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Post Subsidy Conditions: Evaluating the Techno-Economic Performance of Concentrating Solar Power in Spain

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Abstract:

Spain is one of the front runners of the development of Concentrated Solar Power (CSP) projects. In recent years, however, the CSP industry in Spain has faced significant financial challenges due to a dramatic withdrawal of the Feed-in-Tariff (FIT) in 2013.

The primary aim of this paper is to assess when, and under what conditions, CSP projects, in particular, Parabolic Trough Collectors can potentially reach grid parity in the absence of any subsidies. This paper also goes further to investigate whether and how Parabolic Trough Collector (PTC) projects can be financially viable in the post-subsidy period, using the System Advisor Model as a simulation tool to conduct techno-economic analyses.

The simulation results indicated that a 50MWe PTC project with TES of 4 hours and a PPA price of €0.20 per kWh is the most viable model for developing CSP projects in Spain under post-subsidy condition. This paper concludes that, under current retail electricity prices and post-subsidy conditions, PTC projects can reach grid parity and become viable without direct incentives. Even though direct policy support will not be required, the CSP industry in Spain is still far from becoming fully self-sustained.

Keywords: Concentrating Solar Power (CSP), Parabolic Trough Collector (PTC), Feed-in-Tariff (FIT), Grid Parity, Techno-economic model

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Nomenclature

Symbols	Description
A	Area
C_0	Total initial investment cost at year 0
C_n	After-tax cash flow
c, cps	Specific heat
D	Diameter of Pipe
d_{real}	Refers to the discount rate without the inflation rate
$d_{nominal}$	Refers to the discount rate with the inflation rate
f	Friction
Ibn	Direct solar irradiation
L	Length
N	Analysis period and lifetime project
N_{Sca}	Number of solar collector assemblies
n	Number of years analysed
$\dot{m}_s$	Mass flow rate
Q_n	Electricity generated by the system in year n
$\dot{q}$	Heat transfer rate
Re	Reynolds number
V	Velocity of fluid
Z_n	The annual project costs including installation, operation and maintenance, financial fees
ρ_T	The density of fluid
μ_T	The dynamic viscosity of fluid

Abbreviation

CSP	Concentrated Solar Power
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
IRR	Internal Rate of Return
LCOE	Levelized Cost of Electricity
NPV	Net Present Value
PPA	Power Purchase Agreement
SAM	System Advisor Model
SCA	Solar Collector Assemblies

1.Introduction

Concentrated Solar Power plants (CSP) can make a substantial contribution to the transition toward a low carbon energy system. CSP plants are integrated with thermal energy storage, which enables them to become a dispatchable source of energy generation. CSP projects are becoming a proven large scale solar power technology, even though they are not yet competitive with other sources of renewable energy (Smith, 2015). Although global CSP installations have been growing as a result of reductions in costs and the improvements in efficiency, along with policy support, they still have a marginal presence in the world's renewable energy capacity: 0.23% in 2018. Therefore, substantial further cost reductions are still needed (IRENA Statistics, 2019). Hence, the technology needs to be further developed to play an increasingly important role in renewable energy production.

Currently, the United States (US) and Spain account for 87% of total worldwide installed capacity (Chaanaoui et al., 2016). Spain appears to be a precursor in the development of CSP as the first European country to introduce the Feed-in-Tariff (FIT) funding system for solar thermal power (SolarPACES, 2017). The FIT policy has significantly increased the production capacity of CSP projects in the country from 284 MW in 2009 to 2304 MW in 2018 (IRENA Statistics, 2019), outpacing the estimate of the Spanish Renewable Energy Plan made for the time frame of 2005-2010 (Islam et al., 2018). The Spanish government has actively promoted CSP development during recent decades. In April 2019, CSP represented 2% of Spain's renewable energy, as shown in Figure 1 (Evwind.es, 2019).

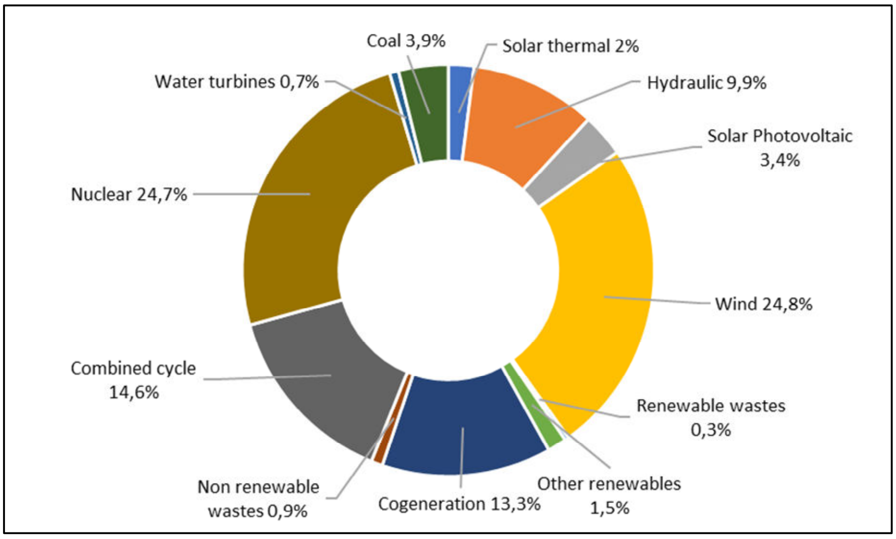

Figure 1: Spain's electricity generation structure, April 2019 (Evwind.es, 2019)

The Spanish renewable energy policies, including Royal Decrees 28128/1998, 841/2002, 436/2004 and FIT have played a significant role in the rapid development of CSP and led Spain to be one of the world leaders of CSP projects (Miguel & Corona, 2018; Perez et al. 2014). Royal Decree 2818/1998 and 841/2002 provided financial support for renewable energy technologies. This support was a regulated tariff that set the price that the producer would receive regardless of the market price, and a premium tariff that was paid on the top of revenue from selling the electricity to the market (Miguel & Corona, 2018). Royal Decree 436/2004 provided more strategic economic support for renewable energy technologies. Under this financial support, the financial incentives were calculated based on the Average Electricity Tariff (Miguel & Corona, 2018).

With the global economic crisis of 2008, the Spanish government reduced or withdrew many renewable energy incentives (Miguel, 2018). This included the removal of Royal Decree 436/2004 in 2012 and its replacement by a Complementary Payment. In 2013, the FIT was replaced by a Complementary Payment, following the moratorium on renewable energy imposed since 2012, to provide reasonable profitability over the lifetime of the project (SolarPACES, 2017). Moreover, this reasonable profitability payment has decreased from 7.5% to between 4 and 5% in January 2020 (LozanoSchindhelm, 2020), and it cannot be guaranteed that this will not change again in the coming years. These policy uncertainties and changes caused a major financial crisis for CSP projects and prevented further growth of the CSP industry in Spain.

The high capital cost of CSP projects represents a significant obstacle to its development, particularly under no subsidy conditions (Khan & Arsalan, 2016). Although the global capital cost of CSP projects is declining each year, the Levelized Cost of Electricity (LCOE) of CSP projects remains higher than that of fossil fuels and some other forms of renewable energy (International Renewable Energy Agency, 2018; Del Río et al., 2018; Khan & Arsalan, 2016; Varpe, 2019; Wenzlawski & Tol, 2003). However, literature indicated that advances in the techno-economic factors could significantly reduce the capital cost and enhance economic performance (Bataineh & Algharaibeh, 2018; Chaanaoui et al., 2016).

Among the existing body of knowledge, several researchers have focused on different factors that can improve the economic performance of CSP; for example, Islam (2019) and Moffatt (2019) evaluated the impact of discount rate on the economic performance of CSP projects. Rendón et al. (2018) assessed the impact of direct capital costs on CSP's cost-efficiency but did not evaluate the impact of these parameters on the post-subsidy conditions. However, as noted by Zhuang et al. (2019), further clarifications must be brought regarding the effect of incentive policies on a CSP plant's economic performance.

Furthermore, there is a limited studies to assess when and under what conditions CSP projects can potentially reach grid parity without any subsidies. Grid parity occurs when an alternative source of energy can produce electricity at an LCOE which is equal or at the same price as purchasing electricity from the grid. This paper, therefore, aims to fill this gap in the literature by investigating the impact of discount rate, power purchase agreement (PPA) tariff rate, thermal storage size, plant capacity and solar multiples on the financial viability of Parabolic Trough Collector (PTC) projects. Thus, the paper aims to determine under what economic conditions PTC projects can reach grid parity. The approach involved using internal rate of return (IRR), LCOE and net present value (NPV) to run a discounted cash flow analyses.

Section 2 surveys the literature on the existing techno-economic assessments of CSP projects and identifies their strengths and weaknesses. Section 3 describes the modelling methodology. Section 4 reports the results. In Section 5, policy approaches and recommendations are discussed.

2. Literature review

2.1 Overview of the main components of a CSP plant

A CSP plant is made of three different components: the solar field, the power block and the storage system (Chaanaoui et al., 2016; Xu et al., 2016). The solar field is composed of solar concentrators, which reflect the direct sunlight and focus it onto a receiver, in which a heat transfer fluid (HTF) flows. The HTF is heated and then pumped to either the storage system or the power block. At the power block, the HTF passes through a heat exchanger transferring its thermal energy into steam, which is used to drive turbines and generate electricity. Most CSP plants use either molten salt or oil as a heat transfer fluid. Molten salt is preferred to oil because it can operate at higher temperatures (Yuasa & Hino, 2017) leading to improved power cycle efficiencies. However, molten salt has higher corrosivity than oil, requiring corrosion-resistant materials that are expensive (Ruegamer et al., 2013). An additional issue is caused by the high melting point of the molten salts, which can be in excess of 250°C, requiring night-time heating for freeze protection. Pan et al. (2019) compared thermal oil and molten salt HTF systems and showed that there is a 1.7% increase in solar field cost due to advanced materials capable of withstanding the higher temperatures, but a decrease in cost of the storage system. This decrease is due to the reduction in volume required to store the same amount of energy at higher temperature.

The thermal storage system is typically either direct or indirect. In a direct storage system, the HTF that is heated by the solar field is pumped into a storage tank until needed at the turbine.

In an indirect storage system, the heat is transferred from the HTF to a different storage medium through a heat exchanger, which is then stored in a tank. The omission of an oil-salt heat exchanger in the direct thermal storage system reduces its cost (Vignarooban et al.,2015). For the purpose of this paper, we used a direct storage system.

There are four different types of CSP technologies: the Linear Fresnel Reflector, the Solar Power Tower, the Parabolic Dish and the Parabolic Trough Collector (Figure 2). The parabolic trough is a long term commercially proven technology which started operation in 1984 and has since had drastic cost reductions (Sargent & Lundy, 2003). Therefore, it is the most established and proven technology with high maturity, representing 85% of existing CSP projects (Simona et al., 2019). Compared to other CSP technologies, it is also more cost-effective to install because of continued optimisation of its components (Chen et al., 2016). This paper, therefore, focuses on Parabolic Trough Collectors (PTC).

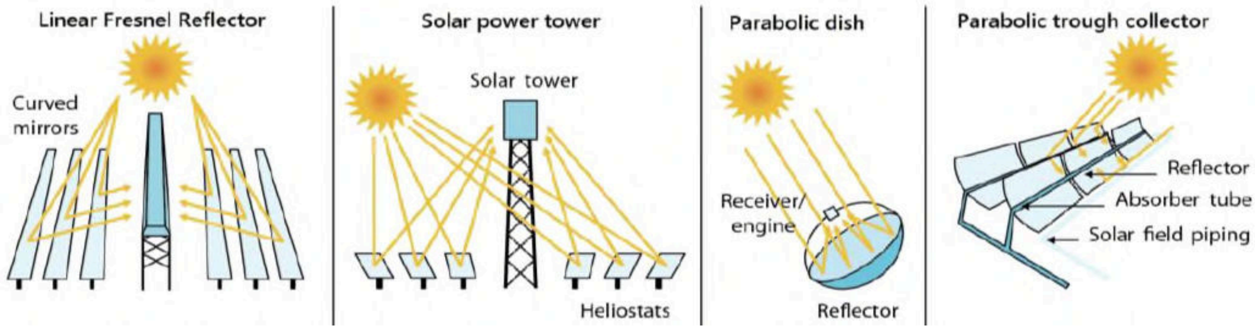

Figure 2: Different types of CSP technologies (González-roubaud et al., 2017)

2.2 Review of techno-economic analysis of CSP projects

Numerous studies have been conducted to investigate the techno-economic performance of CSP projects. The LCOE, which presents the total project lifecycle costs, is commonly used to assess the financial viability of CSP plants (Mohaghegh, 2015; Roni et al.,2019 ; Schmitt et al., 2017; Simsek et al., 2018; Boukelia et al., 2017). LCOE aims to provide a comparison between different technologies, with different project size, capacities and capital costs. The LCOE also can be referred to as the minimum cost at which electricity can be sold to achieve breakeven point over the lifetime of the project (Lai & Mcculloch, 2017).

LCOE is commonly used as a metric to compare the economic competitiveness of different energy generation technologies or for considering grid parity for developing renewable technology. In this paper, the LCOE has been used for assessing the grid parity of PTC projects. LCOE can be calculated by dividing the lifetime costs by the lifetime power generation (Musi et al., 2017). However, some have objected that the concept of LCOE is simple, and it doesn't consider influential parameters. For example, it does not capture the time-varying value of electricity (Musi et al., 2017).

Table 1 summarises the different LCOE values of PTC technologies found in various studies. These values, initially expressed in different currencies, are converted to Euros to enable their comparison. There are a wide range of values; however, it can be seen that the cost of electricity generation from CSP is decreasing significantly.

Table 1: Comparison of existing findings of PTC's LCOE

Source	LCOE (€/kWh)
Boukelia et al. (2017)	0.062
Zhao et al. (2017)	0.150
Simsek et al. (2018)	0.120
Islam et al. (2019)	0.190
Roni et al., (2019)	0.069
US Energy Information Administration (2019)	0.110 (2023 forecast)
Mohaghegh (2015)	0.097 (2030 forecast)

Even though the cost of electricity generation from CSP has decreased significantly, it is still higher than the cost of electricity generated from other technologies (Figure 3).

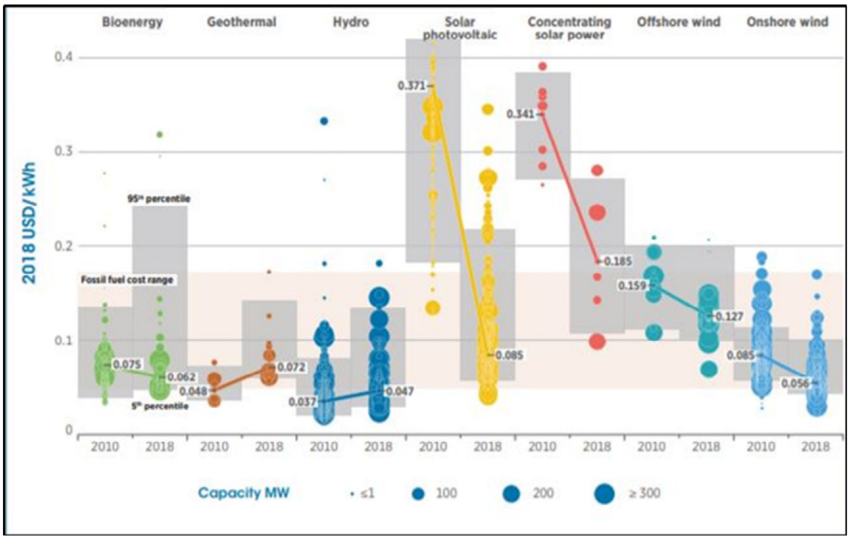

Figure 3: Worldwide LCOE of large scale renewable energy technologies 2010-2018 (IRENA, 2019)

In 2018 the worldwide weighted-average LCOE for hydropower, onshore wind, bioenergy and geothermal projects were close to fossil fuels, so these technologies were intensely competitive without any financial subsidies. With constant cost reduction, solar PV has also started to compete with fossil fuels (IRENA, 2019). However, it should be considered that the competitiveness of renewable energy technologies varies depending on the market and the country that the project is located.

Compared to other types of renewable energy technologies, the global weighted average electricity costs of CSP projects are still in the top half of the fossil fuel cost range (Figure 3). Consequently, further research is needed to improve the cost-effectiveness of CSP projects (Astolfi, 2015).

2.3 Impact of techno-economic parameters on performance of PTC projects

The economic performance of a PTC plant is linked to its physical properties, such as plant size and thermal storage size which varies from one project to another. However, the technical performance of a PTC plant is not the only aspect that needs to be assessed to improve its economic performance. Financial parameters should also be included and adjusted for this purpose. These techno-economic parameters are discussed in more detail below, together with the possible ways they could be improved.

2.3.1 Technical parameters

The high capital cost of CSP projects is a significant barrier to their commercial development. High capacity factors and technical improvements are both driving the cost reduction of the CSP projects as well as LCOE (Mirzania, Balta-Ozkan, & Marais, 2020).

There is a growing body of evidence in academic literature indicating that various technical parameters such as plant sizing, thermal storage sizing and solar multiples can potentially play an essential role in the cost reduction of these projects (Bataineh, 2018; del Río et al., 2018). Bataineh (2018) suggested that increasing plant size has been proven as the simplest way to decrease LCOE. Roni (2019) indicated that the LCOE of PTC projects could be decreased by around 49% by optimisation of solar multiples. Another approach to improve the economic performance of CSP projects is optimisation of technical components (Mirzania, Balta-Ozkan, & Marais, 2020). Topel & Laumert, (2018) suggested that optimisation of the turbine can provide a 5% reduction in LCOE, which can be increased up to 10% if combined with warm-keeping measures to improve the turbine's flexibility. Preferring small diameter tubes enhances the thermal and mechanical performance of the system, counterbalancing the rise in pressure drop and therefore having a positive impact on LCOE (Conroy et al., 2018). In addition to optimisation of the power block, the use of molten salt instead of thermal oil as a heat transfer fluid enhances the system's performance by providing better temperature flexibility (Chaanaoui et al., 2016).

According to Ortega-Fernández et al. (2018), the type of molten salt also plays a role in improving economic performance, as molten salts contribute significantly to the LCOE of the plant. Santos et al. (2018) has argued that moving from oil to molten salt could reduce the overall cost for the HTF in PTC plants by between 40% and 45%. However, in terms of the maturity of technology, molten salt PTC technologies are not still commercially mature. Yet there are limited studies on how the use of molten salt can improve the techno-economic performance of PTC plants.

The type of thermal storage is also another significant factor that can be changed to improve financial performance. Alsagri et al. (2019) showed that incorporating molten-salt thermal energy storage into a PTC plant could reduce its LCOE by as much as 52%. However, due to high cost of molten salt, Conroy et al. (2018b) suggested that for PTC projects with small thermal storage systems (less than 3 hours), liquid sodium may be preferred to molten salt as it enables a reduction of the LCOE by 3%.

The literature review indicated that a wide range of studies have been carried out to evaluate the impacts of different technical parameters and optimisation of CSP components on the economic performance of these projects. However, there is limited available research on the impact of different technical parameters (including solar multiples, plant capacity and thermal storage size), on financial viability and self-sufficiency of PTC projects under post-subsidy conditions. Thus, this paper aims to investigate under what techno-economic conditions PTC projects can be viable and self-sufficient without the help of any subsidies.

2.3.2 Financial and economic parameters

One of the main parameters to be considered in techno-economic assessments is the discount rate, as it enables the evaluation of the time value of money (Moffatt, 2019). According to Ling-zhi et al. (2018), the discount rate reflects the expected returns of the PTC project's investment; therefore, it is a crucial parameter in techno-economic analyses. The inflation rate is another crucial macroeconomic parameter in techno-economic assessments that the project developer has no control over as they are shaped by the wider macroeconomic and market conditions.

Debt interest rate, which refers to the interest rate applied to the amount of money borrowed, is another crucial factor in the financial evaluation of PTC projects (Simsek et al., 2018). Literature indicated that the LCOE of a PTC project could fluctuate significantly depending on the debt interest rate (Aly et al., 2019; Simsek et al., 2018). Aly et al. (2019) suggested that an increase of 11% in the debt interest rate (from 7% to 18%) leads to an 80% increase in the LCOE of a PTC project. Similarly, Simsek et al. (2018) indicate that increasing the debt interest rate from 1% to 7% results in a nearly 28% increase in LCOE.

Incentives or funding support also has a substantial impact on the LCOE calculation. Zhao et al. (2017) found out that the LCOE of a PTC plant can be decreased by 19% with the help of an incentive.

3. Method: using System Advisor Model (SAM) as simulation software

In order to analyse the techno-economic performance of PTC projects, this paper adopted the net present value (NPV) and discounted cash flows methods to develop a viable financial model for PTC projects under post-subsidy condition using simulation software.

Several simulation software were considered for evaluation and simulation of the techno-economic performance of PTC projects in Spain, including SAM, HOMER, and RETScreen (homerenergy, 2019; NREL, 2017; RETScreen, 2020). RETScreen is a renewable energy technology management tool in the form of an excel spreadsheet, which is designed for calculating financial indicators of different types of renewable energy technologies. The main drawbacks of using RETScreen is that the input for solar radiation does not consider daily load and does not take renewable energy fluctuation into account (Lai and Mcculloch, 2017). HOMER is an optimisation software which is used to evaluate the techno-economic performance of the different type of renewable energy technologies based on NPV. While, SAM is a financial performance model designed and developed by the USA National Renewable Energy Laboratories (NREL) in collaboration with Sandia National Laboratories in 2005 (National Renewable Energy Laboratory, 2017b). SAM is used in designing and evaluating the techno-economic potential of various renewable energy technologies for specific sites. The components are indicated by several parameters and time-dependent inputs which can generate and calculate time dependents outputs.

In comparison with HOMER and RETScreen, the methodology and algorithms used in SAM for cost calculations and system design are known and accessible. Conversely, SAM considers and supports sub-hourly simulations and operates with weather data at up to one-minute intervals to estimate solar generation (Table 2). In recognition of the limitations of other tools available, this paper uses SAM as a simulation tool to critically analyse the techno-economic performance of PTC projects.

Table 2: Summary of Rationale for Using SAM over RETScreen and HOMER.
Compiled from (Homerenergy, 2019; NREL, 2017; RETscreen, 2020)

Name of Software	Range of Financial Performance Indicators	Considers Daily Load and Renewable Energy Fluctuation	Cost of Licensing and Availability	Black Box Code Utilisation
System Advisor Model	Yes	Yes	Free	No
RETScreen Expert	No	No	Subscription Fee	Yes
HOMER	Yes	Yes	Subscription Fee	Yes

SAM has been used as a simulation tool by several scholars to investigate the techno-economic performance and financial feasibility of different types of renewable energy technologies. For example, Poghosyan & Hassan (2015) and Agyekum & Velkin (2020) evaluated the techno-economic feasibility of concentrated solar power plants using SAM. Abdelhady et al., (2018) assessed the techno-economic feasibility of the biomass power plant. DiOrio, et al.,(2015) investigated the feasibility of integrating solar PV and battery storage in the US. Similarly Mirzania et al, (2020) evaluated the techno-economic feasibility of integrating solar PV and battery storage for community-owned solar energy projects in the UK.

This paper used SAM (version 2018.11.11) to run the techno-economic analyses for a PTC plant. SAM has multiple performance and financial models. For the purpose of this paper, we used CSP parabolic trough (Physical) as the performance model. We used the PPA utility financial model for the financial and discounted cash flow analyses. In this model, projects are assumed to sell generated electricity through PPA at a fixed price. For this model, SAM calculates the following financial performance indicators:

- Multiyear annual cash flow and financial metrics
- Project Internal rate of return
- After-tax net present value
- Levelized cost of electricity
- Revenue from selling electricity (Power purchase agreement price)

In this paper, the simulations were run using the typical meteorological year weather (TMY) data set. The financial performance predictions for PTC projects are also made based on installation costs, operating costs, and system design parameters. Figure 4 indicates the overview of using SAM and the procedures which were carried out to run techno-economic analyses for a PTC project in Spain.

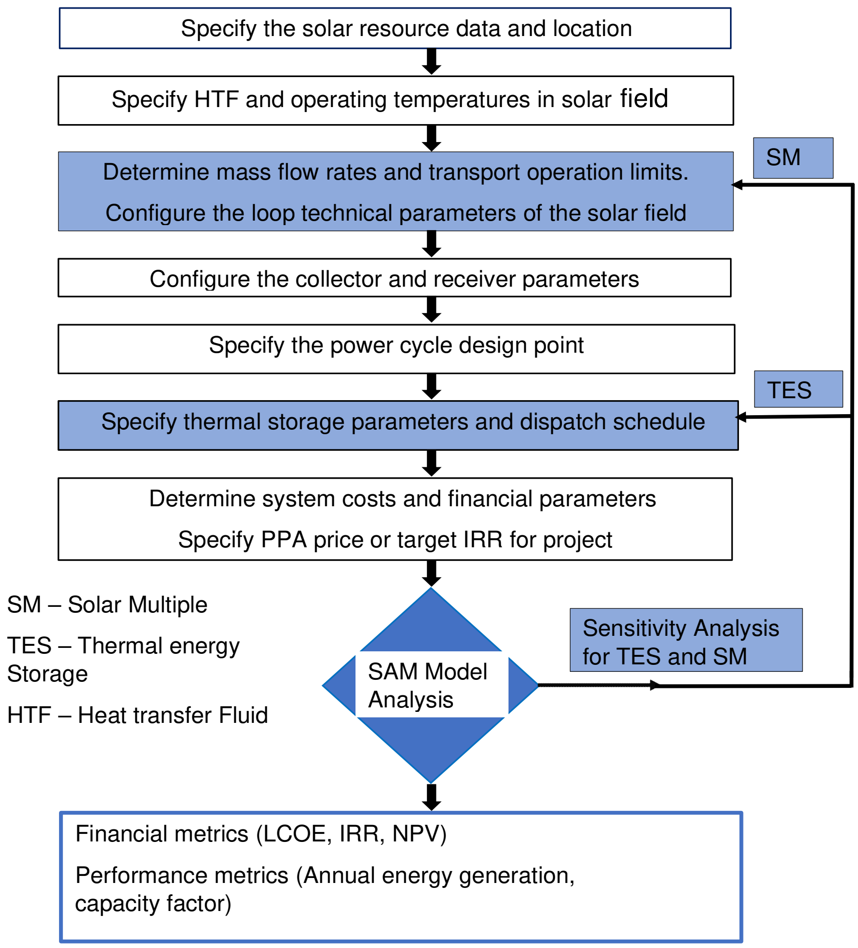

Figure 4: Methodology Flowchart

3.1 Financial analysis

The following section gives an overview of the economic and financial metrics which have been used to evaluate the techno-economic performance of CSP projects. It should be noted that SAM produces all financial results in US dollars, so all results were converted to Euros assuming the conversion rate 1$ = €0.89119 (Exchange-Rates.org, 2019).

3.1.1 Net present value

NPV measures the economic feasibility of the project over its lifetime based on the assessment of both revenues and costs. A discounted cash flow analysis has been used in this paper; the NPV was calculated for different economic scenarios to calculate the annual cash flow for the life of PTC project, using equation 1:

$$NPV = \sum_{n=0}^{N} \frac{C_n}{(1+d_{nominal})^n} \quad \textbf{(1)}$$

Where,

$C_n =$ After-tax cash flow

$n =$ Number of years

$d_{nominal} =$ The nominal discount rate

$N =$ Analysis period / project lifetime

The nominal discount rate is usually considered as the discount rate, which is calculated using the real discount rate and the inflation rate, as shown in equation 2:

$$Nominal\ Discount\ Rate\ = (1 + Real\ Discount\ Rate) \times (1 + Inflation\ Rate) - 1 \quad \textbf{(2)}$$

The discount rate is the primary factor affecting the NPV calculation. Due to the long lifetime of PTC projects, it is crucial to consider the variation in monetary value caused by the discount rate. The NPV enables a calculation of whether the discounted value of future cash flows is higher than the discounted value of future costs at a given discount rate. In other words; a project with a positive NPV is feasible whereas a negative NPV shows that the project does not deliver the required return (Arnold, 2005). Table 3 outlines all the financial parameters that have been used to conduct the cash flow analysis.

Table 3 : Key financial parameters for the modelled PTC project

Parameter	Value
Project lifetime	25 years
Real discount rate	4%
Inflation rate	2%
Nominal discount rate	6%

3.1.2 Levelised cost of electricity

LCOE represents the financial efficiency of the plant and is usually used as a common basis for a comparison with other types of technologies (Zhao et al., 2017). The LCOE is also referred to as the average minimum price at which the generated electricity is required to be sold at to achieve the breakeven point over the lifetime of the project (Lai & Mcculloch, 2017).

The LCOE was calculated using equation 3:

$$LCOE = \frac{-C_0 - \frac{\sum_{n=1}^{N} Z\, n}{(1+d_{nominal})^n}}{\frac{\sum_{n=1}^{N} Qn}{(1+d_{real})^n}} \qquad \textbf{(3)}$$

Where,

C_0 = the project's equity/capital investment (The cost is used in the equation as a negative value).

Z_n = the annual project costs including installation, operation and maintenance, financial costs and fees

Q_n = the electricity generated by the system in year 'n' as calculated using the weather data and the system performance parameters (such as degradation rate)

N = the analysis period / lifetime of the project

d_{real} = the discount rate omitting inflation

$d_{nominal}$ = the discount rate including inflation

A PPA guarantees a certain revenue for the project based on each unit of electricity it produces to make the project viable (World Bank Group, 2017). Therefore, the PPA price should be fixed in a way that supports a PTC plant, while still being low enough to make it competitive with other technologies.

3.1.3 Internal rate of return

The IRR represents the magnitude of the profit over and above the compensation for time and risk (Khare, Khare, Nema, & Baredar, 2019). IRR is the most meaningful tool for investors to measure profitability and is the most commonly used method to calculate the rate of return (Rogers & Duffy, 2012; Talavera et al., 2010). IRR is equal to:

$$NPV = \sum_{n=0}^{N} \frac{C_n}{(1+IRR)^n} = 0$$
(4)

Where
C_n = After-tax cash flow,
N = Analysis period in years

3.2 System Parameters

Table 4 summarises the key system parameters used in the simulation. This study considered Posadas Cordoba, in Spain for the simulation as shown in Figure 5.

Figure 5: Solar Direct Normal Irradiance of Spain (SOLSRGIS, 2020)

The solar irradiation data was obtained from sub-hourly weather data from the NREL website and is imported into SAM. The TMY weather data set are taken from long-term historical data from 1973 to 2017 at weather stations located in Posadas Cordoba (Figure 6).

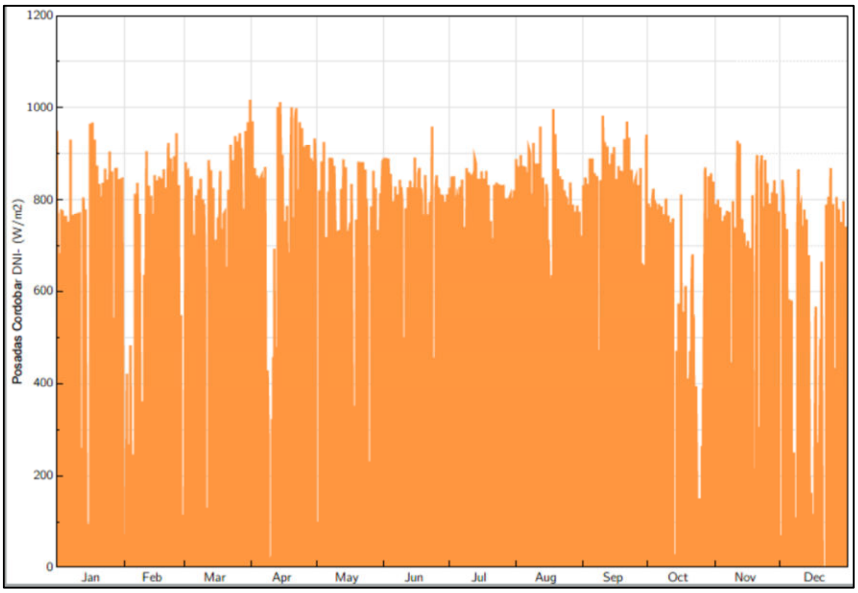

Figure 6: Sub-Hourly direct normal irradiance of Posadas Cordoba, Spain between 1973 and 2017 (National Renewable Energy Laboratory, 2017)

Table 4: Key parameters which used to design the PTC system; compiled from (NREL, 2012)

Component	Parameter	Case
Site Specification	System Location	Posadas Cordoba, in Spain
	Total Installed Capacity	50 MWe
	Solar Multiple	2
	Solar collector assemblies per loop	14
	Minimum single loop flow rate	1.8 kg/s
System Design	Maximum single loop flow rate	16 kg/s
	Collector	Euro Trough ET150
	Receiver	Schott PTR70 2008
	Solar Lifetime	25 Years
	Solar-Field Aperture Area	550,000 m²
	Power Block Turbine Capacity	50 MW

3.2.2 Configuration of the technical parameters of the solar field loop

The heat transfer fluid maximum and minimum single loop flow rates have been calculated using SAM (2014) software (Table 5). EuroTrough ET150 collectors and Schott PTR70 2008 receivers have been chosen, corresponding best to the available equipment and the CSP location (Table 5).

The technical parameters of the solar field require specifying the number of solar collector assemblies (SCA) per loop and the mass flow rates of the HTF. The values for the transport operational limits, including the maximum and minimum header design flow velocities for cold and hot pipe headers are defined from literature, as shown in Table 5 (Wagner, 2014).

Table 5 : Key parameters which used to design solar field of Molten salt PTC plant complied from (Wagner, 2014; NREL, 2019)

Parameter	Value	Reference
Number of Field Sub-sections	8	(Wagner, 2014)
Freeze protection temperature (°C)	260	(Wagner, 2014)
Irradiation at design (W/m^2)	950	(NREL, 2019)
Field HTF Fluid	Hitec Solar Salt	(NREL, 2019)
Design loop inlet temperature (°C)	293	(Wagner, 2014)
Design loop outlet temperature (°C)	550 °C	(Wagner, 2014)
Minimum single flow rate	1.5*	Optimum value
Maximum single flow rate	11*	Optimum value
Headed design min flow velocity	0.7	(Wagner, 2014)
Headed design max flow velocity	1.2	(Wagner, 2014)
Non-solar field land area multiplier	1.4	(NREL, 2019)
No. of SCA/HCE assemblies per loop	14	(Wagner, 2014)

*Determined as the optimum value

Changing the HTF from Therminol VP-1 oil to Hitec solar salt resulted in a high-pressure drop due to the higher viscosity of the salt in comparison to the viscosity of the oil. This resulted in adjusting the solar field parameters to reflect the performance. The pressure drop was designed to avoid rupturing the pipes.

In order to calculate the number of SCAs, iterations are done using pipe pressure loss equations, Reynold's number and changing reference length. The following steps are used to determine the total number of SCA, N_{sca}, and the mass flow rate, $\dot{m}_s$:

1. Using Equation 6, the Reynold's number is calculated using the maximum velocity for molten salt.

$$Re_T = \frac{\rho_T V_T D}{\mu_T} \quad \textbf{(6)}$$

2. Assuming the surface roughness is 4.5e-05 the friction factor was calculated for the laminar and turbulent flows using Equation 7.

$$Friction\ factor = \frac{2d}{\rho v^2\ L}\ \Delta \boldsymbol{P} \quad \textbf{(7)}$$

3. Assuming the initial reference length, $\boldsymbol{l_{ref}} = \mathbf{1}$, the initial pressure difference is calculated using Equation (8), as a scaling factor for the loop (Wagner, 2014).

$$\Delta P_{ref} = \frac{\rho_T {V_T}^2 l_{ref} f_{fT}}{2D} \tag{8}$$

4. The first law of energy balance is used to calculate the mass flow rate (assuming N_{sca} = 8) in the solar field by equating the energy absorbed in the loop in Equation (9) to heat added to the loop given by Equation (10), where heat capacity and density are both considered constant (Wagner, 2014).

$$\dot{q}_{loop} = A_{sca} \eta_{abs} N_{sca} I_{bn} \tag{9}$$

$$\dot{q}_{loop} = \dot{m}_s c_{ps} \Delta T_s \tag{10}$$

Where

$\dot{q}loop$ = energy absorption of the loop in W

A_{SCA} = area of collectors in m²

η_{abs} = efficiency of the collectors

N_{SCA} = number of collectors

I_{bn} =Direct Normal Irradiance (DNI) design point in W/m²

c_{ps} = specific heat in J/(kg*K)

ΔT_s = temperature rise across the loop in K

5. The field flow velocity for the Hitec solar salt is computed using Equation (11) obtained from SAM.

$$V_s = \frac{\dot{m}_s \times 4}{\rho_{s*} \pi \times D^2} \tag{11}$$

6. Using length as the scaling factor and using equation 11, a series parametric analysis has been conducted to calculate the number of solar collector assemblies (SCA), minimum and maximum mass flow rate and header design flow velocity (Table 6).

Table 6: Iterations for solar field parameters to obtain the optimal number of SCAs.

Iteration	$\dot{m}_s$**(kg/s)**	V_s**(m/s)**	Re_s	$f_{fs}(Re_s)$	l'**(m)**	N_{sca}
1	6.4	1.02	75254	0.0195	5.75	16
2	**11.2**	1.8	132802	0.017	2.11	16
3	12.8	2.05	151247	0.0165	1.68	**14**

The parametric analysis indicated that the best value for the number of SCAs and mass flow rate are 14 and 11.2, respectively.

3.3 Specifying the power cycle design point

The power cycle converts thermal energy delivered by the solar field to electrical energy using a conventional steam Rankine cycle power plant. The power cycle was used to set the design gross output of the plant.

The rated cycle conversion efficiency was set to 41.2%. This is the known efficiency for molten salt operating at 550°C steam temperature in SAM (Wagner, 2014). Table 7 defines the rest of the parameters used in the analysis.

Table 7: Key parameters which used to design power cycle and thermal storage complied from (Wagner, 2014; NREL, 2019)

Parameter	Value	Reference
Cycle conversion efficiency	41.2%	(Wagner, 2014)
Ambient temperature at design	42 °C	(Wagner, 2014)
Minimum required start-up temperature	360 °C	(Wagner, 2014)
Salt to steam temperature	500 °C	(NREL, 2019)
Tank height	15m	(Wagner, 2014)
Parallel tank pairs	2	(Wagner, 2014)
Cold tank heater set point	260 °C	(NREL, 2019)
Hot tank heater set point	525 °C	(NREL, 2019)

3.4 System cost assumption

The main costs considered for the simulations were the expenses related to the solar field installation, storage and the cost of the power block, including equipment and labour (Table 8). In order to capture freeze protection costs, a slightly higher price has been simulated for the PTC using salt as the HTF than the PTC using oil. Similarly, to capture fluctuations in the PTC system components' cost, an annual price escalation of 2% has been simulated for all of the system cost analyses in this study.

Table 8: System Costs for the PTC with molten salt as HTF.
Compiled from: Dieckmann et al., 2017; European Solar Thermal Electricity Association, 2016; Pan et al., 2018; Wagner, 2014

Component	Value	Reference
Solar Field Cost €/m²	207	(European Solar Thermal Electricity Association, 2016)
Power Block Cost €/kWh	750	(Dieckmann et al., 2017)
HTF System Cost €/ m²	53	(Dieckmann et al., 2017)
Storage Cost €/kWh	28	(Pan et al., 2018)
Power Plant Cost €/kW	739	(Wagner, 2014)
Balance of Plant Cost €/kW	80	(NREL, 2019)

4. Results and discussion

This section presents the techno-economic simulation results to evaluate how PTC projects can be financially viable in the post-subsidy period, assuming several economic conditions. Sub-section 4.1 to 4.4 presents a series of parametric analyses undertaken to investigate the most viable financial model for developing PTC without help of any incentives. Followed by sub-section 4.5 which presents a series of financial analyses conducted to investigate techno-economic performance of PTC projects assuming rolling back of FIT.

4.1 Role of discount rate on PTC viability

Considering the lifetime of the PTC project, the discount rate is a significant factor to be defined when carrying out a techno-economic assessment. The discount rate is a crucial consideration factor as it reflects the minimum rate of return (Jones et al., 2017). The discount rate also expresses the risk uncertainty and time value of money and must be therefore chosen carefully (Blair et al., 2018).

In order to investigate how PTC projects can be structured to become financially viable without any subsidy, a series of parametric analyses have been run with different discount rates between 6% and 8%. Simulation results indicate that increasing the discount rate from 6% to 8% results in a 24% increase of the LCOE and a 14% drop in NPV. Therefore, the discount rate of 6% has been selected as a baseline for all the analyses of this study. The modelled discount rate compares relatively well with existing studies. Table 9 summarises different discount rates that have been used in different existing studies.

Table 9: Comparison of values of real discount rates in the literature

Source	Location	Technology	Discount rate
Schmitt et al., (2017)	----	Parabolic Trough Collector	5.50%
Miguel & Corona (2018)	Spain	Parabolic Trough Collector	6.90%
Martinez & Hernandez (2012)	Global scale	CSP	7.50%
Alsagri et al., (2019)	Saudi Arabia	Solar Power Tower	8%
Simsek et al., (2018)	Chile	Solar Power Tower & Parabolic Trough Collector	9%

4.2 Impact of PPA price on the viability of PTC

A PPA is the primary source of revenue for PTC projects; therefore, it has a direct impact on the viability of PTC projects. A series of parametric simulations have been run with different discount rates and PPA prices to evaluate the most viable PPA rate for PTC projects under post-subsidy condition.

Based on the simulation results, in order for PTC projects to become feasible without any incentives, they should be able to sell electricity with minimum PPA price of €0.15 per kWh (Figure). Simulation results also demonstrated that projects with the higher discount rate have lower NPV. In other words, they are less financially attractive. As Figure 7 indicates, the project with a discount rate of 6% would result in higher NPV, whereas the PTC project with a discount rate of 8% is less economically attractive. Simulation results showed that the PTC projects with a discount rate of 6% and 7% would generate similar PPA revenues, therefore have resulted in similar NPV (Figure 7).

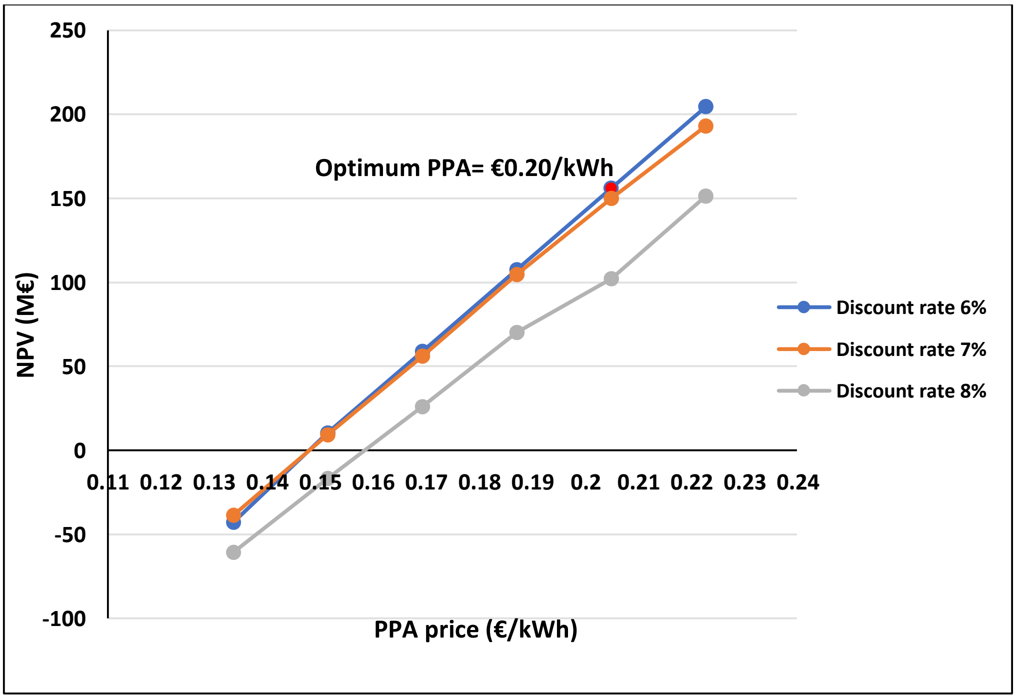

Figure 7: Impact of PPA price on the viability of PTC projects

As Figure 8 shows, the project with the PPA price of 0.15 €/kWh will not be financially attractive as the IRR would be low (6.41%). Simulation results showed that the PTC projects with the discount rate of 7% and 8% would have identical IRR up to a PPA price of €0.20 per kWh. However, beyond a PPA price of €0.20/kWh the IRR begins to increase for a PTC project with a discount rate of 8% (Figure 8).

Simulation results indicated that higher IRR leads to better economy of projects, as IRR is the primary evaluation index for the profitability of the project (Yang et al., 2018). Based on the simulation results, the PTC project with a discount rate of 6% becomes financially attractive under the post-subsidy condition with a PPA price of €0.20 per kWh, which would result in an IRR of 10.89 % (Figure 8). Our results compare very well with the findings of Yang et al. (2018) that calculated an IRR of 11.72% for PTC technology.

A PPA price of €0.20 per kWh is still slightly lower than the current price of electricity of €0.21 per kWh ($0.24 per kWh) that end-users pay (GlobalPetrolPrices.com, 2020). However, a PPA price of €0.20 per kWh might weaken the competitiveness of PTC projects. In fact, our modelled PPA price without a FIT is much lower than La Africana project in Spain, which was set at €0.27 per kWh with the FIT rate (NREL, 2012).

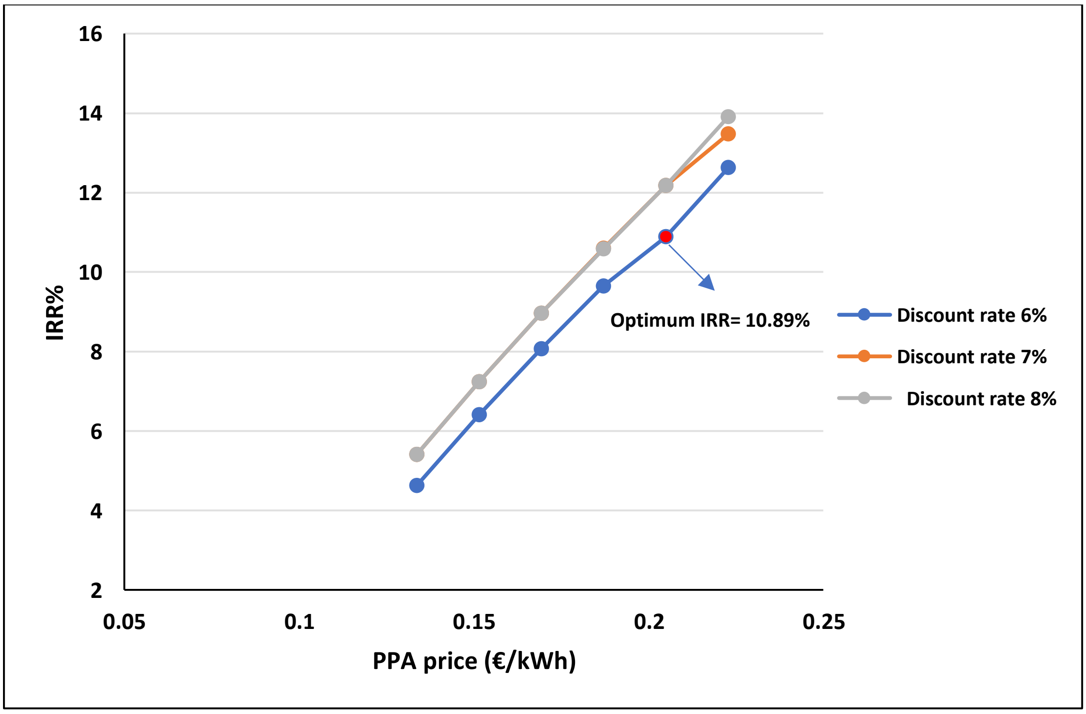

Figure 8: Impact of PPA on the profitability of PTC projects

4.3: Evaluating the impact of different technical parameters on viability of a PTC project

In addition to the financial parameters, which proved to have a significant impact on the project's financial performance, technical variables also influence their viability. The direct normal irradiance (DNI) is a significant determinant of CSP efficiency, and it has a great impact on LCOE (Zhuang et al., 2019; Alsagri et al., 2019). According to Martınez and Hernandez (2012), locations with a DNI less than 1900 kWh/m²/yr are not suitable to obtain a reasonably cost-effective project. Although the area of Posadas Cordoba fulfils this criterion, another location with higher DNI could be chosen to improve the techno-economic performance of the project. Although the selected location mostly imposes the techno-economic performance of a PTC project, it is important to underline how different technical parameters, including solar multiple, plant size and thermal storage capacity, can influence its financial viability.

In the following sections we have conducted a series of sensitivity analyses with different plant capacities, TES sizes and solar multiples to investigate the most viable techno-economic model for a PTC projects under the post-subsidy condition.

4.3.2 Impact of solar multiple

In order to determine the most suitable size of solar multiple for the PTC project located in Posadas Cordoba, a series of parametric simulations with different ranges of solar multiples (between 1.4 and 2.4) were done (Table 10). The simulation results indicated that solar multiple increases have a direct impact on solar energy production and the capacity factor of PTC projects, therefore influencing their viability and profitability (Table 10). The simulation results demonstrated that a solar field with a solar multiple of 2 can increase the PTC's profitability by minimising the installation, operation and maintenance costs, and results in the lowest LCOE. The results of this study are in line with Trabelsi et al., (2018) who found a solar field with a solar multiple between 1.75 and 2 as an optimum size for PTC projects.

Table 10: Impact of the solar field on the techno-economic performance of PTC with 4 hr TES

Solar Multiple	LCOE €/kWh	NPV M€	Annual energy kWh (year 1)	Capacity factor %
1.4	0.179	80	81,427,584	20.7%
1.6	0.168	90	93,828,112	23.8%
1.8	0.157	90	106,724,456	27.1%
2.0	0.15	100	117,074,448	29.6%
2.2	0.154	100	122,258,848	31.0%
2.4	0.160	194	204,101,000	34.5%

As shown in Figure 9, the increase in solar multiple reduces the LCOE drastically. For the PTC project with TES of 8 hours, a solar multiple beyond 2 reduces the LCOE considerably whilst, for the PTC project with TES of 4 hours, the LCOE increases for the project with solar multiples over 2. Similarly, for a PTC project with the TES of 6 hours, a solar multiple of beyond 2.2 begins to increase the LCOE (Figure 9).

Results indicated a solar multiple of 2 results in the lowest LCOE and highest IRR for the PTC projects with TES of 4 hours. Based on the simulation results for the PTC project with the larger TES, the larger solar multiple reduces the LCOE considerably (Figure 9).

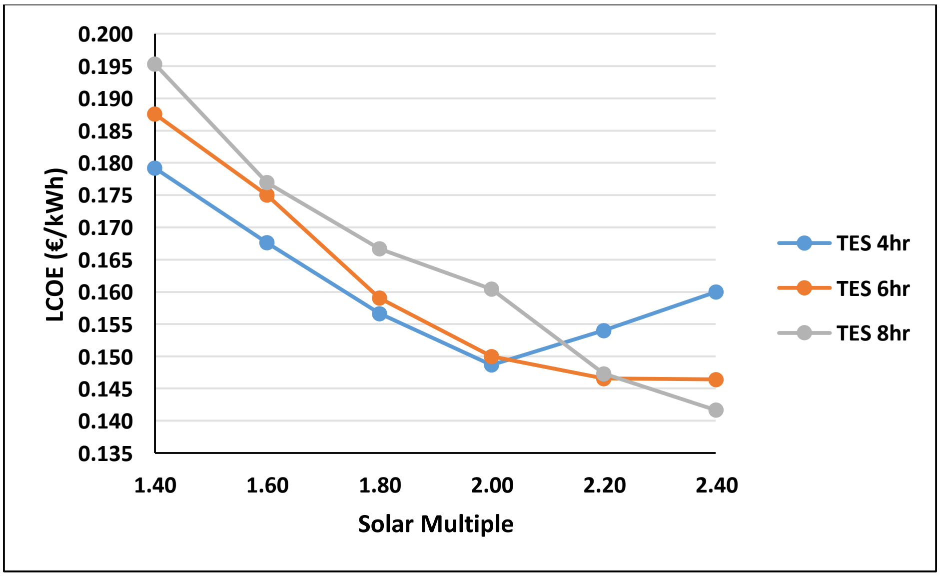

Figure 9: Impact of solar multiple on LCOE

4.3.1 Impact of the plant capacity and TES size

Techno-economic analyses have been undertaken for different sizes of PTC plants between 50 MWe and 200 MWe and with different TES sizes between 4 hours and 8 hours to evaluate plant capacity and TES's impact on the viability of a PTC project.

The simulation results indicated that by increasing the plant capacity the LCOE decreases, making the PTC projects more financially attractive (Figure 11). Whereas by increasing thermal storage the LCOE increases and makes PTC projects less profitable. However, beyond 125 MW, an increase in plant capacity has much less impact on LCOE, especially compared to the embedded rise in costs (FigureFigure 10). Our results compare well with the outcome of Schmitt et al. (2017) and Roni (2019), who both observed that significant LCOE reductions occur between 5 MW and 75 MW. However, as the plant capacity increases the NPV also increases, which boosts the project viability (Figure 11).

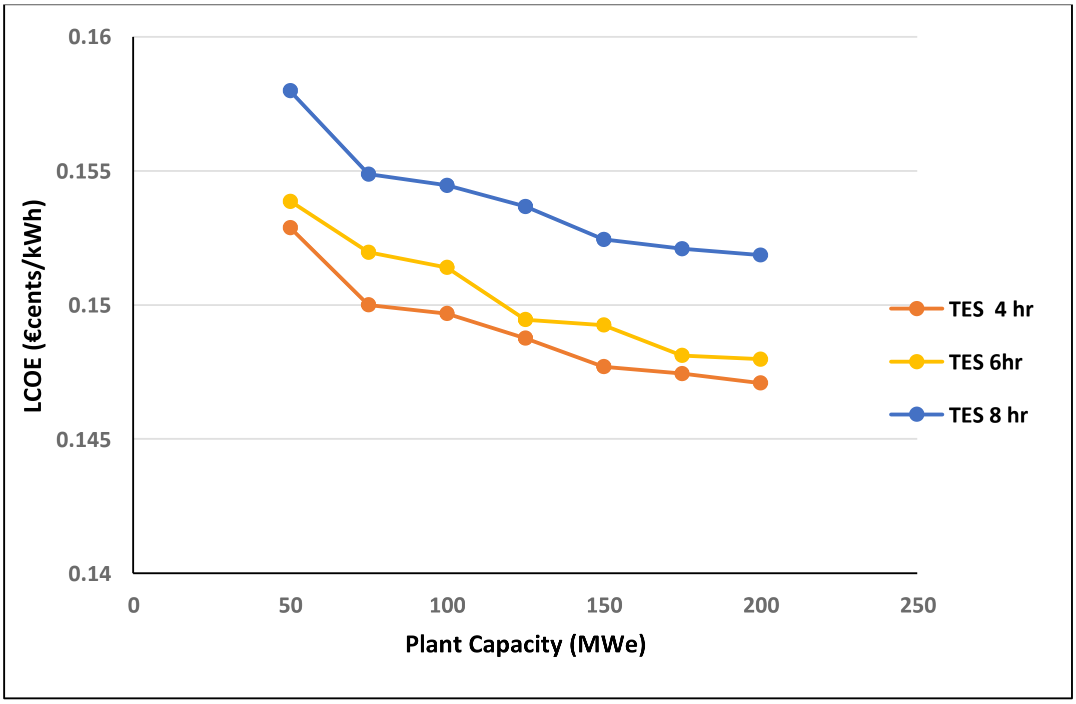

Figure 10: Impact of plant capacity on LCOE

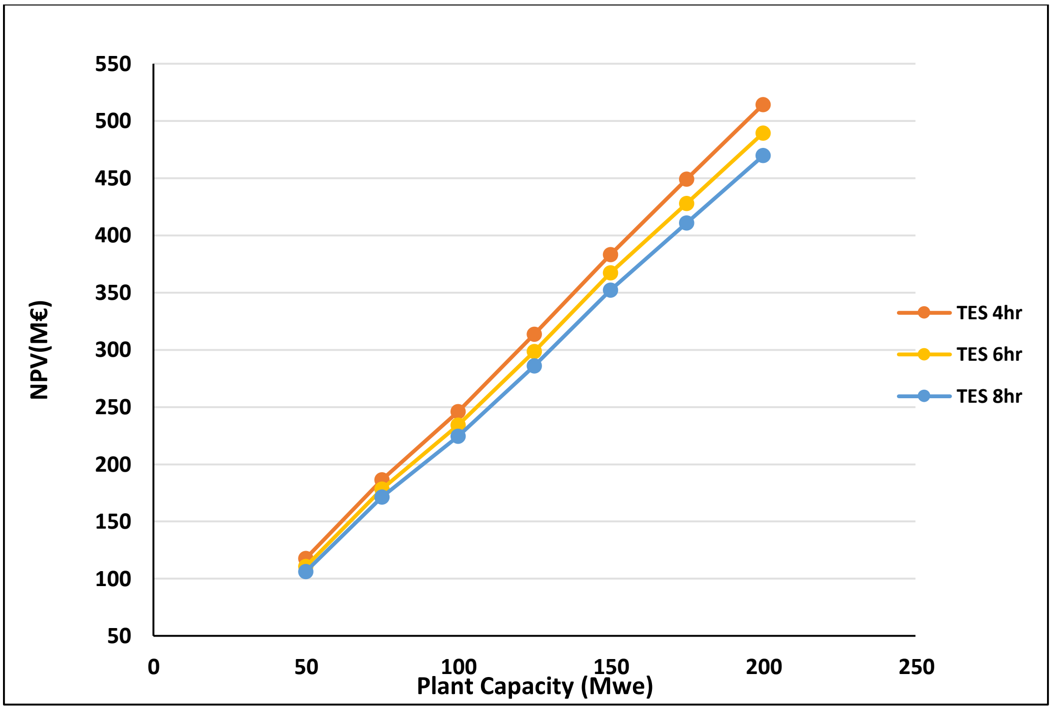

Figure 11: Impact of plant capacity on NPV

Including a thermal storage system (TES) into a PTC plant is an effective way to reduce peak demand pressures and to be able to generate electricity outside of sunlight hours (Zhao et al., 2017). It is thus an asset for the improvement of the project efficiency. Increasing the capacity of thermal energy storage (TES) leads to an increase in capital costs and makes the project less profitable (Figure 12). The profitability of the PTC projects can increase by reducing the TES size.

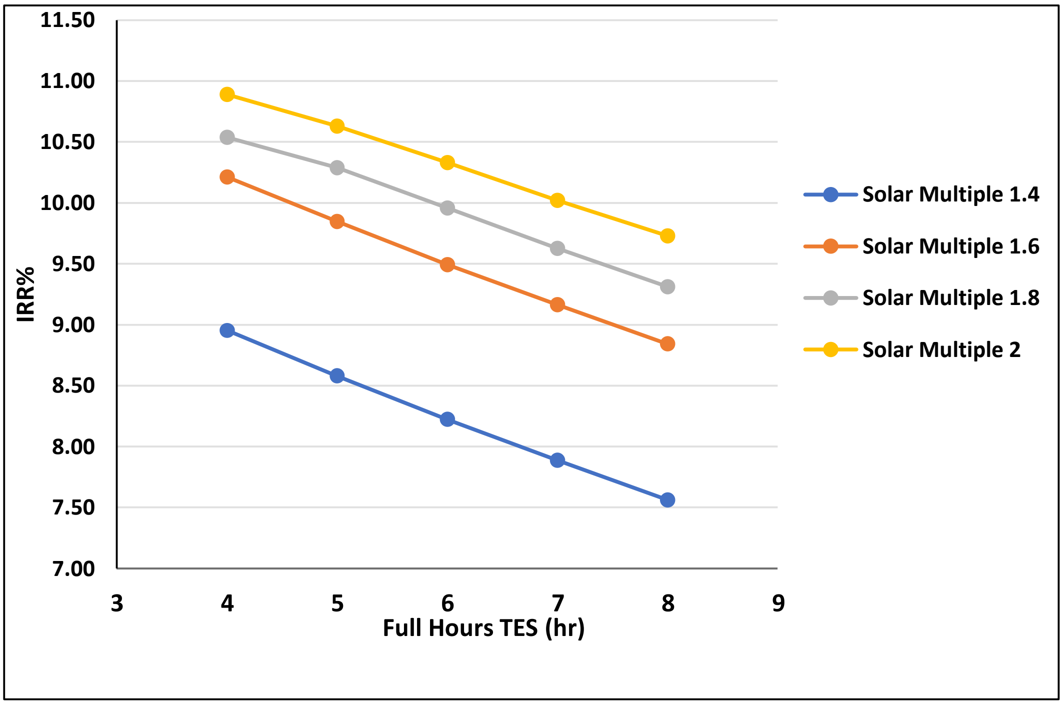

Figure 12: Impact of TES capacity on IRR

Simulation results indicated that a 50 MWe PTC project with TES of 4 hours become financially attractive under post-subsidy condition. However, it might be slightly challenging for a PTC with TES of 4 hours to get competitive PPA. If the PTC projects are not able to get competitive contracts the next viable model for developing a PTC projects would be a 50 MWe plant with TES of 6 hours.

As the size of the TES increases, the financial performance of the project decreases (Figure 11 and Figure 12). This has also been highlighted by Zhuang et al. (2019), who indicated that beyond 4 hours of TES capacity, the improvement in performance factor does not counterbalance the embedded TES costs anymore, reducing the PTC plant’s financial performance. However, the optimal TES capacity may nevertheless vary depending on the project, as a function of several different parameters, including market and electricity pricing structure. Qoaider & Liqreina (2015) evaluated the impact of solar multiple and TES on the techno-economic performance of PTC projects in the Middle East and North Africa (where in some parts the annual solar irradiation can be as high as 2500kWh/m^2). They found that the optimal size of TES can fluctuate between 3 and 10 full load hours, depending on the solar multiple. Roni et al., (2019) investigated the techno-economic performance of CSP projects with and without storage in south-east Bangladesh (where in some parts the annual solar irradiation is over 1900kWh/m^2). They suggested that a CSP project would achieve ideal performance when it has a solar multiple of 6.5 and a TES capacity of 8 hours. Hence, although 4 hours appears to yield the best thermal storage capacity, optimisations of different parameters of the PTC plant may change this value.

4.4 How can a PTC project in Spain reach grid parity?

One of the primary goals of any renewable energy project is to reach grid parity, as it is a primary indicator of competitiveness. Overall, the LCOE of alternative technologies such as PTC plants depends on overall investment costs, local conditions, operating and maintenance costs and financing conditions (Papaefthimioua & Souliotisb, 2016).

Considering the discount rate of 6% with the simulated techno-economic model (Table 11), the LCOE of the PTC project can reach €0.15/kWh, which is much lower than the current price of electricity in Spain (€0.21/kWh)(GlobalPetrolPrices.com, 2020). This means that PTC projects located in Posadas Cordoba, Spain, where the DNI is 2274 kWh/m^2/yr, can reach grid parity and become financially viable without the help of FIT and other kinds of incentives (Table 12 and Figure 13).

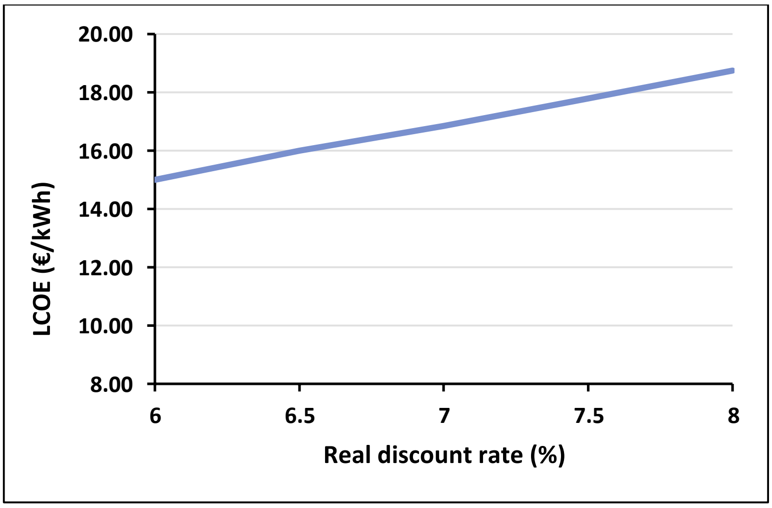

Figure 13: Reaching grid parity under post-subsidy conditions

Table 11: Key parameters of the viable model under post-subsidy condition

Variable	Value
Plant Capacity	50 MWe
Thermal Storage Capacity	4 hr
Solar Multiple	2
Discount rate	6%
IRR	10.89%
PPA Price	€0.20/kWh

Table12: Techno-economic performance of a PTC project with developed model under post-subsidy condition

Component	Value
Annual energy yield (year 1)	117,074,448 kW
Capacity factor	29.6%
PPA Price	€0.20/kWh
Net capital cost	€310,434586
LCOE	€0.15/kWh
IRR	10.89%
NPV	1E+08

Our finding is in line results of Papaefthimioua & Souliotisb, (2016) who stated that early grid parity had already been reached in parts of Spain, Italy and Cyprus. It has also been estimated that locations with high solar irradiation, like Southern Spain, and high electricity prices will reach grid parity first. However, Hernandez-Moro et al. (2012) have predicted that PTC projects will reach grid parity between 2021 and 2026. The rapid growth of PTC projects in countries such as Morocco, South Africa, Kuwait and Saudi Arabia played a significant role in the establishment of PTC and decreased their capital costs (Business Wire, 2019). Reports from the IRENA cost and auction databases indicated that the worldwide LCOE of PTC projects in 2018 was 26% lower than in 2017 and 46% lower than in 2010 (helioscsp, 2020). Furthermore, with a significant number of PTC plants being commissioned in China, it was predicted that the rate of decline in LCOE in 2019 and 2020 would be higher than that observed in 2018 (helioscsp, 2020). Schmitt et al. (2017) predicted that by 2030 the LCOE of PTC projects will significantly decrease to €0.053 per kWh. Similarly, Roni et al., (2019) estimated that by 2030 the LCOE of PTC projects in south-east Bangladesh would reach €0.069 per kWh**.**

The analysis above indicates that, under current retail electricity prices and post-subsidy conditions, PTC projects reached grid parity and became viable without direct incentives. Even though a reduced level of direct incentives and policy support will be needed, the PTC industry in Spain is far from becoming fully self-sustained as companies have not yet managed to shift their existing strategies from technology push to demand pull (KPMG LLP, 2015).

International experience with other countries, including Greece and Italy, has proven that reaching grid parity cannot guarantee that the solar industry will be self-sustaining (KPMG LLP, 2015). Therefore, it will be necessary for Spain to start arranging post-parity for the PTC industry, providing an opportunity for PTC projects to build scale. This way, it can ensure that PTC projects do not just become competitive with other technologies but also become the cheapest technology. Currently, in Spain, the only way that this can be achieved is through rolling back FIT for CSP projects, which provide an opportunity for the CSP industry to continue scaling up and increase the viability and attractiveness of CSP projects for investors. Therefore, the following section presents the results of the parametric analyses that have been run to investigate the most promising FIT rate for CSP projects in Spain under current economic conditions.

4.5 Determining the most promising FIT rate

The analysis above indicates that the PTC projects are not financially attractive without FIT unless the PPA price is brought to €0.20 per kWh, which weakens the competitiveness of PTC projects.

In order to assess the most promising FIT rate for the viability of CSP projects, a sensitivity analysis has been run with different range of FIT rates between €0 and €0.22 per kWh. The simulation results indicated that incentives of €0.13/kWh lead to the most promising CSP project (Figure 14). With this level of financial support decreasing the PPA price to €0.13/kWh, the CSP project becomes profitable and fully competitive. Therefore, the LCOE significantly reduces to €0.1/kWh (Figure 15). For the most viable PTC projects, the existing literature calculated an LCOE of €0.1/kWh (Zhao et al., 2017, Simsek et al. 2018, Islam 2019), which compares very well with our result (€0.1/kWh).

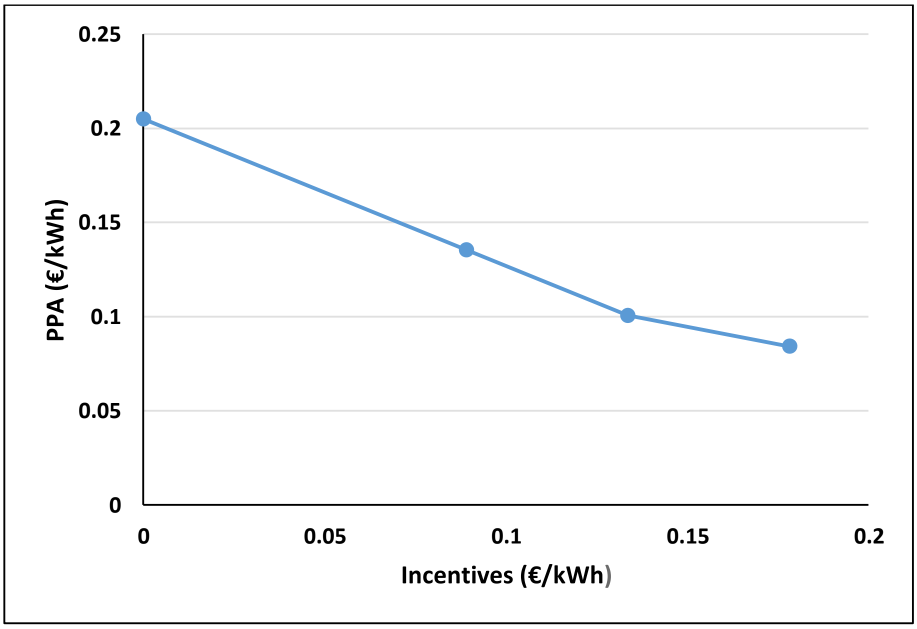

Figure 14: Impact of rolling back FIT on the profitability of PTC

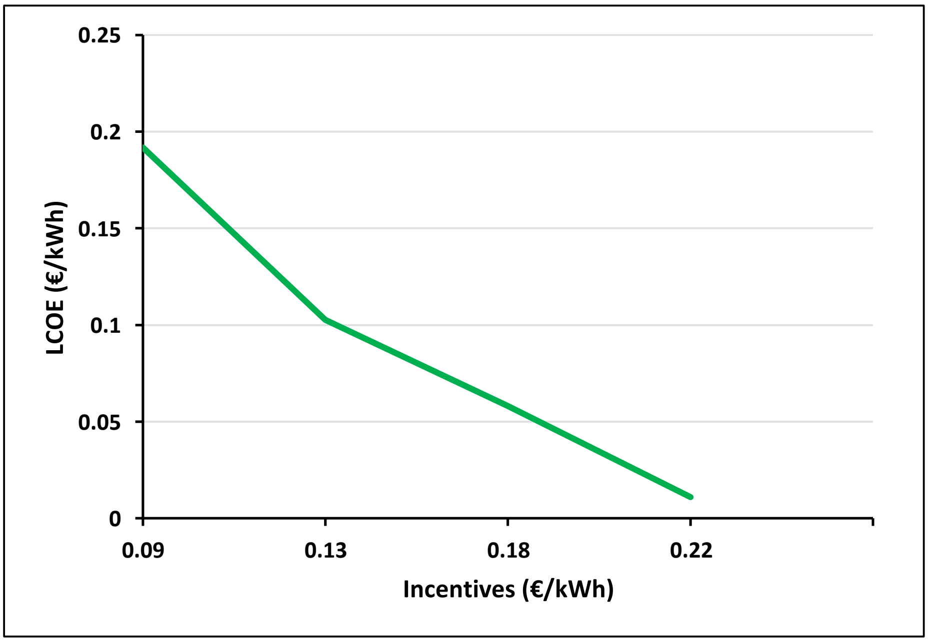

Figure 15: Impact of rolling back FIT on LCOE

Our modelled PPA prices compare very well with the findings of Servert et al. (2015) and Hansson et al. (2017), who highlighted that the average PPA tariff for a PTC project lies between €0.085/kWh and €0.109/kWh.

However, in some cases, auctions can be designed as a means to support PTC projects (Mir-artigues, 2019), which led producers to propose ever lower prices in order to win the auction. Consequently, the PPA price can reach values as low as €0.062/kWh (Lilliestam & Pitz-paal, 2018) or even less than €0.049/kWh (Simsek et al., 2018). In such a case, the choice of PPA tariff value that has been made in this modelling could be reduced. However, even though auctions can lead bidders to accept the lowest price to get a PPA contract, they can also have adverse effects, such as ineffectiveness, since bidders may refuse the PPA (Mir-artigues, 2019). The consequences can be severe for a PTC project as it is shown that in some cases, the rejection of the PPA can lead to the withdrawal of funding (Perez, Lopez, Briceño, & Relancio, 2014). Hence, agreeing on a PPA price that enables the reduction of prices and supports the project is of significant importance.

5. Conclusion and recommendation

We simulated the impact of various physical and technical parameters including the thermal storage system, solar multiples, and plant capacity on different financial variables of a PTC project. The simulation results indicated that a 50MWe PTC project with TES of 4 hours and a PPA price of €0.20 per kWh can provide the best financial yield under post-subsidy condition. However, due to the fact that these projects are still under active development, improving the techno-economic performance of PTC projects is not sufficient to make these projects fully self-sustained and financially attractive without the FIT. Therefore, it is crucial to find a solution to develop a funding scheme that would effectively support the development of PTC projects while remaining feasible for the Spanish government. Based on funding policies that have been adopted in other European countries, several possibilities could be explored to that end. Project-scale based incentives, as in Italy, or regional support, as in France, could be used as a model, since their situations may have similarities with Spain. As noted in the literature, there are other types of policy support schemes that can be considered, such as investment tax credit, land cost reduction, sales tax reduction or depreciation modes that could be more suitable to Spain’s situation than production-based credits. Ultimately, the solution may reside in a combination of several of these funding policies, as proposed by Zhao et al., (2017). It is, however, clear that finding a way to develop a coherent funding scheme is crucial to revive CSP in Spain.

5.1 Policy implication: establishing new financial support

To design cost-effective financial support, Spain could draw on other countries, such as Italy and France, which both have different incentive schemes in place. In Italy, it takes the form of subsidies per square metre of collector area, which depends on the plant’s gross surface and the presence or absence of a cooling system (National Renewable Energy Action, 2012), which aims to adapt the level of incentives to the scale of the project rather than its production. In France, a FIT of €0.048/kWh is allocated to solar thermal projects and can be accumulated with local and regional funding (French Department of Ecological Development, 2019). There are, therefore, different types of incentives applicable to CSP.

The incentives that have been modelled in this paper are in the form of production-based incentives that have been previously used by the Spanish government. However, several different models exist and could be investigated for future new funding schemes, such as investment tax credit, depreciation modes, production tax credit, or also investment-based incentives and sales tax reduction, which have lower impacts on LCOE reduction (Simsek et al., 2018). Land cost reduction is also a possible support policy as land costs are a significant proportion of the total investment costs (Zhao et al., 2017) and can, in some cases, lead to a reduction in LCOE of up to 26% (Zhuang et al., 2019). The optimal solution may be to combine multiple incentive policies: Zhao et al. (2017) argues that a decrease of 19% in LCOE could be reached by combining preferential loans, tax support and zero land cost policies.

Even though forecasting future incentives in Spain at a value of €0.13/kWh may seem quite optimistic, it reflects the fact that there are several opportunities to improve PTC financial performance in the coming years. As shown by our analysis, optimal solutions such as reducing the size of thermal storage, increasing the number of solar multiples and the PPA price can boost the profitability of PTC projects.

5.2 Further avenue for research

Based on the technical specification of La Africana project, this paper used Hitec Solar salt as a heat transfer fluid. However, it would be advantageous to evaluate the impact of a different type of heat transfer fluid on the techno-economic performance PTC project. According to Rendón et al. (2018), depending on the choice of molten salt, the power block's efficiency can be improved by 4%. Pan et al., (2018) highlighted that by using solar salt as heat transfer fluid instead of Hitec salt, LCOE decreases by 12%. In addition, Zhuang et al. (2019) highlighted that the TES capacity may vary between 4 and 6 hours, depending on the type of molten salt. Therefore, using the optimum heat transfer fluid is another approach to enhance the performance of the PTC project.

PTC projects can potentially sell their generated electricity at a negotiated price through PPA based on delivery time and season. Accordingly, it would be valuable to evaluate the impact of different time of delivery approaches for the PPA on PTC projects' techno-economic performance under post-subsidy condition.

Furthermore, it would also be advantageous to investigate the influence of the meteorological input parameters on the techno-economic performance (NPV, LCOE and IRR) of PTC projects. These uncertain input parameters can include future weather data, precipitation amount and cloud cover.

Acknowledgments

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