Integrated Solar Combined Cycle Power Plants: Paving the Way for Thermal Solar

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Abstract

Integrated Solar Combined Cycle Power Plants (ISCCs), composed of a Concentrated Solar Power (CSP) plant and a natural gas-fired Combined Cycle (NGCC) power plant, have been recently introduced in the power generation sector as a technology with the potential to simultaneously reduce fossil fuel usage and the integration costs of solar power. This study quantifies the economic benefits of an ISCC power plant relative to a stand-alone CSP with energy storage, and a NGCC plant. A combination of tools is used to estimate the levelized cost of electricity (LCOE) and the cost of carbon abatement (CoA) for CSP, NGCC and ISCC technologies under different natural gas prices, and at several locations experiencing different ambient temperatures and solar resources. Results show that integrating the CSP into an ISCC reduces the LCOE of solar-generated electricity by 35-40% relative to a stand-alone CSP plant, and provides the additional benefit of dispatchability. An ISCC also outperforms a CSP with energy storage in terms of LCOE and CoA. The current LCOE of an ISCC is lower than that of a stand-alone NGCC when natural gas prices reach 13.5 $/MMBtu, while its CoA is lower at a fuel price of 8.5 $/MMBtu. Although, under low to moderate natural gas price conditions an NGCC generates electricity and abates carbon emissions at a lower cost than an ISCC; small changes in the capacity factor of an ISCC relative to the NGCC, or capital cost reductions for the CSP components significantly tilt the balance in the ISCC's favor.

1. Introduction

The Integrated Solar Combined Cycle Power Plant (ISCC) has been introduced in the power generation sector as a technology with the potential to help reduce the costs of solar energy for electricity generation. An ISCC power plant combines a Concentrated Solar Power (CSP) plant and a Natural Gas-Fired Combined Cycle (NGCC) power plant. The CSP energy is used to either produce additional steam that is integrated in the NGCC's steam turbine to generate electricity [1], or to heat the compressed air in the gas turbine before entering the combustion chamber [2]. ISCC plants effectively help integrating solar power into the grid by circumventing the non-dispatchability of the CSP [3] and providing reductions of operating and capital costs, and the possibility of increased operational flexibility when compared to a standalone NGCC [4].

The concept of the ISCC as a parabolic trough solar plant integrated with modern combined cycle power plants was initially proposed in the early 1990s by Luz Solar International, the builders of the SEGS trough plants in California [1, 5]. The first plant materializing this concept was the Archimede Project in Sicily Italy, which consists of two 380 MWe gas-fired combined cycle power plants and a 5 MWe parabolic trough solar field that uses molten salts as heat transfer fluid (HTF) [5]. As of 2015, there are at least 157MW of thermal solar plants integrated with a natural gas combined cycle plant, including the 75MW Martin Next Generation Solar Energy Center in Indiantown Florida, 20MW ISCC Ain Beni Mathar in Morocco, 20MW ISCC Hassi R'me in Algeria, 20MW ISCC Kuraymat in Egypt and the 17MW ISCC Yazd in Iran. [6-9]

Previous literature evaluates the technical and economic advantages of the ISCC, explores different solar thermal technologies, and discusses alternative setups to optimize performance. J.H. Peterseim et al. [6] evaluated all suitable CSPs technologies for integration with Rankine cycle power plants. The study concluded that line focusing systems such as Fresnel and parabolic trough are ideal for integration of lower temperature steam (<400°C), Fresnel systems are also the best for medium temperatures (380°C to 450°C), and Direct Steam Generation solar towers are the best for higher temperatures (>450°C). Kelly et al. [10] studied two integrated plant designs using Gate Cycle modeling software and concluded that annual solar contributions of up to 12 percent in an ISCC should offer economic advantages over a conventional solar-only parabolic trough power plant; and that the most efficient use of solar thermal energy is the production of high-pressure saturated steam for addition to the heat recovery steam generator. Rovira et al. [11] assessed a number of ISCC configurations with solar parabolic trough collectors and found that the direct steam generation (DSG) configuration is the best choice for solar energy integration although there may be problems with the control of solar field during solar radiation transients, two-phase flow inside the receiver tubes, and temperature gradients in the receiver tubes. Montes et al., [12] and Nezammahalleh et al., [13] conducted a techno-economic assessment of an ISCC using Direct Steam Generation (DSG) in parabolic trough collectors and showed the great influence of solar field size as function of the power cycle capacity (i.e. the solar multiple) in daily operation, annual performance, and economy of a DSG parabolic trough plant. Yuanyuan et al., [14] proposed and investigated a new ISCC system with two-stage solar DSG input to increase solar share. Compared with a one-stage ISCC plant, the two-stage ISCC was found to provide better performance and increased net solar-to-electricity efficiency (of up to 30%). Recently, Mokheimer et al., [15] investigated the technical and economic feasibility of integrating a Parabolic Trough Collector (PTC) system with a gas turbine cogeneration system considering different generating capacities of gas turbine and areas of PTCs. They concluded that hybrid systems with gas turbine generating capacities less than 110 MWe result in a negligible increase in the LCOE but are more economically attractive compared to cogeneration coupled with a CO_2 capturing technology. O. Behar et al. [5] conducted a worldwide technical review of ISCC plants and the status of related research development and deployment (RD&D), and concluded that there has been an exponential increase in the R&DD specially on the DSG-ISCC technology which may offer better performance than the widely installed parabolic trough-ISCC plants.

Other studies discuss operational issues and present costs and benefits for operational ISCC plants in Egypt [7] and Algeria [9]. J. Antonanzas et al. [8] analyzed the overall potential for solar thermal integration in 51 NGCC plants in mainland Spain under different operating scenarios finding that ISCC technology offers enormous opportunity to improve yield and efficiency in peak periods and reduce CO_2 emissions. The study addressed the penalty of solar dumping when ISCC is operated in solar boosting mode and also gas turbine efficiency when ISCC is operated in solar dispatching mode. Also, J. Antonanzas et al. [16] looked at the feasibility of integrating CSP parabolic trough systems with 21 Algerian open cycle gas turbines and combined cycle gas turbines concluding that a yield increase of 24.9 GW h/year and CO_2 emission savings of 9.91 kton/year are feasible with solar field sizes ranging from 30 to 37 loops in combined cycle centrals while in the case of open cycle gas turbines, a solar potential of 1085.7 GW h/year and CO2 emission savings of 652.1 kton/year were recorded with solar shares in the range of 3–4%.

Most past studies conduct a static analysis of the performance of ISCC plants without accounting for the variation of solar energy production and other factors likely to significantly affect the economics of this technology. One exception is the work of Moore and Apt [17] who simulate one year of hourly operations of an ISCC located in Phoenix Arizona, receiving prices that vary in the same way the median of all nodal hourly prices in California ISO. The plant is run to maximize hourly marginal profits so for every hour any of three situations occurs: 1) the plant runs only with natural gas (i.e. "at base load"); 2) the plant operates as an ISCC with both gas and whatever solar energy is available (i.e. "with duct firing"); or 3) the plant does not run at all. A parametric analysis that varies natural gas prices between 2 and 12 $/MMBTU and adjusts hourly electricity prices to reach annual averages between 35 and 85 ($/MWh), results in ISCC capacity factors of 3%- 90% and unsubsidized Levelized Cost of Electricity (LCOE) from the solar portion of the ISCC of 170-380 ($/MWh).

Although previous literature provides valuable insights on the economics of ISCC plants, it is still unclear how this technology compares to other sources of baseload power when CO_2 emissions benefits are considered, and what is the effect of ambient temperature and other factors likely to affect performance and costs. To fill this gap, this paper uses the most up-to-date data to assess the economic and environmental benefits of an ISCC - configured for solar-dispatching operation mode- as a source of baseload dispatchable electricity. The Levelized Cost of Electricity (LCOE) and Cost of CO_2 Abatement (CoA) have been estimated by simulating hourly ISCC operations for five different U.S. locations to account for fluctuations in the solar resource and ambient temperature under varying assumptions regarding natural gas prices, solar energy resources, tax incentives, capacity factors, and capital costs. We conclude that the ISCC is a cost effective way to harness solar power and reduce air emissions from electricity generation. Hence, although only a relatively small amount of solar share (3%-15%) can be economically incorporated in an ISCC, incorporating this technology in the several NGCC plants that may be built in the U.S. to replace coal-fired power plants is an alternative that should be seriously considered in regions with good solar resources.

2. Method

We consider the integration of the most efficient NGCC and CSP technologies available in today's market, and estimate its LCOE, air-emissions, and CoA in comparison to those of the standalone technologies by simulating operations over one typical year in each of five possible U.S. locations. A custom-made thermodynamic model of an ISCC plant composed of a 500-MW NGCC plant and a 50-MW solar field is developed to properly represent operations under different temperature and solar radiation conditions.

The specifications of the NGCC plant are those of the GE FlexEfficiency-60 Combined Cycle power plant [18], while the solar component of the ISCC (i.e. solar field) is assumed to be identical to that of a CSP with parabolic trough solar collectors. Figure 1 presents a schematic of the ISCC analyzed in this paper.

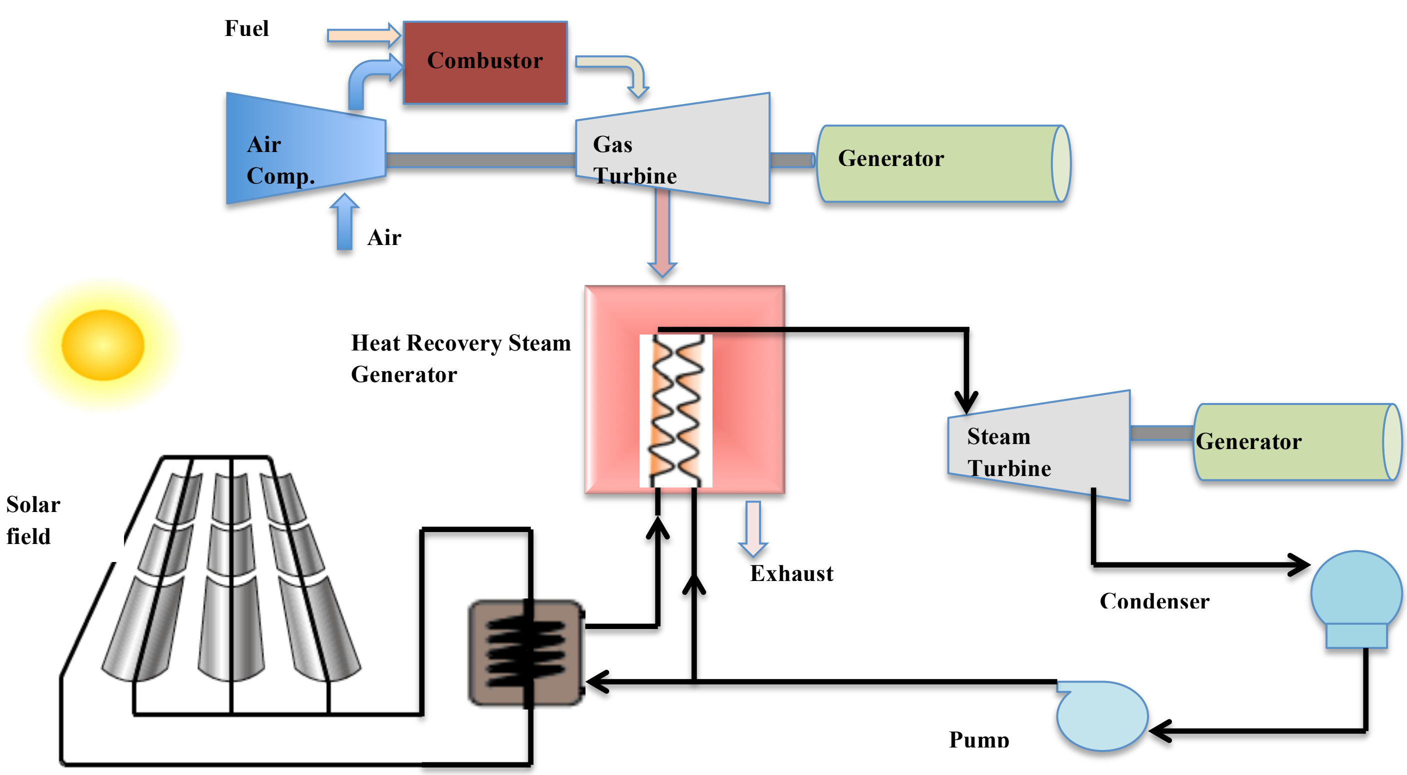


Figure 1. Diagram of an ISCC plant

Although other CSP technologies such as linear Fresnel lens, and solar tower could be used as the solar component of the ISCC [19], we choose a parabolic through system because it is a technology widely deployed today with an installed capacity six times larger than other CSP technologies combined [20], it has an excellent operating history of more than 30 years [3, 20], and it offers the most economical alternative for large power plant applications [21].

We assume the CSP is similar to the 64MW Nevada Solar One CSP Trough plant in Boulder city, NV [22] and assume a CSP capacity equal to 10% of the NGCC. Typically, the CSP share of the ISCC plants installed around the world does not exceed 15% of the total nameplate capacity [5]. This is consistent with previous studies that show this share minimizes the steam turbine efficiency reduction when solar-generated steam is not available [10, 23] and is also in accordance to our analysis of the tradeoffs between capital and operating costs with an increased CSP share (See SI section S.3.3).

2.1 NGCC Assumptions

Consistent with the GE specifications, the NGCC plant is assumed to achieve 61% efficiency at typical conditions when loaded at 80% of its nameplate capacity or more [18], a ramp rate of 50MW/min, a start-up time of less than 30 minutes, and availability factor of 87%. (see Supporting Information (SI) section S.1 for details on the NGCC model). The capital cost of a 500MW NGCC is assumed to be 917 k$/MW of net installed capacity while the fixed O&M cost is estimated to be 13.1-14.91 k$/MW annually [24-26]. We assume a range of 4-18 $/MMBtu for gas prices when calculating the LCOE and CoA, consistent with the AEO 2014 projections of natural gas prices rising from $4.52/MMBtu in 2014 to $13.82/MMBtu in 2040 under the reference case, and to $8.65/MMBtu and $18.6/MMBtu in 2040 under the high and low oil and gas resources cases respectively [24].

2.2 CSP Assumptions

We assume the capital cost of the CSP are 4000 $/kW (in 2012 US dollars) which is the actual cost of the recently completed Genesis Solar Energy Project in Blythe, California [20, 27]. (See CSP modeling in SI section S.2 and sensitivity on capital costs in section 3.4.4). Having excellent solar resources and the optimal solar field size, the annual CSP plant capacity factor would be between 25% and 30% and the CSP plant would generate between 100 and 122 GWh/year [21, 23]. The analysis of a stand-alone CSP assumes sitting in Las Vegas, NV. For the analysis of a CSP plant with energy storage (i.e. CSP+ES) we assume the CSP is coupled with a properly sized Molten Salt System (MSS); a thermal energy storage technology commercially available at unit storage cost of 80 $/kWht [22].

2.3 ISCC Assumptions

The ISCC power plant is assumed to operate in a dispatching mode where the solar steam generated by the CSP is augmented and expanded in the NGCC steam turbine to generate additional power. We choose to represent this mode of operation because it generates the highest economic and environmental values (see SI section S.3.4 for more details). The ISCC under this study is composed of two gas turbines (each one has 165 MWe), heat recovery steam generators (HRSGs) that produce steam at high pressure (16,547 kPa), intermediate pressure (2,482 kPa) and low pressure (552 kPa), a steam turbine (220 MWe), and a solar field (50 MWe). The technical and economic parameters of the ISCC studied are summarized in Table 1.

The solar field is comprised of parallel rows of Solar Collector Assemblies (SCA) and requires an area of 255 acres in which 74 acres (299,540 m^2) are used for the aperture reflective area (i.e. the area of the collector that reflects sunlight toward the receiver). SCAs supply thermal energy to produce steam to drive a steam turbine in a Rankine cycle with solar to thermal efficiency of 60.6%. The concentration factor of solar radiation on the absorber is about 80%, and the maximum temperature in the absorber is about 400 °C. The solar field design-point adopted is based on an assumption of direct solar irradiance of 900 W/m^2 and air temperature of 25 °C. The parabolic trough plant is coupled to the high-pressure level in the HRSGs.

A thermodynamic model developed in MATLAB simulates plant operations by applying mass and energy balances to every component of the combined cycle and the parabolic trough collector field for different input data (see SI section S.1 and S.2). The model has been validated by comparing the NGCC simulation results with DOE/NETL cost and performance baseline estimates for NGCC plants [28] and also by comparing the CSP simulation results with NREL SAM model's output. The comparison of results is presented in the SI section S.3.2.

Table 1. ISCC plant's technical and economic parameters

Parameter	Value [29,30]
Overall gross plant capacity (MW)	550
Gas turbine capacity (MW)	330
HRSG capacity (MW)	220
Solar field capacity (MW)	50
Gas turbine isentropic efficiency (%)	80-90 (90)
Compressor isentropic efficiency (%)	75-90 (87.5)
Gas turbine inlet temp. (°C)	1,280 -1,400 (1370)
Fuel higher heating value (kJ/kg)	52,288
Air compressor outlet/inlet pressure ratio	1-25 (18.5)
Steam turbine isentropic efficiency (%)	80-90 (85%)
Steam turbine inlet temp. (°C)	280-600 (570)
Steam turbine inlet pressure (kPa)	12,755-17,237 (16,547)
Boiler pressure (kPa)	17,237
Boiler efficiency (%)	80
Condenser pressure (kPa)	3.45 -13.79 (10.34)
Condensate pump efficiency (%)	75-90 (80)
Solar field outlet oil temp. (°C)	390
ISCC capacity factor (%)	87

Parameter	Value
NGCC capital cost (2012$/kW)	876-1050 [24-26] (917)
NGCC O&M fixed cost (2012$/kW-yr)	13.1-14.91[24-26] (14)
NGCC O&M variable cost (2012$/MWh)	2-3.6 [24-26] (3)
CSP capital cost (2012$/kW)	3000-5067 [24,31-33] (4000)
CSP fixed O&M cost (2012$/kW-yr)	60-67.26 [24,34] (65)
Discount rate (before tax) (%)	7.5
Insurance rate (%)	0.5
Plant lifetime (years)	25
Real bond interest rate (%)	5.83
Real preferred stock return (%)	5.34
Real common stock return (%)	8.74
Percent debt (%)	45
Percent equity "preferred stock" (%)	10
Percent equity "common stock" (%)	45
Federal tax rate (%)	34
State tax rate (%)	4.2
Property tax rate (%)	2
Inflation (%)	2.5

* Some parameters have a range of operating or estimated values. Values in parentheses are those used in all the base-case simulations

To properly account for varying solar resources (as measured by the Direct Normal Irradiance DNI) and temperature conditions likely to affect the performance of the CSP component, it is assumed that the ISCC plant could be located in one of five different locations in the U.S.; Barstow, CA; Honolulu, HI; Las Vegas, NV; San Antonio, TX; and San Diego, CA. Hourly solar radiation data and hourly temperature for a typical year for these sites has been obtained from the NREL System Advisor Model (SAM) database [22] which generates a typical year data file based on satellite-derived data over the period 1998-2005. The annual average solar energy resource (DNI) and temperatures for each site are summarized in Table 2.

Table 2: Descriptive statistics of solar resources and temperature for the typical year data reported in [22].

Location	Solar Hours per day			Direct Normal Irradiance			Ambient Temp.(°C)		
	Annual average	Range	Standard deviation	Annual average (kWh/m^2)	Daily Range (W/m^2)	Standard deviation (W/m^2)	Annual average	Range	Standard deviation
Barstow, CA	9.3	0-13	4.0	2981	0-1016	395	20.1	1.2-41.9	9.4
Honolulu, HI	6.7	0-11	3.0	2102	0-965	326	23.7	9.6-26.4	1.3
Las Vegas, CA	8.8	0-13	3.1	2802	0-1004	387	18.9	-0.6-40.4	9.7
San Antonio, TX	5.4	0-11	3.5	1714	0-964	302	20.0	-1.6 - 38	8.1
San Diego, CA	6.7	0-12	3.2	2082	0-951	332	16.8	7.9-31.5	4.0

2.4 Levelized Cost of Electricity (LCOE) Calculation

LCOE ¢/kWh for all the technologies considered in this study is estimated using eq. (1):

$$LCOE = \frac{CC_{annual} + O\&M_{annual} + FC_{annual}}{E_{annual}} \qquad (1)$$

where

CC_{annual} is the total annualized capital cost ($), obtained by multiplying the Capital Cost by the Fixed Charge Factor (FCF) which is a levelizing factor that depends on the expected life time of the investment and a number of financial variables. A Fixed Charge Factor (FCF) of 0.1128 (excluding any Investment Tax Credits) is assumed which is the default FCF used in [35]. This assumption is based on economic figures and equations explained in SI section S.1.3.

$O\&M_{annual}$ is the annual operational & maintenance cost –both fixed and variable, excluding fuel costs-($)

FC_{annual} is the annual fuel expenses ($)

E_{annual} is the annual electricity generation (MWh)

2.5 Cost of Carbon Abatement (CoA) Calculation

CoA in $/tonne CO_2 for a technology k is estimated by using eq. (2):

$$Cost\ of\ CO_2 abatement\ of\ technology\ k\ (\frac{\$}{tonne}) = \frac{LCOE\ k - LCOE\ ref}{(CO_{2\ emissions\ rate\ ref}) - (CO_{2\ emissions\ rate\ k})} \quad (2)$$

Where $CO_{2\ emissions\ rate\ k}$ is the rate at which CO_2 is emitted by technology k expressed in tonnes/MWh, and $CO_{2\ emissions\ rate\ ref}$ is the rate at which CO2 is emitted from a reference technology. The estimates of CoA in this study assume a CO2 emissions rate of 1950-2210 lb/MWh, which are the average emissions of coal-fired power plants observed in years 2007-2010 in the U.S. [36]. The LCOE of this reference technology $LCOE_{ref}$ is assumed to range between 2.5 (for an existing coal-fired power plant with no capital charges) and 5.6 ¢/kWh (for a coal plant still paying its capital costs) [35]. Although there is much uncertainty about the emissions of the plants that are or will be shutdown or ramped down during the operation of an ISCC (i.e. uncertainty about emissions displaced), estimating the CoA relative to an average coal plant offers useful information particularly for comparison with other carbon abatement alternatives. Also it is worth noting that, for the purpose of comparing the ISCC's CoA relative to other dispatch able technologies such as the NGCC or CSP+Storage, any choice of reference technology in the CoA estimation yields identical results.

3. Results

3.1 Standalone Concentrated Solar Power (CSP)

The levelized cost of electricity (LCOE) of a standalone CSP located in Las Vegas, Nevada is 20-23 ¢/kWh. If a 50 MW CSP plant displaced the average U.S. coal-fired power plant in the US it would abate 103,487-117,285 tonnes of CO_2 annually and the abatement of CO_2 emissions would come at a cost of 150-215$/$CO_2$ tonne. If instead of replacing a coal plant the CSP replaced the highly efficient NGCC considered in this study then it would reduce carbon emissions by only 0.34-0.40 tonne/MWh, which combined with an assumption of NG prices in the range 6-12 $/MMBTU -which is the range of the projected average NG prices under all AEO 2014 scenarios over the next 25 years- results in a CO_2 abatement cost CoA of 270-480 $/$CO_2$.

3.2 Concentrated Solar Power with Energy Storage (CSP+ES)

The costs and performance of a CSP equipped with different sizes of MSS ranging from 2 to 18 hours of energy storage capacity located in Las Vegas, NV have been examined using the SAM model. It is found that in order to have a fully dispatchable CSP, the MSS should back up 300% of the solar field nameplate capacity which would rise the LCOE from 20.4 to 24.9 ¢/kWh and the corresponding CO_2 abatement costs to 155-235 \$/tonne assuming the emissions and LCOE of a reference plant equal to the average coal-fired power plant in the U.S.

3.3 Standalone NGCC

The LCOE ranges from 4.8 to 13.8 ¢/kWh when natural gas prices are in the range 4-18 \$/MMBtu. If the NGCC replaces the average U.S. coal-fired power plant, then the CO_2 abatement cost is 40-200 \$/tonne. These LCOE estimates assume the plant operates at a capacity factor equal to its availability.

3.4 Integrated Solar Combined Cycle (ISCC)

Results show that an ISCC reduces the costs of harnessing solar power for electricity generation. As mentioned in the introduction, integrating the solar component of a conventional parabolic trough CSP plant into an NGCC leads to significant reductions in the capital cost as well as the operating and maintenance costs due to utilization of common equipment such as steam turbine, heat sink and balance of plant (BOP) and also due to elimination of thermal inefficiencies from daily start-up and shut-down of solar steam-turbine. NREL [23] has estimated the expected reduction in the capital and O&M costs are about 28% and 67%, respectively. From our results we are able to estimate the reductions on capital and O&M as reductions in LCOE. Comparing the levelized cost of solar electricity (LCOE-solar) of a 50 MW CSP integrated into an NGCC (i.e. in an ISCC) with the 50 MW standalone CSP power plant described in section 2.2 we find that the LCOE-solar of the ISCC is 35-40% less than that of a standalone CSP. For example, the LCOE-solar of an ISCC at Barstow, CA is about 11.3 ¢/kWh while the LCOE of a standalone CSP is 19.1 ¢/kWh.

3.4.1 NGCC efficiency reductions from partial loading during cloudy days and non-solar hours

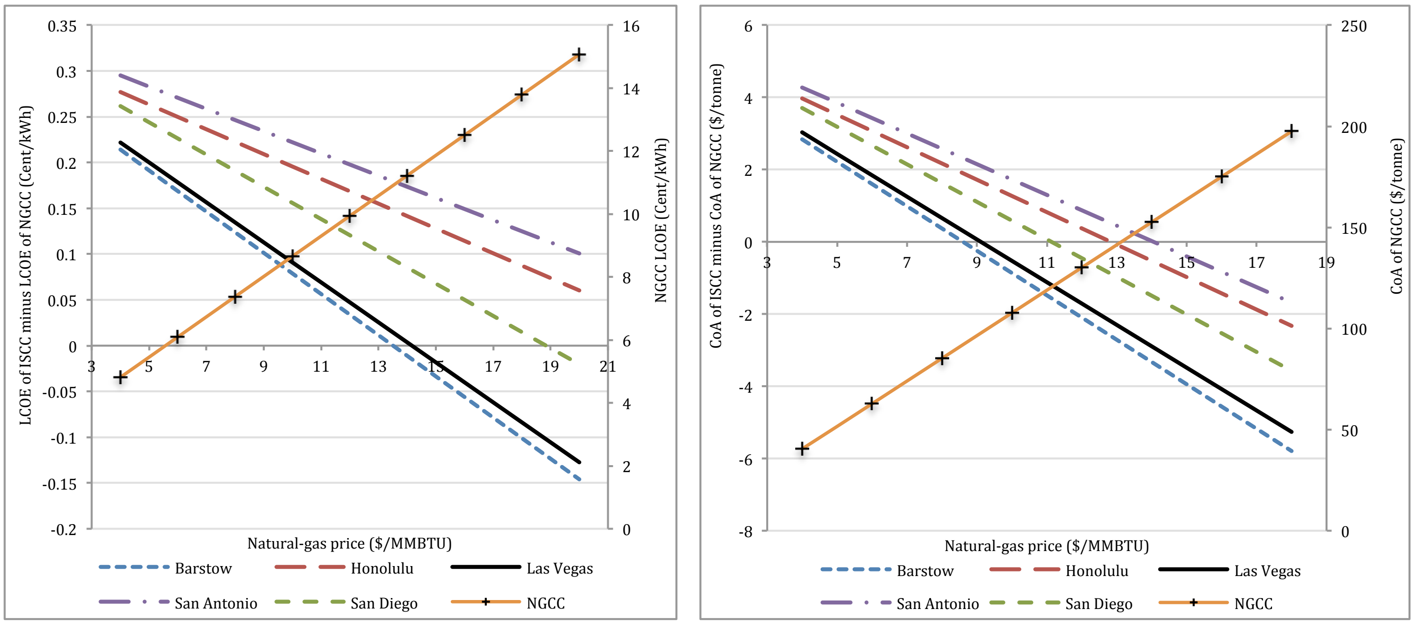
An ISCC configured for solar-dispatching operation mode has a steam turbine capable of handling all the steam generated by the NGCC as well as the steam generated by the solar field when operating at full capacity. Hence the steam turbine will operate away from its optimal design point during nights or cloudy days when the input stream from the solar field is diminished or absent. For the ISCC considered in this study, at non-solar hours, the steam turbine will operate at 77% of its capacity which, according to the Bartlett equation [37], results in an efficiency reduction of 0.01% (see Appendix A-1.2). Such reduction is taken into account by the thermodynamic model used to simulate ISCC performance. For example, for an ISCC in Las Vegas, the total annual electricity generation –in a "typical year"- is estimated to be 3,858 GWh/yr from which 125 GWh/yr are generated by the solar field. Thus, the annual solar share of the electricity generated is about 3.2% and the annual electricity generation reduction in the steam turbine cycle due to inefficiencies that result from partial loading when the solar field goes off is 48.3 MWh/yr.

3.4.2 Impact of solar resources and ambient temperature on ISCC performance

Figure 2(a) depicts the difference in LCOE between the ISCC and NGCC plants at the selected sites and for different assumptions about natural gas prices. It shows that sites with higher average DNI result, ceteris-paribus, in lower LCOE. At a natural gas price of \$6/MMBtu, the LCOE of an ISCC in Barstow, CA -with the highest annual average DNI of the considered five sites at 2981 kWh/m^2- is 6.26 ¢/kWh, while the LCOE of an identical plant located in San Antonio, TX -annual average DNI of 1714 kWh/m^2- is 6.36 ¢/kWh. The ambient temperature, on the other hand, has significant but conflicting impact on the two main components of the ISCC plant. While increasing the ambient temperature reduces the gas turbine efficiency, it boosts the solar field conversion efficiency. It is found that for the ISCC of this study the percent reduction on the gas turbine efficiency is lower than the percent increase in solar conversion efficiency; however, because of the small contribution of the solar field to the annual electricity generation at the ISCC, in general, higher average temperatures mean higher LCOEs. This is illustrated by the plants in Honolulu, HI (6.34 ¢/kWh) and San Diego, CA

(6.31 ¢/kWh); two sites that have almost the same annual average DNI of 2080-2100 kWh/m^2, but differing average ambient temperatures of 23.7 °C and 16.8 °C, respectively. Indeed while the turbine cycle efficiency operating at Honolulu (23.7 °C) is 0.69% lower than when operating at San Diego (16.8 °C) (consistent with results reported by [38,39]), the electricity generation of the solar field at Honolulu is 1.4% higher. However, because the contribution of the solar field to the annual electricity generation at the ISCC plant is less than 3%, a 1.4% increase in the electricity from the solar field results on just a 0.042% increase in total electricity generation.

While comparing LCOE gives information about the economic benefits of an ISCC under high natural gas prices, it fails to account for the environmental superiority of the ISCC that results from its lower CO_2 –and other- emissions. Figure 2(b) shows the CoA of an ISCC in the five considered locations and an NGCC, relative to the average U.S. coal-fired power plant. The figure shows the natural gas prices that are required for the ISCC and the NGCC to have identical CoA (i.e. the breakeven natural gas prices).



(a) (b)

Figure 2. Differences in LCOE (a) and CoA (b) of 500 MW NGCC & 550 MW ISCC Plants at different fuel prices (assumed constant over 25 years), and locations. The fuel price at which the difference in LCOE (or CoA) is zero, is the "break-even natural gas price"

Interestingly, the breakeven NG prices found for CoA are much lower than those for LCOE. For example, while $13.5/MMBtu is the breakeven NG price for LCOE at Barstow, CA and Las Vegas, NV, just $8.5/MMBtu is the breakeven NG price for CoA at these locations.

Another way to compare the ISCC and NGCC accounting for their differences in CO_2 emissions is by assuming a carbon price. Figure 3 depicts the LCOE of ISCC at Las Vegas, NV, assuming carbon prices of $39 and $53 per tonne representative of the estimated social cost of carbon (SCC) in 2015 and the average SCC over the years of 2015-2040 [40]. The figure also shows the effect of a 30% reduction in capital costs due to the Solar Investment Tax Credit (ITC) which provides investors with a 30% tax credit for installation expenses of qualifying renewable energy facilities including CSP plants installed by the end of 2016.

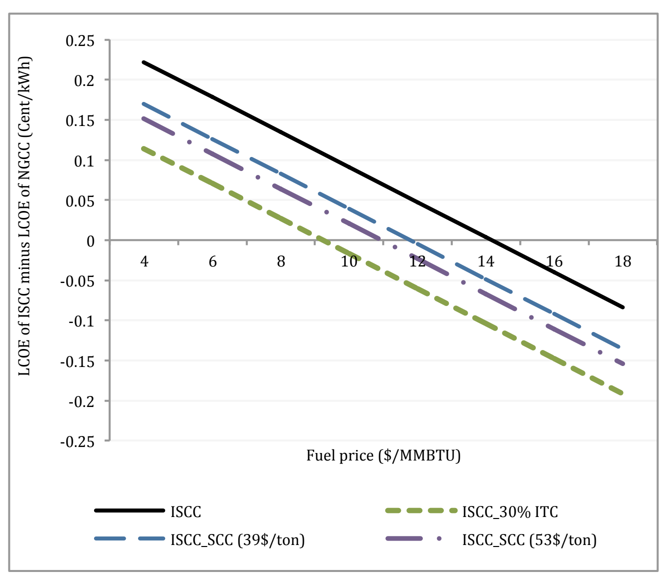


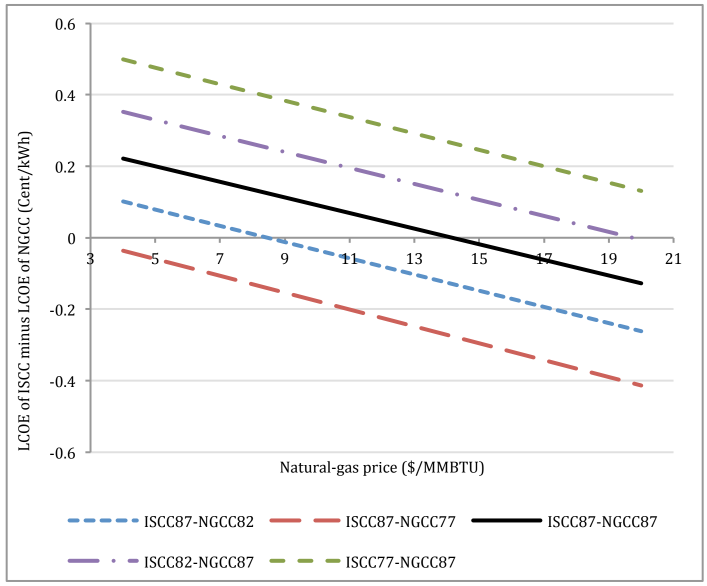
Figure 3. Difference in the LCOE of 550 MW ISCC Plant and LCOE of 500 MW NGCC at different fuel prices, with and without ITC and different carbon price values.

3.4.3 Effect of capacity factors in the comparison of LCOE and CoA of different technologies.

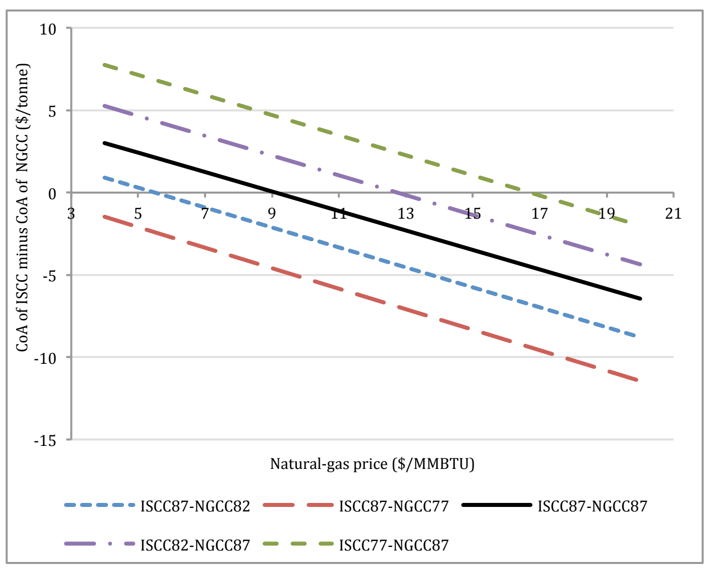
So far, the LCOE estimates presented assume the plants operate at a capacity factor equal to their availability. This assumption fails to capture the fact that, instead of operating as baseload plants, they may be ramped up and down by an electricity system operator to balance electrical demand and supply. Made uniformly across the plants compared, this assumption does not affect their relative profitability, however, it ignores the fact that differences in marginal costs and operational flexibility will determine the ultimate dispatch order. This is important, because if for example, the NGCC were dispatched less than an ISCC, the capacity factor of the NGCC would be lower and the corresponding LCOE values would change in favor of the ISCC. In general, because of its zero marginal cost, a CSP with energy storage (ES) would be dispatched before an NGCC or ISCC, so for the purposes of estimating the relative LCOE and CoA costs it is safe to assume that the capacity factor of the CSP+ES is equal to its availability. However, there is not clear indication of the relative dispatch order between the NGCC and the ISCC. An accurate estimation of the capacity factor of the NGCC and ISCC in a power system requires simulation of balancing authority operations and/or electricity market outcomes using unit commitment/economic dispatch models [41] that properly account for the need to balance generation with time-varying electrical load, and for the costs and performance of all power generators when dispatched at different output levels.

To appreciate the difficulty of correctly inferring the relative capacity factors of the ISCC and NGCC without a proper modeling framework it is useful to consider that given that the marginal costs of the NGCC are lower than those of the ISCC at non-solar hours, and higher during solar hours, one could conclude that in cases of lower electrical demand, the ISCC should operate during the day and shutdown at night when the NGCC can operate more efficiently. However this conclusion may be wrong because it does not account for path-dependencies that are considered in a multi-period optimization framework. A cold start of the ISCC in the morning could offset the gains from reduced natural gas consumption during the day. It may be that the systems' costs over the full day period are minimized when the ISCC is kept operating at night even if its fuel efficiency is lower than that of the NGCC, because this avoids the morning start-up costs and takes advantage of the low marginal costs of the ISCC during the solar hours.

To explore how the LCOE and CoA comparisons would change we consider higher and lower ISCC's capacity factors relative to a NGCC plant. We assume that the change in capacity factor does not affect the plants efficiency but instead changes the proportion of time the plants are shutdown hence modifying both the plants electrical output and the associated operating variable costs. The results, as depicted in figure 5 (a) & (b), show that the change in the capacity factor has a significant impact on the LCOE and CoA. As the capacity factor of ISCC is 10% higher than NGCC, the CoA and LCOE of the ISCC are less than those of the NGCC for natural gas prices in the range considered (i.e. 4-18$/MMBTU). On the contrary, when the ISCC's annual capacity factor is lower than that of the NGCC by 10%, the LCOE of the ISCC is higher than the LCOE of the



(a)



(b)

Figure 5. Difference in LCOE (a) and CoA (b) for 550 MW ISCC Plants and 500 MW NGCC at different capacity factors of ISCC and NGCC. The number after the plant type refers to capacity factor. For example, ISCC87 refers to an ISCC operated at an 87% capacity factor

NGCC for all natural gas prices in the range 4-18 \$/MMBTU, while the CoA of the ISCC is only lower than the CoA of the NGCC for gas prices that exceed 17 \$/MMBtu. If the capacity factor of ISCC is just 5% higher than that of NGCC, the breakeven gas prices for CoA and LCOE of ISCC are about \$5.5/MMBtu and \$8/MMBtu, respectively.

3.4.4 Uncertainty on future capital costs of a CSP and its impact on relative LCOE and CoA estimates.

Estimates of the capital costs of a CSP plant reported in the literature are between 3000 and 5067 2012\$/kWe [24, 27, 31-33, 42, 43]. IEA [32] estimates the capital cost of a CSP plant in 2014 to be around 4200 \$/kW, decreasing to 3000 \$/kW by 2020. Similarly, a study published by International Renewable Energy Agency (IRENA) in 2013 reported that the costs of installed parabolic trough systems ranged from 3400-4600 \$/kW for load factors of 20-27% [33], and projected a 30-50% reduction in capital costs by 2020 due to technological learning and economies of scale following the increasing deployment of CSP power. This projection of capital cost reductions was also consistent with the ambitions of the SunShot Initiative, an aggressive R&D plan launched by the U.S. DOE in 2011 [43], to make large-scale solar energy systems cost competitive (6 cents/kWh or less) without subsidies by the end of the decade. This would have required a reduction of more than 50% in capital costs, estimated to be about \$4,000/kW in early 2012. However, during the last 4 years, the EIA estimates of capital costs reported in the Annual Energy Outlook reports (AEO) for a CSP have been significantly revised up and down, probably due to both changes in the forecast of deployment, and the expected cost reductions that would result from each unit of deployment. [44, 45].

To explore the effect that lower CSP costs would have on ISCC economics, figures 9 and 10 show how the breakeven NG price changes –from the LCOE and CoA perspectives- when the capital cost of a CSP are assumed to be on the low range of the capital cost estimates (i.e. \$3000/kWe). At this lower CSP capital cost case, the LCOE of an ISCC located in excellent solar resources areas such as Barstow, CA and Las Vegas, NV is found to be 6.18 ¢/kWh (at a natural gas price of \$6/MMBtu) compared with 6.26 ¢/kWh in the base case (refer to section 3.4.2). Accordingly, the breakeven gas prices for CoA and LCOE of ISCC become about \$6.5/MMBtu and \$10/MMBtu, respectively. In comparison, the breakeven gas prices for CoA and LCOE of ISCC in the base case are \$8.5/MMBtu and \$13.5/MMBtu, respectively.

4. Discussion

At current U.S. NG prices, assuming identical capacity factors, and in the absence of a carbon price, the ISCC is not cost competitive with an NGCC plant. Investors considering this technology may be motivated by the need to comply with Renewable Portfolio Standard (RPS) targets. Indeed, the most cost effective way to reduce the electricity costs of a CSP is by coupling it with an NGCC into an ISCC system. The levelized cost of electricity from a CSP that is part of an ISCC plant is 35%-40% lower than the LCOE of a stand-alone CSP. Also, the ISCC provides a modest hedge against high natural gas price fluctuations since the break-even natural gas price assuming excellent solar resources such as those in Barstow, CA and Las Vegas,NV varies between 13.5 \$/MMBtu and 14 \$/MMBtu which are high values, but not implausible as it can be judged from the prices projected by EIA [24] under the Low Oil and Gas Resource Scenario.

The advantages of an ISCC over an NGCC are clearer when CO_2 emissions are considered. In a world where the objective is to minimize the cost of reducing CO2 emissions at the lowest possible cost, an ISCC in Barstow would be more economic than a NGCC for natural gas prices above 8.5 \$/MMBtu. If the current scheme of the solar investment tax credit (ITC) [46], which provides a 30% tax credit for projects that are placed in service prior to January 2017, were extended, the LCOE of the CSP and ISCC would be reduced by 25-28% and 3-4%, respectively, which would make the ISCC more economical than an NGCC at fuel price of 8.5-9.5 \$/MMBtu, even in the absence of a carbon price.

5. Conclusion

This study provides an economic assessment of an ISCC, a technology that integrates solar thermal energy into efficient and widely installed natural gas combined cycle power plants. The benefits from such integration include reduction in the capital and fixed and variable operations and maintenance costs resulting from shared equipment and personnel and from CSP and NGCC efficiency improvements.

The analysis shows that the ISCC is a much better way to harness thermal solar electricity than a stand-alone CSP or a CSP with energy storage. However, under low and moderate natural gas prices and in the absence of carbon prices, capacity factor differences or subsidies, the NGCC generates electricity at lower costs. Considering a price for carbon emissions would significantly reduce the gap between ISCC and NGCC LCOEs and would make the breakeven gas price to be in the range of 10.5-12 $/MMBtu at excellent solar resources locations. A further reduction in the breakeven gas price - range of 8.5-9.5 $/MMBtu- would be achieved under the 30% ITC program.

On the other hand, the ISCC environmental advantages can be further appreciated when looking at its CoA relative to CSP and NGCC at natural gas prices of 8.5-9 $/MMBtu. Although only a relatively small amount of solar share (3%-15%) can be economically incorporated in an ISCC, deploying this technology in the several NGCC plants that may be built in the U.S. to replace coal-fired power plants is an alternative that should be seriously considered in regions with good solar resources.

If the CSP capital costs were to go down to $3,000/kW –a plausible event in the next decade-, then the ISCC plant would be more competitive than an NGCC with gas prices in the range of 9.5-10.5 $/MMBtu even if there are no subsidies or carbon pricing. Such break-even gas price could be much lower if CSP achieves higher capital cost reduction as expected by DOE, IEA and IRENA.

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Supplementary Information

S.1 Modeling of NGCC plant

S.1.1 NGCC efficiency

Natural Gas Combined Cycle power plants generate electricity with the gas turbine generator and use the waste heat (hot exhaust gases) to make steam to generate additional electricity via a steam turbine. NGCC plants are being installed in increasing numbers across the world in regions where there is access to large quantities of natural gas. According to the EIA 2013AEO report, the U.S. will add 9.6 GW of NGCC generated capacity in the next 5 years [24]. Typical Combined cycle block sizes offered by three major manufacturers (Alstom, General Electric and Siemens) are roughly in the range of 50 MW to 500 MW.

NGCCs can be used for both baseload and peak power generation. The performance of NGCC power plants is well estimated using the Brayton cycle and Rankine cycle equations, which as found in most engineering thermodynamics textbooks [29, 30, 39] are:

- The Brayton Cycle

Assuming that compressor efficiency is η_c and turbine efficiency is η_t then the actual compressor work $\dot{W}_C$ and the actual turbine work $\dot{W}_G$ are given by:

$$\dot{W}_C = \dot{m}_a(h_2 - h_1)/\eta_c \qquad \text{(S1)}$$

$$\dot{W}_G = (\dot{m}_a + \dot{m}_f)(h_3 - h_4)/\eta_t \qquad \text{(S2)}$$

The net work done is

$$\dot{W}_{Net} = \dot{W}_G - \dot{W}_C \qquad \text{(S3)}$$

where

$\dot{m}_a$ *and* $\dot{m}_f$ are mass flow of air and mass of fuel flow, respectively.

h_1, h_2, h_3 *and* h_4 are enthalpy entering the compressor, enthalpy at the exit of compressor, entering the gas turbine, and leaving the gas turbine, respectively.

The thermal efficiency of the Brayton cycle can be expressed in terms of the enthalpies as follows:

$$\eta_b = \frac{w_{Net}}{q_{in}} = \frac{(h_3-h_4)-(h_2-h_1)}{(h_3-h_2)} = \frac{(h_3-h_2)-(h_4-h_1)}{(h_3-h_2)} = 1 - \frac{(h_4-h_1)}{(h_3-h_2)} \qquad \text{(S4)}$$

where w_{Net} is the net work per unit mass and q_{in} is total heat supplied in the combustion per unit mass.

Since the processes at the turbine outlet and compressor inlet are on a constant pressure (P_1=P_4) as are the processes at the compressor output and turbine inlet (P_2=P_3), the change in enthalpy (i.e. h_4-h_1, h_3-h_2) equals change in temperature multiplied by the specific heat capacity C_p (J/kg °K) and therefore equation (S4) can be written as follows:

$$\eta_b = 1 - \frac{C_p(T_4-T_1)}{C_p(T_3-T_2)} = 1 - \frac{(T_4-T_1)}{(T_3-T_2)} \qquad \text{(S4a)}$$

Also, since the compression in the compressor and the expansion in the gas turbine are adiabatic and reversible processes, we describe the following relationships between temperatures and pressures:

$$\frac{P_1}{P_2} = \frac{P_4}{P_3} \Rightarrow \left(\frac{T_1}{T_2}\right)^{\gamma/(\gamma-1)} = \left(\frac{T_4}{T_3}\right)^{\gamma/(\gamma-1)}, \text{ (}\gamma\text{ is constant)} \qquad \text{(S5)}$$

Hence, $\frac{T_1}{T_2} = \frac{T_4}{T_3}$ or $T_4 = \frac{T_1 T_3}{T_2}$. Substituting this relationship in (S4a) will yield the following expression of the thermal efficiency of the Brayton cycle:

$$\eta_b = 1 - \frac{T_1\left(\frac{T_3}{T_2} - 1\right)}{T_2\left(\frac{T_3}{T_2} - 1\right)} = 1 - \frac{T_1}{T_2} \tag{S6}$$

This expression relates directly the ambient temperature with the efficiency of the gas turbine cycle. Thus, the cycle's efficiency increases as the ambient temperature of the air decreases.

- The Rankine Cycle

The steam generator heat

$$Q_s = h_{1s} - h_{4s} \tag{S7}$$

Turbine work

$$W_S = \dot{m}_s(h_{1s} - h_{2s}) \tag{S8}$$

Pump work

$$W_p = \dot{m}_s(h_{4s} - h_{3s})/\eta_p \tag{S9}$$

Overall cycle work

$$W_{Total} = W_G + W_S - W_C - W_p \tag{S10}$$

Overall cycle efficiency

$$\eta = \frac{W_{Total}}{\dot{m}_f(LHV)} \tag{S11}$$

where h_{1s}, h_{2s}, h_{3s} *and* h_{4s} are enthalpy of the steam at the turbine inlet, enthalpy at turbine outlet, the enthalpy at the condenser exit, and the enthalpy at the pump exit, respectively. $\dot{m}_s, \eta_p$ and LHV are mass of the steam flow, the pump's efficiency and the lower heating value of fuel, respectively.

S.1.2 Effect of NGCC partial load operation on efficiency

The percent reduction in efficiency, as a function of the steam flow ratio, can be calculated as follows [37]:

$$\%Reduction = 0.191 - 0.409\left(\dot{m}/\dot{m}_{ref}\right) + 0.218\left(\dot{m}/\dot{m}_{ref}\right)^2 \tag{S12}$$

$$\eta_{s,turbine} = (1 - \%Reduction)\times\eta_{s,turbine.ref} \tag{S13}$$

where $\dot{m}$ and $\dot{m}_{ref}$ are the steam flow rates at the operational and the full load conditions, respectively.

S.1.3 Fixed Charge Factor (FCF)

The FCF is used to annualize capital costs over the plant life in order to calculate the LCOE. FCF depends on the present value of the future yearly carrying charges which is the sum of the book depreciation, deferred taxes, return on debt, return on equity, income taxes paid, and the ad valorem tax. It can be expressed in the following equation [35]:

$$FCF = \frac{\sum_{m=1}^{25} CC_m PV_m}{A_n} \quad \text{(S14)}$$

where CC_m is year by year carrying charges, PV_m is the present value factor of a future expense in a given year, and A_n is the annuity factor. The CC_m can be calculated as follows:

$$CC_m = D_b + t_{d,m} + RD_m + RE_m + t_{p,m} + a \ \ for\ m = 1, 2, \ldots, n \quad \text{(S15)}$$

where D_b is the book depreciation, $t_{d,m}$ is the tax preferences, $RD_m$is the return on debt in year m, RE_m is the return on equity in year m, $t_{p,m}$ is the taxes paid per year, a is the ad valorem tax r_{debt} and n is the plant life time.

For the ISCC plant, a Fixed Charge Factor (FCF) of 0.1128 (excluding any Investment Tax Credits) is assumed, which is the default FCF used in [35] and corresponds to simple real interest rate of 7.5%, Federal tax rate 34%, State tax rate of 4.15%, property tax rate of 2% and a capital lifetime of 25 years

S.2 Modeling of CSP Plant:
S.2.1 Description

A simple description of conversion processes occurring in the solar power plant is given in many thermal solar energy textbooks and publications [5-9, 11, 19]. The incident solar radiation on the collectors' field propagates along the parabolic mirror and is converted into absorbed power. The absorbed power is then converted into useful thermal power and thermal losses. Useful thermal power is expressed as heating of the thermal fluid. The heat transfer process between the thermal fluid and water results in high enthalpy water-vapor, converted into mechanical power in the conversion block (turbo-generators). Mechanical power is then, efficiently converted into electric power.

The heat received by parabolic trough solar field (i.e. useful thermal power, W) can be expressed as

$$Q_{solar} = m_{tf} \cdot c_p \cdot (T_o - T_i) \quad \text{(S16)}$$

Where m_{tf}, c_p, T_o and T_i are mass flow rate of thermal fluid (kg/s), specific heat of thermal fluid (J/kg K), outlet temperature of solar field (K), and inlet temperature of solar field (K), respectively

The overall efficiency of the solar field is:

$$\eta_{solar} = \frac{Q_{solar}}{I_C \times A_C} \quad \text{(S17)}$$

where I_C and A_C are direct irradiance normal to the aperture plane (W/m^2), and collector aperture area (m^2), respectively.

The total collector area A_c required to generate specific value of electric power from solar field can be found by the following relation:

$$A_c = \frac{P_{solar}}{I_C \cdot \cos(i) \cdot \eta_c \cdot \eta_t \cdot \eta_a} \quad \text{(S18)}$$

Where P_{solar} is design power output (MW), i is incident angle, η_c is the collector efficiency, η_t is turbine cycle efficiency, and η_a is generator efficiency.

Solar to electrical energy efficiency is defined as:

$$\eta_{S-E} = \frac{W_{solar}}{Q_{solar}} \quad \text{(S19)}$$

where W_{solar} is the net power output of the solar only plant. The derivation of each parameter is presented in many references [47].

S.2.2 Capital and O&M Cost Assumptions

The estimated capital cost for 50 MW concentrated solar thermal plant without storage varies between 3000 and 5000 2012$/kWe based on figures from [24, 31, 32, 42]. In this study the capital cost is chosen to be 4000 $/kW which is the actual capital cost of the recent Genesis Solar Energy Project in Blythe, California [27]. Based on the experience in SEGS projects, there are recognized economies of scale which can be determined by the following scaling equation [3]:

$$Cost_2 = (C_2/C_1)^{0.7} \times Cost_1 \quad \text{(S20)}$$

where:

Cost1 is the reference cost for a piece of equipment of capacity C1

Cost2 is the predicted cost of the equipment at the desired capacity C2.

The O&M costs are estimated to be 60-67.26 2012$/kW-yr [24, 34]

S.2.3 Concentrated Solar Power (CSP) with energy storage

The NREL SAM software was used to simulate the performance of the CSP located at Las Vegas, NV and equipped with different sizes of molten salt energy storage ranging from 2 to 18 hours. SAM model is briefly described in section S.3.1. Figure S1 demonstrate the performance of the CSP systems. For each chosen size of the energy storage, the solar multiple has been optimized to achieve the lowest LCOE. Thus, for 2 hours energy storage, it is found that solar multiple of 2.2 is the optimal size which results in LCOE of 20.4 cent/kWh and about 38% capacity factor while 18 hours energy storage requires 5.8 solar multiple to achieve the lowest LCOE at 24.9 cent/kWh and delivers capacity factor of 76%.

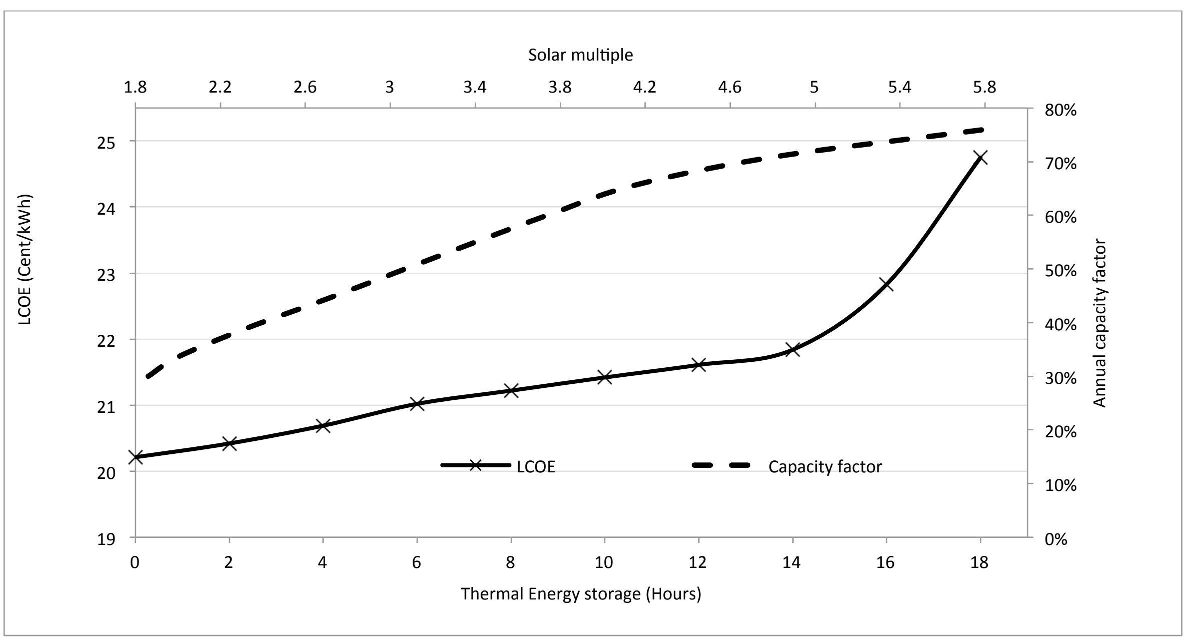

Figure S1. Annual capacity factor and LCOE as function of solar field and thermal energy storage

S.3 ISCC Plant

S.3.1 ISCC model

Different from other studies that use NREL SAM to simulate the thermal output of the CSP component of the ISCC, this thesis uses a custom made thermodynamic model implemented in Matlab to simulate the operations of the NGCC and solar field simultaneously. The main benefit of combining the NGCC and solar field models into one thermodynamic model is avoiding overestimating the losses at the solar field. Using two programs to evaluate the two systems separately and then combining the results could result in lower solar power generation estimates due to a possible double counting of the parasitic losses in the CSP portion.

The enthalpy and entropy quantities, temperature, and flow pressure are computed during the entire cycle of ISCC operations. These calculations are based on thermodynamic equations presented in section S.1 and S.2 The main input variables for the combined cycle plant in the model are summarized in table 1 and include the following:

a. Gas turbine and heat recovery steam generator capacities.

b. Gas turbine inlet temp (F)

c. Air compressor outlet/inlet pressure ratio

d. The air compressor inlet temperature

e. The isentropic efficiency of the gas turbine, air compressor, and steam turbine.

f. The heat recovery steam generator (HRSG) exhaust gas temperature

g. The pressure and temperature at the steam turbine inlet.

h. The pressure and efficiency of the boiler

i. The condenser pressure.

j. The efficiency of condensate pump

The input variables for the solar field portion of the ISCC plant are exactly similar to the input variable in the NREL System Advisory Model (SAM) which is described in the following paragraphs; however, the developed Matlab code is only designed for parabolic trough concentrating solar power while SAM includes performance models for various renewable technologies such as photovoltaic systems (flat-plate and concentrating), parabolic trough concentrating solar power, power tower concentrating solar power (molten salt and direct steam), linear Fresnel concentrating solar power, Dish-Stirling concentrating solar power, wind power, geothermal power, and biomass power.

SAM represents the cost and performance of renewable energy projects using computer models developed at NREL. SAM includes several libraries of performance data and coefficients that describe the characteristics of system components such as photovoltaic modules and inverters, parabolic trough receivers and collectors, wind turbines, and biopower combustion systems. Also, it can automatically download data and populate other input variable values such as solar resource data and ambient weather conditions from online NREL database. For those components, users simply choose an option from a list, and SAM applies values from the library to the input variables. For the remaining input variables, users either use the default value or change its value. These main input variables for the CSP-parabolic trough plant are:

- Installation costs including equipment purchases, labor, engineering and other project costs, land costs, and operation and maintenance costs.

- Collector and receiver type, solar multiple, storage capacity, power block capacity for parabolic trough systems.

- Analysis period, real discount rate, inflation rate, and tax rates.

- Tax and cash incentive amounts and rates.

SAM displays modeling results in tables and graphs, ranging from the metrics table that displays levelized cost of energy, first year annual production, and other single-value metrics, to tables and graphs that show detailed annual cash flows and hourly performance data. The Matlab code, in the other hand, only displays the major performance indicators such as LCOEs under different policies, daily, monthly and annually electricity generations, size of the solar field, annual solar share, and annual avoided CO2 emissions.

To consider the steam generated by solar field, the annual energy (MWh) from the solar steam is calculated as follows [48]:

$$E_{Solar} = 2.78\times10^{-7}\times\sum_{x=1}^{8760} m_{solar,x}\,(h_{sg,x} - h_{3s,x}) \qquad \text{(S21)}$$

Where:

$2.78*10^{-7}$: Conversion factor from kJ to MWh

$m_{solar,x}$: Mass flow of the steam leaving the solar steam generator during hour x (kg)

$h_{sg,x}$: Average specific enthalpy of the steam leaving the solar steam generator during hour x (kJ/kg)

$h_{3s,x}$: Average specific enthalpy of the water at the condenser outlet during hour x (kJ/kg)

The annual energy (MWh) of the high pressure steam can be determined as follows [48]:

$$E_{Solar} = 2.78\times10^{-7}\times\sum_{x=1}^{8760} m_{s,x}\,(h_{1s,x} - h_{3s,x}) \qquad \text{(S22)}$$

Where:

$2.78*10^{-7}$: Conversion factor from kJ to MWh

$m_{s,x}$: Mass flow of the high pressure steam entering the steam turbine during hour x (kg)

$h_{s1,x}$: Average specific enthalpy of the high pressure steam entering the steam turbine during hour x (kJ/kg)

$h_{sg,x}$: Average specific enthalpy of the steam leaving the solar steam generator during hour x (kJ/kg)

The energy efficiency of ISCC plant is simply a ratio of useful output energy to input energy. Accordingly, the efficiency of the reference ISCC plant under consideration in this study is calculated as the ratio of the net produced power by the generators of gas turbine and steam turbine, and the thermal energy supplied by the fuel and solar field:

$$\eta_{ISCC} = \frac{W_{Total}}{\dot{m}_f(LHV)+Q_{solar}} \qquad \text{(S23)}$$

If the thermal energy input by solar field is considered free to the NGCC plant, Q_{solar} term shall be omitted and thus the overall efficiency of the ISCC will be higher than the efficiency of the standalone NGCC plant.

The fraction of solar energy input to the total energy input of ISCC plant is defined as:

$$SS = \frac{Q_{solar}}{\dot{m}_f(LHV)+Q_{solar}} \qquad \text{(S24)}$$

The code also calculates the simple levelized cost of electricity for NGCC, solar portion of ISCC, and ISCC technologies. The estimated LCOE is based on equation (1) and the economic input parameters that are reported in table 2. The code is available at Duke University Energy Initiative website under project teams list which can be accessed at http://energy.duke.edu/education/bass-connections.

S.3.2 Thermodynamic and economic model validation

The developed thermodynamic model in Matlab has been validated by comparing its performance results for standalone 565 MW NGCC plant with the DOE/NETL cost and performance baseline estimates for similar NGCC plant. The performance of the solar field portion has been benchmarked with the NREL System Advisory Model (SAM) model output results for two different size systems and at two different locations, namely are Las Vegas, NV and San Diego, CA.

Table S-1, S-2 and S-3 show the comparison of results. As can be seen, the code shows good performance and produces values very close to the reference ones.

Table S-1. Comparison between Matlab code and DOE/NETL report [28] for 565 MW NGCC

Output	NETL	Matlab	Error (%)
Fuel consumption (kg/s)	21.08	20.98	-0.49
Air flow (kg/s)	876.32	887.52	1.28
Steam flow rate (kg/s)	234.22	234.63	0.17

Table S-2. Comparison between Matlab code and NREL/SAM for 50 MW CSP at Las Vegas, NV.

Output	NREL/SAM	Matlab	Error (%)
Net electric output (kWh/yr)	114716	114781	0.057
LCOE (Cent/kWh)	20.3	20.28	-0.099

Table S-3. Comparison between Matlab code and NREL/SAM for 30 MW CSP at San Diego, CA.

Output	NREL/SAM	Matlab	Error (%)
Net electric output (kWh/yr)	52364	52848	0.924299137
LCOE (Cent/kWh)	26.7	26.5	-0.74906367

S.3.3 Economies of scale and optimal sizing of the ISCC components

Integrating the solar component of a conventional parabolic trough CSP plant into an NGCC leads to significant reductions in the capital cost as well as the operating and maintenance costs due to utilization of common equipment such as steam turbine, heat sink and balance of plant (BOP) and also due to elimination of thermal inefficiencies from daily start-up and shut-down of solar steam-turbine. As estimated by NREL [23] the expected reduction in the capital and O&M costs are about 28% and 67%, respectively. On the other hand, such integration will slightly reduce the Rankin steam bottoming cycle efficiency when solar is not available and steam turbine must run at part load. The steam cycle efficiency reduction can be calculated using Bartlett equation [37].

Comparing the levelized cost of solar electricity (LCOE-solar) of a 50 MW CSP integrated into an NGCC (i.e. in an ISCC) with the 50 MW standalone CSP power plant described in section 2.2 it is found that the LCOE-solar of ISCC is

35-40% less than that of the standalone CSP. For example, the LCOE-solar of ISCC at Barstow, CA is about 11.3 ¢/kWh while standalone CSP is 19.1 ¢/kWh.

Typically, the CSP share of the ISCC plants installed around the world does not exceed 15% of the total nameplate capacity [5]. This is due to tradeoffs in both capital and operating costs of the ISCC when the solar share is increased. Increasing the design solar share in the ISCC plant reduces the capital costs of the CSP component due to economies of scale, but increases the capital costs due to the requirement of a larger steam turbine. Increasing the solar share also affects the fuel costs. On one hand it reduces the efficiency of the steam turbine cycle when the solar field goes off because the steam turbine is sized to operate with all the steam generated from the solar field and gas turbine cycle, and thus it operates at reduced efficiency when no steam is provided from solar filed during the night or cloudy weather as discussed in section 3.4.1 but on the other hand it reduces the overall need for natural gas. The net impact of these effects depends on natural gas prices, plant capacity factors and hourly variations in electricity prices. Figure S2 shows the break-even natural gas price that would make an investor indifferent between an NGCC and an ISCC located in Las Vegas for different solar shares. From the figure it is clear that the lowest breakeven natural gas price is obtained for a solar share of about 10%. Increasing the solar shared beyond this point is not economical due to the tradeoffs between the different costs. For example, increasing the solar field from 2% to 22% reduces the levelized cost of solar electricity from 15.5 ¢/kWh to 14.4 ¢/kWh; however, the ISCC LCOE (assuming $6/MMBtu for NG price) rises from about 6.0 ¢/kWh to 6.6 ¢/kWh due to the combined effect of an increase in the capital costs of a larger steam turbine and an efficiency reduction in the steam turbine cycle.

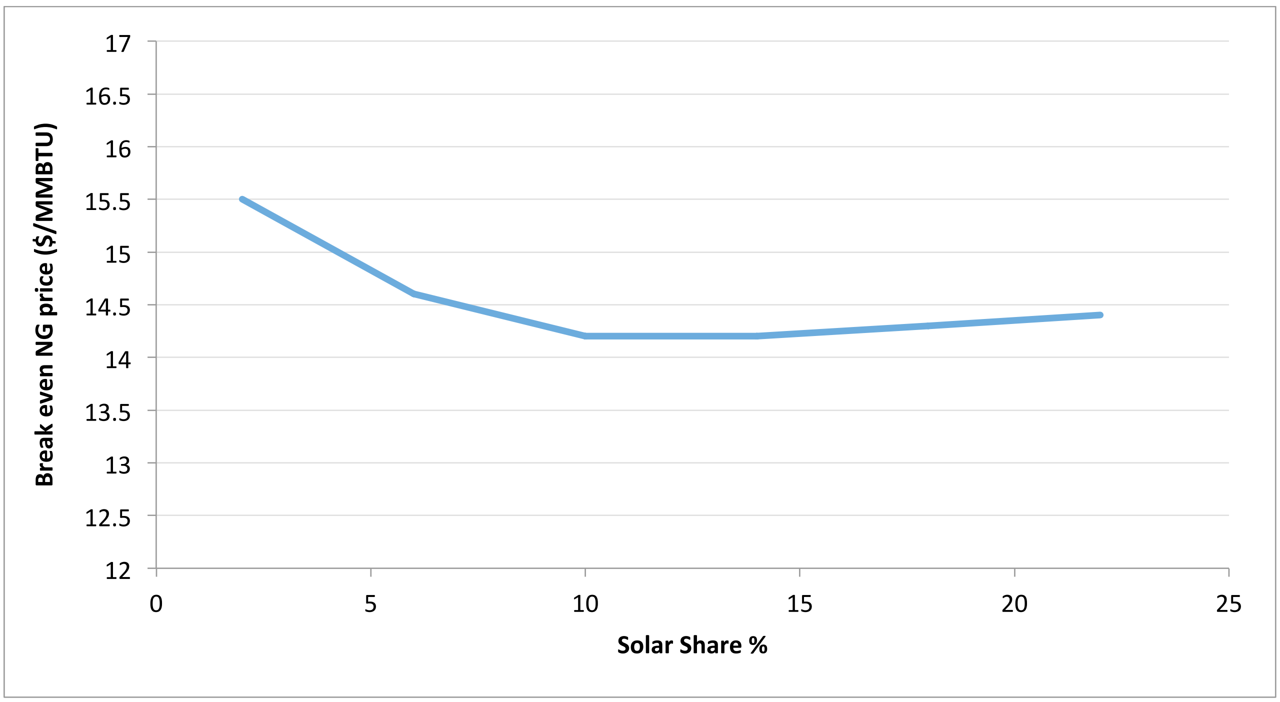

Figure S2. Break-even NG price at different design solar share of CSP integrated with 500 MW NGCC Plant located in Las Vegas

S.3.4 Economic and environmental performance of different modes of ISCC operations

All analyses have been conducted and presented in this study are based on the solar dispatching mode of ISCC operations where additional steam is generated by the solar field and expanded in the steam turbine of the NGCC to produce additional power. Thus, the steam turbine and the condenser in the NGCC plant need to be oversized to accommodate the additional steam from the solar field. The other type of operation mode is the solar boosting mode where NGCC runs under full load and utilizes the solar steam only to fully or partially compensate the NGCC power output reduction during high ambient temperature condition in order to maintain the rated power output throughout the year while it dumps the excess solar thermal energy. Thus, there are no modifications required to enlarge NGCC steam turbine and condenser.

Both modes of operations have been tested assuming that the ISCC plant is located at Las Vegas, NV and NGCC rated capacity is 500 MW similar to the one presented in this study. Figure S3 shows the power output from the NGCC as well as the potential solar power integration under solar boosting mode operation. The solar filed is sized to be 9 MW to compensate the maximum steam turbine power reduction which was found to be 7.3 MW on July 9th at 4PM where temperature was 40ºC and solar irradiance was 860 W/m^2. The system experiences significant solar energy dumping when NGCC is operated in good weather condition. The results show that 60% of the available solar power generation is not utilized (i.e. dumped). On the other hand, system still experiences reduction in the plant output under severe weather condition when ambient temperature is high and solar resources are low or none.

Figure S4 depicts the difference in LCOE between the ISCC and NGCC plants under the two modes of ISCC operations; solar dispatching and solar boosting modes. Both ISCCs consists of 500 MW NGCC integrated with 9 MW CSP and has similar plant characteristics to the ISCC presented in this paper. Also, to appreciate the effect of the economies of scale, the graph includes the reference case study of Las Vegas 550 MW ISCC (500MW NGCC+50MW CSP) which runs under solar dispatching mode. Similar graph is generated to show the CoA for these three cases. Both graphs show that operating ISCC in dispatching mode achieves better economic and environmental performance compared with the boosting mode operations.

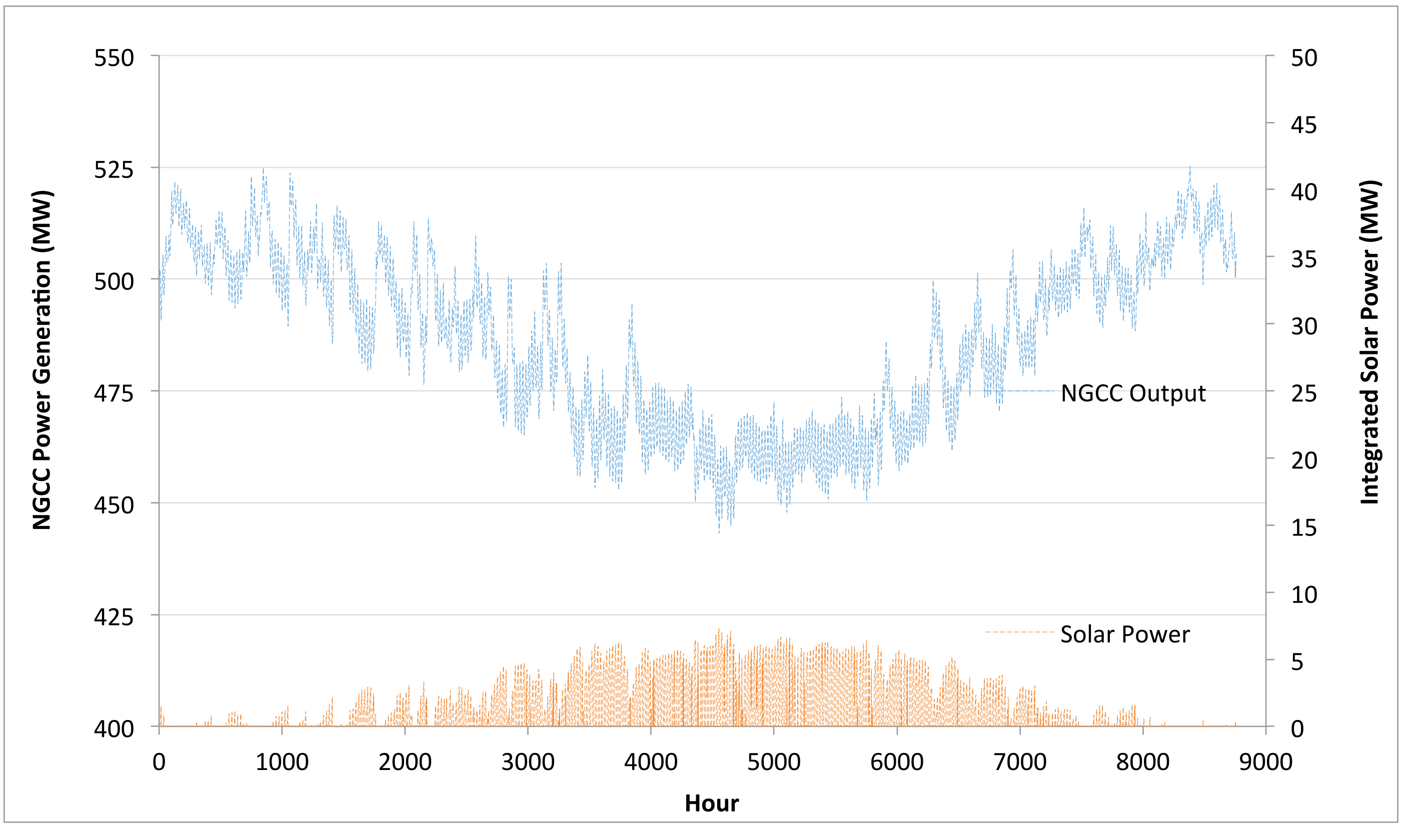

Figure S3. Power output from 500 MW NGCC and 8 MW integrated solar power throughout the year in Las Vegas, NV

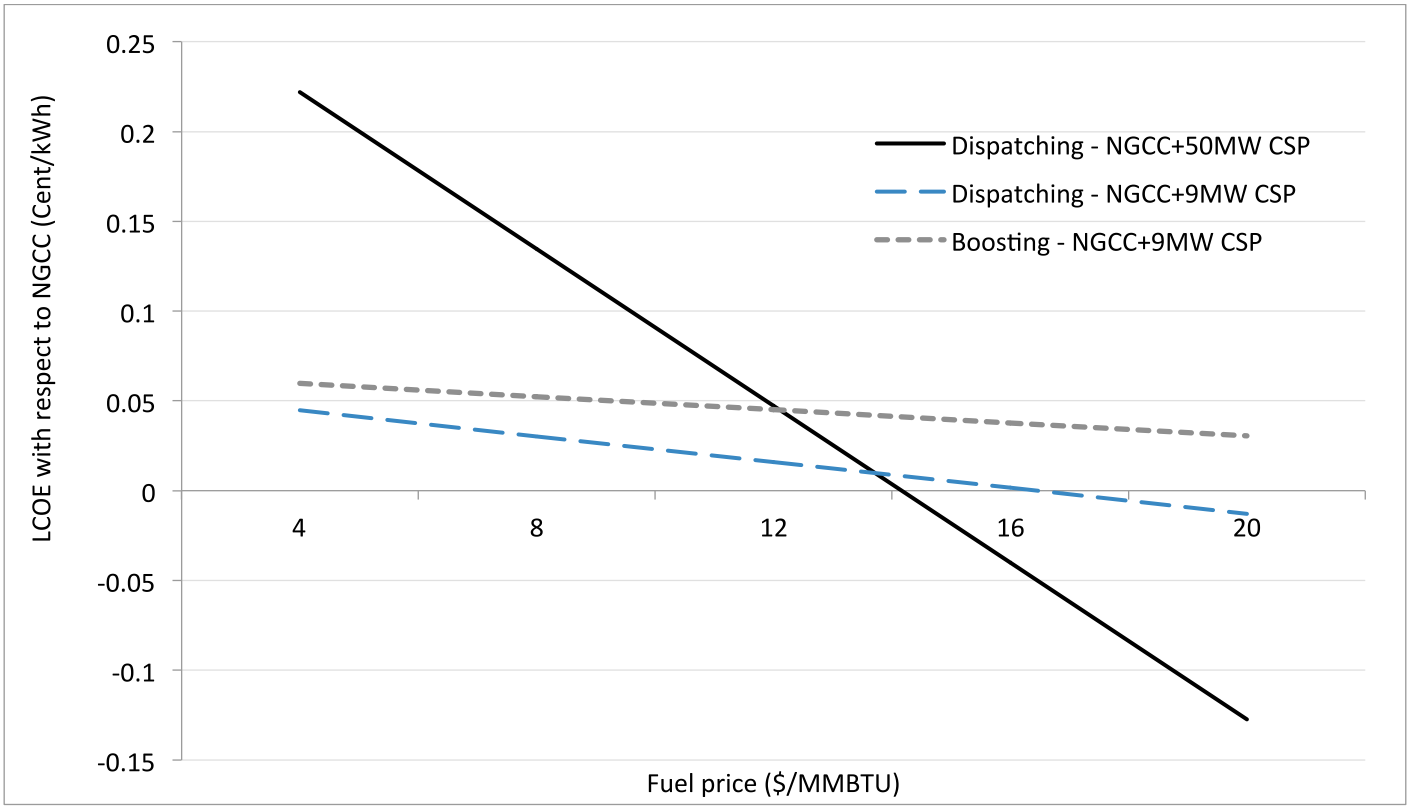

Figure S4. Difference in the LCOE of 500 MW NGCC and LCOE of various ISCC Plants at different fuel prices

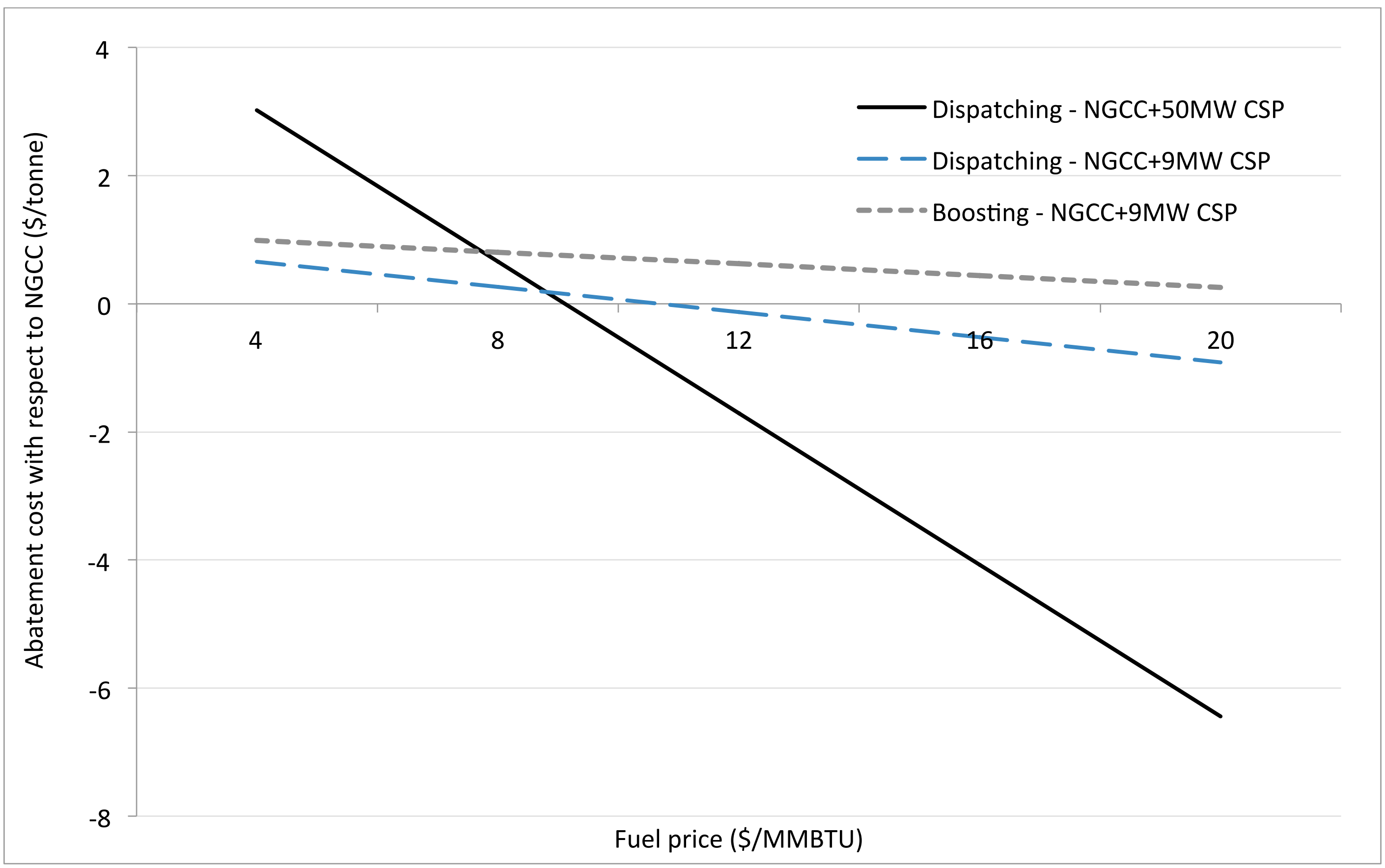

Figure S5. Difference in the CoA of 500 MW NGCC and CoA of various ISCC Plants at different fuel prices