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Publisher's version / Version de l'éditeur:
https://doi.org/10.1002/pip.998
Progress in photovoltaics : research and applications, 19, March 2, pp. 240-246, 2010

PROGRESS IN PHOTOVOLTAICS: RESEARCH AND APPLICATIONS
Prog. Photovolt: Res. Appl. (2010)
Published online in Wiley InterScience (www.interscience.wiley.com). DOI: 10.1002/pip.998

BROADER PERSPECTIVES

Solar based large scale power plants: what is the best option?

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ABSTRACT

There are very few published data comparing performance and cost of thermal and photovoltaic (PV) based solar power generations. With recent intense technology and business developments there is a need to establish a comparison between these two solar energy options. We have developed a simple model to compare electricity cost using these two options without any additional fuel source of hybridization. Capital along with operation and maintenance (O&M) costs and other parameters from existing large scale solar farms are used to reflect actual project costs. To compete with traditional sources of power generation, solar technologies need to provide dispatchable electric power to respond to demand during peak hours. Different solutions for energy storage are available. In spite of their high capital cost, adding energy storage is considered a better long term solution than hybrid solar systems for large scale power plants. For this reason, a comparison between the two solar options is also provided that include energy storage. Although electricity storage is more expensive than thermal storage, PV power remains a competitive option. Expenses related to O&M in solar thermal plant are about ten times higher than PV, an important factor resulting in higher energy cost. Based on data from proven commercial technologies, this study showed that PV holds a slight advantage even when energy storage is included. Copyright © Crown in the right of Canada. Published by John Wiley & Sons, Ltd.

KEYWORDS
power plant; photovoltaic solar; thermal solar; energy storage; cost assessment

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Received 15 April 2009; Revised 19 January 2010

1. INTRODUCTION

Solar energy is poised to become a major contributor to future energy needs. Solar energy is abundant, clean, and renewable. As a source of energy, solar is used in different conversion processes including solar-to-heat, solar-to-fuel, solar-to-chemicals, and solar-to-electricity.

The first conversion process is mostly used for water and space heating with a significant market share [1]. The next two conversion processes are still under development [2]. Water photo-electrolysis process for hydrogen production remains the most promising option that could facilitate the deployment of hydrogen economy. For example, hydrogen could be used as fuel and as a chemical in petrochemical industry.

The last conversion process (solar-to-electricity) is attracting much more attention and is already used commercially via two main options. Direct solar-to-electricity conversion using the photoelectric effect is obtained with different semiconductor materials compositions including crystalline silicon, amorphous silicon, cadmium telluride (CdTe), and $CuIn_{1-x}Ga_xSe_2$. Below, we simply refer to this option as the solar photovoltaic (PV). Indirect solar-to-electricity using thermal process has been used in relatively larger commercial plants for decades. Using parabolic mirrors, direct solar irradiation is concentrated onto a tube containing circulating heat-transfer-fluid (HTF). Heated fluid (to around 400°C) is circulated through a heat exchanger to produce water vapor [3]. Following a precisely controlled heating and super-heating stages, this vapor is directed to a steam turbine to finally produce electricity. Below, we simply refer to this option as the solar thermal. It is also referred in the literature as the concentrated solar power (CSP) [3].

Very few attempts have been made to establish a fair and quantitative comparison between these two solar-to-electricity conversions options. Until recently, solar PV is mostly used in residential and commercial buildings with an average installed power of about 3 and 50 kW, respectively. On the other hand, solar thermal option is mostly developed in larger scale with power output of around 50 MW often with natural gas hybridization. With the recent development of utility scale PV farms, an updated comparison is warranted to evaluate the advantage and disadvantages of these two solar options.

Several large scale PV solar farms have been recently developed mostly in Spain. About 20 PV solar farms are operational or under-construction with a rated power ranging from 20 up to 60 MW each (www.pvresources.com). This rated power is comparable to the nine Solar Energy Generating Systems (SEGS) power plants built in California ranging from 14 MW (SEGS I) to 80 MW (SEGS IX). These SEGS plants operate mostly in the hybrid solar-natural gas mode. Other parabolic trough plants are also completed (Solar One in USA and Andasol 1 in Spain) or under construction (Hassi-Rmel, Algeria). Solar One and Andasol 1 are not based on hybrid design. The majority of today's solar power plants are based on hybrid design using natural gas boiler to increase the capacity factor and optimize the capital investment in the power block. Actual solar contribution to the overall energy mix in these plants could be as low as 5% of the total energy output. These hybrid power plants cannot be used to compare the merits of the two solar options, particularly if the long term goal of solar energy development is to compete or even replace fossil fuel as baseload power generations. Other hybrid options including PV-diesel and PV-thermal systems [4] are not considered in this study.

Availability of technical and financial data from existing large scale solar power plants is the biggest challenge that we encountered while researching on this subject. Very few actual data have been reported in the literature on large scale solar PV power plants. Data on a 5 MW crystalline silicon utility-scale and grid-connected PV system in Arizona (USA) has been reported in this journal [5,6]. The 5 years of operation experience in this system provides a good benchmark for comparison with other utility scale power generation. In the case of solar thermal, the 50 MW CSP plant in Spain (Andasol 1) completed in 2008 will be used as the benchmark.

Three studies comparing the two solar options have been reported [7–9]. A study was conducted by a group of solar thermal experts few years ago using simulation without any specific reference to field data from an existing solar plant [7]. The results comparing non-tracking PV system and 2-axis-tracked PV system with 1-axis tracked parabolic trough power plants, showed a clear advantage of the solar thermal option particularly in areas with large direct solar irradiation. In the case of the solar thermal, based on data reported in Ref. [7], capital and operation and maintenance (O&M) costs are estimated to around \$4.9/W and 4%, respectively. In the case of SEGS power plants, reported data showed that O&M cost is around 7% of the capital cost [8]. Based on Integrated Solar Combined Cycle System (ISCCS) with a 67 MW solar field, steam unit and solar field O&M cost is estimated at 8.5% if we include all the components [10]. Only one study on multi-megawatt PV plant has been reported so far [5,6,11]. Installed capital and O&M costs of about \$6.84/W_{ac} and 0.4% have been estimated, respectively.

Energy storage options should be included to provide a better match between solar electricity production and demand. Lead-acid batteries are widely used in off-grid PV applications although the rated power is often very small. Storage will likely increase the cost of PV relatively to solar thermal. To the best of our knowledge there are no data comparing these two solar options including energy storage.

As reported elsewhere [7], solar irradiation level is a critical parameter. There are two main geographical references with large scale deployment of these solar technologies. In one hand Germany with low solar irradiation where mostly small and distributed PV plants are installed. On the other hand, large thermal solar power plants have been built in south of California and Spain under high solar irradiation. These two examples provide hardly a fair basis for comparison given the large discrepancy in irradiation, size, and cost structure.

Capital cost, O&M, solar radiation, and performance ratio (PR) values are key parameters to compare the economic value of both solar options. Other parameters that could affect electricity cost (C_{el}) include performance degradation, labor cost, technology choices, residual plant value, exchange rate, interest rates, and local taxes. This paper provides some perspective and simple comparative study between solar thermal and solar PV power generation with and without energy storage under different solar insolation conditions. Establishing a fair comparison is very important for private and public institutions to make the best long term decisions for both R&D and technology investments strategies.

2. APPROACH

For each solar option, annual electricity output (E_{out}) along with capital and O&M costs (C_{tot}) are calculated for each year. Thus the average annual C_{el} will be:

$$C_{el}\,[\$/\mathrm{kWh}] = \frac{C_{tot}\,[\$]}{E_{out}\,[\mathrm{kWh}]}$$

Annual capital and O&M costs are used to estimate C_{tot}. A net present value (NPV) is thus estimated for each solar option using a discount rate of 7%. Details are provided below.

As mentioned above, it is difficult to compare technical and economical merits of the two solar options. The main difficulty resides in setting a fair baseline for comparison and using appropriate value for key parameters. These parameters should be obtained from commercially proven technologies, not based on promising laboratory results. Numerous promising technologies have been developed, but very few large scale commercial demonstrations have

DOI: 10.1002/pip.998

been made. For this study, only commercially proven technologies will be considered. In the case of solar thermal, the parabolic trough using synthetic oil as the HTF is the only commercially proven technology. Similarly, crystalline silicon has been used to build several gigawatts (GW) of PV solar plants. These two technologies remain the only mature and financially bankable technologies for large scale solar farms.

Fresnel mirror used to directly heat water to saturation are now developed in pilot stages that could potentially reduce significantly the cost of solar thermal plants [3,12]. With its low processing temperature combined with cheaper components, this technology hold serious promises for low C_{el}. However, no commercial demonstration has been made so far. Three thin film PV technologies have been developed and used recently in commercial solar farms. Thin film based PV provides several advantages for large scale module manufacturing, with potentially higher performance/cost ratio [13]. In spite of their low production cost, the lack of long term history data is still hindering large scale deployment of these thin film technologies.

Regardless of the technology and size, the basic design of the solar farm is quite simple. A pictorial design of thermal solar and PV based solar power plants including energy storage is provided in Figure 1. Thermal based solar farm involve one more energy conversion stage when compared to PV solar. As it will be discussed later, energy storage options are included in this comparison. In the case of solar thermal, heat storage using molten salt is the most appropriate technology. For PV, sodium nickel chloride (Na–NiCl) battery storage is considered.

Appropriate estimation of impinging solar irradiation levels is critical for both options. In the case of PV the global irradiation on the inclined array is the most appropriate input parameter. In the case of solar thermal, direct solar radiation should be used as the parabolic trough is rotating during the day. Values of these two solar irradiation parameters have been taken from Ref. [7] for three different geographical areas. We have considered three cities to cover mostly the geographical areas with high direct solar radiation to satisfy solar thermal power plants requirements. Almeria (Spain), Cairo (Egypt), and Luxor (Egypt) cities with an estimated global radiation (on a 30° tilted surface) of 2100, 2400, and 2700 kWh/m^2/year, respectively, have been chosen to illustrate our comparison. Direct solar irradiation of 1800, 2300, and 2700 kWh/m^2/year have been used for Almeria (Spain), Cairo (Egypt), and Luxor, respectively [7].

A nominal peak power of 50 MW is used, corresponding to the peak power of Andasol 1 (Granada, Spain). The C_{el} will be estimated over a period of 20 years, a compromise between the typical length of feed-in-law tariff period, lifetime of solar technologies and bank loan structures.

Effective power efficiency, based on field data, should be used instead of the nominal output power under STC.

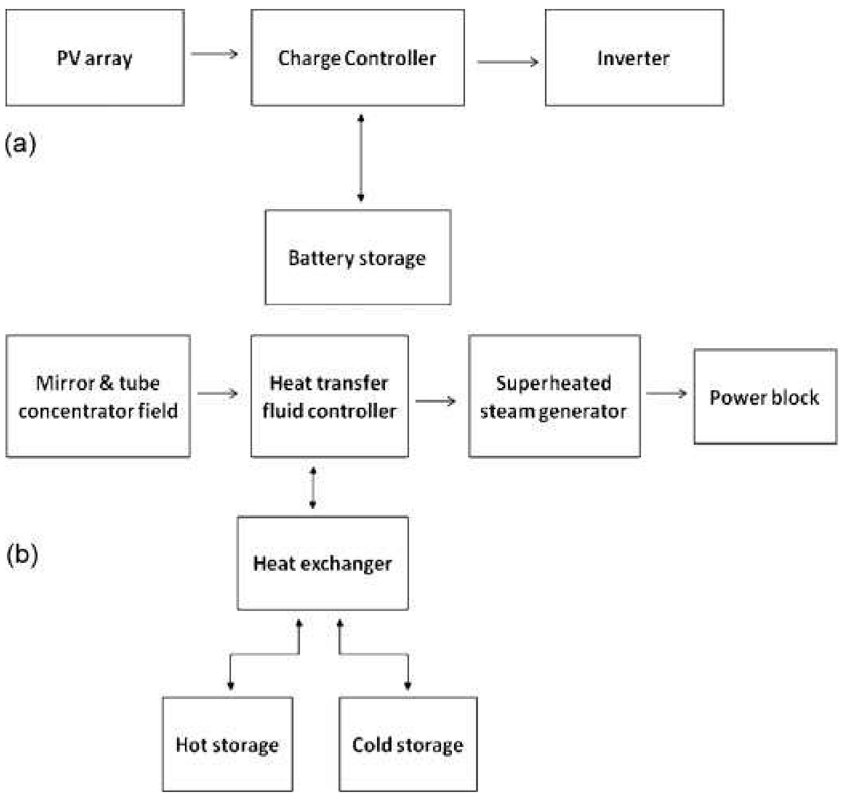

Figure 1. Simplified representation of a typical photovoltaic (a) and thermal (b) based solar power plants including energy storage.

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DOI: 10.1002/pip.998

Using field data, adjustments should be made to account for PR, another important parameter for technology ranking. This parameter adjusts for power loss by operating under conditions different from those defined in STC. For example, higher operating temperature lowers the performance of PV modules. For PV, estimated annual E_{out} (kWh/year) is given by:

$$E_{out} = I \times S \times \eta_{pv} \times PR$$

where I, S, η_{pv}, and PR are the solar insolation, effective surface area, efficiency and PR, respectively. The PR factor based on field data will thus includes all the losses related to the BOS and the PV module. A PR value of 0.8 has been estimated for Nicosia with an average insolation of 2000 kWh/m^2/year [14]. A similar value has been also reported elsewhere [5,6,11]. Even higher PR values have been claimed in commercial literature.

In the case of solar thermal a similar formulae will be used to estimate E_{out}. The only difference involves annual efficiency which already includes both η and PR parameters. Thus in the case of solar thermal estimated annual E_{out} (kWh/year) is given by:

$$E_{out} = I \times S \times \eta_{ST}$$

where η_{ST} defines the overall power efficiency of the solar thermal plant on an annual basis (see below) [15].

2.1. Power efficiency and annual efficiency

For the PV option, efficiency of 14% has been used under STC. Using a PR value of 0.8, the effective annual power efficiency for the PV power plant is 11.2%. However, it is worth noting that proven PV technologies with higher efficiency (SunPower with an efficiency of nearly 20.3%) and lower efficiency thin film technologies (Showa shell at 13.5%) are reported on certified modules [16].

The overall power efficiency (η_{ST}) for solar thermal plants, which includes the PR factor, has been estimated by evaluating the efficiency of the different components of the parabolic trough solar thermal plants [15]:

$$\eta_{ST} = \eta_{SF} \times \eta_{down} \times \eta_{turb} \times \eta_{par} \times \eta_{ava}$$

where η_{SF} (0.37), η_{TPP} (0.93), η_{turb} (0.38), η_{par} (0.83), and η_{ava} (0.98) correspond to the power efficiency of the solar field, thermal to power plant, stream turbine, parasitic and plant-wide availability, respectively. Numbers given between parentheses correspond to the actual efficiency value [15]. Estimated overall power efficiency is thus $\eta_{ST} = 0.106$. In his study, Quaschning [7] used an overall power efficiency of parabolic solar thermal that increases with insolation of the site. An efficiency of 14% is used with a direct horizontal irradiation of about 27 000 kWh/m^2/year. This number is not representative of existing commercial systems power efficiency. Furthermore, insolation of 2700 kWh/m^2/year is not a realistic figure, given the large amount of water required for solar thermal and usually not available in high insolation areas [9]. An efficiency value $\eta_{ST} = 0.11$ will be used, a slight over-estimation of the efficiency taken from the NREL report [15] which also agrees with a recent EPRI report [17].

US dollar ($) currency is used in our C_{el} estimation. When prices are made available in Euros (€), the following conversion ratio is used: €1 = $1.40. We will not consider residual value for the project after 20 years of operation. An overall discount rate of 7% is assumed for both solar options. We did not consider the fact that solar thermal will not generate revenue until the project is 100% completed. Solar thermal plant requires at least 2 years before completion, representing a significant loss of revenue. In the case of PV power plant, its modular architecture allows electricity production even if only a small fraction of the modules is installed.

A nominal power efficiency of 50 MW is considered in this study (Table I). An annual efficiency of 11% for solar thermal and 11.2% for PV requires an effective solar field area of 454 546 and 446 430 m^2, respectively. Using these effective solar field areas, energy outputs is calculated under different irradiation levels for each solar option (Table II).

2.2. Energy storage

It is important to distinguish between the storage options available and appropriate for solar thermal and solar PV. The former takes advantage of potentially cheaper thermal storage. The latter is mostly limited to electric storage similar to what is currently used in consumer electronics and automotive sectors. It is also possible to store PV electricity in other energy forms such as pumped hydro, hydrogen, and compressed air [18–20]. Pumped hydro and compressed air energy storage (CAES) provide the cheapest storage options for utility scale power plants, although their suitability depends on other parameters. CAES has been already used in large scale electricity storage with a nominal capacity of 100 MW or more [17]. With an average installed cost of about $0.5/W for centralized utility scale [17], CAES is the best economical option when natural storage space is available.

Table I. Technical and financial parameters used in this study for solar thermal and solar photovoltaic.

Parameters	Thermal	PV
Nominal power (MW)	50	50
Power efficiency	0.11	0.14
PR	—	0.8
Direct capital cost ($/W)	5.60	5.44
Indirect capital ($/W)	1.40	1.40
Storage cost ($/W)	1.68	2.2
O&M (%)	4	0.4
Discount factor (%)	7	7

See text for details.

DOI: 10.1002/pip.998

Table II. Estimated electricity cost obtained from solar thermal and solar photovoltaic under different solar insolations.

	Irradiation (kWh/m^2/year)	Thermal with storage ($/kWh)	PV with storage ($/kWh)	Thermal without storage ($/kWh)	PV without storage ($/kWh)
Almeria: global non-tracked	2100		0.37		0.27
Almeria: direct 1-axis tracking	1800	0.41		0.33	
Cairo: global non-tracked	2400		0.32		0.24
Cairo: direct 1-axis tracking	2300	0.32		0.26	
Luxor: global non-tracked	2700		0.28		0.21
Luxor: direct 1-axis tracking	2700	0.27		0.22	

Several storage options have been considered for solar thermal power plants [21–24]. Using eutectic salts, early cost estimation for 6 h storage is around $32/$kWh_{th}$. More recent data provided cost of thermal storage using molten salt at around $56/$kWh_{th}$ [22]. Salt based thermal storage is relatively efficient. A thermal loss of 2% has been estimated for over 1 year due to heat loss in the cold and hot tanks [24]. To this, one should also add losses via the two heat exchanger (oil to hot salt and hot salt to oil) and the long network of transfer tubes.

Although CAES and pumped hydro are cheaper storage options, advanced batteries are chosen in this study because of their potential for future cost reductions. Furthermore, contrarily to thermal, pumped, and compressed air storage technologies, advanced batteries are much easier to adapt to medium size rated power capacity critical in distributed power generation.

There are numerous battery storage technologies developed for consumer electronics, electric cars, and stationary applications [25,26]. Efficiency, durability, and cost are critical factors. For this study, advanced rechargeable Na–NiCl batteries (often referred by the name Zebra and currently used to power electrical cars) will be used. Based on their demonstrated overall efficiency of 90% [27], life-cycle-cost, and non-toxicity of its base materials (Ni and salt), this technology looks promising for large scale deployment. Based on unit cost of $109/kWh [28], the overall storage capital cost will be:

$$C_{bat} = 1.2 \times 350\,000\,\text{kWh} \times [\$109/\text{kWh}] = \$45\,780\,000$$

We have used the maximum electrical storage of $50\,\text{MW} \times 7.5\,\text{h} = 350\,\text{MWh}_{el}$. The factor 1.2 is used to provide additional reserve to avoid discharging the battery below 80% of its full capacity. This will allow longer number of cycles [27]. Based on 2500 cycles lifetime (up to 5000 cycles have been suggested by the manufacturer and demonstrated on the Mercedes A-Class electric car), Na–NiCl batteries should be replaced twice during the 20 years period. Considering that the batteries represent about 70% of the overall storage system cost, the capital cost for the battery storage over 20 years period is approximated to:

$$C_{bat} + 2 \times 0.7 \times C_{bat} = \$109\,872\,000$$

This is equivalent of an average of $2.20 per unit power installed PV.

It is important to note that this storage capacity is hypothetical and should be adapted to the actual solar irradiation intensity. Indeed, during day time, only excess E_{out} will be used for storage. A more precise model should be used to estimate optimum stored electricity.

Based on an energy volume density of 180 Wh/l of the Zebra battery used in electric cars [29], the volume of the storage battery has been estimated by dividing the total battery storage capacity (350 MWh) by energy density (180 Wh/l). Thus the total volume of the battery is about 2000 cm^3. Although huge, this is quite small when compared to the volume of the storage tank of solar thermal (58 944 m^3) with a 38 m diameter base and 13 m high [30]. This difference in size is quite normal, given the difference in energy density. Furthermore, stored thermal energy needs to be converted back to electricity using steam turbine with an efficiency of about 37.5%.

2.3. Operation cost

In the case of the PV plant built in Arizona [5], O&M are estimated to 0.12% of installed capital cost, corresponding to about $0.004/kWh. One should also add the cost of re-building inverters (about 7 years) that is estimated to $0.007/kWh [5]. An overall O&M cost of 0.4% is thus assumed for large scale PV solar farm. On the other hand, O&M cost for solar thermal power plant is set to 4% of the capital cost. O&M cost of about 6% has been estimated for a 15 MW solar thermal plant [15]. Even higher value has been also reported elsewhere [8,10].

This relatively high O&M cost for solar thermal is quite obvious and justified. About 40 employees are required onsite for operating the solar thermal operation [9]. Biweekly mirror cleaning is needed to keep high conversion efficiency. Only remote video-surveillance is required for PV plant. Furthermore a variety and large amount of chemicals involved in the operation of the plant, adding to the overall O&M cost. In addition, safety practices are required due to the fact a small accident could lead to a disaster. Storage tank containing about 3400 m^3 of the HTF exploded at the SEGS II solar thermal plant in 1999 [31]. An even bigger disaster has been avoided, since the flames were within reach of sulfuric acid and caustic soda containers. Although different salts are currently used as storage media, there are still safety and security issues that require additional measures which could increase the overall capital and operations costs of solar thermal power plants with storage. There are also safety issues related to battery storage, although quite limited in the case of stationary applications [26,32].

2.4. Capital cost and energy cost

Table I summarizes the main technical and financial parameters of the two solar options. Based on the large PV plant experience reported in Ref. [5], an overall cost of $\$6.84/W_{ac}$ is used in our calculation. The following cost breakdown has been reported per unit alternative current power (W_{ac}) [5]:

- Module: 4.22.
- Array field – BOS: 0.71.
- Inverter and transformer: 0.51.
- Indirect (overhead): 1.40.

As it is the case of solar thermal, we will separate direct capital cost ($5.44/W_{ac}$) from indirect cost ($1.40/W). No O&M will be attached to the indirect cost. To that, storage cost will be added, which is estimated to about $\$2.20/W_{ac}$.

The overall capital cost of the Andasol 1 is $434M of which $364M is direct capital cost (http://www.schott.com/newsfiles/20060925151741_DuF_Andasol_E.pdf). Per unit watt the capital cost is thus $\$8.64/W_{ac}$. The relative cost breakdown is provided below [15]:

- Solar collection system: 58%.
- Thermal storage systems: 23%.
- Power block: 14%.
- Steam generation or exchange system: 3%.
- Structure and improvements: 2%.

Based on this cost breakdown, storage is thus estimated to cost around $\$1.68/W_{ac}$. Thermal storage cost is thus around 25% less than battery storage.

Table II summarizes the results of our simulations. When storage is not included, C_{el} using PV is lower in most cases. As expected, adding the storage option, the cost differential is reduced. Solar thermal has a slight cost advantage only under extremely high solar irradiation (2700 kWh/m^2/year) when storage is included. Under high solar irradiation, the two solar options provide similar production cost. However, at relatively lower irradiation (e.g., Almeria), solar PV shows some cost advantages. With an irradiation of 2100 kWh/m^2/year (Almeria), there are limited available places outside desert areas. Solar thermal in areas with irradiation above 2100 kWh/m^2/year is not really practical and sustainable.

Even with a feed-in-law tariff of $0.38/kWh (Spain) and direct irradiation of 2140 kWh/m^2/year, the Andasol 1 project is still economically viable. We could expect higher power efficiency using improved solar field components in the future, although probably at higher capital cost. PV efficiency of 14% is the average value for the crystalline silicon modules. Higher efficiency modules (up to around 20%) are used in commercial power plants. However, these high efficiency modules will likely cost more.

Potentially higher efficiency and cost effective technologies are also under development in both CSP and PV areas. If these new technologies are considered, our conclusions could somehow change. However this sensitivity analysis is out of the scope of this manuscript. Furthermore, unless field data are made available, it is quite impossible to make a fair comparison based on newly developed technologies. Any improvement in efficiency will affect cost of the components including BOS.

Fthenakis *et al*. [33] obtained similar conclusions when comparing CSP and PV technologies. The peak production cost of electricity using CSP and PV has been estimated to $0.21/kWh and $0.16/kWh, respectively. When storage is included in PV plant, the production cost increased to $0.21/kWh. These authors used similar nominal rate power and did not include any hybridization.

3. OTHER ISSUES

Besides capital and O&M costs, there are numerous other factors that should be considered when comparing different solar power options (Table III). For example, land requirements could be critical. Annual power efficiency and required distance between two parallel string of module/trough to avoid shading and/or allow regular maintenance must be considered. The effective solar field is relatively the same since the overall efficiency of both solar thermal and solar PV are the same. However, larger distances are required in the case of parabolic trough to allow trucks to move freely for regular water cleaning.

The most daunting issue with solar thermal is their water requirement [10]. A 50 MW plant requires around 850 000 m^3 of water annually. Given solar thermal operates only under direct irradiation (often arid regions) there are very few areas in the world with high direct radiation endowed with enough renewable water resources.

Solar thermal provides relatively better potential for green house gas (GHG) mitigation. For parabolic trough, only 13.6 g CO_{2eq} is emitted for each kWh of produced electricity [34]. Relatively higher emission are reported for crystalline silicon based PV electricity (30 g CO_{2eq}/kWh) [35,36]. When compared to coal and natural gas both solar options allow significant GHG mitigation. Even when 1 ton of saved CO_2 costs $100, 100 g of CO_2 will provide an additional $0.01/kWh financial incentive. Although CO_2 emission reduction is significant, its impact on the financial comparison between solar thermal and solar PV is minimal. This comparison does not take into account of additional emissions from energy storage life cycle analysis.

Table III. Summary of the main characteristics of PV and thermal options.

Parameters	Photovoltaic	Solar thermal
Power plant size and construction	Suitable for small (1 kW or less) and large (5 MW or more)	Only large plant (50 MW or more)
About 1 year to complete	At least 2 years to complete	
Operation and cost	Remote control low operation cost: clean module two times a year	Onsite control. High operation cost: mirror surface should be always clean
Occasional rain provides sufficient cleaning for single surface	Twice a month mirrors cleaned with de-carbonated water. More than 50 employees	
Irradiation conditions	Operate under any sunny condition (include diffuse light)	Operates only under direct
Maturity	Mature in the case of silicon. Improvement in power efficiency (20%) and raw material use (10 g/W)	Mature. Possibility of improvement using new design
Water requirements	Minimum water requirements	Require large amount of water (a problem in high insolation areas)
Components and chemical inventory	Only inverter should be changed after 7 years	Large amount and variety of chemicals
Difficulty to operate	No moving part (except when tracking systems are used). Offsite monitoring	Moving parts
Experienced engineers are required all the time on site		
Raw materials availability and cost	Shortage of solar grade silicon has been solved	One producer of eutectic salts, with new suppliers entering the market
Storage options	Electricity storage is beneficial to improve grid stability and power quality	Thermal storage is cheaper but there are some safety issues
Power efficiency	Up to 20% efficiency proven commercially	Higher efficiency obtained with solar tower technology
Land requirements	Less land requirements. Anywhere	About 50% more land required. Only in areas with high direct irradiation
Life cycle analysis (without storage)	30 g/kWh CO_2eq	13 g/kwh CO_2eq

4. CONCLUSIONS

Parabolic trough (solar thermal) and crystalline silicon (solar PV) technologies have been used to establish a comparison between the two solar options. Using data from existing large scale solar farms, a framework for a technico-economic comparison has been provided. In spite of its simplicity, proposed model of comparison provides a fair baseline for comparing the cost of electricity. Solar thermal is not the best economical option for distributed power generation due to higher capital and O&M parameters. Besides PV, module and storage costs, there are also other parameters to consider. Solar insolation, availability of water and land are also very important, favoring mostly the solar PV option.

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