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Modelling Concentrating Solar Power with Thermal Energy Storage for Integration Studies

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Modelling Concentrating Solar Power with Thermal Energy Storage for Integration Studies

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***Abstract*—Concentrating solar power with thermal energy storage (CSP-TES) can provide multiple benefits to the grid, including low marginal cost energy and the ability to levelize load, provide operating reserves, and provide firm capacity. It is challenging to properly value the integration of CSP because of 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. To optimize the use of this limited energy, CSP-TES must be implemented in a production cost model with multiple decision variables for the operation of the CSP-TES plant. We develop and implement a CSP-TES plant in a production cost model that accurately characterizes the three main components of the plant: solar field, storage tank, and power block. We show the effect of various modelling simplifications on the value of CSP, including: scheduled versus optimized dispatch from the storage tank and energy-only operation versus co-optimization with ancillary services.**

Keywords–concentrating solar power; thermal energy storage; production cost model; optimization

I. INTRODUCTION

Concentrating solar power with thermal energy storage (CSP-TES) can provide multiple benefits to the electric grid, including low marginal cost energy and the ability to levelize load, provide ancillary services, and provide firm capacity [1]. Variable generation integration studies use a variety of traditional utility planning tools to evaluate the costs, benefits, and operation strategies of high penetration solar and wind energy [2]. Production cost models (PCMs), which simulate the operation of grid, are often used to estimate the operational value of different generation mixes. PCMs are also used to evaluate aspects of system reliability and operation and estimate fuel costs and emissions. PCMs have the primary objective function of committing and dispatching the generator fleet to minimize the total cost of energy production, while maintaining adequate operating reserves to meet contingency events and regulation requirements.

CSP-TES has historically had limited analysis in commercial PCMs. CSP-TES is an energy-limited, dispatchable source of renewable electricity generation. This makes it challenging to quantify the value of CSP-TES and provide comparisons to alternative generation sources. Some simplifications include optimizing CSP-TES outside of a production cost model using a price-taker model [3] or reducing the complexity (number of decision variables) of the commitment and dispatch [4]. Several studies have examined CSP in greater detail using PLEXOS [5,6]. This paper demonstrates the operational and production cost differences between pre-scheduled, optimized, and co-optimized dispatch of CSP-TES. We discuss the implementation of a concentrating solar power plant in a PCM in Section II and the performance and relative value of CSP-TES under different modelling conditions in Section III.

II. CONCENTRATING SOLAR POWER MODEL

A. Concentrating Solar Power With Thermal Energy Storage

A CSP plant with TES consists of three independent, but interrelated, components that can be sized differently: the solar field, which produces thermal energy from solar radiation; the thermal storage tank; and the power block, which converts thermal energy into electricity. These components are shown in Fig. 1. The plant modelled in this simulation is a parabolic trough system, which collects the sun's energy using curved mirrors that focus sunlight on receiver tubes that run the length of the solar field. The reflected sunlight heats a fluid flowing through the receiver tubes. This heat transfer fluid is passed through a steam generator, producing steam for use in a conventional steam-turbine generator.

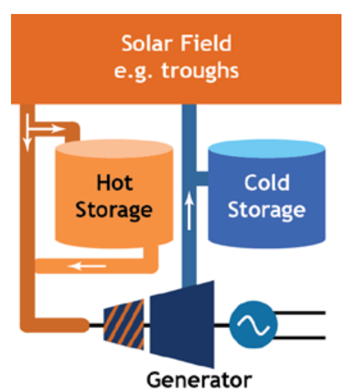

Figure 1. Components of a concentrating solar power with thermal energy storage power plant.

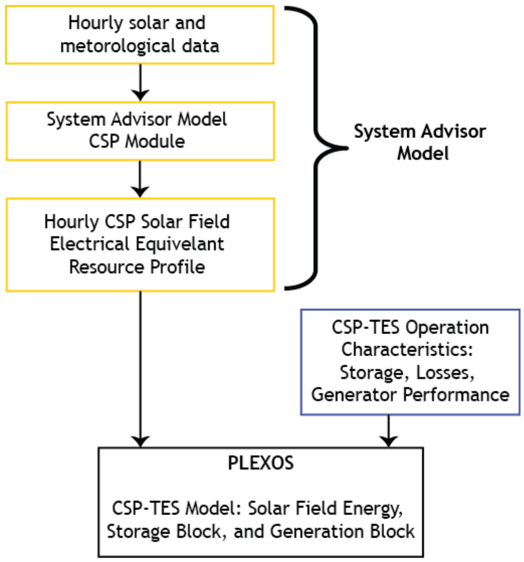

Figure 2. Implementation of CSP-TES in PLEXOS: convert direct normal irradiance to electrical equivalent energy from solar field, specify operational characteristics, and optimize CSP storage and generation in PLEXOS.

Fig. 2 shows how the solar irradiance is converted into electrical energy and implemented in PLEXOS. First, an hourly flow of solar-generated electric energy is produced using the System Advisor Model (SAM) version 2013-1-15 [7]. This occurs outside the production cost model. The CSP simulations used the dry-cooled physical trough model with hourly inputs for direct normal irradiance, dry-bulb temperature, wet-bulb temperature, pressure, relative humidity, and dew point [8]. The model converts hourly irradiance and meteorological data into thermal energy and then models the flow of thermal energy through the various system components, finally converting the thermal energy into net electrical generation output. Irradiance and psychometric data were derived from the National Solar Radiation Database (NSRDB) [9,10].

The "electrical equivalent" thermal energy generated by SAM is an input to PLEXOS as the limited energy available for either generation or storage. The modelled dispatch of CSP energy in PLEXOS is based on the hydro generation module, modified to incorporate the thermal losses and startup costs specific to CSP. In each hour, PLEXOS can directly generate electricity from the solar field energy, store solar field energy, draw energy from storage, or a combination. The ability to store energy is limited by the capacity of the storage tank, measured here in terms of hours of rated plant output that can be stored. The simulations in this paper assume 6 hours of storage. In addition to the hours of storage, a key parameter in the CSP simulation is the solar multiple (SM), which is a measure of the relative size of the solar field and power block and is an important factor in determining a plant's capacity factor and effective use of solar radiation. [1] The SM in PLEXOS was established by scaling the power block to some fraction of the maximum output of the solar field. This simulations in this paper use an SM of 2.2.

B. *CSP-TES Operation Parameters: Losses, Flexibility, Operating Reserve Provision*

The modelled power block includes the essential parameters of the CSP power block, including start-up energy, minimum generation level, limited ramp rate, minimum up/down times, and maximum starts per day. Jorgenson et al. (2013) thoroughly explores the thermal losses and operating properties of CSP-TES that are summarized here [11]. TABLE I contains the power block properties for two operating paradigms: low and high operational flexibility. Operational flexibility is not well established, and thus a range enables an analysis of its impact. Analysis of gas-fired steam generators in the Western Electricity Coordinating Council (WECC) Transmission Expansion Policy Planning Committee (TEPPC) database guided the range of the property values (see [11] and [12]).

TABLE I. CSP-TES PROPERTIES WITH HIGH AND LOW OPERATION FLEXIBILITY FOR THE 300 MW (MAXIMUM CAPACITY OF THE POWER BLOCK) SIMULATED

Operation Property	**Low Flex**	**High Flex**
Minimum generation Point	75 MW	45 MW
Ramp rate	12 MW/min	30 MW/min
Minimum up/down time	6 hours	1 hour
Number of starts per day	1	Unconstrained
Start-up energy	180 MWh	60 MWh
Start-up cost	$30,000	$3,000
Variable O&M	$3/MWh	$1.1/MWh

The model considers start-up losses in the dispatch decision by assuming that a certain amount of energy is lost in the start-up process. Start-up losses are calculated relative to the amount of energy the power block could produce in one hour. For instance, if the power block requires 20% start-up energy, that is equal to 20 MWh per 100 MW of plant capacity [3]. 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.

C. *Power System and CSP-TES Scenarios*

To evaluate the impact of different modelling approaches to CSP-TES on an electric power system, we developed a test case composed of two balancing areas largely in the State of Colorado, USA. The test system is described extensively in [5,13,14]. The Colorado test system consists of two balancing

[1] The SM normalizes the size of the solar field in terms of the power-block size. A solar field with an SM 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). The collector area of a solar field with a higher or lower SM will be scaled based on the solar field with a multiple of one (i.e., a field with an SM of 2.0 will cover roughly twice the collector area of a field with an SM of 1.0).

areas (Public Service of Colorado (PSCO) and Western Area Colorado Missouri [WACM]) using data derived from the TEPPC model and other publicly available datasets. Transmission is modelled zonally, without transmission limits within each balancing authority area. Projected generation and loads were derived from the TEPPC 2020 scenario [12]. Hourly load, wind, and solar profiles were based on 2006 data and scaled to match the projected TEPPC 2020 annual load. The system peaks in the summer with a 2020 coincident peak demand of 13.7 GW and annual demand of 79.0 TWh. A total of 201 thermal and hydro generators are included in the test system, with total capacities listed in Table 2. We adjusted the conventional generator mix to ensure the available capacity (after outages) was always at least 9% greater than demand by adding a total of 1,450 MW (690 MW of combustion turbines and 760 MW of combined cycle (CC) units). This adjustment was necessary, in part because the simulated system does not include contracted capacity from surrounding regions, nor any capacity contribution from solar and wind resources. The base case of the test system assumes a wind and PV penetration of 16% on an energy basis. For comparison, Colorado received about 11% of its electricity from wind in 2012 [15]. Discrete wind and solar plants were added from the WWSIS datasets until the installed capacity produced the targeted energy penetration.[2]

TABLE II.TEST SYSTEM GENERATOR CAPACITY IN 2020

Generator Class	System Capacity [MW]
Coal	6,178
Combined cycle (CC)	3,724
Gas turbine/gas steam	4,045
Hydro	773
Pumped storage	560
Wind	3,347 (10.7 TWh)
Solar PV	878 (1.8 TWh)
Solar CSP[a]	300
Other[b]	513
Total	15,793

[a] CSP with thermal energy storage (6 hours) is not present in the base case.
[b] Includes oil- and gas-fired internal combustion generators and demand response.

Fuel prices were derived from the TEPPC 2020 database. Coal prices were $1.42/MMBtu for all plants. Natural gas prices varied by month and range from $3.90/MMBtu to $4.20/MMBtu, with an average of $4.10/MMBtu. No constraints or costs were applied to carbon or other emissions.

We generated hourly requirements for contingency, regulation, and flexibility reserves. Contingency reserves are based on the single largest unit (a 810-MW coal plant), and allocated with 451 MW to PSCO and 359 MW to WACM, with 50% met by spinning units. Regulation and flexibility reserve[3] requirements vary over time based on the statistical variability of load, wind, and PV, with the methodology described in detail by Ibanez et al. [16]. The technical report by Hummon et al. describes the application of the methodology to the test system [14].

An additional cost was assigned to plants providing regulation, associated with additional wear and tear and heat rate degradation associated with non-steady-state operation. This is functionally equivalent to a generator regulation "bid cost" in restructured markets, discussed in PJM Manual 15: Cost Development Guidelines [17]. The assumed regulation costs, by unit type, are provided in TABLE III.

TABLE III. REGULATION BID COSTS BY GENERATOR TYPE FOR THE COLORADO TEST SYSTEM.

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

There is no CSP in the base case of the Colorado test system. Six CSP-TES scenarios are compared to the base case. There are three CSP plant optimization scenarios (pre-scheduled dispatch, system-optimized dispatch, and co-optimized dispatch and operating reserve provision) and two sets of operating properties (high and low flexibility, see TABLE I), for six total scenarios. In each scenario, the maximum capacity of the CSP power block is 300 MW, the solar field is sized to have an SM of 2.2, and the storage block is 6 hours (1.8 GWh). They differ slightly in total energy delivered to the grid due to losses and operation strategy of the CSP-TES plant, 0.4% and 5.0% amongst the high and low flexible operation groups, respectively.

The pre-scheduled dispatch profiles are generated outside of PLEXOS using a simple dispatch routine written in Matlab. The pre-scheduled dispatch honors the high and low flexibility properties, including minimum generation point, start-up energy, minimum up/down times, and maximum number of starts per day. It is not pre-scheduled against load but assumes that the CSP-TES operates at full output until there is insufficient energy from the solar field or storage tank. This may decrease the pre-scheduled value during winter months when the Colorado test system has a double demand peak in the morning and evening.

[2] The sites were chosen based on capacity factor and do not necessarily reflect existing or planned locations for wind and solar plants.

[3] For these services, only the "upward" reserve requirements were evaluated. The need for downward reserves becomes of greater importance at high renewable penetration when conventional thermal generators are operated at or near their minimum generation points for more hours of the year. Future work will evaluate the cost and price of separate up and down reserve products in these scenarios.

System-optimized dispatch scenarios allow PLEXOS to optimize the storage and release of the "electrical equivalent" thermal energy for dispatch (see Section IIA and IIB). The third optimization scenario uses the same system-optimized CSP-TES model and includes co-optimization of the CSP-TES capacity for energy and reserves. Reserve provision requires that the CSP-TES power block be operating at or above the minimum generation point. The total reserves provisioned and energy dispatched from CSP-TES is limited by the total capacity of the plant as well as the mutual exclusivity of the ramp rate (e.g., if the generator is ramping at full ramp rate for energy, then there is no ramp available for reserve provision).

The PLEXOS simulations performed in this analysis used day-ahead scheduling with a 48-hour optimization window, rolling forward in 24-hour increments. The extra 24 hours in the unit commitment horizon (for a full 48-hour window) were necessary to properly commit the generators with high start-up costs and the dispatch of energy storage, including CSP-TES. All scenarios were run for one chronological year using PLEXOS version 6.207 R08, using the Xpress-MP 23.01.05 solver, with the model performance relative gap set to 0.5%.

III. Results

A. Performance of CSP-TES

The simulation of the three CSP optimization scenarios results in differing daily dispatch of CSP-TES for a common set of flexible operation properties. Fig. 3a and Fig. 3b demonstrate the hourly CSP-TES energy from the solar field (high flex operation) and three optimization scenarios for three days in May and October, respectively. The solar field energy is greater than the maximum capacity of the CSP-TES power block (300 MW) during peak solar hours. The "extra" energy from the solar field is stored, to be dispatched later. The pre-scheduled dispatch keeps the power block at full capacity until the thermal storage is depleted. Optimally dispatched CSP differs from the pre-scheduled dispatch. For example, on October 20 and 21 during the midday, generation from the CSP power block is reduced and excess solar field energy stored; then, in early evening, the power block resumes full output at 300 MW.

Fig. 3c shows the annual daily average performance of CSP-TES. The simulation of optimally dispatched CSP-TES peaks between 6:00 pm and 9:00 pm, while the pre-scheduled dispatch declines steadily during those hours. Overnight, co-optimized CSP-TES operates near minimum generation instead of shutting down in order to provide reserves. Fig. 3c also demonstrates that the optimally scheduled CSP generation closely follows the marginal price of energy.

B. Production Cost Savings

To understand the impact of CSP-TES optimization and flexible operation, we compare the total production cost of each scenario with the base case. The total production cost savings from adding co-optimized CSP-TES ranges from 2% to 3% of the base case total production cost ($1,210 million), depending on the flexibility of the operation of the CSP power block. Fig. 4 shows the distribution of production cost savings by the services CSP-TES provides to the grid, for the low and high flexibility operation properties. Low marginal cost energy accounts for ~75% of the total production cost savings of the co-optimized CSP-TES unit. Enabling the model to optimize the dispatch of the solar field energy increases the total production cost savings by 20% and accounts for ~15% of the total production cost savings of the co-optimized CSP-TES unit. This is calculated by finding the incremental total production savings from the pre-scheduled scenario to the optimal dispatch scenario. Reserve provision from CSP accounts for ~10% of the total production cost savings for the co-optimized CSP-TES unit. Again, this is calculated by finding the incremental increase in production savings between the optimal and co-optimized CSP-TES dispatch scenarios.

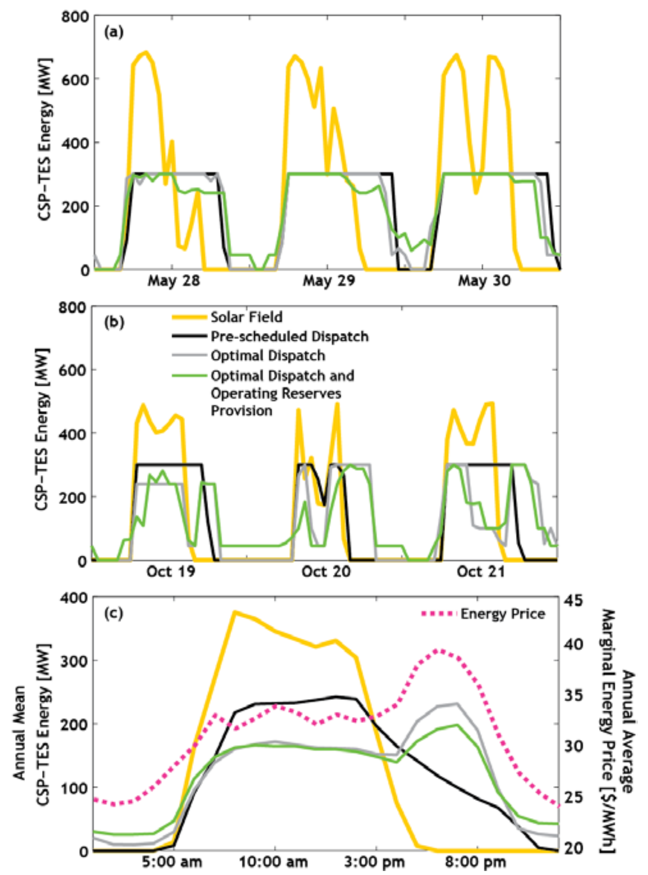

Figure 3. CSP-TES energy for three days in (a) May, (b) October, and (c) annual daily average. Panel (c) also displays the annual daily average marginal price of energy (right axis). Solar field energy is the electrical equivalent of the solar energy collected by the solar field. The dispatch profiles are the generation out of the CSP power block with high flex operation properties.

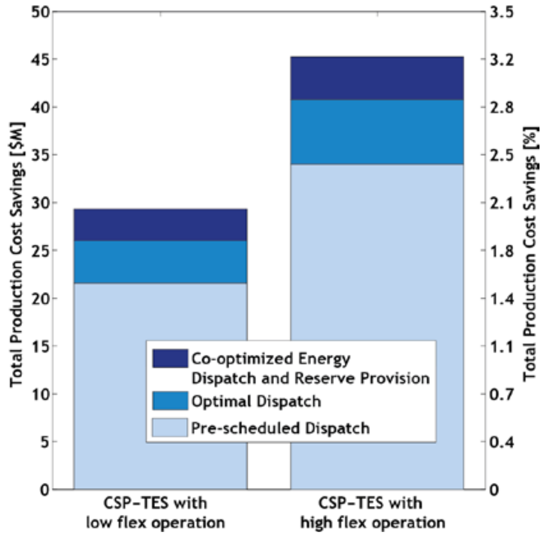

Figure 4. Total production cost savings calculated by comparing the total production cost of each incremental change in CSP-TES modelling: fixed dispatch of CSP-TES, dispatchable CSP-TES, and dispatchable CSP-TES with operating reserve provision.

TABLE IV shows the components of total production cost: fuel, variable operation and maintenance (VO&M), start and shutdown, and regulation bid. Most of the production cost savings from adding CSP-TES energy to the system is from displaced fuel costs. The addition of optimally dispatched CSP-TES results in fewer starts and an increase in the fuel cost savings over the pre-scheduled CSP. Co-optimized CSP-TES avoids additional fuel costs as well but also avoids regulation bid costs by displacing the slightly higher bid cost of CC units, $6/MW-h, with the CSP-TES bid cost of $4/MW-h.

TABLE V shows the annual generation for the base case and the change in annual generation for the high flexibility optimization scenarios. The addition of low marginal cost generation preferentially displaces high marginal cost generation: gas-fired turbines (CT) and CC units. Optimal CSP-TES dispatch increases the displacement of generation from combustion turbines. The displaced fuel in the pre-scheduled scenario, measured in thousands of MMBTU, is 90% natural gas and 10% coal and increases to 95% natural gas in the optimal dispatch scenario.

Fig. 5 shows the effect of pre-scheduled and optimal dispatch of CSP generation for three seasons: summer, fall, and winter. The change in seasonal average daily generation for CSP, coal, CC, and CT generators is calculated by subtracting the scenario generation profiles from the base case. Positive change in generation means that the optimization scenario has higher generation than the base case. Average daily summer pre-scheduled (Fig. 5a) and optimized (Fig. 5b) dispatch of CSP-TES closely resemble one another, and thus the operation of all generators is similar between the two scenarios. Summer CSP generation displaces high-cost gas-fired CCs and CTs during peak demand hours. Optimal dispatch in the fall and winter peaks in the early evening, displacing CTs, while pre-scheduled dispatch primarily displaces CCs during the daytime. Winter dispatch (Fig. 5e-f), under either optimization, shows a distinct increase in coal generation during all hours, while generation from CCs decreases during all hours. CSP generation displaces some CCs during the daytime, thus reducing the magnitude of CCs necessary to run at minimum generation overnight. The dispatch from the co-optimized scenario is nearly the same as the optimized scenario. In other words, the provision of reserves does not significantly change the dispatch of CSP-TES.

Co-optimization of CSP-TES increases coal generation relative to the optimal dispatch scenario, while generation from CCs and CTs decreases (see Table 5). To investigate the co-optimization of CSP-TES, we calculate the change in annual generation and reserves provision, by generation type, from the optimized dispatch scenario to the co-optimized scenario (see Fig. 6). The regulation reserves provision from CSP-TES displaces higher cost reserve provision, primarily CC generators. CC units are sometimes started only to provide regulation reserves [14]. When this occurs, other online generators back down in order for the new CC unit to operate at minimum generation. Thus, displacing CC regulation reserves may also displace energy from the minimum operating level of the CC units. Indeed, 34% of the displaced CC regulation provision corresponds to hours when the number of CC units online decreases.[4] Other generators must make up the displaced CC energy. We calculate the ratio of the increase in generation from each type of unit during two sets of hours: first, when CC units reduced both their reserve provision and energy generation; and second, all other hours. We find that the ratio for increased coal generation is 14.6, compared to -2, 0, and -1.6 for CT, PHS, and CPS, respectively. This suggests that coal generators are increasing energy production when some CC units are no longer providing regulation reserves and generation.

TABLE IV. BREAKDOWN OF PRODUCTION COST SAVINGS WITH THE ADDITION OF CSP-TES (HIGH FLEXIBILITY OPERATION)

	Base Case [M$]	**Pre-Scheduled CSP-TES Dispatch**	**Optimal CSP-TES Dispatch**	**Co-Optimized CSP-TES Energy and Reserve Provision**
		Increase from Base Case [M$ / %]		
Fuel cost	1,210	-34 / -2.8	-37 / -3.1	-43 / -3.5
VO&M cost	152	0 / 0	-1 / -0.7	-1 / -0.6
Start & shutdown cost	59	0 / 0.3	-2 / -4.2	-1 / -1.3
Regulation bid cost	5	0 / -0.1	0 / 1.2	-1 / -15.4
Total generation cost	1,426	-34 / -2.4	-41 / -2.9	-45 / -3.2

[4] The number of CC units committed (online) decreased during 2,371 hours between the optimal and co-optimized scenarios. During those hours, the regulation provision from CC decreased 105 GW-h. The total regulation provision from CC decreased 305 GW-h.

TABLE V. CHANGE IN ANNUAL GENERATION AND FUEL OFFTAKE FROM BASE CASE WITH THE ADDITION OF CSP-TES (HIGH FLEXIBILITY OPERATION)

Generator Class	Base Case [GWh]	Pre-Scheduled Dispatch	Optimal Dispatch	Co-Optimized Dispatch and Reserve Provision
		Increase from Base Case [GWh / %]		
Coal	46,089	-65 / -0.1	-31 / -0.1	125 / 0.3
Combined cycle (CC)	14,791	-802 / -5.4	-760 / -5.1	-960 / -6.5
Gas turbine/ gas steam	1,035	-146 / -14	-232 / -22.2	-225 / -21.6
Other	95	-1 / -0.9	-1 / -0.9	-6 / -6.2
Hydro	3,792	0 / 0	0 / 0	0 / 0
PHS	1,040	11 / 1.1	-2 / -0.2	-103 / -9.9
Wind	10,705	0 / 0	0 / 0	0 / 0
PV	1,834	0 / 0	0 / 0	0 / 0
CSP	*0*	*1,017 / -*	*1,021 / -*	*1,018 / -*
Fuel Class [1,000 MMBTU]		**Increase from Base Case [1,000 MMBTU / %]**		
Coal offtake	487,589	-772 / -0.2	-390 / -0.1	1,310 / 0.3
Gas offtake	126,771	-7,871 / -6.2	-8,749 / -6.9	-10,659 / -8.4

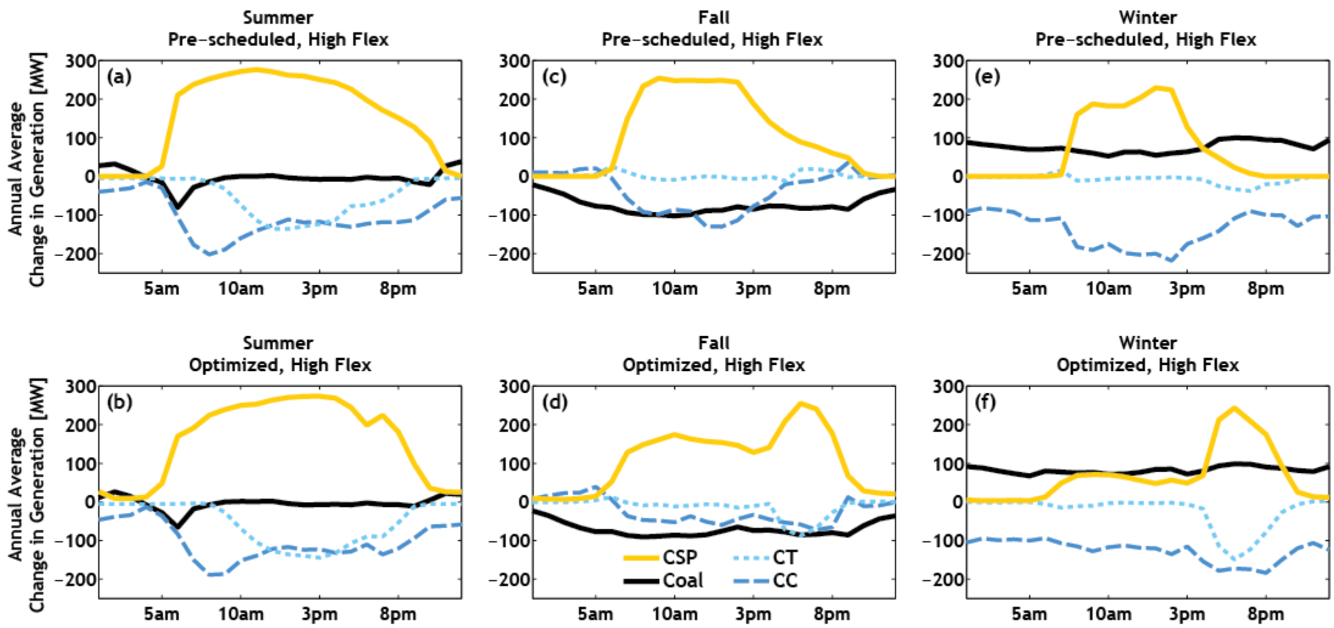

Figure 5. Change in seasonal (first column: summer, second column: fall, third column: winter) daily average generation for pre-scheduled (top row) and optimal dispatch (bottom row) scenarios, compared to the base case.

CSP-TES contingency reserve provision displaces coal, CT, and pumped hydro storage (PHS) contingency reserves, roughly equally. Coal units are primarily dispatched at full output both to reduce the cost of energy and to increase coal plant efficiency. Contingency reserves from coal often come at the opportunity cost of providing energy, the more valuable service, to the system. Displacing coal capacity for contingency requirements with CSP-TES increases the availability of coal capacity to provide energy. CTs primarily provide peak energy, and thus are rarely committed in order to provide contingency reserves. CTs provide contingency reserves from partly loaded units, at no opportunity cost, and therefore displacing the CT contingency reserves does not change the total generation from CTs.[5] CSP-TES displaces both energy and contingency reserve provision from PHS. The PHS schedule is influenced by energy arbitrage opportunities, operation limits, and operating reserve provision. Further discussion on the provision of reserves and energy from CTs and PHS see [13,14].

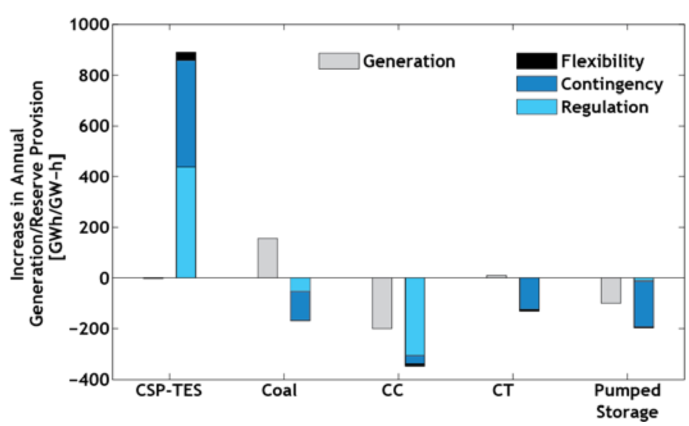

Figure 6. Increase in generation and reserve provision between the optimal CSP-TES dispatch scenario and the co-optimization scenario under high flexibility operation properties.

[5] We confirm this by calculating the average increase in generation from CTs under two conditions: first, hours when contingency reserves from CTs are reduced (4,242 hours); and second, hours when contingency reserves from CTs are increased (1,057 hours). CTs increase generation on average 24 MWh during the later hours, while generation decreases an average of 4.5 MWh during the former hours.

CSP-TES provides 17% (10%) of the annual reserve requirement in the high (low) flexibility scenario, split roughly evenly between regulation and contingency reserves, with virtually no change to CSP-TES energy dispatch. Fig. 7 shows the depression of marginal reserve prices for contingency and regulation reserves between the optimal CSP dispatch scenario and co-optimized CSP scenario. The flat regulation price regions (hours 5,500- 8,000) are periods when the regulation price is set by the bid price of the marginal unit ($6/MW-h for CC and $4/MW-h for CSP). During more than one-third hour in the co-optimized scenario, CSP sets the marginal price for regulation, primarily displacing regulation reserve from CCs.

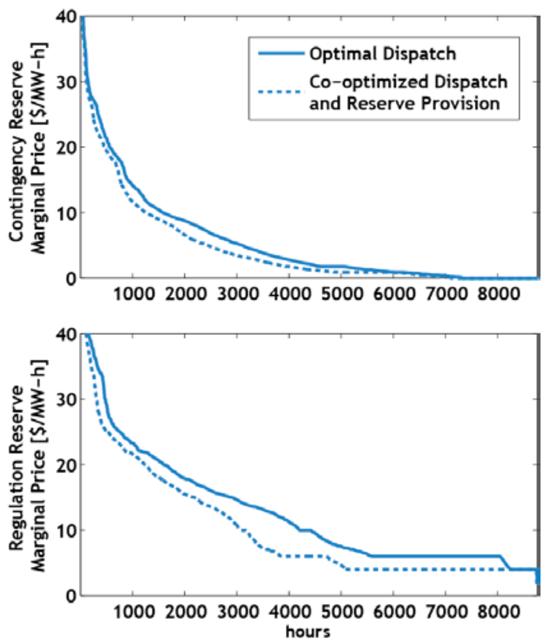

Figure 7. Marginal price duration curves for contingency reserves and regulation reserves.

Conclusions

CSP-TES can provide multiple benefits to the electric grid, including low marginal cost energy and the ability to levelize load and provide operating reserves. Implementation of CSP-TES in commercial production simulation and planning tools is an important component of valuing this technology. This study evaluated the operation of CSP-TES in three optimization scenarios, with low and high operation flexibility, in a test system based on two balancing areas in Colorado and Wyoming. The highest value scenario, co-optimization of CSP-TES for energy and reserves with high operation flexibility, reduced total production cost by 3.2%. The high flexibility properties enabled 50% more value than the low flexibility operation.

Pre-scheduled CSP-TES dispatch captures about 75% of the total production cost savings, by offering low marginal cost energy to the system during times that are well correlated to peak demand hours. Overall, we found that the optimally dispatched CSP plants avoided 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. Optimally dispatched CSP-TES captures about 15% of the total production cost savings. Co-optimized CSP-TES further reduced total production cost by reducing both regulation bid costs and fuel costs and accounts for about 10% of the total cost savings.

This analysis did not perform a complete assessment of the value of CSP with TES. A primary limitation is related to sub-hourly operation and dispatch of reserves in real time operation. Future CSP-TES production cost modelling work will assess methods of optimal real time dispatch of CSP generation and deployment of flexibility reserves held in the day-ahead model.

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