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Economical comparison between Photovoltaic Panels and Parabolic Trough Collectors for the energy generation

Degree final Project - Energy Engineering

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1. Introduction

Now a day it is being carried out a change on the energetic model on a global level and at all the stages of the generation and consumption. That is, it is being changed the way in which the energy is produced, distributed and consumed. That means that, starting from an energetic model that began to be exploded in S.XVIII in England because of the industrial revolution, which was based principally on the electrical energy production based on the thermodynamic technologies, using fossil fuels such as coal and later the oil and gasoil, it has been tried to reduce the energy production using fossil fuels. In order to reduce the greenhouse emissions produced because of the combustion of the fossil fuels, different technologies based on clean and renewable resources have been introduced to this energetic model. These new and clean resources have been the water, the Sun and the wind.

Since when this model change started, promoted principally by *protocol of Kyoto* (which came into effect in 2005 and had as objective reduce the greenhouse emissions at least a 5% from 2008 to 2012) [1], it have been installed 2.01 millions of MW [2] from renewable energies, 258 GW [3] of them are from the photovoltaic technology and 5 GW [4] from the thermo-solar technologies. Since then, the CO_2 emissions have been reduced by a 11.8% [5], when considering this data, we have to take on account that the energy consumption has also increased considerably due to the urban development and the population growth specially on the cities.

In Brazil, the installed power from photovoltaic modules during the last years has been of 27.764 MW [6] , and anything form thermo-solar plants. When mentioning the installed power from photovoltaic, it is considering both little installations distributed for the auto-consume and high power plants for the electrical energy selling.

The principal difference between both energy production technologies is that, while the photovoltaic modules turn the solar radiation directly into electrical power generating a direct current, the thermo-solar fields need to transform the thermal energy obtained on the collectors from the sun radiation into mechanical energy through a thermodynamic cycle and, after that, into electrical energy using an electric generation. This difference makes that each technology have diverse extent and limitations on their applications. For example, when designing a little power electrical generation plant or an installation for the auto-consume, photovoltaic modules are used, as they doesn't need of additional elements for the energy generation, elements that would require more space and would suppose an extra initial inversion. On the other hand, the thermo-solar plants are usually used in energy generation projects looking for a bigger power. Moreover, this kind of centrals can complement its thermodynamic cycle used to transform the heat obtained from the radiation by a boiler fuelled with another fuel as could be the natural gas or the biomass. In addition, the thermo-solar electric plants offer the opportunity providing a thermal storage, opposite to the photovoltaic technology, which can't storage the reaching solar energy and the energy generated have to be distributed at the same moment it is generated. Thanks to the thermal storage and the boiler complementation, contrary to the photovoltaic plants, the thermo-solar plants allows to sell and make available a firm energy, which benefits the electrical distribution net's stability.

It is also important to point out that, although the thermo-solar technologies are able to storage thermal energy and to complement the solar radiation with other fuels, both depends entirely on the sun radiation and, there so, their performances are volatile and unpredictable.

2. Objective

The objective of this project, there for, is to compare both technologies and all their elements so as to resolve which one of them is more profitable in economical terms.

To this end it will be worked on the basis that the electrical energy must be confirmed and ensured, provided that the consumers could dispose of energy whenever they need it and not just when the solar radiation is favorable for the energy generation. Taking into account that request, it will be supposed that a photovoltaic plant should be complemented by an adaptable way of energy generation for that hours in which there is not generated electrical energy at the photovoltaic plant or it is not produced enough energy. An option for this complementation of energy generation would be a thermal plant. The Parabolic through solar plant, on the contrary, already dispose of a thermodynamic cycle that can be adapted to ensure a stable energy.

Therefore, knowing that the photovoltaic plant must dispose of a thermal central to generate energy when it is not generated by the photovoltaic plant, and that the parabolic trough central, on the opposite side, already have a thermal plant for its solar energy generation and that it can be used to be complemented by another source of energy at the moments in which it is not generated thermal energy from the Sun, we can draw that both centrals need a thermal plant.

So the comparison that will be carried out about these two solar technologies will put aside the initial inversion referent to the thermodynamic cycle of the parabolic trough central, as it can be dismissed because of the necessity of the photovoltaic solar plant having to be supported by a thermal plant to complement and ensure its energy. This comparison, then, will consider the collectors' field of both plants, as well as the extra elements as could be the inverters on the case of the photovoltaic field and the distribution lines connections of each central.

To be able to carry out such comparison of the fields, it will be searched an adequate location to design both projects, this is, a location where the solar radiation is ideal to design a solar energy generation plant. Both centrals will have the objective of producing the same total annual energy, as it will be on this way that the solar fields will be compared. There for, both solar fields will be designed and sized and it will be compared the economical cost that each central supposes to be able to confirm a determined annual energy, being the generated annual energy using the sun as primary energy the same in both centrals.

3. Location analysis

The first thing that has to be done to develop this project is to choose an ideal location for the solar field, which will be the same as for the Cylinder-Parabolic Collectors as for the photovoltaic panels. For the selection of the place will be taken on account the solar incidence on that place, so it can be produced the maximum of energy by square meter; the accessibility to a transformation point, so it will be easy to introduce to the greed the energy generated, decreasing the costs related to the energy transport; and the proximity to a water resource, which is really important for the thermal plant, as it have to condensate the steam at one point of the thermodynamic cycle.

After choosing the ideal location for our project, it will have to be found the appropriate information of the solar radiation in the chosen place and process the data to know the energy that can be produced by square meter in every period of the year. Moreover, it will be found the ideal inclination of the solar collectors, so it profits the maximum the solar incidence.

3.1. Solar resource

The best location for the solar receptors will be that with a higher direct radiation, which is the only type of radiation that is profitable for the solar collectors and photovoltaic panels. Being the direct radiation the difference between the global and de diffuse radiation.

The global radiation is understood as the total energy that hits the surface of the earth, being this affected by the air temperature, the humidity, the visibility, the clouds, and the height of the surface that is being studied. The diffuse radiation is that one that is dispersed through the atmosphere, changing their direction and the direct radiation then, is that one that arrives at the surface without experimenting changes during their way through the atmosphere.

So on, to decide the place where is going to be developed the study of the project, are going to be taken in consideration the maps that shows the annual and seasonal average global radiation, as well as that ones that shows the diffuse radiation.

Image 1 Brazilian map of the annual global solar radiation average [7]

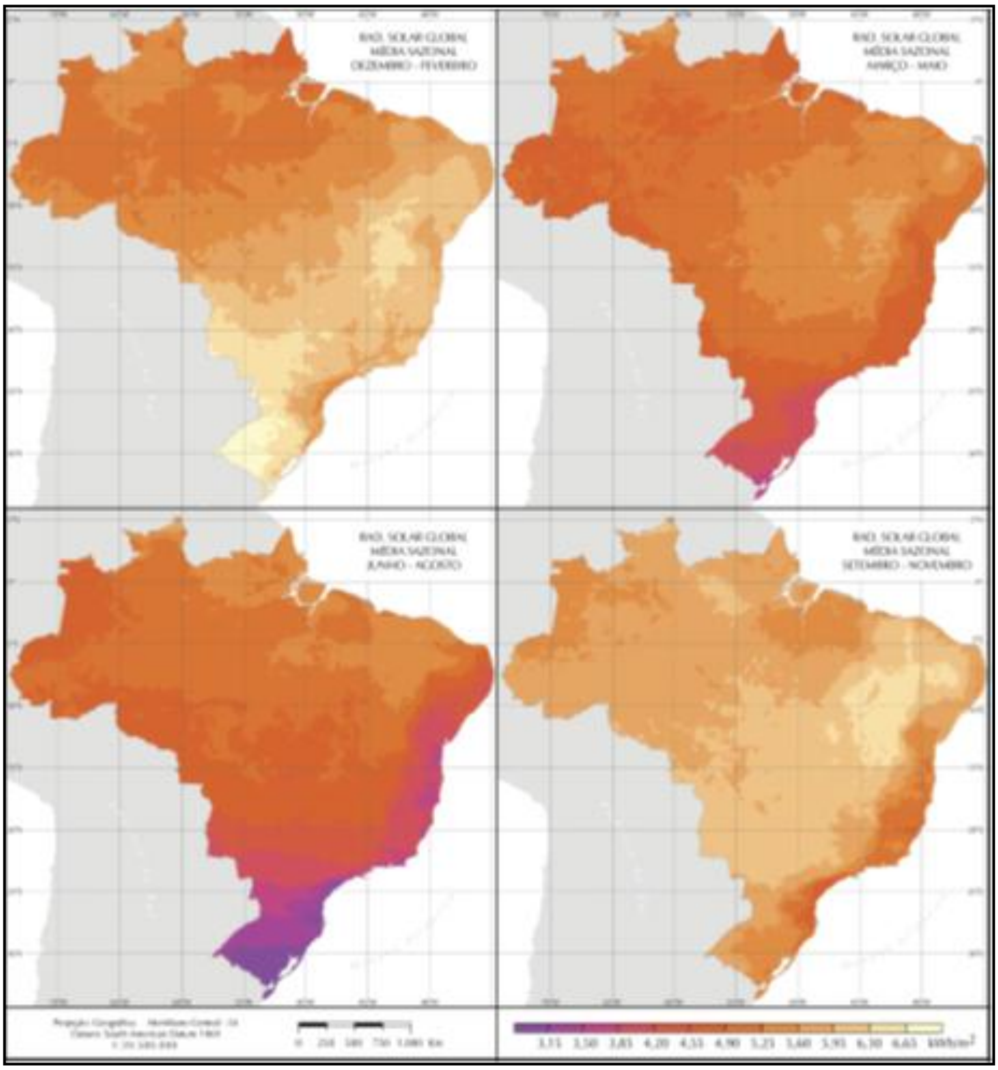


Image 2 Brazilian map of the annual global solar radiation average [7]

Looking at the maps, and knowing that the most clear tones of red indicate the highest global radiation (7 kWh/m²) and the darkest tones of red indicates the lowest global radiation (3 kWh/m²), we can perceive that the best location will be one near the coordinates 10°-15° S, 40°-45° W , which have a annual average global radiation of 6,3 kWh/m².

But, as it have been told above, the important radiation for the solar panels well work is the direct radiation, so the area selected have to have a low diffuse radiation as well as a high global radiation, so the direct radiation will be the highest possible.

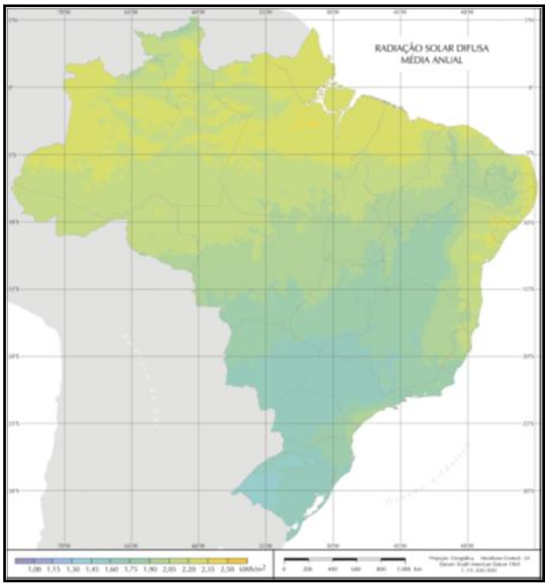


Image 3 Brazilian map of the annual diffuse solar radiation average [7]

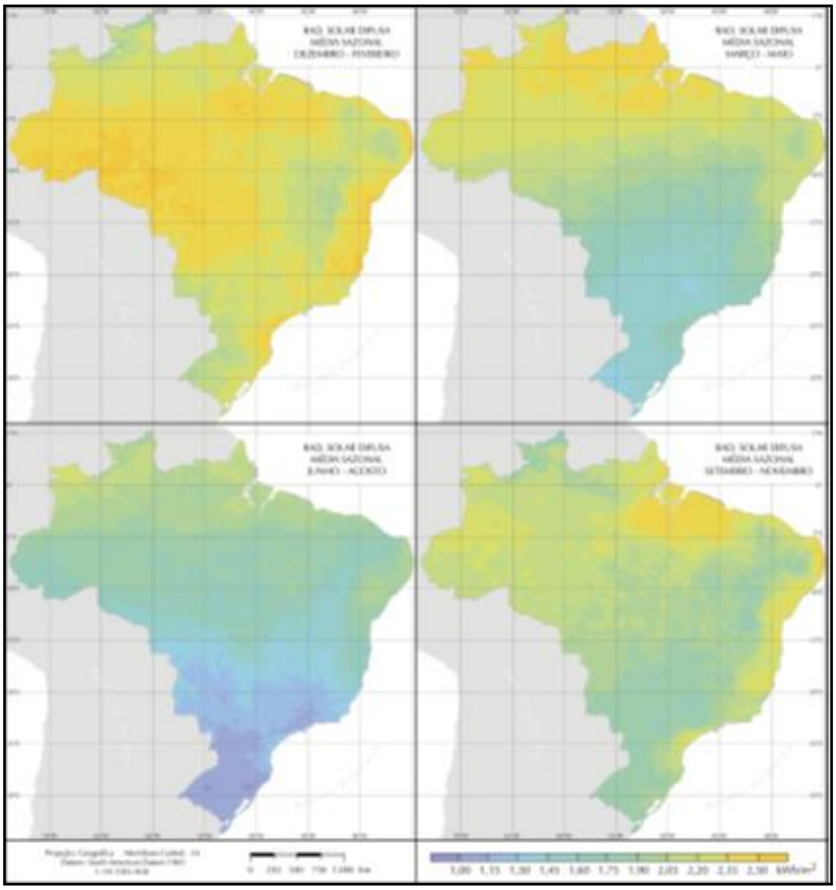


Image 4 Brazilian map of the seasonal diffuse solar radiation average [7]

Being the darkest tones of blue the lowest diffuse radiation (1 kWh/m²) and the darkest tones of yellow the highest diffuse radiation incidence (2,5 kWh/m²), it's easy to see that, in the area that have been chosen previously, 10°-15° S, 40°-45° W, the diffuse radiation is quite low. So, being the global radiation high and the diffuse radiation low, that area will be the one with a highest direct radiation.

3.2. Accessibility to a transformation point

Also have to be taken on account that the generation plant has to be near to a transformation point, were the energy is going to be transformed and introduced to the electric distribution greed.

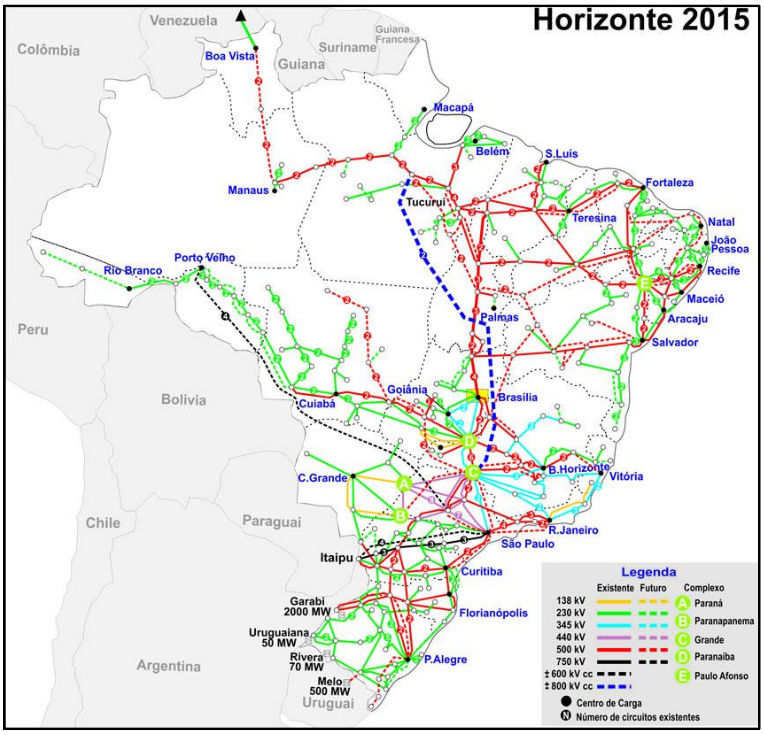


Image 5 Brazilian electric greed at 2015 [8]

Looking at the map above can be perceived that the great amount of transformation points are near to the urban areas, as it is there where the energy is consumed and it would be too expensive to transport the energy for large distances, overall taking on account the energy looses that this involves.

Near the ideal selected area are a few transformation points and distribution lines with a capacity for 230 kV. So, as the selected area is an area well connected in terms of electrical distribution, it can be assumed that it will be easy to inject the produced energy into the greed.

3.3. Proximity to a water resource

The proximity of the thermal plant to a water resource is important for the refrigeration of the thermal cycle and condensation of the steam in the condenser. The river have to have flow enough to absorb the thermal energy that is detached from the condenser without incrementing the water temperature more than 2 °C.

The selected location is close to two rivers. The closest is 'Rio Dois Riachos' which is located 200m far from the location, the other one is 'Rio Dos Milagres' which is 700m far from the location. The best option would be the closest one, but none of them are useful, as they don't have enough flow and, moreover, they are seasonal rivers, so depending on the season f the year and the precipitations in that season, they are not carrying any water.

3.4. Final location

So, finally is chosen the location 12°S 42°W for the simulation of the project. This location corresponds to a place near the Brazilian town *Barra do Mendes,* in the municipality of *Iracè*, state of *Bahia.*

Image 6 Project location; Brazilian map

Image 7 Project location; Map from Bahia

This location can easily not be the perfect location to carry out the project of an energy generation solar plant, due to the fact that it doesn't have enough water resources and, moreover, the physical characteristics of the land haven't been studied and the area selected is, in fact, a mountainous region, so it probably doesn't meet the requirement of having a slope less than 20% to build a solar plant. But, as this is just a comparative simulation and the final object is not the one to build a real generation plant to sell the energy to make profitable the inversion, these aspects are not really relevant. The process of looking for an ideal location is just a step to search useful solar data to carry out the simulation.

3.5. Solar incidence for the chosen location

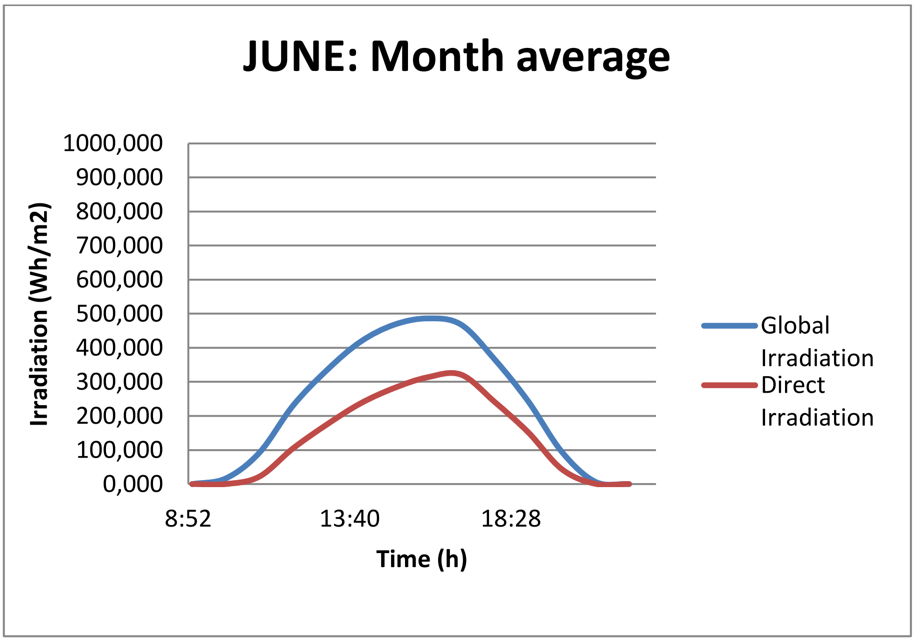
Now that the project location has been elected, the irradiation information for that area can be searched. It is needed the irradiation data for a entire year, this way we can simulate the performance of the solar plants depending on the day of the year, as depending on the season the irradiation is stronger than at others.

It is not enough knowing the diary average irradiation, as there is a great difference between the initial and final hours of the day and the ones at the mid-day, especially when referred at the horizontal plane. So we are going to look for hourly average irradiation data, this way the simulation is going to be approximated close enough to the annual generation referred to the solar panels and its going to be easy to compare with the demand curve.

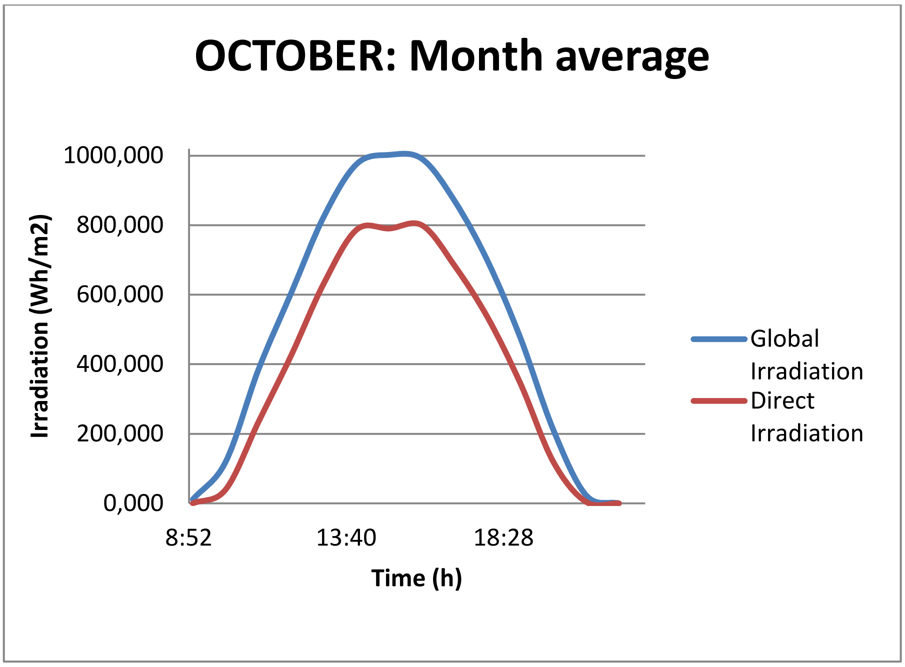
The irradiation data have been finally obtained from the *HelioClim* Solar radiation Data base [9]. It provides the Direct, Diffuse and Global radiation from any location. In this case, however, it just was able to provide the data for the year 2005.

Once we have the annual data, it is going to be made an average day for each month, so it is going to be possible to calculate the sun following system, varying each month, as the sun trajectory is not the same each day of the year, but it doesn't vary too much each day.

In the following graphics are drawn the incident irradiation (W/m^2) on the horizontal plan for an average day of the month. The months shown are those with the highest and lowest irradiation index, corresponding to January and August respectively. As can be sawn, the irradiation at the beginning and at the end of the day is much lower, for that reason is going to be necessary to design a *Sun Following System*.



Graphic 1 Average hour irradiation distribution for the month of June



Graphic 2 Average hour irradiation distribution for the month of October

In the graphics above are shown both the direct irradiation and the global irradiation. Depending on the technology that is going to be used to transform the solar energy, it is going to be taken on account one or the other. In the case of the Parabolic Through Collectors (CPC), the only solar incidence that is useful is the Direct irradiation, that is the one that arrives directly from the sun, without suffering any type of changes on its trajectory. In the case of the Photovoltaic panels, they transform into electrical energy both direct and diffuse irradiation, being the diffuse irradiation the one that comes from all directions, as its trajectory has been modified by the clouds and other particles in the atmosphere. The sum of the diffuse and direct irradiation is named Global irradiation.

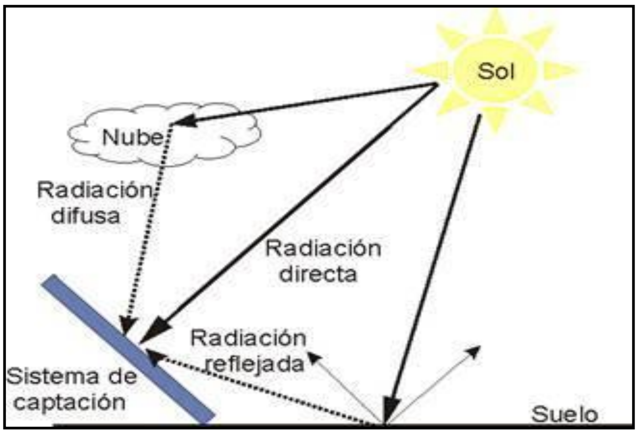


Image 8 Solar radiation components

3.6. Sun following System

The aim of the sun following system is to maximize the solar incidence each hour of the day at every day of the year. To achieve that, we try to collocate the sun collectors as perpendicular to the sun incidence as possible.

3.6.1. Panels Orientation

In the following figure are shown the different trajectories of the sun depending on the year seasons. Being I: Winter, O-P: Autumn and Spring and V: Summer. As it can be sawn, the sun trajectory in Winter is shorter and lower, the opposite from Summer trajectory.

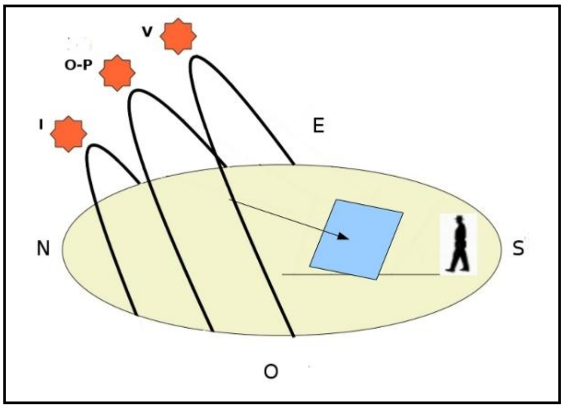


Image 9 Sun trajectory during the day. From East to West

The sun captators are usually oriented in the direction North-South, as the maximum solar radiation is in the equator. For that reason, being in the Northern hemisphere, the panels are orientated to the south (Equator), and being in the Southern hemisphere the panels are oriented to the north, as it is our case. As the sun trajectory is from East to West, if the panels where oriented to any of this directions, they would receive the maximum radiation at half-day, but they will lose energy at one part of the day.

3.6.2. Sun Tracking for the CPC

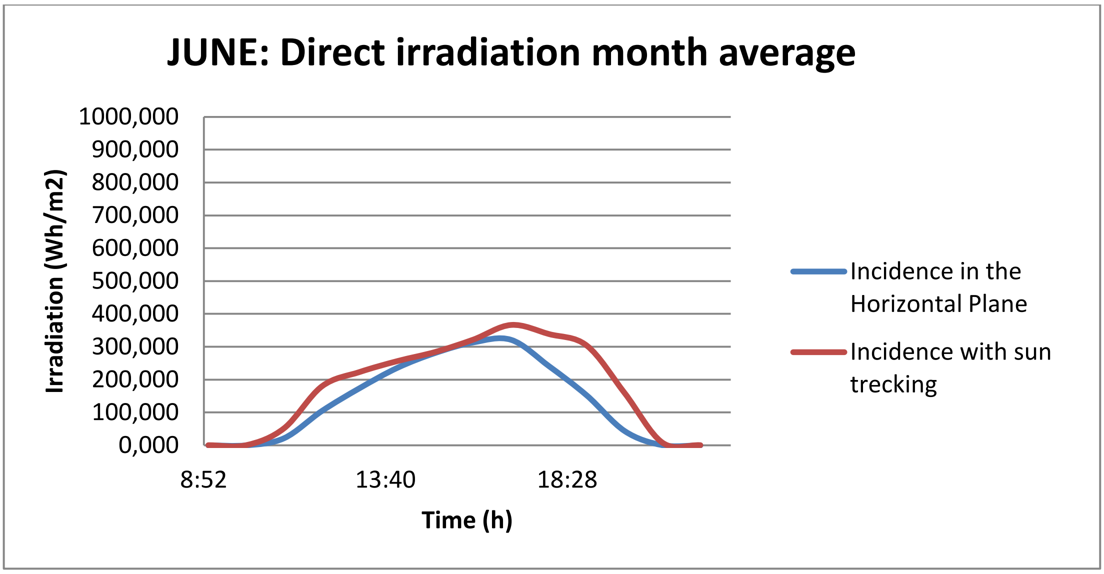
There are a few types of sun-following systems. The sun tracking can be made using one or two axis. There are three types of following-system using one axis: in the **polar axis**, in this case, the receptor surface spins on an axis orientated to the north and with an inclination equal to the latitude of the location, the spinning velocity is 15° per hour, what makes 360° (a complete round) per day; in the **azimuthal axis**, in which the surface turns on a vertical axis, in this case, the surface angle is always equal to the latitude and the normal angle of the surface is equal to the meridian where the Sun is; in the **horizontal axis**, in which the panel spins on a horizontal axis oriented to the north-south direction, the objective is that the normal of the receiving surface is always coincident to the meridian in which the Sun is.

Knowing the different types of Sun-tracking systems, and the characteristics of our solar plants, we can choose the best system for each installation.

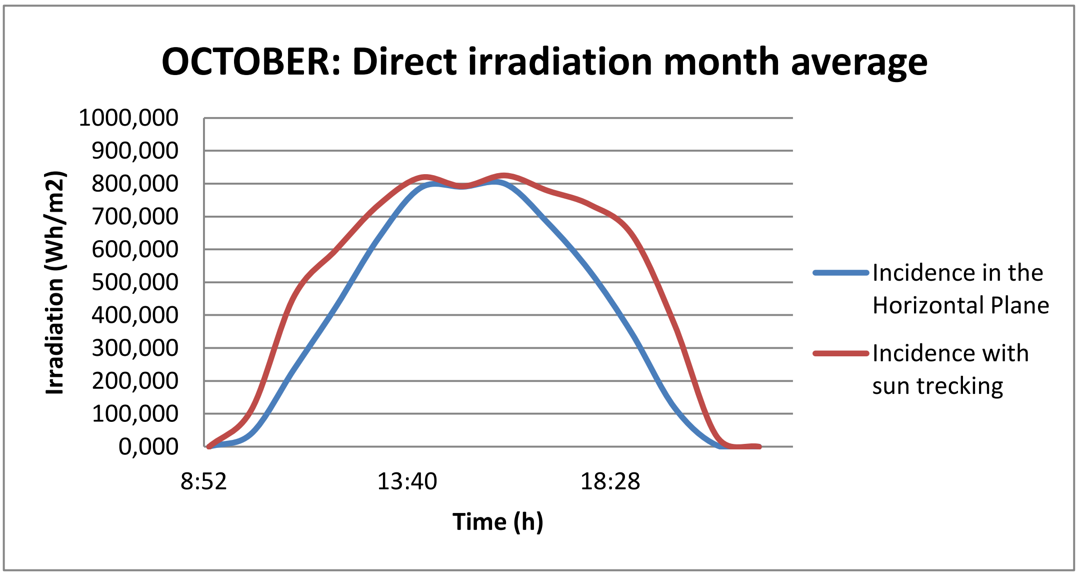
In the case of the *Parabolic trough collectors* plant, as it is orientated to the north and the objective is to obtain the maximum incidence during the day, the best Sun-following system is the one that turns in the Polar Axis.

3.6.3. Solar incidence after the Sun-Following System

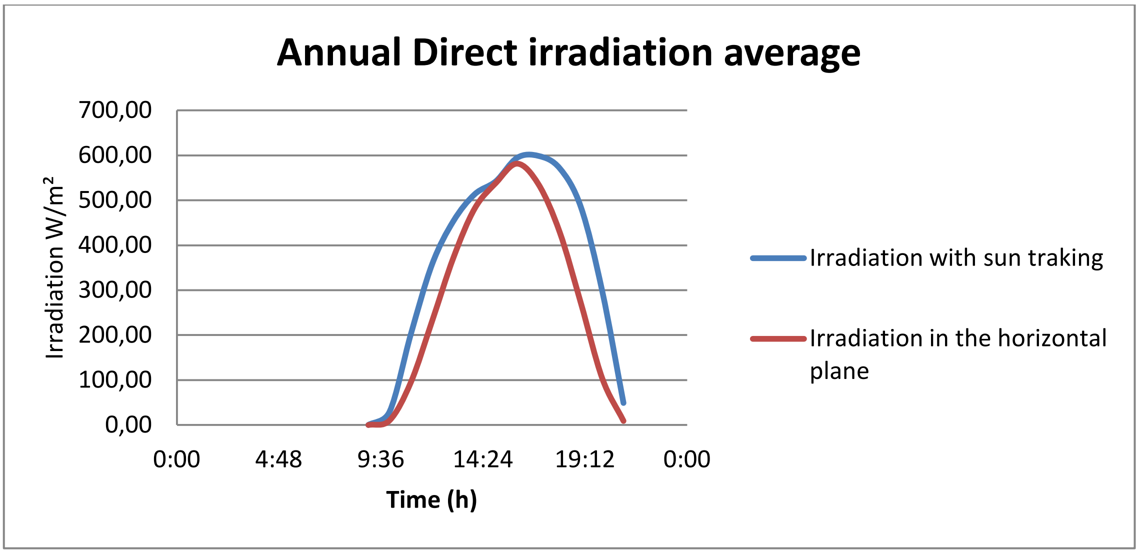
Once the Sun-tracking system is implemented in the **polar axis**, it can be drawn a new irradiation curve, that, as it is shown in the following graphics, it is increased the solar incidence in the firsts and last hours of the day, having the same incidence as in the horizontal plane at noon.



Graphic 3 Average Direct irradiation distribution with and without sun-trecking for the month of June



Graphic 4 Average Direct irradiation distribution with and without sun-trecking for the month of October



Graphic 5 Direct irradiation on an average day of 2005

There so, the incident radiation on the panels changes from 1336.37 KWh/m².year on the horizontal plant to 1713.98 KWh/m².year using the sun-tracking system. That supposes an increment of 377 KWh/m² each year and the average hourly increment of radiation of all the year is about 86 W/m².

3.6.4. Photovoltaic solar panels inclination

In the case of the Photovoltaic panels' plant, contrary to the Parabolic Trough assemblies, it does not incorporate a sun following system in each row of panels. Adding this technology would suppose an additional initial investment and, taking on account the performance of the current photovoltaic plants, the difference on the incident irradiation that it makes (and, there so, on the generated energy) does not return on the investment of the installation of sun following systems. That is why it has been decided to install the panels with a fixed inclination through the whole year.

The inclination selected will be that one that offers the maximum annual solar incidence, being that inclination higher than 10°, as this is the minimum inclination that the panels must have to carry out a self-cleaning, that is, in order that the dirt does not accumulate too easily on the panels. To calculate the optimal inclination (that one that will offer the maximum annual energy generation), will be taken on account some constants and the latitude of the energy generation plant location.

$$\beta_{opt} = 3{,}7 + 0{,}69 * |\varphi_{lat}| = 11{,}98$$

Where β_{opt} represents the ideal inclination and $|\varphi_{lat}|$represent the locations latitude. Being the resulting inclination 11.98°, it can be rounded up to 12° [10].

Once it have been decided the ideal inclination for the panels, it will have to be recalculated the solar incidence. Having the data of the irradiation on the horizontal plan, it will have to be corrected for the selected inclination. This correction will be done by multiplying the solar irradiation on the horizontal plan by a correction factor K. This factor varies for each latitude, inclination and month of the year and it can be obtained using tables.

Latitud = 12°

Inc	Ene	Feb	Mar	Abr	May	Jun	Jul	Ago	Sep	Oct	Nov	Dic
0	1	1	1	1	1	1	1	1	1	1	1	1
5	1.03	1.02	1.01	1	.98	.98	.98	1	1.01	1.03	1.04	1.04
10	1.06	1.04	1.01	.98	.96	.95	.96	.98	1.02	1.05	1.07	1.07
15	1.08	1.05	1.01	.97	.93	.92	.93	.96	1.01	1.06	1.09	1.1
20	1.09	1.05	1	.94	.89	.87	.89	.94	1	1.07	1.11	1.12
25	1.1	1.05	.98	.91	.85	.83	.85	.91	.99	1.07	1.12	1.13
30	1.1	1.04	.96	.87	.8	.77	.8	.87	.96	1.06	1.12	1.13
35	1.09	1.02	.93	.83	.75	.72	.74	.82	.94	1.05	1.12	1.13
40	1.08	1	.9	.78	.69	.65	.68	.77	.9	1.02	1.11	1.12
45	1.06	.97	.86	.73	.63	.58	.62	.72	.86	.99	1.09	1.1
50	1.03	.94	.81	.67	.56	.51	.55	.66	.81	.96	1.06	1.08
55	1	.9	.76	.61	.49	.44	.48	.6	.76	.92	1.03	1.05
60	.96	.85	.7	.54	.41	.36	.4	.53	.7	.87	.99	1.01
65	.91	.8	.64	.47	.34	.28	.33	.46	.63	.82	.94	.97
70	.86	.74	.58	.4	.26	.2	.25	.38	.57	.76	.89	.92
75	.81	.68	.51	.33	.18	.12	.17	.3	.5	.69	.83	.87
80	.74	.62	.44	.25	.11	.1	.09	.23	.42	.62	.77	.81
85	.68	.55	.37	.17	.1	.09	.09	.15	.35	.55	.7	.74
90	.61	.48	.29	.11	.09	.08	.08	.08	.27	.48	.63	.67

Table 1 K Factor for latitude 12°

As the tables available that we have been able to found only show the K factors for the positive latitudes, it is needed to extrapolate the data for the latitude +12˚ to the latitude -12°. There so, we will change the K factor of the opposite months. On the basis of the solstices, (being the winter solstice at the north hemisphere in December and in June at the South hemisphere and the summer solstice at the north hemisphere in June and in December at the south hemisphere) the data from the month of June will be changed by the data on the month of December and vice versa. So the K factors from the months of summer at the North hemisphere will be the K factors of the months of summer at the South hemisphere, remaining equal the months of September and March.

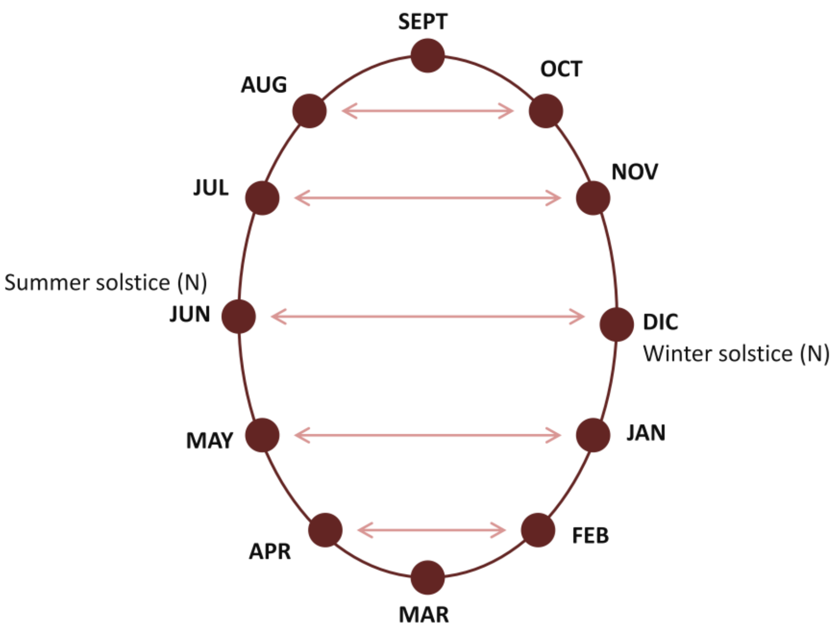


Image 10 Equivalent months of the year on the North hemisphere and the South hemisphere

In order to obtain the K factor for an inclination of 12 degrees, it is carried out a simple interpolation between the 10° and 15° inclination, so the K factors resulting are the followings:

Latitude	12°		Inclination	12°	
JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
0,948	0,976	1,01	1,044	1,068	1,082
JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
1,078	1,054	1,016	0,972	0,948	0,938

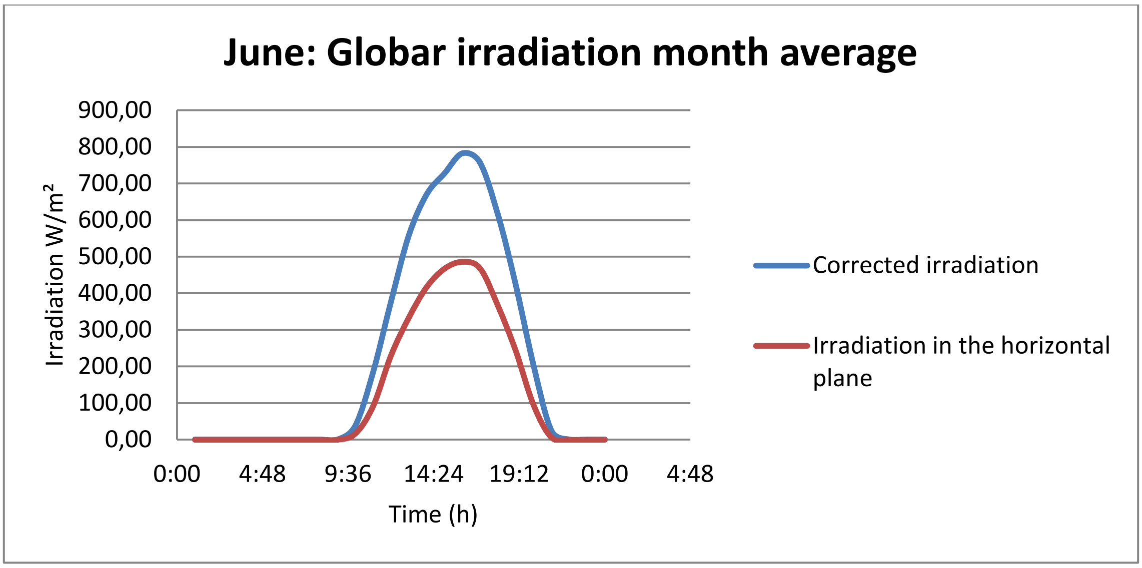
Table 2 K factor for an inclination of 12°

Once we have obtained the K factor to correct the irradiation is as simple as multiplying this factor by the irradiation in the horizontal plane:

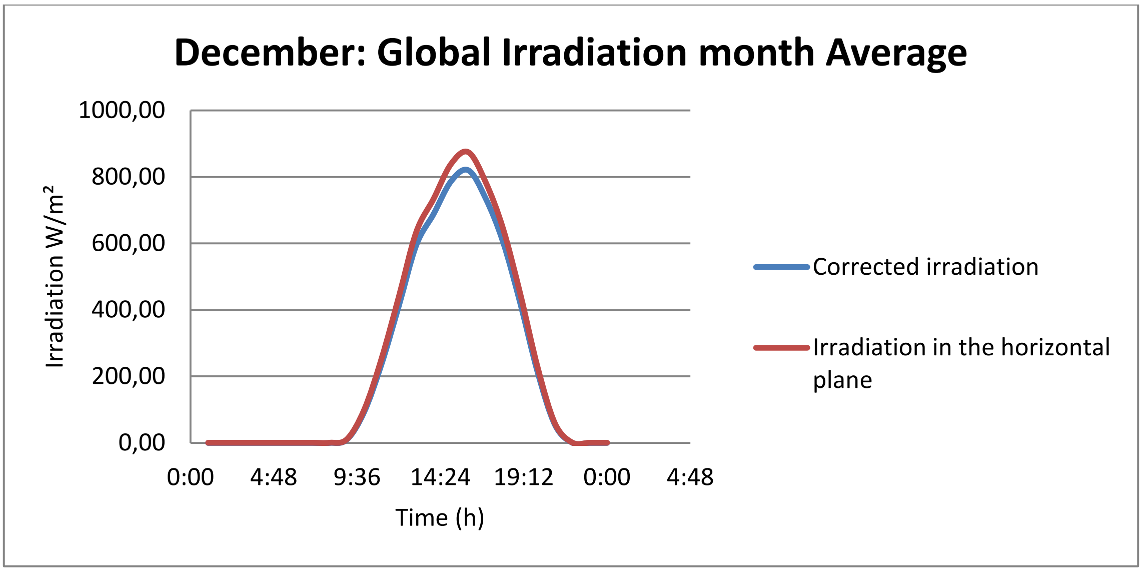
$$I_{12^\circ} = K * I_H$$

3.6.5. Solar incidence on the inclined surface

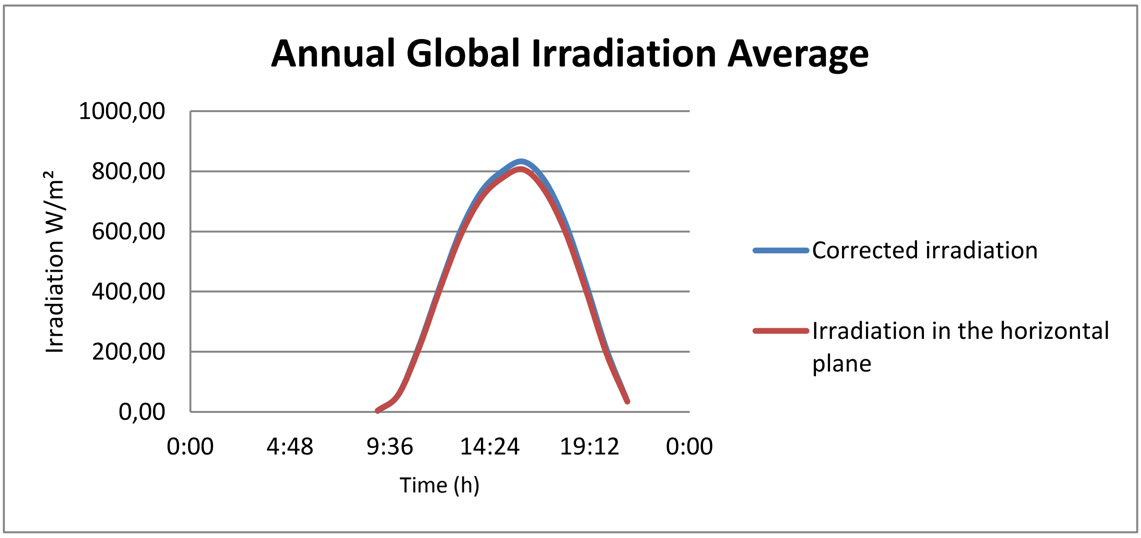
On the graphics below are shown the incident global irradiation on the horizontal plane and on the inclined plane during an average day of June and December. June shows the highest difference between these two incidences, while December shows a loss of incident irradiation when using an inclined plane.



Graphic 6 Difference between the solar incidence on the horizontal plane and on an inclined plane for an average day of the month of June



Graphic 7 Difference between the solar incidence on the horizontal plane and on an inclined plane for an average day of the month of December

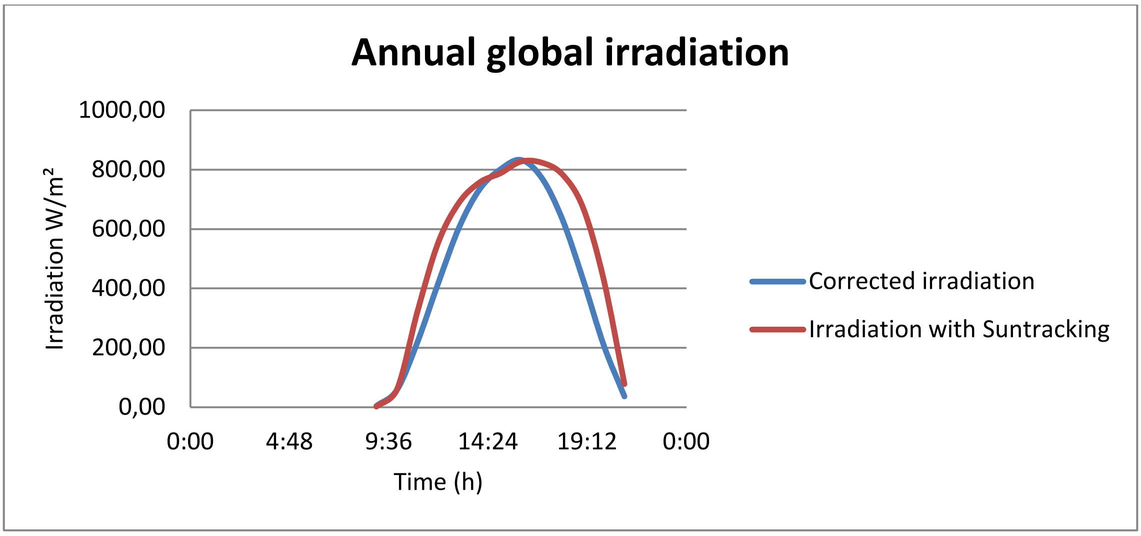


Graphic 8 Difference between the solar incidence on the horizontal plane and on an inclined plane for an annual average day

Although at some months of the year the fact of inclining the panels is unfavorable, as the incident irradiation at the inclined plane is lower than on the horizontal plane, the annual incidence irradiation is higher using the inclined panels, although this difference is very thin, due to the fact that the inclination is very low.

It can be sawn a better performance of the panels at the months of winter while working on an inclined plane as the trajectory of the sun is lower than at the rest of the year and the inclination is favorable to it. On the opposite, during the months of summer, the trajectory of the sun is higher, which means that a lower inclination would be more favorable, as this will make that the panels were more perpendicular to the sun incidence, increasing the irradiation incidence. On the same way, at the months of spring and autumn this difference is very tight.

On the graphic below is shown the difference between the average annual global irradiation incident on the panels while using a fixed inclination and while using a sun-tracking system.



Graphic 9 Difference between a fixed inclined panel and a sun-following panel of the annual global irradiation

3.6.6. Irradiation resume

In addition to the graphics, it also can be made a quantitative comparison between the difference of the solar incidence before and after applying the sun-tracking systems. As it is shown in the following tables:

Technology:	**CPC**	**Useful Irradiation:**	**Direct Irradiation**	**System:**	**Sun-tracking on the polar axis**
Annual hourly Direct Irradiation average during the hours of sun (W/m^2)					
On the Horizontal plane	305,11	With sun-tracking	391,3	Difference	**86,19**
Total annual Direct Irradiation (kWh/m^2.year)					
On the Horizontal plane	1336,37	With sun-tracking	1713,98	Difference	**377,52**

Table 3 Comparison of the Direct Irradiation incidence depending on the CPCs inclination

Technology:	**PV**	**Useful Irradiation:**	**Global Irradiation**	**System:**	**Fix inclination**
Annual hourly global Irradiation average during the hours of sun (Wh/m^2)					
On the Horizontal plane (H)	426,64	With sun-tracking (St)	565,35	12º inclination (Fi)	442,56
Difference between St-H	**138,71**	Difference between St-Fi	**122,79**	Difference between Fi-H	**15,92**
Total annual Global Irradiation (kWh/m^2.year)					
On the Horizontal plane (H)	2024,40	With sun-tracking (St)	2476,23	12º inclination (Fi)	2069,90
Difference between St-H	**451,83**	Difference between St-Fi	**4063,32**	Difference between Fi-H	**45,50**

Table 4 Comparison of the Global Irradiation incidence depending on the panels inclination

4. Cylinder-parabolic energy generation plant

The parabolic trough systems are the most mature CSP electricity generation technology, with around 30 plants and 1220 MWe of installed power in the world until 2011 [11], corresponding to the 96,3% of the CSPs installations. They consist of large arrays of solar collectors, which are composed from tracking groups of parabolic collectors, receiving tubes and tracking systems. In the receiving tubes a thermal fluid is heated, and this fluid is used to generate steam in a Rankine cycle. These systems can also have an optional thermal storage and/or a fossil fuelled boiler to complement the power produced by the thermal fluid.

The figure below is shown a diagram that shows the basic components of the parabolic trough system. Each solar collector consists of a linear parabolic-shaped reflector that focalize the isolation onto a receiver tube at the focal point, as shown:

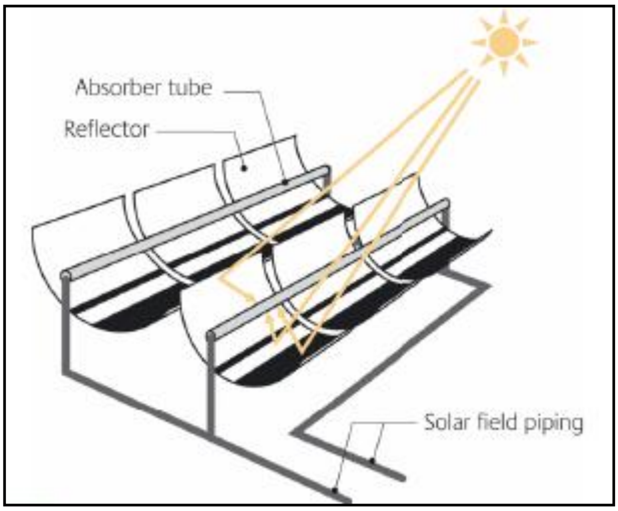


Image 11 Parabolic trough system

To make sure that the sun is continuously focused on the receiver so the maximum isolation is incident, the collectors follow a tracking from east to west, following the sun trajectory during the day. The oil that goes through the receivers is heated to temperatures above 350°C, so it produces superheated steam in a heat exchanger with a pressure around 50-100 bar, it is then fed into a steam turbine to produce electricity. In the case of our plant, the steam heated by the thermal fluid is going to be, sometimes, heated again by a gas-natural fuelled boiler, so the steam can achieve the temperature and the pressure required to generate the nominal power, so the heat exchanger of the thermal fluid would be just a pre-heater.

4.1. Collectors field

4.1.1. Collectors selected

The solar resource capitation technology that is going to be used has to be chosen to size the area of the solar field. In this case, parabolic trough collectors are going to be used, as they are which affords to us a better profitability of the solar radiation.

The collector that will be used is the 'Helio-Trough' [12] design, from the company Flagsol. The measures and physic characteristics of this technology are shown below through images, designs and graphics.

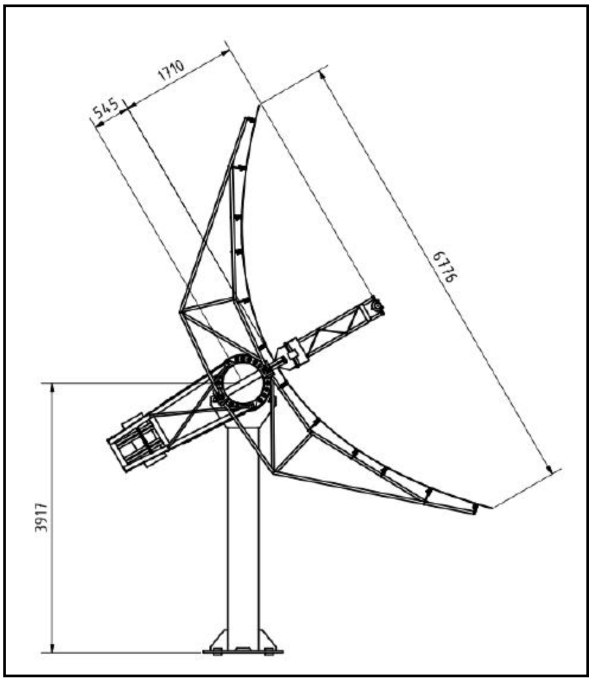


Image 12 Schematic design to show the collector's sizes

In the image above are shown some of the measures of the collector in meters. Being the height of 3.917 m, the axis diameter of 0.545 m, the focal length (distance from the axis to the tube receiver) of 1.71 m and the aperture of 6.776 m.

In the image below is made a comparison between different parabolic trough collectors' designs from the same company, Flagsol. Apart from some sizes already shown on the image above, is shown the receiver tube diameter (88.9 mm), and the collector curve angle that is 89.5 °.

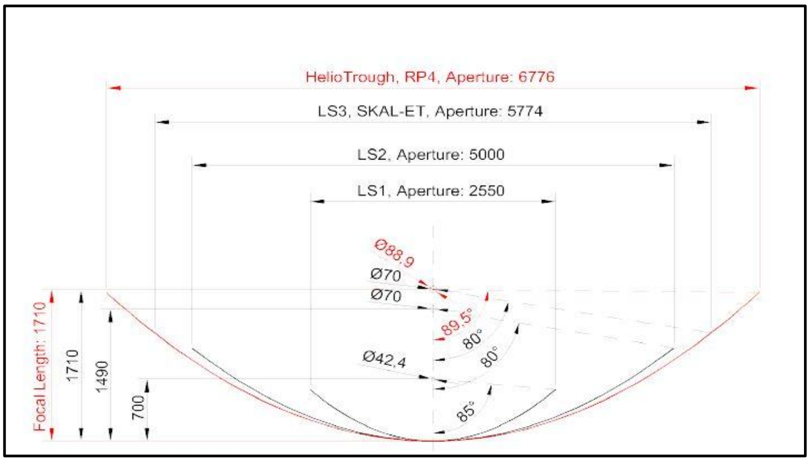


Image 13 Sizes of different collector designs from Flagsol

In the image below is shown the way to assemble the collectors, as well as the distance that shall be left between them. An assemble of collectors consists on ten collectors of 19 m, leaving a distance of one meter after five collectors, what means a distance of 191 m for each assembling. Between each assembling have to be left a distance of 2.5 m and a distance of 22 m between each row of collectors in order to avoid shadows between them.

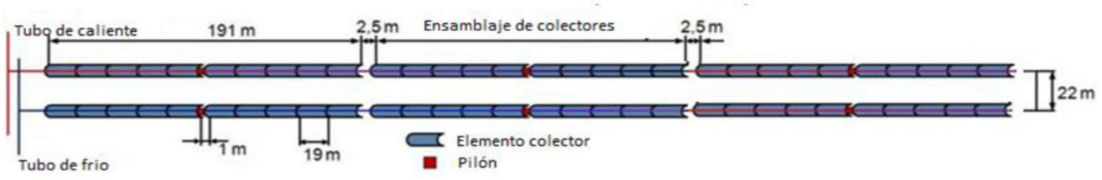
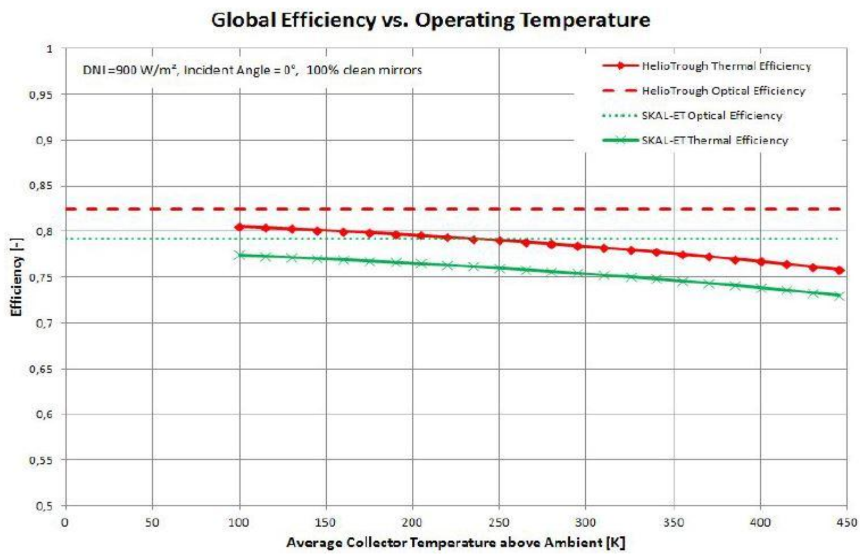


Image 14 Collectors assembling

As well as the dimensions of the collectors their performance in function of the temperature is also important. In the graphic below is made a comparison between two models of parabolic trough collectors from the company Flagsol. We are just going to care about the Helio-Through performance, which is drawn in red. As can be perceived, the optical efficiency does not vary in function of the temperature, and it is maintained at 82.5%. Conversely, the thermal efficiency varies with the variation of temperature of the fluid inside the receiver tube. The thermal efficiency decrease as the temperature rises, being this efficiency 80% when the temperature is of 100°C and 75% when the fluid works at 450°C.



Graphic 10 Collector performance

A resume of the characteristics of the Helio-Trough collectors is shown below:

Focal Length	1.71 m	**Receiver tube diameter**	88.9 mm
Aperture	6.776 m	**Optical efficiency**	82.5%
Collector length	19	**Thermal efficiency at 100°C**	80.5%
Assembling length	191 m	**Thermal efficiency at 200°C**	79.5%
Distance between assembling	2.5 m	**Thermal efficiency at 300°C**	78%
Distance between rows	22 m	**Thermal efficiency at 400°C**	77%

Table 5 Helio-Trough collector physic characteristics

4.1.2. Thermal fluid selected

The function of this fluid is to increase its temperature from 300°C to 400°C during its way through the receiver tube. So it has to be chosen a thermal fluid capable to achieve the 400°C without suffering a status change while working with a not too high pressure.

The thermal fluid selected is the DOWTHERM-A [13], due to its low solidification point, its good heat transference proprieties and its low viscosity. The only inconvenient is its high price. This fluid has its boiling temperature at 257°C when working in atmospheric pressure, but, if the pressure is increased to 12 bars, its boiling point is at 410°C, which is enough for our working conditions.

It is also important to take on account that at atmospheric pressure it has its solidification temperature at 12°C. Fortunately, in rear occasions the temperature, in the region where the project study is made, gets lower than 12°C, being 15°C the lower annual temperature.

The tables below show some of the most important characteristics of the DOWTHERM-A thermal fluid, as its basic characteristics and the specific heat at some important temperatures, as well as the density at these temperatures.

Self-ignition temperature	599°C
Freezing temperature	12°C
Critic temperature	499°C
Critic pressure	31.34 bar
Density at 25°C	1056 kg/m^3

Table 6 Basic characteristics of DOWTHERM-A

Temperature [K]	Temperature [°C]	Specific Heat [kJ/(kg*K)]	Density [kg/m^3]
573.15	300,15	2.359	806.8
623.15	350	2.511	748.6
673.15	400.15	2.701	680.2

Table 7 Specific heat and density at some useful temperatures

4.1.3. Required surface

In order to calculate the required surface composed by parabolic-trough collectors, first it have to be defined the electric power that it would suppose in nominal conditions. This quantity is going to be fixed, in some measure, on an arbitrary way, as it just depends on the contribution that we want the solar plant to have in the electric production. This contribution, when expressed in percentage, is named “solar fraction”. The objective will be that, in nominal conditions, the solar field suppose a 35% of the final electrical power, knowing that most of the times the power afforded by the collectors will be lower, and sometimes it will be higher. The 35% of an 115MW's plant would be 40 MW.

Once it have been defined the fraction of the electrical power that is going to be afforded by the solar field working in nominal conditions, it have to be applied all the performance parameters involved in the process from when the solar radiation hits on the collectors until the electrical energy is generated. That is, it will be applied the generator efficiency, the thermal cycle efficiency and the collectors efficiency. To calculate the collectors performance it will have to be taken on account the optical efficiency, which is maintained constant while the temperature varies, as it is shown in graphic 7, ant the thermal performance, which decrees as the temperature rises, as it is shown in the graphic 7 too. As the thermal efficiency of the collectors varies depending on the thermal fluid temperature that flows through the receiving tubes, and knowing that this temperature should be between 300 and 400 °C, it will be applied an average efficiency between 300 °C (at the beginning of the receiving tubes) and 400 °C (at the end of the tubes). These efficiencies are approximately: 98% the generator efficiency, 30% the efficiency of the Rankine cycle, 82.5% the optical efficiency and 75% the collectors' thermal efficiency, being the collectors' performance of 61.875%.

Appling these efficiencies to the final power that it have to be generated, it results that the incident solar power on the collectors have to be of 219,886 MW or 219 866 W.

$$\boldsymbol{Psolar} = Pel/(\eta_{generator} * \eta_{cice} * \eta_{optic} * \eta_{thermal}) =$$

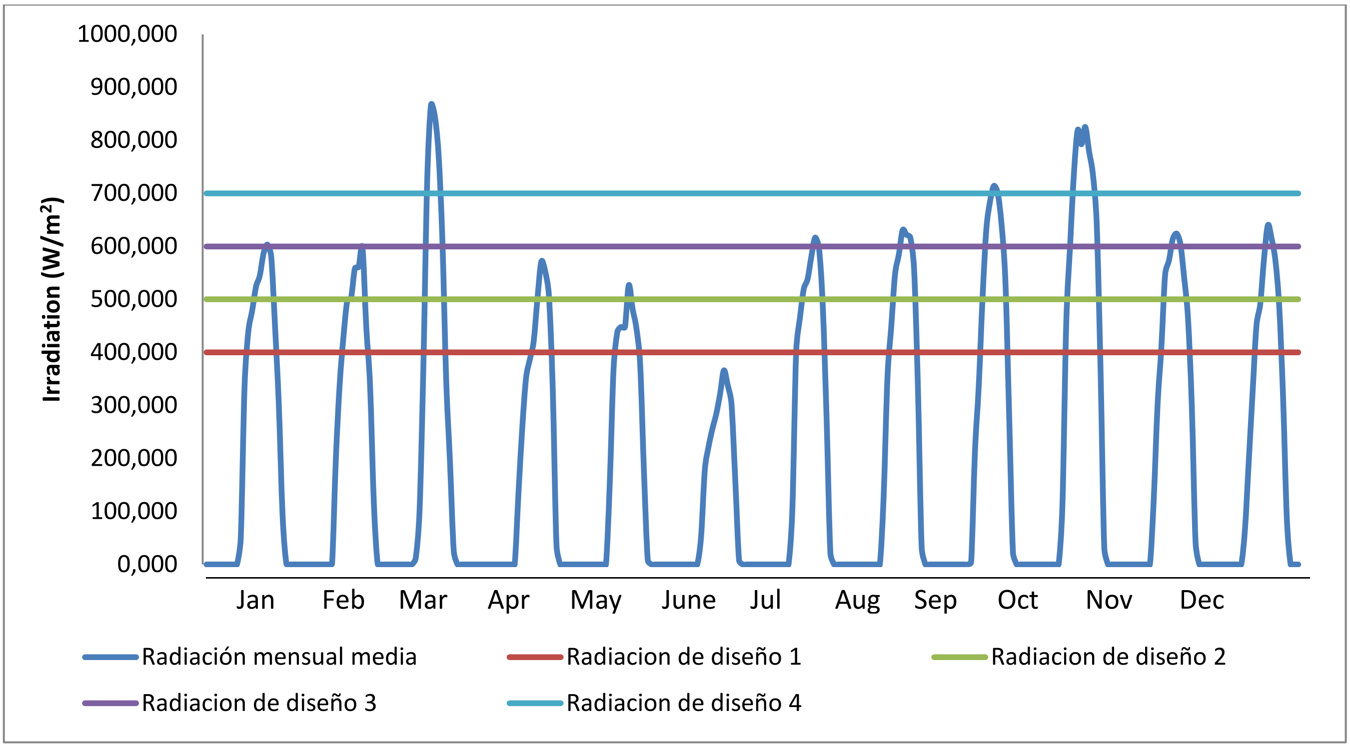
$$= 40\ MWe * 0.98 * 0.3 * 0.825 * 0.75 = \mathbf{219.886\ MW}$$

Therefore, to calculate the required surface to capture all the required incident power, the Incident Power (P_{solar}), in W, has to be divided by the Design Irradiation (I_{design}), in W/m^2. Being the Design Irradiation the radiation for which the solar plant will produce the nominal power fixed.

$$Area = \frac{Psolar}{I_{design}}$$

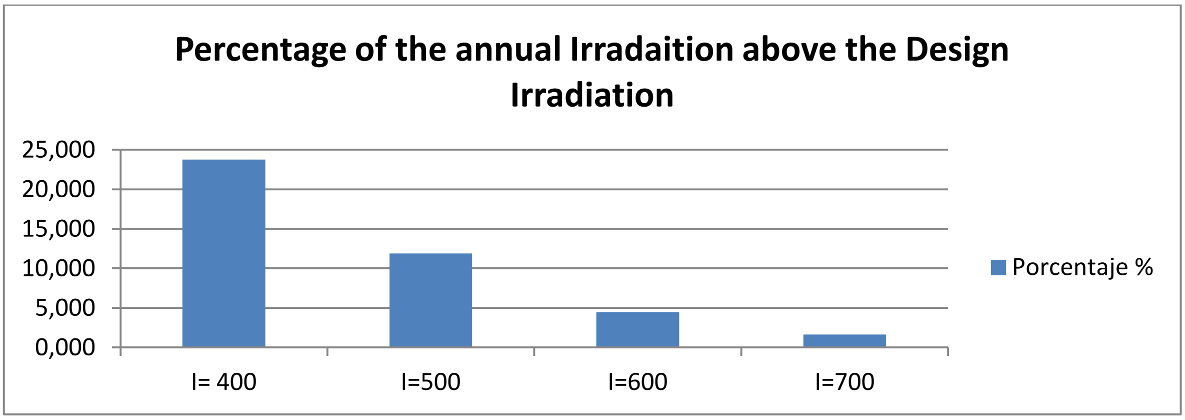
To calculate the capitation area, therefore, first we have to define the design irradiation which we are going to work with. To determinate the ideal design irradiation it will be studied the annual performance of the central working with different design irradiations. These design irradiations will be 400, 500, 600 and 700 W/m^2.

On the graphic below it is shown the hourly behavior of the irradiation in a average month day of each month of the year (showed in blue). It is also shown these different design irradiations studied. This way it can be seen in a visual way the area of the irradiation curve (in blue) that stays above and below of each design irradiation line. Representing the quantity of radiation above and below the different design irradiations.

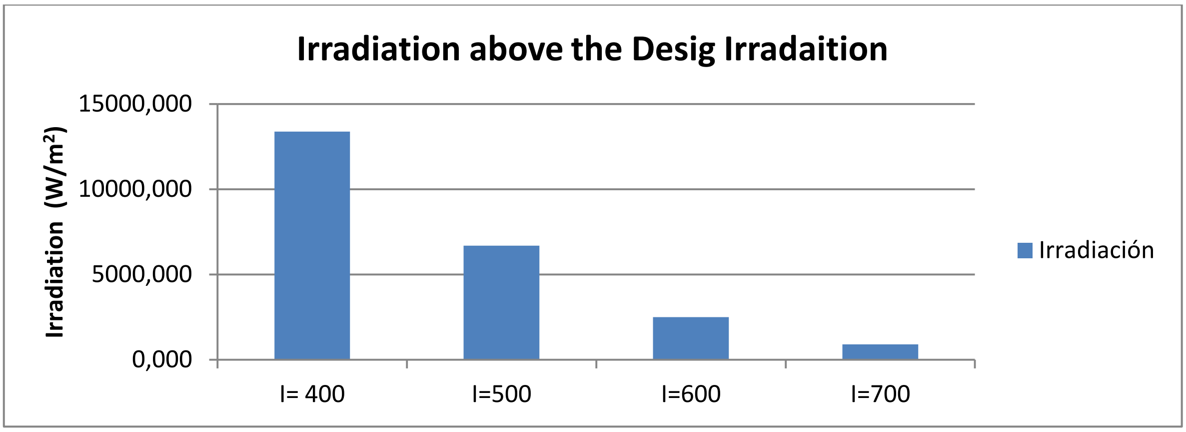


Graphic 11 Comparison between the different design irradiations

In the two bar charts below can be seen the percentage of the irradiation that stays above the design irradiation line showed on the graphic above and the numerical quantity that it supposes, respectively.

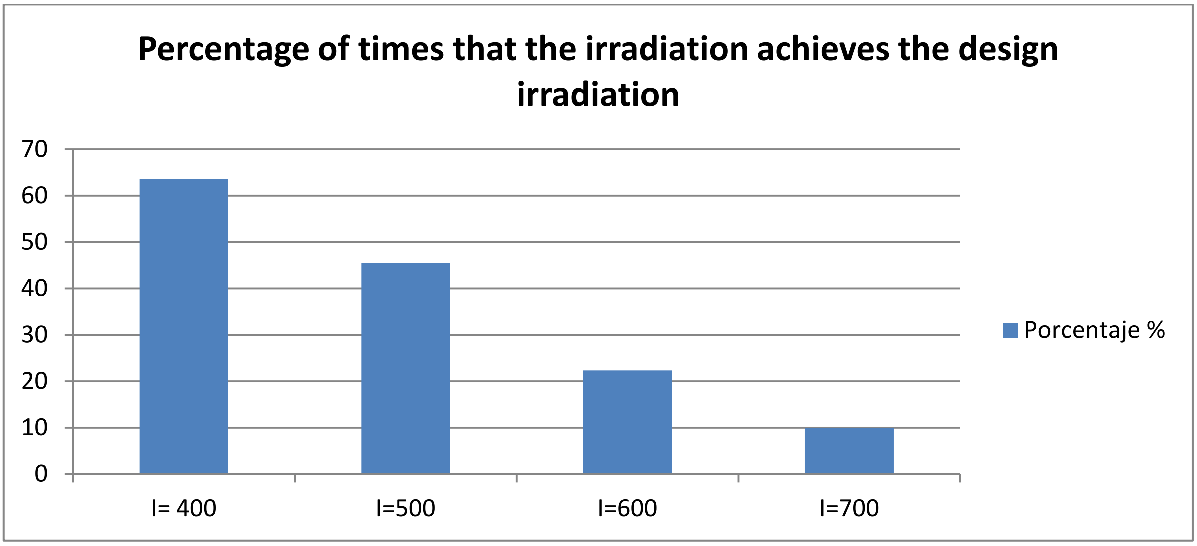


Graphic 12 Percentage of the annual irradiation above the design irradiation



Graphic 13 Quantity of irradiation above the design irradiation

On the chart below it can be seen the percentage of times that the incident irradiation achieves the design irradiation, being the design irradiations of 600 W/m^2 and 700 W/m^2 achieved just a 20% and a 10% respectively.



Graphic 14 Percentage of times that the irradiation achieves the design irradiation

After studding the behavior of the solar field depending on the fixed design irradiation we have come the conclusion that the ideal design irradiation for the plant is 500 W/m^2, as the radiation achieves that design irradiation almost the 45% of the time and it does not exceed this irradiation too much during the year, being the area above the design irradiation line of the 12%. It have been chosen this design irradiation because it offers an average behavior. As the objective of the plant is not to become autonomous, it doesn't really matters if it exceeds the power fixed for the design power, as this will only suppose a decrease on the use of fuel.

Now that it has been defined the design irradiation with which our generation plant is going to work it can be easily calculated the capitation surface required to produce the desired electrical power.

$$Area = \frac{Psolar}{I_{design}} = \frac{219.886\ MW}{500\ W/m^2} = 439771,8683\ m^2$$

4.1.4. Number of Collectors required

In order to calculate the necessary number of collectors, knowing that the required area is 439.771,87 m^2 and that the collector area is 128,82 m^2, it seems as simple as divide the required area between the collector area, so we obtain the required number of collectors to achieve this area.

$$N^{\underline{o}}\ captadores = \frac{Area}{Area\ captador} = \frac{439771{,}8683\ m^2}{128{,}82\ \frac{m^2}{capt}} = 3414\ captadores$$

It has also to be taken on account that the collectors' assembly is made ten by ten, so the number of collectors will be, in fact, multiple of ten. So this number will be provisional, as it will also depend on the collectors' distribution on the field, being able to vary in order to provide an optimal distribution of the solar field.

4.1.5. Captators Distribution

In order to know the number of collectors that have to been placed in each row, that is, the number of collectors in series that are going to be arranged, it has to be taken on account the physic limitations of the collectors and the thermal fluid that flows through the receiving tube. The most important restrictions, the ones that limit the energy that can reach the thermal fluid, are the maximum speed of the fluid, which is 1.5 m/s, and the boiling temperature of the thermal fluid, that is 412 °C. So the thermal fluid cannot circulate at a speed higher than 1,5 m/s and neither increase its temperature above 410 °C. Those situations could occur in the case that the thermal fluid was too much time through the receiving tubes and receiving the solar energy that reaches the collectors, for that reason the number of collectors in each row have to be limited, because, in the case that the ideal number were exceeded, the fluid in extreme radiation conditions for sure would surpass the physic limitations imposed by the collectors and by the fluid. Exceeding these conditions, the pressure in the tubes would increase too much and they would probably break.

So, in order to determine the number of captators in each row it have to be taken on account the power required to increase the fluid temperature 100 °C, from 300 °C to 400 °C, and the power that can be transformed by a collector.

$$N^{\underline{o}}\ collectors/row = \frac{Power\ to\ increase\ the\ Temperature}{Power\ transformed\ by\ the\ ccollector}$$

The required power to increase the fluid temperature 100 °C will be given in function of the maximum speed, the receiving tube area, the fluid density at the working temperature (it will be used the average density at 300 °C and 400 °C) and the enthalpies of the thermal fluid for both temperatures (300 °C and 400 °C) and 12 bar of pressure.

$$Power\ to\ increase\ the\ Temperature = C_{max} * A_{reciver} * \rho_{300} * (h_{400C} - h_{300C})$$

The power transformed by the collector is given in function of the collector area, the maxim irradiation and the collector efficiency. The final equation is the following:

$$Power\ transformed\ by\ the\ ccollector = A_{collector} * I_{design} * \eta_{collector}$$

$$\boldsymbol{N^{o}\ collectors/row} = \frac{C_{max} * A_{reciver} * \rho * (h_{400C} - h_{300C})}{A_{collector} * I_{design} * \eta_{collector}/1000} =$$

$$= \frac{1.5\, m/s * 0.0062\, m^2 * 743.5\, kg/m^3 + (800 - 550)\, kJ/kg}{128.82\, m^2 * 500\ W/m^2 * 0.61875/1000} = \mathbf{24.12}$$

According to the calculations, the ideal number (and maximum number) of collectors in each row is 24,12. Since the assembly of the collectors is done ten by ten the number of collectors should me multiple of 10. So the number of collectors in each row has to be 20 or 30, that is, 2 or 3 assemblies. As it has been explained before, in the case that the number of collectors in each row exceeds the ideal number, the thermal fluid inside the receiving tubes, in extreme conditions of radiation, will exceed the maximum speed and the maximum temperature. For that reason it has to be done a rounding low, so the final result is 20 collectors in each row, that is, 2 assemblies.

It also has to be re-measured the number of collectors in the solar collectors' field. Being the initial resulting number 3414, and knowing that the assembling are made of ten collectors and that in each row there are going to be 2 assemblies, the number of collectors in the solar field should be multiple of 20. So, the final number of collectors is 3420.

Taking on account that there are 20 collectors in each row and that are needed 3420 collectors, can be deduced that the number of collectors rows will be of 171.

$$\boldsymbol{N^{o}rows} = \frac{N^{o}\ collectors}{N^{o}\ \ collectors/row} = \frac{3420}{20} = \mathbf{171\ rows}$$

So the final area will also change from the initial area calculated, being the new area the multiplication of the final number of collectors and its area:

$$Area = \ N^{o}\ collectors * Collectors\ Area = 3420 * 128{,}82 = 440564{,}4\ m^2$$

In the following table are shown the main results of the calculations made in the solar capitation field sizing:

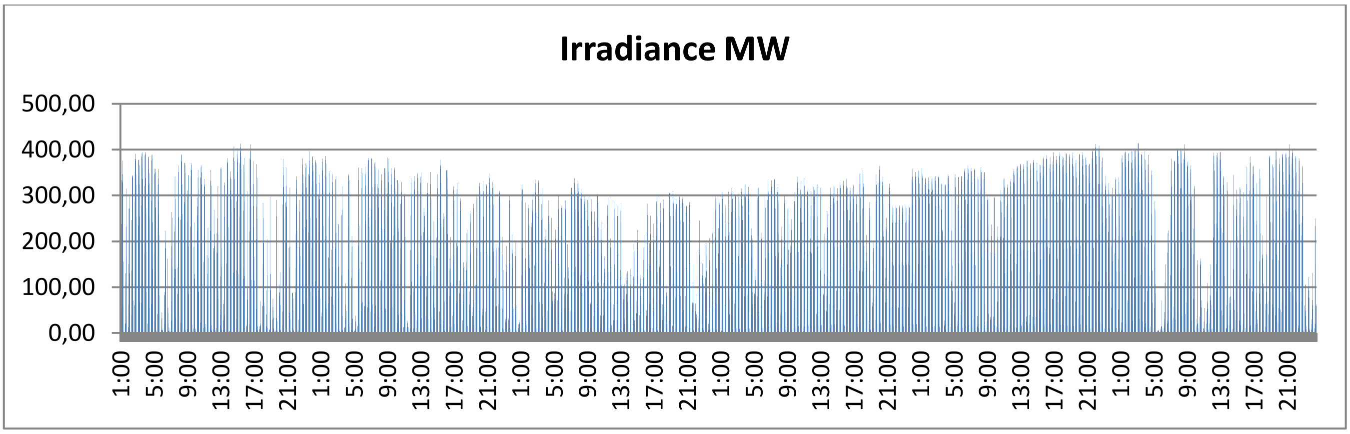
Solar Power Required	219.88	MW
Design Irradiation	500	W/m^2
Area required	439771,87	m^2
Number of collectors	3420	Collectors
Collectors in each row	20	Collectors
Number of rows	171	Rows
Final capitation Area	440564,4	m^2

Table 8 Main solar field results

4.1.6. Incident power on the Collectors

Once it have been seized the solar field, and having the data of the hourly direct irradiation with sun-tracking for a whole year, it can be drawn a bar chart showing the irradiance of the solar field.

The irradiance is the quantity of incident radiation in a determined surface, this is, radiation (W/m^2) multiplied by the surface (m^2), and it is expressed in W. So the irradiance in the solar field will be obtained by the multiplication of the hourly irradiation data by the collectors' field surface.



Graphic 15 Hourly irradiance for a whole year

Taking on account the calculations realized previously relating with the sizing of the solar field ad the number of collectors in each row, it can be determined the mass flow of the thermal fluid that comes from the receiving tubes. This flow will be different depending on the conditions, this is, it will be different in each radiation value.

The mass flow will depend on the fluid speed (c), the area of the receiving tube (Ar) and the density of the fluid (ρ), being the equation as follows:

$$\dot{m} = c * Ar * \rho$$

Being the objective to increase the fluid temperature from 300 °C to 400 °C, the only parameter of the equation that can vary is the velocity, which will vary depending on the irradiation. Remembering the expression used to calculate the ideal number of collectors in a row, it is going to be isolated the velocity, so all the other parameters will be known and unchanging, except the irradiation.

$$\boldsymbol{N^{\underline{o}}\, collectors/row} = \frac{c * A_r * \rho * (h_{400C} - h_{300C})}{A_{collector} * I * \eta_{collector}/1000}$$

$$c = \frac{N^{\underline{o}}col. * A_{collector} * I * \eta_{collector}/1000}{A_r * \rho * (h_{400C} - h_{300C})}$$

$$\boldsymbol{c} = \frac{20 * 128.82\, m^2 * I * 0.61875/1000}{A_r * \rho * (800 - 550)} = \boldsymbol{0.00637659} \frac{\boldsymbol{I}}{\boldsymbol{A_r * \rho}}$$

As the parameters of the receiver area and the density also appears in the mass flow equation, they are going to override each other, so once the velocity is replaced in the mass flow expression, it will be just a constant multiplied by the Irradiation:

$$\dot{m} = c * Ar * \rho = 0.00637659 \frac{I}{\cancel{A_r * \rho}} * \cancel{Ar * \rho} = \boldsymbol{0.00637659 * I}$$

This expression calculates the mass flow that comes out of the receiving tube, to calculate the total mass flow, this is, the mass flow that is going to arrive to the heat exchanger, there is need to multiply it by the number of rows that compose the solar field.

$$\dot{m}_{total} = \dot{m} * 171$$

In the following table are shown some important calculations of the annual radiation, irradiance, electrical power, fluid speed and mass flow.

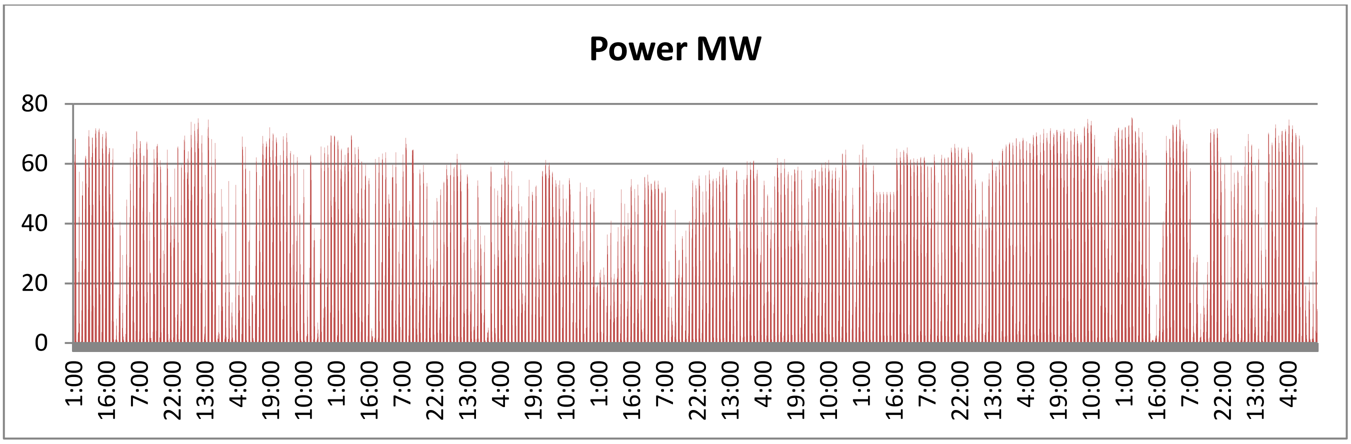
AREA		440564,4		m^2
	MAXIMUM	**AVERAGE**	**DESIGN**	
Radiation	942,00	413,77	500,00	W/m^2
Irradiance	415,01	182,29	220,28	MW
Power	75,50	33,16	40,07	MW
Speed	1,30	0,57	0,69	m/s
Flow in the receiver	6,01	2,64	3,19	kg/s
Total flow	1027.15	415.1	545.20	kg/s

Table 9 Main data of the Parabolic-Trough solar plant

4.1.7. Transformed power from the Collectors

It can also be determined the electrical power produced by the solar contribution, by applying the efficiencies that are involved in the energy transformation process.

This electrical power hourly contribution is shown in the bar chart below:



Graphic 16 Electric power produced by the solar field contribution

4.2. Pumping group

The thermal fluid circulating through the collectors' field needs to be pumped, so it can circulate. In the case of maximum irradiation (1000 W/m^2), the mass flow of the thermal fluid will be 1090.4 kg/s. Knowing that the density of the thermal fluid is 743.5 kg/m^3 and making the conversion, we know that the volumetric flow in these conditions is 1.466 m^3/s (387.27 gallons/s).

It is planned to place duplex diaphragm large pumps, in this case the maximum flow that can goes though each pump is 660 gpm (gallons per minute), while in our case it is needed to pump 23236.57 gpm. Being the maximum pumped flow 660 gpm there will be needed 35.2 pumps. There so, there is going to be placed 36 pumps with the capacity to pump 645.5 gpm.

4.3. Simplified scheme of the plant

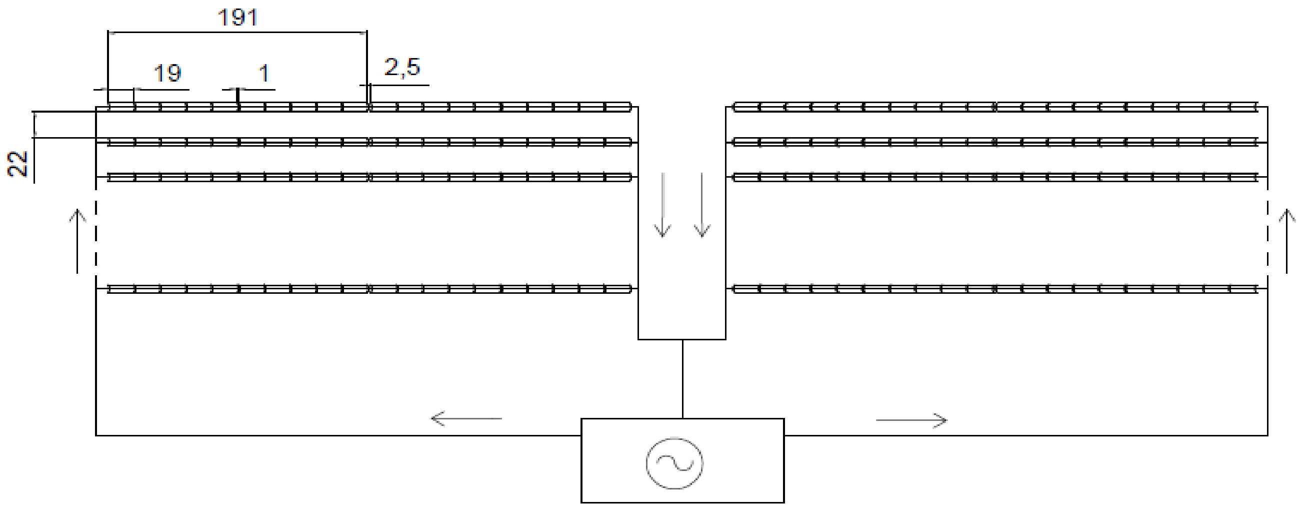


Image 15 Scheme of the collectors distribution and the plant dimensions

On the image above is showed in a schematic way, the distribution of the parabolic trough collectors. The plant will be formed by 3414 collectors of 19 m each one. These collectors will be assembled on groups of ten, and each group will have a length of 191 m. In each row of the field there will be two assembles of collectors, with a distance of 2.5 m between them. There so, there will be 2 assembles of 10 collectors each one in each row, that means that there will be 171 rows in total.

Between each row, there is needed to leave an space of 22 m in order to avoid possible shadows during the day, what will suppose a loss of solar incidence, and there for, a loss of energy. Instead of distributing all the rows in parallel, they will be divided in two groups, so there will be, on one side, a group of 85 rows in parallel and, on the other side, a group of 86 rows in parallel too.

All the thermal fluid coming from the both sides of the collectors' field will be brought up together before getting in the thermodynamic process.

4.4. Resume

FIELD		
Collector model	Helio-Trough	Flagsol
Thermal Fluid	DOWTHERM-A	
Field area	440564,4	m^2
Nº collectors	3414	
Collectors x row	20	
Rows	171	
Max. Fluid speed	1.5	m/s
Efficiency	18.2	%

Table 10 Parabolic Trough collectors field characteristics

ENERGY		
Annual irradiation	1.74	MWh/m^2year
Total radiation	165.635	GWh/year
Design irradiation	500	W/m^2
Annual electrical energy	139,2785355	GWh/year
Power at I_d	40	MW
Solar fraction	13.82	%

Table 11 Parabolic Trough generation plant characteristics

5. Photovoltaic plant

At the solar-photovoltaic plants the electricity is generated through photovoltaic panels, where the global irradiation is transformed directly into electrical energy using a technology based on the photovoltaic effect. This technology takes advantage from the properties of the semiconductors materials.

The photovoltaic panels are formed by photovoltaic modules, and these ones are made up of photovoltaic cells, where the transformation of solar incidence into electricity is made.

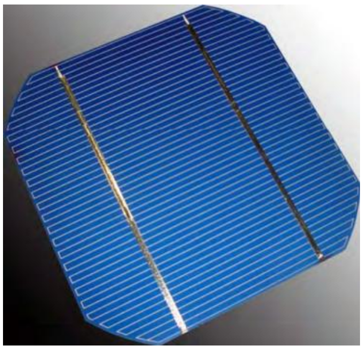


Image 16 Photovoltaic cell [14]

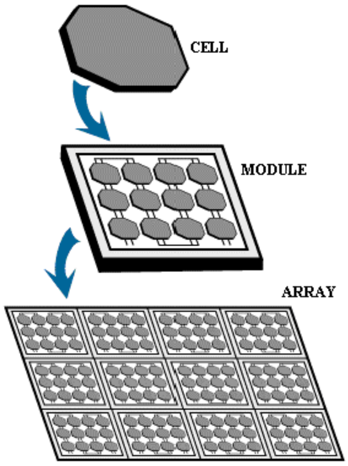


Image 17 Photovoltaic panels' formation [15]

The photovoltaic cell is made up of two layers of semiconductors materials doped in a different way. The first layer, that one called Layer N, is formed by a material with an excess of electrons, that is, its charge is Negative. The second layer, the one called Layer P, is formed by a material with a deficit of electrons, so it will be positively charged. Being these layers doped in a different way, that means, with a different charge, there exist a difference of potential between them. When the light impacts on the cell, the electrons from the Layer N, catch the energy from the photons and this energy is used to skip from the Layer N, with an excess of electrons, to the Layer P, with a deficit of electrons. When the electrons pass from one Layer to another, a direct current is generated.

An external conductor is used to join the negative layer with the positive layer, where is generated a flux of electrons (electric current) as soon as the light impacts on the cell. The intensity of the electric current generated will vary at the same proportion as the impacting light intensity.

At the image below is explained, in a visual way, the process that a photovoltaic cell follows once the light gets to it. On the image, the red balls represent the electrons, which move from the layer N to layer P through the conductor to fill the gaps of layer P:

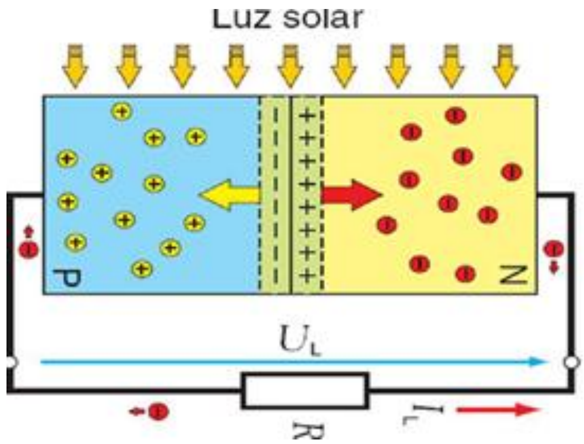


Image 18 Visual explanation of a photovoltaic cell performance

The photovoltaic cells from a module are connected in parallel and in series with each others as is shown on the image bellow. The modules connected in series are called *strings*. In the case that one of the modules are shadowed, the cells of the module doesn't work as a electric generator and makes the opposite function, it works as a resistance, that means that it would consume part of the energy produced from the other modules of the string and it would also increase the temperature. This situation is called as *hot point*. To avoid this situation, a diode is connected to the modules, placed in parallel to the module, so, in case that a module is not working, the current would pass through the diode, so the module would be *bypassed*.

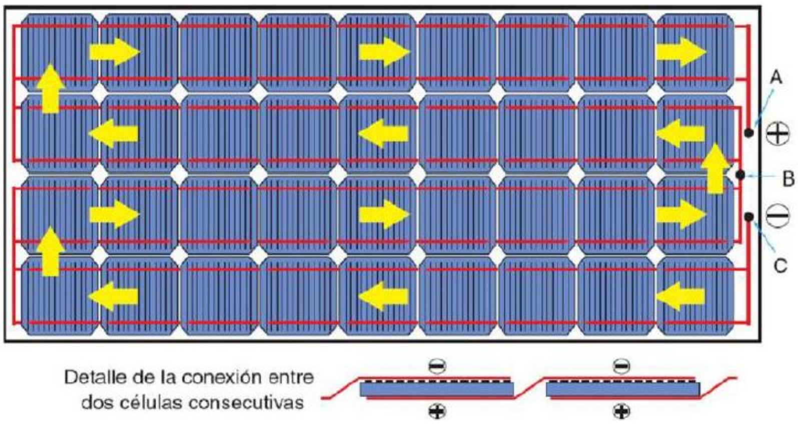
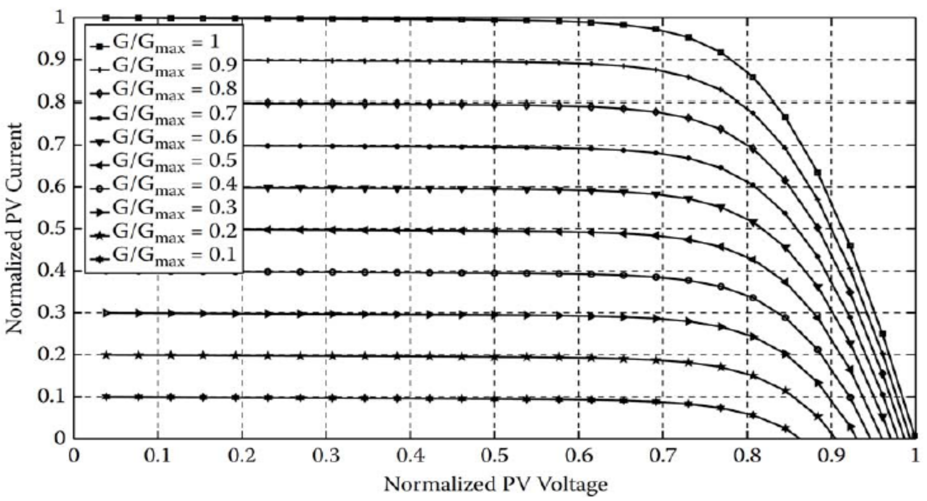


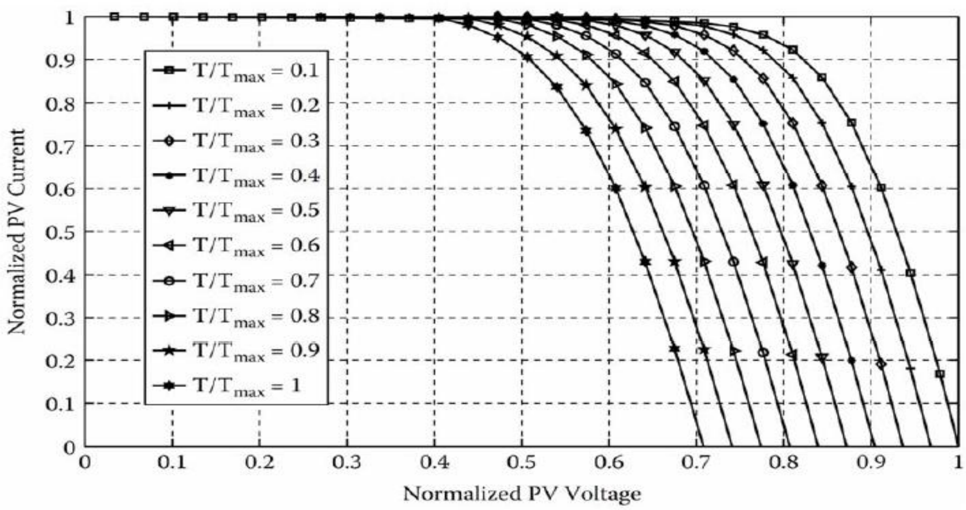
Image 19 Photovoltaic modules distribution in an array

The Power generate by the photovoltaic modules depends on the irradiation and also on the temperature on the way it can be perceived on the following graphics about the general performance of photovoltaic modules, that show, in the first one, the difference on the current depending on the radiation when working at ambient temperature (25 °C) and, in the second one, the difference on the voltage depending on the temperature when working at the optimal irradiation (1000 W/m²):



Graphic 17 Current and voltage variation depending on the irradiation (G) on the photovoltaic modules [16]

As it can be seen, the maximum power is generated when the irradiation (G) is the same as the maximum irradiation (1000 W/m²). At that condition is generated the maximum current. That is normally 1 A. This current remains constant while the voltage increases until gets closer to 1 V. More closely it gets to 1 V, lower the current it becomes, beginning this decrease from 0.7 V.



Graphic 18 Current and voltage variation depending on the Temperature (T) on the photovoltaic modules [16]

In this graphic it can be seen that when the temperature (T) is equal to the maximum temperature (T/Tmax=1) the current decreases earlier in function of the voltage. This is, when the temperature is the maximum, the generated current remains at 1 A until 0,4 V, once it arrives to 0,4 V, it decreases until 0 A at 0.7 V. On the other side, when the temperature is the lowest (in this graphic, ten times lower than the maximum), the generated current remains constant at 1 A until 0.7 V, when it begins to decrease until 0 A at 1 V.

5.1. Panels selected

The photovoltaic modules selected for the project simulation are made up of 76 cells connected 6 in series and 12 in parallel (6x12). The dimension of each cell is of 156.75x156.75 mm, which is 0.0245 m^2, and the total dimensions of the module are 1965x991x45 mm, being the module area of 1.94 m^2. The model is the JAM6(K)-72-350/PR, fabricated by the company "JA SOLAR". Each module has a maximum power voltage (Vmp) of 38.58 V and a maximum power of 350W at Standard Test Conditions, STC. Being this conditions an Irradiance of 1000 W/m^2, a Cell Temperature of 25ºC and an Air mass of 1,5.

These modules have been approved by some certificates; some of them are the IEC 61215, the ISO 9001 and the ISO 14001. Its efficiency is about 18% and it also offers a 10 years warranty and 20 years of linear power warranty. The characteristic curves of the modules showing the performance of the Current (I) in function of the Voltage (V) depending on the irradiance (W/m^2), the performance of the Current in function of the Voltage depending on the Temperature (ºC) and the performance of the Power (W) in function of the Voltage depending on the Irradiance, can be founded at photovoltaic modules data sheet [17], as well as the datasheet of the product.

On the tables bellow are shown the basic and most important characteristics of the model, the ones that will be necessary to carry out the further calculations of the photovoltaic field project.

MODEL	JAM6(K)-72-30/PR	
Rated Maximum Power at STC	350,00	W
Open circuit Voltage Voc	47,24	Voc/V
Maximum Power Voltage Vmp	38,58	Vmp/V
Short Circuit Current	9,61	Isc/A
Module Efficience	0,18	%
Power Tolerance	-0+5	W
Temp Coefficient of Isc	0,06	%/ºC (αIsc)
Temp Coefficient of Voc	-0,30	%/ºC (βVoc)
Temp Coefficient of Pmax	-0,39	%/ºC (ϒPmp)
Length	1,96	m
Width	0,99	m

Table 12 Photovoltaic modules' basic characteristics

It have been chosen this model of photovoltaic module between the other models of this fabricant because is the one that offers a major power, a major Voltage and the better efficiency.

It also have to be taken on account that the modules' characteristics mentioned above are related to the power generation when working on ideal conditions (STC), it means an irradiation of 1000W/m², an environment temperature of 25 °C and an air mass of 1,5.

It means that the power generation, won't only depend on the incident irradiation on the modules, it will also depend on the temperature, as the temperature will make the modules efficiency change. That is, unless the temperature is 25 °C, the modules efficiency will be lower than 18%. Attending to the characteristics mentioned above, the temperature coefficient of Pmax (ɣPmp) is -0.39%/°C. That means that for each degree that the environment temperature differs from the STC temperature, it will supposes a loss of 0.39% of the generation power.

The equation to calculate the losses due to the temperature is the following [18]:

$$FT = 1 + \frac{\Upsilon \text{Pmp}}{100} * (T - 25°\text{C})$$

There so, in order to correct the efficiency taking on account the losses due to the temperature, it will be calculated the temperature losses using the average maximum temperature. Is going to be used the maximum temperature instead of the average temperature because what affects on the efficiency is the difference from the STC temperature, there so, if it is used the average temperature, it does not reflect the difference from 25 °C.

Temperature °C		
	Average (Sun hours)	Maximum average
January	28,1	30
February	27,2	29,2
March	26,4	28,5
April	25,6	28,5
May	25,1	28
June	24,8	27,7
July	25	28,4
August	26	29,5
September	27	30,2
October	27,5	30,1
November	27	30
December	27	29,5
Annual	26,39	29,13

Table 13 Month temperatures at Iracé [19]

According to the equation described before, then, the losses due to the temperature along the year are the following:

$$FT = 1 + \frac{-0.39}{100} * (29.13 - 25°\text{C}) = \mathbf{0.9839}$$

That means that the maximum efficiency on the panels (18%), must be multiplied by the efficiency owing to the temperature (98.39%), so it can be obtained the annual average corrected efficiency of the modules:

$$\eta_{corrected} = \eta_{STC} * \eta_{temperature} = 0.18 * 0.9839 = 0.1777 = \mathbf{17,77}\%$$

There so, the efficiency used to calculate the dimensions and distribution of the photovoltaic field will be 17.77% instead of 18%. And, when calculating the annual energy generation will be used different temperature efficiency for each month, calculated using the average maximum temperatures of each month.

5.2. Converter selected

Due to the characteristics of the energy produced by the photovoltaic modules, this energy can't be injected directly to the distribution electrical greed. This energy needs to be converted by the inverter, an additional power unit. The inverter transforms the power arriving in direct current, to a determined voltage as alternate current. There so, the converters are that ones in charge of performing the conversion DC/AC so the photovoltaic generators can be connected to the distribution net.

The inverter selected for this project is the "Sunny central 500 HE-US", with a nominal power at DC of 509 kW and a maximum PV power of 560 kW. This inverter offers a maximum efficiency of 98.6% at the maximum AC power.

On the following table are described the most important characteristics of the inverter, that ones that will be useful for the further calculations of the photovoltaic field.

Model	SUNNY CENTRAL 500 HE-US		
Characteristic	**Value**	**Unit**	**Abbreviation**
	Input Data		
Max. PV Power	565	kWp	P_{PV}
DC Voltage range	330-600	V	U_{DC}
Max. permissible DC Voltage	600	V	U_{DC}, max
Max. permissible DC Current	1600	I	I_{DC}
	Output Data		
Nominal Power AC	500	kW	P_{AC}
Max. AC Current	1470	A	I_{AC}, nom
Oltage Range AC	180-220	V	U_{AC}
	Others		
Max. efficiency	98,6	%	

Table 14 Inverters basic characteristics

5.3. Required surface

In order to compare in an equivalent way the two types of solar fields, both should be sized with the objective of producing the same amount of energy during the whole year. Therefore, the photovoltaic solar field should be able to generate approximately a total annual energy of 139.28 GWh taking on account the 2005 radiation data, which will be the same ones used for the sizing of the parabolic-trough field, and there so, an equivalent comparison will be available.

On the section before have been introduced the characteristics of the photovoltaic modules and the inverters. Among the characteristics presented there were the efficiency of each one. Knowing both performances (18% for the photovoltaic modules and 98,6% for the inverter), it will be calculated the solar energy that should reach the solar field during the whole year so, once it is transformed by the photovoltaic modules and by the inverter, the final energy is that one mentioned before.

$$Incident\ energy = \frac{Final\ annual\ energy}{\eta_{pv\ mdule} * \eta_{inverter}} = \frac{139.278535\ GWh}{0.1777 * 0.986} = 794.9639\ GWh$$

Knowing that the maximum irradiation that a photovoltaic module can absorb is 1000 W/m², the maximum annual solar energy that can be transformed by a module would be of 2.07 MWh/m². There so, knowing the total energy that should reach the solar field (GWh) and the expected annual radiation per square meter (MWh/m²), it can be calculated, through a simple division, the area of photovoltaic modules that will be required to reach that amount of energy.

$$Required\ area = \frac{Total\ incident\ energy}{Annual\ energy\ per\ m^2} = \frac{794963{,}9MWh}{2.06849\ MWh/m^2} = 384322{,}82m^2$$

Once it is calculated the minimum area that is necessary to obtain the fixed final energy, it can be calculated the number of photovoltaic modules required to fill this area:

$$Nº\ photovoltaic\ modules = \frac{Field\ Area}{Module\ Area} = \frac{384322{,}82\ m^2}{1.9384\ m^2} = 198268{,}48\ modules$$

This number of required photovoltaic modules is not the definitive, is just the minimum number of modules to obtain the objective annual energy. Depending on the modules distribution for their connection to the inverters, the final number of modules will vary.

5.4. Panels distribution

The modules distribution series/parallel will depend just on the characteristics and requests fixed by the inverters, which will admit a maximum power value to transform.

5.4.1. Number of modules in series

Knowing that the range of voltage of the inverter at the maximum power of the photovoltaic modules is 330 - 600 V, the voltage generated by the group of modules in series should be between these two values.

There so, in order to calculate the optimal number of photovoltaic modules in series connected to de inverter, it will be verified that in the following cases the voltage is in the range specified [20]:

$$\begin{cases} V_{max}(T_{min}) = V_{mp} * N_s\big(1 + \alpha * (T_{min} - T_{amb})\big) \\ V_{max}(T_{max}) = V_{mp} * N_s\big(1 + \alpha * (T_{max} - T_{amb})\big) \\ V_{oc}(T_{min}) = V_{oc} * N_s\big(1 + \alpha * (T_{min} - T_{amb})\big) \end{cases}$$

Where V_{mp} is the maximum power offered by the photovoltaic module, and its value is 38.58 V, V_{oc} is the Open Circuit voltage of the module, which value is 47.24 V and α is the Voc's Temperature Coefficient of the modules, with a value of 0.30 %/°C. The minimum and maximum temperatures are the range of temperatures where the photovoltaic modules will work according with the place where it is located, these temperatures at the location selected and applying large margins will be "-10 – 60 °C" and T_{amb} is the environment temperature: 25 °C. The only value that will be variable, there so, is Ns, which is referred to the number of panels in series that will be connected to the inverter, being the final equations as follows:

$$\begin{cases} V_{max}(T_{min}) = 38{,}58 * N_s\big(1 + 0{,}003 * (-10 - 25)\big) \\ V_{max}(T_{max}) = 38{,}58 * N_s\big(1 + 0{,}003 * (60 - 25)\big) \\ V_{oc}(T_{min}) = 47{,}24 * N_s\big(1 + 0{,}003 * (-0 - 25)\big) \end{cases}$$

Applying these equations for some values of Ns we obtain the following results:

Ns	Vmax(Tmin)	Vmax (Tmax)	Voc(Tmin)
5,00	213,15	172,65	261,00
6,00	255,79	207,17	313,20
7,00	298,42	241,70	365,40
8,00	341,05	276,23	417,60
9,00	383,68	310,76	469,80
10,00	426,31	345,29	522,00
11,00	468,94	379,82	574,20
12,00	511,57	414,35	626,40
13,00	554,20	448,88	678,60

Table 15 Calculations' results to decide the number of modules connected in series

Previously we said that the range of voltage of the inverter is 330-600 V, just for security, the margins will be reduced by 10 V, so the range is decreased to 340-590 V. There so, the voltage generated by the group of modules in series should be in the boundaries specified at all the tree cases explained before. Studding the previous table, it can be inferred that the only options that respect all the conditions is connecting 10 or 11 modules in series to the inverter. However, in order to do not exceed the power that the inverter can admit, it is going to be chosen the lowest option, so the number of **modules in series will be 10**.

5.4.2. Number of panels in parallel

To calculate the maximum number of modules in parallel (Np) it also will be taken on account the temperature and the maximum value of direct current that can be admitted by the inverter, that in this case is 1600 A. There so, the direct current (DC) generated by the group of modules in parallel when working at the maximum temperature can't overpass the 1600A. As well as in the previous calculations, for security reasons, this limit will be reduced by 10 A, so the maximum current that we will admit will be 1590 A, attending the following equation [21]:

$$I_{SC}(T_{Max}) = I_{SC} * N_{p\ Max}\left(1 + \beta * (T_{Max} - T_{amb})\right)$$

In this equation, β makes reference to the Temperature Coefficient of Isc, and its value is 0.06%/°C, and Isc is the Short Circuit Current of the photovoltaic modules, which value is 9.61A. Therefore, the only variable parameter of the equation is the maximum number of modules in parallel connected to the inverter:

$$I_{SC}(T_{Max}) = 9{,}61 * N_{p\ Max}\left(1 + 0{,}0006 * (60 - 25)\right)$$

As well as it have been done when calculating the required number of modules connected in series to the inverter, it will be calculated Isc for some values of Ns:

Ns	Isc(Tmax)
158	1559,37626
159	1569,24573
160	1579,1152
161	**1588,98467**
162	1598,85414
163	1608,72361

Table 16 Calculations' results to decide the number of modules connected in parallel

Attending to the results showed at the table above, the maximum number of photovoltaic modules connected in parallel to the inverter is 161, this connection will suppose a Direct Current input to the inverter of 1589 A, just in the limit fixed. However, if the number of modules in parallel were 161, as the maximum input current at the inverter permits, the input power at the inverter would over pass the maximum when the panels generate the maximum power (350 W), as can be seen at the following calculations:

$$Maximum\ power\ generation\ by\ a\ module = I_{max} * \eta_{max} * A = 1000\frac{W}{m^2} * 0{,}18 * 1{,}94 = \mathbf{349,2\ W}$$

$$Maximum\ modules\ to\ the\ inverter = \frac{Input\ power\ at\ the\ inverter}{Maximum\ module\ power} = \frac{500\ kW}{0{,}3942\ kW} = \mathbf{1431\ modules\ by\ inverter}$$

Taking on consideration these calculations, it is fixed that the maximum number of modules connected to an inverter is 1431 modules, in order to not exceed the input power of the inverter. Being the number of modules in series already calculated, now it is calculated the number of modules in parallel that are necessary:

$$Modules\ in\ parallel = \frac{total\ modules}{modules\ in\ series} = \frac{1431}{10} = 143{,}1 = \mathbf{143\ modules\ in\ parallel}$$

As this number is lower to 161, that is the maximum parallel modules that an inverter can admit in order to not over pass the input current, the number of modules in parallel will definitely be 143.

There so, the number of modules connected to each inverter will be 10 in series and 143 in parallel, making a total of 1430 modules by inverter. That will suppose a maximum input power at ideal conditions of:

$$Input\ power\ at\ the\ inverter_{max} = Power\ by\ module_{max} * N^{o}{}_{modules} = 349{,}2 * 1430$$

$$Input\ power\ at\ the\ inverter_{max} = 499{,}356\ kW$$

Appling this configuration for each inverter the inverters will work at the maximum power some times and it won't be over sized.

5.4.3. Final number of modules

Taking on account the calculations made at the previous sections we know that the minimum number of photovoltaic modules that the solar field needs to achieve the required annual energy is 195073 modules. We also know that each inverter will have connected a group of 1771 modules, 11 in series and 161 in parallel, in order to meet the limits imposed by the inverter. There so, dividing the number of modules required by the number of modules connected to the inverter the number of inverters required can be determined:

$$N\ inverters = \frac{N\ modules}{modules\ x\ inverter} = \frac{198269}{1430} = 138{,}65 = \mathbf{139}$$

In this case the number of inverters will be rounded upper, as rounding per would suppose an excess of 501 modules in comparison with the 198,269 required, which does not make a big difference. This excess of modules supposes an increase of 352 MWh/year. So, rounding upper the number of inverters, the final electrical energy generated at the photovoltaic field will be 139.63 GWh/year, while the objective was to generate 139.28 GWh/year. It will suppose an increase of 0.35 GWh/year.

There so, disposing 139 inverters and 1430 photovoltaic modules by inverter, the total number of modules will be 198770, and the field area 385294.97 m².

5.4.4. Distance between rows

In order to avoid looses of generated energy due to the shadows produced between the modules rows it have to be calculated the necessary distance between rows, which will depend on the inclination of the modules and the latitude of the location [22].

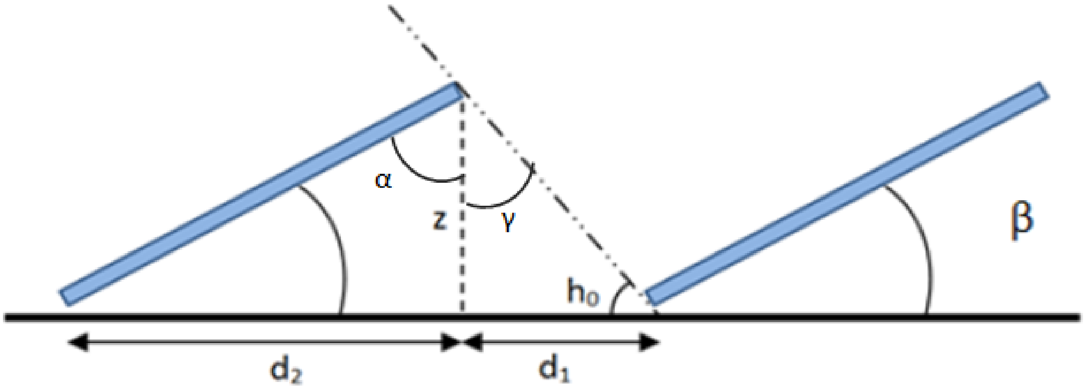


Image 20 Geometric scheme of the distance between two photovoltaic modules

β represents the modules inclination, which, as it have been determined in a previous section, is 12°. Knowing this and the modules longitude (1,96 m), it can be calculated z and d2:

$$\alpha + \beta + 90° = 180° \quad ; \quad \alpha = 180° - 12° - 90° = 78°$$

$$\frac{\sin 90}{1{,}96} = \frac{\sin \beta}{z} \; ; \; \frac{\sin 90}{1{,}96} = \frac{\sin 12}{z} \quad ; \; z = 0{,}4075$$

$$\frac{\sin 90}{1{,}96} = \frac{\sin \alpha}{d2} \; ; \; \frac{\sin 90}{1{,}96} = \frac{\sin 78}{d2} \quad ; \; d2 = 1{,}9172\, m$$

To calculate d1 we have to previously calculate *ho*, which is the minimum angle to avoid the shadows between the photovoltaic modules. This angle will be calculated referred to the winter solstice, as this is when the Sun height is lower and there for the shadow goes further. The *ho* angle is calculated as follows:

$$ho = (90° - |\varphi|) + \delta$$

$$ho = (90° - 12°) - 23{,}45° = 54{,}55°$$

In this equation φ refers the latitude of the solar field location, which is -12˚, and δ is the declination of the earth the day of the winter solstice, -23.45˚.

$$\gamma + \beta + 90° = 180° \quad ; \quad \gamma = 180° - 90° - 12° = 35{,}45°$$

$$\frac{\sin ho}{z} = \frac{\sin \beta}{d1} \; ; \; \frac{\sin 35{,}45}{0{,}4075} = \frac{\sin 12}{d1} \; ; \; d1 = 0{,}29\, m$$

There so, the distance between each row must be of 2.2072 m. which means that for each module we have to count on a length of 2.2072 m instead of 1.96 m. The total area of the field, without taking on account the inverters and transformation stations, will be 433862.31 m^2:

$$Field\ Area = No\ modules * d12 * H = 198770 * 2{,}2072 * 0{,}99 = 434776{,}62\, m^2$$

5.5. Final energy generation

There so, once the inclination of the panels has been fixed and that the optimal number of modules for the installation and its average efficiency have been corrected and there so the final area, it can be recalculated the final total energy that will be produced along the year:

$$Annual\ energy = Annual\ radiation * Field\ Area * \eta_{modules} * \eta_{inverter}$$

$$Annual\ Energy = 2068479{,}52\ W/m^2 * 385294.97\, m^2 * 0{,}1777 * 0{,}986$$

$$Annual\ Energy = 139630.84\ \mathrm{MWh}$$

5.6. Installed Power

The installed power of a photovoltaic plant is that one that the whole modules are capable to produce. That is, the maximum power that the plant can generate in the case of optimal irradiation and temperature.

The installed power of the generation plant can be calculated by the following equation:

$$P_{instlled} = P_{Wpp} * A_{util} * \eta_{total}$$

Where the P_{wpp} is the maximum incident radiation that the modules are able to capture and transform, the A_{util} is the area occupied by the modules and the η_{total} the efficiency of the plant at optimal conditions, which are the best efficiency the modules can have multiplied by the inverters efficiency. Considering these parameters, the equation can be solved:

$$P_{instlled} = 1000 \frac{W}{m^2} * 139630.84\, m^2 * 17.8\% = 69.58\, MW$$

An installed power of 69.58 MW can seem too much for a photovoltaic energy generation plant, as the usually dimensions are around 40-50 MW. However, there is already a photovoltaic plant in China of an installed power of 850 MW, producing 483 GWh/year and filling a field of 9.16 Km^2. There was also, in Brazil, a project from ENEL, an Italian energy company, of 292 MW of installed power, expected to generate 600 GWh/year and to size 690 hectareas, this project would be the biggest photovoltaic plant of Brazil. There so, now a day, or at list in a few years, this amount of installed power won't be too much any longer.

5.7. Resume

MODULES			INVERTER		
Model	JAM6(K)-72-30/PR		**Model**	Sunny Central 500HE-US	
Area	1,9384	m²	**Efficiency**	98,60	%
Efficiency	17.77	%	**Input Voltage**	330 - 600	V
Maximum Power Voltage	38,58	Vmp/V	**Maximum Imput Current**	1600	A
Open Circuit Voltage	47,24	Voc/V	**Nominal Output Power**	500	kW
Maxi irradiation	1000,00	W/m²	**Nominal AC Voltage**	200	V
			FIELD		
Annual Generation	139630,8	MWh/year	**Number of modules**	198770	unt.
Annual Radiation	2,07	MWh/m²year	**Number of inverters**	139	unt.
Total modules Area	385295	m²	**Distance between rows**	2,21	m

Table 17 Resume of the photovoltaic plant characteristics and calculations

6. Conventional Power Plant

A thermal plant, or conventional power plant, produces electrical energy by transforming the liberated energy in a chemical reaction into mechanical energy. This chemical reaction is produced by the combustion of fuels; these can be the traditional ones as the Natural Gas or the petroleum or alternative as biodiesels or biomass.

This type of electric energy generation plants are adaptable to the demand, as its power can be regulated by the amount of fuel it is burned at the boiler. There so, they can be used to firm the energy that the renewable energies can´t firm. That is, in case of not having sun to produce electrical energy at a photovoltaic plant or not having wind in an wind park, the energy demand from the consumers have to be supplied, there is when the renewable energies needs the support of the conventional and adjustable generation plants.

6.1. Thermal cycle

6.1.1. Cycle description

The chosen thermal cycle for the electric generation power plant is a Rankine cycle, or steam cycle. This cycle, a part from the boiler, which is present in all of this kind of cycle, it also counts on a steam pre-heater, on an exhaust-heat exchanger to recuperate the heat of the exhaust gases coming from the boiler and on a second turbine.

The scheme below shows, in a simplified way, the different stages of the Rankine cycle.

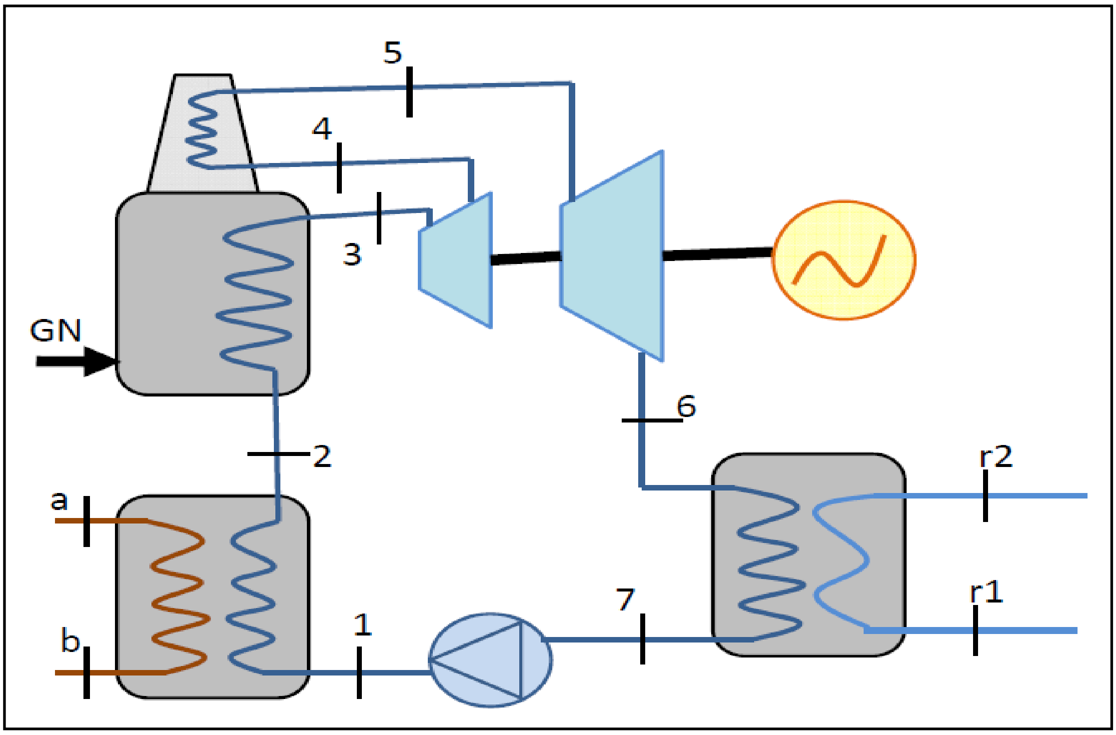


Image 21 Simplified scheme of the thermal cycle

Between the points 1 and 2 of the cycle it is placed a heat exchanger. In this exchanger the thermal fluid comes from the collectors' field after having absorbed the energy of the sun and being heated and transfers its heat to the fluid that goes through the Rankine cycle. The fluid in the Rankine cycle is water, that in the point 1 it is found in liquid state, and in the point 2, depending on the mass flow of the thermal fluid in the exchanger, it can be founded as super-heated steam. In this heat exchanger the thermal fluid will go in at 400 °C (at the point A) and, after transferring its heat to the Rankine Cycles fluid, it will go out at 300 °C at the point B. The state of the water at the point 2 will depend on the irradiation at that moment and, there so, on the speed and mass flow of the thermal fluid.

Between the stage 2 and 3 of the cycle there is a fossil fueled boiler, in this case the fossil fuel is Natural Gas. The objective of the boiler is that at the 3th point the water becomes overheated steam and achieves a determined and constant temperature at a certain pressure. To that end, the flow of the Natural Gas burned at the boiler must be regulated to supplement the heat transferred from the thermal fluid to the water of the cycle at the heat-exchanger. This is, at the boiler will be burned the Natural Gas required in each moment to increase the enthalpy of the fluid from the point 2 (that will be variable) to the enthalpy of the point 3.

From point 3 to point 4 it will be placed a high pressure turbine. Here, the steam delivers internal energy to the turbine and goes out as saturated steam ad with a lower pressure that at the entrance.

At the phase 4-5 it is set a heat exchanger. This heat exchanger uses the heat coming from the exhaust gases from the boiler and, if it is necessary, extra natural gas to reheat the saturated steam coming from the high pressure turbine and turn it into overheated steam to fulfill the conditions to go into the second turbine.

Between stage 5 and 6 there is the second turbine of the cycle, the low pressure turbine. In this turbine, as at the high pressure turbine, the overheated steam coming from the exhaust-heat exchanger gives part of its internal energy, making the turbine spades spin and turning the steam internal energy into mechanical energy, which will be transformed into electrical energy trough the electric generator connected to the turbines axis.

Once the fluid comes out from the last turbine as saturated steam, at the point 6, it will go through a condenser. At these phase the fluid will go in as saturated steam, with a high steam title, and will go out as saturated liquid (with 0% of steam). To this, the fluid from the Rankine Cycle will transfer heat to the fluid at the Refrigeration Cycle, which, in this case, is water.

After the condenser, the fluid will go through the last phase of the cycle, between points 7 and 1. Between these two points there is a pump, which will pump the fluid and increase its pressure to make it circulate through the cycle at the desired pressure. The fluid can only go through the pump as a liquid, this is why it is necessary to condensate the saturated steam coming out from the turbine before entering at the pump.

6.1.2. Cycle operation

As the major part of the cycle is going to be equal in both thermal cycles (the one that gives support to the photovoltaic plant and the one that transforms the thermal energy obtained at the collectors field), it is not going to be calculated all the parameters of the cycle, as it won't have an useful utility for the economical comparison that it is wanted to do.

The only element that differs from both cycles is the heat exchanger used at the Parabolic Trough generation plant, which will be necessary to give the thermal energy obtained at the solar field to the fluid circulating at the thermal cycle, which in this case is water.

It will also be explained how the turbine power have been selected and the basic characteristics and performance.

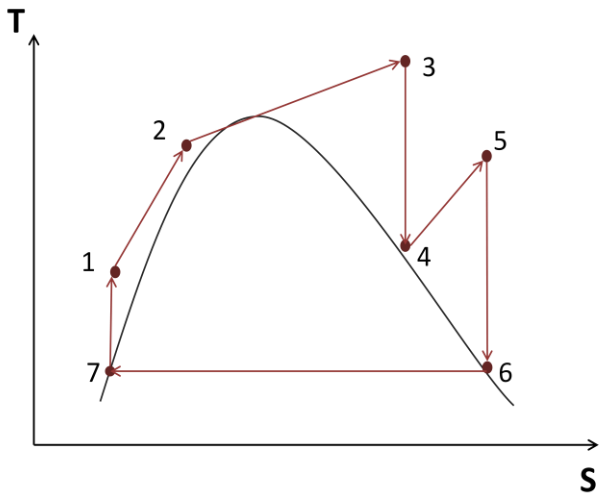


Image 22 S-T Rankine Cycle diagram

The graphic above represents the T-S (Temperature – Entropy) diagram that follows our thermal cycle. The curve represents the critical conditions characteristics, that is, when a point is placed inside this curve it means that the water is saturated, it is changing from liquid to steam or from steam to liquid. While suffering this transformation the water remains at the same temperature, while its entropy and enthalpy changes, as it happens in the process 1-2. At the left side of the curve, the fluid is in a liquid state, and at the right is as steam.

From 1 to 2 the water is heated at the heat exchanger, increasing the pemperature and the enthalpy, but remaining the pressure constant. From 2 to 3 happens the same as at the porces 1-2 in the boiler. From 3 to 4 the water gives its energy to the turbine, decreasing its pressure, temperature and enthalpy almost until the saturated conditions, but the entropy (in an ideal turbine with a 100% efficiency) remains constant. From 4 to 5 the water is reheated in an isobaric process (constant pressure). From 5 to 6, as at the process 3-4, the water gives its energy in an isentropic process until having saturated characteristics. From 6 to 7 the water is condensed at a constant temperature, passing from saturated steam (100% steam) to saturated liquid (0% steam). Finally, from 7 to 1 the water goes through the pump, where its pressure its incremented in an isentropic process (in an ideal case).

Heat exchanger

As it is the only element of the cycle that is going to be taken in consideration when comparing economically both ways of energy generation, it have to be studied its performance, its working parameters and its area. This will be studied when working with a maximum irradiation of 1000 W/m^2.

In order to calculate the required area of the heat exchanger it is going to be considerate the following equation:

$$A = \frac{Q}{U * \Delta T_{lm}}$$

Where *A* is the area required by the exchanger, *Q* is the transferred energy at the heat exchanger, *U* is the heat transfer coefficient, which depends on the way the heat is transferred, and the ΔT_{lm} is the logarithmic temperature average.

The Temperatures of the thermal fluid will always be of 400 °C at the entrance of the heat exchanger and of 300 °C at the exit, which means an enthalpy difference of 250 kJ/kg. What will vary in function of the incident irradiation at the collectors field will be the mass flow of the thermal fluid. This mass flow when having an irradiation of 1000 W/m² is of 1090.4 kg/s, that means that the thermal energy that the thermal fluid is capable to give to the thermal cycle is 272599.22 kW, which, considering a typical efficiency of this type of heat exchangers of 70%, means that the absorbed heat by the fluid that circulates through the cycle is 190819,46 kW.

$$Q_{given} = \dot{m} * \Delta h = 1090.4 \ kg/s * 250\, kJ/kg = 272599{,}22\, kW$$

$$\boldsymbol{Q_{transferred}} = Q_{given} * ef = 272599{,}22\, kW * 0.7 = \mathbf{190819.46}\, \boldsymbol{kW}$$

To calculate the logarithmic average temperature should be defined first both temperatures of the water at the entrance and at the exit of the heat exchanger. The temperature at the exit will vary in function of the thermal fluid in the exchanger, however, in the case of maxim irradiation, we know that the enthalpy of the cycle fluid will increment 545 kJ/kg (taking on account that the water mass flow f the cycle is of 350 kg/s).

$$\Delta h_{water} = \frac{Q_{transferred}}{\dot{m}} = \frac{190819.46\, kJ/s}{350\, kg/s} = 545.2\, kJ/kg$$

The temperature of the water at the entrance will be fixed at 170 °C (The temperature after passing through the condenser and condensing the steam coming from the Low Pressure Turbine until saturated liquid at a pressure of 7.73 bar will be 169 °C and its entropy 2.03 kJ/kgK, after increasing the fluid pressure in the pump from 7.73 bar to 140 bar and considering that the entropy in this process remains constant, looking at the water properties tables, the liquid will be at 170 °C). And its state will be super-cooled liquid and will have an enthalpy of 726,6 kJ/kg. After passing through the heat exchanger, the fluid will have an enthalpy of 1271,8 kJ/kg, this, at 140 bar, means a temperature of 287,5 °C at the exit of the exchanger when working with the maximum irradiation.

Knowing the temperatures at the input and output of the exchanger, the Logarithmic average temperature can be calculated:

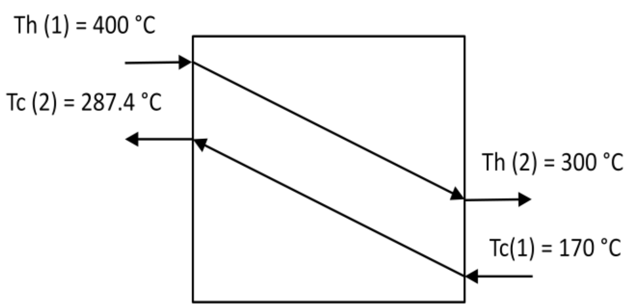


Image 23 Temperatures at the Heat Exchanger

$$\Delta T_2 = Th_2 - Tc_2 = 300\ °C - 287.4\ °C = 112.6\ °C$$

$$\Delta T_1 = Th_1 - Tc_1 = 400\ °C - 170\ °C = 130\ °C$$

$$\boldsymbol{\Delta T_{ln}} = \frac{\Delta T_2 - \Delta T_1}{\ln\left({}^{\Delta T_2}/_{\Delta T_1}\right)} = \frac{112.6 - 130}{\ln\left({}^{112.6}/_{130}\right)} = \mathbf{121.1}\ °C$$

The Heat Transfer Coefficient *U* is a coefficient that depends on the way the heat is exchanged. In that case, it is exchanged as a cross-current exchange by convection. For his type of exchanges the U coefficient varies from 50 to 10000 [W/m² °C]. For our heat exchanger it have been supposed a *U* value of 7,000 W/m² °C [23].

$$\boldsymbol{A} = \frac{Q}{U * \Delta T_{lm}} = \frac{190819.46\ kW}{7\left[\frac{kW}{m^2 * °C}\right] * 121.2\ °C} = \mathbf{224.91\ m^2} = 2421\ ft^2$$

Therefore, the Heat Exchanger will have the following characteristics:

Thermal Fluid Temperature at the entrance	400	°C
Thermal Fluid Temperature at the exit	300	°C
Water Temperature at the entrance	170	°C
Water Temperature at the exit	287.4	°C
Transferred energy	190819.5	kW or kJ/s
Heat Transfer Coefficient	7000	W/m² °C
Area	224.91	m²

Table 18 Heat exchanger characteristics

Turbines

When choosing the power that will be installed at the turbines, it have to be taken on account that, as the thermal cycle gives support to the photovoltaic plant, it will adapt the energy produced to the produced energy at the photovoltaic field. There so, while some times (mostly at night) the turbines will work at full power, other times they will work at a power of almost 70 MW less (as it is the installed power of the photovoltaic plant, and the produced power when the irradiation is 1000 W/m²). Taking this in consideration, the maximum power of the turbines minus the maximum power that the photovoltaic field can produce, must be higher or equal to the minimum power in which the turbines can work.

When talking about the thermal cycle supporting the Parabolic Trough plant, it will always work at the maximum power. That is, when there is no thermal energy given by the thermal fluid to the thermal cycle (at night, for example), the boiler will have to heat all the water circulating through the cycle, and when there thermal fluid gives energy to the cycle, the water will be pre-heated at the heat exchanger and complemented with the boiler to achieve the necessary proprieties at the entrance of the turbine.

Considering this, there is going to be installed turbines from the fabricant SIEMENS. The firs turbine will be the SST-400, able to work between 35 MW and 65 MW, and the second turbine will be the SST-300, able to work between 10 MW and 50 MW [24]. There so, the maximum power between them would be 115 MW. That means that the minimum power in which they will be able to work should be 45 MW (115 MW – 70 MW = 45 MW), which is exactly the minimum power in which they can work (35 MW + 10 MW = 45 MAW).

	HIGH PRESSURE TURBINE	LOW PRESSURE TURBINE	
MODEL	SST-400	SST-300	
EFFICIENCY	0,98	0,97	%
MINIMUM POWER	35	10	MW
MAXIMUM POWER	65	50	MW
MAXIMUM ENTRANCE PRESSURE	140	120	bar
MAXIMUM ENTRANCE TEMPERATURE	540	520	ºC
MAXIMUM PRESSURE DIFFERENCE	60	45	bar
EXIT PRESSURE AT BACKPRESSURE	25	16	bar
EXIT PRESSURE FOR CONDENSATION	0,3	0,3	bar

Table 19 Cycle turbines basic characteristics

Boiler

The function of the boiler in both cases is to complement the energy generated at the solar fields with energy coming from a fuel as can be the Natural Gas. As it have been said before, in the case of the thermal cycle for the Parabolic Trough fields, the turbines will be always working at full power, so the characteristics at the exit of the boiler and at the entrance of the turbine will be fixed in order to generate the maximum Power. It means that at the point 3 of the cycle, the water should be at 540 °C and 140 bar. Looking at the water properties table, that means an enthalpy of 3434.2 kJ/kg. That means that the input of natural gas at the boiler will have to be regulated in order to increment the enthalpy of the water coming out from the heat exchanger until 3434.2 kJ/kg.

At night, as there is no Sun and none of both plans are working, both thermal cycles will work the same. That is, generating all the installed power of the turbines with Natural Gas. There so, the boiler will be in charge of heating the water from 170 °C to 540 °C, both points at 140 Bar.

To calculate the amount of Natural Gas that is needed to feed the boiler, are going to be made the following calculations:

1º How much does the enthalpy need to be increased:

$$\Delta h_{2-3} = h_3 - h_2$$

2º How much energy is needed to increase the enthalpy to the point 3:

$$Q_{absorbed} = \dot{m} * \Delta h_{2-3}$$

3º How much energy must be delivered by the fuel:

$$Q_{delivered} = \frac{Q_{absorbed}}{\eta_{boiler}}$$

4º How much Natural Gas is needed to deliver this amount of energy:

$$\dot{m_{GN}} = \frac{Q_{delivered}}{PCI_{GN}}$$

Unless the mass flow of water at the cycle, the boiler efficiency and the Natural Gas PCI, all the parameters are variable

7. Connection from the photovoltaic plant to the electric grid

In order to transport the energy generated at the photovoltaic plant in an adequate way, it means, fulfilling a determined characteristics defined by the electricity transportation company, the energy generated (at direct current and low voltage) must be transformed before the evacuation of it into the distribution greed. To do this it is necessary the installation of inverters and transformation centers.

As the thermal cycle and the electric generator of the thermal central would be the same ones that must be installed at the parabolic trough collectors' generation plant, the energy transformation centers will also be the same. There so, taking on consideration the initial premise mentioned in the *objective* of the project, the photovoltaic plant will need a thermal generation plant to affirm the energy at the moments when the photovoltaic plant is not able to generate energy , as it can be at night or at hours when it not enough sun. There so, to affirm that energy it is needed a thermal plant and, there so, two connections to the electricity network, one of them form the photovoltaic plant ant the other one from the thermal plant. On the other side, the parabolic trough energy generation plant only needs one connection to the electricity network, that one from the electric generation from the thermal cycle.

There so, as the installation of a photovoltaic plant requires an additional connection to the electricity network installation, to carry out the economical comparison, it is going to be considered just the installation for the photovoltaic plant.

On this chapter there is going to be listed and described the electrical elements that are necessary at a photovoltaic plant to transform the energy that is produced at the photovoltaic modules, to change its current and to increase its voltage in order to obtain an adequate energy characteristics for the electricity transportation network, as well as to reduce the losses when transporting it through the plant.

As what it really matters of the project is the amount and the type of elements that are needed at the central for the economic study, there are going to be carried out just the needed calculations to resolve this.

During the voltage transformation process carried out at the photovoltaic plant there are going to be tree stages. The first phase, the one at low voltage and direct current, goes from where the energy is generated (from the photovoltaic modules) to the inverters, where the DC is changed to AC. The second phase, yet at low voltage, is the one where the voltage is increased from Low Voltage to Medium Voltage; this phase begins at the output of the inverters and ends at the output of the transformation centers. The third phase is the one that transports the energy through the photovoltaic field at medium voltage to reduce the losses. And the last phase is the evacuation phase, this one links the internal distribution network with the general electrical network, to do this it is transformed the energy at an electrical substation property of the electrical distribution company.

In addition to the study of the electrical elements that are needed at the different stages of the energy transformation of the photovoltaic plant, there are also going to be listed and described the auxiliary elements that are necessary at the plant, as they can be the protection elements that are needed at each phase.

7.1. 1st phase – Low-Voltage, Direct Current

The first part of the electrical energy generation process, as it has been said before, is the one that happens on the photovoltaic modules. There, the energy is generated at Low Voltage and Direct Current. This generated energy will be driven through conductors in Direct Current up to the inverters, were the DC will be turned to AC, which is the necessary current for being able to distribute the energy through the electricity networks.

This chapter will include the different types of conductors that are necessary at the first phase of the process, as well as the *combiner boxes* that are needed to adapt the outputs of the photovoltaic modules to the inputs of the inverter.

7.1.1. Combiner boxes

Previously it have been calculated the number of photovoltaic modules that are going to be connected to the inverter, that number was 1430, being distributed as 10 modules connected in series and 143 connected in parallel. That means that it is necessary to hook up 143 conductors into the inverter. However, the selected inverter to be installed in the plant, the Sunny Central 500ES-US, only allows between 12 and 18 inputs, there so, in order to be able to connect al the modules to the inverter, it is going to be necessary to use *combiner boxes*, so the number of conductors arriving at the inverter will be reduced considerably. In order to take the maximum profit of the combiner boxes, there are going to be used 12 combiner boxes of 12 inputs (SCCB-12 – SMA) for each inverter. Twelve combiner boxes with 12 inputs means 144 inputs, as we are needing 143 inputs, there is going to be one left. This number of combiner boxes selected also agrees with the minimum inputs of the inverter, being also 12.

The combiner boxes selected will be from the fabricant SMA, SCCB-12 model, the one showed at the image below:

Image 24 Combiner Box SCCB-12

7.1.2. DC conductors section

The DC conductors will transport the energy generated at the modules to the inverters and they have to be able to disperse the heat that it is generated by the intensity that circulates by the same.

There are going to be needed two types of conductors, the ones from the modules to the combiner boxes, made up of copper, and the ones from the combiner boxes to the inverter, made up of aluminium, which will require a bigger section, as it will have to conduct a higher current. Both cables, however, are going to be unipolar.

The cable section that is needed to connect positive side of one module with the negative side of the next one between the modules in series does not need to be calculated, as they are usually given by the fabricant with the modules and its section is of 4 mm².

From every group of 10 modules in series are going to be two cables, one from the positive terminal and another for the negative terminal. From every combiner box will also get out one positive and one negative cable, which will be connected to the inverter.

Cable Modules – Combiner boxes

According to the norm NEC-690.8, the conductors used at the photovoltaic installations can't transport more than the 80% of the maximum capacity that can circulate through them. Taking on account the same norm and the thermal criteria, the maximum current it can circulate should be the sum of the connections in parallel multiplied by 1.25. There so, being just one connection in parallel and being the short circuit current 9.61 A:

$$\boxed{I_{max} = 1 * 1{,}25 * I_{cc} = 1{,}25 * 9{,}61 = 12.0125\ A}$$

Also according to the norm NEC-240.4(D)(3) the section that should be used for this conductors is od 2,08 mm², which is able to transport up to 15 A. Meeting, this way, also the requirement that says that the maximum current that can circulate through the conductors must be the 80% of the maximum current that the conductor is able to transport. However, as the 80% of 15 is 12, this cable section would be too accurate, there so, and since the section given by the fabricant for the modules is 4 mm², there are also going to be used cables of a 4 mm² section to transport the energy from the modules to the combiner boxes.

Cable Combiner boxes – Inverter

In this case, as well as at the case before, the conductors will have to respect the recommendations mentioned in the norm NEC-690.8, that says that the current that a cable should be able to support have to be the sum of the currents of the cables in parallel multiplied by 1,25. This time, differently from the before, the number of cables in parallel is 12, there so, the maximum current will be the following:

$$\boxed{I_{max} = 12 * 1{,}25 * I_{cc} = 12 * 1{,}25 * 9{,}61 = 144{,}15\ A}$$

In the case that the environment temperatures were over 30 °C there will be needed a correction factor, but as the average temperatures in our location during the sun hours is 26 °C and the maximum temperature of the year is 31 °C, this correction is not needed.

The conductor, according to the same norm, can't transport more than the 80% of the maximum current that it is able to transport. There so, the current that the conductor should be able to transport is the following:

$$I = \frac{I_{max}}{0{,}8} = \frac{144{,}15\ A}{0{,}8} = 180{,}1875\ A$$

There so, the cable need will be the one that is able to transport a current of 200 A, being its section of 107 mm^2.

7.2. 2nd phase: Transformer LV - MV

In that phase the energy will be driven from the inverter, at Low Voltage, to the transformer, where the voltage is going to be increased to Medium Voltage. This conversion is necessary to transport the energy through the photovoltaic field, this way the voltage losses on the conductors will be considerably reduced. Moreover, the voltage will also have to be increased before the energy evacuation to the electrical network, so it would have to be done anyway.

The right performance of the voltage transformation centres can be deteriorated and, there so, its useful life can be reduced due to the increase of currents and temperatures. The high temperatures can reduce the capacity of the transformers to support the short-circuits efforts and they can accelerate the accumulative thermal degradation of the conductors isolation and other materials.

The temperature factor is an important factor to decide the load capacity in which a transformer can work. For example, the transformers localized in regions with low temperatures are able to work at a higher load capacity, and the ones localized in regions with higher temperatures can work in overload without decreasing its useful life. For that reason it is going to be studied the most unfavorable day of the year, to see if in that case the transformers work in overload and, if it were the case, up to which level they could be overloaded.

7.2.1. Low-Voltage to Medium-Voltage center transformation

The transformed that is going to be used to increase the voltage at the exit of the inverter will be the *Pad-Mounted*, produced by the fabricant *COOPER INDUSTRIES*, and it will provide a natural refrigerant and will be immersed in ONAN (Oil Natural Air Natural) as isolating.

Image 25 Pad-Mounted Transformer, by Cooper Industries

It is able to transform up to 1 MW, there so, there are going to be connected two inverters of 500 kV for each transformer, being needed 70 transformers of 1 MW for 139 inverters of 0.5 MW.

Load distribution

As it have been said before, it have to be studied the load on the most unfavorable day of the year, that is, the hottest day and the most irradiated day. According to the *Atmospheric Science Data Center* from the *NASA*, which offers the historical data of some metrological factors, the hottest temperature of the 2005 is the October 15th of 31°C. Carrying out the calculations of the efficiency correction explained previously in another chapter, the modules efficiency for this temperature is 17.64%.

Knowing the incident radiation on the modules and the data exposed above, it can be calculated the power that will have to be transformed by the transformation center using the following equations:

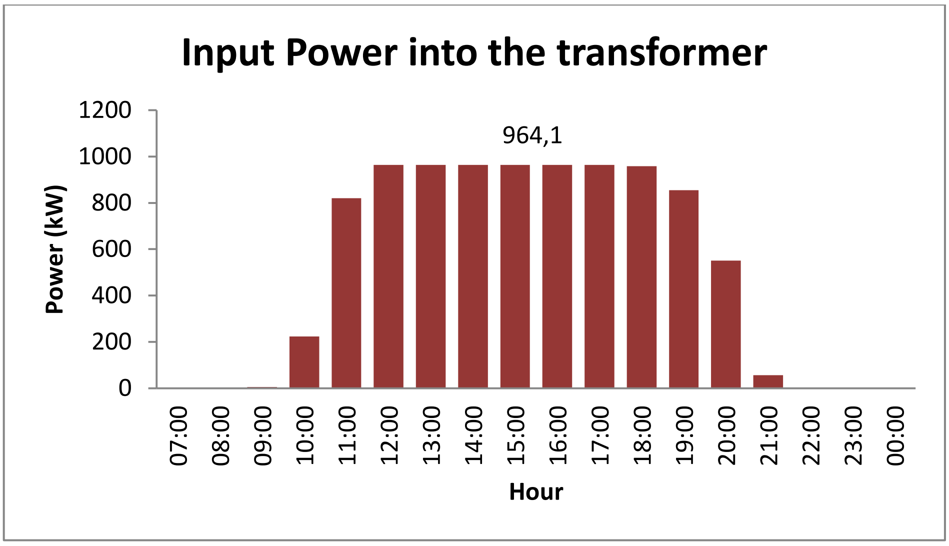
$$Output\ Power/Module\ [W] = Irradiation\ [W/m^2] * A[m^2] * \eta_{31°C}$$

$$Output\ Power/Inverter\ [kW] = \frac{Output\ Power\ [W]}{Module} * \frac{Nº\ modules}{Inverter} * \eta_{inverter} \div 1000$$

$$Input\ Power/Transformer\ [kW] = \frac{Output\ Power}{Inverter}[W] * \frac{NºInverters}{Transformer}$$

Hour	Incident Power [W /m²]	Corrected incident Power [W/m²]	Output Power /Module [W]	Output Power /Inverter [KW]	Input Power /Transformer [kW]
08:00	0,000	0,000	0,000	0,000	0,000
09:00	5,000	5,000	1,709	2,410	4,820
10:00	232,000	232,000	79,317	111,835	223,670
11:00	851,000	851,000	290,942	410,223	820,445
12:00	1027,000	1000,000	341,883	482,048	**964,095**
13:00	1060,000	1000,000	341,883	482,048	**964,095**
14:00	1067,000	1000,000	341,883	482,048	**964,095**
15:00	1001,000	1000,000	341,883	482,048	**964,095**
16:00	1055,000	1000,000	341,883	482,048	**964,095**
17:00	1031,000	1000,000	341,883	482,048	**964,095**
18:00	994,000	994,000	339,831	479,155	958,311
19:00	887,000	887,000	303,250	427,576	855,152
20:00	572,000	572,000	195,557	275,731	551,462
21:00	58,000	58,000	19,829	27,959	55,918
22:00	0,000	0,000	0,000	0,000	0,000

Table 20 Load distribution f the transformer at the most unfavorable day of the year



Graphic 19 Load distribution of the transformer at the most unfavorable day of the year

On the graphic above is drawn the load distribution at the input of the transformer at the most unfavorable day of the year. Being that day the October 15th, as it has the highest temperature of the year and the irradiation is also maxim.

As it can be seen, due to the decrease of the modules efficiency because of the high temperatures and to the efficiency of the inverter, the power that will arrive at the input of the transformer will be 0.965 MW, it means, less than 1 MW, the maximum power able to transform. There so, it is not necessary to calculate the limit of the overloading, as it won't ever be overloaded.

7.2.2. Conductors between the inverter and the transformer

The current that will be needed to be transported from the inverter to the transformer will be already at AC. And the section of the conductors will be determined taking on account the voltage losses and the current.

According to the inverters fabricant requests, the cable length between the inverter and the transformer has to be less than 15 m, made of copper and three-phase without neutral. It also has to be a unipolar cable buried in a tube.

Taking in consideration the calculations made in similar projects [25], the cables used to transport the energy from the inverters to the transformers will be made of cooper, isolated, unipolar, with a section of 253,354 mm², with 6 conductors for each phase and buried in non metallic tubes. There so, there will be 6 buried tubes with 3 conductors inside each one, one conductor for each phase and without neutral. This way, the will be 6 tubes disposed as the following figure:

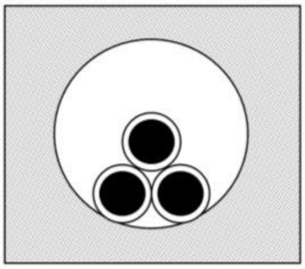


Image 26 conductors' disposition from the inverter to the transformer

Considering this characteristics, the Voltage losses will be about the 0.15% of the conducting voltage; the maximum current that will have circulate by the conductors when the inverters working at maximum power, taking on account that the maximum current that an inverter can provide at 200 V is 1470 A, is 1603 A; and the minimum section to avoid short-circuits when working at the maximum current should be 202.68 mm², what means that a section of 253.354 mm² is also permitted, as the fabricant does not produce wires with a section of 202.68 mm².

7.3. 3th phase: Medium Voltage Line

In order to reduce the voltage losses produced while transporting the energy, it is going to be transported through the generation plant as Medium Voltage instead of Low Voltage, that's why the energy have been transformed before arriving at the evacuation point.

7.3.1. Distribution

The conductors used to transport the energy can be disposed as branches or as rings, each disposition having its advantages and disadvantages. It is going to be disposed as rings, as, although it requires a larger length of cable than the branch distribution and a bigger section for the conductor (what will suppose a higher inversion), it offers more reliability than the branch disposition, as it offers the possibility to drive the energy through other paths in the case of a failure on some of the installation elements.

Taking on basis a 20 MW photovoltaic project [25], which also connects the plant using a rings distribution, there are going to be installed 14 rings of 5 MW each one, making a total maximum power distributed of 70 MW. Making an approximation based on the data from that project, it is solved that the longitudes of each ring is the following:

RING	LENGTH (m)
1	1800
2	2150
3	2520
4	2895
5	3255
6	3620,5
7	3986
8	4351,5
9	4717
10	5082,5
11	5448
12	5813,5
13	6179
14	6544,5
TOTAL	**58362,5**

Table 21 Rings length extrapolation

7.3.2. Conductors characteristics

According to the NEC the minimum section required for a circuit with three conductors unipolar made of aluminum and buried in a tube is 177.35 mm ² and have and admissible current of 305 A.

Being 14 rings, three will be 28 circuits. These 28 circuits will later be grouped before the sectioning center. There so, it have to be applied the corrector factor referring to a link of more than 20 circuits, which is 0.38. So it can be calculated the admissible current:

$$0.38 * 305\ A = 115.9\ A$$

Knowing the power it will circulate by the cable is 5 MW, that each ring will be of 21 kV and that it have a power factor of 0.9, it can be calculated the maximum current that it will circulate:

$$I_{max} = \frac{S}{\sqrt{3} * U_n * cos\varphi} = \frac{5000\ kW}{\sqrt{3} * 241\ kV * 0.9} = 152{,}738\ A$$

Making this calculation, it can be resolved that the maximum current that it will circulate through the conductors it is higher than the admitted current on the conductors: (115,9 A < 167.75 A), there so, the current admitted by this type of conductor is not enough , it would be necessary a wire with a bigger section that admits a current of 400 A

$$0{,}38 * I_{admited} > 152.7\ A \rightarrow I_{admited} > \frac{152.7\ A}{0{,}38} = 401{,}82\ A$$

There so, the wire that should be used at the rings should have a section of 203 mm², which is able to transport 400 A. However, as the currents supported by the conductors is too limited and the fabricant only produces wires for 350 kcmil (177 mm²) or 500 Kcmil (253 mm²), there is going to be used a wire with a section of 253 mm².

7.4. 4th phase: Evacuation

The energy generated at the photovoltaic plant must be, at the end of the energy process transformation, be evacuated to a substation (property of the electrical network company). The plant location is relatively near to an already existent substation, 1 km far from the photovoltaic field location.

It will have to be chosen between copper and aluminum wire, as well as the section needed to transport all the energy to the company substation. To decide this parameters will be studied the Voltage losses, the overheating and short-circuit.

Although the aluminum wire supposes much more losses, which are reflected on the economic aspects, it stills being cheaper to install than the copper wires, as they are much more expensive. There so, it is going to be used a conductor made of aluminum with a section of 506,708 mm².

As this type of cable is sized to transport the energy from a generation plant with a installed power of 20 MW, it is not enough to transport the energy of our plant, however, the fabricants does not produce wires with bigger sections, there so, there is going to be used 3 conductors with a section of 1000 kcmil for each circuit.

7.5. Auxiliary elements for protections

In order to guaranty a reliably and continuous service, there are going to be installed elements in charge to regulate and protect the installation for a correct performance of the photovoltaic plant.

Protections for the First Phase:

When referring to the protections for the Direct Current stage we consider that the short-circuit current at his level it is not enough high to be dangerous for the people, as this current is 9.61 A. However, there are going to be installed fuses at the positive pol, inside the combiner boxes. It is not required to put circuit breakers at the negative poles, as they are already connected to the ground. These fuses will have an standardized value of 15 A.

This part of the photovoltaic plant will be protected against the overvoltage through a *discharger*, also placed in the combiner-boxes.

Protections for the Second Phase:

Each transformer will be protected by a switchbreaker at the load, a Cooper Power Systems' switch (equipped with a E40 sensor), ELSP fuse connected in series with the Coopers switch, a Bunchholz rele and protections for thermal overloads.

The transformers will also have a grounding configuration for the neutral. This configuration will consist on two buried pikes of 4 m length and a diameter of 15.87 mm, and they are going to be placed with a distance of 6 m between them.

Protections for the Third Phase:

There is need to put protections where the circuits are combined. This is going to be protected by a switchbreaker and with a fuse, protecting as well the transformers against any fault.

Common protections:

All the metallic elements from the installation must be connected to the ground, so the current can be derived to the ground if something happens. The objective of this protection is to guaranty the people security, to protect the installations and to improve the service quality.

This configuration will be made by a net of copper conductors that will go through the whole installation. The length of this net is usually of 400 m for each MW, there so, our photovoltaic plant will need about 28,000 m of cooper wire to make up this protection net, and the section used for this wire will be of 42,4 mm². To this net will be connected the metallic elements of the inverter and transformer, the metallic structures from the photovoltaic modules, the combiner boxes and the negative pole of the photovoltaic modules (this connection will be carried out at the inverter, through the GFDI system).

7.6. Resume

The elements required for the energy transformation process of the photovoltaic plant, there so, are the followings:

- **139** inverters *Sunny Central 500E-US* from *SMA*; to transform the energy generated on the photovoltaic modules from DC to AC.
- **70** transformers *Pad-Mount 1 MVA* from *Cooper Industries*; to increase the voltage from LV to MV.
- **1,668** combiner-boxes *SCCB-12* from *SMA*; to combine 12 wires coming from the modules in one going to the inverter.
- **296,111.7** meters of "*CABLE TECSUN(UL)-PV Wire, Cu, (PRYSMIAN), 12 AWG/4.0mm², code 20025134"; in order to transport the generated current from the modules to the combiner-boxes.*
- **41,283** meters of *"CABLE SUPERFLEX XLPE, (PRYSMIAN), Al, AWG 4/0 /107mm², 600 V, code Q0T300A"*; going from the combiner-boxes to the inverter inputs, buried in tubes at a 0.3 m depth.
- **834** meters of "*Cable 2kV OKOGUARD-OKOLON, RHW-2, (Okonite), 6 x 3 x (1 x 500 kcmil)/ 253 mm², Cu, code 113-24-2531"*, going from the inverter to the transformer. They will go through PVC tubes and at a 0.6 m depth.
- **28** cells in C.S.
- **58,362.5** meters of "*Cable OKOGUARD URO-J, 25kV EPR, (Okonite), 3 x (1 x 500 kcmil), Al, code 135-23-6468"*; to transport the energy at Medium Voltage through the

photovoltaic plant to the sectioning center. These will be installed inside PVC tubes buried at a 0.45m depth.

- **2,000** meters of "*Cable OKOGUARD URI-J, 25kV EPR, (Okonite), 2 x 3 x (1 x 1000 kcmil)/507 mm², Al, code 160-23-5099";* it will transport the energy from the generation plant to the distribution network company substation. It will be buried at a 0.75 m depth.
- **198,770** cylindrical fuse *KTK-R* from *Cooper Industries Bussmann* for a 15 A current. Inside the combiner-boxes.
- **198770** voltage discharger for photovoltaic applications from *Cooper Industries Bussmann*. In order to protect form overvoltage, inside the combiner-boxes.
- **70** swithbreakers *"800-65, Cooper Power Systems",* one in each transformer.
- **70** *"Cooper Power Systems MagneX"* switches equipped with sensors. One in each transformer with a 50 kA cut capacity.
- **70** *E40* sensors. One for each transformer.
- **70** *ELSP* fuses, connected in series with the Magnex switch, with a cut capacity between 400 A and 50 kA.
- **70** *Buchholz rele – 63B.*
- **70** protections for thermal overloads.
- **17,968** m of *1 AWG (42.4 mm^2)* cable for the ground net.

8. Economical study

In this chapter it will finally be made the economical comparison between the costs that supposes each energy generation plant. The generation plants that will be compared, as it has been said along the project, are designed to produce the same annual energy, as this is the way to be able to do a worthy comparison.

The aspects of each plant that will be taken on account when doing the comparison are: the initial inversion of each plant, the annual costs of O&M and the useful life of the elements of each central, so we will have to take in consideration in how many years the initial elements will have to be replaced.

8.1. Initial investment

Technically, the initial investment of a Parabolic Trough generation central should include, apart from the elements that make part of the solar field, the costs of all the elements of the thermal cycle (pipes, pump, boiler, turbines, condensers, and regenerators) and the cost of the electric line that will give the electrical energy generated at the electrical distribution network.

As it have been said at the *Objective* of the project, it have been supposed that, as all the renewable energies are variables and unreliable, they have to have the support of a conventional and reliable energy resource (unless they had some kind of storage that permit to firm an energy offer to the electrical network, being able to attend the demand at any time). In the case of the Parabolic Trough plant, it is needing of a thermal cycle in order to transform the thermal energy obtained by the thermal fluid at the receiving tubes into electrical energy, this thermal cycle can also works with a fueled boiler when the thermal fluid does not brings enough energy or at the ours that there is no Sun. So, in the case of the Parabolic Trough central, it can firm the energy just by using a fueled boiler as support at its thermal cycle. In the case of the Photovoltaic generation plant, its energy will have to be supported by a conventional thermal plant that attends electrical the demand when the photovoltaic plant can't attend it. Therefore, as it should be included in both initial inversion projects the elements referred to the thermal cycle, they stay annulled one by the other and they are not going to be considered at any of both inversions. The same will happen with the electrical line that evacuates the energy generated at the thermal cycle to the electrical network.

Therefore, the elements considered at the Parabolic Trough generation plant will be: the collectors, the assemblies that join the groups of collectors, the pipes used to transport the thermal fluid from the heat exchanger to the receiver tubes, the thermal fluid, the pumping group (which will make the thermal fluid circulate through the pipes), the heat exchanger (as it is an extra element of the thermal cycle that does not appear at the conventional thermal cycle considered for the photovoltaic plant), the foundations of the collectors (which include the excavation and the foundations) and the workforce to build all the field.

For the initial inversion of the photovoltaic plant will be considered: the principal elements, as can be the photovoltaic modules and their support, the inverters and the transformers; the connection elements as the combiner boxes and the different types of conductors used, including the ones in charge to give the generated energy to the electrical distribution network; the protection elements as the tubes were the conductors will be buried, the ground network and other fuses and switches to avoid that a located fault affects the entire plant; the foundations, both the ones for the modules and for the inverters and transformers; and the workforce that is needing to build the generation plant.

8.1.1. Initial investment of the Parabolic Trough field

	Amount	Units	Unitary cost ($)	Total (U$)	Cost per KW ($/KWp)
COLLECTORS FIELD					
Collectors	3414	Un.	23000 [26]	78522000	1040,026
Assembly	171	Un.	1000	171000	2,265
Pipe in and out the collector	1339,6	m	40 [27]	53584	0,7097
Distribution pipe through the field	8313	m	450 [27]	3740850	49,548
Pipe in and out the thermal cycle	100	m	550 [27]	55000	0,7281
EXTRA ELEMENTS					
Thermal fluid	2150	m^3	3200 [28]	6880000	91,126
Heat Exchanger	1	ud	275000 [29]	275000	3,642
Collectors Field Pumping group	36	ud.	82900 [30]	2984400	39,528
FOUNDATION [31]					
Excavation	2632875	m^3	1,43	3765011,25	49,868
Foundations	75949,2	m^3	109,6	8324032,32	110,252
WORKFORCE				4219003,075	55,881
TOTAL				108989880,6	1443,574
				108,99	milions

Table 22 Initial investment of the Parabolic Trough field

8.1.2. Initial investment of the photovoltaic field

Element	Amount	Units	Unitary cost (US$)	Total (US$)	Cost per KW ($/KWp)
PHOTOVOLTAIC FIELD [31]					
Photovoltaic Module	198770,00	Un	330	65594100	943800
Combiner-box	1668	Un	505	842340	12120
Inverter	139,00	Un	98000	13622000	196000
Transformer	70	Un	30000	2100000	30215,83
Modules support (10 modules)	19877	Un	5500	109323500	1573000
CONDUCTORS [31]					
Module - Combiner box	296111,7	m	1,22	361256,27	5197,93
Combiner box - Inverter	41283	m	7,60	313750,80	4514,40
Inverter - Transformer	834	m	62,50	52125	750
Rings	58362,5	m	15,91	928547,38	13360,39
Generation plant - Substation	2000	m	50,04	100080,00	1440
GROUND NETWORK [31]					
Copper conductor	17968	m	14,43	259278,24	3730,62
Steel pike	140	Un	27,86	3900,40	56,12
PVC conductor	546	m	9,29	5072,34	72,98
TUBES [31]					
Combiner box - Inverter	41283	m	25,33	1045698,39	15046,02
Inverter - Transformer	834	m	22,56	18815,04	270,72
Rings	58362,5	m	4,38	255627,75	3678,10
MODULES FOUNDATIONS [31]					
Foundation	66424,8	m3	109,62	7281486,58	104769,59
Excavation	2302672	m3	1,43	3292821,60	47378,73
Iron	586745,4	kg	1,95	1144153,53	16462,64
INVERTERS AND TRANSFORMERS FOUNDATIONS [31]					
Concrete	281,88	m3	109,62	30899,69	444,60
PROTECTIONS [31]					
Cylindrical fuses	198770	Un	1,17	232560,90	3346,20
Voltage discharger	198770	Un	81,14	16128197,80	232060,40
SECTIONING SWITCHES [31]					
Line cell	27	Un	12752	344304	4954,01
Protection cell	3	Un	20876	62628	901,12
Measuring cell	6	Un	10590	63540	914,24
WORKFORCE				3689875	53091,73
TOTAL				227096558,70	3267,58
				227,10	millions

Table 23 Initial investment of the Photovoltaic field

8.1.3. Ground cost

The total surface occupied by the Parabolic Trough solar field is 1,465,299 m^2, while the useful surface (the surface occupied by the collectors) is 440,564.4 m^2. This huge difference is because the distance that needs to be left between each row of collectors is really high.

On the other side, the total surface occupied by the Photovoltaic solar field is 620,991.75 m^2, while the useful area occupied by the photovoltaic panels is 385,294.97 m^2.

That means a difference on the required area of 844,307.25 m^2. The ground cost in Brazil is estimated between 4 thousand and 40 thousand BRL/he [32], what means between 0.12 USD/m^2 and 1.21 USD/m^2 (being the cheapest lands at the Nord-East, where the project is placed, and the most expensive ones at the South). That means that, considering an average cost of the land, the cost of the necessary ground to build the Parabolic Trough project would be 974,423 $ and the cost of the land to build the Photovoltaic field is 412,959 $, being the cost of the land for the Parabolic Trough field 561,464 $ more expensive than for building the Photovoltaic plant.

Considering this approximated cost of the land would mean an initial inversion for the Parabolic Trough project of 133.85 millions $ and an initial inversion for the Photovoltaic project of 227.51 millions $.

Land cost	2.2	BRL/m^2	**0.665**	**USD/m^2**
	Parabolic Trough	**Photovoltaic**	**Difference**	
Useful Area	440,564.4	385,294.97	402,034.43	m^2
Total area	1,465,299	620,991.75	844,307.25	m^2
Land cost	974,423	412,959	**561,464**	USD

Table 24 Land costs calclations

8.2. Annual costs

The annual costs are referred at those related with the Operation and Maintenance (O&M). Although this costs are really variable in function of the place the plant is placed and other parameters, it will e considered an O&M costs for the photovoltaic plant of 16 $/kW.year, as the National Renewable Energy Laboratory [33] published that for a photovoltaic plant with an installed power between 1 and 10 MW the O&M cost is 16 $/kW.year with a deviation of 9 $/kW.year, that means that the O&M cost of a photovoltaic plant with an installed power higher than 1 MW is between 7 and 25 $/kW.year.

On the other side, in the case of the Parabolic Trough costs, it is much harder to find information about costs, however, it has been found an article[34] that approximates the O&M costs for the Parabolic Trough plants at 20 €/kW.year, what means 22.39 $/kW.year.

That means an Operation and Maintenance annual cost of 1,112,000 $ for the Photovoltaic plant and an annual cost of 1,700,856.35 $ for the parabolic Trough field. Being the diference between them of 588,856.35 $ (being the O&M costs of the Parabolic Trough field more expensive than the costs of the hotovoltaic plant).

	Parabolic Trough	Photovoltaic	Difference	
Installed Power	69.5	75.965	6.465	MW
O&M cost	22.39	16	6.39	$/kW.year
Annual cost	1.7	1.112	0.589	Millions $/year

Table 25 Annual costs for Operation and Maintenance

8.3. Comparison

Once we have all the data it have been possible to find and to calculate, there can be compared some different parameters between both equivalent projects. Parameters as the installed power in each plant, the final annual energy, the total area occupied to build each plant, the total inversion (including the cost of the land exposed before) and the annual costs of the Operation and Maintenance.

	Parabolic Trough	Photovoltaic	Difference	
Installed Power	75.96	69.50	6.46	MW
Annual generated Energy	139.28	139.63	0.352	GWh
Total occupied area	146.53	62.10	84.43	He
Total initial inversion	109,96	227.51	117.55	Millions $
O&M annual costs	1.70	1.11	0.59	Millions $

Table 26 Economical differences between both projects

The first difference that has to be evaluated is the little difference between the annual generated energy (caused because of the necessity to adjust the number of photovoltaic modules to the inverters characteristics). Although this energy difference is relatively low compared with the total generated, here are going to be evaluated the extra earnings that the sale of this energy supposes. According to the information of the "Leilões" from the CCEE (Câmara de Comercialização de Energia Eletrica- Brazil) the energy is sold around 300 R$/MWh, what means 91 $/MWh. Knowing that the amount of energy generated by the Photovoltaic plant above the Parabolic Trough plant is 352 MWh/year, the extra earnings that the Photovoltaic plant will have above the Parabolic Trough plant are of 32,032 $/year.

Considering that the useful life of the elements is approximately the same, and this is about 25-40 years [35]. It can be done a simplified evaluation of the accumulated costs along the life time. In this evaluation are going to be considerate the initial inversions of each field, the annual O&M costs along the 40 years and the extra energy earned by the Photovoltaic plant. However, there is not going to be considerate the decrease of efficiency of the elements (as they have been considered almost equal) and the possibility of a change on the price of the energy.

There so, to calculate the invested amount of money on the Parabolic Trough plant along its life time (no taking on account the earnings for the sold energy)it is going to be done the following:

$$\text{Total invested}_{\text{CPC}} = \text{Initial investtment} + \ O\&M_{\text{annual}} * 40 \text{ years} =$$
$$= 109.96 \ + 1.7 * 40 = 177.96 \, millions \, \$$$

And to calculate the amount of money invested on the Photovoltaic plant is going to be done the following:

$$\text{Total invested}_{\text{PhV}} = \text{Initial investtment} + \ O\&M_{\text{annual}} * 40 \text{ years} =$$
$$= 227.51 \ + 1.112 * 40 = 271.99 \, millions \, \$$$

Considering that at this plant there is an extra earning due to the excess of generated energy, these earnings are going to be subtracted from the invested money along the 40 years of usefull life of the central:

$$Equiparable \ investment_{PhV} = \text{Total invested}_{\text{PhV}} - \text{Earned money by energy sale} =$$
$$= 271.99 - 1.281 = 270.7 \, millions \, \$$$

There so, the difference of the cost of each project (considering the presented hypothesis at the *Objective*) is about 92.73 millions $, as the money earned from the energy generation is the same in both projects (unless the already considered earnings for the photovoltaic plant). That means a difference of 16.64 $/MWh produced along the 40 years (being the photovoltaic project more expensive).

9. Conclusions

The objective of this Project was to compare economically two different technologies that produce electrical energy using the Sun as first resource. The two compared technologies were the Parabolic Through collectors (Thermo solar technology) and the Photovoltaic. To compare both technologies it has been raised the hypothesis that, as the solar energy is unpredictable, variable and volatile, the energy that it is produced using the energy given by the Sun should have another way to produce electrical energy to support its energy generation, as there is a demand that have to be accomplished and is the energy generation that should adapt to the demand curve. Is for this reason (to firm a straight energy service) that the renewable energies must have the support of other controllable and conventional electrical generation technologies, as until now it have not been found a viable and rentable way to storage the amount of energy that should be stored if the demand curve should be supplied just by renewable technologies.

Considering this hypothesis, both technologies would need the support of another generation central, as it could be a conventional power plant with a Rankine thermal cycle. There so, when doing the economical comparison, there is going to be taken on account just the elements disposed at the collection field and, in the case of the photovoltaic technology, also the connections to the distribution net, as these connections are not the same ones as the ones from the power plant.

In order to make an equivalent economical comparison, there have to be compared two generation plants with the same solar resources (at the same emplacement) and the same annual energy generation, as in this way both plants would earn the same money from the generated energy sale. The design of both plants has been made with the required precision to calculate the required elements in each generation plant and the amount of elements needed. There so, the loses at the solar fields have not been considered; losses as pressure loses due to the friction and deviations at the pipes or thermal losses due to the convection with the pipes, at the Parabolic Trough case; voltage losses at the Photovoltaic field.

There so, it have been designed a Parabolic Trough field able to generate an amount of electrical energy of 139278.50 MWh each year (considering direct radiation data from 2005). To generate this amount of energy it needs 3414 cylinder-parabolic collectors disposed in a way that they need a field with a total area of 1465299 m^2. The total initial investment have been calculated to be 109.96 millions \$, and the annual costs have been estimated to 1.7 millions \$. The Photovoltaic plant will be able to generate 139630.84 MWh, for what will need 198770 photovoltaic modules and a field of 620991 m^2. The total initial investment (also considering the other elements required for the transformation and distribution of the energy) Is about 227.2 millions \$, and the annual costs due t the Operation and Maintenance are 1.112 \$.

In this comparison have not been taking on account the common elements as the conventional power plant, the earnings because of the generated energy, the operational costs, etc. It is also difficult to know if in a real case this will be the final budget, as generally, the budgets of a big project are agreed with the fabricants to settle discounts due to a big amount of bought materials. However, the data for the photovoltaic projects is quite transparent.

On the opposite side, the data referred to the thermo solar technologies are poorly spread and they are not clear, so there are very little references and studies about that and that gives the kind of information that is necessary to make up an approximation about the cost of a project.

It has been considered that the price of the Parabolic trough collectors is 23,000 $ because an study carried out by the NREL solves that the cost is 178 $/m^2 [26], what, taking on account the area of the collectors selected, means an amount of almost 23,000 $ for each collector. There have been found another study [36] about the price of this collectors along the years that solves that, while at the beginning the cost of the structure was about 12,500 € and the cost of the receiving tube was 850 €, now, due to the improvements on this technologies, the costs have been decreased to 8,000 € for the structure ad 500 € for the receiving tube, what would mean a cost of 8,500 € for each collector (7,735 $). As it have been said there is too little transparency about this data, and it is hard to know which data is the correct one (id any f them is), is for that reason that have been chosen the most expensive one to make the economical evaluation.

Carrying out this study it has been seen a huge difference between the investments required in each case, taking on account the hypothesis rose. However, this hypotheses may seem too exaggerated, giving too much facilities to the thermo-solar plants to seem more profitable, as there is being considerate just the elements of the solar field (while it can't work just by its own), while in the case of the photovoltaic plant it has been considered all the elements involved in the production, transformation and distribution of the energy. This hypothesis does not take on account the demand curve and the energy generation adaptation to it. It does not take on account that in the electrical energy market are lots of generation plants injecting energy to the network, as they can be the wind power plants (also renewable and unpredictable), the nuclear power or the hydraulic power (also adjustable and able to give support to the renewable energies).

What is clear is that the best option for a stable electric system is the Thermo-Solar power technologies; as they are much more adaptable tan the photovoltaic plants. As the Thermo-solar plants give the option to install a thermal storage system able to storage energy up to 7 hours, which would make the energy generation more stable and adjustable to the demand curve. Moreover, in case of not having solar resources for a long time and having the necessity to produce energy, it can be produced by the help of another fuel, as can be the conventional ones or new ones as biomass or biofuels. While the photovoltaic plants can destabilize the system, as the energy produced needs to be injected immediately to the distribution network, varying at every moment and making another power plant adjust its production.

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