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Economic implications of thermal energy storage for concentrated solar thermal power

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ABSTRACT

Solar energy is an attractive renewable energy source because the sun's energy is plentiful and carbon-free. However, solar energy is intermittent and not suitable for base load electricity generation without an energy backup system. Concentrated solar power (CSP) is unique among other renewable energy options because it can approach base load generation with molten salt thermal energy storage (TES). This paper describes the development of an engineering economic model that directly compares the performance, cost, and profit of a 110-MW parabolic trough CSP plant operating with a TES system, natural gas-fired backup system, and no backup system. Model results are presented for 0–12 h backup capacities with and without current U.S. subsidies. TES increased the annual capacity factor from around 30% with no backup to up to 55% with 12 h of storage when the solar field area was selected to provide the lowest levelized cost of energy (LCOE). Using TES instead of a natural gas-fired heat transfer fluid heater (NG) increased total plant capital costs but decreased annual operation and maintenance costs. These three effects led to an increase in the LCOE for PT plants with TES and NG backup compared with no backup. LCOE increased with increasing backup capacity for plants with TES and NG backup. For small backup capacities (1–4 h), plants with TES had slightly lower LCOE values than plants with NG backup. For larger backup capacities (5–12 h), plants with TES had slightly higher LCOE values than plants with NG backup. At these costs, current U.S. federal tax incentives were not sufficient to make PT profitable in a market with variable electricity pricing. Current U.S. incentives combined with a fixed electricity price of \$200/MWh made PT plants with larger backup capacities more profitable than PT plants with no backup or with smaller backup capacities. In the absence of incentives, a carbon price of \$100–\$160/tonne CO_{2eq} would be required for these PT plants to compete with new coal-fired power plants in the U.S. If the long-term goal is to increase renewable base load electricity generation, additional incentives are needed to encourage new CSP plants to use thermal energy storage in the U.S.

1. Introduction

Solar energy is an attractive renewable energy source because the sun's energy is plentiful and carbon-free. However, solar energy is intermittent and not suitable for base load electricity generation without an energy backup system. Concentrated solar power (CSP) is unique among solar energy technologies because it has been operating commercially at utility-scale since 1985 [1], and it generates electricity with a thermal power cycle similar to that used in conventional fossil fuel-fired power plants. One advantage of this type of power cycle is that the thermal inertia in a CSP system is generally sufficient to sustain energy production during cloudy periods of up to a half hour [2]. Moreover, thermal energy can be stored for later use at a low cost relative to a backup system that uses batteries; or it can be combined with an on-site fossil fuel backup system. Both of these options have the ability to increase the capacity factor (ratio of annual electricity generation to potential electricity generation) of a CSP plant and thus increase its viability as a base load generator. The southwest region of the United States has the potential for up to 200 GW of installed CSP capacity using existing transmission lines [3]. This translates to 12%–20% of current U.S. electricity generation.[1] Given the urgent directive by climate experts to drastically reduce greenhouse gas (GHG) emissions [5], coupled with global concerns over rising

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[1] Assumptions: 4119 TW-hours (TWh) of net electricity generation in the U.S. in 2008 [4]; 30%–50% capacity factor [1].

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Nomenclature

θ	incidence angle o
A_{SCA}	SCA aperture area m^2
C	cost \$US2009
C_{OM}	annual operation and maintenance cost \$/yr
CF	plant capacity factor %
CRF	Capital recovery factor %
D_{htr}	natural gas-fired heater heat duty MJ/h
d_o	outer diameter of solar field pipe m
F_{asset}	percentage of direct capital cost considered as depreciable asset %
F_{debt}	debt portion of capital cost %
F_{dep}	depreciation factor %
$F_{equityC}$	common equity portion of capital cost %
$F_{equityP}$	preferred equity portion of capital cost %
F_s	mirror soiling factor
GHG	greenhouse gas emissions tonnes/MWh
Δh	enthalpy change J/s
h_e	enthalpy at exit J/s
h_{es}	enthalpy of isentropic state at exit J/s
h_i	enthalpy at inlet J/s
i	discount rate %
IAM	incidence angle modifier
$I_{loan,j}$	loan interest for year j \$
ITC	federal investment tax credit %
K	piping thermal losses J/m^2
k_{eP}	cost of preferred equity %
k_{eC}	cost of common equity %
k_L	loan interest rate %
L	length of pipe in solar field m
LAC	levelized annual capital cost \$/yr
LAC_{ITC}	subsidized, post-tax levelized annual capital cost \$/yr
LAC_{tax}	post-tax levelized annual capital cost \$/yr
l_{br}	length of space between SCA rows m
LCOE	pre-tax levelized cost of energy \$/MWh
$LCOE_{ITC}$	subsidized, post-tax levelized cost of energy \$/MWh
$LCOE_{tax}$	post-tax levelized cost of energy \$/MWh
l_{gap}	length of gap between solar collector assemblies (SCA) m
$loan_o$	initial loan balance at time zero \$
l_{sca}	SCA length m
m	mass flow rate kg/s
M	mass kg
n	book life years
η	efficiency or effectiveness %
η_{opt}	SCA optical efficiency %
NPV_{dep}	net present value of general depreciation for federal tax deductions \$
NPV_{depA}	net present value of accelerated (5-yr) depreciation for federal tax deductions \$
NPV_{int}	net present value of loan interest for federal tax deductions \$
n_{sca}	number of SCAs per row %
p	price of electricity \$/MWh
P_{CO_2}	carbon price required for trough plant to be competitive with coal plant \$/tonne CO_{2eq}
P_{loan}	uniform annual loan payment \$/yr
Q	thermal energy MJ
r	density kg/m^3
R	annual revenue \$/yr
R_{taxC}	corporate tax rate (federal + state) %
t	hours of TES storage capacity h
T	temperature °C
T_o	ambient temperature °C
V_{asset}	value of depreciable asset \$
w	work per unit mass J/kg s
W	power J/s
w_{sca}	SCA width m
$W_{tdesign}$	design turbine output MJ

energy costs, the economic implications of developing this vast resource with different backup systems must be evaluated.

The United States has approximately 522 MW of currently operating parabolic trough (PT) CSP capacity, which relies almost exclusively on fossil fuel-fired heaters and boilers [6]. In the last four years, Spain has become the world leader in PT with molten salt thermal energy storage (TES), with more than half of its 850 MW installed capacity operating with TES [7]. In the past three decades, several models have been developed to estimate the performance and cost of parabolic trough CSP with TES [8]; however, very few of them are currently available for public use. The U.S. National Renewable Energy Laboratory's (NREL's) System Advisor Model (SAM) is a publicly available open access model based on more than two decades of collaboration between NREL and the CSP industry. Several studies have demonstrated through the use of SAM and NREL's preceding in-house Excelergy model that there is significant potential to increase the capacity factor (up to 65% [9]) and to reduce the levelized cost of energy[2] (LCOE) for a PT plant through the adoption of thermal energy storage [10–13]. Kelly [14] showed through an Excelergy optimization that the use of a natural gas backup system could increase the LCOE of a PT plant by up to 5% compared to having no backup system. Sioshansi and Denholm [15] concluded that TES has the potential to increase CSP value by allowing generation to be shifted to higher-priced hours and by increasing the use of thermal energy from the solar field. Several international studies have calculated the LCOE of PT plants in other countries [16–19], but these studies have not compared the LCOE of PT plants with TES to other backup systems. Izquierdo et al. [20] showed that increasing TES capacity in a PT plant in Spain can lower LCOE when the solar field area is selected for the lowest LCOE in each parametric case.

The rapidly growing CSP industry appears to be adopting two main energy backup systems (molten salt TES and fossil fuel-fired heaters), yet no previous study has directly compared the economic implications of these two systems. The study presented here examines these implications through an engineering-economic model. The model compares the LCOE and expected annual profit of a parabolic trough CSP plant with varying TES capacities (1–12 h[3]) and compares these results to a similar PT plant with a natural gas-fired heater.

2. Methods

An engineering-economic model was developed to simulate the hourly and annual performance and cost of a PT plant with two different backup systems: 1) a thermal energy storage system (PT-

[2] The levelized cost of energy (LCOE) is a commonly used metric that represents the performance and cost as a dollar amount per unit energy generated.

[3] An "hour" of TES refers to the amount of time the power cycle can operate using only energy from the TES system.

TES), and 2) a natural gas-fired heat transfer fluid (HTF) heater (PT-NG). A visual representation of the engineering portion of this model is presented in Fig. 1. Typical meteorological year (TMY3) direct normal radiation (DNR) and ambient temperature data for Daggett, California [21] were used as inputs to a series of component-based mass and energy balances to simulate the thermodynamic operation of the system.

The PT-TES model incorporates seven distinct operation modes, which are presented in Table 1. The hourly simulation selects operation modes based on whether all criteria are satisfied, following the hierarchy shown in Table 1. For example, if Day_TESC fails, the simulation will attempt to run Day_SOLAR. If Day_SOLAR fails, the simulation will attempt Day_TESD, and so on. The PT-NG model only uses Day_SOLAR, Night_SD, and Night_FP, and incorporates an additional mode similar to Day_TESD that uses the HTF heater in place of the TES system. The PT-NG model uses as inputs the T_1, W_{net}, and W_{sold} results from the PT-TES model (see Equations (28) and (29)), and the solar field area for PT-NG is selected to minimize the difference between W_{sold} from each model, in order to simulate two different power plants that generate comparable amounts of hourly and annual electricity.

The hourly simulation uses an iterative process that selects an operation mode based on the net energy captured by the solar field (Q_{SF}), the total mass of salt in the "hot" TES tank (M_{salt}), and the temperature of the HTF. The minimum Q_{SF} for the 110-MW (MW) system modeled here is 245 MW-hours (MWh). The hourly Q_{SF} value depends on hourly ambient conditions and HTF temperature, as shown in Equation (1) through (3). The solar field area (A) is specified at the beginning of each simulation and varied to achieve the lowest levelized cost of energy. Equation (2) is a simplified version of the calculation used to determine the length of pipe in the solar field, which is a required input to Equation (3). The full calculation is presented in Appendix A.

$$K = a + b \bullet (T_{HTF} - T_o) + c \bullet (T_{HTF} - T_o)^2 \tag{1}$$

where a, b, and c are empirical thermal loss coefficients [22].

$$\begin{aligned} L = \; & l_{gap} + 2 \bullet w_{sca} + 2 \bullet l_{br} + (A/A_{SCA}) \bullet ((l_{sca} \bullet w_{sca} \\ & - A_{SCA})/w_{sca} + l_{sca} + l_{br}/(A_{SCA} \bullet n_{sca}) + \; (2 \bullet w_{sca} + 2 \\ & \bullet l_{br})/n_{sca} - (2 \bullet A_{SCA} \bullet (w_{sca} + l_{br}))/A) \end{aligned} \tag{2}$$

$$\begin{aligned} Q_{SF} = \; & A \bullet \mathrm{DNR} \bullet \cos(\theta) \bullet \eta_{opt} \bullet \mathrm{IAM} \bullet F_s - K \bullet \pi \bullet d_o \bullet L \\ & \bullet (T_{HTF} - T_o) \end{aligned} \tag{3}$$

where l_{gap} = 1 m, w_{sca} = 5.77 m, l_{br} = 15 m, A_{SCA} = 817.5 m^2, l_{sca} = 149 m, n_{sca} = 4, d_o = 0.07 m, and η_{opt} = 82% [22].

Equation (4) shows how the model calculates the total amount of M_{salt} using the design values presented by Kelly and Kearney [13]. The HTF factor (F_{HTF}) was selected as 1.5 after several iterations of the model indicated that the hourly m_{HTF} rarely exceeded 1.5 times the design value. The number of hours of TES capacity refers to the number of hours the turbine could operate at full rated capacity using only the thermal energy from the storage system. The extra salt factor (F_{salt}) represents the amount of salt that must remain in the TES tanks at all times. In this study, the nominal value for F_{salt} was 1.14 (calculated from [13]).

$$\begin{aligned} M_{salt} = \; & -((3600 \bullet (m_{HTF} - m_{HTFo}) \bullet F_{HTF} \bullet (\Delta h_{HTF})) \bullet t \\ & \bullet F_{salt})/(\Delta h_{salt}) \end{aligned} \tag{4}$$

where m_{HTF} = 1206 kg/s, m_{HTFo} = 121 kg/s, F_{HTF} = 1.5, F_{salt} = 1.14

The model calculates the design states and mass flow rates of all fluids in the system shown in Fig. 1 through a series of component mass and energy balance equations based on the First Law of Thermodynamics, assuming steady-state conditions and zero kinetic or potential energy flows (Equations (5)–(27)). The key design inputs to these equations include: T_1 = 393 °C, T_3 = 225 °C, T_5 = 293 °C, T_6 = 373 °C, pressure $(p)_4$ = 110 kPa, p_5 = 620 kPa, p_6 = 10,001 kPa, p_7 = 1900 kPa, p_8 = 1700 kPa, p_9 = 700 kPa, p_{11} = 8 kPa, p_{12} = 200 kPa, p_{18} = 10,200 kPa, $\eta_{turbine}$ = 85%, η_{pump} = 80%, $\eta_{preheater}$ = 80%, TES heat exchanger effectiveness of

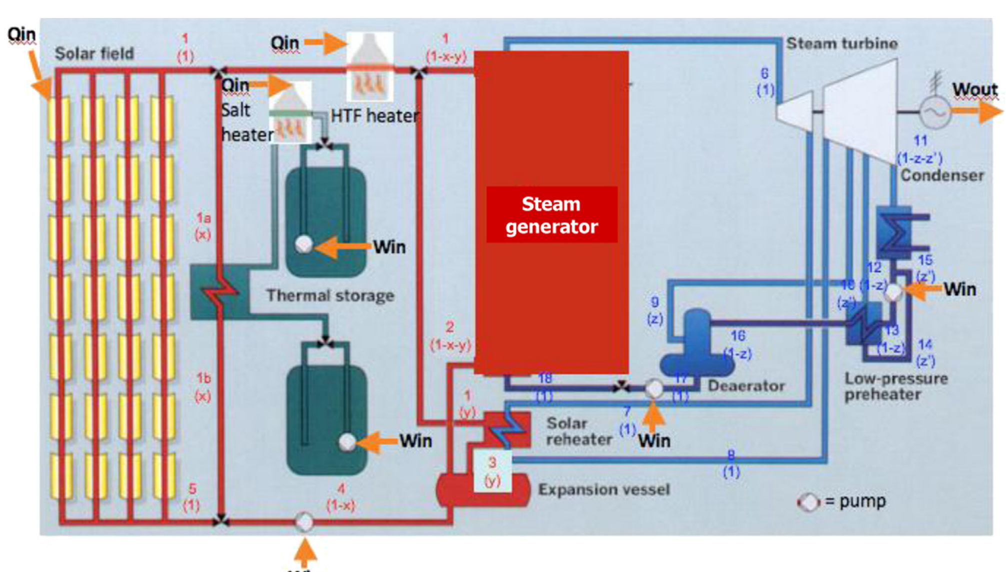

Fig. 1. Parabolic trough plant schematic (adapted from [11]). Hourly direct normal radiation (DNR) enters the solar field and is concentrated on the heat transfer fluid (HTF) in the receiver tubes (red lines on left side of figure). The HTF is pumped to the power cycle where energy is transferred to steam (blue lines on right side) via the steam generator and reheater. The heat from the steam drives the turbines to generate power (Wout) and the cooled HTF returns to the solar field. When the TES system is charging, some HTF flows to the heat exchanger to transfer energy to molten salt. Hot salt is stored in one tank and cold salt in the other. When the ambient temperature threatens to freeze the salt, the salt heater is activated to maintain the temperature above freezing. The HTF heater is used to maintain the HTF temperature above freezing when altering the HTF mass flow rate fails to prevent freezing. The HTF heater is used as an alternative to the TES system in the PT-NG plant. The heat energy input to the two heaters from natural gas combustion is represented as Qin. Five pumps are used in the system, and the power required to operate them is shown as Win. Red numbers (left side of figure) refer to HTF states, blue numbers (right side of figure) refer to steam states, and numbers in parentheses represent mass flow fractions.

Table 1
Plant operation modes.

Mode ID	Description	Criteria
Day_TESC	Only the solar field delivers thermal energy to the power cycle; excess solar energy "charges" the TES system	Q_{SF} > min M_{salt} < max
Day_SOLAR	Only the solar field delivers thermal energy to the power cycle; the TES system is idle	0 < Q_{SF} ≤ min M_{salt} ≤ min
Day_TESD	The solar field and the TES system deliver thermal energy to the power cycle	0 < Q_{SF} < min M_{salt} > min
Night_TESD	Only the TES system delivers thermal energy to the power cycle; HTF circulates through the solar field at a minimum mass flow rate to stay warm	Q_{SF} ≤ 0 M_{salt} > min
Night_SD	The power cycle is idle; HTF circulates through the solar field at a minimum mass flow rate to stay warm	Q_{SF} ≤ 0 M_{salt} ≤ min
Night_TESFP	The power cycle is idle; HTF circulates through the solar field at a minimum mass flow rate, and the TES system protects the HTF from freezing	Q_{SF} ≤ 0 M_{salt} > min T_{HTF} ≤ min
Night_FP	The power cycle is idle; HTF circulates through the solar field at a minimum mass flow rate, and the natural gas-fired heater protects the HTF from freezing	Q_{SF} ≤ 0 M_{salt} ≤ min T_{HTF} ≤ min

heating = 88%, TES heat exchanger effectiveness of cooling = 91%. The hourly simulation also uses Equations (5)–(27) to set the hourly states, beginning with a starting T_5 value of 100 °C.

Heat exchangers (steam generator/reheater, condenser, LP preheater, TES heat exchanger, salt & HTF heaters).

$$h_i = (\eta \bullet h_{es} - h_e)/(\eta - 1) \quad (5)$$

$$h_e = h_i + \eta \bullet (h_{es} - h_i) \quad (6)$$

$$h_e = h_i + (m_{steam} \bullet (h_{i\_steam} - h_{e\_steam}))/m_{HTFadj} \quad (7)$$

$$Q = m \bullet (\Delta h) \bullet 3600 \quad (8)$$

where, η = heat exchanger effectiveness, adj = adjusted with fractions shown in Fig. 1

Turbines

$$w = \eta \bullet (h_i - h_{es}) \quad (9)$$

$$h_e = h_i - w \quad (10)$$

$$W = w \bullet m_{steam} \quad (11)$$

Rankine cycle pumps

$$w = (h_i - h_{es})/\eta \quad (12)$$

$$h_e = h_i - w \quad (13)$$

$$W = w \bullet m_{steam} \quad (14)$$

Expansion vessel

$$h_4 = (1 - y) \bullet h_2 + y \bullet h_3 \quad (15)$$

Solar field pump

$$W = m_{HTF} * \left(r_4^{-1} * (p_4 - p_5)/\eta\right) \quad (16)$$

$$h_5 = h_4 - w \quad (17)$$

Mass flow rates and fractions

$$z = (h_{17} - h_{16})/(h_9 - h_{16}) \quad (18)$$

$$z' = (z \bullet (h_{16} - h_{14}) + h_{14} - h_{16})/(h_{14} - h_{12}) \quad (19)$$

$$m_{steam} = W_e/(h_6 + h_8 - h_7 - z \bullet h_9 - z' \bullet h_{12} - (1 - z - z') \bullet h_{11}) \quad (20)$$

$$m_{HTF} = (Q_{SF} \bullet 1000,000)/(h1 - h5) \quad (21)$$

$$y = -(m_{steam} \bullet (h_7 - h_8))/(m_{HTF} \bullet (h_1 - h_3)) \quad (22)$$

$$x = (h_1 - h_{1a})/(h_{1b} - h_{1a}) \quad (23)$$

$$m_{salt} = x \bullet m_{HTF} \bullet F_{HTF} * (\Delta h_{HTF})/(\Delta h_{salt}) \quad (24)$$

Therminol VP-1 (HTF) and nitrate salt properties [23]

$$h_{HTF} = 1.377 \bullet T^2 + 1.498e3 \bullet T - 1.834e4 \quad (25)$$

$$h_{salt} = 8.6e - 2 \bullet T^2 + 1.443e3 \bullet T \quad (26)$$

$$r_{HTF} = -7.762e - 4 \bullet T^2 - 6.367e - 1 \bullet T + 1.0740e3 \quad (27)$$

The net electricity generated by the system is calculated using Equation (28), and then separated into electricity sold and bought (Equations (29) and (30)) for the cost model. The power losses due to auxiliary equipment such as electronic motors, drives, computers, etc. (W_{aux}) are calculated using the series of equations described in [24] and presented in Appendix B. Equation (31) calculates the capacity factor based on electricity sold, while Equation (32) calculates capacity factor based on net electricity generated (after subtracting electricity used by pumps during nighttime hours).

$$W_{net} = W_{turbines} - W_{pumps} - W_{aux} \quad (28)$$

$$W_{sold} = W_{net} \text{ when } W_{net} > 0 \quad (29)$$

$$W_{bought} = \text{abs}(W_{net}) \text{ when } W_{net} < 0 \quad (30)$$

$$CF = W_{sold} \Big/ \left(W_{tdesign} \bullet 8760\right) \quad (31)$$

$$CF_{net} = W_{net} \Big/ \left(W_{tdesign} \bullet 8760\right) \quad (32)$$

where W_{aux} refers to power losses through auxiliary loads

The economic model calculates the total capital cost of the plant and the annual operation and maintenance (O&M) costs using a slightly adapted version of the National Renewable Energy Laboratory's System Advisor Model's cost model [25], which was developed for a plant with a solar field area of 854,000 m^2.

Appendix C presents the full set of specific capital and O&M costs used in this study. Calculations were added for the capital cost of the HTF and salt heaters (Equations (33) and (34)) [26].

$$D_{htr} = (\max(Q_{htr}) \bullet 0.00094781712)/1000,000 \quad (33)$$

$$C_{htr} = 13402 \bullet D_{htr} + 367,158 \quad (34)$$

The pre-tax LCOE is calculated using Equations (35)–(38). The post-tax levelized annual capital cost (LAC) and LCOE are calculated using Equations (39)–(49), and incorporate U.S. tax deductions from loan interest and depreciation, using a 30-year general depreciation schedule [27]. Equations (50)–(52) calculate the subsidized LAC and LCOE, which incorporate current federal subsidies for CSP: a 30% U.S. federal investment tax credit (ITC) applied as a cash grant to the debt and equity portions of the capital investment along with the accelerated 5-year depreciation schedule [27]. The following specific financial parameters were selected for this analysis to be consistent with the SAM default utility independent power producer (IPP) financial parameters [28] and the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG) recommendations for renewable power generation financing [29]: $F_{debt} = 40\%$, $k_L = 8\%$, $F_{equityP} = 8\%$, $k_{eP} = 5.34\%$, $F_{equityC} = 52\%$, $k_{eC} = 8.74\%$, $i = 8.17\%$ (calculated), $n = 30$ years, CRF = 9.03% (calculated), $R_{taxC} = 43.84\%$, $F_{asset} = 84\%$, F_{dep} = see [27], ITC = 30%.

$$i = F_{debt} \bullet k_L + F_{equityP} \bullet k_{eP} + F_{equityC} \bullet k_{eC} \quad (35)$$

$$\mathrm{CRF} = \left(i \middle/ \left(1-(1+i)^{-n}\right)\right) \quad (36)$$

$$\mathrm{LAC} = C_{cap} \bullet \mathrm{CRF} \quad (37)$$

$$\mathrm{LCOE} = (\mathrm{LAC} + C_{OM})/W_{sold} \quad (38)$$

$$P_{loan} = C_{cap} \bullet F_{debt} \bullet \left[k_L \middle/ \left(1-(1+k_L)^{-n}\right)\right] \quad (39)$$

$$\mathrm{loan}_o = C_{cap} \bullet F_{debt} \quad (40)$$

$$I_{loan,j} = \mathrm{loan}_{(j-1)} \bullet k_L \quad (41)$$

$$\mathrm{loan}_j = \mathrm{loan}_{(j-1)} + I_{loan,j} - P_{loan} \quad (42)$$

$$\mathrm{NPV}_{int} = \sum\left[\left(\mathrm{loan}_{(j-1)} \bullet k_L \bullet R_{taxC}\right) \middle/ (1+i)^j\right], \text{ for } j = 1 \text{ to } n \quad (43)$$

$$V_{asset} = C_{direct} \bullet F_{asset} \quad (44)$$

$$V_{dep,j} = V_{asset,j} \bullet F_{dep,j}, \text{ for } j = 1 \text{ to end of depreciation schedule} \quad (45)$$

$$V_{asset,j} = V_{asset,(j-1)} - V_{dep,(j-1)} \quad (46)$$

$$\mathrm{NPV}_{dep} = \sum\left[\left(V_{dep,j} \bullet R_{taxC}\right) \middle/ (1+i)^j\right], \text{ for } j = 1 \text{ to end of depreciation schedule} \quad (47)$$

$$\mathrm{LAC}_{tax} = \left[C_{cap} - \left(\mathrm{NPV}_{dep} + \mathrm{NPV}_{int}\right)\right] \bullet \mathrm{CRF} \quad (48)$$

$$\mathrm{LCOE}_{tax} = (\mathrm{LAC}_{tax} + C_{OM})/W_{sold} \quad (49)$$

$$C_{capITC} = (1 - \mathrm{ITC}) \bullet C_{cap} \quad (50)$$

$$\mathrm{LAC}_{ITC} = \left[C_{capITC} - \left(\mathrm{NPV}_{depA} + \mathrm{NPV}_{intITC}\right)\right] \bullet \mathrm{CRF} \quad (51)$$

$$\mathrm{LCOE}_{ITC} = (\mathrm{LAC}_{ITC} + C_{OM})/W_{sold} \quad (52)$$

The expected annual profit (P) is calculated using Equations (53) and (55) and hourly historic electricity pricing data from the California Independent System Operator (CAISO) from 2008 [30]. This calculation assumes that the power plant receives the real-time price of electricity from the CAISO. An alternative P is calculated under the assumption that the plant owner enters into a power purchase agreement (PPA) with a fixed electricity price ($200/MWh), and this calculation is shown as Equations (54) and (56). Each profit calculation is repeated for each respective LCOE category.

$$R = \sum (p \bullet W_{sold}) \quad (53)$$

$$R_{PPA} = W_{sold} \bullet p_{PPA} \quad (54)$$

$$P = R - \mathrm{LCOE} \bullet W_{sold} \quad (55)$$

$$P_{PPA} = R_{PPA} - \mathrm{LCOE} \bullet W_{sold} \quad (56)$$

Many economists agree that an effective way to encourage widespread greenhouse gas (GHG) emissions reductions is to put a price on carbon either through a tax or a tradable permitting system. This action would in effect “fix” the market failure associated with the fact that climate change consequences (a set of externalities) are not currently valued in the cost of GHG-emitting processes. The purpose of this study is neither to argue the benefits or drawbacks of such a system, nor to propose a specific “carbon price”. However, given that such a system may be implemented in the U.S. in the future, this paper includes a calculation of the carbon price that would be necessary for the specific CSP power plant configurations analyzed here to compete with a new coal-fired power plant with no CO_2 controls or capture system. Equation (57) calculates the carbon price using the unsubsidized pre-tax LCOE for each PT configuration and a range of literature values for life cycle GHG emissions from the PT power plants. The LCOE value and operational CO_2 emissions for the coal-fired power plant were calculated using the Integrated Environmental Control Model (IECM) v6.2.4 [31], developed by researchers at Carnegie Mellon University. Appendix D includes details about the specific input values used in the IECM to calculate the LCOE of a new coal-fired power plant that could be comparable in size and financing to a new PT plant. The life cycle GHG emissions value for the coal-fired power plant were estimated by combining the upstream emissions from Jaramillo et al. [32] and the operational emissions from the IECM.

$$p_{CO_2} = (\mathrm{LCOE}_{PT} - \mathrm{LCOE}_c) \div (\mathrm{GHG}_c - \mathrm{GHG}_{PT}) \quad (57)$$

where, c = coal; LCOE_{PT} is calculated by Equation (38); LCOE_c = $70/MWh [31]; GHG_c = 0.98 tonnes CO_{2eq}/MWh [32] and [31]; GHG_{PT} = 0.01–0.19 CO_{2eq}/MWh [33].

3. Results and discussion

The solar field area for the PT-TES plants was selected to minimize the LCOE, while the solar field area for the PT-NG plants was selected to minimize the difference between W_{sold} in the two models in order to simulate two power plants of similar size and electric output with different backup systems. Fig. 2a shows that the solar field area increased with increasing storage capacity in order to capture enough energy for the TES system. The solar field area for the PT-NG plant increased as well because it was required to meet the hourly and annual solar-generated electricity output of the PT-TES plant without being able to store excess solar energy during high DNR hours. An “hour” of backup system capacity refers to the amount of time the power cycle can operate using only

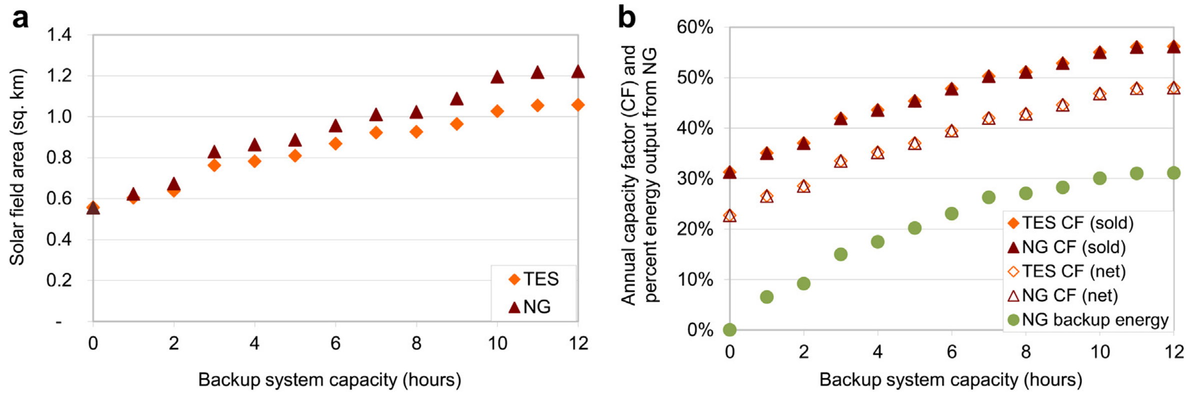

Fig. 2. Solar field area (a) and plant capacity factor/percent NG backup (b). The graph on the left (a) shows the solar field area selected for PT-TES to minimize LCOE and the area selected for PT-NG to match PT-TES hourly and annual electricity output. The graph on the right (b) shows the corresponding annual plant capacity factors (CF) and the percent of annual electricity output from the natural gas-fired heater in the PT-NG plants (NG backup energy).

energy from either the TES system or NG-fired HTF heater depending on the plant type, with no energy coming from the solar field. The backup system capacity for each PT-NG plant is constrained by the respective PT-TES plant's hourly and annual energy output requirement. The plant with 0 h of backup capacity does not incorporate a TES system and only uses the NG-fired heater for HTF freeze protection. The PT-TES plants had nearly identical capacity factors to the respective PT-NG plants because the model was designed to match annual electricity generation for a given backup capacity. Overall, capacity factor increased with backup capacity as the plants operated for more annual hours. The PT-NG plants used the NG-fired heater to generate 7–31% of annual electricity.

The net capacity factor for each system was 15%–27% smaller than the capacity factor based on electricity sold because the calculation for the former subtracts nighttime pump energy from annual electricity generation while the latter calculation does not. Fig. 2b highlights a discrepancy in capacity factor that has significant implications in the comparison of intermittent renewable energy systems with other energy systems. The levelized cost of energy is commonly used by stakeholders from a variety of backgrounds and energy interests to compare a wide range of energy options. Decision-makers often use LCOE to justify why one energy option should be selected over another, and the capacity factor is a crucial element in the LCOE calculation. However, the capacity factor value not only depends on the highly variable nature of the energy resource, which changes by the hour, minute and second, but also by the way the term is defined. Traditional thermodynamic modeling of power systems suggests that the net capacity factor should be used because it is the sum of the energy inputs and outputs in the system. However, with solar power plants, there is a distinction between energy consumption during night and day hours. If the power cycle is operating, it is reasonable to assume that the electricity generated by the system can be used to power the pumps and auxiliary equipment. When the power cycle is not operating, the power plant purchases electricity from the grid to run the pumps and auxiliary equipment for HTF freeze protection. From a thermodynamic standpoint, this distinction may not be important because the end sum is the same whether you add energy inputs and outputs together in one sum or separate electricity sold and bought on an hourly basis and add them together at the end. But from a business standpoint, the distinction is very important. It is unclear whether the annual electricity generation values that are publicly reported for currently operating PT plants subtract nighttime pump and auxiliary loads, but it is reasonable to assume that they do not because the important value for the developer, utility, and public is how much energy was generated and *sold*. Furthermore, it is much more accurate for economic modeling to separate sold energy and purchased energy because the power plant is, in reality, purchasing electricity from a utility during nighttime hours. For this reason, the economic results presented below were calculated based on sold electricity.

Fig. 3a shows that the capital costs increased for both plants with increasing backup capacity, as a larger solar field was required. For all plants, the solar field was the most expensive component, contributing 52% of the total plant capital cost for the 0 h configuration. The indirect capital costs (which include engineering, procurement, construction, land, sales tax, and miscellaneous as described in Appendix C) and the cost of the thermal energy storage system represented the next largest component costs. Fig. 3b shows that the total plant capital cost for the PT-TES plants was generally larger than the PT-NG costs. The U.S. federal investment tax credit lowered the total plant capital cost of each plant by 30%. For simplicity, it was assumed that all plant components would be eligible for the ITC. Under this assumption, the relative difference between costs for PT-TES and PT-NG plants with similar backup capacities was the same with the subsidy as without. However, the NG-fired heater may not be eligible for the ITC. Taking this into account would reduce the difference in subsidized total plant capital cost between the PT-TES and respective PT-NG plants with larger backup capacities. Although, it is unlikely that excluding the NG heater from the ITC would result in lower PT-TES costs than PT-NG because the NG heater is such a small percentage of the total plant capital cost for the PT-NG plants. Overall, the unsubsidized capital costs ranged from $5400 per kW of installed turbine capacity to $12,000/kW for the PT-TES plants and from $5500 to $9100 for the PT-NG plants. The following average capital costs for other energy technologies put these values in some context: $2600/kW for coal; $1000/kW combined cycle gas; $4300 for nuclear; $1700/kW for onshore wind; $3300/kW for offshore wind; and $6000/kW for solar photovoltaic (PV) [34].[4]

Fig. 4a shows the relative contribution of labor, service contracts, and utilities to the total annual O&M costs. Total annual O&M costs increased with increasing backup system capacity for both plant types. Labor costs increased slightly with higher backup capacities and larger solar field areas to maintain. Electricity and natural gas purchases represented the largest portions of annual O&M costs. Fig. 4b shows the annual operation and maintenance costs divided by the annual electricity sold. Although total annual O&M costs

[4] All values are in $2009. However, the average capital cost value for solar PV is from data obtained in 2007–2009. Recent sharp decreases in the price of PV panels have substantially lowered the current installed cost of PV systems.

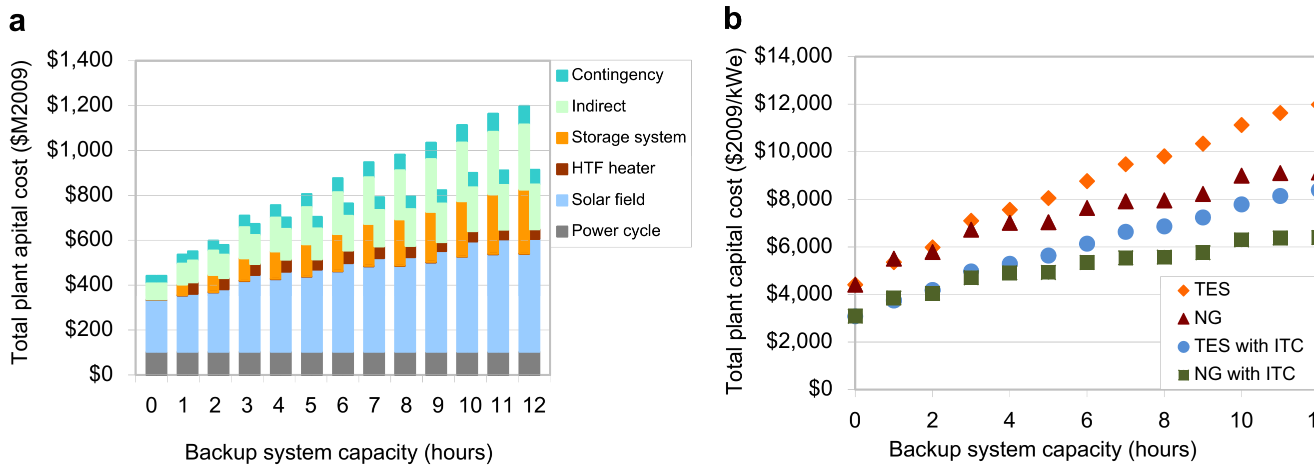

Fig. 3. Total plant capital cost. The graph on the left (3a) shows the component costs of the unsubsidized total plant capital cost for each plant (PT-TES is represented by each bar on the left, and PT-NG is represented by each bar on the right). The graph on the right (3b) shows the total plant capital cost per unit installed capacity (kilowatt electric (kWe)) with and without the 30% investment tax credit (ITC).

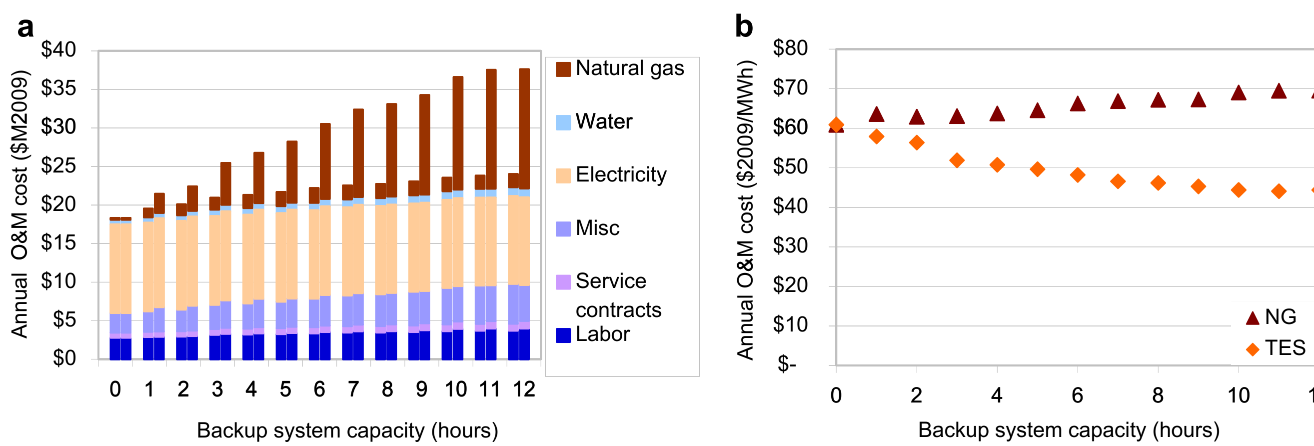

Fig. 4. Annual operation and maintenance (O&M) cost. The graph on the left (a) shows the component costs of the annual O&M costs for each plant (PT-TES is represented by each bar on the left, and PT-NG is represented by each bar on the right). The graph on the right (b) shows the annual O&M costs for each plant per unit electricity sold. Key assumptions: natural gas = $US 5.92/MMBtu (the national average annual natural gas price from 1997 to 2008 [36]); auxiliary electricity = $US 135.15/MWh (the mean annual commercial price of electricity in California from 1998 to 2008 [37]); water = $US 0.37/kL ([25]). All unit costs were inflation-adjusted to $2009 using the CPI calculator [38].

increased with increasing TES capacity (because of increased fuel, electricity and water purchases), annual O&M costs per unit of electricity sold decreased with increasing molten salt TES capacities because of increasing annual electricity generation and relatively stable utility costs. Annual O&M costs per unit electricity for PT-NG, however, increased with increasing backup capacity because annual fuel purchases increased substantially to match PT-TES electricity generation. The following average annual O&M costs for other energy technologies put these values in some context: $26/MWh for coal; $51/MWh combined cycle gas [35]; $12/MWh for onshore wind; $29/MWh for offshore wind; and $10/MWh for solar photovoltaic (PV) [34].[5]

Fig. 5 presents the levelized annual capital cost and LCOE for each plant type. The LAC results had the same relative patterns as the total plant capital cost results. The post-tax costs were lower overall than the corresponding pre-tax costs due to the savings associated with depreciation and loan interest. The ITC, combined with accelerated depreciation, lowered the LAC even further. For each set of results presented, the plant with no storage/backup (0 h) had the lowest LCOE. For smaller storage capacities (1–4 h of backup capacity), the unsubsidized, pre-tax LCOE for the NG plant was 1–5% higher than the respective TES plant. For larger storage capacities (5–12 h), the NG LCOE was 2–9% lower than the respective TES plant. The combination of ITC and accelerated depreciation caused the LCOE of the NG configurations to be 1–6% higher than the respective TES cases since the ITC reduced the capital cost of the TES plants but did not change the O&M costs for the NG plants. Most of these LCOE values, even with incentives, are twice as expensive as a new coal-fired power plant with similar financing – LCOE around $70/MWh [31]. Unsubsidized wind power ranges from $75 to $160/MWh depending on siting and whether the project is land-based or offshore, and unsubsidized solar photovoltaic ranges from $250 to $450/MWh depending on the specific technology [39].

Fig. 6 displays the carbon price required for each of the parabolic trough power plant configurations analyzed in this study to be competitive with a new coal-fired power plant. The carbon price calculation is based on the pre-tax unsubsidized LCOE. The average prices (mean of the high and low bounds represented by the bars in Fig. 5) ranged from a minimum of $100/tonne CO_{2eq} with 0 h backup to a maximum of about $160/tonne CO_{2eq} with 12 h TES and $140/tonne CO_{2eq} with 12 h NG backup. This analysis assumed the same GHG emissions all PT plant types for simplicity. In reality, the GHG

[5] All values were converted to $2009 for comparative purposes using the CPI calculator [38].

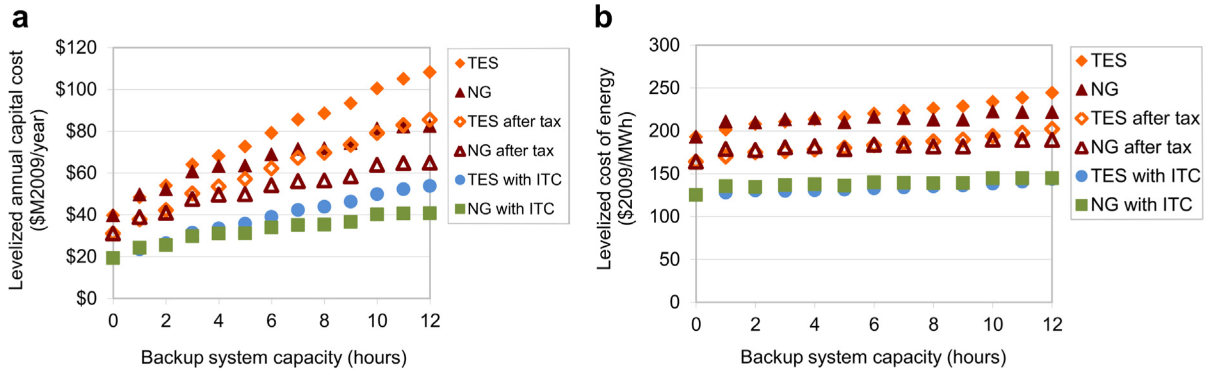

Fig. 5. Levelized annual capital cost (a) and levelized cost of energy (b). Graph (a) shows the levelized annual capital cost, and graph (b) shows the levelized cost of energy for each plant pre-tax, post-tax, and subsidized post-tax (with ITC and accelerated depreciation). Key assumptions: $F_{\mathrm{debt}} = 40\%$, $k_L = 8\%$, $F_{\mathrm{equityP}} = 8\%$, $k_{eP} = 5.34\%$, $F_{\mathrm{equityC}} = 52\%$, $k_{eC} = 8.74\%$, $i = 8.17\%$ (calculated), $n = 30$ years, CRF = 9.03% (calculated), $R_{\mathrm{taxC}} = 43.84\%$, $F_{\mathrm{asset}} = 84\%$, ITC = 30%.

emissions would increase with increasing NG use, and the plants with natural gas backup would require a higher carbon price than the respective TES plants. An even higher carbon price would be required for each configuration if the parabolic trough plants were being compared to a modern natural gas combined cycle (NGCC) power plant providing base load electricity. Since the CO_2 emission rate from such a plant is about half that of a coal-fired plant [31], the resulting carbon prices would be roughly twice the values shown here for a comparable LCOE using NGCC. Carbon prices of \$100–160/tonne CO_{2eq} are high compared to the \$20–80/tonne CO_{2eq} range suggested by the Intergovernmental Panel for Climate Change as the global price by 2030 needed to stabilize carbon at around 550 parts per million (ppm) by 2100 [5].

Fig. 7 presents the expected annual profit for the various incentive and pricing scenarios modeled. All of the unsubsidized scenarios resulted in negative annual profits (i.e., losses), with similar patterns across different plant configurations as the LCOE results. The 30% ITC was not sufficient to guarantee an annual profit with variable hourly electricity pricing. However, the \$200/MWh PPA alone was enough to bring the unsubsidized pre-tax annual profit of the plant with 0 h TES/NG into the positive region with a value of \$2 million per year. Nearly all of the unsubsidized post-tax scenarios with the PPA resulted in a profit, ranging from \$1 M with 11 h TES to \$10 M with 1 h TES and from \$6 M with 12 h NG to \$9 M with 5 h NG. The plant with 0 h backup had the highest unsubsidized post-tax PPA profit, with \$11 M/year. The combination of the ITC/accelerated deprecation and PPA resulted in the highest annual profit for each plant configuration. In all other incentive/pricing combinations, the 0 h case had the highest profit (lowest loss) compared with other capacities. With the ITC/PPA combination, the 0 h case had nearly the lowest annual profit at \$23 M. Annual profit increased from \$24 M with 1 h TES to a maximum of \$33 M with 10 h TES. The profit for the NG backup cases ranged from \$22 M with 1 h to a maximum of \$31 M with 9 h. NG profit results were 2–11% lower than the comparable PT-TES cases when the ITC/PPA combination was modeled. These results indicate that the current federal tax incentives combined with a reliable PPA may provide an incentive for TES over natural gas backup and over no TES/NG backup.

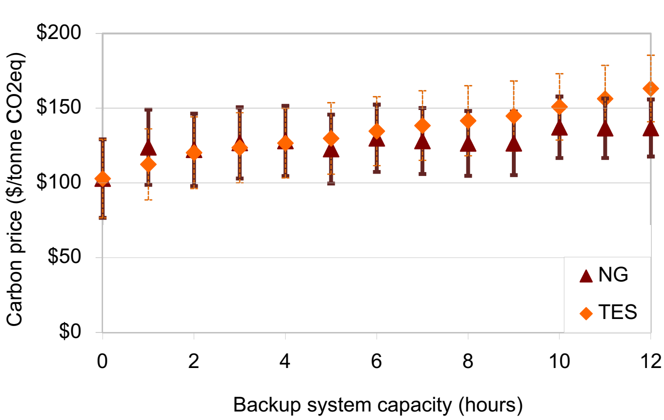

Fig. 6. Required carbon price. This graph shows the carbon price that would be required for each plant to be competitive with coal electricity generation in the United States. Assumptions: coal LCOE = \$US 70/MWh [31]; coal greenhouse gas (GHG) emissions = 0.98 tonnes CO_{2eq}/MWh [32] and [31]], and PT GHG emissions = 0.01–0.19 CO_{2eq}/MWh [33]. The bars represent the range of results associated with GHG emission bounds.

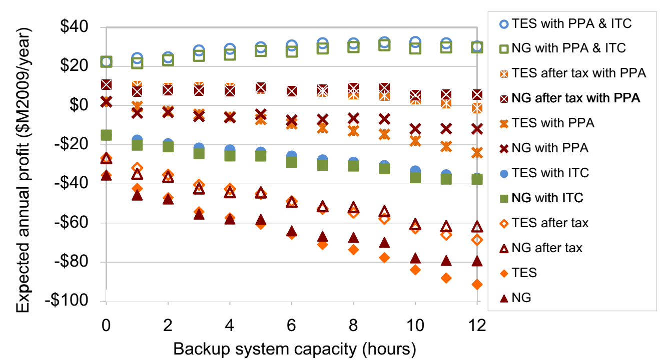

Fig. 7. Expected annual profit. This graph shows the expected annual profit for each plant, using the pre-tax, post-tax, and subsidized post-tax levelized cost of energy (with 30% investment tax credit (ITC) and accelerated depreciation), hourly electricity pricing, and power purchase agreement pricing (PPA) of \$US 200/MWh.

4. Conclusions

The results of this analysis show that two-tank molten salt thermal energy storage can increase the annual capacity factor of a parabolic trough CSP plant with hourly solar radiation similar to Daggett, CA from around 30% with no storage to up to 55% with 12 h of storage when the solar field area is selected to provide the lowest levelized cost of energy. Using TES instead of a natural gas-fired heat transfer fluid heater increased total plant capital costs but decreased annual operation and maintenance costs. These three effects led to an increase in the levelized cost of energy for PT plants with NG and TES backup compared with PT plants that only used enough backup to provide freeze protection and plant startup/shutdown (0 h backup in this analysis). LCOE increased with increasing backup capacity for plants with TES and NG backup. For small backup capacities (1–4 h), plants with TES had slightly lower LCOE values than plants with NG backup. For larger backup capacities (5–12 h), plants with TES had slightly higher LCOE values than plants with NG backup. At these costs, current U.S. federal tax incentives (30% investment tax credit combined with 5-yr accelerated depreciation) were not sufficient to make PT profitable in a market with variable electricity pricing. Current U.S. incentives combined with a fixed electricity price of $200/MWh made PT plants with larger backup capacities more profitable than PT plants with no backup or with smaller backup capacities. In the absence of incentives, a carbon price of $100–$160/tonne CO2eq would be required for these PT plants to compete with new coal-fired power plants in the U.S.

These results have some initial policy implications that warrant further investigation. First, when comparing energy technologies, it is important to document whether capacity factor and/or levelized cost of energy calculations for intermittent renewable resources are based on the annual electricity sold by the power plant (the value most often reported by power plant owners) or on the net annual electricity (the thermodynamic value that subtracts nighttime electricity purchases from electricity sold). In addition, if long-term policy goals seek to encourage renewable energy deployment as base load generators, current tax incentives need to be combined with a generous power purchase agreement to encourage plants with larger backup system capacities. Alternatively, a feed-in tariff (a guaranteed fixed price of electricity per unit sold) may be a more direct way to encourage more backup in PT plants than tax incentives since the fixed electricity pricing represented by the PPA in this analysis had a greater effect on profitability than the tax incentives. If the policy goal is to encourage PT plants with TES instead of NG backup (i.e., encourage higher capacity factors that are based on more renewable energy), additional incentives may be required to make TES competitive with NG backup at annual capacity factors greater than 50%. New policy measures could require that future PT plants use TES in order to receive tax incentives and/or guaranteed pricing or provide larger incentives for plants that use TES than for plants that use no backup or NG backup.

Incentivizing TES over NG may be attractive for environmental reasons because TES allows a PT plant to increase annual electricity generation (compared to no backup) with less greenhouse gas emissions and other pollutants compared with natural gas backup. There could also be some economic advantages to incentivizing TES over NG. First, TES results in lower annual operation and maintenance costs per unit electricity sold than NG backup. In addition, a sensitivity analysis on the model results showed that the LCOE of the PT plants modeled in this study were less sensitive to variability in nitrate salt pricing than to variability in natural gas pricing. Since the nitrate salt for a PT-TES plant is purchased at the beginning of the plant lifetime and does not require significant purchases thereafter, if the salt is purchased at low cost initially, the plant will have lower and more predictable annual costs. Future studies should examine the feasibility and economic effects of policy options that encourage base load renewable energy generation from a variety of energy sources.

Acknowledgments

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Appendix A

Fig. A.1 shows the general solar field layout used in the piping calculations, where "hot" header piping refers to the pipe that carries the hot HTF from each SCA loop to the power block, and "cold" header piping refers to the pipe that carries the cooled HTF from the power block heat exchanger to each SCA loop.

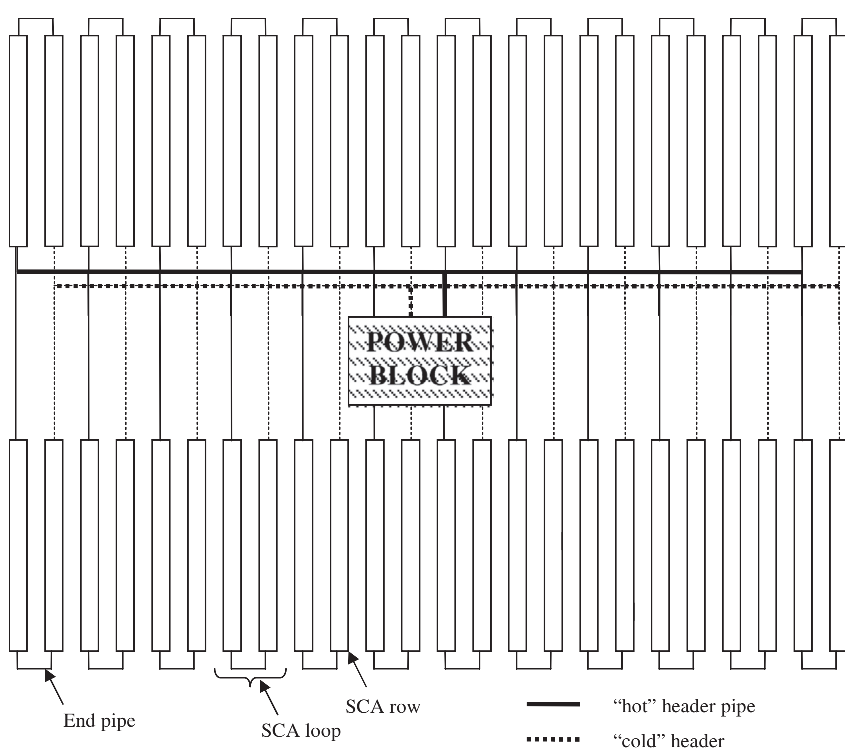

Fig. A.1. Solar field layout for piping calculations.

Table A.1 presents the design parameters used in Equations (A.1)–(A.14) to calculate the total solar field pipe length. The solar field area presented in Table A.1 is an example used to demonstrate the piping calculations. In the main text, the solar field area for each PT-TES configuration was selected to minimize the levelized cost of energy. The solar field area for each PT-NG configuration was selected to match the hourly and annual electricity generation from each respective PT-TES configuration.

Table A.1. Solar field design parameters for Daggett, CA. (Bold-faced items were calculated using the equations displayed below).

Symbol	Description	Design value	Units
d_o	Outer diameter of the steel absorber pipe [11]	0.07	m
l_{sca}	Length of one Eurotrough SCA [40]	148.5	m
A	Total solar field area	388,979	m^2
N_{sca}	Number of SCAs in solar field	476	
w_{sca}	SCA width [40]	5.77	m
$A_{scacalc}$	Calculated SCA aperture area	856.8	m^2
A_{sca}	Useful SCA mirror aperture area [1]	817.5	m^2
A_{gap}	Area of gaps between mirrors and modules in SCA	39.3	m^2
L_{gap}	Length of absorber pipe for mirror and module gaps	3245	m
L_{sca}	Total length of SCA absorber pipe	70,659	m
n_{scarow}	Number of SCAs in a row	4	
$l_{betweensca}$	Distance between each SCA in a row [28]	1	m
N_{rows}	Number of rows in solar field	119	
$L_{betweensca}$	Total length of absorber piping used to connect SCAs within a row	357	m
N_{loops}	Number of SCA loops in solar field	59	
$l_{betweenrow}$	Distance between each row [28]	15	m
$L_{endpipe}$	Total length of absorber pipe used to connect SCA loops	892	m
$L_{absorber}$	Total length of absorber pipe in solar field	75,152	m
$L_{coldheader}$	Length of "cold" header piping	1215	m
$L_{hotheader}$	Length of "hot" header piping	1173	m
L_{header}	Total length of header piping in solar field	2388	m
L_{pipe}	Total solar field pipe length	77,540	m

$$N_{sca} = A \div A_{sca} \tag{A.1}$$

$$A_{scacalc} = l_{sca} * w_{sca} \tag{A.2}$$

$$A_{gap} = A_{scacalc} - A_{sca} \tag{A.3}$$

$$L_{gap} = N_{sca} * (A_{gap} \div w_{sca}) \tag{A.4}$$

$$L_{sca} = N_{sca} * l_{sca} \tag{A.5}$$

$$N_{rows} = N_{sca} \div n_{scarow} \tag{A.6}$$

$$L_{betweensca} = (n_{scarow} - 1) * l_{betweensca} * N_{rows} \tag{A.7}$$

$$N_{loops} = N_{rows} \div 2 \tag{A.8}$$

$$L_{endpipe} = l_{betweenrow} * N_{loops} \tag{A.9}$$

$$L_{absorber} = L_{gap} + L_{sca} + L_{betweensca} + L_{endpipe} \tag{A.10}$$

$$L_{coldheader} = \left(N_{loops} - 1\right) * (w_{sca} + l_{betweenrow}) \tag{A.11}$$

$$L_{hotheader} = L_{coldheader} - 2 * (w_{sca} + l_{betweenrow}) \tag{A.12}$$

$$L_{header} = L_{coldheader} + L_{hotheader} \tag{A.13}$$

$$L_{pipe} = L_{absorber} + L_{header} \tag{A.14}$$

Appendix B

Table B.1 presents the design parameters used in Equations (B.1)–(B.15) to calculate the total parasitic losses from the system, the annual electricity generation, and the annual capacity factor for a parabolic trough plant. The calculated values presented in Table B.1 are sample values used to demonstrate the necessary calculations. Hourly parameter values represent the 129th hour of a complete simulation of a plant with 6 h of thermal energy storage.

Table B.1. Parasitic energy losses and net electricity output (adapted from [24]). (Bold-faced items were calculated using the equations displayed below).

Symbol	Description	Design value	Units
$W_{tdesign}$	Design turbine gross electric output	110	MWh
F_{PB}	Fixed power block loss factor	0.0055	MWh/MWh
$E_{PARFIxED}$	Fixed parasitic energy losses for power plant – calculated for each hour of simulation	0.605	MWh
F_{BOP}	Balance of plant loss factor	0.02467	MWh/MWh
$E_{PARBOPD}$	Design parasitic losses from balance of plant operations	2.7	MWh
A_{BOP}	Balance of plant coefficient	0.517	
B_{BOP}	Balance of plant coefficient	0.483	
F_{PBLOAD}	Hourly power block load factor – ratio of actual to design electric output	1	MWh/MWh
E_{PARBOP}	Hourly parasitic losses from balance of plant operations – calculated during any hour that the power block operates	2.7	MWh
F_{CT}	Cooling tower loss factor	0.017045	MWh/MWh
E_{PARCTD}	Design parasitic losses from cooling tower operations	1.9	MWh
A_{CT}	Cooling tower coefficient	0.794	
B_{CT}	Cooling tower coefficient	0.242	
C_{CT}	Cooling tower coefficient	−0.036	
E_{PARCT}	Hourly parasitic losses from cooling tower operations – calculated during any hour that the power block operates	1.5	MWh
F_{HTR}	Natural gas-fired heater loss factor	0.02273	MWh/MWh
$E_{PARHTRD}$	Design parasitic losses from natural gas-fired HTF heater	2.5	MWh
Q_{HTR}	Hourly thermal energy required from heater for HTF freeze protection; calculated in plant operation modes	0	MWh

(*continued*)

Symbol	Description	Design value	Units
$F_{HTRLOAD}$	Heater load factor – the ratio of heat energy supplied by the HTF heater to the design thermal input of the Rankine cycle	0	
A_{HTR}	Heater coefficient	0.517	
B_{HTR}	Heater coefficient	0.483	
E_{PARHTR}	Hourly parasitic losses from natural gas-fired HTF heater – calculated during any hour that the heater operates	0	MWh
E_{SCA}	SCA tracking energy for Eurotrough collector	125	Wh/sca
E_{PARSCA}	Hourly parasitic loss from SCA tracking – calculated during any hour the solar field is tracking the sun	0.13	MWh
E_{NET}	Hourly net electricity generation	102	MWh
E_{SOLD}	Hourly electricity sold	102	MWh
E_{BOUGHT}	Hourly electricity purchased	0	MWh
W_{NET}	Annual net electricity generation – the sum of hourly electricity generation	380	GWh
W_{SOLD}	Annual net electricity generation – the sum of hourly electricity sold	460	GWh
CF	Plant capacity factor, based on W_{SOLD}	48	%
CF_{net}	Plant capacity factor, based on W_{NET}	39	%

$$E_{PARFIXED} = F_{PB}*W_{tdesign} \tag{B.1}$$

$$E_{PARBOPD} = F_{BOP}*W_{tdesign} \tag{B.2}$$

$$F_{PBLOAD} = (W_{turbines} - W_{pumps})/W_{tdesign} \tag{B.3}$$

$$E_{PARBOP} = E_{PARBOPD}*(A_{BOP}*F_{PBLOAD} + B_{BOP}) \tag{B.4}$$

$$E_{PARCTD} = F_{CT}*W_{tdesign} \tag{B.5}$$

$$E_{PARCT} = E_{PARCTD}*\left(F_{PBLOAD}*A_{CT}^2 + F_{PBLOAD}*B_{CT} + C_{CT}\right) \tag{B.6}$$

$$E_{PARHTRD} = F_{HTR}*W_{tdesign} \tag{B.7}$$

$$F_{HTRLOAD} = Q_{HTR}/Q_{HTFmin} \tag{B.8}$$

$$E_{PARHTR} = E_{PARHTRD}*(A_{HTR}*F_{HTRLOAD} + B_{HTR}) \tag{B.9}$$

$$E_{PARSCA} = (E_{SCA}*N_{sca})/1000,000 \tag{B.10}$$

$$E_{NET} = W_{turbines} - W_{pumps} - (E_{PARFIXED} + E_{PARBOP} + E_{PARCT} + E_{PARHTR} + E_{PARSCA})$$

$$E_{SOLD} = E_{NET}, \text{ when } E_{NET}>0 \tag{B.12}$$

$$E_{BOUGHT} = |E_{NET}|, \text{ when } E_{NET} < 0 \tag{B.13}$$

$$W_{NET} = \sum E_{NET} \tag{B.14}$$

$$W_{SOLD} = \sum E_{SOLD} \tag{B.15}$$

Appendix C

The total plant capital cost is the sum of the direct and indirect capital costs. Table C.1 presents the key parameters used in Equations (C.1)–(C.37) to calculate the total plant capital cost. These equations and parameters are adapted from the SAM Parabolic Trough Cost Model 5-12-2010 spreadsheet [25]. Table C.1 shows the total capital cost results for a PT-TES plant with 6 h of thermal energy storage. Equation (C.37) shows how the total plant capital cost is reduced with the federal investment tax credit (ITC), which is currently applied as a cash grant option.

Table C.1. Total plant capital cost parameters. (Bold-faced items were calculated using the equations displayed below).

Parameter	Description	Unit	Nominal value
Direct capital cost			
A_{ref}	Reference solar field area from SAM	m^2	854,000
$C_{SI,prep}$	Site improvement cost – site preparation	$M	$1.8
$C_{SI,C\&G}$	Site improvement cost – clearing and grubbing	$M	$0.4
$C_{SI,GDRRD}$	Site improvement cost – grading, drainage, remediation, retention, detention	$M	$9.9
$C_{SI,RPF}$	Site improvement cost – roads, parking, fencing	$M	$10
$C_{SI,WSI}$	Site improvement cost – water supply infrastructure	$M	$1.4
C_{SI}	Total cost of site improvements	$M	$24
$C_{HTF,FPS}$	Heat transfer fluid system cost – freeze protection system	$M	$0.5
$C_{HTF,U}$	Heat transfer fluid system cost – ullage system	$M	$0.9
$C_{HTF,p}$	Heat transfer fluid system cost – pumps	$M	$5.1
$C_{HTF,ENBS}$	Heat transfer fluid system cost – expansion, nitrogen blanketing system	$M	$6.6
$C_{HTF,SFPIVF}$	Heat transfer fluid system cost – solar field piping, insulation, valves, fittings	$M	$43
$C_{HTF,PBPIVF}$	Heat transfer fluid system cost – power block piping, insulation, valves, fittings	$M	$1.0
$C_{HTF,FSS}$	Heat transfer fluid system cost – foundations and support structures	$M	$1.9
$C_{HTF,f}$	Heat transfer fluid system cost – fluid	$M	$19
C_{HTF}	Total cost of heat transfer fluid system	$M	$78
$C_{SCA,unit}$	Unit cost of solar collector assemblies and installation	$/m^2	$295
C_{SCA}	Total cost of solar collector assemblies and installation	$M	$256
C_{SF}	Total cost of solar field	$M	$358
C_{PBunit}	Unit cost of power block	$/kW	$941
C_{PB}	Total cost of power block	$M	$104
F_{CCT}	Fraction of power block cost that is directly related to cooling system		9%
C_{CT}	Unit cost of wet cooling system	$/kW	$85
Q_{TESref}	Reference TES thermal capacity	kWht	1750
$C_{saltunit}$	Unit cost of solar salt	$/kg	$1
C_{salt}	Total cost of solar salt	$M	$57
$C_{TES,PHx}$	Thermal energy storage system cost – pumps and heat exchangers	$M	$31
$C_{TES,T}$	Thermal energy storage system cost – tanks	$M	$45
$C_{TES,PIVF}$	Thermal energy storage system cost – piping, insulation, valves & fittings	$M	$1.5

(*continued on next page*)

(*continued*)

Parameter	Description	Unit	Nominal value
$C_{TES,FSS}$	Thermal energy storage system cost – foundations and support structures	\$M	\$0.5
$C_{TES,IC}$	Thermal energy storage system cost – instrumentation and controls	\$M	\$6
$HD_{salthtr}$	Heat duty of salt heater, calculated as the maximum $\lvert Q_{saltFP}\rvert$	MMBtu/ hr	1611
C_{TEShtr}	Total cost of natural gas-fired heater for salt freeze protection	\$M	\$22
C_{TES}	Total cost of TES system	\$M	\$165
$C_{TESunit}$	Unit cost of TES system	\$/kWh	\$88
HD_{htfhtr}	Heat duty of HTF heater, calculated as the maximum $\lvert Q_{htr}\rvert$	MMBtu/hr	110
C_{HTFhtr}	Total cost of natural-gas fired HTF heater	\$M	\$1.8
C_c	Contingency for unforeseen costs that may arise in the future; percentage of total direct capital cost	% of C_{direct}	10%
C_{direct}	Total direct capital cost of power plant	\$M	\$691
Indirect capital cost			
$C_{directREF}$	Reference direct capital cost	\$M	\$659
R_{EPMC}	Cost of engineering, procurement, management and construction – includes plant design, construction management, commissioning/ start-up, owner's costs, and interest during construction	% of C_{direct}	15%
C_{EPMC}	Total cost of engineering, procurement, management and construction	\$M	\$108
R_{PLM}	Project, land and miscellaneous costs – includes permitting, licensing, legal, and land costs	% of C_{direct}	4%
C_{PLM}	Total project, land and miscellaneous costs	\$M	\$18
F_{land}	Ratio of total land to solar field area		4.1
A_{total}	Total land area required for power plant	km^2	3.6
$C_{land,unit}$	Unit cost of land	\$/acre	\$10,000
C_{land}	Total cost of land	\$M	\$8.8
R_{taxS}	Sales tax rate, applied to 84% of direct capital costs	%	8.75%
C_{tax}	Total cost of sales tax	\$M	\$51
$C_{indirect}$	Total indirect capital cost of plant	\$M	\$186
Total capital cost			
C_{cap}	Total plant capital cost	\$M	\$878
ITC	Federal investment tax credit, currently applied as a grant	% of C_{cap}	30%
C_{capITC}	Total plant capital cost with ITC	\$M	\$614

$$C_{SI,prep} = 1,799,000*\left[A \div A_{ref}\right]^{0.9} \tag{C.1}$$

$$C_{SI,C\&G} = 376,000*\left[A \div A_{ref}\right]^{0.9} \tag{C.2}$$

$$C_{SI,GDRRD} = 9,742,000*\left[A \div A_{ref}\right]^{0.9} \tag{C.3}$$

$$C_{SI,RPF} = 10,176,000*\left[A \div A_{ref}\right]^{0.9} \tag{C.4}$$

$$C_{SI,WSI} = 1,402,000*\left[A \div A_{ref}\right]^{0.9} \tag{C.5}$$

$$C_{SI} = C_{SI,prep} + C_{SI,C\&G} + C_{SI,GDRRD} + C_{SI,RPF} + C_{SI,WSI} \tag{C.6}$$

$$C_{SF} = A*C_{SFunit} \tag{C.7}$$

$$C_{HTF,FPS} = 469,000*\left[A \div A_{ref}\right]^{0.9} \tag{C.8}$$

$$C_{HTF,U} = 926,000*\left[A \div A_{ref}\right]^{0.9} \tag{C.9}$$

$$C_{HTF,p} = 5,066,000*\left[A \div A_{ref}\right]^{0.9} \tag{C.10}$$

$$C_{HTF,ENBS} = 6,537,000*\left[A \div A_{ref}\right]^{0.9} \tag{C.11}$$

$$C_{HTF,SFPIVF} = 42,200,000*\left[A \div A_{ref}\right] \tag{C.12}$$

$$C_{HTF,\ PBPIVF} = 1,000,000*\left[A \div A_{ref}\right]^{0.9} \tag{C.13}$$

$$C_{HTF,FSS} = 1,842,000*\left[A \div A_{ref}\right]^{0.9} \tag{C.14}$$

$$C_{HTF,f} = 19,174,000*\left[A \div A_{ref}\right] \tag{C.15}$$

$$\begin{aligned} C_{HTF} =& C_{HTF,FPS} + C_{HTF,U} + C_{HTF,p} + C_{HTF,ENBS} \\ &+ C_{HTF,SFPIVF} + C_{HTF,\ PBPIVF} + C_{HTF,FSS} + C_{HTF,f} \end{aligned} \tag{C.16}$$

$$C_{PB} = C_{PBunit}*W_{out}*1000 \tag{C.17}$$

$$C_{CT} = C_{PBunit}*F_{CCT} \tag{C.18}$$

$$C_{salt} = M_{salttotal}*C_{saltunit} \tag{C.19}$$

$$C_{TES,PHX} = 29,766,000*\left[Q_{TEStotal} \div Q_{TESref}\right]^{0.8} \tag{C.20}$$

$$C_{TES,T} = 42,882,000*\left[Q_{TEStotal} \div Q_{TESref}\right]^{0.8} \tag{C.21}$$

$$C_{TES,PIVF} = 1,418,000*\left[Q_{TEStotal} \div Q_{TESref}\right]^{0.8} \tag{C.22}$$

$$C_{TES,FSS} = 520,000*\left[Q_{TEStotal} \div Q_{TESref}\right]^{0.8} \tag{C.23}$$

$$C_{TES,IC} = 5,677,000*\left[Q_{TEStotal} \div Q_{TESref}\right]^{0.8} \tag{C.24}$$

$$C_{TEShtr} = 13,402*HD_{salthtr} + 367,158 \tag{C.25}$$

$$\begin{aligned} C_{TES} =& C_{salt} + C_{TES,PHX} + C_{TES,T} + C_{TES,PIVF} \\ &+ C_{TES,FSS} + C_{TES,IC} + C_{TEShtr} \end{aligned} \tag{C.26}$$

$$C_{TESunit} = C_{TES} \div (Q_{TEStotal}*1000) \tag{C.27}$$

$$C_{\mathrm{HTFhtr}} = 13,402 * \mathrm{HD}_{\mathrm{htfhtr}} + 367,158 \tag{C.28}$$

$$C_{\mathrm{direct}} = (C_{\mathrm{SF}} + C_{\mathrm{PB}} + C_{\mathrm{TES}} + C_{\mathrm{HTFhtr}}) * (1 + C_c) \tag{C.29}$$

$$C_{\mathrm{EPMC}} = R_{\mathrm{EPMC}} * C_{\mathrm{direct}} * [C_{\mathrm{direct}} \div C_{\mathrm{directREF}}]^{0.9} \tag{C.30}$$

$$C_{\mathrm{PLM}} = R_{\mathrm{PLM}} * C_{\mathrm{direct}} * [C_{\mathrm{direct}} \div C_{\mathrm{directREF}}]^{0.9} \tag{C.31}$$

$$A_{\mathrm{total}} = F_{\mathrm{land}} * A \tag{C.32}$$

$$C_{\mathrm{land}} = C_{\mathrm{land,unit}} * A_{\mathrm{total}} \tag{C.33}$$

$$C_{\mathrm{tax}} = R_{\mathrm{taxS}} * 0.84 * C_{\mathrm{direct}} \tag{C.34}$$

$$C_{\mathrm{indirect}} = C_{\mathrm{EPMC}} + C_{\mathrm{PLM}} + C_{\mathrm{land}} + C_{\mathrm{tax}} \tag{C.35}$$

$$C_{\mathrm{cap}} = C_{\mathrm{direct}} + C_{\mathrm{indirect}} \tag{C.36}$$

$$C_{\mathrm{capITC}} = (1 - \mathrm{ITC}) * C_{\mathrm{ca}} \tag{C.37}$$

Table C.2 and Equations (C.38)–(C.54) display the parameters and calculations used in the operation and maintenance model, which were adapted from the SAM spreadsheet. The values in Table C.2 are illustrative results from the 6 h PT-TES case.

Table C.2. Operation and maintenance cost parameters. (Bold-faced items were calculated using the equations displayed below).

Parameter	Description	Unit	Nominal value
Fixed labor costs			
C_{ADMIN}	Cost of administration personnel: plant manager, administrative aide, financial manager, purchasing, human resources, plant engineer, performance engineer, information technology, and clerks	$M	$0.9
$C_{\mathrm{OPS,PEOT}}$	Cost of operations personnel: plant equipment operators and technicians	$M	$0.5
$C_{\mathrm{OPS,other}}$	Cost of operations personnel: operations managers, senior operators, control room operators	$M	$0.5
C_{OPS}	Total cost of operations personnel	$M	$1
$C_{\mathrm{PBTESm,TC}}$	Cost of power block and TES maintenance personnel: technicians, electricians, and clerks	$M	$0.5
$C_{\mathrm{PBTESm,other}}$	Cost of power block and TES maintenance personnel: supervisors, foremen		$0.1
C_{PBTESm}	Total cost of power block and TES maintenance personnel	$M	$0.6
$C_{\mathrm{SFm,TC}}$	Cost of solar field maintenance personnel: technicians and clerks	$M	$0.7
$C_{\mathrm{SFm,other}}$	Cost of solar field maintenance personnel: supervisors and foremen	$M	$0.1
C_{SFm}	Total cost of solar field maintenance personnel	$M	$0.8
C_{OMlabor}	Total cost of labor for operations and maintenance	$M	$3.4
Fixed other costs			
$C_{\mathrm{SC},G}$	Cost of service contracts: groundskeeping	$M	$0.1
$C_{\mathrm{SC,MW}}$	Cost of service contracts: mirror washing	$M	$0.4
$C_{\mathrm{SC,WT}}$	Cost of service contracts: water treatment	$M	$0.15
$C_{\mathrm{SC,other}}$	Cost of service contracts: control systems, office equipment	$M	$0.2
C_{SC}	Total cost of service contracts	$M	$0.8
Variable costs			
C_{NGunit}	Unit cost of natural gas	$/MMBtu	$5.92
η_{htr}	Efficiency of natural gas-fired heater	%	80%
η_{HTFhx}	Efficiency of heat exchanger in natural gas-fired heater	%	90%
Q_{NGa}	Quantity of natural gas needed to supply annual heat input to salt and HTF heaters	MMBtu	311,660
C_{NGa}	Total annual cost of natural gas for heaters and power cycle	$M	$1.8
$V_{\mathrm{H_2Oa}}$	Volume of water required annually to operate power plant	Million gallons per year	689
$C_{\mathrm{H_2unit}}$	Unit cost of water	$/gallon	$0.0014
$C_{\mathrm{H_2Oa}}$	Annual water cost	$M	$1.0
C_{auxunit}	Unit cost of auxiliary electricity	$/MWh	$135
F_{aux}	Factor to represent the quantity of auxiliary electricity required for each MWh of electricity generated by the power plant	MWh/MWh	0.0103
Q_{aux}	Amount of auxiliary electricity purchased by power plant each year	MWh/year	80,172
C_{aux}	Annual cost of auxiliary electricity purchase	$M	$11
$C_{\mathrm{utilities}}$	Total annual cost of utilities	$M	$14
C_{OMmisc}	Annual cost of miscellaneous materials and maintenance for site improvements, solar field, HTF, TES, natural gas heaters, and the power cycle	$M	$4
C_{OM}	Total annual cost of plant operation and maintenance	$M	$22

$$C_{\mathrm{OPS,PEOT}} = 536,786 * \left[A \div A_{\mathrm{ref}}\right] \tag{C.38}$$

$$C_{\mathrm{OPS}} = C_{\mathrm{OPS,PEOT}} + C_{\mathrm{OPS,other}} \tag{C.39}$$

$$C_{\mathrm{PBTESm,TC}} = 476,472 * \left[A \div A_{\mathrm{ref}}\right]^{0.7} \tag{C.40}$$

$$C_{\mathrm{PBTESm}} = C_{\mathrm{PBTESm,TC}} + C_{\mathrm{PBTESm,other}} \tag{C.41}$$

$$C_{\mathrm{SFm,TC}} = 675,505 * \left[A \div A_{\mathrm{ref}}\right] \tag{C.42}$$

$$C_{\mathrm{SFm}} = C_{\mathrm{SFm,TC}} + C_{\mathrm{SFm,other}} \tag{C.43}$$

$$C_{\mathrm{OMlabor}} = C_{\mathrm{ADMIN}} + C_{\mathrm{OPS}} + C_{\mathrm{PBTESm}} + C_{\mathrm{SFm}} \tag{C.44}$$

$$C_{SC} = C_{SC,G} + C_{SC,MW} + C_{SC,WT} + C_{SC,other} \quad (C.45)$$

$$Q_{NGa} = [(\Sigma|Q_{htr}| + \Sigma|Q_{saltFP}|) \div (1{,}000{,}000 * \eta_{htr} * \eta_{HTFhx})] * 0.00094781712 \quad (C.46)$$

$$C_{NGa} = Q_{NGa} * C_{NGunit} \quad (C.47)$$

$$V_{H_2Oa} = (M_{water} \div 993.3408) * 264.172052358 \quad (C.48)$$

$$C_{H_2Oa} = V_{H_2Oa} * C_{H_2Ounit} \quad (C.49)$$

$$Q_{aux} = \sum [F_{aux} * E_{SOLD}] + \sum E_{BOUGHT} \quad (C.50)$$

$$C_{aux} = Q_{aux} * C_{auxunit} \quad (C.51)$$

$$C_{utilities} = C_{NGa} + C_{H_2Oa} + C_{aux} \quad (C.52)$$

$$C_{OMmisc} = 0.003 * C_{SF} * \left[A \div A_{ref}\right] + 0.003 * C_{TES} * \left[Q_{TEStotal} \div Q_{TESref}\right]^{0.7} + 0.01 * C_{HTFhtr} + 0.02 * C_{PB} \quad (C.53)$$

$$C_{OM} = C_{OMlabor} + C_{SC} + C_{utilities} + C_{OMmisc} \quad (C.54)$$

Appendix D

This Appendix describes the inputs used in the Integrated Environmental Control Model [31] to simulate a new coal-fired power plant that is comparable with the CSP plant configurations examined in this study for the purpose of calculating a carbon price. Table D.1 presented the inputs used in the first graphical user interface (GUI) “Configure Plant”.

Table D.1. Inputs to “Configure Overall Plant” screen.

Fuel type	Coal
Nox control	In-furnace controls, Hot-side SCR
Particulates	Fabric filter
SO_2 control	Wet FGD
Mercury	Carbon injection
CO_2 capture	None
Cooling system	Wet cooling tower
Wastewater	Chemical treatment
Flyash disposal	No mixing

The next GUI, “Set Parameters” includes several pages of input data. Table D.2 presents the inputs to these pages that differed from the default values and the specific page in which they were entered.

Table D.2. Input parameters to "Set Parameters" pages.

Parameter	Value	Units	Location
Type of dollars	Constant	Dollars	Overall plant – 4. Financing
Plant of project book life	30	Years	Overall plant – 4. Financing
Real bond interest rate	8	%	Overall plant – 4. Financing
Real preferred stock return	5.34	%	Overall plant – 4. Financing
Real common stock return	8.74	%	Overall plant – 4. Financing
Percent debt	40	%	Overall plant – 4. Financing
Percent equity (preferred stock)	8	%	Overall plant – 4. Financing
Percent equity (common stock)	52	%	Overall plant – 4. Financing
Federal tax rate	0	%	Overall plant – 4. Financing
State tax rate	0	%	Overall Plant – 4. Financing
Property tax rate	0	%	Overall plant – 4. Financing
Investment tax credit	0	%	Overall plant – 4. Financing
Natural gas cost	5.92	$/mscf	Overall plant – 5. O&M costs
Water cost	1.4	$/kgal	Overall Plant – 5. O&M costs
Current fuel	Wyoming powder river basin	N/A	Fuel – 1. Properties
Gross electrical output	110	MW	Base plant – 1. Performance
Unit type	Supercritical	N/A	Base plant – 1. Performance

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