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ALTERNATIVE APPROACH TO DETERMINING THE PREFERRED PLANT SIZE OF PARABOLIC TROUGH CSP POWER PLANTS

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ABSTRACT

The share of Concentrated Solar Power plants in power generation has increased significantly in the last decade due to the need to develop and deploy clean technologies that help reduce the carbon footprint of the power generation industry and, at the same time, are less voracious in terms of fossil fuel consumption. As a governmental support to promote the installation of solar plants, different incentives are found in most countries: complementary rates to the market price of electricity (premium), tax credits, financial support, long term power purchase agreements and, in general, other mechanisms that are generally grouped in a “feed-in tariff” that should ideally be more demanding (stringent) over time. The objective of these measures is to make this technology competitive in the mid/long term. At the same time, and in order to distribute these economical resources as fairly as possible, governments have usually limited the power output of those power plants benefitting from these incentives, as a means to prevent oligopolies that would eventually stop technology evolution while concentrating on preserving market conditions. This has led to the common 50 and 80 MW limits that exist in Spain and the USA respectively. As a consequence, OEMs and EPCs have focused on developing reliable and cost-effective CSP plants of these sizes, especially 50 MW. This work is based on unrestrained regulatory or market scenarios, with the aim of finding out which plant size yields the best efficiency at the lowest cost of electricity (COE). In other words, the objective is to establish the plant size of interest for power producers and consumers, should CSP facilities compete in the same market conditions as conventional fossil-fuel plants. The work begins by reviewing briefly the origins of the usual constraints applied to CSP plants. Then, a survey of existing literature dealing with the issue of technical and economic CSP optimization is presented, with a special focus on the work by B. Kelly from Nexant Inc. Taking this work as reference, a model of performance of parabolic trough plants developed in Thermoflex environment to put forth strong project specific feature of CSP facilites. Thermal storage and natural gas hybridization are included among the key design parameters.

1. INTRODUCTION

1.1. The origin of the 80 MW plant size limit in the US

The oil embargoes of the 1970s led to the enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA was, in part, intended to augment electrical utility generation with more efficient power generation and to conserve energy while ensuring equitable rates for consumers. One of the means to accomplish PURPA’s goal was through the establishment of a new class of non-utility generating facilities, known as qualifying facilities (QFs), compelling the resistant public utilities to purchase all of the generated power from the latter. The QFs fall into two categories:

- Qualifying Small Power Production Facilities.
- Qualifying Cogeneration Facilities.

The small power production facilities under PURPA are electric generating facilities that use renewable energy as their primary source while up to 25% of the energy input can be drawn from fossil fuel. Under PURPA legislation, qualifying facilities (QFs), which include Solar Power Plants, were exempted from the Public Utility Holding Company Act of 1935 (PUHCA) and the Federal Power Act (FPA) regulatory framework that had been set in order to control excessive consumer rates, high debt to equity ratios and unreliable services of public utilities [1].

Under the Energy Tax Act of 1978, renewable energy businesses have also benefited from tax credits that went up to 30% on residential income for the purchase of alternative energy equipment and an energy tax credit (ETC) that went up to 25% for renewable energy projects carried out in California, plus other tax benefits such as 5 years depreciation for federal and state purposes and exemption from property taxes [2].

In addition to PURPA, the fuel use act of 1978 (FUA), from which the QFs were exempted, banned utilities from using natural gas to feed new generating facilities, thus providing an extra advantage to QFs. This act was repealed in 1987, but when it was initially established it presented a backing argument, in addition to the aforementioned numerous incentives to QFs and to renewable energy in particular, for establishing a limit on renewable plants size [1].

The objective of the plant size limit was to assure utilities that renewable energy projects such solar would not take an unfair advantage of the guaranteed market conditions created by PURPA, Energy Tax Act and the Fuel Use Act. The cap on the plant size was first placed at 30 MW but was eventually increased in the late 1980s to 80 MW, following strong lobbying in Washington by the California based Thermal Solar Energy Company LUZ [2].

The rationale behind the company's lobbying was that the power purchasing contract that was set between the QFs and the public utilities associated the price of the purchased kWh with the market price of fossil fuel. So, with a sharp decline in fuel prices in the late 1980s, in addition to ending tax incentives, renewable energy companies like LUZ had to struggle greatly to stay profitable. Therefore, the simple act of increasing PURPA's permitted plant size limit or even repealing it would allow renewable energy companies and particularly the ones investing in solar thermal plants, to take advantage of economies of scale and reduce their kWh cost. With this argument, LUZ managed in the late 1980s to change the limit on renewable energy plant size from 30 to 80 MW.

1.2. The origin of the 50 MW plant size limit in Spain

Akin to the United States, following the second oil crisis of the late 1970s and the need to mitigate the risk of the country's dependence on foreign oil, the Spanish government enacted a new regulatory law 82/1980 to promote energy conservation through the development of small hydro power plants and auto-generation. With the same rationale as in the US, a set of incentives such as guaranteed power off-takes were proposed by the National Energy Plan 1991-2000 and enacted through the 40/94 law, with the objective of increasing electricity production through cogeneration and renewable energy.

The eligibility criterion on plant size, to be able to profit from government incentives, was limited by the 40/94 law at 100 MVA. However, in order to promote a more efficient energy distribution, the initial 100 MVA size limit was later reduced to 50 MW by the 54/97 law and was subsequently integrated in the Royal Decree 2818/1998 under the special framework section (*Régimen Especial*). The discernible arguments for this reduction are as follows [3]:

- To improve the energy distribution network by promoting decentralized small cogeneration plant in order to get the consumers who use heat in the form of steam close to the heat generation source.
- To foster competition by incorporating several companies rather than just a few selected ones in satisfying the country's need in renewable power.

2. REVIEW OF POTENTIAL COST REDUCTION FROM PLANT SCALE-UP

It is usually claimed from within the solar industry that the cost of electricity could be significantly reduced if the permissible power output of this type of power plants were increased. This statement, which seems reasonable from the lessons learned with other technologies, gives place to debate about which the most interesting plant size is; i.e. what power output should OEMs and EPCs adopt in their designs. To this aim, the most relevant reports analyzing the preferred plant size in terms of thermodynamic and economic optimization are reviewed in this section.

2.1. Sandia Report, 1991 [2]

This report states that the levelized 1988 electrical energy cost was reduced by approximately one third from around 12 to 8.5 ¢/kWh when the size of the California SEGS plant, owned previously by LUZ, was lifted from 30 to 80 MW [2]. The report also adds that further economies could be achieved with plants larger than 80 MW. Nonetheless, no further details on optimum design capacity are provided.

2.2. Sargent & Lundy Analysis, 2002 [4]

S&L used the EPRI SOAPP model to estimate the reduction in steam turbine and balance-of-plant costs when increasing the solar trough plant size from 100 to 400 MW. The report provides information on the levelized cost of electricity reduction as calculated by S&L as well as by NREL's proprietary code SunLab when integrating the impact of R&D progress between 2004 and 2020, economies of scale, economies of learning resulting from an increased deployment rate between the two aforementioned dates, as well as experience related to O&M cost reduction. The conclusions estimated by S&L were more conservative than those of SunLab.

All of the aforesaid factors included were expected to reduce the LCOE by 30% for solar-only plants without storage according to S&L, whereas SunLab data, which included 12 hours thermal storage capacity, showed a cost reduction of up to 57%. Of the projected cost reduction, plant scale-up from

Year	1991	2002	2003		2005	2006
Author	Sandia	Sargent & Lundy	NREL		DLR	Nexant
Evaluated Plant Configuration[1]	w/o Storage	w/o Storage	w/o Storage		w/o Storage	Solar-only w/o Storage
Evaluated Size Range Segment	30-80 MW	100-400 MW	30-80 MW	100-400 MW	< 80 MW	88 - 220 MW
Percent LCOE Reduction	30 %	6 %	30 %	20 %	Not specified	15 %
Remaining Economies Beyond the Studied Range	Yes, but Not Specified	None	None		None	None
Size Limit for Economies of Scale	Not Specified	400 MW	400 MW		80 MW	~ 200 MW

Table 1. Summary of reports on scale-up cost reduction estimates.

100 to 400 MW was suggested to provide 20% of the total aforementioned cost reduction [4]. In other words, scale-up from 100 MW to 400 MW would reduce the levelized cost of electricity by 6% for a solar-only plant according to S&L analysis and 11% for a solar plant with storage according to SunLab results.

2.3. NREL Report, 2003 [5]

This report about the potential for economies of scale in parabolic trough plants is based on the 2003 analysis done by Sargent & Lundy Consulting Group referred to in the previous paragraph, and on the information generated out of the SEGS plants operated in the California desert.

When scaling-up from 30 to 80 MW, a 30% drop in the Levelized Cost of Electricity going from a 2002 LCOE of 13 ¢/kWh to a value of 9.4 ¢/kWh must be expected [5]. This percent reduction is in correspondence with the 1991 Sandia report on lessons learned from the SEGS California plants [2]. In addition, the report claims that further economies of scale could be seized all the way to 400 MW if flexible hoses were replaced by ball joint assemblies shifting the trade-off point between the scale-up benefits and the parasitic loads further to the right. The analysis predicts a 20% reduction in the LCOE when increasing the size of a no-storage solar-only trough plant from 100 to 400 MW. This percent reduction is on the conservative side in comparison with the prior study of Sargent & Lundy [4].

2.4. DLR Report, 2005 [6]

DLR report states that all of the scale-up benefits have been drawn at the size of 80 MW based on operating and investment information deduced from the LUZ plants data at the Kramer’s Junction, California [5]. No further economies of scale are believed by the authors to be realistically achievable beyond the 80 MW size. This conclusion, according to the report, is applicable only to parabolic trough plants using oil as heat transfer fluid.

[1] In some reports, configurations with storage options were also evaluated. However, since not all of the references have provided such information, for comparison, only data related to the no-storage option are presented.

2.5. Nexant’s Analysis, 2006 [7]

This analysis is considered to be the most comprehensive and exhaustive in comparison with all of the aforementioned studies in terms of scale-up effects on the cost of electricity for a parabolic trough plant. Interestingly, the development of optimum solar field multiple and optimum field piping configuration is done prior to evaluating the effect of plant size increase on Rankine cycle efficiency and on parasitic load. The impact of scaling up is assessed for two plant configurations:

- A parabolic trough solar-only plant with no storage.
- A hybrid parabolic trough plant with 3 hours of storage.

LCOE calculations for each of the above plant configurations and three different power outputs, 88 MW, 165 MW and 220 MW, yield the conclusion that the most economic hybrid plant size with thermal storage is 200 MW, and 250 MW for the solar-only with no storage.

The underlying principle behind these optimum values is that for the hybrid configuration with thermal storage, multiple equipment items related to the storage and the heat transport fluid system will be required past the 200 MW limit. For the solar-only without storage case, the limit is estimated to be around 250 MW and the justification is that the Rankine cycle efficiency has reached its peak value. In the latter configuration as well, multiple equipment items such as additional heat transport fluid pumps will be required past 250 MW [7].

Contrary to what has been mentioned in the DLR report, this analysis shows some gain in the Levelized Cost of Electricity from economies of scale beyond the 80 – 100 MW plant size. On the other hand, this projected reduction is less than what was presented in the 2003 NREL report on reducing the cost of parabolic trough plants. For the solar-only with no storage, the percent reduction in the LCOE when increasing the plant size from 88 MW to 220 MW according to the Nexant report is around 15% [7] which is between the 20% projected reduction in the 2003 NREL report and the 6% deduced from the 2002 Sargent & Lundy report.

3. FUEL USE POLICY LIMIT

The limit on the amount of fuel use was, in addition to the plant size, a design constraint put in place in the U.S. in 1978 by PURPA. The goal of this restriction was merely to avoid an inequitable treatment between the renewable power plant developers who disposed of a number of tax cuts and a certain guaranteed market conditions, and large utilities which generated electricity mainly through conventional power plants and did not share the same advantages as renewable energy developers.

To qualify as a renewable energy project and benefit from PURPA's conditions, 75% of the total facility energy input must be renewable, geothermal, biomass, waste or any combination of these. The use of fossil fuels such as oil, gas and coal for up to 25 percent of the total primary energy input was introduced in order to alleviate any technical complexities or shortcomings for starting-up and/or controlling the renewable energy projects such as solar thermal plants [8].

The objective of using fossil fuels is principally to fulfill the requirements of the plant with regard to ignition, start-up, testing, production control, and also to prevent unanticipated equipment outages that could directly affect public safety and welfare as a result of a blackout. Particularly, the natural gas option in thermal solar plants was not intended, by the legislative authorities, to be utilized as a tool to mask the high cost of thermal solar plants, but rather to assist alleviating the technical challenges that this developing technology holds.

In Spain, a similar legislation was introduced limiting the fraction of power generated in a thermal solar plant which emanates from fossil fuels to 12 and 15 percent depending on which of the two subsidized energy sale options -offered by the government- the power producer chooses to follow [9].

With the purpose being to promote renewable energy and reduce the country's dependence on fossil fuel, the intention of the Spanish government by permitting the use of fossil fuels in solar thermal plants is only to curb the intermittence of the solar radiation and to ease the start-up process of the plant. The use of fossil fuels in achieving a lower average cost of electricity would defeat the purposes of increasing the use of renewable energy and mitigating the risk of dependence on foreign fossil fuel. In fact, burning natural gas in a cycle that offers approximately 32% thermal to electrical efficiency, rather than utilizing it in combined cycle power plants with 58% efficiency, does not reduce the country's dependence on foreign fossil fuel; on the contrary, it increases it.

Given that 25% of the kWhs produced are drawn out of natural gas combustion, the hybrid cost of electricity formula is then presented as follows:

$$(1 - R_f) \times C_{solar-only} + \frac{R_f}{\eta_{RC}} \times C_{fuel} = C_{hybrid} \qquad \text{Eq. (1)}$$

where:

- $C_{solar\text{-}only}$ is the estimated total cost per kWh with no fuel use in [\$/kWh].
- R_f is the fraction of annual power that is produced from fossil fuel.
- C_{fuel} is the cost of fuel in [\$/kWh$_t$].
- η_{RC} is the thermal to electrical efficiency of the Solar Rankine Cycle[2].
- C_{hybrid} is the estimated total cost of the kWh produced in hybrid mode, in [\$].

Let us assume that we have a 50 MW solar thermal facility with a 40% capacity factor; the plant's annual electrical production would then be approximately 175 GWh. The added cost on the overall system, by producing 25% of the plant electricity from natural gas in a 32% thermal to electrical efficiency cycle rather than in a 58% efficiency combined cycle, is estimated as follows:

$$R_f \times E \times 10^6 \times C_{fuel} \times \left(\frac{1}{\eta_{RC}} - \frac{1}{\eta_{CC}}\right) = C_{added} \qquad \text{Eq. (2)}$$

Where the notation in Eq. (1) is used and:

- η_{CC} is the estimated Combined Cycle efficiency.
- C_{added} is the estimated added cost to the overall economic system in [\$].

Based on the equations above and assuming the input data in Table 1, a sensitivity analysis of the fuel utilization ratio versus the kWh hybrid cost and the overall added cost to the economic system were derived and summarized in Figs. 1 and 2 below.

Parameter	***Unit***	***Value***
Solar-only Production Unit Cost	¢/kWh	18
Solar Rankine Cycle Efficiency	%	32
Annual Electricity Production	GWh	175
Combined Cycle Efficiency	%	58

Table 2. Sensitivity analysis. Inputs.

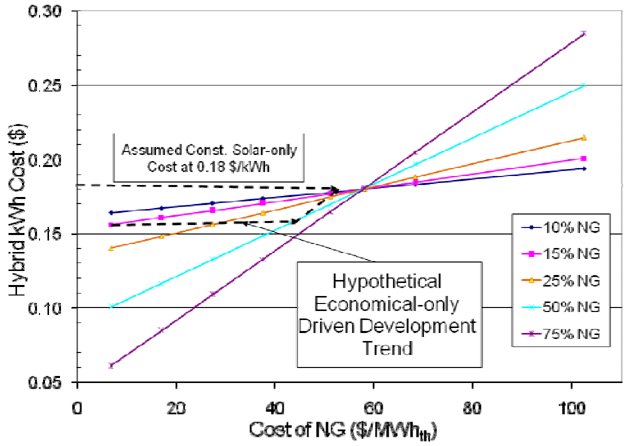

Figure 1. Impact of NG on Hybrid Solar Plant kWh Cost.

[2] Note that the efficiencies of solar field and steam generator do not intervene here since they are off-service when the plant operates on fossil fuel. The natural gas boiler efficiency is taken close to 100% (a typical value is 98%) and therefore is not in Eq. (1) either.

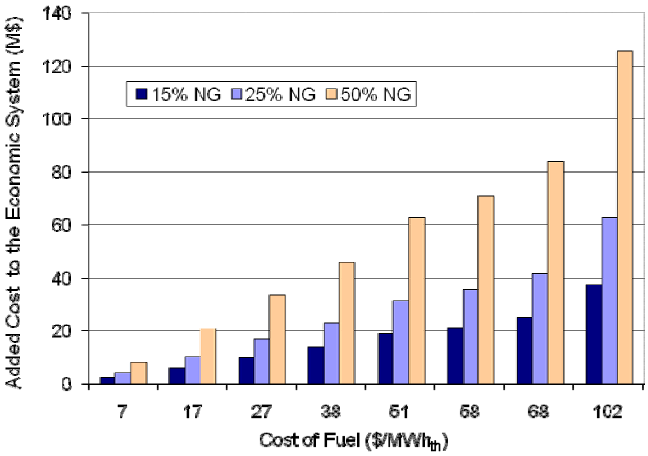

Figure 2. Impact of Utilizing Natural Gas in Thermal Solar Plants on the Overall Economic Cost

A hypothetical approach driven by pure economics (return on investment) rather than power generation and technical innovation will tend to increase the percent fuel leverage, if fuel price rises, in order to maintain the hybrid generated electricity cost constant. Should fuel prices continue to rise, the leverage option will be fully exploited. With no technical innovation being explored to drive down the cost portion of the solar-only plant and if fuel prices continue to increase, the hybrid cost has no direction to go but up. In such a scenario, not only does the economic system run a risk of a sudden rise in the cost of electricity, but this scenario also produces a large additional cost onto the entire system. This exponential cost burden increase on the country's economic system is generated from consuming more fuel at higher cost in a 32% efficiency solar Rankine cycle in lieu of a 58% combined cycle power plant.

Hence, setting a limit on fuel usage forces the industry to stay focused on reducing the cost of the solar-only plant in order to keep the hybrid cost constant should fuel prices increase, rather than simply increasing the fossil fuel consumption in the plant.

4. ECONOMIC DIRECT NORMAL IRRADIATION THRESHOLD

The direct normal irradiation (*DNI*) used by Concentrating Solar Power (CSP) plants is considered one of the key factors that affect the solar plant size, its performance, land occupation and hence its levelized cost of electricity.

Solar concentration, which represents the ground basis of the CSP technology, is based on converting the direct component of the solar radiation, namely *DNI*, into high temperature heat by directing the latter onto a focused and smaller surface area which is the tube collector. Heat is hence carried in the tube by a heat transport fluid (HTF) to feed a Rankine cycle power block where the heat is consequently converted to electricity.

Under constant Rankine cycle efficiency, the electricity generated by the power block is directly proportional to the heat input into the cycle as per the following formula:

$$\eta_{Power\ block} = \frac{Power}{Power\ block\ heat\ input} \qquad \text{Eq. (3)}$$

Likewise, the heat input absorbed by the solar collectors and delivered to the power block is proportional to the Direct Normal Radiation input. If we consider that the solar components' efficiencies do not vary significantly and assume that the plant has been redesigned to keep the efficiency constant under a lower *DNI* design input conditions.

$$Power\ block\ heat\ input = DNI \times C_r \times \eta_{solar\ field} \qquad \text{Eq. (4)}$$

where C_r is the concentration ratio of the solar receiver.

Knowing that the levelized cost of electricity (LCOE) is inversely proportional to the plant power output as depicted in Eq. (5) below, a drop in the annual radiation from 1800 kWh/m^2 yr to 1600 kWh/m^2 yr would mean an approximate 20% rise in the plant's LCOE.

$$LCOE = \frac{I + L_e + M + R + F}{E_1 \times \sum_{i=1}^{n} \frac{1}{(1+r)^i}} \qquad \text{Eq. (5)}$$

where:

- *LCOE*: Levelized cost of energy [$/kWh].
- *I*: Discounted investment cost [$].
- L_e: Discounted sum of input energy expenses [$].
- *M*: Discounted sum of operating expenses [$].
- *R*: Discounted sum of replacement costs [$].
- *F*: Discounted financial costs [$].
- E_1: Annual energy produced [kWh/year].
- *r*: Discount rate [-].
- *n*: Design life [years]

The formula used to calculate the Levelized Cost of Electricity evaluates the cumulative cost of running the electricity generation facility over its entire life with respect to the total electrical energy generated from first start-up to the decommissioning and eventual dismantlement of the plant. The economical terms in Eq. (5) are expressed in discounted monetary values in order to account for the time value of money, yielding a final value of the LCOE in [$/kWh]. This parameter so expressed can then be used to compare the real cost of electricity produced with different technologies.

Existing literature advocates that 1900 kWh/m^2 yr is approximately the threshold below which the CSP technology is not advised for power generation [10,11]. This is merely caused by the fact that the kWh cost in such low *DNI* areas will overrun the cost of electricity through other alternatives. That being said, the photovoltaic technology which uses both direct and indirect sun radiation is expected to offer a better economic solution below the 1900 kWh/m^2 yr radiation input.

5. REVIEW OF THE LEVELIZED COST OF ELECTRICITY CALCULATION METHODS

A literature survey based on determining the preferred plant size of CSP systems and, in general, the appraisal of investment projects in the power generation industry confirms the lack of consensus about which the representative parameter to evaluate the real cost of energy produced is. The following LCOE calculation methods have been found:

A. Discounting the future expenditures (cash out-flows) and power output streams and dividing the present value of lifetime costs by the present value of lifetime output [4,12,13].

$$LCOE = \frac{\sum_{i=1}^{n} \frac{I_i + M_i + F_i}{(1+r)^i}}{\sum_{i=1}^{n} \frac{E_i}{(1+r)^i}} \quad \text{Eq. (6)}$$

where I_i, M_i and F_i are the investment, operations/maintenance and fuel expenditures in the i^{th} year.

B. Discounting the future cost stream and converting its present value to an Equivalent Annual Cost (*EAC*) in [$/year] using a standard annuity formula. This *EAC* is then divided by the undiscounted average annual electrical output $\bar{E}_a$ in [kWh/year] over the plant lifetime to yield the *LCOE* [13].

$$\sum_{i=1}^{n} \frac{I_i + M_i + F_i}{(1+r)^i} = \frac{EAC}{r} - \frac{1}{(1+r)^n} \times \frac{EAC}{r} \quad \text{Eq. (7)}$$

$$LCOE = \frac{EAC}{\frac{1}{n}\sum_{i=1}^{n} E_i} = \frac{EAC}{\bar{E}_a} \quad \text{Eq. (8)}$$

This second method is known as the “annuity” method and should give the same results as the previous one provided that all the financial input data are the same: discount rate, lifetime (maturity) and cash flow stream.

C. References [14,15] report that the levelized capital cost is computed by multiplying the present value of the annual capital expenditures by the capital recovery factor, Eq. (9), which converts this value to a stream of equal annuities for a certain period of time (maturity, design life). The capital costs include all capital-related costs (equipment, debt services and others).

$$crf = \frac{r \times (1+r)^n}{(1+r)^n - 1} \quad \text{Eq. (9)}$$

Formally, the capital recovery factor is applied to the present value of the annual capital costs over the design life of the plant.

References [6,15,16] make use of the capital recovery factor to calculate the Levelized Cost of Electricity with the following equation:

$$LCOE = \frac{crf \cdot K_{invest} + K_{O\&M} + K_{fuel}}{E_{net}} \quad \text{Eq. (10)}$$

where K_{invest} is the total investment (including financial services), $K_{O\&M}$ is the annual operation and maintenance costs, K_{fuel} is the annual fuel costs and E_{net} is the annual net electricity production.

The main difference with respect to the previous methods is the fact that the costs due to operation, maintenance and fuel consumption are not levelized (discounted) in the *LCOE* formula. In other words, real values instead of present values of such streams of cash flows are used.

D. The last method splits the economic life of the plant in two phases: the first period of time ends when the debt and interests are completely repaid, in the assumption that the project is entirely funded by a bank (no private equity share); the second period of time starts at this point and ends with the design life of the plant [17].

The Levelized Cost of Electricity is then computed taking into account the contribution from these two periods of time as per the formula in Eq. (11), where:

- c_i: overnight specific investment cost [$/kW].
- c_c: constant annual operational and maintenance cost [$/kW].
- c_v: variable operational and maintenance cost [$/kWh].
- c_f: fuel cost [$/MWh].
- η: plant efficiency.
- l_f: load factor [-].
- n_{lr}: years of loan repayment [year].
- n_{ltm}: plant lifetime [year]
- r: discount rate [-].
- r_i: average interest rate for loan repayment [-].
- r_f: average rate of foreseen fuel price change during plant lifetime [-].

It is thus exposed in this section that different formulae to calculate the Levelized Cost of Electricity have been used in the past, differentiated by some conceptual keypoints that are considered fundamental. The facts that costs are broken down into different concepts, for instance fixed and variable O&M, and that real or present (discounted) values are employed in

$$LCOE = \frac{\sum_{i=1}^{n_{lr}} \frac{1}{(1+r)^n} \cdot \left[\frac{r_l \cdot c_i}{1-(1+r_i)^{-n}} + c_c + 8760 \cdot l_f \cdot \left(\frac{c_f \cdot (1+r_f)^n}{1000 \cdot \eta} + c_v\right)\right]}{\sum_{n=1}^{n=n_{ltm}} \frac{8760 \cdot l_f}{(1+r)^n}} + \frac{\sum_{n=n_{lr}}^{n_{ltm}} \frac{8760 \cdot l_f}{(1+r)^n} \cdot \left(\frac{c_f \cdot (1+r_f)^n}{1000 \cdot \eta} + c_v\right)}{\sum_{n=1}^{n=n_{ltm}} \frac{8760 \cdot l_f}{(1+r)^n}} \quad \text{Eq. (11)}$$

the *LCOE* formula are definitely misleading when trying to make a comparison of the expected cost of electricity from different sources.

According to the authors, the first method presented, Eq. (6) is best balanced between accuracy and complexity. Method B is considered to be based on an apparent annuity which does not necessarily correspond to reality in terms of the discounted annual cash flow of expenditures, even though methods A and B yield the same results for the same boundary and initial conditions. Method C is considered not correct since the time value of money is only taken into account for the capital investment costs but not for the operation/maintenance or fuel costs, as neither is it for the generated electricity. Finally, Method D is quite similar to Method A though it is based on discounting each individual concept of the annual cash flow stream rather than discounting the total cash flow stream for each year as a whole. Method A's approach is preferred by the authors due to its ease of use.

6. FACTORS AFFECTING THE LEVELIZED COST OF ELECTRICITY

The parameters affecting the levelized cost of electricity *LCOE* are easily deduced from the aforewritten formulae. They can be grouped in two different categories:

- Costs [$]: investment, operation and maintenance, finance services, fuels, etc.
- Electricity production [kWh].

Changes occurring in any of these parameters are thus reflected in the value of the LCOE, though with a different intensity. This section provides a summary of the most relevant factors giving rise to such changes.

6.1. Factors that affect electricity production

1. Direct normal irradiation threshold. This factor depends mainly on the location of the plant as commented previously in Section 4. This plant site needs to be characterized by a high direct annual irradiation and to dispose of plain ample land areas where the large footprint of the plant can be accommodated. These features are best encountered in remote regions where electric power transmission grids are not usually available. Moreover, even if such electric grids existed, long distances would need to be covered in order to reach the nodes of energy consumption, hence incurring important electrical losses [18].

2. Development of technology. Improving the performance of the principal equipments of CSP plants like collectors, heat transfer fluid system, power block and others translates into higher plant efficiency. This in turn yields more power output (W_{rated}) for the same solar energy collected. Incorporating a thermal storage system and/or fossil fuel hybridization increases the load factor (c_f), what adds up to the previous annual power output (E) upsurge.

$$E = 8760 \times W_{rated} \times c_f$$

where E is the plant annual electricity production [kWh], W_{rated} is the rated power output [kW] and c_f is the load factor [-].

Technology development is expected to have a major impact on the cost of electricity in the mid-term, as new concepts of CSP plants that are not mature yet are put in the market.

6.2. Factors that affect costs

1. Scale factor. This aspect affects investment, operation and maintenance and fuel costs directly. As aforesaid, the cost of electricity generated from solar energy should be drastically reduced by merely scaling-up the power output capacity of the plant, an effect that is extendable to most power generation technologies. Figure 3 illustrates the impact of economies of scale on the levelized cost of electricity as reported by Nexant Inc [7].

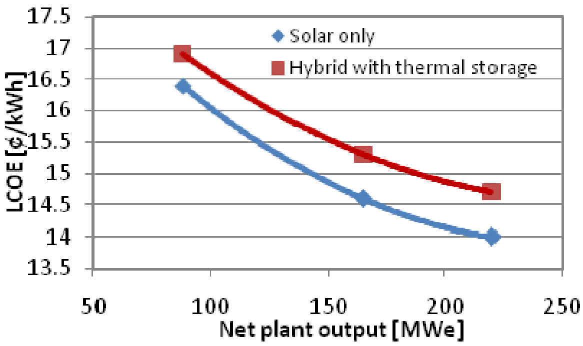

Figure 3. Effect of plant scale-up on the levelized cost of electricity.

Nexant's report nevertheless confirms that there exists an optimum or preferred plant size beyond which no further economies of scale are achieved, mostly due to an excessive cost of the thermal storage system. It is also stated that the added cost associated with the substitution of the turbo-generator when the plant is scaled-up (a transition from single flow turbines to multiple-flow tandem compound low pressure units is necessary beyond a certain exhaust mass flow) has a minor impact on the total plant cost and therefore the preferred plant size. This statement is based on a turbo-generator estimated cost of 200 $/kWe.

2. Incentives to promote solar energy. The levelized cost of electricity is also an approximate index of how far a technology is from being competitive in a deregulated market, thus providing an estimate of the incentives required to foster solar energy deployment. Presently, two different policies are usually adopted by public

administrations: subsidy and transfer payment. For instance, the owners of CSP plants in Spain, mostly non-utilities, can take advantage of a feed-in tariff that permits selling electricity under long-term power purchase agreements to the national grid operator, though this is limited to a number of "qualified" facilities whose power outputs do not exceed 50 MW [9].

Supporters and opponents to these policies discuss tirelessly the suitability of this decree that regulates the generation of electricity from renewable energy sources, as opposed to other policies that also promote the utilization of the same type of primary energy. Hence, in the US, deductions in tax credits (10%) and Corporate Tax Rates (35%) are the types of subsidy conceived by the public administrations and even though Corporate Tax Rates do not intervene in the calculation of the levelized cost of electricity, the corresponding deduction stimulates the construction of such facilities.

Policymakers can therefore choose whether to reduce, or even remove, price risks by designing incentive schemes and new energy policies for the mid-term. In this regard reference [19] claims that the most effective energy policies are those based on tax credits on investments or capital costs (US case) rather than monetary incentives or direct subsidies to power production (Spanish case).

3. Financial issues. Most of the times, accomplishing the investment project of constructing a CSP power plant depends on getting the necessary funding external to the company. This funding is usually obtained from bank loans but, even in these cases, banks do not usually lend the total budget of the project. It is thus necessary to make use of private equity resources. The configuration of the total debt in terms of debt(bank)/equity ratio and the corresponding interests and times for repayment are factors that affect the levelized cost of electricity dramatically (this is illustrated in Section 7).

4. Inflation. The generalized steady growth of the prices of all the services needed annually in a CSP plant rises the operation/maintenance costs and the fuel costs, bringing about a similar increase in the levelized cost of electricity.

5. Rate of discount. Interpreted as the return on investment after taxes expected by the private investors (private equity), the discount rate is therefore adequate to evaluate the present value of a stream of cash flows projected in a future time (again, after taxes).

All the previous factors taken into account, the levelized cost of electricity for CSP facilities take values in the range from 0.22 to 0.36 \$/kWh[3] [6] and it is most sensitive to the Direct Normal Irradiation and the investment costs [18].

7. SENSITIVITY ANALYSIS

The world economy has gone through different periods of instabilities as for now, when many developed countries are submerged into a time of economic recession. During these periods, the risk for lenders (whether banks or others) of not having their money and interests repaid increases.

This section presents a sensitivity analysis of the economic and financial aspects that impact the levelized cost of electricity most, focusing on the features of debt management and its evolution in recent times. Amongst others, the following relevant parameters are studied:

1. Equity/debt ratio.
2. Bank loan: Interest rate and debt term.
3. Private equity: internal rate of return and amortization period.
4. Inflation.

The aforelisted parameters are combined to yield four different representative ownership scenarios of a CSP power plant [20]:

- Generating company.
- Independent power producer.
- Regulated investor-owned utility.
- Municipal utility.

This analysis concentrates on the first two owning schemes, namely A and B, which are based on a market-driven rate of return approach:

- Scenario "A": big generating companies are less risky from the point of view of investors, since the return on their investment is secured not by a single project but on a pool of them and a portfolio of corporate assets that assure debt repayment. Realistic values for the parameters under analysis are:
    - Loan debt rate and loan term: 7.5% / 28 years.
    - Equity rate and amortization period: 13% / 28 years.
    - Capital distribution: 35% debt – 65% equity.
    - Inflation rate: 2.5 %.
- Scenario "B": independent power producers do not have the financial resources of big generating companies and their profitability relies strongly, if not exclusively, on the success of the investment project being analyzed. Hence, higher returns on investments and shorter amortization periods must be expected, along with other requirements that guarantee debt repayment (for instance, debt service reserves and coverage ratios). Realistic values for the parameters under analysis are:
    - Loan debt rate and loan term: 8% / 15 years.
    - Equity rate and amortization period: 17% / 15 years.

[3] These values are 0.16 to 0.23 €/kWh in reference [6] from 2003. They have been updated to 2011 USD [\$] considering the annual inflation rates for the period 2003-2011 (according to data from Eurostat for the UE-15) and a 1.3469 €/\$ exchange rate (average rate for January 2011 according to data from the European Central Bank).

- o Capital distribution: 60% debt – 40% equity.
- o Inflation rate: 2.5%.

Scenarios A and B are applied to a reference parabolic trough power plant whose main features correspond to the Andasol 1 plant located in Southern Spain. This is a 50 MW plant with a 7.5 hours thermal storage system that yields a remarkable 40% capacity factor. The main technical and economical features of this plant are taken from references [21-24]:

- Design life: 30 years.
- Rated power output: 50 MW.
- Trough technology: SKAL-ET 150.
- Capacity factor: 40 % (7.5 h thermal storage and 15% natural gas consumption).
- Total investment cost: 358,407,700 $ (2.1 $/kWhy).
- Operation and maintenance costs: 53.5 $/MWh or 2,672,500 $ (subjected to inflation).
- Annual insurance cost: 1% of the total capital cost (3,584,077 $) (not subjected to inflation).

The application of Method A (Section 5) to Scenarios A and B yields Levelized Costs of Electricity of 27.6 and 30.5 ¢$/kWh respectively. This translates into a 10% difference just due to the ownership/financing structure, showing the fundamental interest of this aspect of CSP economic analysis. For other structures shifted towards private or public (commercial banks) investors (for instance, municipal utilities for which debt share reaches 100%), these differences are thus expected to increase. A first approach to a sensitivity analysis of the *LCOE* with respect to various financial parameters is given in Figure 4.

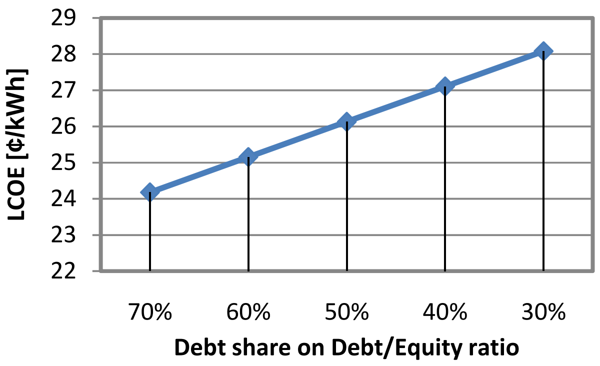

Figure 4. Effect of debt share (debt/equity ratio) on the levelized cost of electricity.

Figure 4 illustrates the impact of the debt to equity ratio on the levelized cost of electricity. This ratio is mostly dependent on the ownership structure [20] and can alter the *LCOE* as much as 15-20% when shifted from an equity-based financing scheme to a bank-based one, Scenarios A and B respectively. The higher return on investment demanded by private investors in case B brings about a higher *LCOE*, despite their lower share and shorter repayment term that would partly compensate for this effect (accelerated repayment). This is further shown in Figure 5 below; in effect, the *LCOE* of Scenario A is 1-2 ¢$//kWh higher for the same rate of return than Scenario B which has a higher equity share. Nevertheless, the combination of rate of return, amortization period and equity share of Scenarios A and B yield a lower *LCOE* for the first case.

Figure 6 shows the effect of the bank interest rate on the real (non-discounted) and present values of debt services. The most interesting feature to be observed in this graph is the fact that even though the debt services increase steadily with the interest rate in both cases, the difference between them is proportionally higher in present value (around 50%) than in real value (around 10%). This is caused by, first, a higher debt share for Scenario B and, second, a shorter repayment term.

The latter difference is further exposed in Figure 7, where the real and present values of the annual total costs over the design life of the project are plotted.

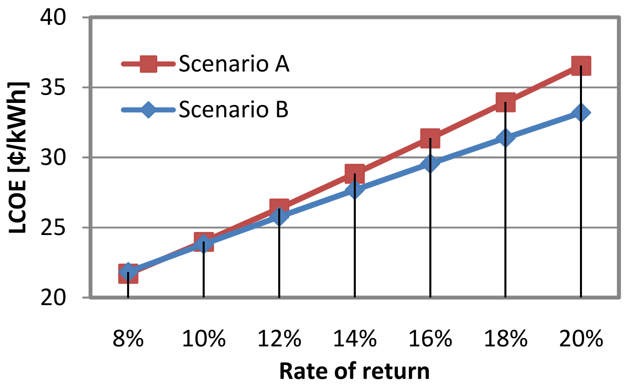

Figure 5. Effect of the rate of return (return on equity) on the levelized cost of electricity.

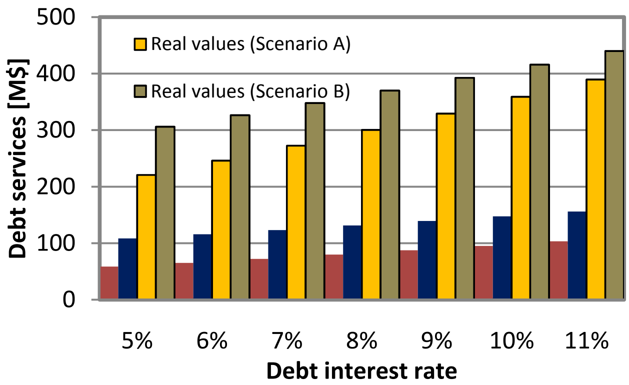

Figure 6. Effect of debt interest rate on debt services over the amortization period.

In effect, Figure 7 illustrates that the shorter amortization terms of equity and debt caused by the risk perceived by the investors in Scenario B imply higher annual costs at the beginning of the project (solid dark line) with respect to Scenario A for which, on the contrary, repayment is extended over the entire design life of the plant in Scenario A (year 28 of 30). In spite of a dramatic decrease in total costs after year 15 in case B, the time value of money favors the project with expenditures done at a later time, especially when the rate of return is high (what happens in Scenario B). Overall, these different financial behaviors yield a present value of the total costs of 362 M$ and 311 M$ for Scenarios A and B respectively.

Following the same argument and in order to calculate the levelized cost of electricity, the aforementioned costs are divided by the present values of the energy produced, which are 1312 MWh and 1020 MWh for cases A and B in spite of both scenarios having the same technical specs. This drop in the present value of energy for case B due to a higher rate of discount that, again, penalizes energy produced at a later time, is proportionally higher than the difference in the present value of costs and therefore $LCOE_A < LCOE_B$.

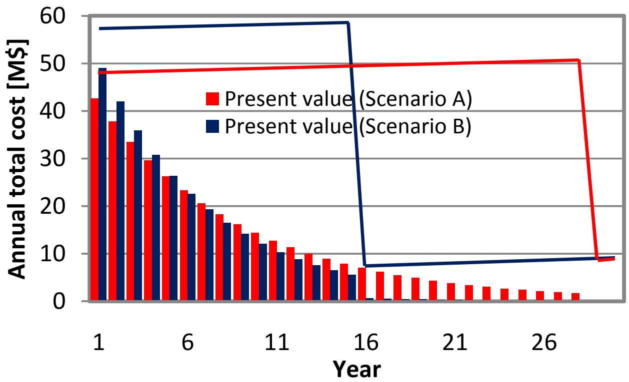

Figure 7. Real and present values of annual costs.

8. CONCLUSIONS.

The process of selecting an optimum plant size is by and large project specific. The calculated size that will result into the lowest *LCOE* is thus influenced by the technical characteristics of the plant and the project financial structure.

The project technical aspects which could significantly alter the calculated optimum plant size are mainly those aspects that appreciably change plant capacity factor such as the site location, the allowed fossil fuel usage ratio, storage and plant component efficiency.

The optimum plant size is also affected by the project financial structure. A design modification which could allow the plant to increase its power production with a “Y” added cost in Capex would lead to two different *LCOE* under two different financial scenarios. The more leveraged project would incur less total cost with the design modification shifting the optimum design point further to the right (higher output).

The aim of this work was then to demonstrate that an absolute value of the Levelized Cost of Electricity in terms of ¢$/kWh does not exist but, on the contrary, depends on more information that is project specific and must be inevitably added to this figure for it to be meaningful. Hence, future research by the authors focuses on developing comprehensive tools to evaluate the impact of the numerous aspects involved in determining the CSP’s *LCOE* so as to have a useful tool to determine the technical and economical feasibility of such plants in different scenarios. Some of the issues that will be analyzed, part of which have already been mentioned in this paper, are: economies of scale and preferred plant size, component efficiency, thermal storage capacity, technology breakthroughs, incentive policies, forecast of inflation and financial parameters, hybridization, forecast of fuel costs, regional costs.

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