avoided starts (a net benefit), while a negative number means an increase in starts. This table demonstrates a significant reduction in starts due to the flexible operation of CSP with TES.

Table 7. Avoided Starts

	Avoided Starts (Total/%)							
	Low RE Scenario				High RE Scenario			
	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)
Coal	3/ 0.4%	-1/ -1.1%	-5/ -0.7%	-8/ -1.1%	-16/ -2.2%	4/ 0.6%	-3/ -0.4%	-18/ -2.5%
Combined Cycle	-77/ -6.3%	18/ 1.5%	53/ 4.3%	56/ 4.6%	9/ 1.2%	17/ 2.2%	-56/ -7.2%	129/ 16.5%
Gas Turbine/ Steam	362/ 4.6%	-412/ -5.2%	-271/ -3.4%	1,099/ 13.8%	432/ 4.1%	-640/ -6.1%	-361/ -3.4%	871/ 8.3%

5.3 Capacity Value

The value calculated in Section 5.2 only addresses the variable operational value. Both CSP and PV have the ability to provide system capacity and replace new generation. However, the actual capacity value of solar technologies depends on their coincidence with demand patterns and how this coincidence changes as a function of penetration.

At low penetration, the capacity credit (equal to the fraction of capacity that is available during periods of high net demand) of PV and CSP without TES is relatively high. Figure 17 shows the simulated solar output during three peak demand days in the low RE system, including the system annual peak on July 27 showing high correlation. As a result, each megawatt of PV or CSP without TES reduces the net demand by a significant amount and eliminates the need for conventional generation.

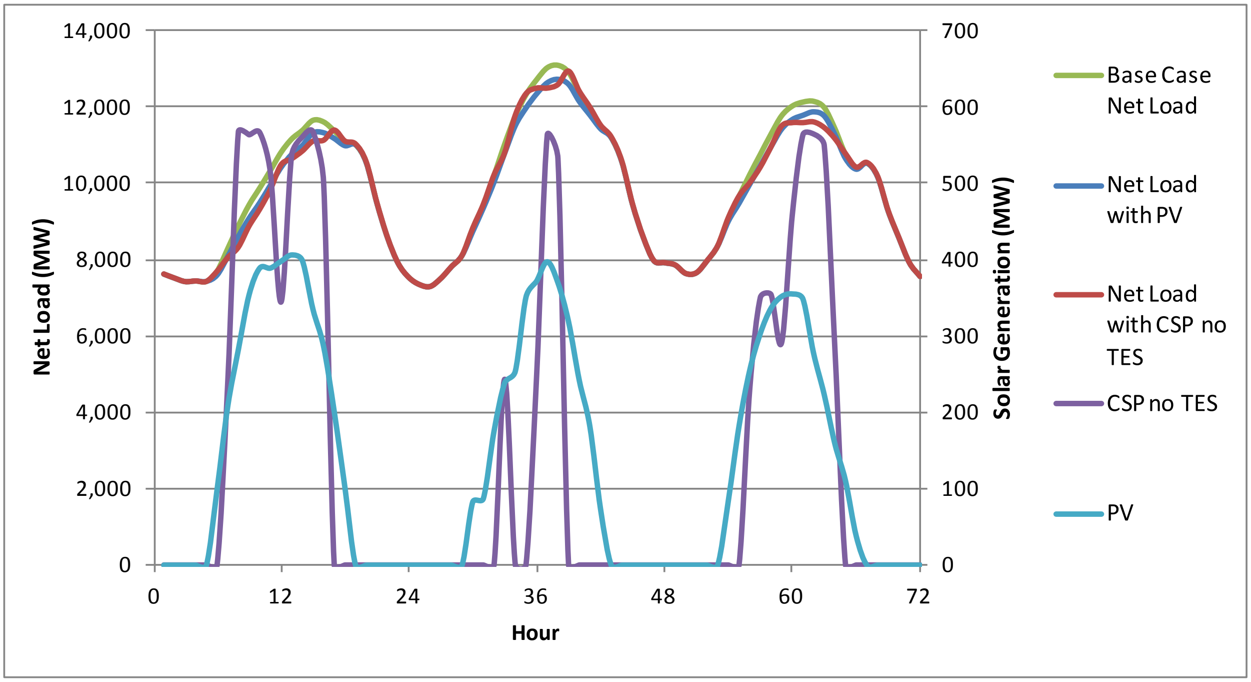

Figure 17. Correlation of demand and solar generation on a 3-day period starting July 26 (low RE case)

As the penetration of PV or CSP without storage increases, the capacity credit drops significantly. Solar energy shifts the peak to later in the day, to periods where solar output is low or zero. In Figure 17, the annual peak demand occurred in the hour ending at 2 p.m. on July 27. (Other peak demand hours are typically an hour or two later.) However, in the high RE case, where solar provides 8% of total demand, the net demand has been shifted to later in the day where solar is no longer highly correlated with load. Figure 18 shows an example of a new period of high peak demand in the high RE case where the net load peaks in the hour ending at 7 p.m. on the first and third day. On these 3 days beginning on July 17, there is still strong solar output, but PV and CSP without storage no longer provide significant amounts of net demand reduction. CSP with storage shifts generation to later in the day and provides a net demand reduction equal to the plant's rated capacity, resulting in a capacity credit of close to 100%. This is shown in detail in Figure 19, which enlarges the net load on July 17 and shows the net demand after removing the generation from the three different solar technologies.

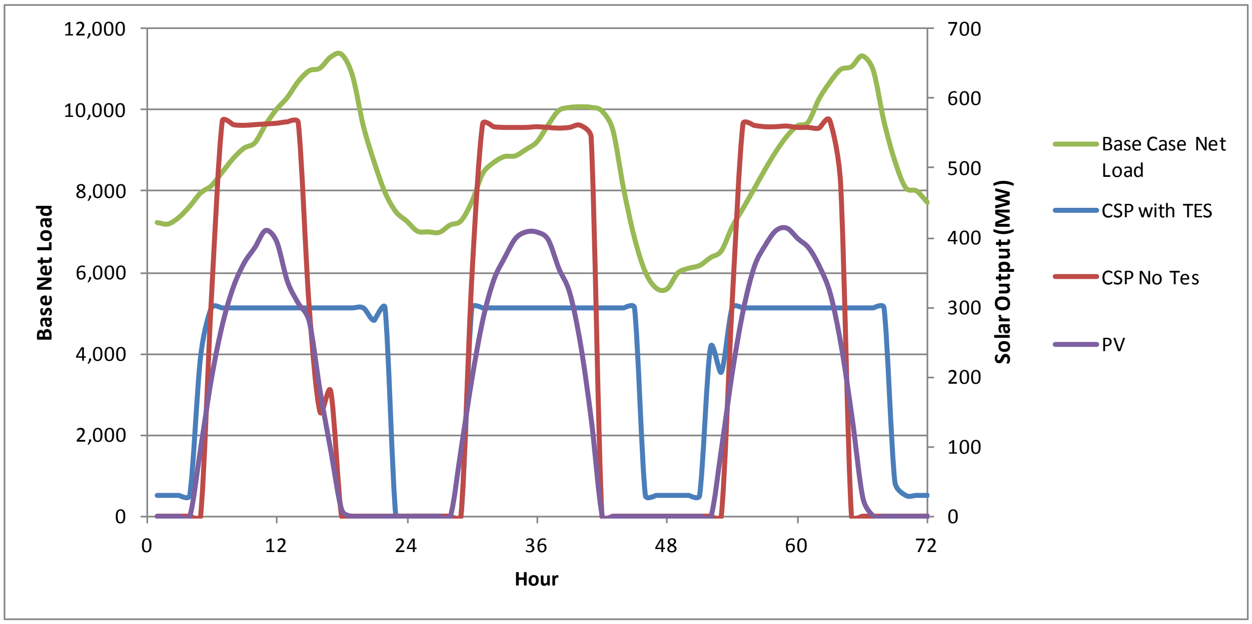

Figure 18. Correlation of demand and solar generation on a 3-day period starting July 17 (high RE case)

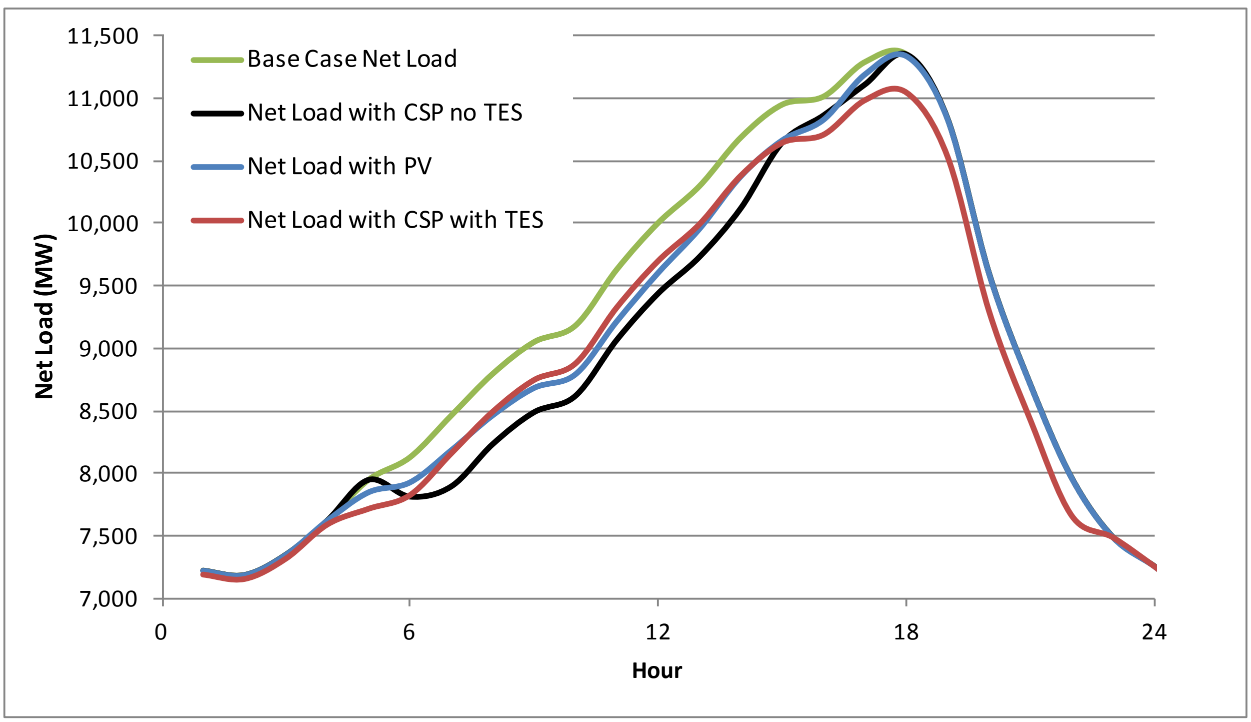

Figure 19. Net demand with different solar generation types on July 17 (high RE case)

Estimation of the monetary value of system capacity begins with an estimate of each plant's capacity credit. There are a number of methods used to estimate the capacity credit of VG sources. We used the simple capacity factor approximation technique, which has been shown to be a reasonable approximation for more computationally complex methods (Madaeni et al. 2012).

Based on 2006 load and solar patterns, in the low RE case, where PV provides about 1% of total demand, each 100 MW (AC rating) of PV or CSP without storage provides about 70–75 MW of system capacity value before taking into account forced outages.[29] This is comparable to a previous estimate of PV in Colorado (Xcel 2009).[30] Adding TES to CSP increases the capacity value substantially.

Table 8 summarizes the capacity value estimates from this analysis. The first row in Table 8 is the capacity credit in terms of fraction of rated capacity. This value assumes an equal outage rate for maintenance across technologies. The second row translates this into an annualized value per installed kilowatt of the corresponding technology by multiplying the capacity credit by the low and high estimated annual value of a reference generator with 100% availability. The low value of the reference generator is $77/kW, based on the estimated annualized cost of a combustion turbine, while the high value is $147/kW, based on the annualized cost of combined cycle generator.[31]

Row 3 of Table 8 translates this value per installed kilowatt into a value per unit of generation. This is calculated by multiplying the value per unit of capacity by the total capacity (to get the total annual value of the installed generator), then dividing this value by the total energy production. This introduces some unusual and somewhat counterintuitive outcomes, resulting largely from the impact of solar multiple and the use of TES, as demonstrated previously by Mills and Wiser (2012). A CSP plant with storage and a PV plant providing equal amounts of energy on an annual basis will have a different installed capacity. In the test system, 300 MW of CSP with a solar multiple of 2.0 and 6 hours of storage provides the same amount of energy as 577 MW of PV capacity. In the low penetration case, CSP provides 294 MW of system capacity at a capacity credit of 98%, while PV at a 70% capacity value provides 404 MW. This means the

[29] Because outages are not considered, the capacity values reported here correspond closer to an "equivalent conventional power" metric where PV and CSP have the same forced outage rate as a conventional generator. If the outage rates are not the same, this could increase or decrease the capacity value metric. For comparison, a forced outage rate in the range of 5%–10% is commonly used for combustion turbines (a typical proxy resource for capacity planning purposes). If the forced outage rate of a CSP plant is the same as a combustion turbine, this means there is no net impact on the relative capacity value for comparison purposes. Alternatively, the outage rate of a PV system is likely lower than that of a conventional thermal generator or CSP plant, therefore adding slightly to its capacity value relative to these technologies.

[30] Our estimate included the turbine overdesign, meaning the peak output of 568 MW exceeds the nameplate rating of 530 MW. This means that during many hours, the capacity value of the plant exceeds 100%. The estimated capacity value based on the nameplate rating is about 70%.

[31] There are significant ranges of the estimated cost of new capacity. The values in this report are derived from PSCO (2011) based on a monthly cost of $6.44 for a combustions turbine and $12.25 for a 1 x 1 combined cycle unit. The high value is less than that used in Mills and Wiser (2012) who used a value of $200/kW-year for the cost of a new combined cycle unit. The range is largely driven by the type of generator that would be effectively replaced by a new solar generator. CSP with TES has a higher overall capacity factor (closer to a mid-merit unit such as combined cycle) and provides relatively high levels of flexibility. CSP without storage or PV replaces units with a much lower capacity factor. A capacity expansion model evaluating different technologies would need to appropriately consider the change in chronological dispatch associated with each generator type for appropriate comparison, similar to the approach taken by Mills and Wiser (2012), who found solar primarily replaces combined cycle units in California.

aggregated PV plant has a higher overall capacity value than the CSP plant, and because both plants produce the same amount of energy, PV produces a higher value of capacity on a per unit of energy basis. This effect disappears in the high RE case where the capacity value of PV and CSP without storage is very low. This issue is illustrated conceptually in Figure 20, where the output of PV and CSP is shown for a single day (July 17). It shows that at the peak hour, a CSP plant without storage has a higher capacity value than the CSP plant with storage. It also shows that this benefit on this particular day is at the very edge of production and again demonstrates the dramatic drop in capacity value of PV and CSP without storage at fairly low penetration.

Table 8. Capacity Value

	Low RE Scenario				High RE Scenario			
	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)	Flat Block	PV	CSP (no TES)	CSP (6-hr TES)
Capacity Credit (%)	100	70	75	98	100	13	3	78
Capacity Value (Low/High) ($/kW)	77/147	54/103	58/110	76/144	77/147	10/19	3/5	60/115
Capacity Value (Low/High) ($/MWh)	8.8/ 16.8	29.7/ 56.6	29.1/ 55.3	21.2/ 40.4	8.8/ 16.8	5.3/ 10.1	1.3/ 2.4	17.1/ 32.6

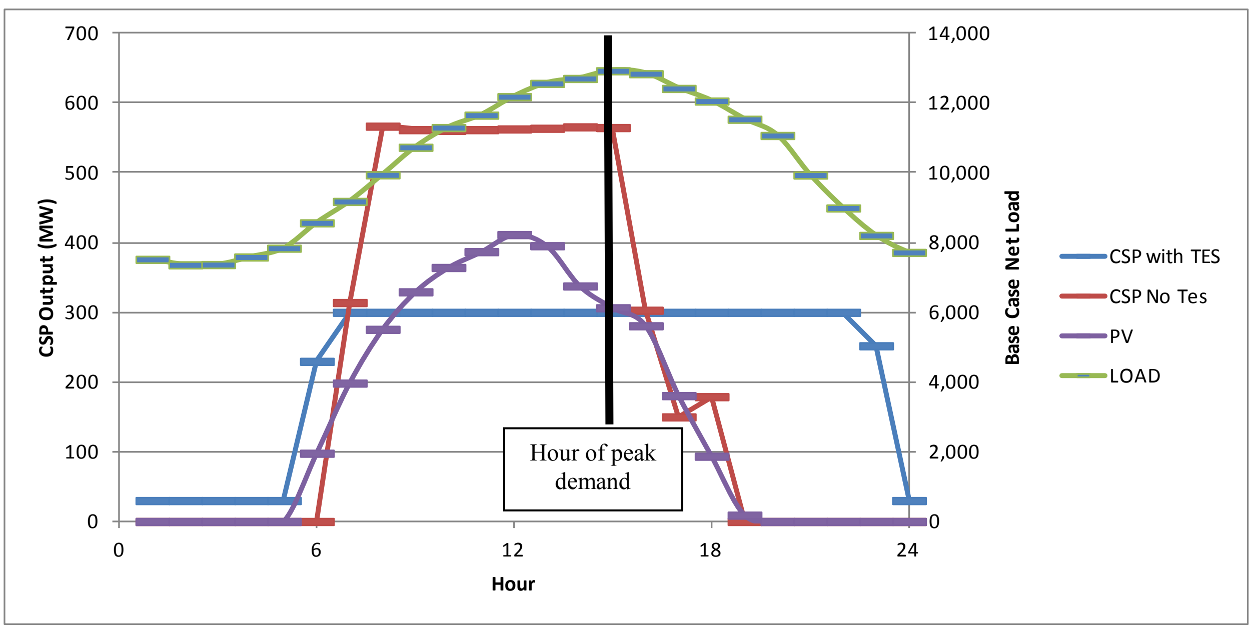

Figure 20. Comparison of solar output on a high-demand day (July 17)

In the high RE scenario, CSP with storage is able to generate at nearly full output during remaining high demand periods in the summer. However, it experiences a reduction in overall capacity value due primarily to limited energy availability during a few hours of relatively high demand in the winter.

5.4 Total Value

The total value of the different generation sources is the sum of the operational value and capacity value. Figure 21 summarizes the values for the different cases by combining the operational value from Table 4 and the capacity value from Table 8.

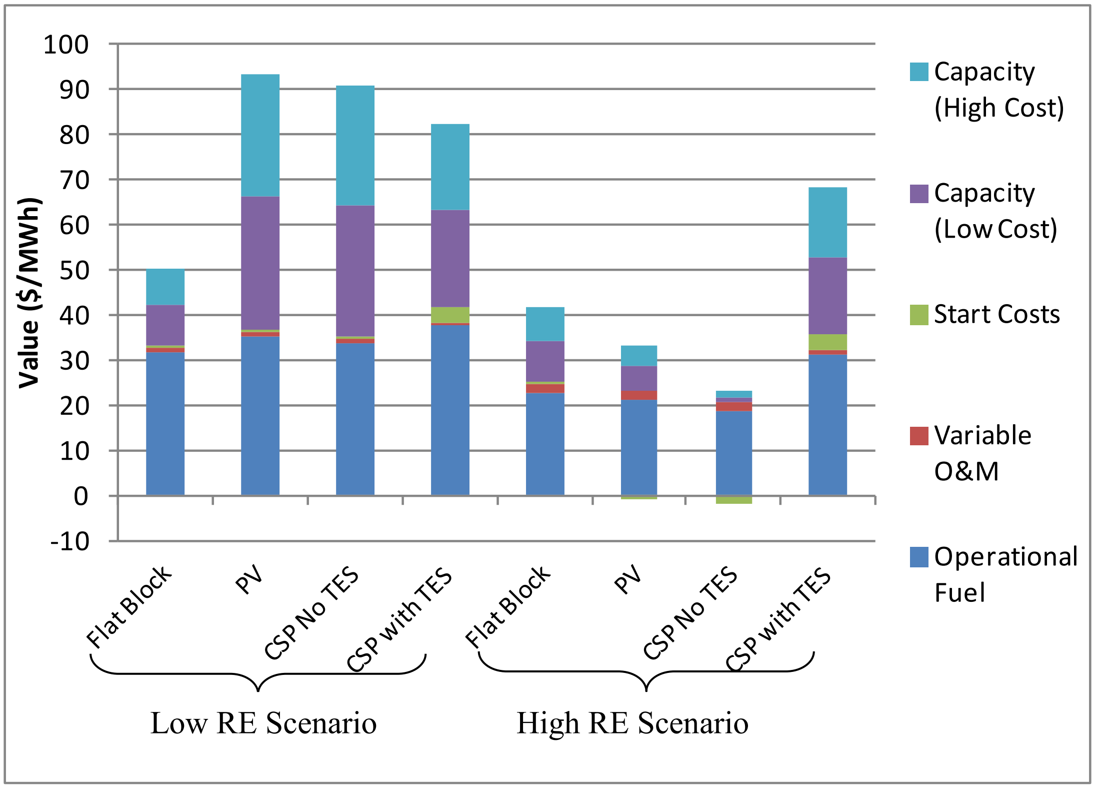

Figure 21. Total value of generation sources in the test system

5.5 Sensitivities and Comparison to Previous Work

5.5.1 Hours of Storage

Additional cases were run with CSP with 8 hours of storage and no changes to the solar multiple. The value of CSP increased slightly, by about $0.9/MWh in the low RE case and about $1.0/MWh in the high RE case. This decrease in marginal value of additional storage for a constant solar multiple or lower has been observed previously (Sioshansi and Denholm 2010.) However, additional analysis is needed to quantify the impact of various amounts of storage and different technology types, particularly under various RE penetration scenarios.

5.5.2 Natural Gas Price

The natural gas price used in the test system ($4.1/MMBTU) is much lower than historical prices. Given the uncertainty over fuel prices and the high level of sensitivity of the results to natural gas prices, we estimated the impact of varying the cost of natural gas. We ran scenarios with generation-weighted natural gas prices equal to $5.9/MMBTU and $7.8/MMBTU. We found that total fuel use is similar in the various cases and the value of avoided fuel is proportional to fuel price. (This relationship would not necessarily hold for lower gas prices, where at some point the dispatch stack of gas and coal generation would be inverted, and the variable cost of coal generation would put a floor on the value of avoided generation.)[32] Additional analysis and discussion of this is provided by Diakov et al. (2012). Figure 22 provides an estimate of the change in the operational value of CSP as a function of natural gas prices for the two RE penetration cases, using a linear fit to the results from the three fuel price scenarios.

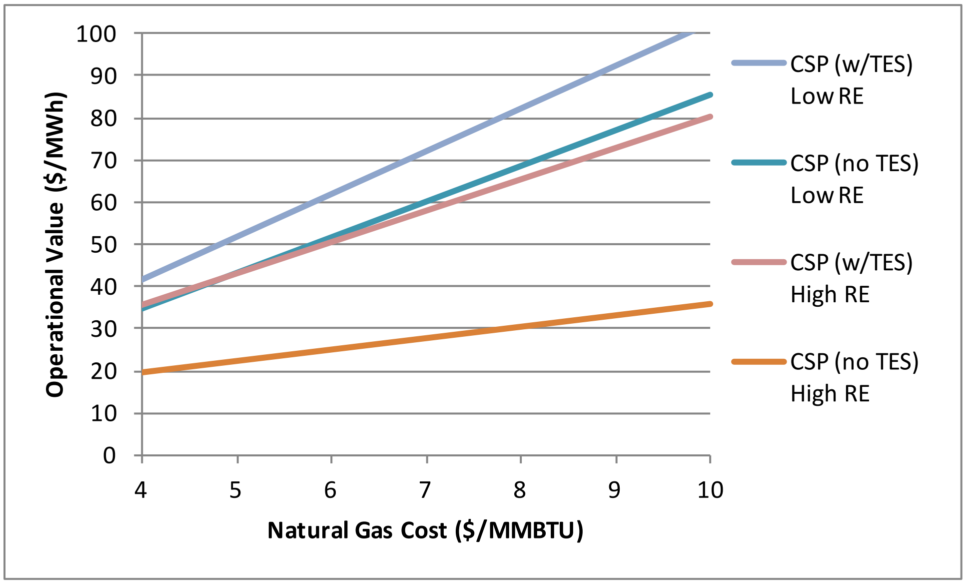

Figure 22. Estimated operational value of CSP as a function of gas prices

5.5.3 Comparison to Previous Estimates

The analysis of CSP in the test system shows much lower operational value for CSP compared to two previous analyses. Table 9 lists the value of CSP with and without storage from two previous studies.

Table 9. Previous Estimates of the Operational Value of CSP With and Without TES

Study Location	CSP Value ($/MWh)		Value Considered	Source[a]
	CSP (no TES)	CSP (with 6-hour TES)		
Arizona	47.0	50.5	Energy Only	1
New Mexico	61.2	66.2	Energy Only	1
California	58.5	67.9	Energy Only	1
Texas	89.4	98.4	Energy (with scarcity)	1
California	53.8 (energy)	56.3 (energy)	Energy + Capacity (Separate)	2

[a]Sources: 1= Sioshansi and Denholm (2010); 2 = Mills and Wiser (2012)

The differences between the test system value and previous analysis result from several factors. For appropriate comparison, the type of market or value must be considered. The first three

[32] This does not include any potential impacts of constraints on carbon or other emissions.

locations in Table 9 are used historic energy-only market prices. These were derived from two regulated markets (Arizona and New Mexico) and a wholesale energy-only market (the California Independent System Operator - CAISO).[33] In these studies, CSP was dispatched against hourly system marginal prices published by the utility or system operator. For the regulated markets, these system marginal prices are calculated in a manner similar to the dispatch model used in this study. For the CAISO market, the data is the system market clearing price calculated by the system operator. The most appropriate comparison in this study is the low RE operational value in Table 4 (equal to $35.5/MWh and $42.1/MWh for plants without and with TES, respectively). These values are lower than results from the previous studies, and the differences can be largely explained by both fuel mix and fuel price. The previous study results used electricity price data from 2005. In 2005, the average delivered price of natural gas to utilities in Colorado was $7.41/MMBTU compared to $4.1/MMBTU in the 2020 test system. Adjusting the value of the test system to this higher-priced gas value using the estimates in Figure 23 produces an approximate CSP operational value of $63/MWh for CSP without storage and $76/MWh for CSP with storage. These values are closer to the previous estimates in Table 9, with the difference likely explained by the fuel mix. The largest difference is between the test system and Arizona, where coal was on the margin for more hours than in the Colorado system where gas is on the margin for almost all hours of CSP generation.[34]

The value for Texas is derived from an energy-only market (the Electric Reliability Council of Texas – ERCOT). However, the CSP value results from the ERCOT case are still higher than can be explained by higher natural gas prices (even after adjusting for the average Texas natural gas price of $8.1/MMBTU in 2005). This difference appears to be driven by scarcity pricing in the ERCOT market. In locations such as ERCOT that do not have capacity markets, high energy prices may be needed to recover capacity costs. These high prices will occur during peak periods where capacity reserves are short. In the ERCOT case, for example, there are over 400 hours where the price of energy exceeded $150/MWh. This means that the values from the ERCOT system represent more than the pure variable cost of CSP benefits. A more appropriate comparison would be to combine the operational value of CSP in the test system (adjusted for the difference in natural gas prices) and the capacity value. However, it is not clear that the scarcity pricing that occurred in ERCOT in 2005 would be sufficient to support new capacity, and ERCOT has changed its rules since 2005 in part to address this issue.[35] As a result, it is difficult to directly compare the Texas results with those from the test system.

The final value in Table 9 is from the Mills and Wiser (2012) analysis in California that used a reduced form dispatch model to estimate both operational and capacity value independently. The analysis used a natural gas price of $6.4/MMBTU. Applying this value to the test system produces an estimated operational value of $55/MWh and $66/MWh for CSP plants without and with TES, respectively, which are closer to the values in the California study. The California study also estimated capacity value—it found somewhat lower capacity credit for CSP plants (particularly with storage), perhaps due to the different load profiles between the two states.

[33] Incentives for new capacity in CAISO are available through the state's resource adequacy program http://www.cpuc.ca.gov/PUC/energy/Procurement/RA/.
[34] For example, in the Arizona load lambda data, coal appears to be on the margin for over 3,000 hours, indicated by a price under $20/MWh.
[35] As an example, the Public Utility Commission of Texas approved an increase in the system-wide offer cap to $4500/MWh in June 2012. http://www.puc.texas.gov/industry/projects/rules/37897/37897adt.pdf

More analysis is needed to understand how the dispatch decisions will affect the operation and associated planning capacity applied to CSP plants with TES.

5.6 Study Limitations and Future Work

This analysis did not perform a complete assessment of the value of CSP with TES. In addition to its limited geographical scope, there are several limitations to the analysis that will be addressed in future studies, including WWSIS II. A primary limitation is related to sub-hourly operation and ramp rates due to both variability and uncertainty. The simulations were performed at an hourly level and did not consider additional ramping that would result at higher time resolution due to solar variability. Furthermore, while flexibility reserves were held to account for solar forecast error, these reserves were not dispatched. This would further increase generator ramp requirements. Finally, the high ramp rates that are observed in these hourly simulations impose no additional cost penalty. WWSIS II will include 5-minute dispatch and the impact of ramping costs. These simulations should aid in identifying cost impacts on conventional generators and possible mitigation through the use of CSP with TES.

This study also did not perform a detailed assessment of the ability of CSP to provide ancillary services, including regulation, flexibility, or spinning contingency reserve. In conventional power systems, these services incur a cost due to two factors. The first is the additional O&M and other operational costs associated with additional cycling and other plant operations required to provide ancillary services. The second is the "opportunity cost" associated with holding plants at part load compared to operating at full output. We did not have sufficient data on the operational cost of CSP plants in providing ancillary services and how these costs compare to other generators to evaluate them in this study.[36] We did perform simulations in an attempt to calculate any reduction in production cost when providing ancillary services from CSP, and found the reduction in total system cost to be extremely small. However, the modeled system has very low costs in general for provision of ancillary services due to the assumed flexibility of many generator types in the database.[37] Additional analysis will be required to further isolate benefits of CSP providing ancillary services.[38]

Finally, this analysis considered a single CSP technology type: wet-cooled trough-type plants with a limited range of storage capacities. Further analysis is needed to evaluate the impact of multiple CSP technology types under a range of renewable penetration scenarios.

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[36] As a result of this lack of data, no plant-level costs were assigned to generators for provision of ancillary services. This assumption will slightly overestimate the value of non-dispatchable solar resources because they will create an additional cost in ancillary service procurement not captured in the model. T

[37] The TEPPC database allows for most gas-fired generators to provide ancillary services over their entire operating range, and the pumped storage units provide operating reserves over virtually their entire capacity. This results in extremely low ancillary service prices and virtually eliminates the opportunity for CSP plants to provide ancillary services and reduce overall system production costs.

[38] Previous analysis demonstrated significant revenue opportunities for CSP in reserve markets (Sioshansi and Denholm 2010). However, this previous analysis did not consider the cost of providing reserves from CSP, and as a "price-taker" simulation it did not perform a system-wide co-optimization of energy and ancillary services, potentially overstating the dispatch of CSP in providing ancillary services. Additional discussion of CSP providing ancillary services is provided by Usaola (2012).

6 Conclusions

Implementation of CSP with TES in commercial production simulation and planning tools is an important component of valuing this technology. This study evaluated the operation of CSP with TES in two scenarios of renewable penetration in a test system based on two balancing areas in Colorado and Wyoming. Overall, we found that the simulated CSP plants were dispatched to avoid the highest-cost generation, generally shifting energy production to the morning and evening in non-summer months and shifting energy towards the end of the day in summer months. This minimized the overall system production cost by reducing use of the least-efficient gas generators or preferentially displacing combined cycle generation over coal generation. The system also dispatches CSP during the periods of highest net load, resulting in a very high capacity value.

Overall, the addition of TES to CSP increases its value; however, the difference in value between plants with and without storage is highly dependent on both the cost of natural gas and the penetration of other renewable sources, such as PV. At low penetration of renewables, the inherent coincidence of solar and price patterns means that CSP without storage (and PV) has relatively high value. Combined with a relatively low gas price of $4.1/MMBTU used in this study results in an incremental operational value of TES of about $6.6/MWh over a plant without TES (at low RE penetration). At higher RE penetration, this difference increases as the value of mid-day generation is reduced—in the high RE test system this difference in operational value grew to $16.7/MWh. In addition, the capacity value of CSP systems with TES remains high, further increasing the difference in value associated with TES.

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