Master Thesis

Master’s degree in Energy Engineering

Design and Modelling of a Large-Scale PV Plant

REPORT

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ABSTRACT

The current project is focused on the design a large-scale PV solar power plant, specifically a 50 MW PV plant. To make the design it is carried out a methodology for the calculation of the different parameters required for the realization of a project of this nature. Subsequently, the different parameters obtained are compared with parameters obtained in literature and with the parameters obtained by means of specialized PV software (*PVsyst* and *SAM*).

Before implementing the design calculation methodology, the main components in a large-scale PV plant are described: PV modules, mounting structures, solar inverters, transformers, switchgears and DC and AC cables. Furthermore, the following aspects are analysed in the current project: legislative and administrative procedures, renewable energy support schemes and environmental aspects associated with large-scale PV plants.

The calculations regarding the PV plant design are made for a specific location previously selected. The site selected for the installation is in the location of *l'Albagés* (*Lledia*) which meets all the requirements for the installation of a PV plant.

The results obtained for four different PV plant scenarios are compared between them in order to obtain the best possible configuration, the different scenarios combine two different modules and two different solar inverters. The calculation methodology is divided in: design calculations, energy calculations, economic calculations and evaluation parameters calculation. The design parameters calculated are the number of PV modules in the system, the number of PV modules in series and parallel and the total installed capacity. The main purpose of the energy calculations is to obtain the Annual Energy Production (AEP) of the system. The cost associated to the PV project and the Levelized Cost of Energy (LCOE) are obtained by means of the economic calculations. Finally, evaluation parameters such as Performance Ratio (PR) or Capacity Factor (CF) are calculated.

The four different scenarios are modelled by means of *PVsyst* and *SAM* and the results obtained are compared with the results obtained in the calculations. The conclusion obtained is that the results obtained with PV software are in accordance with the results obtained by means of the calculation methodology implemented. The scenario analysed with the best results is the scenario which uses CdTe thin-film module technology and the inverters with the highest nominal power. The main results obtained for this scenario are: 484,960 PV modules and 14 inverters; Installed capacity of 53.35 MWp; AEP of 83,001 MWh/year with an LCOE of 3.1154 c€/kWh; and evaluation parameters are 79,73% of PR and 17.76% of CF.

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Contents

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1. INTRODUCTION

During 2015, in Paris was held the United Nations Climate Change Conference, also known as COP21. In that conference the so-called Paris Agreement was reached and signed by most of the major CO_2 emitting countries. The aim of the Paris Agreement is the reduction of greenhouse gases emissions by setting a limit of global warming below 2ºC compared to pre-industrial levels. To comply with the agreements reached in Paris, the countries involved have to consider the decarbonisation of their energy supply since 65% of the global CO_2 emissions come from burning fossil fuels and 81% of the total primary energy supply is based on fossil fuels [1]. One of the ways to decarbonize the energy supply of a country, and probably the only way completely effective, is to make a change towards an energy system with a higher penetration of renewable energy. Photovoltaic solar power plants are nowadays the technology most extended regarding renewable energy generation and since 2016 PV solar energy is the technology with higher growth [2]. The main factor driving the rapid growth of the PV solar capacity is mainly economic, PV solar power plants have reduced their associated cost by 70% [2]. The total cost reduction in PV solar power plants is caused by cost reduction due to technological improvements, economies of scale in manufacturing and innovations in financing [3]. Furthermore, the growing of PV capacity due to cost reduction is not expected to stop in the next years, but it is excepted to increase the growth of PV in the future. In 2014, according to *IFC* [3] total PV installed capacity worldwide was 137 GW with annual additions of approximately 40 GW. Traditionally, the area with practically the totality of the total share of installed PV capacity was Europe, but since 2013 the installed PV capacity in other areas, especially in Asia-Pacific, has grown very rapidly. In 2016 Asia-Pacific became the zone with the highest share of installed PV capacity surpassing Europe. In this context regarding the energy situation in the world and the role of the PV solar power plants is found the project carried out.

1.1. GOALS AND PROJECT SCOPE

The main objective of the project is the design and modelling of a 50 MW PV solar power plant by implementing a calculation methodology. By means of the calculation methodology the following parameters of the PV plant are pursued to obtain through the course of the project: configuration of the PV plant (number of PV modules, number of inverters and how they are connected between them); energy produced by the PV plant; and performance parameters of the plant which can be used to compare the results obtained. Purely electric aspects are not assessed in detail in this project. Another important goal of this project is to make the design of the PV plant economically viable, thus an economic analysis of the PV plant is included in the project, without going into detail in financing models. The last objective of the project is to validate the results obtained by means of specialized software.

2. PV LARGE-SCALE COMPONENTS

In this chapter of the project a description of the main components forming a large-scale PV solar power plant is done. The elements described below are going to be considered during the calculations used for the system design. The components described are: PV modules, inverters, transformers, switchgears and AC and DC cables.

2.1. SOLAR PV MODULES

PV modules convert the solar radiation directly into electric energy by means of the photovoltaic effect, doing this process in a silent and clean manner. There are many different PV modules technologies and nowadays research institutions are making efforts to discover new materials and designs with which the performance of the solar cells can be improved. There are different types of solar cells and their classification can be seen in Figure 2.1. In this project, the two major families of solar cells dominating the market are going to be explained in more detail in this section: silicon crystalline structure and thin-film technology.

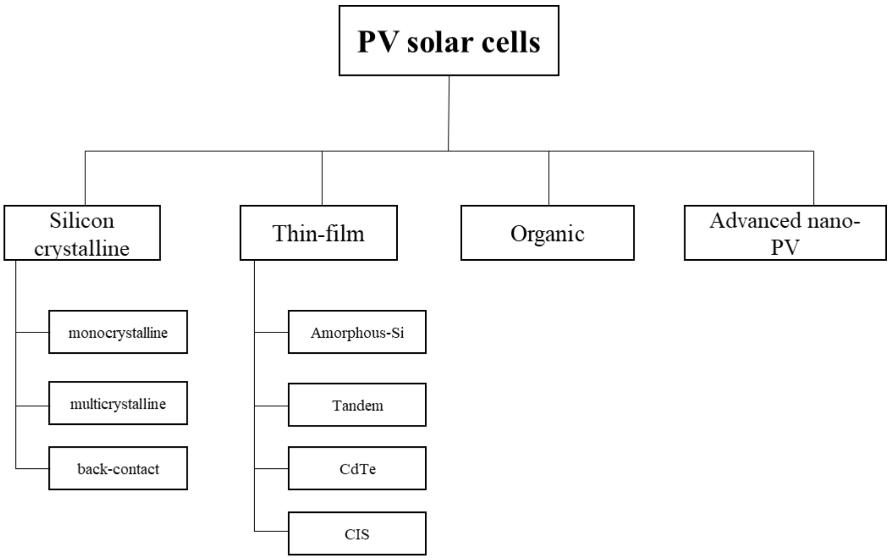

Figure 2.1. Solar PV technologies classification.

In Figure 2.2 the production share of silicon crystalline structure (multicrystalline-Si and monocrystalline-Si) and thin-film technology can be seen. In the early years of photovoltaics, mono-Si practically monopolized the production, and as the years went the production of multi-Si has become more important. The production of thin-film technology remains more or less constant over the years.

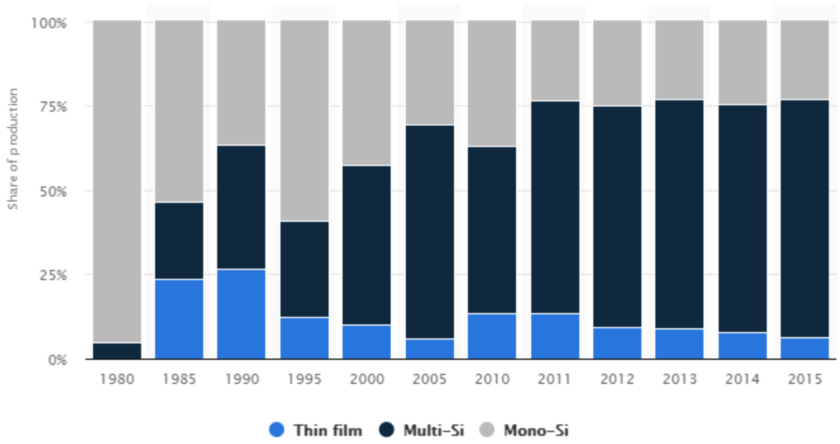

Figure 2.2. Production share of different technologies over the years. Source: Statista [4]

2.1.1. Silicon Crystalline Structure

The first generation of PV modules exiting were silicon crystalline structure modules, despite silicon crystalline technology was the first PV module technology developed, it is not nowadays obsolete and some improvements have been made in recent years regarding this technology, in fact it is still the most used PV module technology [5].

Usually the installation of PV modules requires a larger investment cost than the cost associated with operation and maintenance. Although some governments give very attractive incentives for the installation of PV systems, normally the payback time of these projects is long. Because of that it is crucial to decrease the cost of production by increasing the efficiency of the modules.

In the family of silicon crystalline structure can be found monocrystalline photovoltaic cells, poly-crystalline photovoltaic cells and back-contact photovoltaic cells.

Monocrystalline photovoltaic cell

This technology was in the early years of photovoltaics the module technology most commonly used, both in utility-scale scale and stand-alone applications. But, as years went mono-Si modules have been losing market share.

The manufacturing process of mono-Si modules is called *Czochralski* process which is a method of crystal growth used to obtain single crystals. The processes consist on melting a high-purity, semiconductor-grade silicon. Boron or phosphorous can be added as dopant impurity atoms, thus changing the silicon into p-type or n-type, with different electronic properties. By controlling the temperature gradient and the mechanical strengths of the process it is possible to extract a large single crystal from the melt [6].

According to Green et al. [7] the maximum efficiency achieved under STC for monocrystalline solar cell is 26.7%. Despite of the maximum efficiency record achieved, the module efficiencies normally tends to be lower than cell efficiency due to internal electrical losses. Anyway, the record of efficiency registered by *NREL* for a PV module is 20.4 % for a *SunPower* PV module [5].

Multicrystalline photovoltaic cell

Multicrystalline solar cells or also called poly-crystalline (or poly-Si) solar cells are the result of trying to reduce the costs of production of mono-Si cells by means of new crystallization techniques. This manufacturing technique consists on producing multicrystalline silicon by melting silicon and solidifying it to orient crystals in a fixed direction, the ingot of multicrystalline silicon produced is sliced into blocks and then into a thin wafer [8]. Multicrystalline cells can be easily recognizable because of the aspect of metal flake effect caused by the multiple small silicon crystals that forming it.

The efficiency of this type of solar cells is significantly lower than monocrystalline solar cells, the efficiency record achieved by a multicrystalline according to Green et al. [7] under STC condition is 21.9%. But, once again when looking at commercial available technology the efficiency is lower compared to laboratory test, the efficiency for multicrystalline modules available in the market is in the range from 14% to 19% [9]. Despite of the lower efficiency of this technology, the main advantage of multi-crystalline solar cells respect other solar cell technologies is the reduction of cost achieved by simplifying the manufacturing process.

Back-contact solar cell

Also called rear-contact solar cells have increased the efficiency respect other technologies achieved through a better cell design rather than material improvements [5]. This can be achieved by moving all or part of the front contact grids to the rear of the device [10]. The main advantage of this silicon modules is that shading losses are zero and the contact resistance is low [11]. There are four different back-contact cells technologies: metallization wrap through, emitter wrap through, interdigitated back-contact and advanced back-junction solar cells. All these different technologies of back-contact solar cells are already being used for different industrial processes.

2.1.2. Thin Film Technology

Related to the effort to make PV technology less costly, and hence to make more economically viable projects, appears a new technology called thin-film solar cells [5]. Wolf and Lofersky discovered that by decreasing the cell thickness, open circuit voltage increases due to reduced saturation current and decreasing the geometry factor [12]. Thin-film technology consist on thin layers of a semiconductor material applied to a solid backing material [9]. Using this technology, the amount of required material is reduced without compromising the lifespan of the photovoltaic cell or being hazardous for the environment. Additionally, the cost of production is also reduced due to the photovoltaic materials used are cheaper than those used for crystalline structures [5]. The market share of thin-films is 15-20%, and the market growth in the recent years of this technology have been enormous [5].

The main advantage of thin-film technology is the reduced thickness of the layers, few microns compared with the thickness of crystalline modules (several hundreds of microns) [5]. Furthermore, the very low thickness of the layers provides flexible properties. On the other hand, the fact that thin-film technology involves less photovoltaic material per cell has repercussions on lowering the capacity. But, the capability of this technology to deposit many different materials and alloys leads to improvements in efficiency. Degradation of this technology is also an important aspect to consider, the majority of thin-film cells need an extra barrier to protect them from heat or moist which can accelerate their process of degradation [5].

Amorphous silicon cell

Also called silicon thin-film solar cell is one of the first thin-film technologies developed and also the most commonly used [5] [9]. The main difference between amorphous silicon and crystalline silicon structure is the fact that in this technology the atoms of silicon are distributed randomly and not forming a crystalline matrix. An important disadvantage of this type of photovoltaic cells is the fact that their efficiency is lower than monocrystalline and multicrystalline solar cells, the maximum efficiency achieved in laboratory test is around 10.2% [7]. But, the efficiency for commercially available cells is in the range from 5% to 7% [9]. Despite of the lower efficiency compared with other technologies, amorphous silicon cells are also an attractive alternative because they are less costly due to their specific manufacturing process. Silicon is an abundant non-toxic material which requires low process temperature, enabling module production on flexible and low-cost substrates [13].

In order to upgrade the efficiency of this type of solar cells, there are many variations of thin-film silicon solar cells, the most popular variations are: amorphous silicon carbide (a-SiC), amorphous silicon germanium (a-SiGe), microcrystalline silicon (μc-Si), amorphous silicon-nitride (a-SiN) and hydrogenated amorphous silicon (a-Si:H) [9].

Tandem solar cell

Tandem solar cells were designed in order to increase the efficiency of a-Si solar cells in a cost-effective manner. This technology consists on depositing two or more PV junctions on top of the other where the layer of a-Si is located at the top [5]. This configuration of the solar cell provides an improved range of efficiency 8-9% [5].

Cadmium telluride cell

Cadmium telluride (CdTe) cells are one of the most promising PV materials, since this material has the ideal band gap (1.5 eV) with a high direct absorption coefficient, thanks to these two parameters with a few of micrometres of this material is enough to absorb around 90% of the incident photons [13].

The efficiency achieved in laboratory of cadmium telluride cells is up to 21% [7] and the maximum efficiency achieved for commercially available modules is 9% [5]. This technology is more appropriate for large scale applications because it is easier to accumulate than other thin-film technologies.

The main drawback of this technology is the fact that cadmium is a toxic material, and some measures have to be adopted in order to not to harm the environment [13]. Another important point is the scarcity of telluride which can have repercussion on the future price of these cells [5].

Copper indium diselenide cell

Copper indium diselenide (CuInSe2) and copper indium selenide (CIS) cells are a photovoltaic technology which uses semiconductor elements which are beneficial due to their high optical absorption coefficients and good electrical characteristics [5]. By means of adding gallium (CIGS) the band gap of the photovoltaic device is increased, this type of technology is known as multi-layered thin-film composites [5].

The maximum efficiency achieved for a CIGS thin-film is 19.2% [7] and the efficiency for commercially available modules is 13% [5]. As happened with telluride in CdTe cells, scarcity is also an issue with indium which in addition is a very common material in electronic applications. Because of this fact, recycling is going to be a crucial aspect for the future growth of these technologies.

2.2. MOUNTING STRUCTURES

Mounting structures are used to fix the PV modules to the ground and they determine the tilt angle and the orientation of the modules. A classification of the mounting structures can be done depending on their assembly to the ground [14]:

- Pole mounts. Mounting structures are directly installed into the ground or embedded in concrete.
- Foundation mounts. Structures are fixed into the ground by means of concrete slabs or poured footings.
- Ballasted footing mounts. Mounting structures do not penetrate into the ground and are fixed to it by means of the weight of concrete or steel bases.

The selection criteria of the mounting structures involve many factors such as: cost of manufacturing, cost of installation and difficulty of installation, lifespan of the structures, resistance to corrosion or protection against adverse climatic conditions.

Besides, mounting structures are the responsible to endow to the PV modules the required tilt angle and orientation. Regarding this aspect there are two main categories of mounting structures: fixed structures and tracking axis systems. Fixed structures are not capable to modify neither the orientation nor the tilt angle. This option is the less costly system, but the energy production will be not optimum. Tracking axis systems can be divided in 1-axis tracking systems and 2-axis tracking systems, the difference between both systems is the number of degrees of freedom (see Figure 2.3). Again, there is a compromise between the cost of the system and the energy production of the PV plant, 2-axis tracking system is better than 1-axis tracking systems in terms of energy capture, but it is more expensive to manufacture, to install and also the maintenance is more complex.

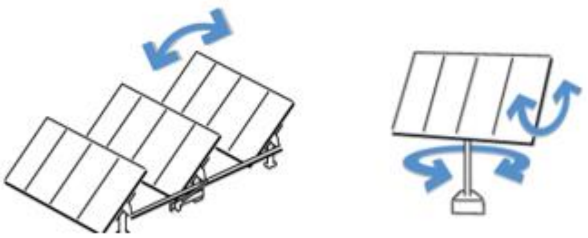

Figure 2.3. Left 1-axis tracking system. Right 2-axis tracking system. Source: [15]

Another aspect to treat when looking at the mounting structures are the shading losses. Tracking systems usually generate more shading losses than fixed systems due to the movement of the PV panels, note that for higher tilt angle of the modules, inter-row spacing has to be higher or the shading losses will be larger. The space required for a typical fixed system is in the range of 1.6 to 2.4 ha per MW, while the space occupation for a typical 1-axis tracking system can be in the range of 1.8 to 3 ha per MW [16]. Because of that reason the sizing of the system and the inter-row spacing of the PV modules should be studied in detail in order to not have unacceptable shading losses. For a good plant design, the comparison between a PV plant using tracking system and without tracking system can be seen in Figure 2.4.

Figure 2.4. Comparison between output power obtained without tracking system (blue) and with tracking system (yellow). Source: [3]

Tracking systems integrated in the mounting structures can be controlled by sensors or by control algorithms which allows to control the system automatically. There is also one specific type of 1-axis tracking system where the change of the tilt angle is done manually and with the change of season (seasonal tilt angle). By changing tilt angle once in winter and once in summer it is achieved an improvement over fixed system regarding the energy capture.

Sensor based control systems use sensors to determine the relative position between the sun and the PV modules. Once the system detects the tilt angle (or orientation) of the PV module is not the optimum the modules are tilted to achieve the optimum angle by means of actuators or motors [16]. Different technologies are used in these systems including light dependant resistors, photo transistors, mini solar cells or complementary metal-oxide-semiconductors (CMOS) [16].

Algorithm based control system uses GPS to determine the position and altitude of the sun. This technology helps to develop predictions models of sun's position which allows to the tracking system to rotate the PV modules in a continuous and smooth manner [16]. One of the advantages of this tracking system respect to sensor-based control system is that algorithm-based control system cannot be disturbed by clouds or other perturbations [16].

2.3. SOLAR INVERTERS

Since PV modules generates power at DC current, at some point this generated electricity is needed to be converted into AC current to accomplish with grid requirements. Distribution inside the PV plant can be done in DC current, and also the power delivered to the grid can also be in DC, but nowadays, AC technology seems to be the most realistic and affordable technology to operate. To invert the polarity of the source to AC and to synchronize the power generated with the grid an inverter is required. The requirements which solar inverters have to meet in any grid-connected installation are two: performance requirements and legal requirements [17]. Performance requirements includes: efficiency, power density, installation cost and minimization of leakage current. The category of legal requirements includes: galvanic isolation, anti-islanding detection, and other technical codes (Table 2.1).

Table 2.1. Legal requirements of utility-scale inverters. Source: [3]

Standard	Description
EN 61000-6-1:2007	Electromagnetic compatibility (EMC). Generic standards. Immunity for residential, commercial and light-industrial environments.
EN 61000-6-2:2007	EMC. Generic standards. Immunity for industrial environments.
EN 61000-6-3:2007	EMC. Generic standards. Emission standard for residential, commercial and light-industrial environments.
EN 61000-6-4:2007	EMC. Generic standards. Emission standard for industrial environments.
EN 55022: 2006	Information technology equipment. Radio disturbance characteristics. Limits and methods of measurement.
EN 50178: 1997	Electronic equipment for use in power installations.
IEC 61683: 1999	Photovoltaic systems. Power conditioners. Procedure for measuring efficiency.
IEC 61721: 2004	Characteristics of the utility interface.
IEC 62109-1&2: 2011-2012	Safety of power converters for use in photovoltaic power systems.
IEC 62116: 2008	Islanding prevention measures for utility-interconnected photovoltaic inverters.

PV inverters can be classified in different topologies [18]. The topology of the solar inverter will determine the connections between the PV modules and the inverter and their possible applications. Different topologies of PV inverters can be seen in Figure 2.5.

A) Central inverters: range of 100-1000 kW with three-phase topology and modular design for large power plants (tenths of MW) with unit sizes of 100, 150, 250, 500 or 1,000 kW.
B) String inverters: for small roof-top plants with panels connected in one string (0.4-2 kW).
C) Multistring inverters: for medium large roof-top plants with panels configurated in one to two strings (1.5-6 kW).
D) Module integrated inverters: for very small PV plants (50-400 W).
E) Mini central inverters, typically > 6 kW for larger roof-tops or smaller power plants in the range of 100 kW and typical unit sizes of 6, 8, 10 and 15 kW.

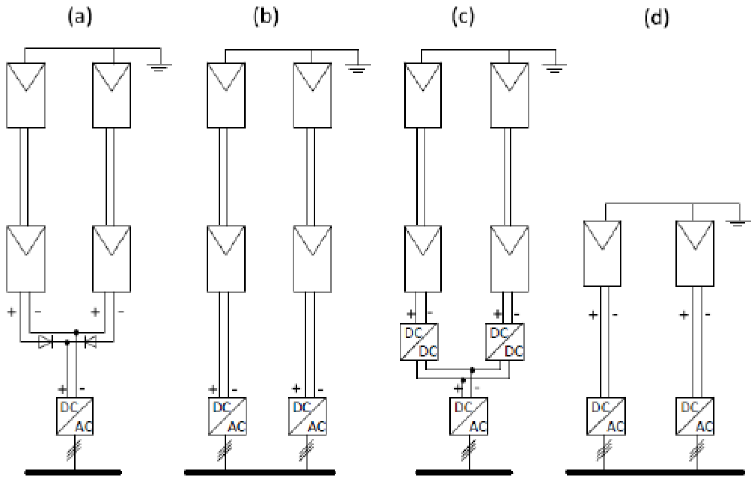

Figure 2.5. PV inverter topologies: (a) Central inverter, (b) String inverter, (c) Multistring inverter and (d) Module integrated inverter. Source: [19]

Because of the purpose of this project is the design and modelling of a large-scale PV solar power plant, in this section the attention will be focused on central inverters. The most used central inverters configuration is two-level voltage source inverter (2L-VSI) which is composed of three half-bridge phase legs connected to a single dc-link [17]. Another configuration, but in this case less mature technology are three-phase 3L-NPC and three phase 3L-T converters [17]. The main advantages of central inverters are the reliability and robustness compared with other inverter's topologies, but the main drawbacks of this technology are the increased mismatch losses and the absence of MPPT for each string of the array connected [3].

Normally, the inverters installed in large-scale PV solar power plants are containerised type. This type of commercially available inverters also contains the transformer and the switchgear in the same structure. With this solution, inverter, transformer and switchgear can be manufactured offside the PV plant reducing the cost of installation [3]. The most common inverter's manufacturers for utility-scale applications are *SMA*, *ABB* and *Kaco*.

2.4. TRANSFORMERS

A transformer is an electric device which transfer electric power applied in a primary winding to a secondary winding by electromagnetic induction. The transfer of power is done at the same frequency, but with different voltage and current. The ratio between the number of turns in the primary winding and the turns in the secondary winding determine if it is a step-up voltage transformer or step-down. Figure 2.6 shows the main components of a transformer and its electrical scheme. Transformers are used in PV solar power plants to step-up the voltage of the power produced in the modules and by means of increasing the voltage the losses of distribution are decreased. There can be two types of transformers inside a PV plant [3]: distribution transformers and grid transformers. Distribution transformers are used to step-up the voltage for the plant collection system. Grid transformers increase the voltage to meet the grid requirements.

The most commonly used distribution transformers in PV power plants are pad-mounted type, in this type of transformers the AC circuits associated are normally installed underground [20]. The maximum voltage ratings for pad-mounted transformers are 35-36 kV. If the interconnection to the grid is above 35 kV a grid transformer is required. The power ratings for grid transformers are in the range from 2,500 kVA to 100 MVA [20]. Another benefit of the utilization of transformers in PV applications is the galvanic isolation of the system provided by the air gap between the transformer windings [20].

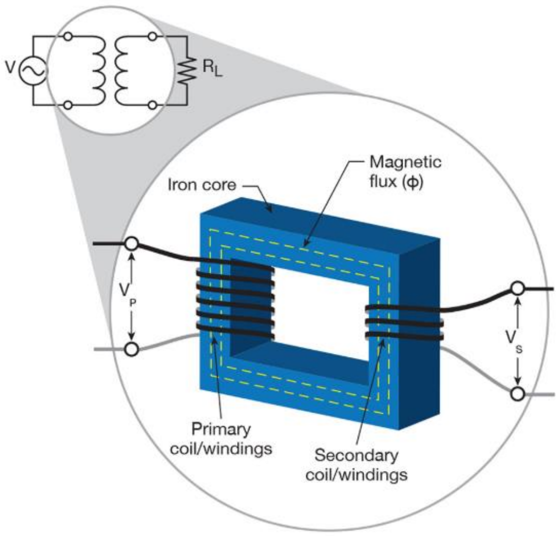

Figure 2.6. Transformer scheme. Source: [20]

Selection criteria for transformers include technical and economic factors [3]: efficiency, guarantee, vector group, system voltage, power rating, site conditions, sound power, voltage control capability and duty cycle among other factors. Furthermore, the selected transformer for any utility-scale PV project should be accredited by ISO 9001 [3].

The main difference between the transformers used for residential applications and utility-scale applications is the admissible voltage level. For residential applications the interconnection between the transformer and the grid is done at 249 Vac single-phase, for utility-scale applications the interconnection is done at voltages in the range of 12-115 kV three-phase [20]. Because of this enormous difference of voltage between applications, the price and volume of transformers in utility applications is not comparable with other applications, even it is usual for transformers in utility applications to be custom made due to variety of different requirements.

2.5. SWITCHGEAR

The switchgear is the set of switches, fuses or circuit breakers used to control, protect and isolate the electrical equipment included in the system. The type of switchgear selected will depend on the interconnection voltage level. Typical switchgear for applications up to 33 kV is an internal metal-clad, cubicle type with gas/air insulated busbars and vacuum of SF_6 breakers [3]. Switchgears installed in a PV power plant should meet the following requirements [3]: accomplish IEC standards and national electrical codes; show the on and off position clearly; option to be secured by locks in off/earth positions; be rated for operational and short-circuit currents; rated for the correct operational voltage; and be provided with suitable earthing. Figure 2.7 shows the general layout of the components described for PV plants: PV modules, distribution transformers, grid transformers and switchgear.

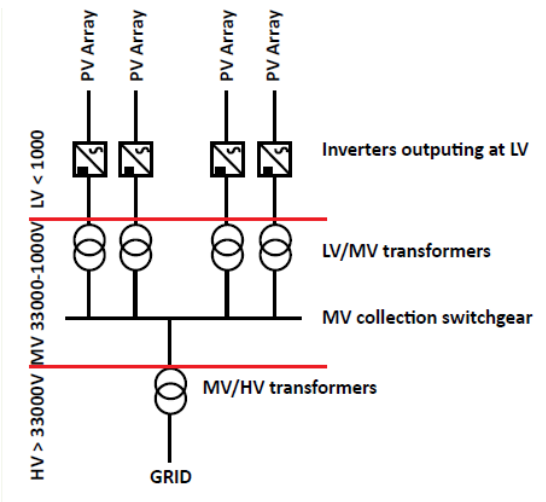

Figure 2.7. PV solar power plant layout. Source: [3]

2.6. DC AND AC CABLES

DC cables connect the PV modules between them and with the inverters while AC cables connect the rest of the electrical equipment inside the PV plant, unless the collection system of the PV plant is operating in DC, but nowadays it is not a common solution. The cables installed in a solar project should meet the international and local requirements of these type of installations. There are three main parameters defining the selection criteria for DC cables [3]:

- Cable voltage rating. The cable selected must withstand the voltage of the PV modules connected. For this calculation open circuit voltage of the PV modules is used.
- Current carrying capacity of the cable. The cable must be sized in order to withstand the current for the worst case possible.
- Minimization of voltage drop. Reduce the energy losses is a key aspect which can determine the viability of a PV plant project, therefore it is important to reduce the voltage drop in the cables. An acceptable voltage drop value would be 3%, but 1% or less of cable losses can be achieved.

The cables installed in a specific PV solar plant should be adequately protected for the site conditions (sun, moist, heat…). Some of the properties of commercial cables complying with standards are [21]: ozone resistant, weather and UV resistant, halogen-free, resistant to acid and bases, flame-resistant, abrasion resistant, resistant to short-circuits up to 200ºC, 25 years lifespan and hydrolysis and ammoniac resistant.

3. LEGISLATIVE AND ADMINISTRTIVE PROCDEDURES

To perform any PV project, and specially a large-scale PV project, some legislative and administrative procedures must be considered and accomplished. In Spain, photovoltaic installations must meet legislations in different levels: European, national, local, *Red Eléctrica Española* regulation, and the specific regulation of the distribution companies.

The administrative and legislative steps which should be followed during the design, installation and operation of PV project located in Spain are described below in order of realization [22]:

1. Land obtention: A contractual agreement is needed between the owner of the land and the project developer, unless the owner of the land is the same as the PV project developer. The normal procedure in those cases is to rent the land for the time which the PV plant is estimated to operate (usually 25 years of operation).
2. Bank guarantee: According to *Royal Decree 1578/2008* the obtention of the bank guarantee or the deposit of the required amount is mandatory and it has to be done in the *Caja General de Depósitos (CGD).*
3. Access point and point of connection. The point of the electrical grid where the energy produced is going to be injected. The point of connection belonging to the closest distribution company has to accomplish technical and economical requirements.
4. Special Regime condition: According *Royal Decree 661/2007* the condition of Special Regime for any energy producer must be granted by the competent authority. Request of Special Regime has to include financial and technical reports as well as the authorization of the site selected for the installation. The denomination of Special Regime installations will be discussed in further sections of the project (see section *4.1. SUPPORT SCHEMES IN SPAIN*).
5. Environmental information request: Evaluation of the possible environmental burdens of the location selected. Often, the selected land has to be reclassified by the corresponding city council.
6. Project report realization: the realization of a project report for large-scale installations is mandatory at this point of the project.
7. List of possible affected: The installation of a PV plant can represent a big impact on the zone where it is going to be installed. Before tanking final decisions, it is recommended to consider all the possible affected and apply the corresponding measures.
8. Administrative authorization and project approval. Administrative authorization is mandatory for photovoltaic installation bigger than 100 kW. To obtain the authorization the project report and all the previous authorizations and approvals have to be delivered.
9. Environmental, urban and cultural licenses: Depending on the autonomous community where the PV project is going to be installed it is required to obtain: The Community Interest

Declaration, Environmental Impact Assessment or the execution of a study of landscaping integration.

10. *IAE (Impuesto sobre Actividades Económicas)* registration: According to *Ministerial Order EHA/1274/2007* any legal person which is going to start the activity of energy production has to register on census of businessmen, professionals and withholding agents. The tariffs are stipulated in *Royal Decree 1175/1990.*
11. Urban classification: By means of urban classification, a land conceived for other activity can be used for a PV plant project. The competent authority of the autonomous community is the responsible to grant the permissions regarding urban classification.
12. Construction permit: this permission authorizes the PV project and it has to be granted by city council.
13. Activity license: This license is required and it has to be granted by the city council. The project report of the PV installation has to be delivered in order to obtain this license.
14. Application for inclusion in special regime. Before starting the construction of the PV plant, the project developer or the investor has to submit the request of Special Regime to Territorial Service of Energy.
15. Contract with distribution company. The distribution company which the PV plant is going to be connected has the legal obligation to collaborate with: admit the energy injection into the grid through an accessible connection point, and technical verification of the energy supply and meter mechanisms.
16. Inscription on the register of pre-assignation of retribution (*RPR*): According to *Royal Decree 1578/2008* all new PV installations have to be registered. In the case of a utility-scale PV installation, this will be catalogued as Type II installation.
17. Construction execution: Once all administrative and legislative requirements have been met, the construction of the PV installation can start.
18. Provisional commissioning record for installation tests: To obtain the definitive commissioning authorization, both provisional commissioning record and end of construction certificate have to be delivered by the competent responsible in charge.
19. Paperwork with distribution company: At this point and once the distribution company is involved in the project and the access point is obtained it is required to sign the technical contract with distribution company.
20. Previous inscription on installations register of special regime: The inscription has to be presented to the Register of Installations of Electric Energy Production in Special Regime in the corresponding autonomous community.
21. Certificate issued by the person in charge of measurement reading: This certificate is issued by the distribution company and the PV project has to accomplish the requirements specified in *Royal Decree 2018/1997.*

22. Electric gird connection: Once the construction of the PV solar power plant is finished and the test are approved by the corresponding authorities, the company owner of the point of connection will authorize the final grid connection.
23. Commissioning record: End of construction certificate has to be delivered in order to apply for the request for commissioning record. Installation with higher power than 10 MW must be affiliated to a control centre of generation.
24. Application to the Activity Code and establishment of C.A.E. (special tax on electricity): The application has to be presented by the owner of the installation to the corresponding administrative office. The application has to be complemented with a description of the installation and the purpose of it. Electricity tax has to be presented by telematics means and filling *Model 560.*
25. Change of ownership: In case of needing a change in the ownership of the PV installation, the paperwork has to be done in the *General Directorate of Industry* of the corresponding autonomous community.
26. Definitive inscription on installations register of special regime: For the definitive inscription it is mandatory to deliver: document of selling option for the energy produced, distribution company certification, Authorized Control Body certificate, end of construction certificate, measurements reading certificate, validation report issued by the system operator, accreditation of accomplishment of the electricity market requirements.
27. Market agent selection: The electricity produced in a PV plant has to be sold to the electricity market, the electricity is sold by means a market agent (according *Royal Decree 661/2007).* Some companies that are dedicated to energy sales are: *Abener*, *Acciona Energía*, *AME, NEXUS*, etc.
28. Billing at PV tariff: The billing of the energy injected into the grid can be done since the first day of the next month from the commissioning record date, but the definitive inscription has to be obtained before.
29. Bank guarantee refund: To obtain the deposited bank guarantee the following documentation has to be presented: bank guarantee refund request for Special Regime installations; commissioning record; and definitive inscription of the installation.

4. RENEWABLE ENERGY SUPPORT SCHEMES

One of the biggest concerns of the energy sector is the decarbonation of the electricity mix. In order to achieve an energy production less dependent of conventional energy generators, some countries have developed support schemes to promote the installation of new renewable energy plants. Support schemes are financial incentives to make renewable energy generators more competitive compared to traditional energy generators. Support schemes can be classified in different categories depending on their nature:

- Support schemes implemented on the energy price or the remuneration received, or if the support schemes are implemented depending on the installed capacity or energy generated.
- Depending on when the support schemes are implemented. They can be implemented during the initial phase of investment or during the final phase of energy generation.

The most popular renewables energy support schemes for photovoltaic solar applications which have been implemented in different countries are: Feed-in tariffs (FITs), Feed-in premiums (FIPs), quota obligations based on Tradable Green Certificates (TGCs), Tenders, investment or financial incentives and tax exemptions.

Feed-in tariffs (FITs) and Feed-in premiums (FIPs)

FITs are generation-based, price regulation support schemes. The unit of energy produced by an energy generator is paid at a fixed price by the utility, supplier or grid operator and also, FITs provides total preferential to this type of energy generation. The fixed tariff which will be paid during the years of operation of the plant is regulated by the government and determined by the system [23]. FIPs are also price regulation support schemes which guarantee to pay the unit of energy on top of electricity wholesale-market. FITs and/or FIPs have been used or are still being used in counties such as Austria, Belgium, Germany, Denmark, France, Italy, The Nederland, Sweden or UK [24].

Quota obligations based on Tradable Green Certificates (TGCs)

TGCs are generation based renewable energy support schemes which impose to consumers, suppliers or energy generators that a quota of the energy consumed or produced has to come from renewable energy. At the end of the period estimated, the actors involved in quota obligations have to demonstrate their compliance by delivering to National Regulatory Authority the quantity of Green Certificates previously assigned [25]. Renewable energy generators can obtain economic benefits from selling Green Certificates, besides of the normal revenues from injecting electricity into the grid. TGCs price covers the gap between the marginal cost of renewable energy and the price of electricity at the wholesale-market [24]. TGCs are used or have been used in countries such as Belgium, Italy, Poland, Sweden or UK [24].

Tenders

Renewable energy producers, or the intermediaries, offer a determined quantity of power for a fixed price in a given period. The companies offering the most competitive energy price win long period contracts, usually the contracts can last up to 20 years. Implementing this support scheme, the variability of the energy in the wholesales-market is eliminated, thus helping renewable energy developers to make their projects more stable, and therefore more attractive to investors. The main drawback of tenders is the fact that the most efficient technologies are a step ahead and this could limit the improvement of other less mature renewable energy technologies. Tenders are used or have been used in countries such as France, Italy, Lithuania or Portugal [24].

Investment and Financial incentives

Some countries grant investment incentives to new renewable energy plants. In this type of support scheme, the competent government covers a part of the capital cost of the new installation. Financial incentives are also granted by some countries in order to promote renewable energy. Reduced VAT or tax exemption are some examples of financial incentives. Examples of counties using those type of support schemes are: Germany, France, The Netherlands or Sweden [24].

4.1. SUPPORT SCHEMES IN SPAIN

The situation in Spain regarding renewable energy support schemes has been very changing along the years. In 2004, *Royal Decree 436/2004* stablished the legal and economic framework for installations in Special Regime. According to this decree the owner of renewable energy installation has two possibilities of remuneration:

- Remuneration based on a feed-in tariff system, where the price will be set according the power installed and the years of operation of the installation.
- The price of the energy sold will the one corresponding to the electricity wholesale-market or the one corresponding to a bilateral contract, but also renewable energy installations will take benefit of an economic incentive to participate in the market and a bonus.

In 2007, after several modifications of the law concerning renewable energy installations, *Royal Decree 661/2007* was approved in order to make the status of this type of installations more stable. In this new decree the owner of a renewable energy installation still had the possibility to choose between feed-in tariff or participate in the energy market. But, in the case of participating in the electricity market the incentives to participate in it were eliminated. The remuneration of the electricity sold had upper and lower limits depending on time.

In 2012, favoured by the economic crisis, all renewable energy support schemes were revised and *Royal Decree 1/2012* was approved. In this law decree all economic incentives for new renewable energy installations were eliminated. In the same year, the *Royal Decree 661/2007* was modified and the existent bonus for energy generation was also eliminated, besides since its approval it is not allowed to change to feed-in tariff remuneration if before the installation has been in the free electricity market.

In 2013, *Royal Decree 9/2013* was approved. In this royal decree there were approved urgent measures to ensure the economic stability of the electric system creating a new legal and economic framework. The category of Special Regime disappeared, thus being all generation installation equal in the regulation and obligations. Despite this, renewable energy installations had the right to receive an additional remuneration if the investment cost cannot be covered by the energy sold.

Finally, one of the last legal norms prevailing nowadays regarding renewable energy generation is the *Royal Decree 413/2014.* According this royal decree the category of Special Regime remains cancelled, and renewable energy installations only are able to receive investment incentives or operation incentives. Investment incentives will be granted if the revenues from participating in the energy market do not cover the investment cost of the installation. Operation incentives are an economical remuneration which cover difference between the operating costs and the revenues from participating the electricity market. It is important to consider that those incentives only will be granted during regulatory useful life of the installation. The calculation of the corresponding incentives will be made by the Ministry of Industry, Energy and Tourism which will establish the corresponding parameters for the evaluation under the concept of "efficient and well-managed company". The remuneration of the renewable energy installations will be established between an upper and a lower limit. If the annual average price is outside of the established limits, the installation will be rewarded during its operational lifetime.

5. ENVIRONMETAL IMPACTS ASSOCIATED WITH LARGE-SCALE PV PLANTS

The benefits of the large-scale PV solar power plants compared to traditional generating technologies are well-known, but the construction, operation and decommission of large-scale PV plants have associated some negative environmental impacts. Most of the environmental impacts regarding this technology are positive for us but there are also negative effects attached which have to be assessed in detail. The main environmental aspects that should be analysed in a PV plant project are the ones related to: land use, human health and air quality, plant and animal life, geohydrological resources and impacts on climate.

The impact of the land use intensity is one of the important aspects to consider in the design of a PV plant. Large-scale installations need large areas of land for their installation and operation. Depending on the site selected the impact due to land use will be higher, e.g., if the land selected is a forested area that area should be transformed to accommodate the PV plant. The installation of a PV plant has direct impact on the soil and ecosystem of the area. Total time to recover the soil and ecosystem of the area after the operation of a PV plant is assumed to be about 50 years [26]. Regarding the impacts affecting the human health and air quality are generally positive impacts. CO_2 emissions are reduced drastically in comparison with traditional electricity generators, furthermore the emission of other pollutants such as Hg, NO_x and SO_2 are reduced [26]. The negative impacts are the increase of particulate matter (including $PM_{2.5}$) in the area and the risk for the employees and public in general to be exposed to soil-borne pathogens [27]. The impact associated to plant and animal life is in correlation with the biodiversity of the land occupied by the PV plant. The main impact on wildlife is caused due to land occupation itself. Usually PV plants are placed in delimited areas, thus the free movement of animals is disturbed. Other aspect to consider is the vegetation, since the vegetation found in the area occupied by the PV modules has to be mowed or removed in the worst cases. Furthermore, the installation of a large-scale PV plant could be the cause of the death of birds and insects [26]. The impacts on geohydrological resources caused by a large-scale PV plant can be the erosion of the topsoil, increase of sediment load, reduction in the filtration of pollutants from air or rainwater, the reduction of groundwater recharge, or the increase of risk of flooding [26]. Replacing traditional electricity generation by PV plants could have a direct environmental impact by reducing the CO_2 emissions from electricity generation producing a potential climate mitigation. The primary energy consumption during the life-cycle of a PV project is in the range from 7000 to 12000 kWh/kWp [28] and the emission factor is in the range from 16 to 40 gCO_2/kWh [26]. A lower value if it is compared with the emission factor from gas-based generation which is 488 gCO_2/kWh [29].

6. LARGE-SCALE PV PLANT DESIGN

The phases of a large-scale PV solar power plant project according to *IFC* [3] are:

1. Site identification or PV project opportunity
2. Pre-feasibility study
3. Feasibility study
4. Permitting, financing and contracts
5. Detailed design
6. Construction
7. Commissioning

This project is focused on pre-feasibility and feasibility phases, but for practical reasons some other stages need to be done executed e.g. site identification. The calculations and estimations of the following sections try to: identify a favourable site for a PV power plant; make an assessment of different technologies (comparison of different PV modules and inverters); and technical and financial evaluation of the PV project.

6.1. SITE IDENTIFICATION

Before doing the required calculations for the design of the PV power plant it is necessary to select the site where the PV plant is going to be installed. The selection of the site it is a very important issue due to the meteorological conditions of the site selected will largely determine the energy production of the PV plant.

First of all, an estimate of the space required for the installation of a 50 MW PV solar power plant is made. To make that estimate, a review of existing large-scale PV solar plants is made in order to make a projection of the space that will be required (Figure 6.1). The projection is done by choosing different PV solar plants of about 50 MW from different countries. The technology used in the different PV solar plants analysed is not considered in this section, because the technology that is going to be used in the current project is going to be defined afterwards.

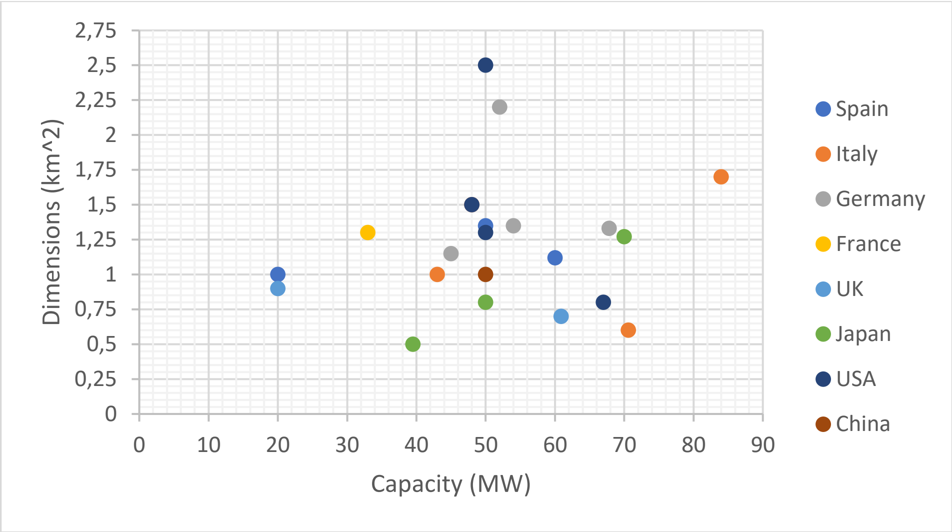

Figure 6.1. PV power plants overview. Spain: Puertollano, Olmedilla, Magascona; Italy: Montalto di Castro, Rovigo, Serenissima, Cellino San Marco; Germany: Alt Daber, Strasskirchen, Waldpolenz, Köthen; France: Crucey, Massangis, Gabardan, Curbans; UK: Swindon, Crundale, Raf Colrishall; India: Bitta; Japan: Tahara, Tottori-Yoango, Kagoshima; USA: Stanford University, Copper Mountain, Hopper, Silver State; China: Datong.

The information extracted from different PV plants do not show a clear relation between the capacity of the plant and the space for installation required. This can be caused due to the following reasons: the technology of photovoltaic modules used among the different PV plants is different, the manufacturer is also different or also the year of construction could influence in this parameter. Another aspect that can be critical in order to establish a relation between capacity and area required is that the space used for other facilities is not clearly specified in the information available from the different PV power plants. Between the examples analysed the maximum space required for a PV plant of 50 MW is 2.5 km^2, corresponding to *Silver State North Solar Project* in USA, and the minimum space required for a plant of 50 MW is 0.8 km^2, corresponding to *Tahara Solar-Wind Joint Project* in Japan. It is known that depending on the latitude where the PV plant is placed, the space between the PV modules rows (and the tilt angle) should be greater or smaller, nevertheless no conclusion regarding this aspect can be obtained.

For the present PV project an area of 2 km^2 is set as a first conservative approximation. This is just an estimated value required to make the first project calculations, during the course of the project this value will be revised and recalculated.

Once the first approximate sizing of the PV power plant is done, some other criteria should be analysed in order to choose the final location. The main aspects taking into account for the site selection are: available area, solar resource, local climate, topography, land use, local regulations, environmental and social considerations, geotechnical conditions, geopolitical risk, accessibility, grid connection, module soiling, water availability and financial incentives [3].

Available area

The coordinates of the site proposed for the installation of the PV solar power plant are 41.45ºN and 0.75ºE corresponding to the location of *l'Albagés (Lleida)*. The approximate space required previously assumed of 2 km^2 can be obtained in this location. As it can be seen in Figure 6.2, this region is one of the less populated in Catalonia.

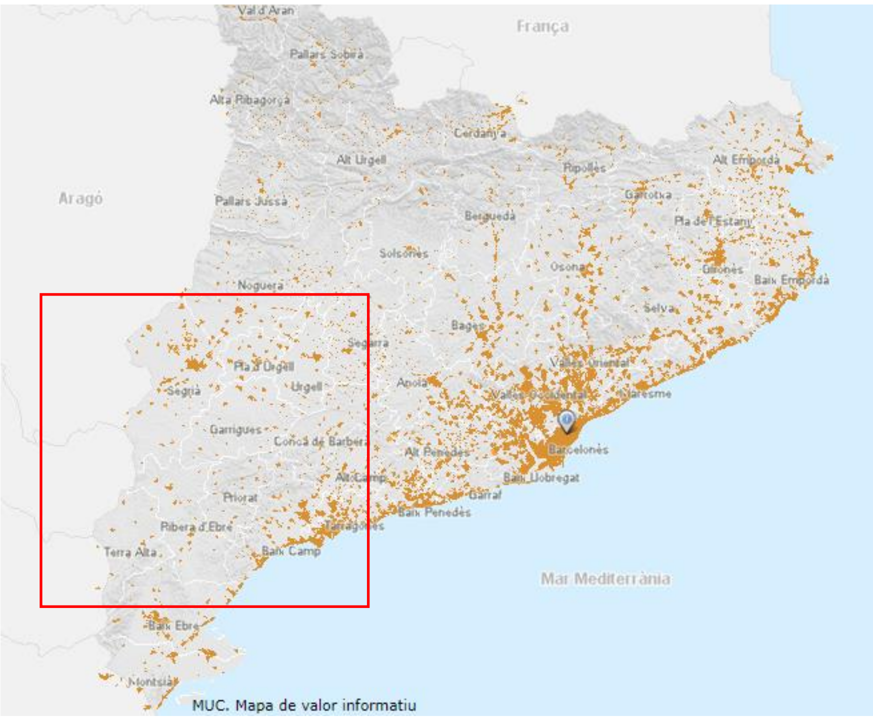

Figure 6.2. Urban map of Catalonia. Source: [30]

In the area delimitated in red in Figure 6.3 can be appreciated that the space of 2 km^2 can be obtained in this area without interfere in any area of population.

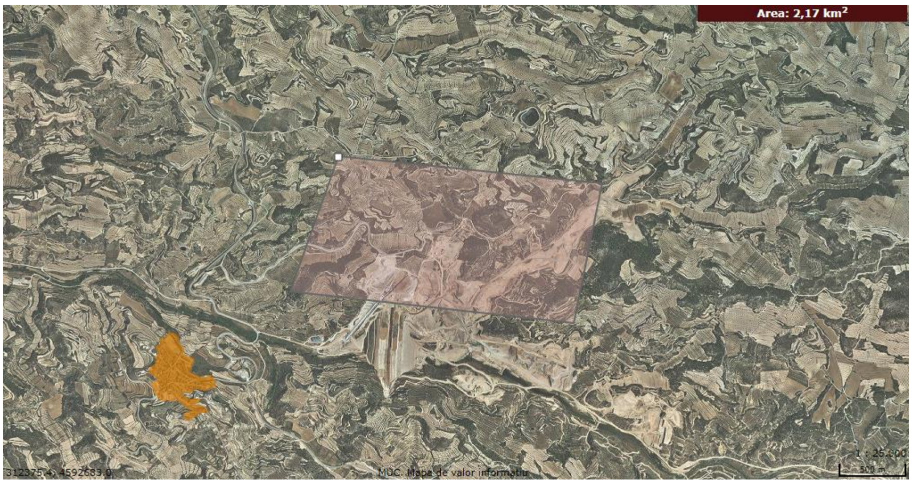

Figure 6.3. Detailed urban map of l'Albagés. Source: [30]

Solar resource

Spain in general and Catalonia in particular are some of the regions in Europe with more solar radiation, in Figure 6.4 it can be observed that the mean solar radiation of the site selected is one of the highest in Catalonia.

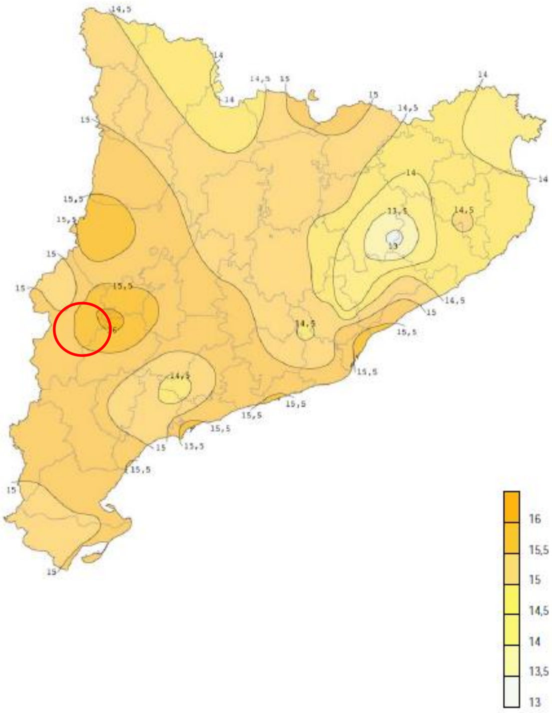

Figure 6.4. Daily global radiation in Catalonia [MJ/m²]. Source: [31]

Irradiance and other meteorological data for the specific location selected is obtained from *PVWatts* calculation tool developed by *NREL* [32]. Due to the lack of reliable data the irradiance obtained is not from the exact site of where the PV plant is going to be placed. The irradiance obtained corresponds to *Lleida* (less than 30 km from the site selected). The meteorological data from two places not too distant should not vary in excess. Figure 6.5 shows the profile of the irradiance during one year obtained.

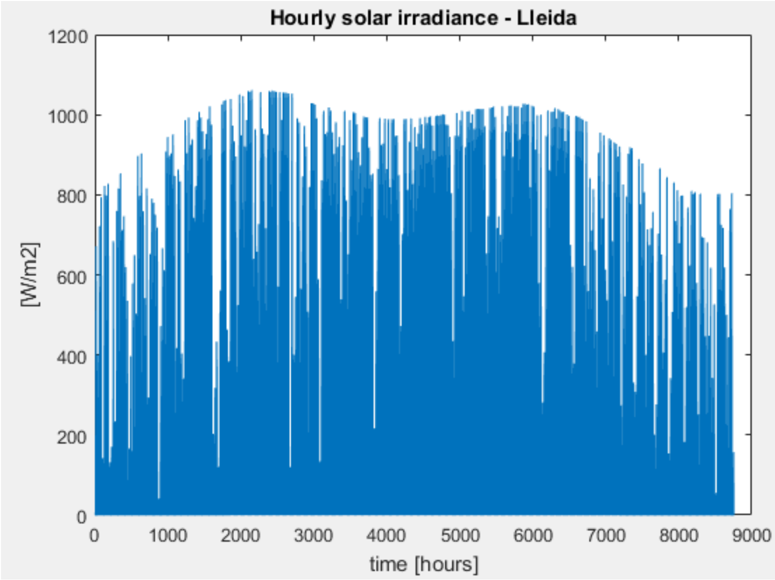

Figure 6.5. Hourly solar irradiance during one year in Lleida. Source: [32]

Local climate

Apart from obtaining the irradiance of the site selected, there are other aspects related with the climate important for the development of a PV solar power plant project: temperature, wind speed, snow risk, air pollutants and risk of flooding. The temperature of the location will determine the efficiency of the solar cells and extreme temperatures can be critical for the correct operation of the PV plant. According to *Iberian Climate Atlas* [33] the location selected does not have extreme temperatures. Also, extreme wind speeds can damage the PV system specially, when solar tracking systems are installed. The location of *l'Albagés* has not significant risk of extreme wind speeds [34]. The snow can reduce the energy production of the plant during winter period and also add additional cost related with mounting structures modifications and mitigating measures. Air pollutants are also an important aspect regarding the energy capture, but for the site selected they are assumed to be in reasonable values which do not affect the correct operation of the plant.

Topography

It is important to study in detail the topography of the site selected because it is directly correlated with the cost of installation and the future energy production. The ideal situation would be a flat terrain or with a slight south-facing slope, other configurations of the terrain could have a negative impact on the cost of the project due to more complex mounting structures. Besides, the presence of mountains near can produce undesirable shades. For this project the terrain where the PV modules are going to be installed is considered flat and also the presence of near mountains is neglected.

Land use

The land selected for the installation of the PV solar power plant should be purchased or leased during the operational life-time. The land where these types of installations is placed is normally unused land or land for agricultural purposes, in this last case reclassification taxes should be paid. Also, before the construction of the plant, it is important to obtain the corresponding permission of the government, therefore the project should be done in collaboration with the competent authorities. For the case of the current project it is assumed that the site selected has not restrictions for the construction of a PV solar power plant.

Local regulations

Every country has different regulations regarding the installation of PV solar power plants in a given area. There can be some restrictions that might not be in favour for the project execution or can be regulations promoting this type of installations. Therefore, it is important to obtain all the information regarding the current regulation of the selected location. For the case of the current project, no special regulations are considered.

Environmental and social considerations

There are some countries with a specific environmental and social regulatory framework regarding the installation of PV solar plants, the aspects which are considered are the following: biodiversity, land acquisition and other social impacts. Regarding the biodiversity of the location, it is important to avoid critical habitats in order to not compromise the viability of the project. For the case of the site selected it is assumed that it is not located in a place with critical habitats [35]. Another crucial aspect is to avoid resettlement, this is avoided in the case of the selected location because it is a zone with low density of population and the specific area of installation is considered as unused land. Also, impact on cultural heritage and visual impact are two aspects to be considered in order to not have a strong social opposition.

Geotechnical conditions

It is important to assess the quality of the ground before choosing the final location of the PV solar power plant. Depending of the results of this analysis the design of the foundation of the PV modules will change. The main aspects which should be analysed are [3]: groundwater level, resistivity of the soil, load-bearings properties of the soil, presence of rock or other obstructions, suitability of chosen foundations and drivability of piled foundations, soil pH and chemical degree of ground contaminants. For this project the conditions of the ground are considered the most suitable for a PV project.

Geopolitical risk

A PV solar power plant is a long-term project and political stability is recommended for avoiding a change of the initial terms during the operational life-time of the plant. Regarding the supports schemes according to *EPIA* [36], Spain has the following political support environment: "Support to PV frozen since 2012 and any new development blocked for several reasons (overcapacity, tariff deficit, etc.). Heavy and slow administrative processes. Many attempts to revitalise the utility-scale segment without incentives, but no significant development so far. Risk of grid tariff imposition". According to *EPIA*, Spain may not seem the best country to develop a PV project.

Accessibility

The accessibility of the site selected for the installation of the PV solar power plant is also an important aspect. The materials needed during the construction and installation of the plant should be transported by cargo trucks, thus the availability of suitable roads is crucial. In case that there were no roads already constructed, the PV solar power plant developer should construct and pay them. For the case of the current project, large expenses in construction of roads are not expected since the area is well-connected by road.

Grid connection

There are three parameters which should be analysed regarding the grid connection [3]: Proximity, the distance between the grid and the PV solar power plant have a direct impact on the initial economic investment; Availability, the percentage of time that the network is able to accept power from the PV solar power plant, the network operator is the responsible to provide this information; Capacity, the power which the network is able to absorb. In case the capacity of the network is not enough to withstand the power generated the network should be upgraded. For this project, the grid connection is considered optimal.

Module soiling

The energy production of the plant can be reduced if the PV modules are covered by dust or other type of particles, this situation can be a major problem if the PV plant is located in a very dusty area, e.g. a desert area. For this project the incidence of dust or other particles in the PV module will be evaluated during calculations, but the selected location is not considered critical area.

Water availability

For large-scale PV power plants, the availability of water is an important factor. Large amounts of water are necessary for maintenance purposes (cleaning). Therefore, the system should be installed preferably near a water source. The availability of water is not a problem for the site selected because it is surrounded by different rivers. Also, it is important to assess the impact on the water availability for local population after the construction of a PV solar power plant.

Financial incentives

No financial incentives or other type of renewable energy generation support schemes are considered during the execution of the PV project. For more information regarding to financial incentives in Spain see section *4.1. Support Schemes in Spain.*

6.2. METHODOLOGY OF CALCULATION

In this section of the chapter it is showed the calculation methodology followed for the obtention of the design parameters, energy results, associated cost of the plant and other important parameters required for the plant performance assessment. The formulas used in this project for the PV solar power plant design are based on the paper published by Kerekes et al. [37], where they propose a methodology for the design and optimization of large-scale PV plants.

6.2.1. Design and Energy Calculations

The steps followed for the calculations regarding the design parameters and energy calculations are shown below:

1. PV modules and inverters selection

Before starting to implement the calculations of the PV plant design it is necessary to select the PV modules and inverters which are going to be used during the process of calculation. Furthermore, it is important to obtain the technical specifications of these components since they are going to be used during calculations. The modules and inverters selected for the PV plant design are listed below:

<u>Trinasolar TALLMAX TSM-PE14A</u>

Trinasolar is a Chinese PV module's manufacturer which operates also in United States and Europe. In 2014 this company became the first PV modules provider with a total of 3.66 GW of installed capacity. The PV module selected belongs to *TALLMAX* series which are PV modules created for utility-scale and commercial installations. The main characteristics of these PV modules are:

Type of technology: multicrystalline solar cells

Dimensions: 1960 x 992 x 40 mm

Weight: 22.5 kg

Maximum open circuit voltage: 45.5 V

Maximum short circuit current: 9.15 A

Peak power: 320 Wp

Module efficiency: 16.5%

See technical datasheet for more information [38].

First Solar Series 4 FS-4110-3

First Solar is a PV module's manufacturer with headquarters in USA and production plants in Germany and Malaysia. This company is specialized in thin-film technology. *Series 4* PV modules are specially designed for utility-scale power plants and to withstand adverse climatic conditions. The main characteristics of this PV modules are:

Type of technology: Thin-film CdTe

Dimensions: 1200 x 600 x 6.8 mm

Weight: 12 kg

Maximum open circuit voltage: 86.4 V

Maximum short circuit current: 1.82 A

Peak power: 110 Wp

Module efficiency: 17%

See technical datasheet for more information [39].

Sungrow SG3000HV

Sungrow is one of the largest inverter's manufacturer in China with over 40% of the market share. The inverter selected is designed for large-scale applications and it has integrated fully grid support. The main characteristics of the inverter are:

Type of inverter: Central inverter

Maximum input voltage: 1500 V

Maximum PV input current: 3508 A

Nominal output power: 2500 kW (at 50 ºC)

Nominal AC voltage: 550 V

Maximum inverter output current: 2886 A

Maximum efficiency: 99%

CEC efficiency: 98.7%

Dimensions: 2991 x 2591 x 2438mm

Weight: 5.9 T

See technical datasheet for more information [40].

KACO new energy blueplanet 2200 TL3

KACO new energy is an inverter's manufacturer with headquarters in Germany which also operates in Asia and EEUU. The inverter selected has been designed with the economic development of utility-scale PV installations in mind. The main characteristics of this model of inverter are:

Type of inverter: Central inverter

Maximum input voltage: 1000 V

Maximum PV input current: 3818 A

Nominal output power: 2200 kW (at 50 ºC)

Nominal AC voltage: 370 V

Maximum inverter output current: 3468 A

Maximum efficiency: 98.3%

CEC efficiency: 98%

Dimensions: 2150 x 3400 x 1400 mm

Weight: 5 T

See technical datasheet for more information [41].

2. Irradiance and meteorological data of the site selected:

Due to the lack of reliable data the information obtained is not from the exact site where the PV plant is going to be placed. The meteorological information corresponds to *Lleida* (around 30 km from the selected site).

The meteorological data is obtained from *PVWatts* calculation tool developed by *NREL* [32] (for more information see section *6.1. SITE IDENTIFICATION*). To obtain the meteorological data required the following system parameters have to be introduced:

- DC system size of the system, for the current project 50 MW.
- Optimum tilt angle. The system is defined as one-axis tracking with seasonal variation. Therefore, there are two optimum angles, one during summer season (14.2º) and other during winter season (53.7º). Optimum tilt angle data is obtained from the *NASA* website [42].
- The optimum azimuth angle for installations in the northern hemisphere is 180º (facing south).

Data obtained that will be used in further calculations:

- Plane of array irradiance [W/m^2]. Useful irradiance in the PV system, this irradiance is the result of the sum of beam radiation, ground-reflected radiation and sky-diffuse radiation.
- Ambient temperature [ºC].

3. Number of PV modules calculation ($\boldsymbol{N_{PV}}$)

Depending on the module technology selected for the PV plant the total number of PV panels required in the system will vary as well as the area needed for the implementation of the PV plant will also differ depending on that parameter.

For calculating the required number of PV panels, N_{PV}, the following equation is used:

$$N_{PV} = \frac{P_{design} \cdot 10^6}{P_{M,STC}} \tag{6.1}$$

Where, P_{design} [MW] is the power plant design capacity and $P_{M,STC}$ [W] is the PV module power rating. The calculation of the number of PV modules is only an indicative calculation based on power plant design capacity, the final number of PV modules in the system will be recalculated afterwards.

4. Area occupied by the PV modules ($\boldsymbol{S_{array}}$)

Calculation of the surface area of each PV module:

$$S_{PV} = length \cdot width \tag{6.2}$$

Where, S_{PV} [m^2] is the product of multiplying the length [m] by the width [m] of the PV module selected.

For calculating the total area occupied by the PV array, S_{array} [km^2], the following formula is used:

$$S_{array} = S_{PV} \cdot N_{PV} \cdot 10^{-6} \tag{6.3}$$

Again, this calculation is not considering the final value of the number of PV modules, therefore this parameter will also be recalculated afterwards.

5. Calculation of the maximum number of PV modules in series and parallel ($\boldsymbol{N_{s,max}}$, $\boldsymbol{N_{p,max}}$)

The calculation of the number of PV modules in series and parallel depends on the specifications of the inverter selected. The algorithm used for the calculation of the maximum number of PV modules in series per inverter is shown in Figure 6.6 :

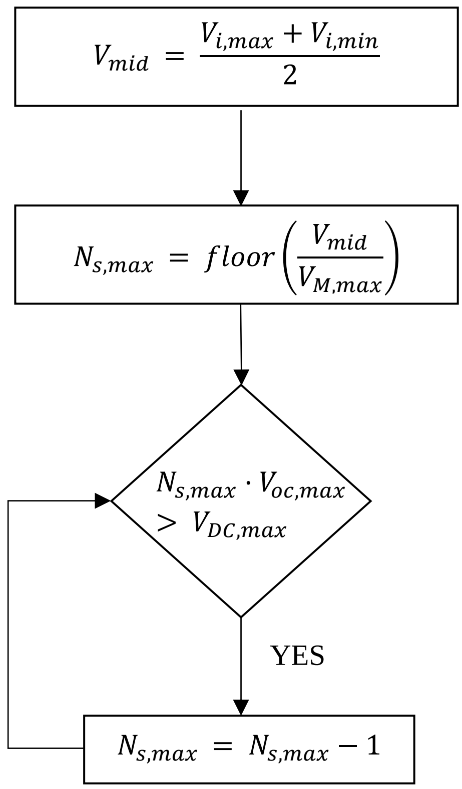

Figure 6.6. Maximum number of PV modules in series algorithm.

Where, the specifications of the inverter are: $V_{i,max}$ [V] is the DC input maximum MPP voltage, $V_{i,min}$ [V] is the DC input minimum MPP voltage and $V_{DC,max}$ [V] is the maximum permissible DC input voltage; and the specifications of the PV module are: $V_{M,max}$ [V] maximum MPP voltage and $V_{oc,max}$ [V] maximum open-circuit voltage.

The optimum number of modules connected in series is a number smaller than $N_{s,max}$, but to simplify the calculations the number of PV modules in series used for further calculations is $N_{s,max}$. By choosing the maximum number of PV modules in series the number of necessary inverters is reduced, but in terms of energy capture this procedure is not always the best option, since the inverter is more efficient when is working closer to its rated power.

The number of PV modules connected in parallel is calculated using the values of current of the module and the current of the inverter:

$$N_{p,max} = floor\left(\frac{I_{DC,max}}{I_{M,max}}\right) \tag{6.4}$$

Where, the specification used of the inverter are: $I_{DC,max}$ [A] is maximum continuous current; and the specification of the PV module used in this calculation: $I_{M,max}$ [A] is maximum MPP current.

As it happens in the previous point when calculating the number of modules in series, the optimum number of modules in parallel is a number smaller than $N_{p,max}$. Again, to facilitate the calculations $N_{p,max}$ is chosen as the final number of modules in parallel.

6. Number of inverters ($\boldsymbol{Ni}$)

After the calculation of the total number of PV modules in the PV plant, the number of modules in series and the number of modules in parallel it is possible to obtain the number of necessary inverters in the system. The formula used for this calculation is the following:

$$Ni = ceil\left[\frac{N_{PV}}{N_S \cdot N_P}\right] \tag{6.5}$$

Where, it is considered $N_s = N_{s,max}$ and $N_p = N_{p,max}$. The final value is obtained by rounding the result to the greater nearest integer the value obtained in the calculation.

7. Final number of PV modules ($\boldsymbol{N_{pv,final}}$), installed capacity ($\boldsymbol{P_{installed}}$) and final area occupied by the PV modules ($\boldsymbol{S_{array,final}}$)

Due to the final number of inverters needed is a rounded number, total number of PV modules previously calculated must be recalculated. Another option, instead of recalculating the number of PV modules, could be that one inverter (or more than one) was not connected to the maximum number of modules in series and parallel. The final solution is to slightly oversize the system in order to make all the PV sets in the system of the same size (number of modules per inverter). The formula used to calculate the final number of PV modules in the PV plant is shown below:

$$N_{pv,final} = N_s \cdot N_p \cdot N_i \tag{6.6}$$

As the number of PV modules is changed respect to the initial design conditions, total installed capacity in the PV power plant is also modified:

$$P_{installed} = N_{pv,final} \cdot P_{M,STC} \tag{6.7}$$

Also, the area occupied by the PV modules must be recalculated. The formula is the same as the one previously explained in Equation (6.3), but in this case the number of PV modules is definitive:

$$S_{array,final} = S_{PV} \cdot N_{PV,final} \cdot 10^{-6} \tag{6.8}$$

8. Solar panel temperature calculation (T_M)

It is important to calculate the temperature of the PV module because this parameter is directly related with the performance of the module. The formula based on [43] used for calculating the temperature of the PV module is the following:

$$T_M = T_{amb} + \frac{G_t}{800} \cdot (N_{OCT} - 20) \tag{6.9}$$

Where, T_{amb} [ºC] is the ambient temperature, G_t [W/m^2] incident solar radiation and N_{OCT} [ºC] nominal operating cell temperature.

9. MPP power of each PV module (P_M)

The power output of each PV module is calculated considering meteorological conditions such as temperature of the PV panel and irradiance (both previously obtained). The formula describing the power output of the PV modules is the following:

$$P_M = P_{M,STC} \cdot \frac{G_t}{1000} \cdot [1 - \gamma \cdot (T_M - 25)] \tag{6.10}$$

Where, γ [%/ºC] is the temperature parameter of the PV module at MPP and it is specified in the technical specifications of the PV modules selected.

10. Actual power output of each PV module (P_{PV})

Once the MPP power of each module is obtained the actual power output of each module can be calculated considering the losses of operation. The formula describing the actual power output is the following:

$$P_{PV} = \left(1 - \frac{df}{100}\right) \cdot \left(1 - \frac{S_p}{100}\right) \cdot P_M \tag{6.11}$$

Where, df (%) is the PV module output power derating factor due to the dirt that is deposited on its surface. df is set at 6.9% [37] for this project. S_p [%] are the losses due to shading effect, these losses are set at 3% [32]. The shading losses considered in this calculation step are only an assumption based on results obtained from the literature, but for a more accurate calculation of shading losses a 3D model of the PV power plant should be modelled or the real shading losses affecting the PV plant operation can be obtained by on field measurements. Once the MPP power of each module (P_M) and actual power output power of each module (P_{PV}) are calculated, the power losses can be easily obtained:

$$P_{PV,losses} = P_M - P_{PV} \tag{6.12}$$

11. Output power of each PV set (P_{in})

The number of PV modules forming a PV set is formed by the number of modules in series multiplied by the number of modules in parallel (see Figure 6.7). The number of PV sets in the PV power plant is equal to the number of inverters required.

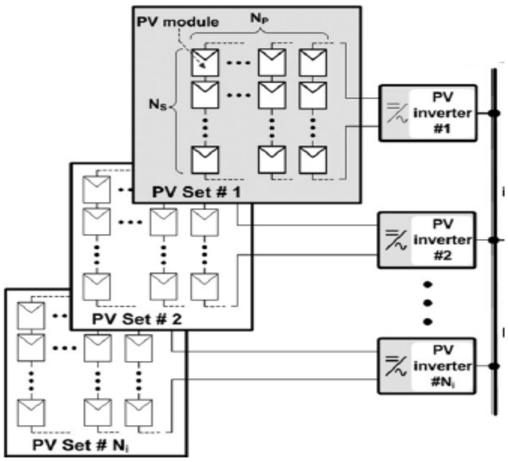

Figure 6.7. PV set configuration on PV plant [37].

The calculation of the output power of each PV set depends on the actual power output of each module, MPP efficiency of the inverter, voltage drop of the dc cable and mismatch losses:

$$P_{in} = N_s \cdot N_p \cdot \frac{\eta_{mppt}}{100} \cdot \left(1 - \frac{\eta_{dc}}{100}\right) \cdot \left(1 - \frac{\eta_{mismatch}}{100}\right) \cdot P_{PV} \tag{6.13}$$

Where, η_{mppt} (%) is the MPP efficiency of the dc/ac inverter. The η_{mppt} is set at 99% according to Valentini et al. [44]. η_{dc}(%) is the voltage drop of the dc cable, 1.5% of DC cable voltage drop is assumed according to *IFC* [3]. Another important factor affecting PV set power output are mismatch losses, $\eta_{mismatch}$. These losses appear due to slight difference in the manufacturing of PV modules interconnected, or also they can be caused due to PV modules experiencing different conditions in the same array. Mismatch losses for this project are estimated at 2% [32]. Once again, Equation (6.13) can be improved by calculating cable losses in a more accurate manner. Furthermore, shading losses can be added to this equation, but a more detailed study of the system is needed in order to obtain realistic values.

12. Total output power of each DC/AC inverter (P_o)

Each PV set is connected to an inverter and depending on the specifications of this inverter, the final energy obtained will vary. The output power of each DC/AC inverter is calculated using the following equations:

1) If $P_{in} \leq P_{i,na}$, then $P_o = \frac{\eta_{inv}}{100} * P_{in}$, else $P_o = \frac{\eta_{inv}}{100} * P_{i,na}$
2) If $P_{in} \leq P_{i,sc}$, then $P_o = 0$

(6.14)

Where, $P_{i,na}$ [W] is the inverter maximum permissible power level, η_{inv} [%] is the inverter power conversion efficiency and $P_{i,sc}$ [W] is the self-power consumption of the inverter.

The efficiency of the inverter is considered constant and equal in all the PV sets to simplify the calculations. Furthermore, the voltage of the PV set is considered always higher than the minimum permissible MPP voltage level of the inverter, in case of this condition were not met the power output of the inverter will be zero.

13. Land occupied by the PV solar power plant ($Land$)

For further calculations it is important to know the area which the PV power plant is going to occupy. To make this calculation some assumptions have been made: The total dimensions of the land occupied is assumed from literature [45] and it is set at 0.036 km^2/MWac ($land_{realation}$).

$$Land = \max(Po) \cdot 10^{-6} \cdot N_i \cdot land_{realation} \quad (6.15)$$

14. Power that PV plant can inject into the grid (P_{PLANT})

Power that can be injected into the grid is calculated considering losses in the step-up transformer and in the AC side cable. The formula used for this calculation is the following:

$$P_{PLANT} = \frac{\eta_T}{100} \cdot \frac{\eta_{cable}}{100} \cdot P_o \cdot 10^{-6} \cdot N_i \quad (6.16)$$

Where, η_T [%] is the efficiency of the interconnection transformer and it is set at 99% [37], η_{cable} [%] is the efficiency of the AC cable connections, this value is set at 99.5% according to literature [46].

For a more accurate result of the total power that PV plant can inject into the grid a more complex study of the system is required. E.g., to obtain the real value of the AC side cable losses, the length of the cables in combination with power loss coefficient should analysed.

For practical reasons this P_{PLANT} is considered as the power that is injected into the grid, without power and voltage grid limitations. For all time steps analysed in the calculation of the power output of the PV plant this condition is assumed to be valid: $P_{PLANT} \leq P_{grid,max}$.

Where, $P_{grid,max}$ [MW] is the maximum power that can be injected into the grid. For more accurate calculation the characteristics of the grid should be analysed in order to evaluate if the condition is accomplished for the period of operation assessed.

15. Total energy injected into the grid from the PV power plant $(E_{PLANT,TOT})$

The energy injected into the grid is calculated considering the time steps used along the previous calculations and adding an availability factor of the PV power plant due to maintenance reasons. The formula used in this step to calculate the energy injected for each time step is the following:

$$E_{PLANT} = \frac{EAF}{100} \cdot P_{PLANT} \cdot \Delta t \tag{6.17}$$

Where, EAF [%] is the energy availability factor of the PV plant due to maintenance of the PV power plant components, this parameter is set at 99.5% [47]. Δt [h] is the time step. Total energy injected into the grid, or annual energy production (AEP) is calculated using the following formula:

$$E_{PLANT,TOT} = \frac{EAF}{100} \cdot \sum_{t=1}^{n} P_{PLANT} \cdot \Delta t \tag{6.18}$$

Where, *t* is the number of time steps considered during the calculations of the PV power plant. For one-year *t* is equal to 8760.

The calculation methodology and the steps explained previously are summarised in Figure 6.8:

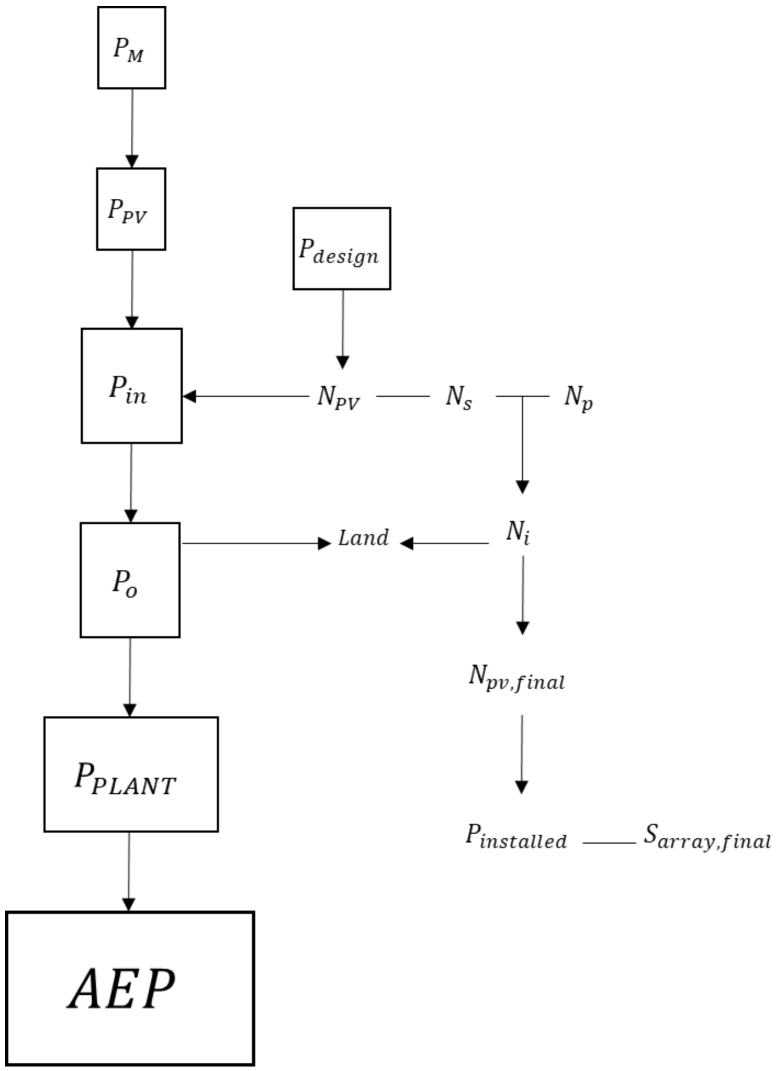

Figure 6.8. Calculation methodology scheme.

6.2.2. Economic Calculations

The methodology and formulas used regarding the economic calculations are also based on the paper published by Kerkes et al. [37]. The steps followed are shown below:

1. Calculation of Total cost of the PV power plant (C_c)

Capital cost is referred to one-time expenses associated with the PV power plant installation. With the purpose of estimate the viability of any energy project it is important to calculate all the expenditures associated with the project. The first step in the economic analysis is the calculation of the total capital cost. The capital cost calculated for this project includes: the cost of the PV array, cost of the inverters, cost of the step-up transformers, BOS cost (electrical wiring, meter, protections, junction boxes, cabinets, switchgear, combiners, fuses, breaker and other non-electrical components), cost of civil work and cost of the land. The formula used to calculate the capital cost is the following:

$$C_c = (N_i \cdot N_s \cdot N_p \cdot \frac{P_{M,STC}}{1000} \cdot C_{PV}) + (N_i \cdot \frac{P_{rated}}{1000} \cdot C_{inv}) + (C_{transformer} \cdot P_{plant,nom} \cdot 1000) + \left(BOS \cdot P_{plant,nom} \cdot 1000\right) + \left(C_{C\&i} \cdot P_{plant,nom} \cdot 1000\right) + (C_{land} \cdot n \cdot land) \tag{6.19}$$

Where, C_{PV} [€/kWp] is the cost of the PV modules, P_{rated}[W] is the power rated of the solar inverters and C_{inv} [€/kWp] is the cost of the solar inverters. $C_{transformer}$[€/kWp] is the cost of the step-up transformers. $C_{C\&i}$[€/kWp] is the cost associated to construction and installation of the PV plant components. BOS [€/kWp] is the cost of the balance of system components. C_{land} [€/km^2-year] and $land$ [km^2] are the cost of the land and the surface area required for the installation of the PV power plant respectively. n [years] is the operational lifetime of the PV plant.

2. **Calculation of the Maintenance cost of the PV power plant during its operational lifetime ($\boldsymbol{C_m}$)**

Besides of knowing the total capital cost the PV power plant, the calculation of the maintenance cost during its operational lifetime it is important to know the economic framework of the project. The formula used to calculate this parameter is shown below:

$$C_m = P_{plant,nom} \cdot 1000 \cdot M_{plant} \cdot n \tag{6.20}$$

Where, M_{plant} [€/kWp] is the maintenance cost of the PV power plant. The annual inflation rate and nominal discount are not considered in this calculation due to the lack of realistic data, but for a more accurate value of C_m these values should be examined carefully.

3. **Calculation of Replacement cost ($\boldsymbol{C_{rep}}$)**

Some of the components installed in the PV power plant will need to be replaced during the years of operation. The time of operation of the PV plant being designed is 25 years. The decision of which components should be replaced will be taken according the specifications of each component.

4. Levelized Cost of Energy calculation ($LCOE$)

LCOE is an economic parameter which it is used to quantify the price of the energy that is being produced for the specific conditions previously described. It is also one of the main parameters to compare different generating technologies. The formula used in this project is the following:

$$LCOE = \frac{C_c + C_m + C_{rep}}{E_{PLANT,n} \cdot 1000} \tag{6.21}$$

Where, $E_{PLANT,n}$ [MWh] is the total energy produced by the PV plant over its operational lifetime.

5. Gross Revenues (R_{gross})

Gross revenues are the sum of all earnings generated by the PV plant during the project lifetime. The calculation is made considering the price of the electricity over the operational lifetime of the PV plant. This price can vary depending on the electricity market of the selected location and also it is important to consider the support schemes available. The formula used for Gross Revenues is:

$$R_{gross} = P_{electricity} \cdot E_{PLANT,TOT} \cdot n \tag{6.22}$$

Where, $P_{electricity}$ [€/MWh] is the price of the electricity for the operational life-time of the PV plant.

6.2.3. Evaluation Parameters Calculation

The parameters that are going to be described below can be seen as quality indicators of the PV solar power plant designed, also these parameters can be used to make final decisions regarding the technology used and to make comparisons between other types of energy generation technologies. The parameters described in this section are: ground coverage ratio, performance ratio, capacity factor and specific yield.

Ground coverage ratio (GCR)

This parameter is an indicator of how the surface of installation is covered by PV modules and which percentage is used for other components. The formula to calculate this parameter based on [48] is shown below:

$$GCR(\%) = \frac{S_{array,final}}{land} \cdot 100 \tag{6.23}$$

The results obtained of GCR will be merely indicative, since the calculation of $land$ [km^2] are based on assumptions.

Performance ratio ($\boldsymbol{PR}$)

Performance ratio expresses the relation between the real performance of the PV solar power plant and its rated power capacity. This parameter can be seen as a quality indicator because usually it is used to compare different photovoltaic systems independently of their installed capacity. The period analysed is one year and the parameter is calculated by the following formula based on [3].

$$PR(\%) = \frac{E_{PLANT,TOT}}{P_{plant,nom} \cdot G_t \cdot 10^{-6}} \cdot 100 \tag{6.24}$$

Where, $E_{PLANT,TOT}$ [MWh] is the total energy generated for the PV power plant during one year.

Capacity factor ($\boldsymbol{CF}$)

This parameter is the ratio of the PV power plant actual energy output for a year and its output at nominal power during a year. It is typically expressed as percentage and the formula based on [3] describing this parameter it is shown below:

$$CF(\%) = \frac{E_{PLANT,TOT}}{P_{plant,nom} \cdot 8760} \cdot 100 \tag{6.25}$$

Specific yield ($\boldsymbol{Yield_{sp}}$)

Specific yield of a PV solar power plant is the total energy output divided by the installed capacity [3]. This parameter expresses the number of hours that the PV array would need to operate at its rated power to generate the same energy. The formula used is shown below, the results can be expressed in kWh/kWp or hours:

$$Yield_{sp} = \frac{E_{TOTAL}}{P_{plant,nom}} \tag{6.26}$$

6.3. RESULTS OBTAINED

The results are obtained by implementing the calculation methodology previously described in *MATLAB* (See *Annex A*). To make the calculations four different scenarios, with two different PV modules and two different inverters, have been selected (see Table 6.1). Later, the results of the different scenarios are going to be compared in order to obtain the most favourable configuration considering different modules and solar inverters technologies.

The main purpose of comparing four different scenarios is to obtain which is the module-inverter combination with the best design results. To do that, two different modules with different technologies are analysed, one module with poly-Si technology and the other with CdTe thin-film technology. Additionally, the rated powers of the modules are markedly different, 320 Wp for poly-Si modules and 110 Wp for thin-film. These two modules technologies are selected for being analysed because poly-Si and CdTe thin-film modules are nowadays one of the most common technologies used in large-scale PV plants. Furthermore, two different inverters are compared in the different scenarios calculated. Both inverters are central-inverters, but the rated power is considerably different, 3,000 Wp for *Sungrow* inverter and 2,000 Wp for *KACO new energy* inverter.

Table 6.1. PV module and inverter selection for each of the different scenarios.

	PV module	**Inverter**
Scenario 1	TrinaSolar TALLMAX-PE14A	Sungrow SG3000HV
Scenario 2	First Solar FS-4110-3	Sungrow SG3000HV
Scenario 3	TrinaSolar TALLMAX-PE14A	Kaco new energy blueplanet 2200TL3
Scenario 4	First Solar FS-4110-3	Kaco new energy blueplanet 2200TL3

Results obtained regarding the number of elements in the system and the installed capacity for each of the scenarios analysed are shown in Table 6.2:

Table 6.2. Results of different design parameters.

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
No. PV modules series per PV set	29	16	18	10
No. PV modules parallel per PV set	406	2,165	442	2,356
No. Inverters	14	14	20	20
No. of PV modules	164,836	484,960	159,120	471,200
Installed capacity (MWp)	52.75	53.35	50.92	51.83

The calculation of the number of PV modules in series is directly linked with the relation between the voltage of the inverter and the voltage values of the PV modules. The number of modules in series in Scenario 1 is larger than the number in Scenario 2, despite these two scenarios are sharing the same inverter technology. This difference is caused due to the MPP voltage and the maximum open-circuit voltage of the modules in Scenario 2 are higher than in Scenario 1. For higher voltage values of the modules, less modules in series can be connected per inverter. The same applies with Scenario 3 and Scenario 4, where, in this case the PV modules selected for Scenario 4 have higher MPP voltage and maximum open-circuit voltage. Comparing Scenario 1 and Scenario 4, using the same PV modules but different inverters, the number of PV modules in series in Scenario 1 are larger because voltage values of the inverter selected for this scenario are higher.

Regarding the number of PV modules in parallel obtained for each scenario, the explanation of the values obtained is similar than the explanation for the number of PV modules in series, but in this case the values are linked with the current values. The scenarios with PV modules with higher current values (Scenario 1 and Scenario 3) allow to connect less PV modules in parallel per inverter. The scenarios using an inverter with higher current input parameters (Scenario 3 and Scenario 4) allow to connect more PV modules in parallel than Scenarios 1 and 2.

The number of inverters in the PV solar power plant is directly correlated with the maximum admissible input power of the inverters, for scenarios using a type of inverter with higher input admissible power (Scenario 1 and Scenario 2) the number of inverters needed is smaller. The opposite happens with Scenario 3 and Scenario 4 where the lower input admissible power of the inverter in those scenarios leads to a larger number of inverters in the system.

Total number of PV modules installed in the PV plant is the result of the combination of the number modules in series, modules in parallel and inverters in the system. The value of the number of PV modules depends on both PV module technology (in greater extent) and inverter selected.

Initial design capacity of the PV plant was 50 MW for all the scenarios, but due to the number of modules in series, modules in parallel and inverters has to be an integer number and also it is decided to make all the PV set of the same size, the design capacity is modified in different manner for all the scenarios, all the scenarios are slightly oversized. The scenario closer to the design capacity is Scenario 3, where installed capacity calculated is 2% higher than the initial design capacity of 50MW. The scenario with the higher difference is Scenario 2 with an installed capacity 6.7% higher than the initial value.

Actual power output for each PV module during one year for time steps of one hour is represented in Figure 6.9. The power profile that is showed in Figure 6.9 shows the power output for each PV module after applying losses due to dirt deposited on it and due to shading effect. This figure is related with the total number of PV modules which are required in the PV plant (Table 6.2). Obviously, the amount of PV modules required will depend on their power output, in Figure 6.9 it can be seen that PV modules used in Scenarios 1 and 3 have more than double of the power output of the PV modules used in Scenarios 2 and 4, therefore it is coherent that the total number of PV modules is also more than double in those scenarios.

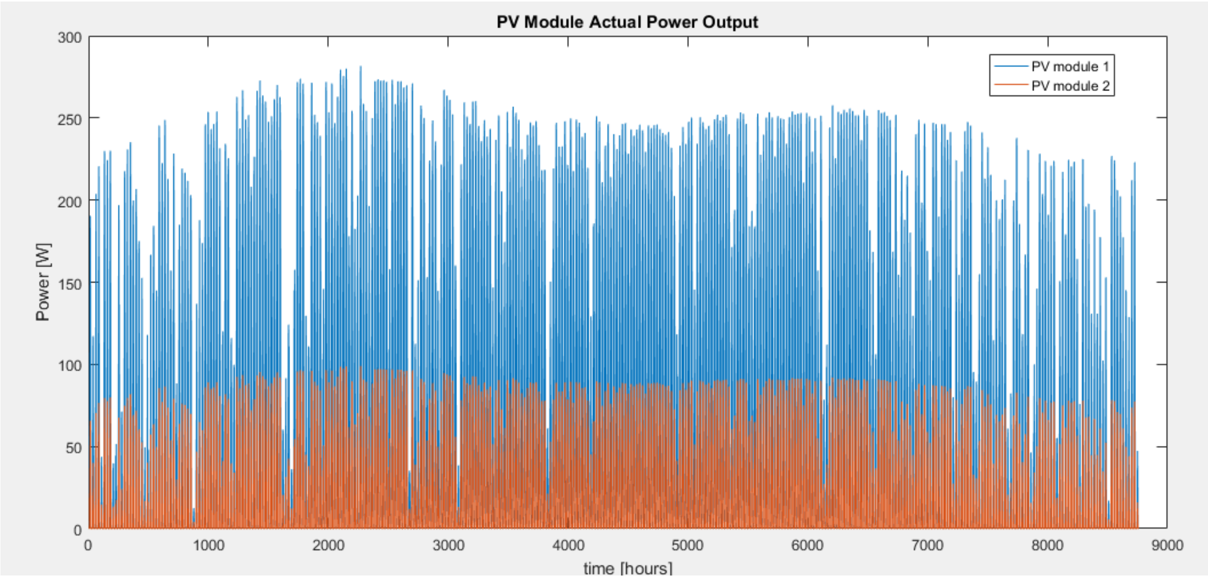

Figure 6.9. PV module actual power output. PV module 1 (blue) is the technology used in Scenarios 1 and 3. PV module 2 (red) is the technology used in Scenarios 2 and 4.

Annual energy output for each module before and after applying losses is shown in Table 6.3. Note that Scenarios 1 and 3 are using PV module no. 1; and Scenarios 2 and 4 are using PV module no. 2 (see Table 6.1). Losses considered in this calculation are: losses due to dirt deposited on PV module surface (soiling losses) and losses due shading effect. The annual reduction factor is not considered due to the calculations are made for the first year of operation.

Table 6.3. Values obtained for PV module MPP output power and actual output power.

	Scenario 1 **Scenario 3**	**Scenario 2** **Scenario 4**
Annual energy output at MPP power of each PV module [kWh/year]	585.6	205.03
Annual energy at actual output power of each PV module [kWh/year]	528.84	185.16
Annual energy losses in each PV module [kWh/year]	56.76	19.87

The losses applied are the same for the four scenarios, thus the amount of annual energy losses of each PV module will depend on their rated power. The losses due to the dirt and the shading losses combined add up to a total of approximate 10% for all scenarios.

Energy output of each PV set and energy output of each inverter for the different scenarios are shown in Table 6.4. Note that the number of PV sets is equal to the number of inverters for each different scenario.

Table 6.4. Values for energy output of each PV set and energy output for each inverter.

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
Annual energy output of each PV set [MWh/year]	5,950.4	6,129.4	4,020.8	4,168.9
Annual energy output of each DC/AC inverter [MWh/year]	5,872.1	6,048.8	3,962.7	4,108.7
Annual energy losses in each PV set [MWh/year]	78.28	80.60	58.14	60.18
Losses in each PV set [%]	1.33	1.33	1.47	1.46

The energy losses between the energy output of the PV sets and the energy output of the DC/AC inverters are caused by the efficiency of the inverter and also, they correspond to a calculation algorithm where: 1) if the power output from the PV set is lower than self-power consumption of the inverter, power output from the inverter will be zero; 2) if the power output from the PV set is lower than maximum admissible input power of the inverter, the power output will only depend on the inverter's efficiency and the output power from the PV set. If the power output from the PV set is higher than maximum admissible input power of the inverter, the power output will be maximum admissible input power of the inverter multiplied by the inverter efficiency (see Equation (6.14)). The percentage of losses in PV set are similar between the four scenarios. For Scenarios 1 and 2 the losses due to the efficiency of the inverter are 1.3% the rest of the losses are caused due to calculation algorithm previously described (approximately 0.03%). The losses due to the inverter's efficiency in Scenario 3 and 4 are 1.4%. The losses from the calculation algorithm in Scenario 3 are 0.07% (the highest losses), and the losses due to calculation algorithm is Scenario 4 are 0.06%.

Table 6.5 shows the values obtained regarding the calculations of the land occupied by the PV plant:

Table 6.5. Values obtained for the land occupied by the PV plant.

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
Land occupied by the PV plant [km^2]	1.576	1.630	1.520	1.582

The values obtained for the land occupied by the PV plant for the four scenarios are very similar between them and they are in the order of 1.5 km^2. The calculations of the land required for the PV plant installation are based on assumptions, the variation of the values obtained are caused due to the variation of the actual power output of the different scenarios. The values obtained for all the scenarios are in accordance with the estimates done in section *6.1. SITE IDENTIFICATION* where the estimated area for the PV plant installation was 2 km^2.

Table 6.6 shows the values obtained in the calculations for the annual energy that can be injected into the grid and annual energy production (AEP):

Table 6.6. Values for annual energy that can be injected into the grid and AEP.

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
Annual energy that can be injected into the grid [MWh/year]	80,981	83,418	78,069	80,945
AEP [MWh/year]	80,576	83,001	77,679	80,541

The values obtained for annual energy that can be injected into the grid are obtained from the power output of the DC/AC inverters and applying losses due to interconnection transformer and losses due to the AC side cable. Thus, the values obtained follow the tendency of the previous calculations: Scenario 2 is the scenario with the highest value, followed by Scenario 1 and 4 (with very close values between them) and finally the scenario with the lowest value is Scenario 3.

AEP values are the same as annual energy that can be injected into the grid but applying a correction factor due to maintenance reasons (99.5% of efficiency). The losses in AEP could be higher if the calculations had considered power restrictions in the grid utilization.

Using *PVWatts Calculator* [32] to make rough estimates, it is obtained an AEP of 76,809 MWh/year for a PV system with silicon modules, and an AEP of 78,064 MWh/year for thin-film modules. Looking at these numbers obtained with *PVWatts*, it can be seen that the values obtained for AEP during the calculations of the four the different scenarios are numbers in the same order of magnitude.

Figure 6.10, Figure 6.11, Figure 6.12 and Figure 6.13 show the graphical representation of the losses involved in the energy generation process for all scenarios as well as the energy output after each step of calculation. These figures do not provide additional information, but with these graphical representations the differences between the four scenarios can be seen in more detail. The conclusions reached are the following:

- Initial energy values for each of the scenarios are calculated considering PV panels working at STC without losses during one year. The differences in the initial values between scenarios are due to differences in the installed capacity (explained in more detail in section *6.2.1. Design and Energy Calculations*).
- The effect of irradiance and temperature describes the photovoltaic energy conversion of the PV modules. The highest losses on the system are caused do to these two parameters since the PV modules are not working at STC always. Irradiance and temperature losses depend on the climatological conditions being considered and the PV module technology. Thus, the scenarios using the same type of PV module have the same irradiance/temperature losses.
- Soling, shading, MPP, mismatch and DC side cable losses represent the same share for all the scenarios. Total sum of those losses is 14.4%, being the losses due to soiling the greatest contributor with 6.9%.
- The losses due to inverter's efficiency are equal in Scenario 1 and Scenario 2, sharing the same type of inverter (losses of 1.3%) and the losses due to inverter efficiency in Scenario 3 and 4 are 1.4%. The losses due to inverter power restriction are different in all scenarios because those losses depend on the calculation algorithm previously explained, which consider the relation between the power output of the PV panels and the specifications of the inverter selected. The energy output after applying losses due to performance of the inverter correspond to the energy output of the dc/ac inverters.
- The losses due to maintenance reasons are assumed constant (0.5%) for all the scenarios independently of the installed capacity.
- The process efficiency for Scenario 1 is 17.44%, for Scenario 2 is 17.76%, for Scenario 3 is 17.41% and for Scenario 4 is 17.74%. The major contributory factors which causes the differences in the efficiency between different scenarios are the effect of irradiance and temperature on the PV module, inverter efficiency and the inverter's power restrictions. Scenarios 1 and 3 having the same module technology have practically the same efficiency, while Scenario 2 and 4 both using CdTe modules, the efficiency is very similar between them. In summary, the scenarios using thin-film CdTe PV modules offer an improved process efficiency compared to scenarios using poly-Si module. The differences in the process efficiency due to the inverter technology are not significant in these calculations.

SCENARIO 1

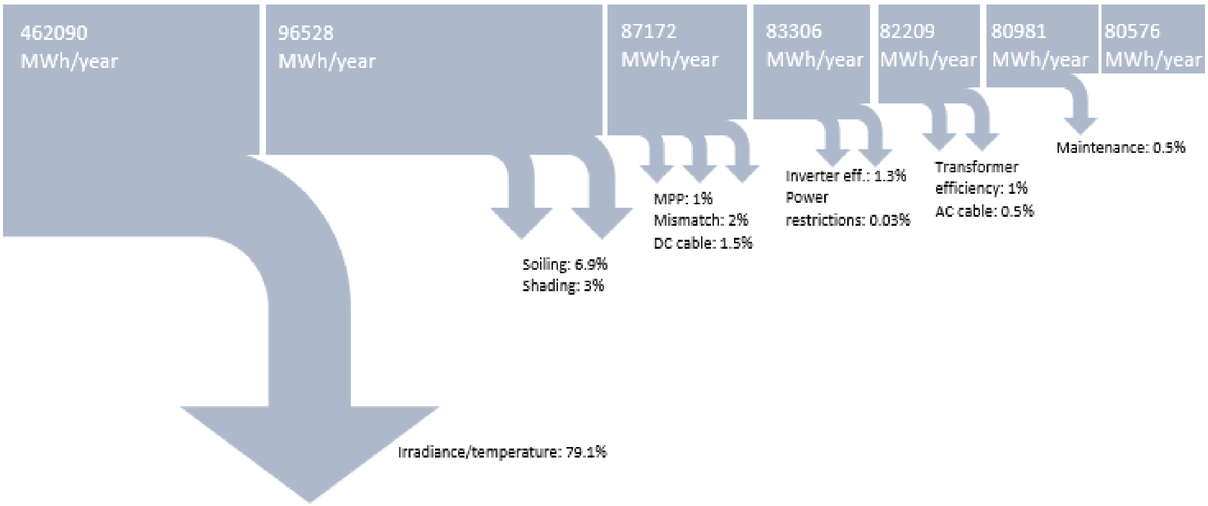

Figure 6.10. Energy flow chart Scenario 1.

SCENARIO 2

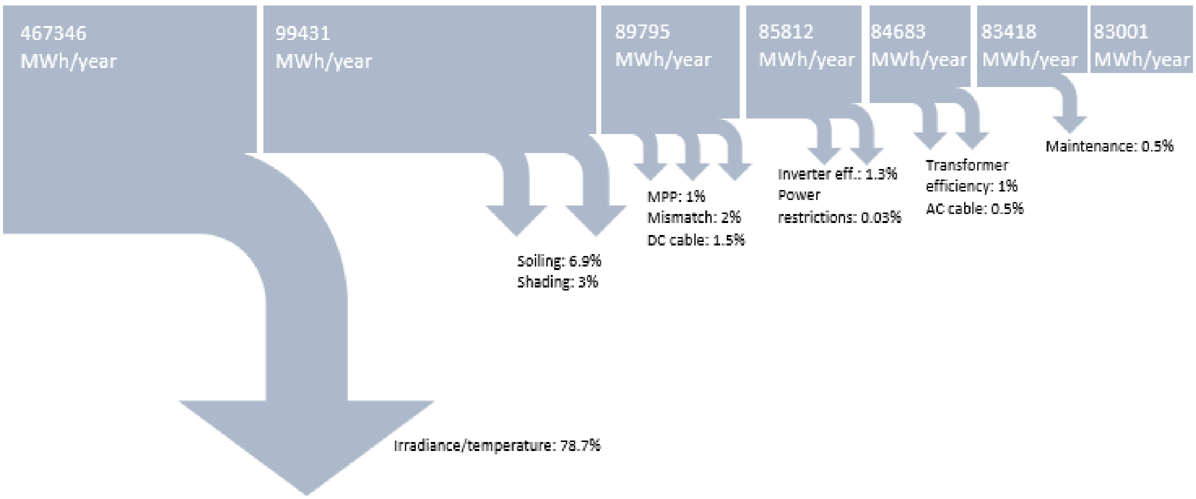

Figure 6.11. Energy flow chart Scenario 2.

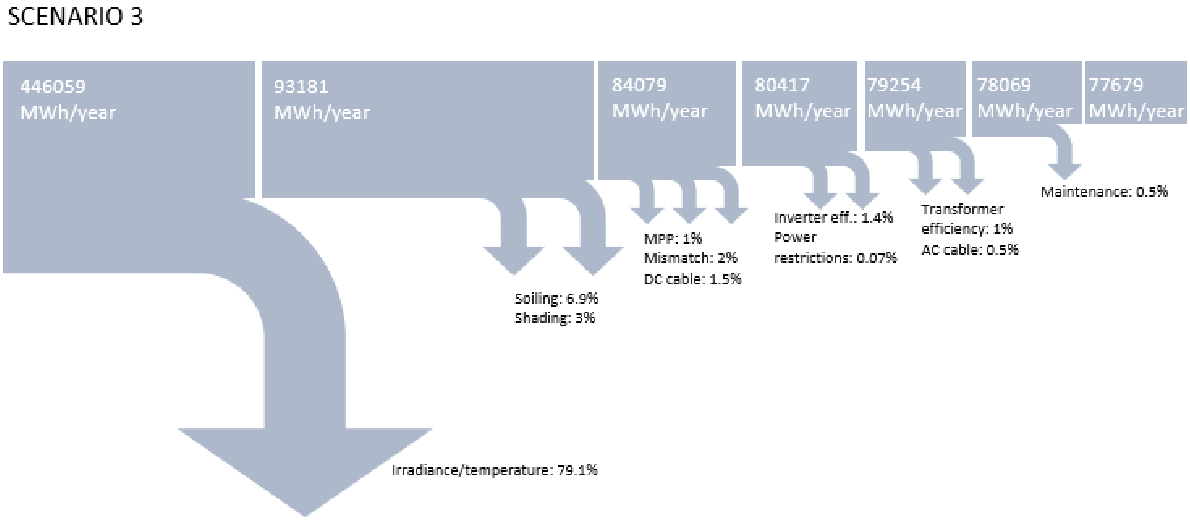

Figure 6.12. Energy flow chart Scenario 3.

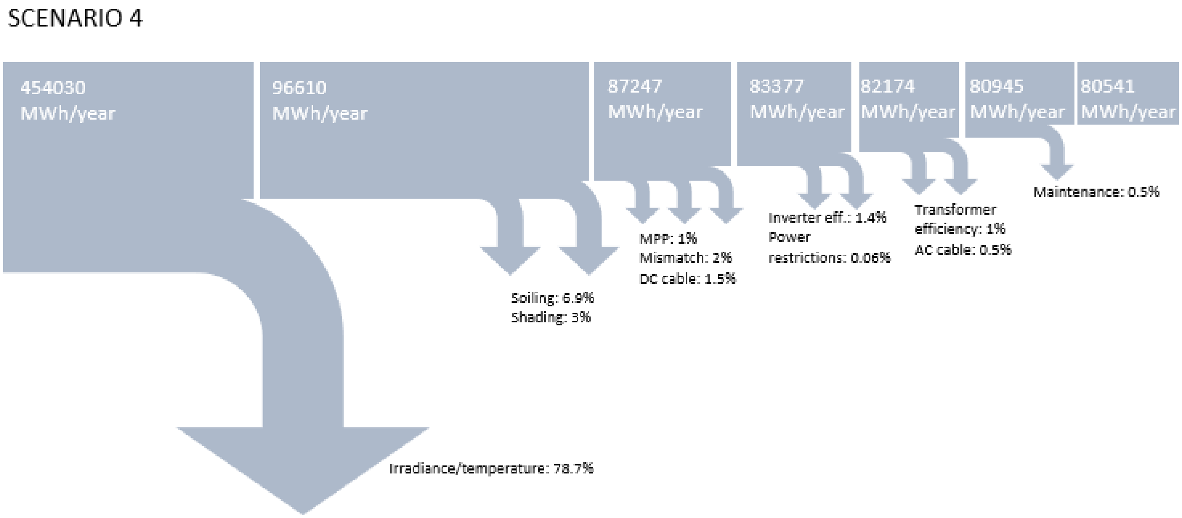

Figure 6.13. Energy flow chart Scenario 4.

6.3.1. Economic Results

To elaborate the economic calculations some assumptions regarding the cost of the components and services involved have been made. Table 6.7 shows the assumptions made during the calculations:

Table 6.7. Cost assumed per component or service considered in the design of the PV plant.

	Value	Reference
PV module [USD/kWp]	600 for poly-Si 500 for thin-film	[49]
Inverter [USD/kWp]	50	[50]
BOS [€/kWp]	74	[51]
Civil work [€/kWp]	165	[51]
Land [€/km2-year]	130,000	[52]
Transformer [€/kWp]	20	[53]
O&M [USD/kWp-year]	18 for poly-Si 19 for thin-film	[49]

Total capital cost results obtained and cost breakdown of the PV power plant is shown in Table 6.8:

Table 6.8. Cost per component and service and the percentage they represent for each scenario.

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
Cost of the PV modules [€]	25,635,000 (55.58%)	21,604,968 (50.93%)	24,746,000 (55.62%)	20,991,960 (50.98%)
Cost of the inverters [€]	1,701,000 (3.69%)	1,701,000 (4.01%)	1,620,000 (3.64%)	1,620,000 (3.93%)
Cost of the transformers [€]	1,055,000 (2.29%)	1,066,912 (2.52%)	1,018,368 (2.29%)	1,036,640 (2.52%)
BOS cost [€]	3,903,300 (8.46%)	3,947,600 (9.31%)	3,768,000 (8.47%)	3,835,568 (9.31%)
Civil work and install. cost [€]	8,703,300 (18.87%)	8,802,024 (20.75%)	8,401,536 (18.88%)	8,552,280 (20.77%)
Cost of the land [€]	5,122,500 (11.11%)	5,297,700 (12.49%)	4,939,800 (11.10%)	5,142,100 (12.49%)
TOTAL capital cost [€]	46,120,000 (100%)	42,420,000 (100%)	44,494,000 (100%)	41,179,000 (100%)

PV modules are the components which contribute the most to the total capital cost, for all the scenarios the cost of the PV modules represents above 50% of the total capital cost. The disparity in the cost of PV modules for the different scenarios are caused due to differences in PV technology and differences in the number of PV modules installed. The cost of the inverters represents about 4% of the total capital cost, the variations in the cost of the inverters between the different scenarios are caused due to the inverter technology employed and the number of inverters in the systems. BOS cost share varies between 8.5% for Scenarios 1 and 3, and 9.3% for Scenarios 2 and 4. Even though, the percentages of those scenarios are equal the cost in € does not match for any of the scenarios. The reason of the disparity of BOS cost is because it depends on the total installed capacity which is different for each scenario analysed. Civil work is the second highest cost considered in the design of the PV plant, civil work cost is in the range of 18.87%, in the lowest cost scenario and 20.77% for the scenario with the highest share of civil work. The variations in the civil work cost between scenarios are caused (as happens with BOS cost) by the total installed capacity of each scenario. The cost of the land is calculated assuming a determined annual fixed cost per surface unit and using the value of land occupied by the PV plant previously calculated. The percentage of the different costs of the land are in the range from 11.10% to 12.49%. Total capital cost is the result of the summation of the cost of all components and services considered in the analysis. Regarding the total capital cost, total installed capacity is not a determining factor. The scenario with the highest total capital cost is Scenario 1, but this scenario it is not the scenario with the highest installed capacity (which it is Scenario 2). Scenario 4 which is the scenario with the lowest total capital cost it is not the scenario with the lowest installed capacity (Scenario 3).

Total capital cost found in literature is very changing, according to *NREL* [50] the estimated total capital cost for a 50 MW PV project is 60,500,000 USD, according to *IRENA* [49] the estimated total capital cost is 75,000,000 USD, according to *Solar Bankability* [54] the estimated cost is 45,000,000 € for low scenario and 60,000,000 € for high scenario, and according to *KIC InnoEnergy* [51] the total cost is around 45,000,000 €. Looking at these values from literature, the values obtained in the calculations are in the same order of magnitude, but they seem a slightly low when comparing with capital cost values obtained in literature.

Operational and maintenance costs (O&M) associated for each of the four scenarios analysed are shown in Table 6.9, the values of O&M costs are calculated for an operational lifetime of the PV plant of 25 years (see in more detail in section *6.2.2. Economic Calculations*).

Table 6.9. O&M costs obtained for each scenario.

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
O&M cost [€/year]	769,060	820,990	742,390	797,690
O&M cost [€] for 25 years operation	19,226,000	20,525,000	18,560,000	19,942,362

The results obtained for O&M are linked with the total installed capacity in each Scenario and also with modules technology being used for each scenario. The O&M costs [€/kWp] are assumed to be higher for the scenarios using CdTe thin-film PV modules than for the scenarios using poly-Si modules. One of the scenarios using CdTe modules is Scenario 2 which is the scenario with the highest O&M cost and also the scenario with the highest installed capacity. In the same way, the scenario with the lowest O&M cost is Scenario 3 which uses poly-Si technology and it is the scenario with the lowest capacity installed.

O&M costs calculated are consistent the with values found in literature. According *NREL* [50] estimated O&M cost for a utility-scale PV plant with one-axis tracker is 925,000 USD-year (calculation for a 50 MW power plant), according to *EIA* [55] the estimated cost is 1,100,000 USD-year, and according to

EPRI [56] estimated O&M cost for a PV plant using poly-Si technology is 1,025,000 USD-year and for CdTe is 1,075,000 USD-year.

The only component considered in the design which has to be replaced during the operational lifetime of the PV solar power plant are the inverters. According to inverter's manufacturers the operational lifetime of central inverters can be 20 years or even more, but on field tests reveal that the real lifetime is in the range of 10-20 years [3]. The other components involved in the design of the PV project are assumed to have lifespans above 25 years. In summary, the replacements costs considered in economic calculations are exclusively the ones derived from the cost of the inverters. Scenario 1 and 2, sharing the same type of inverter and the number of inverters required, have a replacement cost of 1,701,000 €, and Scenario 2 and 3, also with the same type and number between them, have a replacement cost of 1,620,000 €.

Total costs for each scenario over the 25 years of plant operation are: Scenario 1, 67,048,000 €; Scenario 2, 64,646,000 €; Scenario 3, 64,674,000 €; and Scenario 4, 62,741,000 €. The percentages of the elements forming the total cost are similar between the four different scenarios. Capital cost represents around 70% of the total cost, O&M cost is approximately a 30% and Replacement cost is around 2%. The cost breakdown is shown in Figure 6.14.

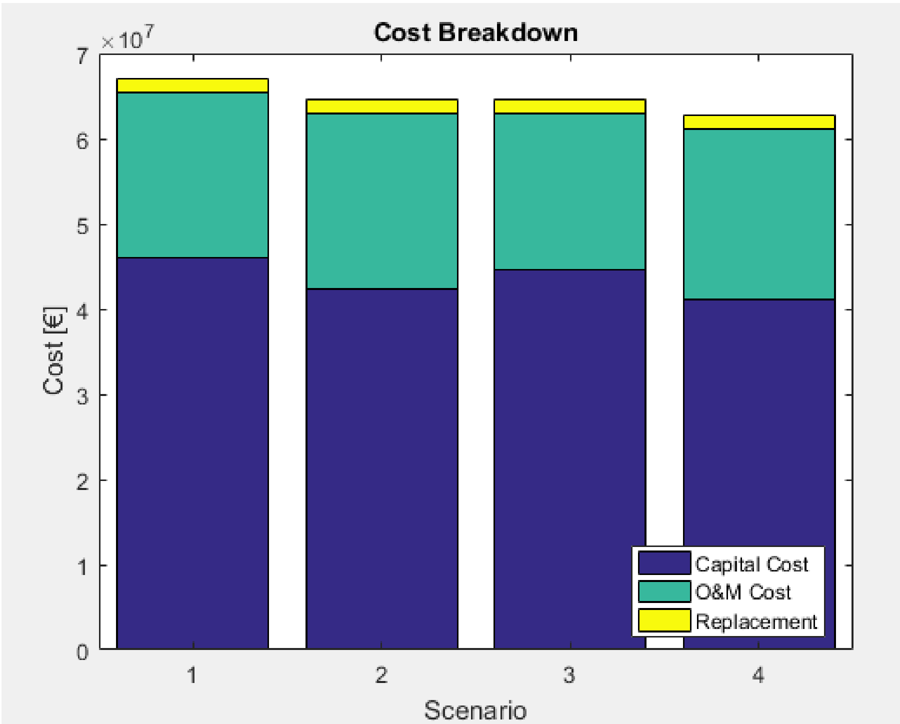

Figure 6.14. Cost breakdown for each scenario.

The levelized Cost of Energy (LCOE) obtained for each of the scenarios are shown in Table 6.10:

Table 6.10. LCOE values obtained for each scenario.

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
LCOE [c€/kWh]	3.3284	3.1154	3.3303	3.1160

The LCOE obtained in Scenario 1 and 3 is very similar between both scenarios, these two scenarios are sharing the same PV module technology, but the inverter used is different. The similarity between both LCOE is caused due to the total cost and AEP is higher in Scenario 1, in the same manner these two factors are smaller in Scenario 3 following the same tendency. Total cost in Scenario 1 is 4% higher than in Scenario 3, as well as AEP in Scenario 1 is 4% higher than in Scenario 3. The same occurs between Scenario 2 and 4 where the LCOE are very similar between them.

Looking at literature different values of LCOE can be found. The diversity between different values can be caused due to the year of publication, country or technology being considered in the project. According to *Solar Bankability* [54] in 2016 the estimated LCOE for utility-scale power plants is in the range from 5.2 c€/kWh to 7.8 c€/kWh, these values are significantly different from the values obtained in calculations. This difference can be caused due to a reduction of the cost associated with PV systems in the recent years and with an improvement of the modules efficiency. *NREL* [50] in 2017 makes a differentiation of LCOE values depending on the zone of installation. E.g. for a utility-scale one-axis tracking PV plant in Phoenix the LCOE is estimated in 3.0 c€/kWh. According to *PV Magazine* [57], citing *Fraunhofer ISE,* LCOE in 2018 ranges from 3.71 c€/kWh to 11.54 c€/kWh in Germany. In summary, the values calculated for the different scenarios are consistent with the values found in literature, but they will be in the lower range of the values observed.

The economic viability of the PV project is evaluated by means of calculating Net Present Value (NPV) and Internal Rate of Return (IRR). The revenues of the PV plant are calculated by multiplying AEP by the selling price of electricity. Since FITs and other financial support schemes have been eliminated in Spain (see section 4.1. *SUPPORT SCHEMES IN SPAIN* for more details), PV solar power plants have to sell their energy in the electricity wholesales market. The price of the electricity in the Spanish market presents a high volatility, making challenging to make a prediction of the electricity price for a 25 years project. For practical reasons a constant electricity price of 0.12 €/kWh is assumed during calculations. This price is based on the former Spanish FIT for ground-mounted installations before its cancellation [58]. Discount rate estimated for the calculations is 8%. Table 6.11 shows NPV and IRR obtained for each of the scenarios analysed:

Table 6.11. NPV and IRR values obtained for each scenario.

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
NPV [k€]	44,686	50,475	43,046	48,964
IRR [%]	19	21	19	21

For a positive value of NPV the project can be accepted because the investment will generate benefits above the required rentability. The NPV of all different scenarios is calculated considering a discount rate of 8%. The scenario with the highest NPV, thus the scenario with the highest potential benefits it is Scenario 2 with an NPV of 50,475 k€. However, all the scenarios analysed have the potential to be accepted due to a positive NPV.

IRR can also be used as a rentability indicator for a project. For a positive value of IRR, the project can be economically accepted. For the case of the scenarios analysed all of them have a positive IRR. The scenarios with the highest IRR are Scenario 2 and Scenario 4 with an IRR of 14% both.

Based on the results obtained of these two economic indicators, it can be asserted that the scenarios with the highest economic viability are the scenarios using CdTe thin-film technology (Scenario 2 and 4). Both scenarios present higher NPV and IRR than the scenarios using poly-Si technology. By looking at NPV, the inverters used in Scenarios 1 and 2 seems to have a better economic impact on the project.

6.3.2. Other Results

Table 6.12 shows the results of other parameters calculated for all the scenarios analysed. These results obtained help to understand the behaviour of the PV plant and permit to make comparisons between different scenarios in order to observe which is the best configuration.

Table 6.12. Obtained values for: Ground Coverage Ratio (GCR), Performance ratio (PR), Capacity Factor (CF) and Specific Yield ($Yield_{SP}$).

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
GCR [%]	20.33	21.42	20.35	21.44
PR [%]	78.28	79.73	78.17	79.62
CF [%]	17.44	17.76	17.42	17.74
$Yield_{sp}$ [kWh/kWp]	1,527.6	1,555.9	1,525.6	1,553.9

GCR calculated for all the scenarios is around 20%. The scenarios using thin-films have a higher GCR than scenarios using poly-Si modules. These values obtained are just indicative values to see how the surface of the PV plant is distributed. GCR calculated does not consider the optimum inter-row spacing between modules in order to decrease the shading effect caused by the tilt angle. PR is a quality indicator, which helps to compare different systems with different installed power. The scenario with the highest

PR is Scenario 2 with 79.73%, however all the scenarios have PR close to 80%. According to *IFC* [3] a typical performance ratio for well-designed PV plant should be in the range between 77% and 86%. CF expresses the ratio of the actual energy output of the PV plant over a year and its output if it had operated at nominal power during a year. The scenario with the highest CF is also Scenario 2 with 17.76%, but all the scenarios present a similar CF. According to *IFC* [3] a capacity factor of 16% would be typical value for a PV plant located in southern Spain. $Yield_{SP}$ is the total annual energy generated over the total capacity installed, it can be seen also as the number of hours which the PV plant is operating at its nominal power. The scenario with the highest $Yield_{SP}$ is Scenario 2, with the values of the other scenarios being similar.

7. RESULTS COMPARISON USING PV MODELLING SOFTWARE

In order to compare the results obtained in the calculations, the design of a 50 MW PV power plant is implemented in different modelling software. In this chapter is shown the methodology of designing and the results obtained with *PVSYST* and *System Advisor Model (SAM)*.

7.1. PVsyst MODELLING

7.1.1. Pre-Design Phase

Before designing the entire system in *PVsyst* a pre-design phase is done in order to obtain the magnitude of the design values. The steps followed during the pre-design phase are the following:

- Site and meteorology: Due to this first pre-design is not a meticulous phase, Barcelona is chosen as the location of PV power plant installation (the nearest available meteorological database). The real location of the PV plant was not able in the initial database, but for further modelling steps it will be added.
- System definition: The nominal power of the system is set at 50 MW, active area and annual yield are automatically calculated. Regarding the optimum tilt angle and azimuth, *PVsyst* find the optimum values (Figure 7.1) depending on the location previously selected. For an optimization on annual yield, optimum tilt angle is defined in 30º and azimuth angle in 0º (south oriented).

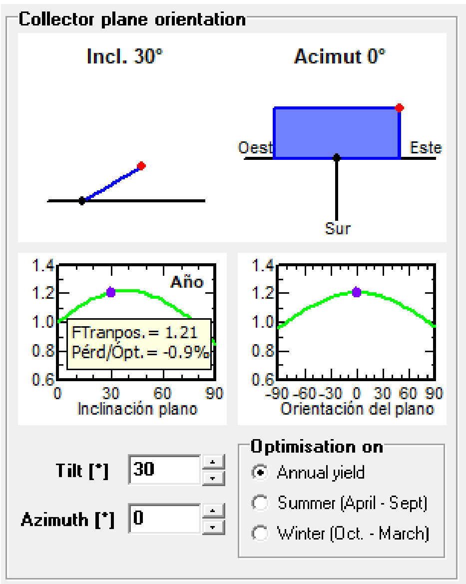

Figure 7.1. Collector plane orientation PVsyst's screen capture.

- System specifications definition: The module type is set as standard with poly-Si module. This type of module technology is not valid for all the possible scenarios described, but since it is a pre-design phase to see the order of magnitude of the values obtained, the design will be made for a single hypothetical scenario. The mounting disposition of the PV modules is defined as ground based and with a ventilation property of free standing.
- Economic input parameters: The cost per module is set at 0.5€/Wp.

The results obtained from the pre-design phase in *PVsyst* are shown in Table 7.1:

Table 7.1. Pre-design phase results obtained with PVsyst.

	Results
Area [km^2]	0.333
AEP [MWh/year]	83881
Energy cost [€/kWh]	0.07
Investment cost [€]	78,866,699

Area occupied by the PV modules simulated in *PVsyst* is similar to the area obtained previously in calculations (in the range from 0.35 km^2 to 0.31 km^2). The result obtained for AEP is also consistent with the values obtained in calculations, with an order of magnitude of 80,000 MWh/year. The result of the energy cost obtained in the simulation is much higher than LCOE obtained in the calculations (almost double). This is caused due to the Investment cost simulated in *PVsyst* differs greatly from the investment cost obtained during calculations. Investment cost or capital cost obtained in the calculations is in the order of magnitude of 40 M€ while the investment cost in *PVsyst* is almost two times higher. Note that these values obtained in pre-design phase are only indicative, specially the economic results. A more detailed economic analysis will be done afterwards.

In Figure 7.2 the AEP distribution can be seen over the months of production. The months with higher solar radiation, spring and summer months, are the months with higher energy production. This AEP distribution is for a fixed tilt angle of 30º, but the production could be increased by incorporating one-axis tracking with seasonal variation.

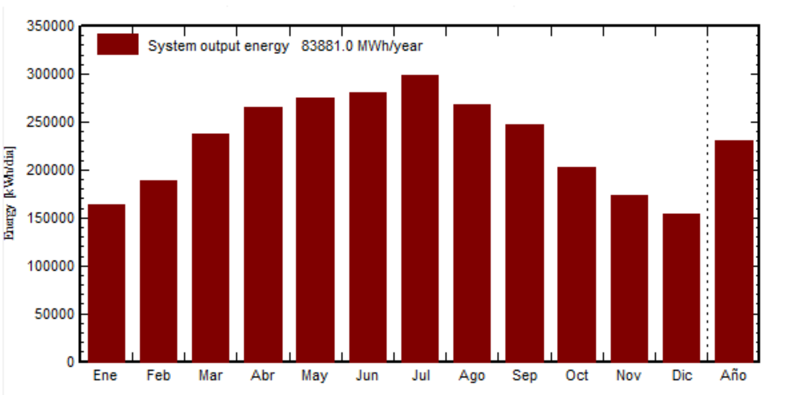

Figure 7.2. PVsyst pre-design phase system output energy

The investment cost (Table 7.1) can be divided in the cost of the different components or services involved in the PV plant design. Again, the values obtained during the simulation done in *PVsyst* are distant from the values obtained in the economic calculations based on estimations. Breakdown of the capital cost calculated during pre-design phase is shown in Table 7.2:

Table 7.2. PVsyst pre-design phase breakdown capital cost.

	Cost [€]
Module	25,000,000
Supports	32,000,000
Inverter(s) and wiring	10,000,000
Transport/Mounting	11,886,699
TOTAL	78,886,699

7.1.2. Design Phase

Once the pre-design phase is done with the corresponding results obtained and they are analysed, the final design of the PV power plant project is made. In the final design phase with *PVsyst* the four different scenarios, with their characteristics, are going to be analysed separately. The steps to calculate the PV solar power plant final design are shown below:

- Location and climate data: In this case, to make the calculation more accurate a location closer to the real location of the PV project is added to the meteorological database. The closer possible location selected is *Lleida* (around 30 km to *l'Albagés*) and the data obtained for further simulations is shown in Figure 7.3.

	Irrad. Global W/m²	**Difuso** W/m²	**Temp.** °C	**VelViento** m/s
Enero	71.4	34.7	9.6	3.00
Febrero	130.4	47.9	10.7	3.40
Marzo	185.9	65.6	13.4	3.50
Abril	235.6	85.8	15.5	3.50
Mayo	274.7	105.4	19.3	3.10
Junio	311.5	100.3	23.5	2.99
Julio	306.0	95.8	26.0	3.20
Agosto	265.9	89.1	25.9	3.00
Septiembre	207.9	69.4	22.2	2.89
Octubre	138.7	57.3	18.8	2.70
Noviembre	92.5	39.4	13.0	3.09
Diciembre	63.3	34.1	9.8	3.00
Año	**190.6**	**68.9**	**17.3**	**3.1**

Figure 7.3. Global and diffuse irradiance, temperature and wind velocity in Lleida.

- PV modules orientation definition: For this simulation, the PV modules are determined as one-axis tracking with seasonal variation. The tilt angle of the PV modules installed is going to be different for winter and summer. In Figure 7.4 the optimum tilt angle for both seasons and the azimuth angle can be seen.

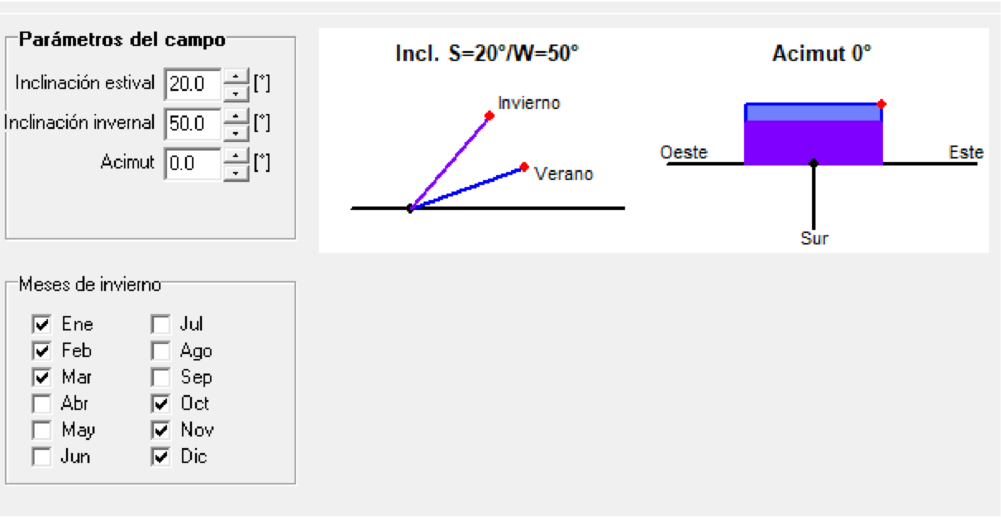

Figure 7.4. PV modules orientation in PVsyst design phase

- System definition: This step is made for each of the different scenarios being studied. The selection of module is set depending on the scenario as well as the inverter selected. The number of PV modules in series, in parallel and the number of inverters needed for each of the scenarios is calculated by *PVsyst* calculation tool by entering the parameter of design capacity.
- Detailed losses definition: Thermal losses are not modified respect to their default value for outdoors systems with free ventilation. Ohmic losses are neither modified respect to their default value. Mismatch losses are set at 2%, same value as considered in the calculations. Losses to the dirt and dust deposited on the module surface are set at 6.9%. Losses named Incidence Angle Modifier (IAM) are not changed respect to the default values, these losses are not considerate during calculations. Auxiliaries energy losses are not considered in the simulation. Ageing of the PV modules is not considered in the simulation. And the availability factor of the system is set in 99.5% (same value as the calculations).
- Other input parameters: Far shadings are not modified respect to default values and near shadings are not considered in the simulation. The system is not restricted with grid power limitations.
- Economic evaluation: Cost of the components and services involved in the PV plant project will be added depending on the scenario analysed. Except for the cost of BOS structures, BOS electrical, civil work, cost of the land and cost of transformers. Table 7.3 shows the cost of the components considered in the initial investment:

Table 7.3. PV plant cost PVsyst input parameters.

Component/Service	**Cost [€/Wp]**
PV module	Depends on the scenario
Inverter	Depends on the scenario
BOS structures	0.06
BOS electrical	0.01
Civil work	0.17
Land	0.1
Transformer	0.02
O&M	Depends on the scenario

7.1.3. Results Obtained with PVsyst

In this section, the results obtained with *PVsyst* for the four scenarios are detailed and analysed. Furthermore, the results obtained in the simulations are compared with the results obtained previously in calculations.

Scenario 1:

The results obtained with *PVsyst* for the first scenario are shown in Table 7.4, as well as the comparison with the results of Scenario 1 obtained in the previous calculations.

Table 7.4. Results obtained with PVsyst compared to results obtained in calculations for Scenario 1.

	PVsyst Scenario 1	**Calculations Scenario 1**
Tilt angle (summer/winter) [º]	20/50	14.2/53.7
Azimuth [º]	0	0
Number of PV modules in series	29	29
Number of PV modules in parallel	5,603 (divided in 14 sets)	406
Number of PV modules	162,487	164,836
Installed capacity [kWp]	51,996	52,750
Modules surface [m^2]	318,828	320,500
Number of inverters	14	14
AEP [MWh/year]	83,283	80,576
PR [%]	79.35	78.29
Yield$_{sp}$ [kWh/kWp]	1,602	1,527.6

Optimum tilt angles obtained with *PVsyst* are different from the tilt angles obtained in the calculations. Tilt angles of the PV modules in *PVsyst* are defined as the optimum value according to the simulation software, 20º in summer and 50º in winter. Tilt angles in calculations are defined as the optimum values according to *NASA* [42] for the specific location selected. This difference between the tilt angles is repeated for all the scenarios. Azimuth angle for both *PVsyst* simulation and calculations is the same, 0º (south-facing) for all scenarios.

The number of PV modules connected in series obtained in the simulation are the same as the number of PV modules in series obtained in the calculations (29 PV modules in series). The number of parallel branches obtained in the simulation is 5,603 but dividing the number of parallel branches by the number of inverters, the result obtained is the number of PV modules connected in parallel per PV set which is 400. There is a significant difference between this number and the number obtained during calculations (406 PV modules in parallel per PV set). This difference is caused due to significant difference in the final number of PV modules in the system, 162,487 PV modules in the simulation compared to 164,836 PV modules in the calculation. The number of inverters required both in calculations and simulation is the same, 14 inverters.

The difference in the installed capacity are caused due to differences in the total number of PV modules installed. In the simulation, total number of PV modules is around 1.5% lower than the total number of PV modules obtained in the calculations. The lower number of PV modules installed in the simulation has impact on a lower capacity installed in the system, 1.5% lower compared to the capacity installed in calculations. The lower number of PV modules and the lower installed capacity obtained in *PVsyst* is in accordance with a lower modules surface compared to the results obtained in the calculations.

AEP for Scenario 1 obtained in *PVsyst* simulation is 83,283 MWh/year, a higher value if it is compared with the result obtained in the calculation which is 80,576 MWh/year. The difference in energy produced over a year is around 3.4% higher in the simulation compared to the result obtained in the calculation. This difference can be caused by the following reasons: 1) Differences in the methodology and formulas used. 2) The performance of the PV modules and inverters in *PVsyst* is based on a combination of the data from the manufacturer and experimental data, while the technical data considered in the calculation is entirely based on manufacturer's information. 3) Meteorological data used is from different sources and could have repercussions on the results.

PR and Specific Yield ($Yield_{SP}$) obtained are similar for both methodologies of calculation, with both parameters higher for the results obtained with *PVsyst*. The differences in these two values can be also caused by the factors listed above.

Scenario 2:

The results obtained with *PVsyst* for the second scenario are shown in Table 7.5, as well as the comparison with the results of Scenario 2 obtained in the previous calculations.

Table 7.5. Results obtained with PVsyst compared to results obtained in calculations for Scenario 2.

	PVsyst Scenario 2	**Calculations Scenario 2**
Tilt angle (summer/winter) [º]	20/50	14.2/53.7
Azimuth [º]	0	0
Number of PV modules in series	15	16
Number of PV modules in parallel	32,121 (divided into 14 sets)	2,165
Number of PV modules	481,815	484,960
Installed capacity [kWp]	53,000	53,350
Modules surface [m^2]	346,907	349,200
Number of inverters	14	14
AEP [MWh/year]	90,176	83,001
PR [%]	84.29	79.76
$Yield_{sp}$ [kWh/kWp]	1,701	1,555.9

The similarities and the differences between *PVsyst* simulation and calculations regarding optimum tilt angle and azimuth are the same as the ones explained for Scenario 1.

In this scenario the number of PV modules in series does not match between the results obtained in simulation (15 PV modules in series) and results obtained in calculations (16 PV modules in series). This difference between values is caused due to differences in criteria for sizing the PV set and differences in assess the maximum admissible voltage of the inverter. For the case of the results obtained in the calculations, the inverter is considered to withstand more input voltage than for *PVsyst* results. The number of PV modules in parallel is also different comparing the two different methodologies of calculation. Total number of parallel branches obtained in the simulation is 32,121 with approximately 2,294 PV modules in parallel per PV set. The difference can be caused do to the same reasons of the difference between the number of modules in series. The number of inverters obtained is the same for simulation and calculations. Due to differences in the number of modules in series and the modules in parallel between the two methodologies of calculation, the total number of PV modules obtained in the system is also different. For this scenario, the number of PV modules is higher for the calculation, 484,960 modules compared to 481,815 in the simulation. The difference between the number of PV modules between both calculation methodologies is around 0.7%. The difference in the number of modules is also directly linked with the difference in the installed capacity obtained for each calculation methodology. Installed capacity in calculations is 0.7% higher than the obtained value for the simulation in *PVsyst*.

Surface area occupied by the PV modules is higher in the calculations because the number of PV modules required is also higher.

AEP obtained for Scenario 2 is higher for the results obtained in the simulation. AEP in simulation is 90,176 MWh/year while the AEP obtained in calculations is 83,001 MWh/year, around 8.6% lower compared with the simulation. AEP in simulation is higher despite total installed capacity in calculations is higher compared to the result obtained in simulation, the following factors can be the responsible of this situation: 1) Losses considered in calculations are higher compared to the losses considered in the simulation. 2) Differences in the methodology and formulas used. 3) The performance of the components can be considered different in the calculations and *PVsyst* simulation. 4) Meteorological data used is from different sources. As PR and Specific Yield are PV plant performance indicators they are also higher for the results obtained with *PVsyst* which has higher AEP with lower installed capacity.

The simulation done for Scenario 2 in *PVsyst* shows the following warning message: "The power of the inverter is slightly undersized". This circumstance leads to high overload losses, in the limit of the acceptable values (3% or higher overload losses will be outside of the admissible limit). Overload losses obtained in this scenario are 2.5%. These losses are caused do to the inverters cannot withstand all the power output from the PV sets and the power output from these is curtailed in order to not to exceed the power input limit of the inverter.

Scenario 3:

The results obtained with *PVsyst* for the third scenario are shown in Table 7.6, as well as the comparison with the results of Scenario 3 obtained in the previous calculations.

Table 7.6. Results obtained with PVsyst compared to results obtained in calculations for Scenario 3.

	PVsyst Scenario 3	**Calculations Scenario 3**
Tilt angle (summer/winter) [º]	20/50	14.2/53.7
Azimuth [º]	0	0
Number of PV modules in series	18	18
Number of PV modules in parallel	8,767 (divided into 22 sets)	442
Number of PV modules	157,806	159,120
Installed capacity [kWp]	50,498	50,920
Modules surface [m^2]	309,643	309,400
Number of inverters	22	20
AEP [MWh/year]	82,829	77,679
PR [%]	81.26	78.17
$Yield_{sp}$ [kWh/kWp]	1,640	1,525.6

The number of PV modules in series is the same for the simulation and the calculations. The total number of parallel branches obtained in *PVsyst* simulation is 8,767 which divided by the number of inverters the result is approximately 399 PV modules in parallel per PV set. There is a significant difference between the number of PV modules in parallel obtained in simulation compared with the number obtained in calculations. This difference can be due to differences in the methodology of calculation. Due to the difference in the number of PV modules in parallel per PV set, the total number of PV modules is also different. For this scenario the total number of PV panels is higher in the calculations, 159,120 compared to 157,806 in the simulation. The higher number of modules in the calculations has impact on a higher installed capacity compared with the installed capacity obtained in the simulation. The number of modules obtained in calculations is around 0.8% higher than the number of modules in simulation, as well as the installed capacity in calculation is 0.8% higher than the installed capacity in simulation.

In this scenario, the number of inverters in calculations and simulation is not the same. The number of required inverters in simulation is 22, while the number of inverters obtained in calculations is 20. This disparity occurs due to differences in the methodology of calculation. According to results obtained in calculations, a lower number of inverters can withstand a higher number of PV modules compared to the results obtained in the simulation.

The results obtained regarding the surface occupied for the PV modules are not consistent. Higher surface is obtained in simulation where the number of PV modules is lower compared to result obtained in calculations. The inconsistency is caused to the surface area per PV module considered in the calculations is different compared to the one considered in *PVsyst.*

As it happens in Scenario 2, AEP is higher for the simulation in *PVsyst*, despite the total installed capacity is higher in results obtained in calculations. AEP calculated in simulation is around 6.6% higher compared to AEP in calculations. The factors which can make the AEP higher in simulation are the same factors which are explained for Scenario 2. Performance ratio and Specific Yield are also higher for the results obtained in the simulation.

Scenario 4:

The results obtained with *PVsyst* for the fourth scenario are shown in Table 7.7, as well as the comparison with the results of Scenario 4 obtained in the previous calculations.

Table 7.7. Results obtained with PVsyst compared to results obtained in calculations for Scenario 4.

	PVsyst Scenario 4	**Calculations Scenario 4**
Tilt angle (summer/winter) [º]	20/50	14.2/53.7
Azimuth [º]	0	0
Number of PV modules in series	10	10
Number of PV modules in parallel	47,273 (divided into 20 sets)	2,356
Number of PV modules	472,730	471,200
Installed capacity [kWp]	52,000	51,830
Modules surface [m^2]	340,366	339,300
Number of inverters	20	20
AEP [MWh/year]	85,730	80,541
PR [%]	81.68	79.62
$Yield_{sp}$ [kWh/kWp]	1,649	1,553.9

The number of PV modules in series is the same for both calculation methodologies. The total number of parallel branches in *PVsyst* simulation is 47,272, but the number of PV modules in parallel per PV set is approximately 2,364, which is a higher number compared to the number of PV modules in parallel obtained in calculations. This difference can be caused to different calculation procedures and different criteria when assessing the maximum admissible input current of the inverters. The difference in the number of modules in parallel has impact on the number of PV modules in the system. The number of PV modules obtained in simulation is 472,730 and the number of modules obtained in calculations is 471,200, around 0.3% lower compared to simulation. The number of inverters obtained in both calculation methodologies is the same (20 inverters). By looking at the installed capacity, the results obtained in the simulation are also around 0.3% higher than the results obtained in the calculations.

For this scenario, the AEP is higher for the results obtained with *PVsyst*, but for this scenario the total installed capacity is also higher in the *PVsyst* simulation. AEP obtained in the simulation is about 6% higher compared to AEP in calculations. In Scenario 1 are explained the factors which can cause this difference between values. PR and Specific Yield values are also higher for the results obtained with *PVsyst* simulation.

The simulation done for Scenario 4 in *PVsyst* shows the following warning message: “The power of the inverter is slightly undersized”. Overload losses in this scenario are 2.2%. Changing the installed capacity to 51 MW overload losses are reduced to 0.2% but reducing the installed capacity AEP is also reduced to 84,400 MWh/year.

7.1.3.1. Losses in the System Obtained with PVsyst

Total losses in the system obtained with *PVsyst* for Scenario 1 are shown in Figure 7.5:

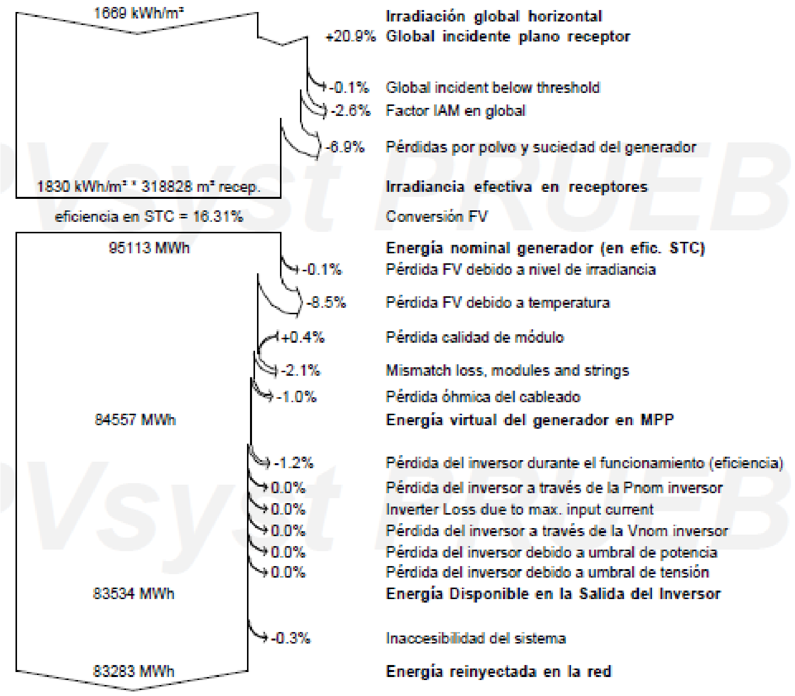

Figure 7.5. PVsyst total losses for Scenario 1.

Comparing the losses in the system obtained with *PVsyst* and the losses obtained in the calculations some differences can be appreciated. The differences in the results are majorly caused due to differences in the representation of the losses for each methodology. The efficiency of the process obtained with *PVsyst* for Scenario 1 is 13%, while the efficiency obtained in calculations is 17.4%. Global incidence below threshold (0.1%) and losses due to IAM (2.6%) are only considerate in *PVsyst* simulation. Total cable losses considered in simulation are 1%, while total cable losses considered in calculations (the combination of AC cable losses and DC cable losses) are 1.8%. Mismatch and maintenance losses are similar between simulation and calculations. The following losses considered in calculations are not considered in *PVsyst* simulations: shading losses, losses due to inverter MPP efficiency and transformer efficiency. Despite the efficiency in calculations is higher than in simulation, the AEP in simulation is considerably higher than in calculations although the installed capacity is similar between them. The inconsistency of the results is caused due to the efficiency in calculations is calculated considering the installed capacity as the first value in the process, while the efficiency in simulations is calculated considering the irradiance per unit area as the first value in the process. This situation is repeated for all the scenarios explained below.

Total losses in the system obtained with *PVsyst* for Scenario 2 are shown in Figure 7.6:

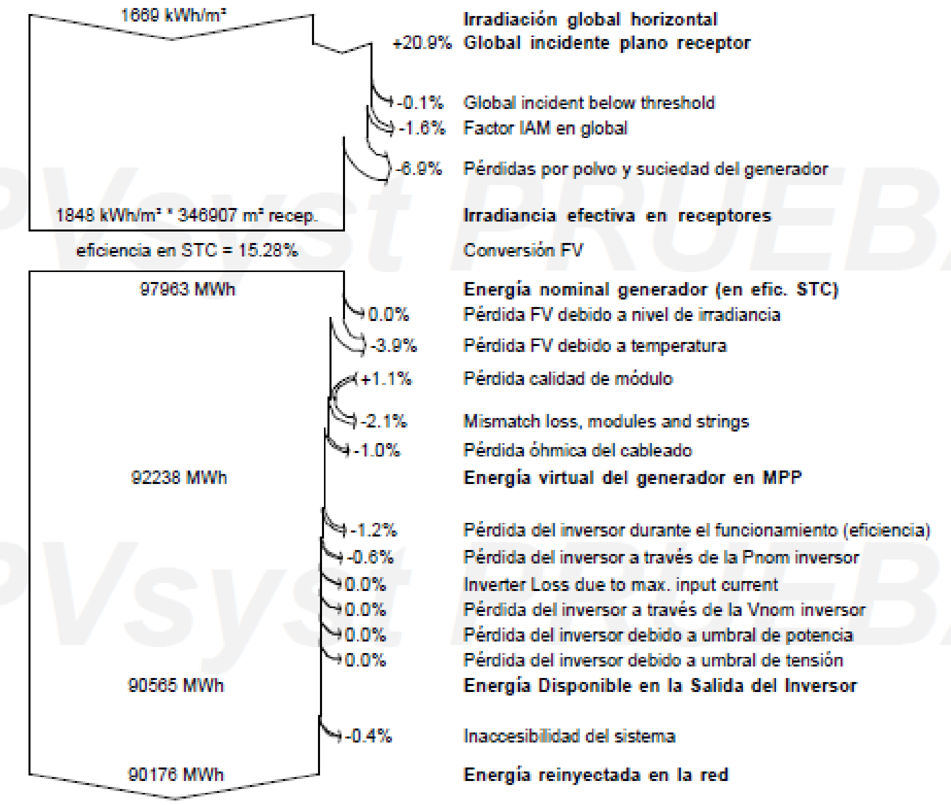

Figure 7.6. PVsyst total losses for Scenario 2.

The similarities and differences between the losses obtained in *PVsyst* simulation and the losses obtained in calculations for Scenario 2 are similar to those explained for Scenario 1. The main differences between the results obtained in both scenarios are the temperature losses, in this scenario temperature losses are 3.9%. Much lower value than temperature losses in Scenario 1 which are 8.5%. This great difference is caused due to different module technology employed. The difference in the efficiency of the process is not compared between simulation and calculations due to the inconsistency of the results (explained previously in Scenario 1).

Total losses in the system obtained with *PVsyst* for Scenario 3 are shown in Figure 7.7:

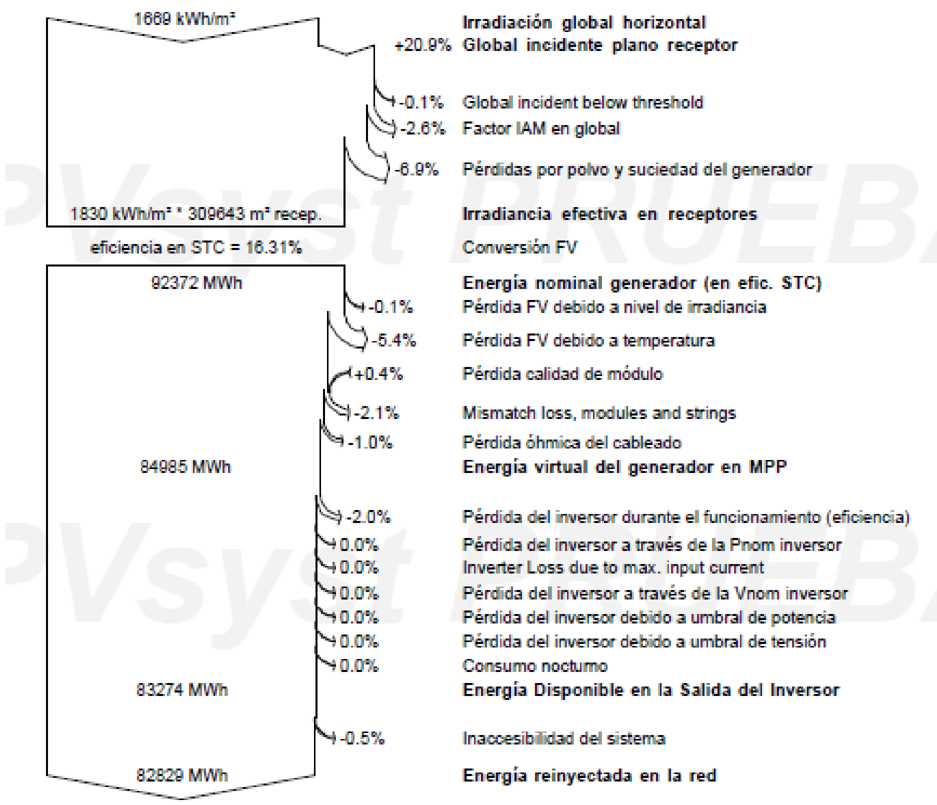

Figure 7.7. PVsyst total losses for Scenario 3.

The similarities and differences between the losses obtained in *PVsyst* simulation and the losses obtained in calculations for Scenario 3 are similar to those explained in the previous scenarios. The main difference is that for this scenario temperature losses are 5.4%. Once again, the efficiency of the process cannot be compared with the efficiency obtained in calculations for this scenario due to differences in the interpretation between both methodologies.

Total losses in the system obtained with *PVsyst* for Scenario 4 are shown in Figure 7.8:

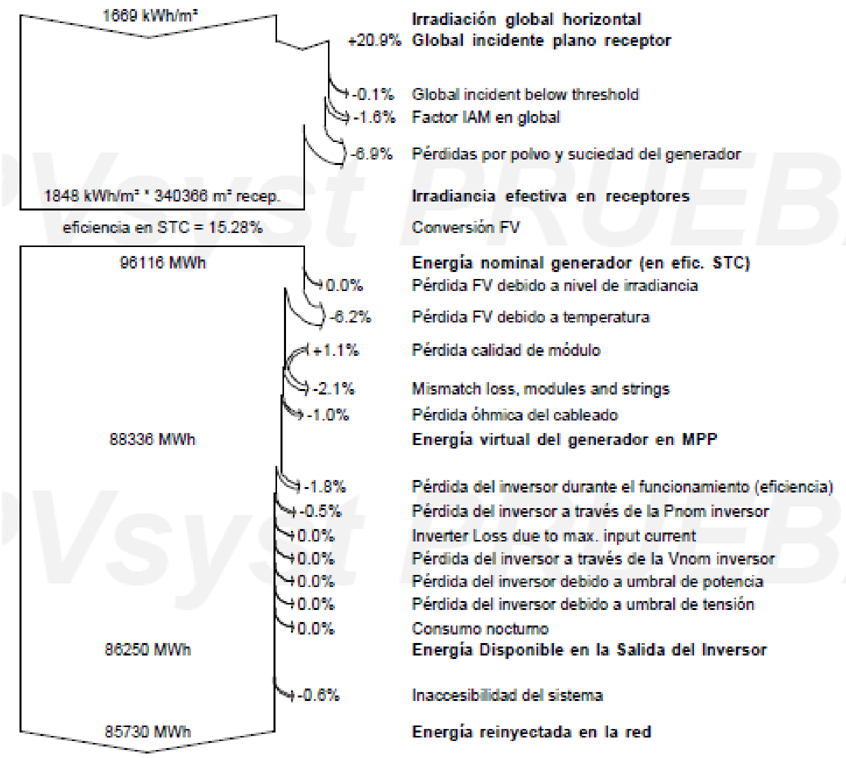

Figure 7.8. PVsyst total losses for Scenario 4.

The similarities and differences between the losses obtained in *PVsyst* simulation and the losses obtained in calculations for Scenario 4 are similar to those explained for the previous scenarios. With the only exception of the temperature losses which are 6.2% in this scenario. The efficiency obtained in calculations cannot be compared to the efficiency of the process in simulation due to calculation differences.

7.1.3.2. Economic Results Obtained with PVsyst

Table 7.8 shows the results obtained with *PVsyst* regarding the cost per component and service for each different scenario:

Table 7.8. PVsyst cost per component and service and the percentage they represent for each scenario.

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
Cost of the PV modules [€]	25,479,098 (55.06%)	21,464,858 (51.32%)	23,775,052 (53.99%)	21,060,122 (51.24%)
Cost of the inverters [€]	2,079,926 (4.49%)	2,180,767 (5.21%)	2,121,530 (4.82%)	1,928,548 (4.69%)
Cost of the transformers [€]	1,039,963 (2.25%)	999,999 (2.39%)	1,000,048 (2.27%)	999,988 (2.43%)
BOS cost [€]	3,639,872 (7.87%)	3,679,979 (8.80%)	3,635,225 (8.26%)	3,620,012 (8.81%)
Civil work and install. cost [€]	8,839,687 (19.10%)	8,499,992 (20.32%)	8,500,405 (19.30%)	8,499,898 (20.68%)
Cost of the land [€]	5,199,816 (11.24%)	4,999,995 (11.95%)	5,000,238 (11.36%)	4,999,940 (12.16%)
TOTAL capital cost [€]	46,278,362 (100%)	41,825,590 (100%)	44,032,498 (100%)	41,108,508 (100%)

The following information can be obtained from Table 7.8:

- Cost of the PV modules represents the highest share of the capital cost for all the scenarios. Cost of the PV modules is in the range from 21 M€ to 25 M€, with a percentage of the total cost in the order of 50%. The scenarios with the highest cost are the scenarios using poly-Si modules. The cost of the modules obtained with *PVsyst* simulation is in accordance with the cost obtained in calculations where the cost of the modules is in the same range (see Table 6.8).
- The cost of the inverters represents about 5% of the total capital cost, and it is in the order of 2 M€ for all the scenarios. Comparing the cost of the inverters obtained in the simulation with the cost of the inverters obtained in calculations, it can be seen that cost of the inverters in calculations is lower, in the order of 1.7 M€. This discrepancy can be caused due to differences in installed capacity between simulation and calculations.
- The cost of the transformers is in accordance between the simulation and the calculation. In both cases cost of the transformers are in the order of 1 M€ and they represent around 2.5% of the total capital cost.
- BOS cost is also in accordance between both different calculation methodologies, being the BOS cost obtained in calculations slightly lower. BOS cost in simulation is in the order of 3.6 M€ for all the scenarios and BOS cost obtained in calculations is in the range from 3.7 M€ to 3.9 M€, the share that it represents is also slightly higher for the results in calculations.

- Civil work and installation cost in *PVsyst* simulation is in the range from 8.5 M€ to 8.8 M€, and it represents around 20% of the total capital cost. This cost in results obtained in calculations is in the same range.
- Cost of the land represents around 12% of the total capital cost and it is in accordance with the cost of the land previously obtained by means of calculations.
- The highest capital cost obtained in calculations is the corresponding to Scenario 1 with 46.3 M€. In calculation the highest capital cost obtained is also the corresponding to Scenario 1 with 46.1 M€. The second highest capital cost is the corresponding to Scenario 3 with 44 M€, which coincides with the second highest scenario in calculations which it is also Scenario 3 with 44.5 M€. The scenario with the lowest capital cost is Scenario 4 both for simulation and calculations with 41.1 M€ and 41.2 M€ respectively.

Table 7.9 shows the comparison of O&M cost between *PVsyst* simulation and the results obtained previously in calculations.

Table 7.9. PVsyst and calculations O&M costs obtained for each scenario.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
PVsyst O&M cost [€/year]	519,982	899,999	729,035	769,491
Calculations O&M cost [€/year]	769,060	820,990	742,390	797,690

O&M cost in Scenario 3 and 4 are close to the values obtained in the calculations, the difference is lower than 4% between both methodologies. O&M cost obtained in simulation for Scenario 2 is around 9.6% higher than the O&M cost for calculations. The greatest difference is found in Scenario 1, where O&M cost obtained in simulation is 47.9% lower than O&M cost obtained in calculations. These discrepancies can be caused due to differences in the number of PV modules installed in the system.

Table 7.10 shows the comparison of LOCE between the results obtained with *PVsyst* simulation and the results obtained previously in calculations.

Table 7.10. PVsyst and calculations LCOE values obtained for each scenario.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
PVsyst LCOE [c€/kWh]	3.0000	3.0000	3.0000	3.0000
Calculations LCOE [c€/kWh]	3.3284	3.1154	3.3303	3.1160

LCOE calculated by means of *PVsyst* is the same for all the scenarios (3 c€/kWh). The scenario with highest similarity of values between simulated and calculated is Scenario 2, where LCOE obtained in simulation is 3.8% lower than LCOE obtained in calculations. The scenario with the highest difference between LCOE values is Scenario 3, where LCOE obtained in simulation is 11% lower than LCOE obtained in calculations. In summary, the results obtained in calculations regarding the LCOE do not differ in excess from the values obtained in the simulation. The lower LCOE values obtained in simulations comparing with the LCOE values obtained in the calculations are caused due to a higher AEP with a similar total cost.

7.2. SAM MODELLING

Another PV software which can be used to compare and verify the results obtained in the calculations is *System Advisor Model* (*SAM*), developed by *National Renewable Energy Laboratory (NREL).* The steps followed to design the PV system are shown below:

- Location and resource definition: Since *SAM*'s library does not include the meteorological data of the selected location (location of *l'Albagés*), the required data is obtained from solar resource external library [59]. The profile of the global irradiance obtained for the location with the coordinates 41.45ºN and 0.75ºE is shown in Figure 7.9.

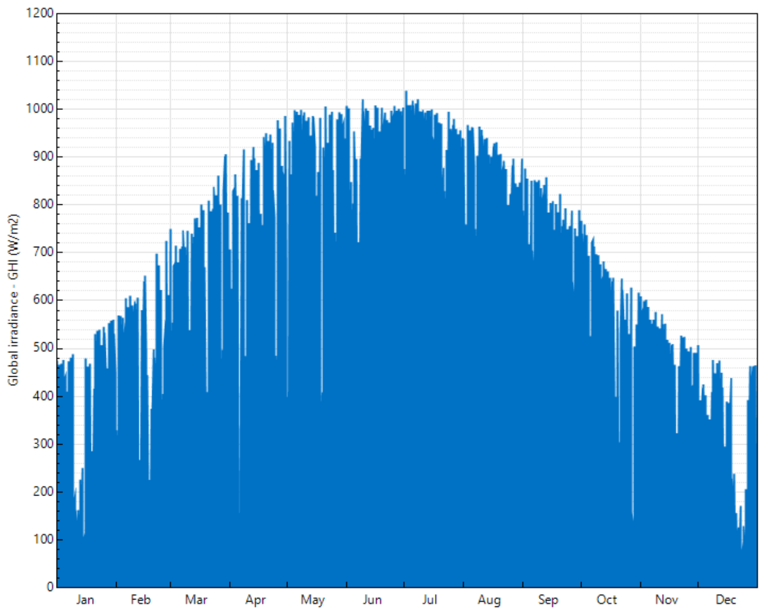

Figure 7.9. Annual global irradiance profile of the selected location.

- Module selection: For scenario 1 and 4, using the same type of module, *Trina Solar TSM-320PE14A* is selected from *SAM*'s library. For Scenarios 2 and 3 the module selected from the library is *First Solar FS-4110-3*. Once the PV modules is selected the I-V curve, and other useful parameters are obtained for each of the modules.
- Inverter selection: The selected inverter for Scenarios 1 and 2 is *Sungrow SG3000HV* and it is not available on *SAM's* library, therefore the specifications are introduced from the manufacturer's datasheet. For the case of the inverter used in Scenarios 3 and 4 (*Kaco New Energy blueplanet 2200 TL3)* the inverter is already available on *SAM's* library.
- System sizing: The size and configuration of the PV plant is obtained by specifying the installed capacity. Depending on the scenario being analysed this installed capacity will vary in order to make the conditions of the simulation more similar to the calculations. Number of PV modules, modules per series, strings in parallel and total area is automatically calculated and optimized

taking into account weather conditions, modules selected, inverters selected and the desired array size.

- Tracking and orientation: The tracking system of the PV power plant is defined as seasonal tilt; where the tilt angle during winter months is set at 53.7º and the tilt angle during summer season is set at 14.2º (same values as used in calculations). Azimuth angle is defined fixed south-facing 180º (depending on the reference is 0º). By introducing these values and the install capacity of the plant, the total area occupied by the PV modules is automatically calculated.
- String configuration: this parameter is not defined because the configuration of the modules in the PV plant has not been analysed in calculations.
- Shading and snow losses: shading losses have been kept with default values from *SAM*, due to there is not available a 3D model of the PV plant to study in detail that type of losses. Snow losses are not considered since the location selected has not a high risk of snowing.
- Losses: Soiling losses, losses due to the dirt deposited on the PV module surface, are set at 6.9% for every month of operation as literature [37] suggest (same as soiling losses in calculations). DC wiring losses are kept with default values applied for central inverters. AC wiring losses are assumed in 1% and the transformer losses are not considered. Curtailment and availability is defined as constant losses of 0.5% (same as maintenance losses considered in calculations).
- Financial parameters: Capital cost is introduced in *SAM* interface depending on the scenario analysed. The cost in $/kW is calculated by dividing the capital cost obtained in calculations by total installed capacity. The same procedure is followed to calculate O&M cost. Fixed charge rate is not modified from the default value provided by *SAM.*

7.2.1. Results Obtained with SAM

Once the system is modelled as explained above, the results obtained with *SAM* can be compared with the results obtained in the calculations. Table 7.11 shows the results obtained with *SAM* for each scenario.

Table 7.11. Results obtained with SAM.

	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
Tilt angle (summer/winter) [º]	14.2/53.7	14.2/53.7	14.2/53.7	14.2/53.7
Azimuth [º]	180	180	180	180
No. of PV modules	164,749	485,712	159,024	471,609
No. of PV modules in series	29	16	16	9
No. strings in parallel	5,681 (divided into 18 sets)	30,357 (divided into 18 sets)	9,939 (divided into 25 sets	52,401 (divided into 26 sets)
Total module area [m^2]	319,613	327,755	308,506	339,558
Number of inverters	18	18	25	26
Capacity installed [kWp]	52,748	53,349	50,915	51,780
AEP [MWh/year]	91,433	94,891	85,202	91,007
PR [%]	81	83	78	82
CF [%]	19.8	20.3	19.1	20.1
Y_{sp} [kWh/kWp]	1,733	1,779	1,673	1,757
LCOE [c$/kWh]	7.14	6.52	7.39	6.55

The following information can be obtained from the comparison between the results obtained with *SAM* and the results obtained in calculations:

- Tilt angle obtained in *SAM* simulation is 14.2º in summer and 53.7º in winter for all the scenarios analysed. These values are not a result of an optimization process by means of a simulation, but they are manually introduced by looking at the values obtained in the calculations. The same happens with azimuth angle, which is 180º (south facing) for all the scenarios.
- For all the scenarios analysed the number of PV modules obtained in simulation is in accordance, with slight variation, with the number of PV modules obtained in the calculations: For Scenario 1 the number of PV modules obtained in the simulation is only a 0.05% lower than the number obtained in the calculations; For Scenario 2, the number of modules obtained in

simulation is 0.16% higher; For Scenario 3, number of modules obtained in simulation is 0.06% lower. Finally, for Scenario 4, the number of modules in simulation is 0.08% higher.

- The number of modules in series is the same for the simulation and the calculations for Scenarios 1 and 2, these two scenarios are considered using the same type of inverter. But, there is a difference of 1 module between simulation and calculations in Scenario 2 and 4, using the same inverter between them.
- The comparison of the number of PV panels in parallel is done considering the number of parallel branches per PV set. For Scenarios 1 and 2, using inverters *Sungrow SG3000HV*, the difference between the number of PV modules in parallel per PV set obtained in calculations and simulation is 29% for Scenario 1 and 28% for Scenario 2, being the results of calculations higher. For Scenarios 3 and 4, using inverters *Kaco new energy blueplanet 2200TL3*, the difference is not that great. The number of modules in parallel in Scenario 3 in simulation is 11% lower, and the number of modules in parallel in Scenario 4 is 17% lower.
- The number of inverters obtained in simulation is the same for Scenario 1 and 2 (18 inverters) but comparing these number with the results obtained in calculations there is a difference of 4 inverters more for both scenarios. For Scenario 3 the result obtained in simulation is 5 inverters more than in calculations, and for Scenario 4 the result obtained in simulation is 6 inverters more than in the calculations.
- The capacity installed obtained in simulation is in accordance with the capacity installed in calculations. Installed capacity obtained in simulation in all the scenarios is less than 0.1% lower than the results obtained in calculations. The difference of the capacity installed between simulation and calculations is caused due to the nominal power of the PV modules considered. In the calculations the nominal power of the modules is obtained from manufacturer and the nominal power of the PV modules in *SAM* is obtained with a combination of data from the manufacturer and experimental data. The difference of the number of PV modules can be also explained because of this circumstance.
- AEP obtained in the simulations present higher values than AEP obtained in calculations: Scenario 1 in simulation is 13.5% higher than AEP in calculations; Scenario 2 has an AEP obtained in simulation 14.3% higher; Scenario 3 is 9.7% higher; and Scenario 4 is 13% higher. This can be caused due to lower losses considered in SAM's simulation or discrepancies in the calculations between both methodologies.
- PR obtained in the simulations are around 80% for all scenarios, being the PR obtained for Scenario 2 the highest with 83%. The PR obtained in the calculations are slightly lower (around 79%), but the scenario with the highest PR is also Scenario 2 with 79.73%.
- CF obtained in the simulations are around 20%, and the highest CF is the corresponding to Scenario 2 with 20.3%. CF obtained in the calculations are lower, these parameters are in the

order of 17.5% for all scenarios. The highest CF in calculations is also the corresponding to Scenario 2 with 17.76%.

- Specific Yields obtained in simulations are higher than the ones obtained in calculations. The scenario with the highest $Yield_{sp}$ is Scenario 2 with 1,779 kWh/kWp. The scenario in calculations with the highest $Yield_{sp}$ is also Scenario 2 with 1,555.9 kWh/kWp.
- The scenario with the highest LCOE obtained in simulations is the corresponding to Scenario 3 with 7.39 c$/kWh, approximately 6 c€/kWh. The highest LCOE obtained in calculations is also the corresponding to Scenario 3 with 3.3303 c€/kWh, but the difference between values obtained in both methodologies is more than significant. The lowest LCOE obtained in simulations is the corresponding to Scenario 2 with 6.52 c$/kWh, approximately 5.5 c€/kWh. The scenario with the lowest LCOE in simulation is in accordance with the scenario with the lowest LCOE in calculations, which it is also Scenario 2 with 3.1154 c€/kWh. In summary, the difference between the LCOE results obtained in *SAM* and the results obtained in calculations is remarkable, for all the scenarios analysed the LCOE obtained in simulations are more than 70% higher than the values obtained in calculations. This considerable difference regarding the LCOE can be caused due to *SAM* obtain the value by means of using financial parameters which are not used in the calculations.
- The losses obtained with *SAM* are similar for all the scenarios analysed (in Figure 7.10 it can be seen the losses diagram for Scenario 2 as example). The most important losses obtained in the simulations are: soiling, about 6.9% for all the scenarios; modules losses, 6.8% for poly-Si modules and 4.3% for CdTe modules; mismatch losses, around 2% for all the scenarios; DC wiring losses, around 2%; availability and curtailment (maintenance), 0.5%; losses due to inverter efficiency, 1.3 % for Scenarios 1 and 2, 1.6% for Scenarios 3 and 4; AC wiring losses, around 1% for all the scenarios. The process efficiency for Scenario 1 is 13.3%, for Scenario 2 is 12.6%, for Scenario 3 is 12.85% and for Scenario 4 is 12.5%. The efficiencies obtained in the simulation are lower than those obtained in the calculations.

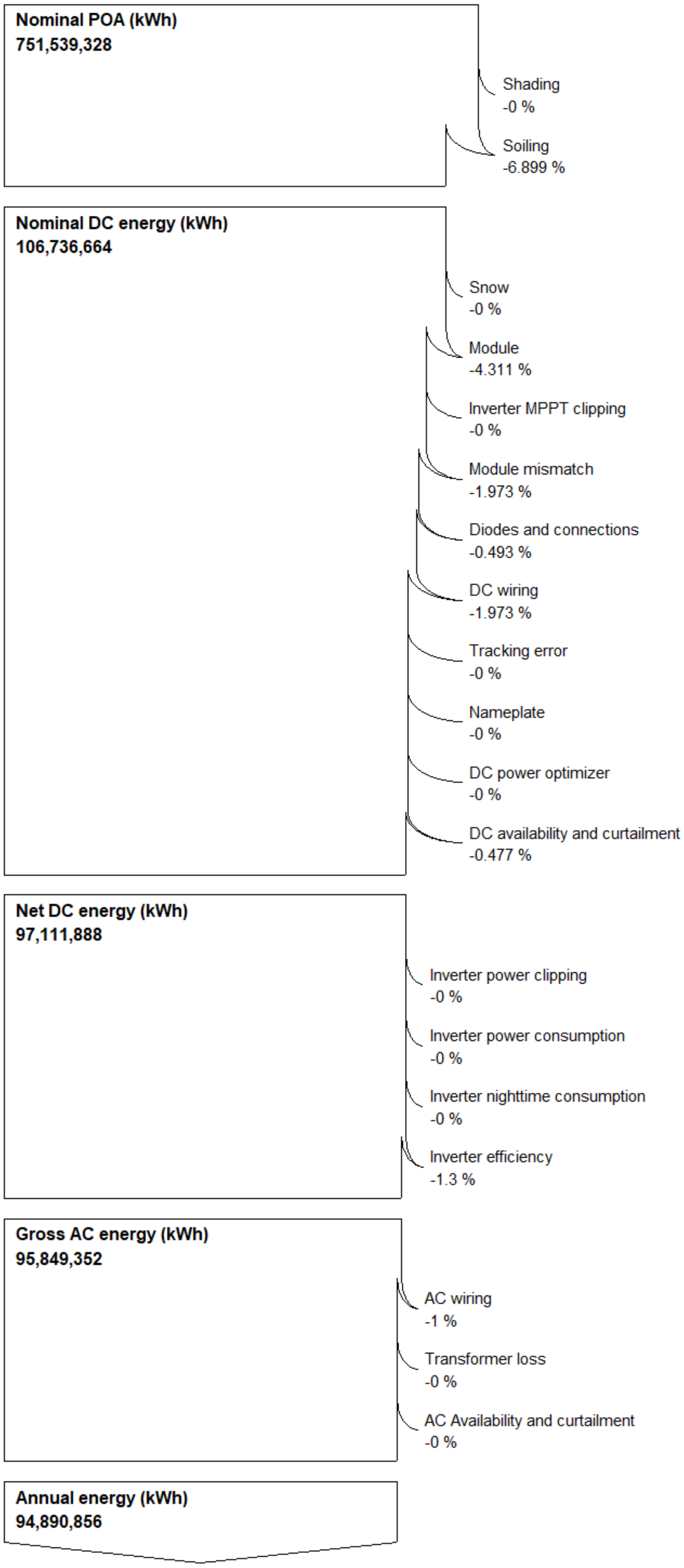

Figure 7.10. Losses diagram obtained wit SAM for Scenario 2.

8. CONCLUSIONS

During the calculations, four different PV solar power plant scenarios are compared, the scenarios analysed combine two different modules and two different inverters. The main objective of this project is to design a PV solar power plant of 50 MW and to do that a calculation methodology is implemented and the different scenarios are compared between them to obtain the best possible configuration. Once the results are obtained through the calculations, these results are compared and verified by means of specialized software (*PVsyst* and *SAM*). The conclusions obtained from the project realisation are shown below:

- The capacity installed is different in each scenario calculated and also the capacity installed in all the scenarios is higher than the design capacity of 50 MW. This is caused due to: 1) the number of inverters in the system has to be an integer number, thus the formula used to obtain the number of inverters uses a function which round the result to the nearest integer greater than the result. 2) It is considered that all the PV sets forming the PV plant have the same number of PV modules.
- The number of modules, their configuration (number of modules in series and in parallel) and the number of inverters is different for all the scenarios calculated. The disparity of these design parameters is exclusively caused due to the module and inverter technology used for each scenario.
- The order of magnitude of AEP calculated is around 80,000 MWh/year for all the scenarios analysed. The results obtained in the calculations regarding the AEP are in accordance with the capacity installed. The scenario with the highest installed capacity is also the scenario with highest AEP, and this relation between installed capacity and AEP is maintained for all the scenarios.
- The losses in the system considered in all scenarios are: losses due to the effect of irradiance and temperature in the PV modules, soiling losses, shading losses, losses due to MPP efficiency of the inverter, PV modules mismatch losses, DC side cable losses, losses due to inverter efficiency, power losses due to power restrictions in the inverter, losses due to transformer efficiency, AC side cable losses and losses and losses due to maintenance of the system (energy availability factor). The energy obtained for all the scenarios is approximately about 17.5% of the installed energy, and the scenarios which presents the best process efficiency are the scenarios using CdTe thin-film modules.
- The capital costs calculated for the different scenarios are in the range from 41 M€ to 46 M€. The components of the PV plant which contributes more to the capital cost are the PV modules with approximately about 50% of the capital cost. Other components and services with important share of the capital cost are the civil work and installation cost and cost of the land,

with about 20% and 12% receptively. The differences in the capital cost obtained for the different scenarios are minimal and they are result of the differences in the installed capacity and the module and inverter technology employed. Capital cost represents about 70% of the total cost associated with the PV plant project.

- The O&M costs calculated are in the range from 740,000 €/year to 820,000 €/year depending on the scenario analysed. The magnitudes of the O&M costs calculated depend exclusively on the installed capacity of the PV plant scenario. The scenario with the highest O&M cost is the scenario with the highest installed capacity, and this relation in maintained for all the scenarios. O&M costs represent about 30% of the PV plant total costs.
- The LCOE calculated for the four different scenarios is similar between them, although with slight differences. The scenarios which have a lower LCOE are the scenarios using CdTe modules. Scenario 2 using *FirstSolar FS-4110-3* modules and *Sungrow SG3000HV* inverters is the scenario with the lowest LCOE with 3.1154 c€/kWh.
- For all the scenarios the economic viability of the project is guaranteed. The four scenarios present positive NPV and IRR. The scenario with the best results regarding NPV and IRR is Scenario 2.
- For all the scenarios the performance ratio (PR) calculated is almost 80%, and the scenario with the highest PR is Scenario 2 with 79.73%. The capacity factor (CF) calculated presents values close to 18%, being the CF of Scenario 2 the highest with 17.76%. The same happens with the specific yield ($Yield_{SP}$) calculated where the values of the different scenarios are similar between them, and the highest value of $Yield_{SP}$ corresponds to Scenario 2 with 1,555.9 kWh/kWp.
- The results obtained with *PVsyst* are in accordance with the results obtained in the calculations. Depending on the scenario some of the design parameters obtained in *PVsyst* and the parameters obtained in calculations are equal, in most of the scenarios the number of modules in series and the number of inverters in the system are the same for both calculation methodologies. Some other parameters slightly differ between the simulation and the calculation, e. g. the number of PV modules in parallel and the total number of PV modules in the PV plant. The AEP obtained *PVsyst* is higher than the AEP obtained in calculations for all the scenarios, the difference is in the range from 2.2% for the scenario with the greatest similarity, to 8.5% for the scenario presenting the highest difference. Capital and O&M costs obtained in *PVsyst* are in the same order of magnitude as the values obtained in the calculations.
- Regarding the LCOE values obtained with *PVsyst*, they are also in accordance with LCOE obtained in calculations. The LCOE obtained in *PVsyst* is 3c€/kWh and it is the same for all the scenarios. The differences between LCOE obtained in *PVsyst* and obtained in calculations

are in the range from 3.8% for the scenario with the greatest similarity, to 11% for the scenario with the highest difference.

- The results obtained with *SAM* are comparable with the results obtained in the calculation with slight differences. The difference in the number of modules in the system between the results obtained with SAM and the results obtained in calculations is less than 1% for all the scenarios, as well as the difference in installed energy. The number of PV modules obtained with *SAM* is the same as the number obtained in calculations for two scenarios, and for the rest of scenarios the difference is minimal. The number of modules in parallel per PV set presents higher differences between the simulation and calculations, the difference is 29% for the scenario with the highest difference and 11% for the scenario with the greatest similarity. Regarding the AEP obtained with *SAM* it presents higher values than the AEP obtained in calculations. The difference of the scenario with the greatest difference is 14.3% and the difference of the scenario with the lowest difference is 9.7%. The scenario with the highest AEP both for *SAM* and calculations is Scenario 2. PR, CF and $Yield_{SP}$ obtained in *SAM* are in accordance with values obtained in calculations, being the values corresponding to Scenario 2 the highest among all the scenarios.
- The LCOE values obtained with *SAM* are in discrepancy with the values obtained in the calculations. This is due two different calculation methodologies have been used to obtain this parameter. The LCOE obtained with *SAM* is calculated by means of Fixed Charge Rate (FCR) methodology where some financial parameters such as recovery factor, project financing factor and construction financing factor are used during calculations. The factors used in FCR methodology are not used in calculations.

In summary, the calculation methodology for a large-scale PV plant design implemented works correctly, since the results obtained in the calculations are similar to the results obtained in literature and similar to results obtained by means of *PVsyst* and *SAM* simulations. The scenario presenting the best results is Scenario 2 which it has the highest AEP, the highest PR, CF and $Yield_{SP}$ and also has the lowest LCOE.

8.1. Future Work

Even though the results obtained in the calculations can be considerate valid, some improvements can be made in the calculation methodology in order to have more accurate results. The following aspects of the PV plant design can be carried out in the future in order to improve the current project.

- Obtain more accurate meteorological data. One of the causes of the differences between the values obtained in simulations and the values obtained in the calculations is because of the disparity of the meteorological data employed in the different methodologies.

- Design the configuration of the components inside the PV plant. By knowing the configuration of the components, and in particular the configuration of the PV modules (optimum inter-row spacing and space for corridors) the magnitude of the shading losses affecting the PV modules can be obtained in a more accurate manner. A 3D model of the PV plant can be designed in order to obtain the shading losses. Furthermore, by knowing the configuration of the components inside the PV plant, AC and DC cables can be properly sized and their voltage drop calculated.
- Another important aspect that can be improved in future work is the methodology calculation of the number of PV modules in series and parallel. In the current project the number of modules in series and in parallel per inverter is equal to the maximum number of modules in series and in parallel admissible per inverter. An improvement regarding these design parameters would be to implement an optimization process to obtain the best modules-inverter configuration.
- Study in more detail which are the grid requirements and calculate if the PV plant designed meet those requirements, if not recalculate the design parameters. Furthermore, obtain the cost associated with grid connections.
- Carry out a study more in-depth regarding the cost associated to the PV plant analysed. Try to obtain the cost of the components/services for a PV project located in Europe, since almost all the cost assumptions made in the project are based on reports developed for North America.
- Include an environmental analysis of the PV project. Obtain the primary energy consumption to implement a large-scale PV plant and calculated the CO_2 savings compared to other traditional electricity generating technology.
- Try to execute the calculation methodology developed with other PV panels, inverters, with different tracking system or located in another site, and examine if the results are in accordance with the results previously obtained.

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ANNEX A

A. PV PLANT DESIGN METHODOLOGY. MATLAB CODE

A. 1. DESIGN AND ENERGY CALCULATIONS

```
Pplantnom = 50;                              % (MW) PV power plant design capacity
for i=1:length (module)                      % Provisional number of PV modules required
    Npv(i) = Pplantnom * 10^6 / Pmstc(i);
    Npv(i) = ceil (Npv(i));
    Spv(i) = len(i) * width(i);              % (m^2) Surface of each PV module
    Sarray(i) = Spv(i) * Npv(i) * 1e-6;      % (km^2) Provisional area occupied by the PV modules
end
```

Figure A.1: N_{PV} and S_{array}

```
% Calculation of the maximum number of PV modules in series and parallel
for i=1: length (inverter)
    for j=1: length (module)
        Vmid(i) = (Vimax(i) + Vimin(i))/2;
        Nsmax(i,j) = floor (Vmid(i) / Vmmax(j));
        while Nsmax(i,j) * Vocmax(j) > Vdcmax(i)
            Nsmax(i,j) = Nsmax(i,j) - 1;              % Maximum number of PV modules in series
        end
        Npmax(i,j) = floor (Idcmax(i)/Immax(j));      % Maximum number of PV modules in parallel
end
end
```

Figure A.2: $N_{s,max}$ and $N_{p,max}$

```
% Number of inverters calculation
Ni1 = ceil(Npv(1)/(Nsmax(1,1) * Npmax(1,1)));   % Number of inverters/number of PV sets - Scenario 1
Ni2 = ceil(Npv(2)/(Nsmax(1,2) * Npmax(1,2)));   % Number of inverters/number of PV sets - Scenario 2
Ni3 = ceil(Npv(1)/(Nsmax(2,1) * Npmax(2,1)));   % Number of inverters/number of PV sets - Scenario 3
Ni4 = ceil(Npv(2)/(Nsmax(2,2) * Npmax(2,2)));   % Number of inverters/number of PV sets - Scenario 4
```

Figure A.3: Ni

```
% Final number of PV modules
Npv1 = Nsmax(1,1) * Npmax(1,1) * Ni1;  % Scenario 1
Npv2 = Nsmax(1,2) * Npmax(1,2) * Ni2;  % Scenario 2
Npv3 = Nsmax(2,1) * Npmax(2,1) * Ni3;  % Scenario 3
Npv4 = Nsmax(2,2) * Npmax(2,2) * Ni4;  % Scenario 4

% Final surface area occupied by the PV modules
Sarray1 = Spv(1) * Npv1 * 1e-6;     % (km^2) Scenario 1
Sarray2 = Spv(2) * Npv2 * 1e-6;     % (km^2) Scenario 2
Sarray3 = Spv(1) * Npv3 * 1e-6;     % (km^2) Scenario 3
Sarray4 = Spv(2) * Npv4 * 1e-6;     % (km^2) Scenario 4

% Final installed capacity (MWdc)
Pinstall1 = Npv1 * Pmstc(1) * 1e-6;  % Scenario 1
Pinstall2 = Npv2 * Pmstc(2) * 1e-6;  % Scenario 2
Pinstall3 = Npv3 * Pmstc(1) * 1e-6;  % Scenario 3
Pinstall4 = Npv4 * Pmstc(2) * 1e-6;  % Scenario 4
```

Figure A.4: $N_{pv,final}$, $P_{installed}$ and $S_{array,final}$

```
% Actual Power Output of each PV module
for i=1:length(time)
    for j=1:length(module)
    Tm(i,j)= Tamb(i) + (irradiance(i)/800) * (NOCT(j)-20);                    % (°C) Temperature of each solar module
    Pm(i,j)= Pmstc(j) * (irradiance(i)/1000) * (1 - gamma(j) * (Tm(i,j) - 25)); % (W) MPP power of each module
    Pmtot = sum(Pm);                                                            % (Wh/year) Energy at MPP power of each module
    Ppv(i,j)= (1 - (df/100)) * (1 - (Sp/100)) *  Pm (i,j);                      % (W) Actual outpt power of each PV module
    Ppvtot = sum(Ppv);                                                          % (Wh/year) Energy at actual outpt power of each PV module
    Ppvlosses = Pm(i,j)- Ppv(i,j);                                              % (W) Losses due to dirt and shading effect for each PV module
    Ppvlossestot = Pmtot - Ppvtot;                                              % (Wh/year) Energy losses each PV module
    end
end
```

Figure A.5: T_M, P_M, P_{PV} and $P_{PV,losses}$

```
Pin1 = Nsmax(1,1) * Npmax(1,1) * (nmppt/100) * (1- (ndc/100)) * (1- (nmis/100)) * Ppv (:,1);   % (W) Power output of each PV set. SCENARIO 1.
Pin1tot = sum(Pin1);                                                                          % (Wh/year) Energy output of each PV set
```

Figure A.6: P_{in}

```
for i=1:length(Pin1)                                  % (W) Power output of each dc/ac inverter SCENARI
    if Pin1(i) < Pisc(1)
        Po1(i) = 0;
    else
        if Pin1(i) <= Pina(1)
            Po1(i) = ninv(1) * Pin1(i);
        else
            Po1(i) = ninv(1) * Pina(1);
        end
    end
end
Po1tot = sum(Po1);                                    % (Wh/year) Energy output of each dc/ac inverter
```

Figure A.7: P_o

```
% Land occupied by the PV solar power plant
land1 = max(Po1) * Ni1 * 1e-6 * landrel;        % (km2)SCENARIO 1
land2 = max(Po2) * Ni2 * 1e-6 * landrel;        % (km2)SCENARIO 2
land3 = max(Po3) * Ni3 * 1e-6 * landrel;        % (km2)SCENARIO 3
land4 = max(Po4) * Ni4 * 1e-6 * landrel;        % (km2)SCENARIO 4
```

Figure A.8: Land

```
% Power that PV plant can inject into the grid
Pplant1 = nt * ncable * Po1 * Ni1 * 1e-6;       % (MW) SCENARIO 1
Pplant1tot = sum(Pplant1);                      % (MWh/year)
Pplant2 = nt * ncable * Po2 * Ni2 * 1e-6;       % (MW) SCENARIO 2
Pplant2tot = sum(Pplant2);                      % (MWh/year)
Pplant3 = nt * ncable * Po3 * Ni3 * 1e-6;       % (MW) SCENARIO 3
Pplant3tot = sum(Pplant3);                      % (MWh/year)
Pplant4 = nt * ncable * Po4 * Ni4 * 1e-6;       % (MW) SCENARIO 4
Pplant4tot = sum(Pplant4);                      % (MWh/year)
```

Figure A.9: P_{PLANT}

```
% Energy prodution
deltatime = 1;                                % time step of 1 hour
Eplant1 = EAF * Pplant1 * deltatime;          % (MWh)      SCENARIO 1. Energy produced in the PV power plant for each time instant
Eplant1tot = sum(Eplant1);                    % (MWh/year) SCENARIO 1. Total energy injected into the grid
Eplant2 = EAF * Pplant2 * deltatime;          % (MWh)      SCENARIO 2. Energy produced in the PV power plant for each time instant
Eplant2tot = sum(Eplant2);                    % (MWh/year) SCENARIO 2. Total energy injected into the grid
Eplant3 = EAF * Pplant3 * deltatime;          % (MWh)      SCENARIO 3. Energy produced in the PV power plant for each time instant
Eplant3tot = sum(Eplant3);                    % (MWh/year) SCENARIO 3. Total energy injected into the grid
Eplant4 = EAF * Pplant4 * deltatime;          % (MWh)      SCENARIO 4. Energy produced in the PV power plant for each time instant
Eplant4tot = sum(Eplant4);                    % (MWh/year) SCENARIO 4. Total energy injected into the grid
```

Figure A.10: $E_{PLANT,TOT}$

A. 2. ECONOMIC CALCULATIONS

```
% Capital cost (€)
Cmodules1 =  Ni1 * Nsmax(1,1) * Npmax(1,1) * (Pmstc(1)/1000) * (PVcost(1) * usdeur);  % (€) cost of the PV modules array
Cinverters1 = Ni1 * (Prated(1)/1000) * (Invcost(1) * usdeur);                         % (€) Total cost of the inverters
Ctrafo1 = cit * (Ni1 * Nsmax(1,1) * Npmax(1,1) * (Pmstc(1)/1000));                    % (€) Step-up transformers cost
Cbos1 = BOS * (Ni1 * Nsmax(1,1) * Npmax(1,1) * (Pmstc(1)/1000));                      % (€) BoS cost of the PV plant
Cconsinstall = ccivil * (Ni1 * Nsmax(1,1) * Npmax(1,1) * (Pmstc(1)/1000));            % (€) Construction & installation cost
Cland1 = cl * land1 * n;                                                              % (€) Total cost of the land
Cplant1 = Cmodules1 + Cinverters1 + Ctrafo1 + Cbos1 + Cconsinstall + Cland1;          % (€) Total capital cost of the PV power plant
```

Figure A.11: C_c

```
% Present value of the maintenance cost (€)
Cm1 = Ni1 * Nsmax(1,1) * Npmax(1,1) * (Pmstc(1)/1000) * Mplantcsi * n * usdeur;   % SCENARIO 1
Cm2 = Ni2 * Nsmax(1,2) * Npmax(1,2) * (Pmstc(2)/1000) * Mplantcdte * n * usdeur;  % SCENARIO 2
Cm3 = Ni3 * Nsmax(2,1) * Npmax(2,1) * (Pmstc(1)/1000) * Mplantcsi * n * usdeur;   % SCENARIO 3
Cm4 = Ni4 * Nsmax(2,2) * Npmax(2,2) * (Pmstc(2)/1000) * Mplantcdte * n * usdeur;  % SCENARIO 4
```

Figure A.12: C_m

```
% Replacement costs
Crep1 = Cinverters1;         % Replacement cost for 25 years operation
Crep2 = Cinverters2;         % Replacement cost for 25 years operation
Crep3 = Cinverters3;         % Replacement cost for 25 years operation
Crep4 = Cinverters4;         % Replacement cost for 25 years operation
```

Figure A.13: C_{rep}

```
% LCOE
LCOE1 = (Ctot1)/(Eplant1tot*1000*n);      % (€/kWh)
LCOE2 = (Ctot2)/(Eplant2tot*1000*n);      % (€/kWh)
LCOE3 = (Ctot3)/(Eplant3tot*1000*n);      % (€/kWh)
LCOE4 = (Ctot4)/(Eplant4tot*1000*n);      % (€/kWh)
```

Figure A.14: $LCOE$

```
% Gross Revenues - 25 years
Rg1 = Eplant1tot * 1000 * Pele * n;      % (€) SCENARIO 1
Rg2 = Eplant2tot * 1000 * Pele * n;      % (€) SCENARIO 2
Rg3 = Eplant3tot * 1000 * Pele * n;      % (€) SCENARIO 3
Rg4 = Eplant4tot * 1000 * Pele * n;      % (€) SCENARIO 4
```

Figure A.15: R_{gross}

A. 3. EVALUATION PARAMETERS CALCULATIONS

```
% GROUND COVERAGE RATIO
GCR1 = Sarray1/land1*100;        % SCENARIO 1
GCR2 = Sarray2/land2*100;        % SCENARIO 2
GCR3 = Sarray3/land3*100;        % SCENARIO 3
GCR4 = Sarray4/land4*100;        % SCENARIO 4
```

Figure A.16: GCR

```
% PERFORMANCE RATIO (%)
PR1 = (Eplant1tot*1000)/(Nsmax(1,1) * Npmax(1,1) * Ni1 * (Pmstc(1)/1000) * ((sum(irradiance)/1000)))*100;  % PR CASE 1
PR2 = (Eplant2tot*1000)/(Nsmax(1,2) * Npmax(1,2) * Ni2 * (Pmstc(2)/1000) * ((sum(irradiance)/1000)))*100;  % PR CASE 2
PR3 = (Eplant3tot*1000)/(Nsmax(2,1) * Npmax(2,1) * Ni3 * (Pmstc(1)/1000) * ((sum(irradiance)/1000)))*100;  % PR CASE 3
PR4 = (Eplant4tot*1000)/(Nsmax(2,2) * Npmax(2,2) * Ni4 * (Pmstc(2)/1000) * ((sum(irradiance)/1000)))*100;  % PR CASE 4
```

Figure A.17: PR

```
% CAPACITY FACTOR (%)
CF1 = (Eplant1tot*1000)/((Nsmax(1,1) * Npmax(1,1) * Ni1 * (Pmstc(1)/1000) * 8760)) * 100; % CF CASE 1
CF2 = (Eplant2tot*1000)/((Nsmax(1,2) * Npmax(1,2) * Ni2 * (Pmstc(2)/1000) * 8760)) * 100; % CF CASE 2
CF3 = (Eplant3tot*1000)/((Nsmax(2,1) * Npmax(2,1) * Ni3 * (Pmstc(1)/1000) * 8760)) * 100; % CF CASE 3
CF4 = (Eplant4tot*1000)/((Nsmax(2,2) * Npmax(2,2) * Ni4 * (Pmstc(2)/1000) * 8760)) * 100; % CF CASE 4
```

Figure A.18: CF

```
% SPECIFIC YIELD (kWh/kWp)
Yield1 = (Eplant1tot*1000)/(Nsmax(1,1) * Npmax(1,1) * Ni1 * (Pmstc(1)/1000));    % Specific Yield CASE 1
Yield2 = (Eplant2tot*1000)/(Nsmax(1,2) * Npmax(1,2) * Ni2 * (Pmstc(2)/1000));    % Specific Yield CASE 2
Yield3 = (Eplant3tot*1000)/(Nsmax(2,1) * Npmax(2,1) * Ni3 * (Pmstc(1)/1000));    % Specific Yield CASE 3
Yield4 = (Eplant4tot*1000)/(Nsmax(2,2) * Npmax(2,2) * Ni4 * (Pmstc(2)/1000));    % Specific Yield CASE 4
```

Figure A.19: $Yield_{sp}$