Sizing of PV installations based on economical pre-feasibility analysis according to self-consumption in Portugal

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Abstract

Portugal is one of the leading countries in Europe in terms of renewable energy mainly due to the large installed capacities of wind and hydro power. In order to achieve the ambitious climate goals – in the most efficient way – an increase of solar energy in the electricity mix is required. The regulatory scheme in Portugal that allows consumers to generate their own solar energy with the focus on local direct self-consumption, referred to as UPAC, is one of the means to incentivize the private investment in – decentralized – solar energy in the country's energy mix.

This thesis has the main objective to promote investment in self-consumption PV system by providing an illustration of the benefits of these projects through savings in energy cost and through internal rate of returns on investments. Also, a methodology is provided and applied in the form of a model using Python that allows to determine the optimal sizing of a PV system for self-consumption that can be applied on specific cases following Portuguese legislation. The methodology is applied on a specific case study, on a logistics warehouse in greater Lisbon, as a means of illustrating the benefits of a self-consumption PV system for the consumer, and the importance of the system size and configuration for the projects rentability. This model was developed because there is no PV system design software available that takes into account the specific Portuguese UPAC regulations.

Keywords

Renewable energy; Photovoltaic; UPAC; Self-consumption; PV-system sizing; Techno-economic analysis

Resumo

Portugal é um dos países lideres na Europa relativamente à produção de energias renováveis, isto deve-se principalmente ao fato de ter instaladas grandes estações de aproveitamento eólico e hidrelétrica. De modo a atingir os ambiciosos objetivos climáticos traçados para o país- da forma mais eficaz- é necessário um aumento da exploração de energia solar como forma de produção de energia. Em Portugal, a legislação exitente permite ao consumidor gerar a sua própria energia solar como fonte de energia para as suas necessidades domésticas. Estas normas conhecidas como UPAC, são uma forma de incentivar o investimento privado no uso da energia solar.

Esta tese tem como objetivo principal promover o investimento em sistemas de auto-consumo, PV, através da consciencialização das melhorias e benefícios associadas a estes sistemas, em termos de redução de custos energéticos e taxa interna de retorno dos investimentos. É ainda apresentada uma metodologia que permite determinar o tamanho "ótimo" de um sistema PV para consumo próprio e para casos específicos, de acordo com a legislação portuguesa. Este modelo tem como finalidade, ilustrar os benefícios gerados através do sistema PV para o consumidor e a importância do tamanho adotado para o sistema e da configuração da rentabilidade do projeto. Foi escolhido este tema de dissertação pois não existe software para dimensionar sistemas de PV que tenha em conta a legislação Portuguesa UPAC.

Palavras-chave

Energia renovável; Energia fotovoltaica; UPAC; Autoconsumo; Análise técnico-económica

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List of Abbreviations

PRE: Production under special regime

PRO: production under ordinary regime

EDP: Electricidade de Portugal

MIBEL: Iberian energy exchange market

ERSE: energy services regulatory authority

REN: Rede Eléctrica Nacional

BTN: Baixa Tensão Normal

BTE: Baixa Tensão Especial

MT: Média Tensão

AT: Alta Tensão

MAT: Muito Alta Tensão

UGS: system general usage tariff

PPA: power-purchase agreements

CMEC: equilibrium maintenance cost contracts

FiT: feed-in tariff

PV: photovoltaic

UPP: small production units

UPAC: self-consumption units

kWp: Kilowatt-peak

NPV: Net present value

IRR: Internal rate of return

TMY: typical meteorological year

DHI: direct horizontal irradiation

DNI: direct normal irradiation

GHI: Global horizontal irradiation

AM: Air mass

P: Pressure

IAM: incidence angle modifier

FD: fraction of diffuse irradiance used by the PV module

SM: spectral modifier

SAPM: Sandia PV array performance model

1. Introduction

The need for energy has been increasing along with society's evolution towards more comfort and a higher quality of life. To fulfill these needs, we have been relying on non-renewable energy resources. The use of these resources resulted, and continues to do so, in a significant increase in greenhouse gas emissions, which in turn provokes an increase of the average temperature on earth (IPCC, 2014). As the awareness of this phenomenon – and its negative side-effects – increased, European and national authorities have been adapting legislation and financial incentives in the favor of renewable energy resources. The two main goals of this action are the reduction of greenhouse gas emissions and decreasing the energy dependence (International Energy Agency, 2016).

The technologies that currently dominate the renewable energy landscape – and are expected to do so until 2050 – are wind turbines, solar photovoltaics, biomass and hydropower (International Energy Agency, 2016). Portugal is one of the leading countries in Europe in terms of the share of renewable electricity consumption, mainly due to the large wind- and hydropower capacity. Although Portugal is blessed with a high level of solar irradiation – it is among the top countries in Europe – the relative share of solar energy in the electricity production is relatively small. In 2017, solar energy accounted for 1.5% of the total electricity production. This means that there is high potential for the development of solar photovoltaic projects in Portugal that allow to harness the power of the abundant solar resource in Portugal and reduce the energy dependence and, in turn, help achieve Portugal's climate goals for 2030 and 2050.

Over the last years however, solar photovoltaic projects gained more and more traction in Portugal. On the one side there is a rise in installed capacity under the form of large photovoltaic plants with the help of power-purchase agreements (PPA), making these projects bankable without the need of government subsidies. On the other side, the clear regulatory framework regarding distributed generation, which is in place since 2014, thrives an increase in the development of decentralized photovoltaic projects.

One of the problems associated with wind and solar power is their inherent variability in terms of production as this causes unpredictability and stress on the electricity grid. One part of the Portuguese regulation regarding distributed generation through PV projects is focused on self-consumption and is referred to as unidade de produção para autoconumo (UPAC). More specifically, this framework stimulates high levels of direct consumption of locally produced electricity and makes it less beneficial to inject any surplus electricity production into the electricity grid. Therefore, in order to be economically viable for the owner, photovoltaic projects have to be sized taking into account the load (or source of electricity consumption) to which the system is connected. As a result of this regulatory framework, project developers will avoid heavy oversizing of PV systems (in relation to the consumption), which allows for higher overall installed capacity of decentralized photovoltaic systems with lower induced stress on the grid. Due to the current electricity and PV market conditions, a wide range of system sizes are economically viable for a single consumer. This makes it possible to for a PV project developer – and it is being done – to use a simple rule of thumb to determine the 'optimal' size of a PV system based on some parameters that describe the consumption such as the maximum power demand and the annual electricity consumption.

Such a rule of thumb generally results in a PV system that makes an attractive investment option but, which is not necessarily the optimal for the specific case. More specifically this means that the investment in the PV system does not achieve the highest possible return. With the aim of avoiding this, in this thesis a methodology is developed to determine the size of a PV system for it to be the best investment option for a specific consumer. Additionally, the model is applied to a case study in order to illustrate the possible benefits of installing a decentralized PV system, and to illustrate the economical sensitivity to a set of parameters that could change over the lifetime of a PV project.

In the remainder of this thesis a concise elaboration on the Portuguese electricity system and the role of renewables is provided, followed by a detailed overview of the developed methodology and the case study to which it is applied. The thesis is concluded by an overview of the main results of the case study as well as a sensitivity analysis, followed by an overall conclusion.

2. Portuguese electricity system and renewables

This section provides a concise overview of the Portuguese electricity system and its most important actors. Also, an elaboration on the electricity prices will be made, along with a comparison with other EU member states. This is followed by an insight on the importance of renewable energy sources within the electricity system and specific policies and regulations aimed to increase the share of renewable energy in Portugal's energy mix and their effect so far.

2.1. Portuguese electricity system

2.1.1. Liberalization of the Portuguese electricity system

After its nationalization in the seventies of the 20th century, the Portuguese electricity sector became a vertically integrated monopoly under the name Electricidade de Portugal (EDP) (Autoridade da Concorrência, 2007). In the eighties, Portugal took its first steps towards the liberalization of the sector (Decreto-Lei n. º 449/88, 1988), and published a regulatory package in 1995 – in anticipation of the European Directive 96/92/CE – that constituted the main pillars that shaped today's electricity system.

Liberalization is the reduction of government regulations, participation and control in the sector, giving a chance to private firms to participate in the sector. The main aspects of this process are vertical unbundling of the sector into generation, distribution, and retail; and privatization of the state-controlled entities (Joskow, 2008). The purpose is increasing the competition in the electricity sector – mainly in generation and retail – which, in turn, leads to higher efficiency in the electricity sector and an increase of consumer welfare (Ghazvini, Ramos, Soares, Vale, & Castro, 2016).

In Portugal and in Europe in general, the Transmission and Distribution layers of the sector have not been liberalized – the state keeps control of these activities - but delivers the management, maintenance and upgrading of the infrastructure to private companies through long-term concessions. The structure of both the regulated electricity sector as the liberalized sector is illustrated schematically in Figure 1.

The liberalization was carried out gradually and, since 2006, all consumers in mainland Portugal are now able to choose their electricity provider. During this process, Portugal and Spain increased the interconnection of their national grids and created an Iberian energy exchange market (MIBEL) which allows bilateral contracts, purchasing and selling of electricity among Portuguese and Spanish market actors. MIBEL consists of a spot market and a derivatives market which are referred to by the names of the responsible market operators, OMIE and OMIP, respectively.

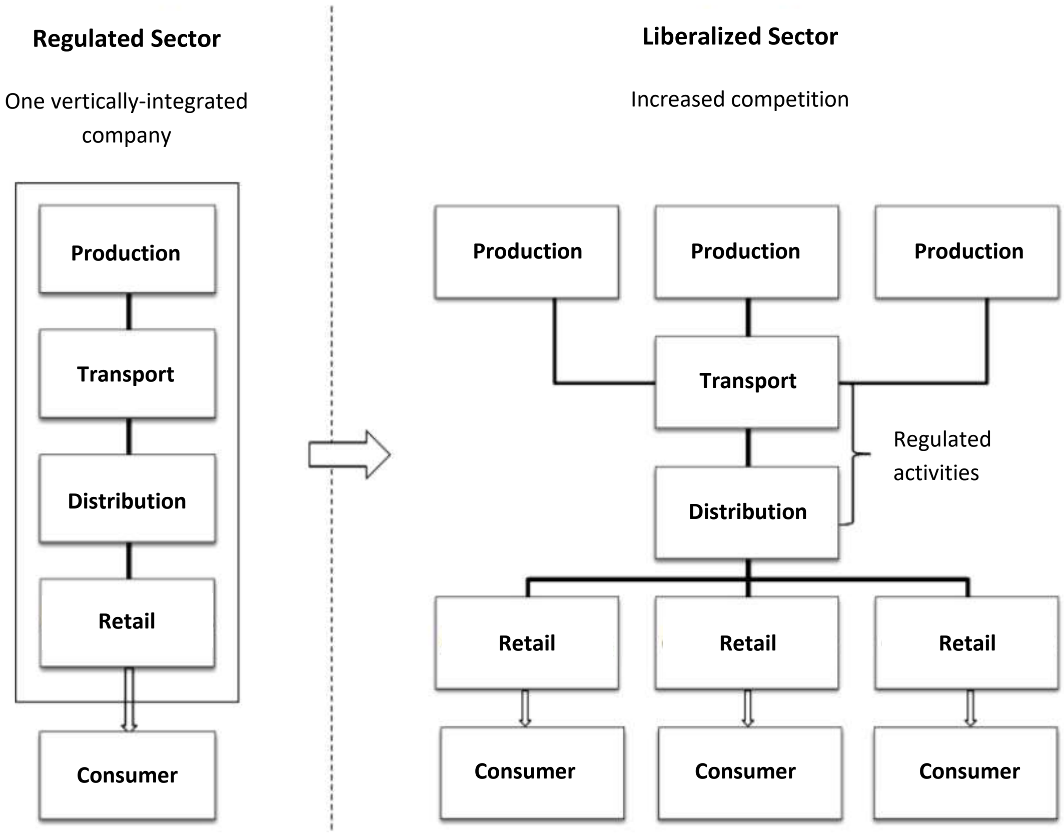

Figure 1: Effect of liberalization in the electricity sector. (Adaption of Pepermans & Proost, 2000)

2.1.2. Current sector structure

Currently, the liberalization is nearly concluded, with the majority of consumers participating in the liberalized market. In this market competitive retailers are obliged to provide pre-contractual offers to consumers and consumers can switch between retailers as often as they want without cost and without the need to change any appliances (e.g. meter). The electricity system consists of generators or producers, the transmission grid, the distribution grid, retailers, and consumers.

There are two main categories of electricity generation in Portugal: Production under special regime (PRE) and production under ordinary regime (PRO). The PRO generation is made up of conventional, thermal electricity generation. The PRE generation is made up of endogenous resources (both renewable and non-renewable), cogeneration, and distributed generation and accounted for 45% of the energy consumption in 2014.

The generation market is still very concentrated with EDP being the dominant entity with a 51% market share in sales to the wholesale market. In terms of installed capacity, the share of EDP is declining however, mainly due to the growth in renewable electricity generation capacity, in which EDP holds only a small share. About 40% of the electricity sales to the wholesale market are made by renewable energy generators (International Energy Agency, 2016).

The transmission and distribution grids are natural monopolies and are regulated by the Portuguese energy services regulatory authority (ERSE). The transmission grid is under exclusive concession granted to Rede Eléctrica Nacional (REN) and consists of lines of 400, 220, and 150 kV (International Energy Agency, 2016). The national distribution grid is under concession awarded to EDP Distribution, although few low-voltage distribution grids are under concessions awarded to local companies. The independent entity ERSE regulates the transmission and distribution tariffs following an additive model that captures all the different cost components for different types of customers and is based on a rate of return on capital investment in infrastructure (Portuguese Competition Authority, 2007).

Electricity consumers are classified based on their needs in terms of voltage and power connection. The most common category is Normal Low Voltage or Baixa Tensão Normal (BTN), with consumers that have a maximum voltage of 1 kV between phases and contracted power up to 41.4 kVA. This usually are households and small offices who buy their electricity through a retailer.

A second category are the consumers in Special Low Voltage or Baixa Tensão Especial (BTE) with contracted power larger than 41.4 kVA, but these customers have been migrating to the Medium Voltage or Média Tensão (MT), with a voltage between 1 and 45 kV. These consumers are connected directly to the medium-voltage distribution network and can buy their electricity through a retailer or can purchase directly from the market or producers. MT-consumers usually are small industries or larger companies with a significant number of electrical and electronic appliances.

The High Voltage or Alta Tensão (AT) and Very High Voltage or Muito Alta Tensão (MAT) are the consumers that have maximum voltages between 45 and 110 kV or above 110 kV, respectively. These consumers can be large factories or the steel industry for example, and are connected directly to the transmission grid. In Figure 2 the current electricity sector is summarized schematically for a clear overview.

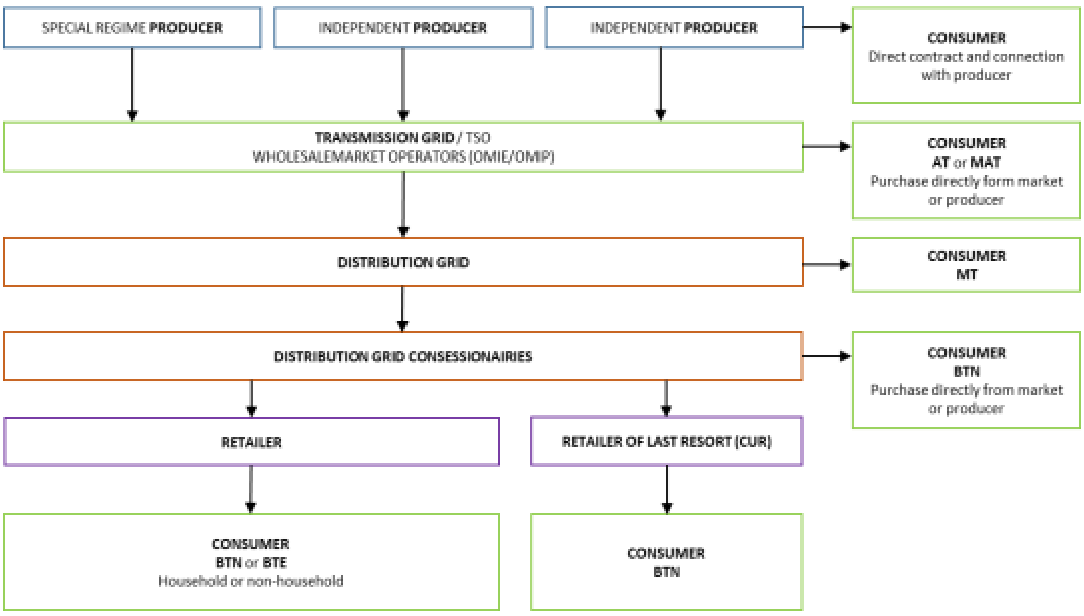

Figure 2: Schematic overview of the Portuguese electricity system (Adaptation of Tavares Da Silva, 2008)

One of the spear points of the liberalization is the creation of the liberalized retail market. At the end of May 2018, 81% of the total clients representing 94% of the national consumption were in the liberalized retail market (ERSE, 2018). Consumers that are still in the regulated market are served by retailers of last resort (CUR) with tariffs determined by ERSE, revised every three months. After several grace periods, these consumers are obliged to switch to the liberalized market by the end of 2020, except for consumers that are economically vulnerable. In terms of the different categories of consumers, practically all of the larger consumers (BTE, MT, AT, MAT) switched to the liberalized market. For households, mainly BTN, 85% of the consumed electricity is bought in the liberalized market (ERSE, 2018).

In the liberalized retail market, EDP Commercial is the market leader, serving 82% of the consumers that represent 42% of the total consumption. They are mainly dominant in the household consumer market with 77.5% of market share.

The market segments of large consumers and of industrial consumers are more competitive. In the industrial segment, Endesa is leading with about 30% of market share, followed by Iberdrola, EDP and Galp with market shares of about 21%, 18% and 11%, respectively. In the segment of large consumers, Iberdrola is leading the market with a share of 33%, followed by EDP, Endesa, Fortia and Galp with market shares of about 22%, 16%, 14% and 8%, respectively.

Portugal is still in the process – although close to the end – of phasing out regulated prices but shows a high external switching rate. The external switching rate is the voluntary action of consumers to change their electricity supplier or retailer and is an indicator of the retail market's competitiveness. Since 2011 the annual external switching rate in Portugal has been growing to almost 21% in 2016 – although this is a reduction as compared to 2015 – for households, making it the leading country in the EU (CEER, 2017). For non-households Portugal has the second highest switching rate in the EU with almost 32% in 2016 (CEER, 2017). Additionally, Portugal is among the countries with the highest relative growth of retailers (CEER, 2017). Together with the high switching rate this indicates a significant progress in the retail market activity.

2.2. Electricity prices in Portugal

2.2.1. Price structure

Electricity prices in the liberalized market in Portugal are composed of five main components: production cost, transmission fee, distribution fee, retailer remuneration, and the 'system general usage tariff' (UGS) (ERSE, 2017).

The production cost is based on the wholesale market prices and is allocated to the consumers based on their energy consumption. The transmission and distribution fees are regulated by ERSE and are based on a predetermined return on investment for the TSO and DSO and are allocated to the consumers based on the extent to which they make use of the infrastructure. The retailers are private entities operating in a competitive market, which implies they require revenues and a certain profit margin in order to survive. The UGS comprises the cost to ensure the proper working of the system that cannot be assigned to a single part of the electricity supply chain.

Figure 3 illustrates the relative weight of these different factors on the consumer electricity price. It can be seen that since 2010, UGS costs correspond to a significant part of the electricity price. This is mainly due to three important costs that are covered through the UGS charged to consumers:

- The first cost stems from the – initially very high – support for renewable- and microgeneration that have been awarded through subsidies, to the PRE producers. The installed capacity of the PRE's has been increasing exponentially since 2007, resulting in a large total of subsidies or feed-in tariffs to be paid.

- The second cost factor is the conversion of the long-term power-purchase agreements (PPA) for conventional power plants, which have been established before the liberalization, to equilibrium maintenance cost contracts (CMEC). These CMEC's include power guarantee incentives and compensation for the termination of the long-term PPA's.

- Lastly, Portugal is paying interests on its 'tariff deficit'. The tariff deficit comes from an undervaluation of the cost of electricity, resulting in regulated tariffs or cap price increases for consumers that were not sufficient to cover the cost, resulting in a deficit.

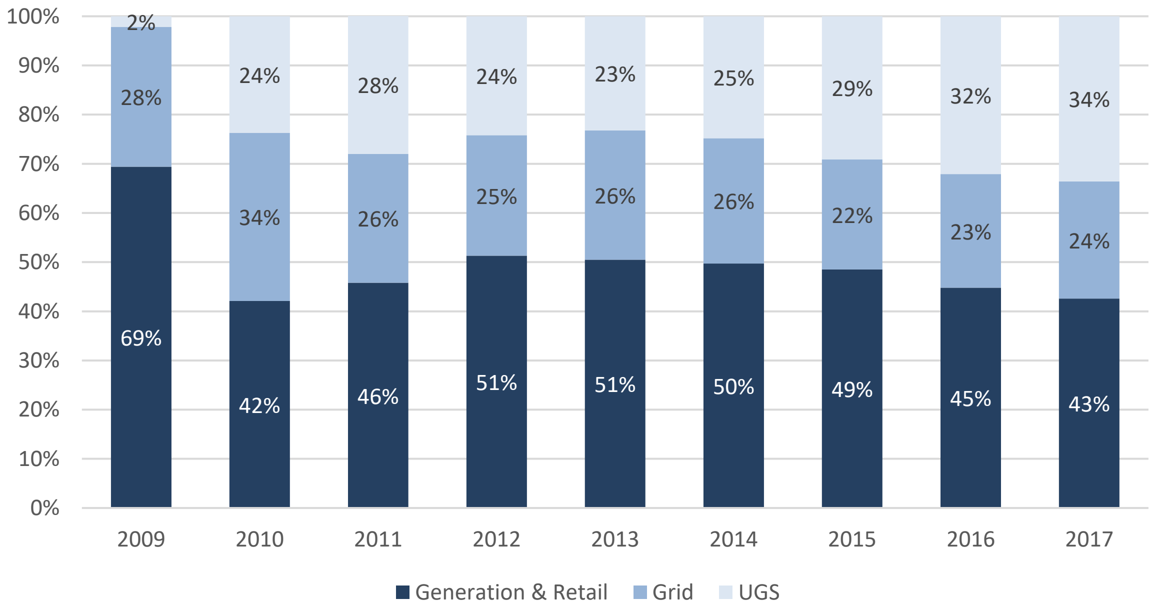

Figure 3: Relative share of the different cost components that make up the consumer electricity price (ERSE, 2017).

2.2.2. Past, current and future price

Figures 4 illustrates that the average price per kWh – including all costs – historically has been highest for low-voltage consumers, followed by medium-voltage and high-voltage consumers. The prices until 2010 are based on the regulated market prices. From 2011 on, the prices are based on the retailers' prices offered to the consumers. It is important to take into account that the graph represents the prices in real terms, based on the electricity prices in 2017. When expressed in nominal prices, the prices form a curve with a general upward slope, mainly under the influence of inflation.

The period 1990 – 2000 is characterized by a general decrease in prices, followed by the period 2000 – 2010 with fairly constant electricity prices. In the most recent period, prices have been going up overall, mainly under the influence of the increase in UGS, which became an important driver of the electricity price since 2010 as indicated in Section 2.2.1. In contrast to the goal of reducing energy prices through more competition in the liberalized market, electricity prices increased. In short, this is argued to be the result of the combination of political decisions and unforeseen fluctuations in the wholesale market. More specifically, the way the integration of renewables in the energy mix was promoted (with very high feed-in tariffs for example); the CMEC's to compensate for the long-term agreements with conventional, thermal electricity producers that were made in the past; and the mismatch between the overall cost of electricity generation, and the regulated price of electricity charged to consumers, which results in high interest payments to be paid on the tariff deficit.

It is important to note however that in since 2015 - 2016, the average reference prices are decreasing slightly for the first time in about 10 years. Additionally, in 2018 the nominal prices remained as good as stable, with a slight reduction in the nominal reference tariff for the highest price ranges which are charged in BTN and BTE, the low-voltage consumers.

Naturally, it is difficult to make forecasts for future electricity prices due to the large amount of influencing factors. The Portuguese secretary of state for energy has announced in May 2018 that the government wants to reduce the electricity price by 10% as compared to the 2015 and 2016 prices. However, the price of electricity in the overall EU-28 market is expected to increase for the next 10 years (Energy Brainpool, 2017).

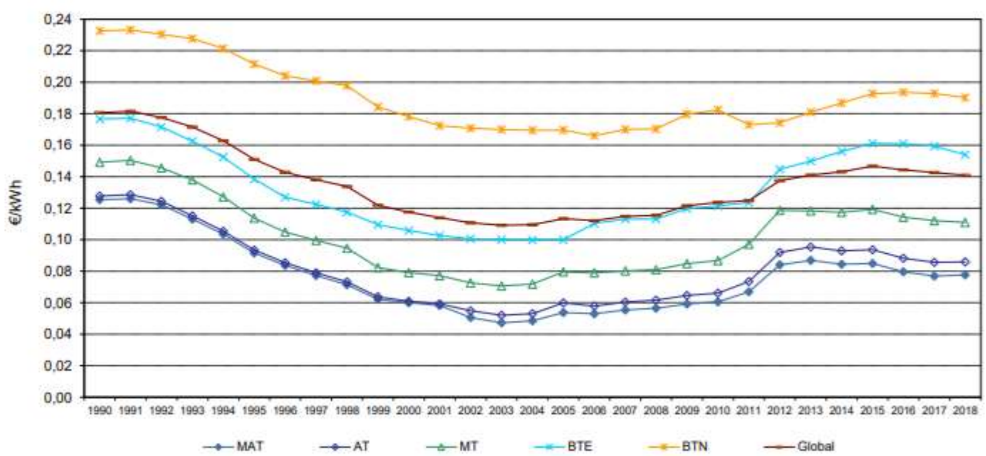

Figure 4: Evolution of the average real reference tariff for final consumers per voltage level, (2017 prices) (ERSE, 2017)

2.2.3. Portugal as compared to the rest of the EU-28

Portugal is among the countries with highest prices of final electricity consumption in the EU-28. When expressed in euro per kWh, Portugal comes fifth in the ranking of energy prices for households and for industrial users after

Denmark, Germany, Belgium and Ireland. The top-7 of countries with highest electricity prices, expressed in euro per kWh, is depicted on the left side of figure 5.

The ranking changes when taking into account the purchasing power parities of the European countries. For example, the purchasing power of Irish consumers is almost 50% higher than those of Portuguese while the electricity prices are practically the same. To have an absolute comparison between countries, on the right side of Figure 5, the top countries in terms of electricity prices expressed in kWh per purchasing power standard (PPS) are listed. The PPS is a fictive 'currency' that eliminates the difference in purchasing power between different countries, making an absolute comparison possible. It can be seen that Portugal is the first country together with Germany in the EU-28 in terms of electricity price for households, and among the highest (third) in Europe for industries.

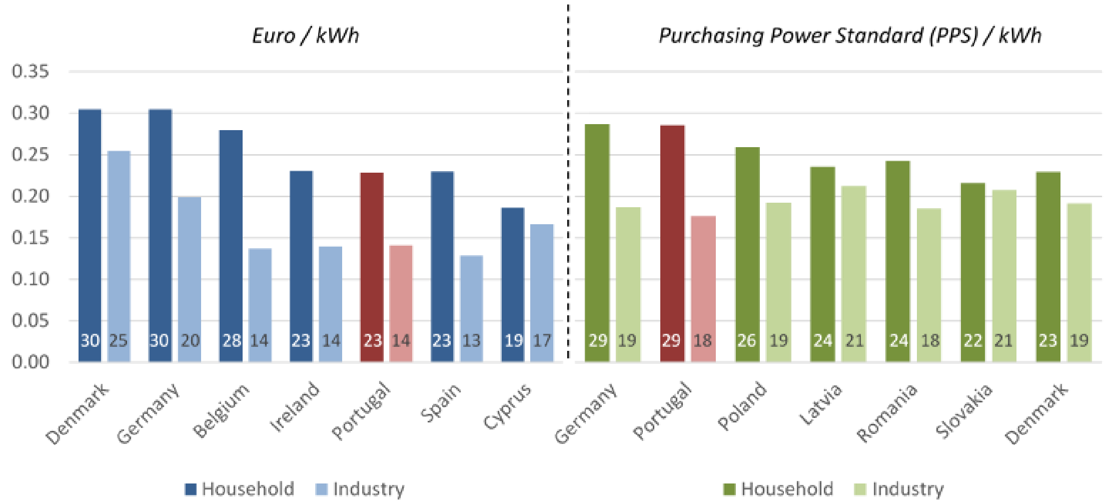

Figure 5: EU-28 countries with the highest electricity prices in 2017 for households and industries expressed in euro/kWh (left) and PPS/kWh (right). Based on data from Pordata, 2018

The high price of electricity in Portugal is to a large extent due to the high taxation of electricity. Figure 6 lists the countries with the highest taxation of electricity among the EU-28 and the EU average, for household consumers. It can be seen that Portugal is the third country with highest taxation of electricity as the total of taxes, VAT and other levies make up 52% of the final electricity price.

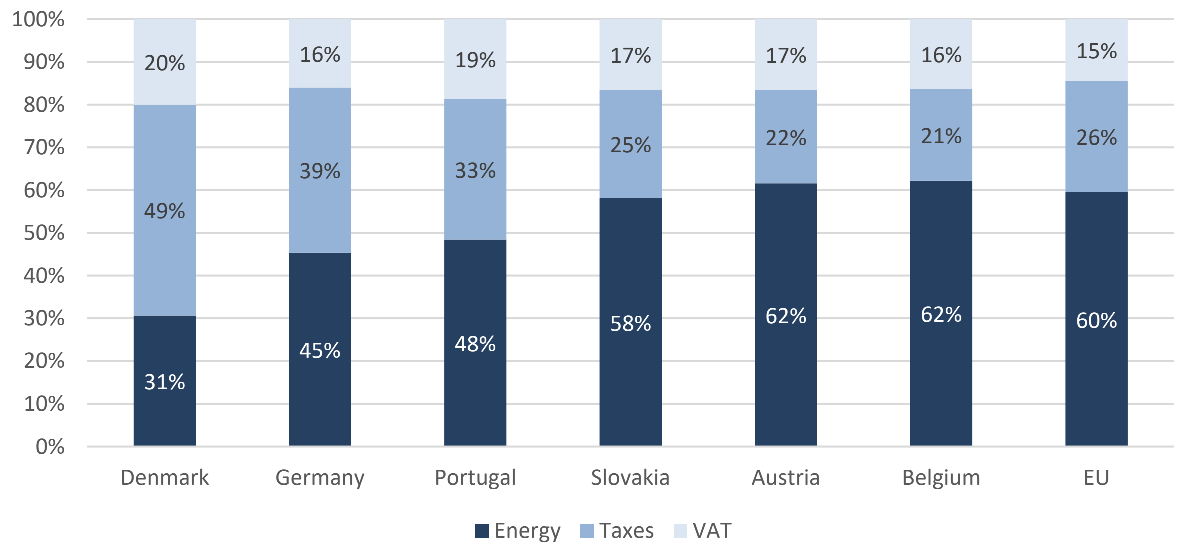

Figure 6: Breakdown of the final electricity prices for households into actual energy cost, taxes, and VAT for the top-6 countries with highest taxation in the EU-28, and the EU average. Based on data from (Eurostat, 2018)

2.3. Renewables in the energy mix

2.3.1. Current electricity mix

Portugal is performing well in terms of the incorporation of renewable energy in the energy mix. In 2016 Portugal reached a share of 28.5% of renewable energy in the gross final energy consumption (not solely electricity), which is close to their 2020 target of 31% (Eurostat, 2018). In terms of electricity, Portugal is generating about 40% to over 60% of it through renewables, depending on the hydrological conditions of the year (APREN, 2018). In 2017 for example this was 41.8% (dry year) while in 2016 this was 57% (wet year).

The main renewable sources are hydro and wind. Hydro has been part of the electricity mix for over 50 years while wind power started to grow significantly since 2004. It is important to note the relative small share of solar photovoltaics (PV) in Portugal's electricity mix, one of the countries with the highest amount of solar irradiation in Europe. In 2017, solar contributed only 1.5% to the total electricity production – including conventional production – as compared to over 13% and 21% by hydro and wind power, respectively (APREN, 2018).

2.3.2. Renewable energy goals

In the framework of the EU 20-20-20 goals, Portugal targets a 31% share of renewable energy in the final gross energy consumption, and 10% of this in the transport sector. After the effective implementation of wind and hydro energy to diversify the energy mix, the country is close to the target of 55% of renewable electricity by 2020. Although the 2030 target discussions are still ongoing, Portugal is likely to target 35 to 45% of renewable energy consumption (Ecofys, 2018). Key part in attaining these targets will be the development of subsidy renewable energy sources, mainly photovoltaic (Ecofys, 2018). Also for the 2020 goals, solar energy is the next step in this diversification of renewable electricity according to the latest National Action Plan for Renewable Energies 2013 – 2020. The installed solar capacity went from 150 MW in 2010 to almost 462 MW in 2016 and is forecasted – by the government – to rise to 900 MW by 2020 (Vitor & Rocha, 2017)

2.4. Distributed generation

Portugal has started incentivizing the generation of electricity since 1988 with the decree-law 189/1988, which instituted a guaranteed feed-in tariff (FiT). Over the years, policies and incentives have been subject to changes, arriving to the laws regarding mini and micro generation of renewable energy in the period 2010 to 2014. These regimes promoted distributed generation by making the access to generation more transparent and ensuring 'special regime' FiT's when certain requirements were met. These laws applied for production capacities of up to 20 kW and ensured FiT's ranging from 0.15 euro/kWh up to 0.196 euro/kWh for a period of 15 years. In 2014 the decree-law 153/2014 has been approved, which established two main frameworks for distributed generation, which make up the current legislative framework: small production units (UPP) and self-consumption units (UPAC).

UPP is the regime that replaces mini and micro generation regulatory framework which is more in pair with the continuous decrease in PV module and inverter prices over the last years (IRENA, 2018). UPP allows for the installation of renewable energy production units up to a capacity of 250 kW which feeds all of the produced electricity into the grid. In the case of solar photovoltaics, the government sets a reference tariff for the three categories within UPP for PV. Producers, in order to obtain a permit to participate in the UPP scheme, bid with a (small) discount to this benchmark tariff. Bids are ranked from highest discount to lowest and a certain capacity per month is allocated to the producers based on the bids they offered. The final tariff for every month, for all accepted producers, amounts to the reference tariff minus the lowest discount to this tariff that got accepted that month. This tariff is applicable for 15 years, without any correction to the tariff (e.g: no adaptation of the tariff to the consumer price index or inflation).

As opposed to UPP, UPAC is focused primarily on self-consumption of the generated electricity. The primary focus is to stimulate the local consumption of the produced energy through a rational installed capacity, adapted to the consumption load through a more direct and subsidy-free regulatory scheme. More specifically, the installed capacity of a UPAC is limited to the contracted power. The production unit has to be registered through an online platform and a small registration fee has to be paid before starting the operations. Once in operation, the consumer (owner of the installation) uses the produced electricity to meet the load, the excess production can be sold to the retailer of last resort. So, the benefit for the consumer mainly comes from the reduction of the amount of electricity to be bought from a retailer, the transportation and distribution costs and – to a smaller extent – from selling the excess electricity to the grid. The system owner is remunerated for the electricity fed into the grid by a certain value per kWh. This value amounts to 90% of the monthly averaged electricity closing price on the daily Iberian wholesale market (OMIE) which, on average, amounted to 0.3967 and 0.5224 euro per kWh for the years 2016 and 2017, respectively. This results in an average selling price of 0.0357 and 0.047 euro per kWh for 2016 and 2017, respectively.

3. Methodology

There exists a wide range of software packages for the sizing, design and simulation of solar PV systems. Widely used software like TRNSYS, Archelios, Polysun, PVSyst and PV*SOL are commercial software packages and provide relatively good estimates of the electricity generation (Axaopoulos, Fylladitakis, & Gkarakis, 2014). These software packages however, are not suited for a pre-feasibility study following the specifics of the UPAC regulatory scheme of Portugal. As the purpose of this work is to provide a means for determining an optimal system configuration based on economic parameters in line with the Portuguese UPAC regulatory framework, it was necessary to build a specific tool.

In order to assess the savings from different PV system implementations under the UPAC scheme, a model has been built in Python (version 2.7). This model allows to define a range of systems by indicating ranges for the module orientation, module inclination, the system size, and the type of installation (directly on the roof, inclined on the roof, or mounted on the ground). Every system within the range of the defined systems actually consists of two subsystems which can differ in the panel orientation, inclination and type of installation to better reflect real-world conditions. For example, an installation on a roof often consist of a number of PV modules on one side of the roof, oriented and inclined in one way, and a number of PV modules on another side of the roof, oriented and inclined in another way.

For the two subsystems of every possible system within the specified ranges, the model makes use of the PVLib Python library to calculate the AC-output of a 24 kWp reference PV system based on the parameters of these two subsystems (module inclination and orientation) and the local irradiation data. This system setup makes use of a 20 kW inverter and PV-array over-dimensioning of 1.2 which is very commonly used as a 'building block' in larger commercial PV installations according to the industrial partners that were consulted for this research. This makes that the modeled system ac-outputs are realistic, and can be compared with output simulations made by a partner with commercial software. The AC output for the 24 kWp reference system is then scaled to the actual size of the subsystem under study. The AC output of both subsystems are summed to obtain the AC-output of the overall system.

The model considers consumption data, in kW for every 15-minute interval, for the entire calendar year. For every possible system within the specified range, the system's AC output is compared to the consumption to determine the amount of electricity that is consumed directly by the load, the amount of electricity fed into the grid and the reduction in peak-power consumption. These values are combined with the applicable tariffs to determine the savings through self-consumption, selling surplus electricity, and reducing the cost of peak-power consumption.

Combining the annual savings with the initial investment cost, maintenance cost, insurance cost, annual degradations of the modules, inflation rate, and discount rate, the model calculates the annual cash flows for a 25-year period along with the corresponding net present value (NPV), internal rate of return (IRR), and payback period for every possible system. The model then provides an output providing all the key performance indicators of the range of systems, which is used to determine the best options in terms of system configuration.

A schematic overview of the model is provided in Figure 7, followed by a detailed overview in the remainder of this section. The Python code of the main model is provided in Annex.

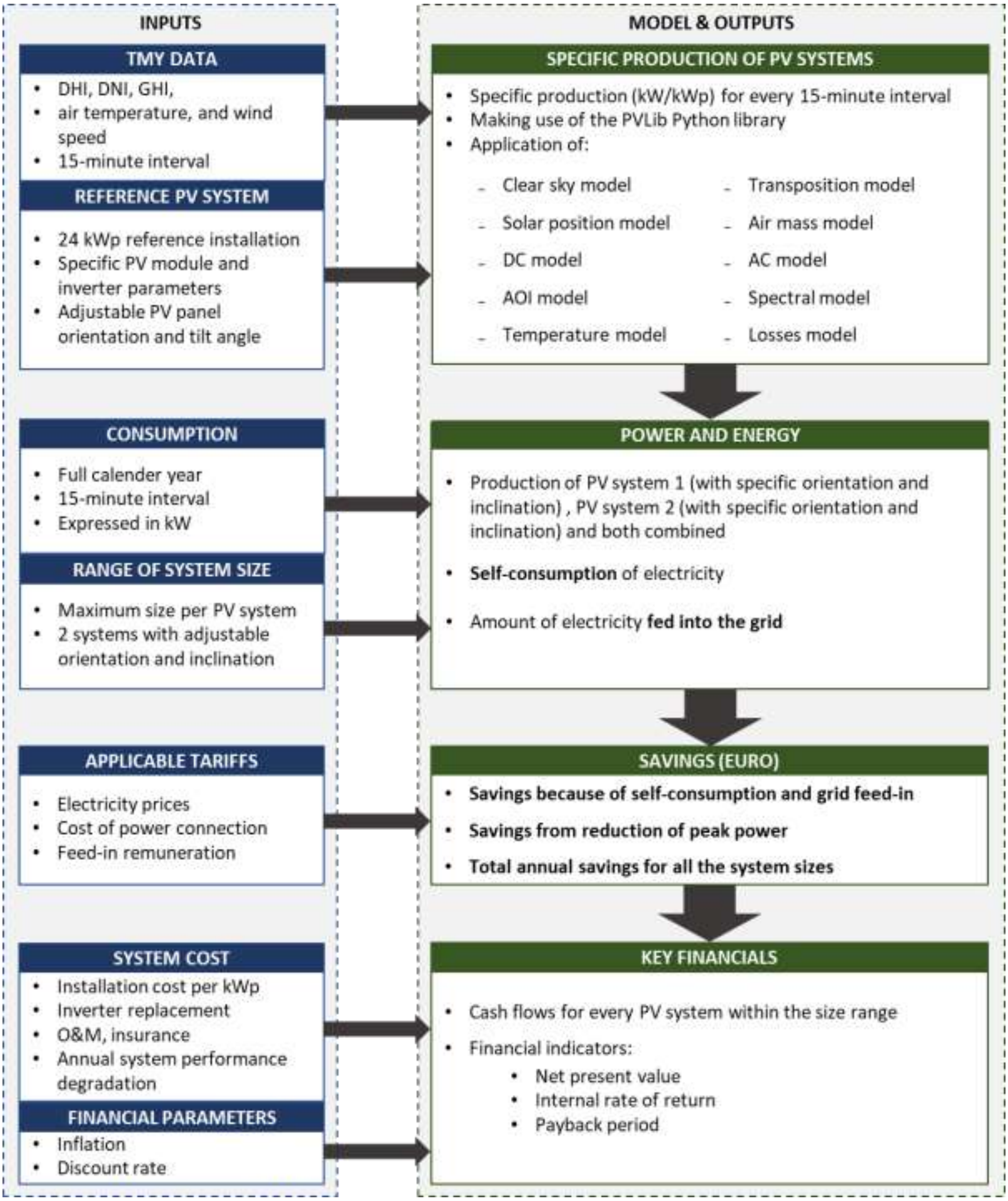

Figure 7: Schematic overview of the developed methodology

3.1. Inputs

3.1.1. Consumption data

One of the main inputs for the model to work is the consumption data. Consumption data can be requested to the distribution company through an online platform, if the local electricity connection is equipped with a telemetering system – in Portugal this is the case for all connections above 41.4 kVA, from the BTE to AT regimes. Upon request, this data is delivered in the form of 12 excel files – 1 for each month – or in the form of one file for the last 12 months which contain the measured requested power every 15 minutes for the last year. The model is built to extract the consumption data from these files and combines them into one series of data consisting of 35,040 data points (365 days x 24 hours x 4 quarter of hours). The consumption is expressed in kW for every date and timestamp.

3.1.2. Weather data

Another important input to the model is the weather data for specific locations. In order to be in line with the consumption data, the data for a typical meteorological year (TMY) needs to have a frequency of 15 minutes. The data was obtained from Meteonorm, which is generally considered a reliable source for weather data. The model is built to extract the TMY data from a CSV-file (Comma separated values). The required data to be extracted are the direct horizontal irradiation (DHI), direct normal irradiation (DNI), global horizontal irradiation (GHI), ambient temperature, and the wind speed for every 15 minutes of the year. Similar to handling the consumption data, the model stores this data in a matrix with a date and timestamp and a length of 35,040 lines of data.

3.1.3. Reference PV system specifications

The model makes use of a reference PV system, characterized by the choice of modules, an inverter, the number of modules per string, and the number of strings per inverter. This reference PV system makes use of the PVLib library to obtain the module and inverter parameters. The module parameters are obtained from the Sandia module database. The inverter parameters are obtained from the CEC inverter database. Another important factor to be passed to the reference PV system is the PV panel tilt and orientation, as this influences the timing and the amount of solar radiation reaching the panels. An elaboration on the reference PV system used for the case study is provided in Section 4.2.

3.1.4. Applicable tariffs

The model requires the input of the electricity prices being charged in order to obtain the savings that stem from the solar energy produced, expressed in euro per kWh. Currently, the model is built to incorporate 4 different prices, depending on the time of consumption. These four prices correspond to different times of consumption, which depend on the time of day, and whether it is a weekday, Saturday, or Sunday or holiday. Additionally, consumers are charged for the power consumption during peak hours. This price is expressed in euro per kW*day. A more detailed overview of how the consumer is charged for electricity is provided in Section 4.1. In addition, to the prices charged, the remuneration in euro per kWh for feeding surplus electricity to the grid is required as an input. As explained in Section 2.4, this feed-in tariff is based on the average monthly Portuguese wholesale price of electricity on the Iberian wholesale market (OMIE). As this price is difficult to forecast for the following years, the author opted to simplify the model by using a single value independent of the time of the year or time of the day.

3.1.5. System cost and financial parameters

In order to evaluate the attractiveness of a PV system it is necessary not only to take into account the savings it generates but, also the costs associated with the system. These costs consist of the initial investment cost, the cost of replacing the inverter twice within the 25 years, the operational and maintenance cost, insurance cost, and the annual degradation of the system's performance. The overall initial investment cost is a required input, expressed in euro per kWp and depends on the size of the system and the type of installation. The cost of the system is determined based on the size of the system and the type of mounting (roof-mounted, roof-inclined, or ground mounted). This is further elaborated in Section 4.3.1. Regarding the inverter, it is assumed that it needs to be replaced every 10 years on average, therefore the cost of replacing the inverter is a required input, expressed in euro per kW. The operations and maintenance, and insurance cost are considered as yearly recurring costs. These costs depend on the size of the installation and are therefore expressed in euro per kWp and as a percentage of the initial installation cost, respectively. Although it is not an actual cost, the annual performance degradation of the system is treated as a cost as it reduces the savings and revenues from the PV system year by year. Additionally, one of the inputs to the model is the inflation rate. This rate can be used to adapt the future prices and costs. The last input to the model is the discount rate. The discount rate is used in the calculations of the NPV and the discounted payback period. These cost factors and financial parameters are further elaborated on in Section 4.3.

3.2. Electricity production – PVLib

The production of the PV system is modelled by making use of the PVLib toolbox. This is a repository for python (also available for Matlab) which allows for high quality PV modelling. The code is open source, so the source code is freely available and can be modified. The toolbox is a product of the collaborative group of PV professionals, PV Performance Modelling Collaborative (PVPMC), facilitated by Sandia Laboratories (Holmgren, Clifford, & Mikofski, 2018)

The developed model mainly makes use of two modules in PVLib, which in turn make use of a range of modules within PVLib to simulate the output of the reference PV System for every 15-minute time period. These two modules are the 'pvsystem' module and the 'modelchain' module. The pvsystem module contains functions for the modeling of the PV system itself, as well as its performance and output. An instance of the pvsystem module is defined by the module tilt and orientation, albedo, module and inverter parameters, the number of modules per string and strings per inverter. The 'modelchain' module contains functions and cases that combine all of the modelling steps.

The obtained AC-output of the reference system through PVLib is normalized against the size of the system, expressed in kWp, to obtain the specific production of the reference system for every 15-minute interval. The specific production is used in the last main part of the built model to estimate the output of PV systems of different sizes, inclinations and orientations.

3.2.1. Modelchain

The modelchain instance of the model takes into account the reference PV system properties as defined in the 'pvsystem' instance and applies the different transposition models to obtain the AC output of the system based on the weather data through the following steps:

1. Load the location of the PV system from the TMY file's meta data
2. Loading the GHI, DNI, DHI, ambient temperature and wind speed
3. Pressure based on the site's altitude
4. Solar position (for the middle of every 15-minute time interval)
5. Relative and absolute air mass
6. Total irradiance
7. Effective irradiance
8. Cell and module temperatures
9. DC output
10. AC output

3.2.2. Pressure calculation

The pressure is calculated based on the location's altitude following a derived relationship between pressure and altitude as described in Equation 1 with pressure P in Pascal and altitude z in meters (Portland State Aerospace Society, 2004).

$$\boldsymbol{P} = \mathbf{100} \times \left(\frac{\mathbf{44331.514}-\boldsymbol{z}}{\mathbf{11880.516}}\right)^{\mathbf{1}/\mathbf{0.1902632}} \qquad (1)$$

3.2.3. Solar position

The solar position is calculated according to the NREL solar position algorithm, which is an application of Reda & Andreas (2007). The solar position method provides the solar zenith, apparent zenith, elevation, apparent elevation, azimuth and the equation of time. It does this based on the latitude, longitude, altitude, pressure, and 'delta-t', which is the difference between terrestrial dynamic time and universal time (a solar time standard). Delta-t is calculated based on the year and month. The method is highly accurate with an uncertainty in the zenith and azimuth angles of ± 0.0003^{o} in the period from 2000 BC to the year 6000. For a detailed overview of the different calculation steps the author refers to the extensive technical report by Reda & Andreas (2008).

3.2.4. Relative and absolute air mass

The next step consists of the calculation of the relative air mass followed by the calculation of the absolute air mass. The air mass coefficient is a ratio that divides the path length of sunlight through the atmosphere for a given zenith angle to the path length of sunlight when the zenith equals zero (Horn, 2013). The PVLib toolbox allows to choose from a range of models to be used for the calculation of the relative air mass. The author chose to make us of the Kasten and Young (KY) model, which is among the most accurate models (Horn, 2013). An extensive overview of the model can be found in the work of (Kasten & Young, 1989) and the actual calculation is shown in Equation 2.

$$AM_{KY} = \frac{1}{cos\theta_{Zrad} + 0.50572(6.07795+90-\theta_{Zdeg})^{-1.6364}} \quad (2)$$

In which AM is air mass, θ_{Zrad} is the apparent zenith angle expressed in radians and θ_{Zdeg} is the apparent zenith angle expressed in degrees.

The absolute air mass is obtained by adapting the relative air mass for the actual pressure as described in Equation 3.

$$AM_{Abs} = AM_{Rel} \times \frac{Actual\ pressure}{Standard\ pressure} \quad (3)$$

With the standard pressure equal to 101,325 Pa or 1 atm.

3.2.5. Angle of incidence

The angle of incidence is the angle between the solar vector and the surface normal. Making use of the PV panels' surface tilt and azimuth (orientation), the angle of incidence is calculated for every 15-minute interval based on the solar zenith and azimuth making use of geometrics.

3.2.6. Total irradiance

In a next step the total irradiance on the panels is determined. The total irradiance on a panel consists of the total of the beam irradiance, the diffuse irradiance and the ground reflected irradiance.

The beam component is calculated by transforming the DNI using geometrics based on the relative position of the sun and the panels (as defined by the sun and surface zenith and azimuth angles).

The ground reflected irradiance is calculated from the GHI, the albedo, and the surface tilt. The albedo is a measure of the reflectivity of the ground and can be adapted within the developed model. For the case study performed, an albedo coefficient of 0.2 is used. The specific relationship between these factors and the ground diffuse irradiance is provided in Equation 4.

$$Groundreflected\ irradiance = GHI \times \mathbf{Albedo\ x}\ (\mathbf{1} - \mathbf{cos}(surfacetilt_{Rad})) \times \mathbf{0.5} \quad (4)$$

The diffuse component of the irradiance is calculated using the Perez model, which is generally perceived as the model that stands out in terms of prediction accuracy (Diez-Mediavilla, de Miguel, & Bilbao, 2005). The Perez model is an anisotropic sky model that separates the isotropic, circumsolar, and horizon brightening components of the diffuse irradiance, relying on a set of empirical coefficients for each term. A detailed overview of the Perez model is described by Perez, Ineichen, Seals, & Michalsky (1990).

3.2.7. Effective irradiance

The effective irradiance is determined by accounting for the incidence angle modifier (IAM), the spectral modifier (SM), and for the fraction of diffuse irradiance used by the PV module (FD).

In order to account for the optical losses due to reflections from the PV modules materials, the IAM is used. This modifier varies with the angle of incidence of the beam radiation on the PV module surface. The calculation of the IAM is done according to the physical IAM model, based on Snell's and Bougher's laws, developed by De Soto, Klein, & Beckman (2006). The SM in this model is set to 1, and the FD is a module parameter retrieved from the Sandia module database. The effective irradiance is obtained through the following equation:

$$\boldsymbol{Effective\ irradiance = SM\ \times (Irradiance_{Beam}\ \times IAM + FD\ \times\ Irradiance_{Diffuse})}\ (5)$$

3.2.8. Temperature effect

The output of a PV module – and thus, the performance of a PV system – is affected by its (cell) temperature. The cell and module temperatures are calculated according to the Sandia PV array performance model (SAPM) (King, Boyson, & Kratochvill, 2004). This model calculates these temperatures based on the incident irradiance, wind speed, ambient temperature, reference irradiance and a set of parameters that depend on the type of solar panel.

3.2.9. DC output

The calculation of the output voltage, current and power of the PV module is based on the effective irradiance, the cell temperature and a range of module parameters. These module parameters include reference values for open circuit, short circuit, and maximum power voltage and currents, temperature coefficients, number of cells in series, and empirically determined coefficients relating voltages and currents to the effective irradiance. The followed method is based on SAPM (King, Boyson, & Kratochvill, 2004) and provides the short-circuit current, the open-circuit voltage, the current, voltage and power at maximum-power point and the current for two other points on the current-voltage curve.

As we are modeling a PV system and not a single module, the outputs for the module are scaled according to the system size. More specifically, the currents are multiplied by the number of strings, and the voltages by the number of modules per string.

3.2.10. AC output

As a last step, the AC output is obtained using Sandia's model for grid-connected photovoltaic inverters (King, Gonzalez, Galbraith, & Boyson, 2007). The model is based on the use of parameters that relate the inverter's AC power output to both the DC power and the DC voltage (King et al., 2007). The parameters used in this model are based on the manufacturer's specification sheets, field measurements during system operation and, detailed performance measurements conducted by recognized testing laboratories. An extensive overview of the model is described by King et al. (2007). The output that is obtained after this step consists of a series of data with the AC output of the reference system for every 15-minute timeframe, expressed in kW.

3.3. Outputs: energy, savings, cost and key financials

After running the model, a range of outputs is obtained that can be used for analyzing the solutions and to assess the most suited sizing for the PV system as part of an economical pre-feasibility analysis. These outputs are obtained for every possible system that is made up of the parameters defined during the input-phase (range of inclination, orientation and system sizes). The most important outputs are the Internal Rate of Return (IRR), Net Present Value (NPV), installation cost, and the first-year savings. The outputs can be subdivided in three groups: energy and power; savings, revenues and costs; and key financials with the outputs of one group serving as an input to the following group.

3.3.1. Energy and power outputs

The first group of outputs consists of the AC power output of the overall system (for every possible system within the specified range). This output is calculated as the sum of the output of both subsystems defining every single system. This output is provided for every 15-minute interval as well as for the entire year. It is important to note that the consumption and AC output are expressed in kW for every 15-minute period. In order to obtain the electricity output in terms of energy, this power output is divided by 4.

Using the consumption for every 15-minute interval and the AC output of the system, the self-consumption and grid feed-in (surplus production) is determined by simple comparison: if the consumption is larger than the production, the self-consumption equals the production and the surplus equals 0. If the production is larger than the consumption, the self-consumption equals the production and the surplus equals production minus consumption. These outputs are provided for every 15-minute interval as well as for the entire year. Additionally, the self-consumption rate is defined as the ratio of the annual total self-consumption over the annual total PV production. The self-sufficiency rate is defined as the ratio of the annual total self-consumption over the annual total electricity consumption.

The reduction in peak-power consumption is calculated on a monthly basis by summing the electricity production (in kWh) during peak hours for one month, dividing it by the number of peak hours in that month, and multiplying it with the amount of days in that month. This is then summed for all months to obtain the annual reduction in peak-power consumption which is expressed in kW.day.

3.3.2. Savings and revenues

As part of the second group, the savings that stem from the use of a PV system are determined. The savings that come from the avoided cost of buying electricity are determined by multiplying the self-consumption (in kWh) with the applicable tariff for every 15-minute interval. The savings that stem from the reduction in peak-power consumption are obtained by multiplying the monthly reduction by the fixed tariff for peak-power consumption. The revenues from selling surplus electricity to the grid are obtained by multiplying the amount of electricity (in kWh) with the applicable feed-in tariff. These outputs are provided for every 15-minute interval as well as on an annual basis. The total annual savings are the sum of these three sources of savings.

3.3.3. Costs

The cost of the PV system consists of the initial investment or installation cost, the maintenance cost, the insurance cost and the cost of replacing the inverter. The costs used for the purpose of this work are based on figures provided by three PV project developers and are provided in Section 4.3.

The initial investment cost or installation cost consists of the cost of modules, inverters, balance of the system, civil works, and licensing. The overall cost depends on the size of the system and the type of installation (roof-mounted, roof-inclined, or ground-mounted). This cost is determined based on data provided by three PV project developers and is elaborated on in Section 4.3.1. The maintenance cost and insurance cost are annually recurring costs that depend on the system size and the initial investment cost, respectively. It is generally assumed – and confirmed by the PV project developers – that inverters have to be replaced on average every 10 years. The cost of replacing the inverters depends on the system size.

3.3.4. Key financials

The most important outputs are the key financials that are used to determine the optimal system configuration – together with the initial investment cost. These key financials are the IRR, NPV and the payback period (in years). In order to determine these numbers for every possible system, the annual cash flows are required. These cash flows are made up for a period of 25 years of operation of the PV installation, which is the typical lifetime used in the economical assessment of PV installations.

The cash flows consist of the initial investment cost, which is incurred in year 0. From year 1 to year 25, the revenues consist of the total savings generated by the PV system, minus the maintenance and insurance cost. For year 10 and 20 also the cost of replacing the inverters is taken into account.

The maintenance and insurance costs are adapted each year for the inflation. The annual savings are adapted each year for the annual depreciation of the PV installation and for inflation of the energy prices according to the Equation 6.

$$\boldsymbol{Savings_{Year\ i} = Savings_{Year\ 1} \times (1 - Degradation)^{i} \times (1 + Inflation)^{i}} \qquad (6)$$

The NPV combines the cash flows and requires the input of a discount rate and is calculated according to Equation 7.

$$\boldsymbol{NPV = \sum_{t=0}^{25} \frac{CF_t}{(1+Discount\ rate)^{t}}} \qquad (7)$$

The IRR is the discount rate for which the NPV of future cash flows equals zero and is obtained by solving Equation 8.

$$\boldsymbol{\sum_{t=0}^{25} \frac{CF_t}{(1+IRR)^{t}} = 0} \qquad (8)$$

The payback period is the time at which the cumulative cash flows are positive. It is calculated by determining the last year in which the cumulative cash flow is negative. Then the fractional part of the payback period is calculated by dividing the cumulative negative cash flow of the last negative year by the cash flow to be received in that year. Summing the fractional part of the payback period with the last year in which the cumulative cash flow is negative, results in the actual payback period.

4. Case study

In this section, the methodology is applied to a case study in order to determine the savings that can be obtained through the installation of a PV system at the consumer's premises. The savings will be determined for a range of PV system sizes, which will serve as an input for investment decision assessment. The sizes range from zero – or without a PV system – up to the maximum capacity that can be installed on site based on available space.

4.1. Consumer

4.1.1. Electricity consumption and cost

In this case study the electricity consumption of a logistic warehouse in the Lisbon region is used as the main input to scale a PV system to its consumption following the self-consumption regime, UPAC, in Portugal. The warehouse falls under BTE and has an annual consumption of 1,529 MWh. The consumption data available is for the year 2017, expressed as the average active power consumption for every 15 minutes of the year. The monthly consumption for the year 2017, illustrated in Figure 7, indicates a higher electricity consumption during the cooling season from April to October due to a higher cooling load in the building. The calculated total electricity cost for 2017 amounts to € 157,875.

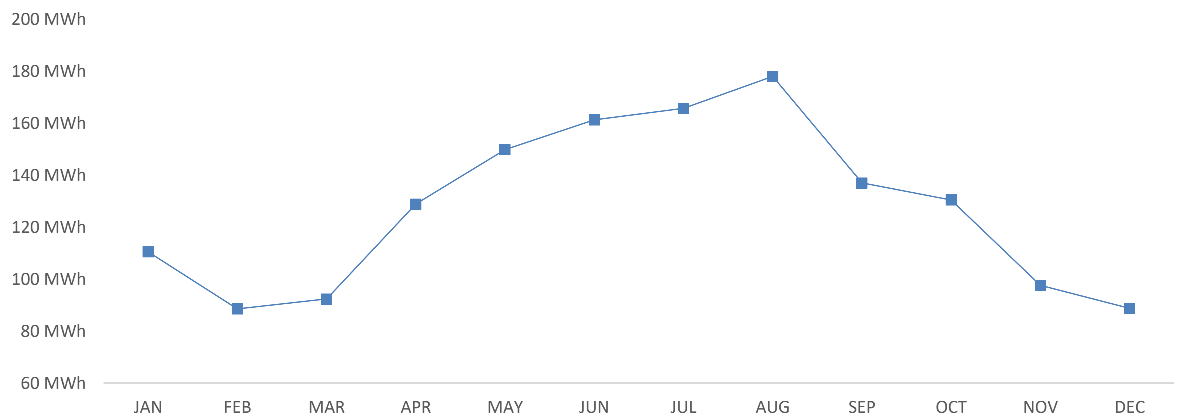

Figure 8: Monthly electricity consumption 2017

The logistic warehouse – under the BTE regime – has a contract with its retailer and the main components making up the electricity cost are: active energy consumption, grid access fees, and power connection fees.

The active energy and grid access fees are based on 4 tariffs: super off-peak (Super Vazio), off-peak (Vazio), high (Cheia), and peak (Ponta). Excluding VAT (23%), these amount to 5.36, 6.17, 8.93, and 9.99 c€/kWh. The applicable tariff depends on whether it is winter or summer, the time of the day and whether it is a working day, a Saturday or, a Sunday or holiday and is referred to as 'weekly cycle tariff'. A detailed overview of the tariff structure is provided in Table 1.

The power connection fees consist of a remuneration for contracted power, and for power consumption during peak periods. The remuneration for contracted power is – like all other fees to be paid – charged on a monthly base and is based on the maximum power demand of the last 12 months (including the month that is billed to the consumer). The tariff amounts to 3.97 c€ /kW.day. The contracted power charges are not considered in this optimal sizing model for two main reasons: its share in the total energy cost is with about 3% relatively low and, the installation of a PV system has a very low effect on reducing the maximum power because it is over a one-year period and this maximum power can occur at any time during the day (so also during the night).

The cost of power consumption during peak hours on the other hand, does have a significant impact on the overall energy bill, and is impacted by the PV system. This fee is charged in order to incentivize consumers to reduce their consumption during the peak periods (Ponta). Also, this fee is billed on a monthly basis and is based on a tariff of 0.2641 €/kW.day. This fee is determined according to Equation 9.

$$\boldsymbol{Fee\ Power_{Ponta}} = \boldsymbol{Consumption_{Ponta}\ (kWh)} \times \frac{\boldsymbol{Days\ in\ month}}{\boldsymbol{Hours\ of\ ponta}} \times \boldsymbol{0.2641}\ {}^{€}/_{\boldsymbol{kW}} \times \boldsymbol{day} \quad (9)$$

	Winter			Summer		
	Weekday	**Saturday**	**Sunday**	**Weekday**	**Saturday**	**Sunday**
Ponta	09:30 - 12:00 18:30 - 21:00			09:15 - 12:15		
Cheia	07:00 - 09:30 12:00 - 18:30 21:00 - 24:00	09:30 - 13:00 18:30 - 22:00		07:00 - 09:15 12:15 - 24:00	09:00 - 14:00 20:00 - 22:00	
Vazio	00:00 - 02:00 06:00 - 07:00	00:00 - 06:00 06:00 - 09:30 13:00 - 18:30 22:00 - 24:00	00:00 - 02:00 06:00 - 24:00	00:00 - 02:00 06:00 - 07:00	00:00 - 02:00 06:00 - 09:00 14:00 - 20:00 22:00 - 24:00	00:00 - 02:00 06:00 - 24:00
Super Vazio	02:00 - 06:00	02:00 - 06:00	02:00 - 06:00	02:00 - 06:00	02:00 - 06:00	02:00 - 06:00

Table 1: Overview of tariffs that are applicable at different times during the day, week and year.

The developed model applies the tariff structure – for active energy and peak power consumption – to the consumption profile and provides us with the current annual cost for the consumer (without PV system). These costs amount to € 139,642 and € 18,232 for the active energy and power, respectively. This equals to a total expenditure of € 157,875 for 2017.

4.1.2. Physical layout

The logistics warehouse has a roof layout as shown in Figure 9, in which the green rectangle indicates the roof area suited to mount solar panels. The inclination of the roof is 15 degrees and as can be seen in Figure 9, half of the available space is oriented towards the NE, while the other half is oriented towards the SW. The available roof area suited for solar panels amounts to about 5,600 m^2 which offers space for an installation of about 700 kWp (350 kWp with NE-orientation and 350 kWp with SW-orientation.

Figure 9: Satelite image of the logistics warehouse, indicating its orientation and the roof space suitable for the installation of solar PV. (Source: Google maps)

4.2. Reference PV system

As mentioned in Section 3.2, the model makes use of a reference system's production in order to obtain the specific production – expressed in kWh per kWp – which serves as an input for sizing the actual PV system. The reference system consists of 4 parallel strings of 20 modules of 300 W each, connected to a 20 kW inverter. This means that the ratio of the capacity of the panels (24 kWp) to the capacity of the inverter (20kW) equals to 1.2, which is the oversizing factor. This system setup has been chosen as an oversizing of 1.2 is recommended for commercial size projects, and the industrial partner for this thesis often works with a very similar set-up, which allows for a reliable verification of the model's outcome in terms of electricity production.

The selected modules are Canadian Solar's 300 W monocrystalline CS6X panels. Each module consists of 72 cells with an overall module efficiency of 15.63% at Standard Test Conditions (1000W/m^2, 1.5 air mass spectrum, and a cell temperature of 25^o C). The modules maximum system voltage amounts to 1000 V, and its dimensions are 1954 x 982 x 40 mm. The choice for these panels is based on the availability of its data in the Sandia module database, it's average size for commercial and industrial applications, and because of the good reputation of the (Bloomberg Tier-1) manufacturer. The main module parameters, as published by Sandia Laboratories are provided in Table 2.

Canadian solar CS6X Mono (300W)	Current (A) / Voltage (V)
Short-circuit current	8.64 A
Open-circuit voltage	43.59 V
Optimum operating current	8.14 A
Optimum operating voltage	34.95 V

Table 2: Main module parameters obtained from Sandia Laboratories

The inverter selected for the reference system is the Fronius Symo 20.0-3 480V. This inverter has been selected because of the manufacturer's good reputation, the availability of data in the CEC inverter database, and because it is often used by one of the industrial partners providing data as an input for the case study. It's main characteristic parameters are provided in Table 3.

Fronius Symo 20.0-3	Power (kW) / Current (A) / Voltage (V)
AC output power	20 kW
DC input power	20.46 kW
Maximum input voltage	1000 V
Maximum input current	58 A

Table 3: Main inverter parameters obtained from SAM Library of CEC inverters

4.3. Financial parameters and other assumptions

4.3.1. PV system cost

An important factor for sizing the PV system is the initial cost of the system. In order to determine realistic prices for the different types and sizes of PV systems, data provided by three solar photovoltaic project developers have been used. More specifically, minimum reference prices for different PV sizes and mounting types (roof-mounted, roof-inclined, and ground-mounted) have been obtained. By combining the data of the three project developers, a wide range of combinations of sizes and mounting types was obtained which was used to perform a power regression (cost for 15 sizes per mounting system). The prices for PV installations can vary due to several factors such as the distance from the grid connection point, the type of roof, ease of access of the roof, underground when mounting on the ground. For this reason, the prices used in the case study of Section 5 are minimum prices. The effect of higher installation costs is taken into account in Section 5.4.3, where a sensitivity analysis is done in regard to the PV installation cost. In the remainder of this section details regarding the prices for the different mounting methods are provided. As an indication of the cost drivers of a PV system installation, the price breakdown of a standard, roof-mounted system is provided in Figure 10. It is important to note that the relative shares of these drivers can vary significantly based on the factors described above. From figure 10 it can be seen that the PV modules are an important cost driver. Balance of the system consists of all the parts that are used to transport the DC current to the inverters and the AC current to the connection point. Civil works here include preparing the roof for installation (e.g. walking paths, safety wire, …) and the structures to mount the modules.

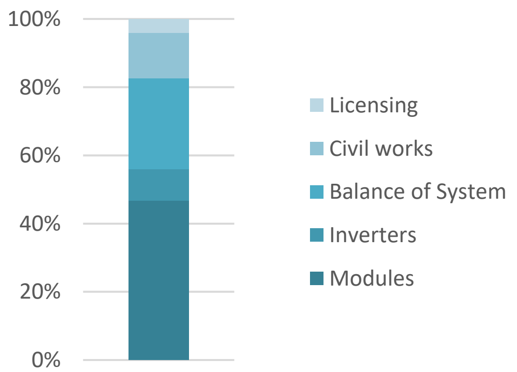

Figure 10: Breakdown of PV installation cost for a typically roof-mounted installation into the main cost drivers.

Figure 11 provides an overview of the cost per kWp for different sizes for the three different mounting types. It can be seen that for smaller systems the roof-mounted and roof-inclined systems are more expensive due to the relative large share of the cost of civil works for the installation. Roof-mounted installations are the least costly for larger installations. Ground-mounted and roof-inclined system costs converge for larger systems due to the larger share of the cost of structures in the overall cost.

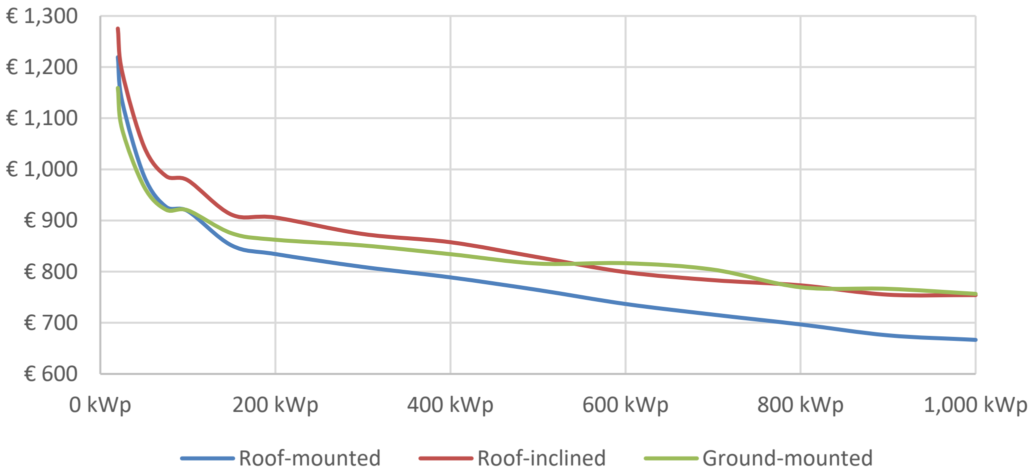

Figure 11: Overview of the reference prices used for different sizes of roof-mounted, roof-inclined, and ground-mounted systems in € per kWp.

Based on the different prices available, three regressions have been performed in order to obtain an equation that is used in the model and provides a cost expressed in euro per kWp for every possible system size within the range of 20 kWp to 1 MWp. For the roof-moutned, the roof-inclined, and ground mounted systems these are power-regressions that are provided in Equations 9, 10 and 11, respectively, all three of them with R^2-value of 0.98 indicating a good fit:

$$\boldsymbol{Cost_{Roof-mounted} = 1749.2 \times Size^{-0.138}} \qquad (10)$$

$$\boldsymbol{Cost_{Roof-inclined} = 1739.6 \times Size^{-0.122}} \qquad (11)$$

$$\boldsymbol{Cost_{Ground-mounted} = 1429.6 \times Size^{-0.092}} \qquad (12)$$

For this case study, the scenario of combining roof-mounted with roof-inclined modules has been investigated in which case the price of a system depends – as in all the other cases – on the overall size of the system (not the size of the roof-mounted and the roof-inclined systems individually). For this reason a regression has been done to determine the difference in cost between a roof-mounted and a roof-inclined system, taking into account the overall system size. In order to obtain a good fit, a polynomial regression has been performed to determine the ratio indicating the cost of a roof-inclined system over a roof-mounted system for the overall system size, ranging from 20 kWp to 1 MWp. Figure 12 shows a graph indicating the data points and the regression curve. The regression function provides a good fit with an R^2-value of 0.97 and is described in Equation 12, with MF meaning multiplication factor and the size referring to the overall system size:

$$\boldsymbol{MF_{inclined/_{Roof}} = 3 \times 10^{-10} \times Size^3 + 4 \times 10^{-7} \times Size^2 + 0.0002 \times Size + 1.0469} \qquad (13)$$

A 100 kWp installation consisting of a 60 kWp module-array that is roof-mounted, and a 40 kWp module-array that is roof-inclined is used as an example to clarify the determination of the cost. The overall system size is used as an input in the $Cost_{Roof\text{-}mounted}$ equation above. This gives a cost of € 926.49 per kWp. The same size is used as an input to the $MF_{inclined/roof}$ equation, yielding a multiplication factor of 1.0712. The overall system cost is then defined as 60 kWp x 926.49 €/kWp + 1.0712 x 40 kWp x 926.49 €/kWp, and equals € 95,288.

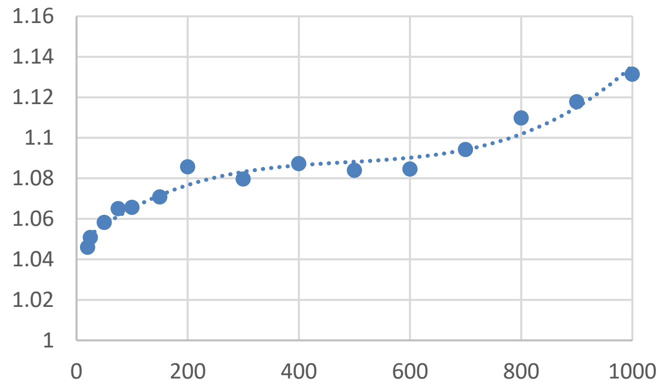

Figure 12: Ratio of the price of a roof-inclined system over a roof-mounted system for different total PV system sizes (indicated on x-axis) along with the 3rd order polynomial regression line.

4.3.2. Other financial parameters

Based on the advise of one of the PV project developers, for this case study, the maintenance cost is set to € 10 per kWp, the insurance cost to 0.35% of the installation cost, and the inverter replacement cost to € 70 per kWp. Also in line with the advise of the PV project developers and in line with general assumptions, the annual degradation of the PV system is assumed to be 1%.

According to data of Pordata the inflation rate in Portugal for the years 2017 and 2018 was about 1.6%. Forecasts up to 2022 indicate that the inflation rate will remain between 1 and 2% but, tending more towards 2%. As it is difficult to make long term predictions of inflation, a conservative value of 1.5% has been used for this case study.

For the discount rate, the author has opted to use a value of 10%. Allthough it is likely that this is an overestimate for this particular case study, it is a value that is frequently used and it fits the more conservative and illustrative approach of this case study.

5. Case study results

5.1. Roof mounted system following the roof's inclination

The first scenario analyzed is a solar system installed on the roof, following the roof's inclination and orientation. As mentioned in Section 4.1, the available roof area suited for solar panels amounts to about 5,600 m^2 which offers space for an installation of about 700 kWp. The roof has an inclination of 15º, with one half of the available surface oriented North-East and the other half oriented South-West. The TMY data used is for the actual location of the logistics company, in the Lisbon area. The applied discount rate, annual inflation rate and annual system degradation rate are 10%, 1.5% and 1%, respectively.

5.1.1. Best and worst performing system configurations

The simulation was performed for a range of system sizes ranging from 0 to 700 kWp in steps of 10 kWp with a maximum size per orientation of 350 kWp which results in 1296 different system combinations. The results show that the optimal system consists of 280 kWp, with all the PV modules placed on the sides of the roof that have SW-orientation. The obtained IRR is 21.50% with a NPV of € 218,957 and a payback period of 4.6 years. The self-consumption rate – the amount of produced electricity that is consumed locally – amounts to 90% and the self-sufficiency rate – the share of locally consumed electricity in the total electricity consumption – to 26.6%. The investment cost amounts to € 225,056, which corresponds to € 804 per kWp. The first-year savings because of the PV system amount to € 52,155 and consist for 78% of avoided costs of buying electricity from the retailer, for 4% of the remuneration for electricity fed into the grid, and for 19% of savings on the monthly cost for peak-power consumption. Knowing that annual total expenditure for (active) electricity consumption and peak-power consumption remunerations amounts to € 157,875, this system configuration results in a reduction of 33%.

The 10 best performing systems consist of those systems that are completely oriented SW with sizes from 240 kWp up to 330 kWp with a minimum IRR of 21.4%. The IRR's of these projects lie very close to each other because of the offset between the self-consumption rate and the investment cost. More specifically, for a system larger than 280 kWp the self-consumption rate decreases. This means that there is more electricity fed into the grid which has a negative impact on the savings per kWp – as the value for self-consumption is higher than the feed-in remuneration of 4 cents per kWh. Because the installed capacity is higher however, this loss is offset to a large extent by the reduction in installation cost per kWp. As the IRR's of these best performing systems lie very closely to each other, an investment decision can be made based not only on the IRR but including the NPV and initial investment cost. Larger systems (among the best performing configurations) will have a slightly lower IRR but their higher initial investment also yields higher savings and therefore a higher NPV. Smaller systems on the other hand could be preferred in order to limit the initial investment while still maintaining an IRR close to the optimal configuration.

The worst performing systems are those with a capacity in the range of about 10 to 100 kWp, with the majority of modules oriented towards the NE. Although these systems achieve a self-consumption rate of about 100%, their limited size and relative low production per kWp installed make these systems less interesting with IRR's ranging from 10.6% (10 kWp NE) to 15.5% (100 kWp NE). More specifically, the installation cost ranges from about € 1,273 to € 926 per kWp – which is significantly higher than € 804 per kWp for a system of 280 kWp. In terms of production of the systems with different orientations, a difference of about 27% is observed between the annual production of a NE-oriented system and of a SW-oriented production. More specifically, for this case, the yield of a SW-oriented system amounts to 1,616 kWh per kWp per year as compared to only 1,269 kWh per kWp per year for a NE-oriented system.

The choice for a system with only SW-oriented modules follows the logic of higher solar radiation, and therefore higher productivity of SW-oriented modules. Additionally, for this specific case of the logistics company, the consumption profile shows – on average – higher consumption levels during the afternoon. As in the Northern hemisphere the sun moves from East in the morning towards West in the afternoon/evening, the production profile of SW-oriented panels fits this specific consumption profile better.

Figures 13 and 14 illustrate the effect of the orientation on the production of a 280 kWp system for summer and winter, respectively. More specifically, there are three 280 kWp systems taken into account: system 1 is a 280 kWp with NE orientation, system 2 is a 280 kWp with SW orientation, and system 3 is a 280 kWp installation with 140 kWp oriented towards the NE, and 140 kWp towards the SW.

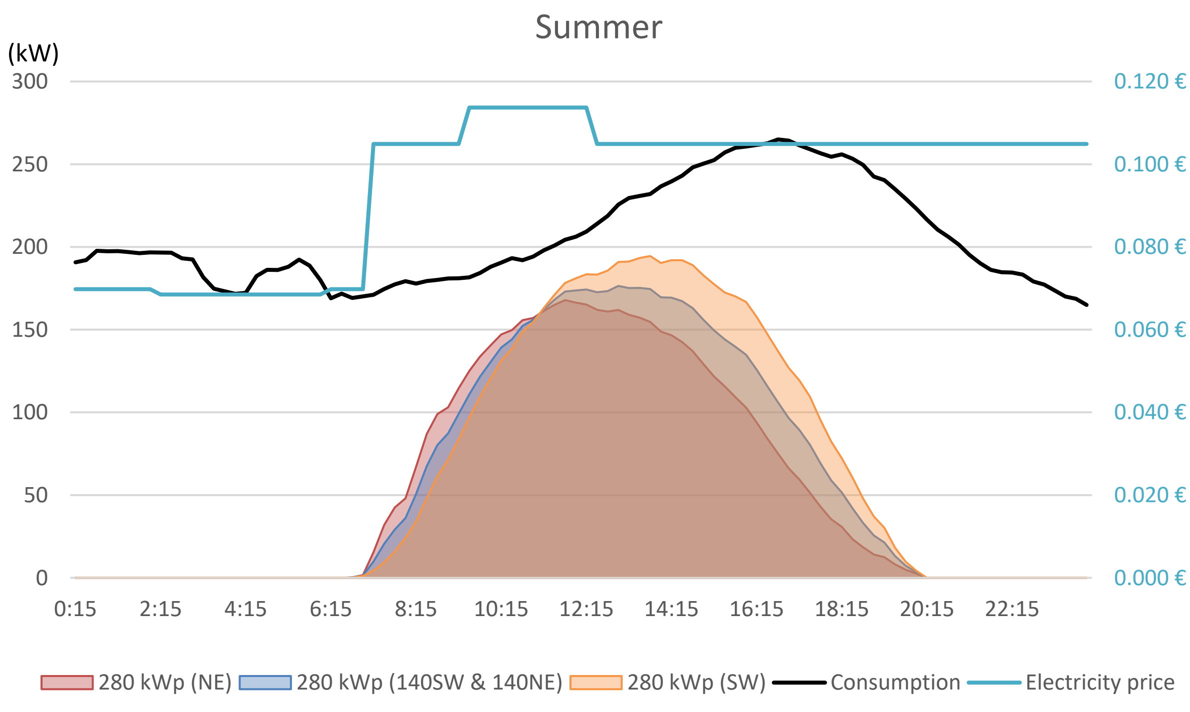

Figure 13: Summer average daily production profile for 3 system configurations along with the consumption profile and electricity price.

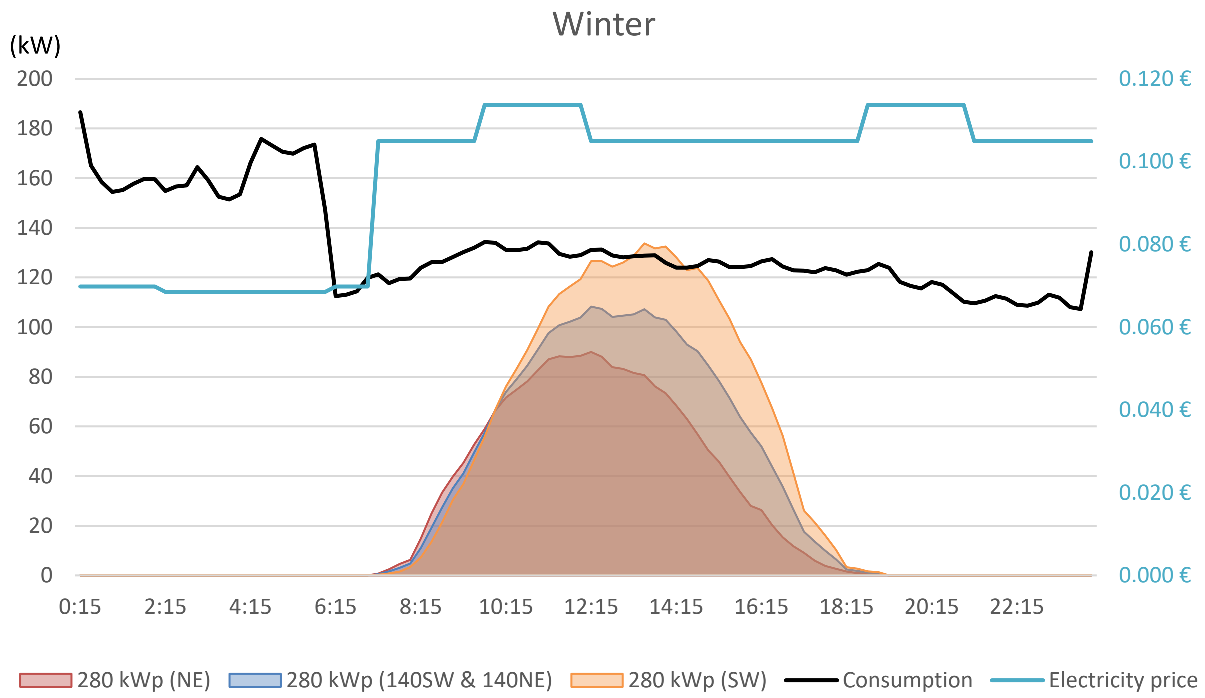

Figure 14: Winter average daily production profile for 3 system configurations along with the consumption profile and electricity price.

An overview of key indicators regarding the PV system configurations is provided in Table 4. The investment cost for the three systems under study here are all equal to about € 225,000. These numbers clearly indicate the superiority of the SE-oriented 280 kWp system. Although this system's self-consumption rate is the lowest of the three systems, its absolute value of self-consumed electricity is the highest of the three studies with about 406 MWh for the first year.

System	IRR (%)	NPV (€)	Production (MWh/yr)	Year-1 savings (€)	Payback period	Self-consumption	Self-sufficiency
NE	17.56	140,333	355.19	43,804	5.55	93%	22%
SW	21.50	218,957	452.58	52,155	4.60	90%	27%
NE + SW	19.63	181,368	403.88	48,162	5.01	92%	24%

Table 4: System key performance indicators for different configurations of a 280 kWp roof-mounted system

The larger systems, ranging from 500 to 700 kWp, are less attractive investments due to their oversizing. This means that more of the produced electricity has to be fed into the grid, leading to lower savings per kWp as the remuneration for feeding in electricity is lower than the avoided cost of electricity through self-consumption. These systems have IRR's ranging from close to 19% – for the 500 kWp system with the maximum amount of panels SW-oriented (350 kWp) – down to 16.3% for the largest possible system of 700 kWp. The largest possible system results in a self-consumption of about 60%, and a self-sufficiency rate of almost 40%.

5.1.2. The logistic warehouse moved to Faro and Porto

As a comparison, the optimal system sizes and key financials are simulated for the same consumption data and roof size constraints but, using the solar irradiation of Faro and of Estarreja. Faro is a city in the outer South of Portugal, in the Algarve region and Estarreja is a municipality in the Northern part of Portugal, about 40 km South of Porto. The more southern, the higher the annual solar irradiation which results in higher electricity output of solar modules. More specifically, Faro receives an average of 1.944 kWh/m^2 of annual global horizontal solar irradiation where Lisbon and Estarreja receive on average 1.758 kWh/m^2 and 1.556 kWh/m^2 per year (based on the Meteonorm TMY data for the three locations).

Figure 15: The different locations for the logistics warehouse on the map of Portugal

In line with the expectations, the PV system outputs are higher in the South than in the North, which makes that the optimal size of the system is the largest in the North and decreases towards the South to fulfill the logistics warehouse demand for electricity in an economically optimal way. An overview of the optimal system designs for the three locations, along with key performance indicators is provided in Table 5.

Location	Lisbon	Faro	Estarreja
System (kWp)	**280** SW	**260** SW	**350** SW
IRR (%)	21.5	23.1	17
NPV (€)	218,957	228,490	156,446
Payback (years)	4.6	4.3	5.7
Year-1 savings (€)	52,155	52,178	51,802
Initial cost (€)	225,056	211,128	272,789
Production (MWh/yr)	452.6	452.1	438.2
Self-consumption rate	90%	89%	92%
Excess production	10%	11%	8%
Self-sufficiency rate	27%	26%	26%

Table 5: Optimal size and key financials of the PV system for the locations Lisbon, Faro, and Estarreja

5.1.3. A roof with perfect East-West orientation

An interesting variation on the actual case study is where the assumption is made that the roof is oriented East-West rather than the original orientation NE-SW. For this case, the optimal system configuration consists of a 320 kWp system of which 70 kWp is oriented towards the East, and the remaining 250 kWp is oriented towards the West. This configuration yields an IRR of 19.83%, a NPV of € 208,027 and a self-consumption rate of 89.55%. This result opposes the previous results that indicated that it was always optimal to place all the modules on the side that is oriented most towards the West.

This different outcome is due to the Peak – or Ponta – hours from 9:15 to 12:15 during summer. Modules facing East, produce relatively more than panels facing West during this period. This has a positive effect on the savings in the reduction of peak-power consumption and the value of the avoided cost of consuming electricity (as the Ponta period is the most expensive of all periods). Figure 16 provides a comparison of the annual production in kWh per kWp for East and West oriented modules along with the division of the production over the different tariff periods. The panels oriented towards the East have a lower overall yield but the share of production during peak hours amounts to 26% as compared to only 18% for West-oriented panels and also in absolute terms, the East-oriented modules produce more electricity than the West-oriented modules.

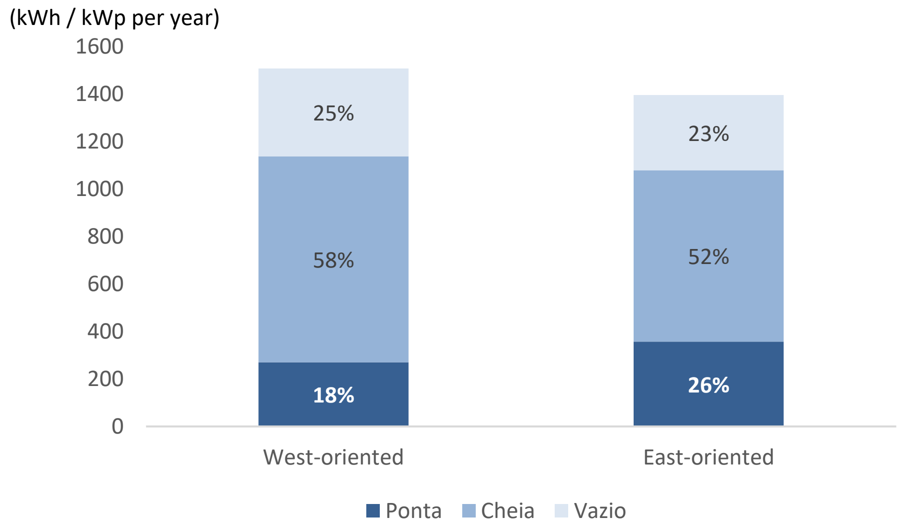

Figure 16: Comparison of the annual production in kWh per kWp of East- and West-oriented modules and their relative division over the different tariff periods.

To illustrate this, the comparison is made between the optimal configuration and a PV system with 320 kWp of West-oriented modules. This effect can be seen by comparing the annual average of the daily yield for both systems, as illustrated in Figure 17. This figure shows that including the East-oriented modules in the configuration increases the production before noon but, decreases the overall energy yield of the system.

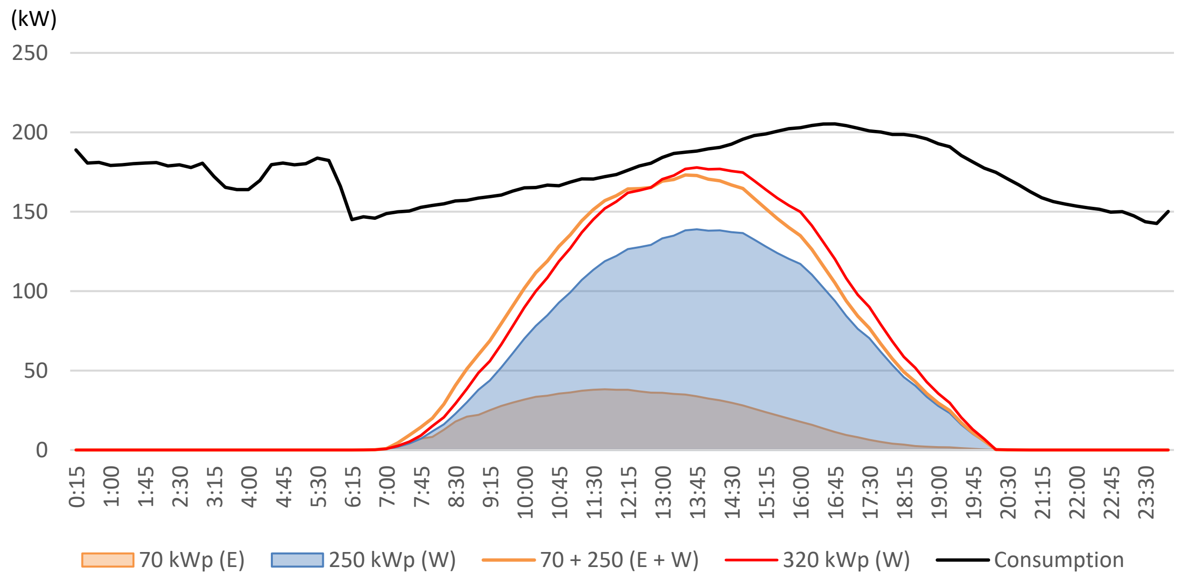

Figure 17: Yearly average of the daily yield of different system configurations with East and West panel orientations along with the annual average of daily consumption.

It is important to note that the differences between the results of both systems are small with a very small effect on the IRR of only about 0.5%. An overview of the key performance indicators of both systems are provided in Table 6.

System	IRR (%)	NPV (€)	Production (MWh/yr)	Year-1 Savings (€)	Savings from reduction peak-power	Self-consumption
70 + 250 (E+W)	19.8%	208,027	474.7	54,606	19%	89.5%
320 (W)	19.8%	207,565	482.5	54,557	18%	89.1%
320 (E)	19.5%	200,050	446.7	53,759	22%	88.0%

Table 6: Overview of key performance indicators for three system configurations (70E + 250W, 320W, and 320E)

5.2. Roof mounted system with structures

In the second scenario for this case study, modules are no longer placed directly on the roof with a NE orientation but, put on structures to give them a certain inclination facing SW or SE (roof-inclined installation). This means that the system configuration consists of a certain amount of modules placed on the SW-oriented part of the roof, and a certain amount of modules placed on the NE-oriented part of the roof, but placed in such a way using structures that they also face the South-West or South-East. These orientations are chosen considering that the structures can only be placed following or in a 90-degree angle of the roof's direction. Additionally, North-East orientation of the roof is not considered due to the low amount of solar radiation reaching the panels.

As described in Section 4.3.1, because of the need for inclining structures, roof-inclined installation is more expensive than a regular roof installation, following the roof's inclination and orientation. The advantage of the roof inclined installation is the option to vary the module's inclination in order to maximize the yield per module. In Lisbon, the tilt angle for South-oriented panels that maximizes the energy yield is 35 degrees (Jacobson & Jadhav, 2018), but this angle decreases when changing the orientation away from the exact 180-degree South-orientation. Taking into account the higher electricity prices during peak hours and the peak power consumption compensations in the Portuguese system however, it can be beneficial to choose the tilt in a way that overall production is lower but the production during peak hours is higher, similar to the results presented in Section 5.1.3.

5.2.1. Optimal system for the actual roof layout with inclined panels oriented SW or SE

When running the model for the actual roof layout with space for 700 kWp in the Lisbon area, the result is exactly the same as in the first scenario described in Section 5.1.1 for inclinations of the panels on structures ranging from 10 to 40 degrees (SW-orientated or SE-oriented). This is a system with 280 kWp installed on the side of the roof oriented to the South-West, without panels on structures on the NE side of the roof. This means that the increase in the overall yield of electricity and/or the increase of electricity production during peak-hours does not offset the additional cost of placing the panels on structures to such an extent that it is economically more viable than placing the modules directly on the SE-oriented roof.

5.2.2. Optimal system when assuming a roof with half of the size

A variation to the original second scenario has been made in order to obtain results that provide a better insight in the use of roof-inclined systems. More specifically, it has been assumed that only half of the original roof size is available for solar panels. This assumption also strokes with reality of a roof inclined installation because in order to avoid shading, there needs to be more space between the modules on the roof. Therefore, in this variation the maximum size of the system amounts to 340 kWp of which half can be placed along the roof's inclination facing SW and half on structures with an inclination ranging from 0 to 40 degrees (with steps of 5 degrees), facing SW, on the other side of the roof (with NE orientation).

In line with the expectations, based on the previous results and in particular the result of Section 5.2.1, for every inclination angle of the roof-inclined installation, the optimal configuration also includes the maximum capacity of 170 kWp being put directly on the roof with a 15-degree angle facing SW. In regard to the roof-inclined modules, Figure 18 illustrates that the annual production in kWh per kWp reaches its maximum for a tilt angle of 35 degrees, reducing gradually when adapting the tilt angle and reducing more strongly towards a 0-degree inclination. Also the amount of production during the peak hours varies with the tilt angle, reaching its maximum at a tilt angle of 10 degrees (SW-oriented) and again reducing gradually when adapting the tilt angle, as illustrated in Figure 18.

As illustrated in Figure 18, when the panels are inclined to 0 degrees and are horizontal to the earth surface, the total production per kWp for these modules decreases relatively strongly. Therefore, for this inclination the optimal system consists of only 170 kWp of modules on the roof facing SW without inclined panels. Adding up to 60 kWp of 0-degree inclined modules however, only decreases the IRR by 0.1% while increasing the NPV by about € 40,000. Also for other inclinations of the roof-inclined installations, the IRR's for sizes ranging from 50 to 90 kWp lie very closely to each other.

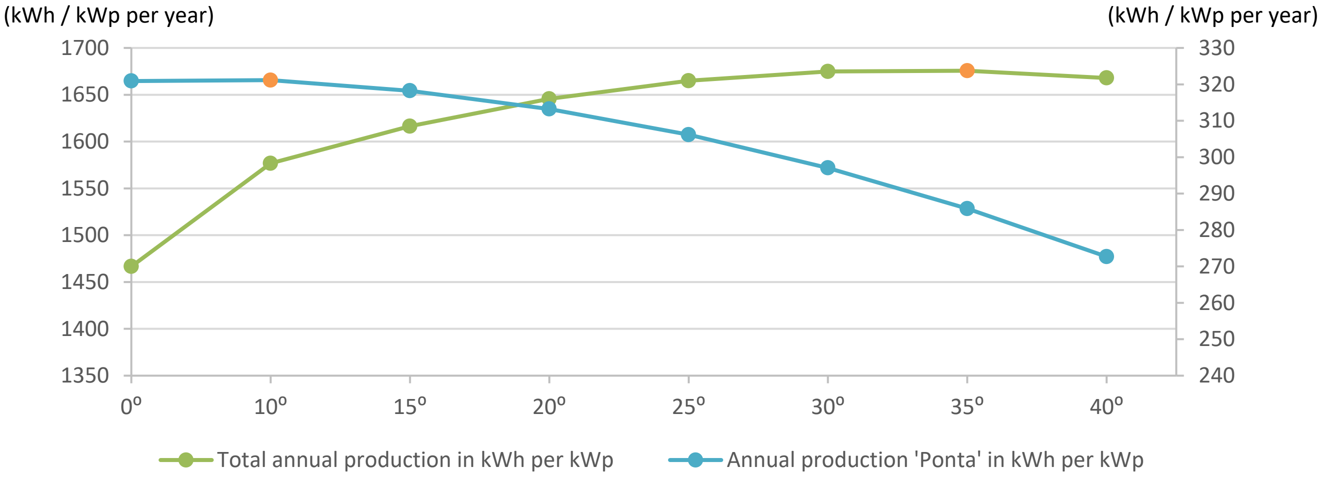

Figure 18: Total and peak Production of the PV system in the Lisbon region in kWh per kWp for orientation towards the SW with inclinations ranging from 0 to 40 degrees with 0 degrees equal to horizontal.

Figure 19 illustrates the optimal configurations for every tilt angle of the inclined modules. It can be seen that the overall optimal configuration for this case consist of the 170 kWp SW-oriented modules placed directly on the roof, and 80 kWp on the other side of the roof (that faces the NE), with an inclination of 25 degrees towards SW – so in total an inclination of 40 degrees (15 + 25) as compared to the roof). The choice for an inclination of 25 degrees illustrates the trade-off between overall electricity production of the system and the electricity production during peak-hours ('Ponta').

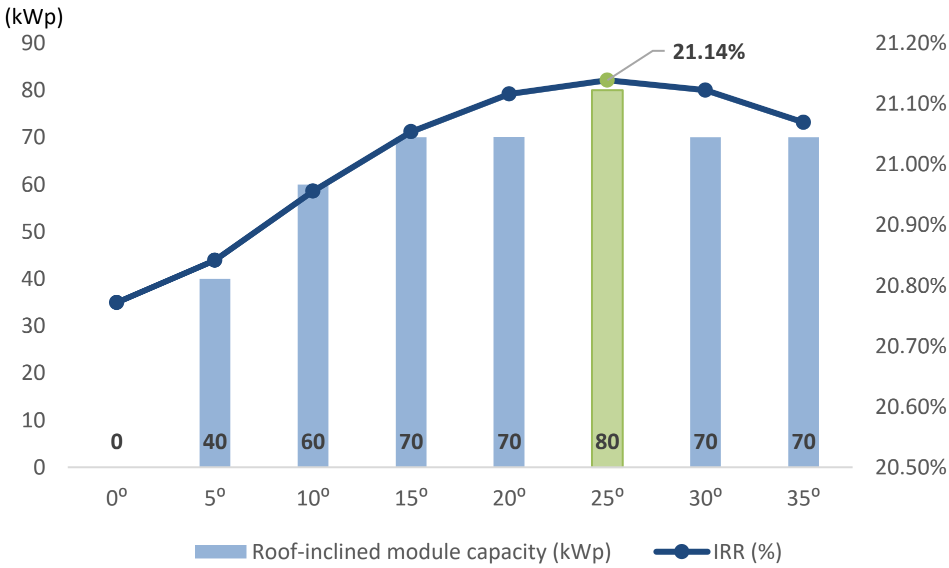

Figure 19: Overview of the optimal PV system configurations for different inclinations of the 'roof-inclined' modules, all in combination with 170 kWp of SW-oriented modules mounted on the roof with a 15-degree inclination.

In Table 7 the key performance indicators for the optimal systems for the three best performing tilt angels are listed. As mentioned earlier, the financial key indicators lie very closely to each other as do the self-consumption and self-sufficiency rates. It can be seen that the cost for installing modules with a structure to give them a different inclination adds a premium to the cost per kWp and that – as in all the scenario's and as described in Section 4.3.1 – the cost per kWp decreases with the overall system size.

System	Inclination	Production (MWh/yr)	Production (kWh/kWp)	Year-1 Savings (€)	Cost SW-roof (€/kWp)	Cost NE-roof (€/kWp)	Total cost (€)
170 + 70	**20º**	390	1,625	45,590	821	870	200,446
170 + 80	**25º**	408	1,632	47,378	816	866	208,061
170 + 70	**30º**	392	1,633	45,602	821	870	200,446

System	Inclination	IRR	NPV (€)	Payback	Self-consumption rate	Self-sufficiency rate
170 + 70	**20º**	21.12%	188,207	4.68	93%	24%
170 + 80	**25º**	21.14%	195,765	4.68	92%	25%
170 + 70	**30º**	21.12%	188,318	4.68	93%	24%

Table 7: Overview of the key performance indicators of the best performing configurations for the inclinations of 20, 25, and 30 degrees with the roof space limiting to a 340 kWp installation.

To conclude this section, it can be noted that, based on the proposed optimal configurations and their corresponding IRR's, placing modules directly on the roof with a 15-degree inclination towards the SW (as is the case in Sections 5.1.1 and 5.2.1) is still the preferred option over using modules that need to be place on structures to provide them with a different orientation and inclination.

5.3. Ground-mounted PV system

As a third scenario, for the same consumption of the logistics warehouse, it is assumed that the panels are ground-mounted on the terrain right next to the warehouse. In this scenario there is the freedom to choose both the tilt angle as well as the orientation of the modules but, all modules are installed with the same orientation and tilt angle. As explained in Section 4.3.1, the price per kWp of this system follows Equation 11 with the cost expressed in € per kWp and the size in kWp.

For this scenario, because of the variation of the tilt and orientation angles, there are a lot of simulations to be done as every variation induces a different production profile. In order to cut down on calculation times, a 3-step approach is used. The first step consists of a high-level analysis with a wide range of orientation and tilt angles but, with relatively large steps in these angles. In a second step, simulations are performed on a smaller range of orientation and inclination angles, based on the results of step one. In the last step, the simulation is performed for a limited range but with 1-degree steps in the orientation and tilt angles.

In a first step to determine the optimal configuration, different system configurations were simulated to obtain a rather high-level overview of the most optimal system configurations. More specifically, the model has been run for systems with an orientation ranging from 0 degrees – so, facing North – up to 360 degrees – so, turning around completely and facing North again – with steps of 30 degrees. The system capacity was varied between 0 and 400 kWp. 400 kWp was taken as the maximum to obtain a wide margin over the optimal system size, which is likely to be below 280 kWp as this was the result of scenario 1 and in this scenario (3) the tilt and orientation are variable, so the production per kWp will likely be increased, reducing the overall required system capacity.

The results of the first step are in line with the expectations that a system oriented due South with a tilt angle of 35 degrees yields the best result. A graphical overview of the best performing configurations for different combinations of orientation and tilt angles is provided in Figure 20. As can be seen, and in line with previous results, the tilt angle yielding the best results decrease with orienting the panels away from the South. Additionally, when modules are oriented South, the optimal configuration consist of 220 kWp capacity. This capacity increases when the orientation is diverted away from the South as illustrated in Figure 20. It is interesting to note that the optimal installed capacity for orientations of 210 and 240 degrees are lower than the optimal capacity in scenario 1 (with orientation of 225 degrees, or due South-West). This is due to the higher production per kWp of the system because of a more suitable inclination or tilt angle (as compared to 15 degrees in scenario 1) and due to the higher cost per kWp as compared to scenario 1 (because the modules are ground-mounted).

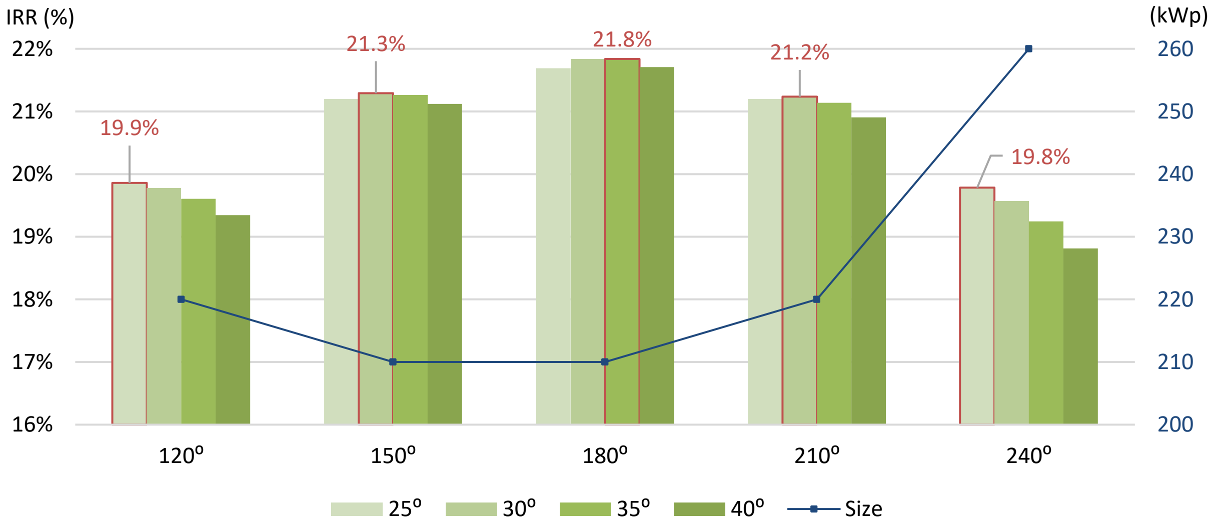

Figure 20: IRR's of the optimal system configuration for orientation angles of 120 to 240 degrees with tilt angles of 25 to 40 degrees. The line indicates the size of the most optimal configuration per orientation angle.

In a second step, the same method has been applied but with the orientations ranging from 150 to 210 degrees with steps of 5 degrees and module inclination angles of 30 and 35 degrees. The choice for these module tilt angles is based on the results of the first step, which indicate that these tilt angles result in the highest IRR's for this module orientation range.

The results obtained in the second step align with the results of the first step. The best-performing configuration still is the configuration of 210 kWp oriented South (180 degrees) with a tilt angle of 35 degrees. An illustration of the effects of the orientation and inclination is provided in Figure 21. The trend lines in Figure 21 indicate that for orientations from 165 to 180, a tilt angle of 35 degrees yields better results while for orientation angles from 180 to 200 degrees, a tilt angle of 30 degrees yields better results.

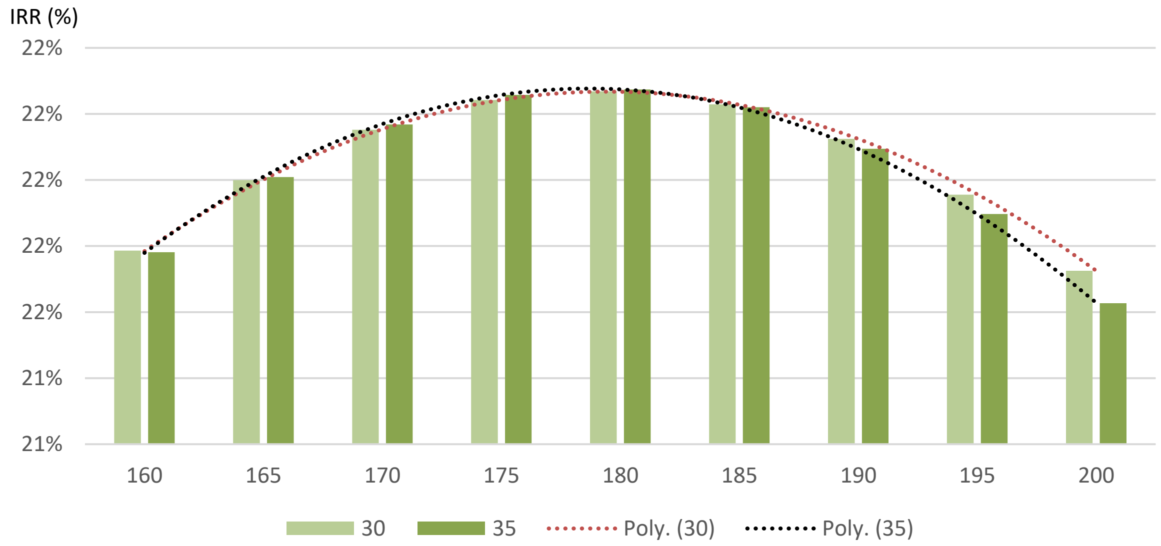

Figure 21: IRR's for the optimal configuration of the PV system for the orientation angles ranging from 160 to 200 with module tilt angles of 30 and 35 degrees.

In the third step, the module's orientation is varied between 175 and 185 degrees with steps of one degree while the tilt angle is varied between 30 and 38 degrees, also in steps of one degree. The results show the optimal configuration to consist of 210 kWp with an orientation of 179 degrees and an inclination of 33 degrees. Due to the small variations in orientation and tilt angles, the results lie very close to each other. The difference in IRR between the optimal result and the expected optimal configuration with modules due South and 35-degree inclination only amounts to 0.01%. The optimal solution yields an electricity production that is slightly lower than the expected optimal solution (about 310 kWh) but, it produces relatively more during the peak hours ('Ponta') and increases the self-consumption slightly. This induces higher savings because it avoids buying electricity at the highest price to a larger extent and it reduces the peak-power consumption compensation.

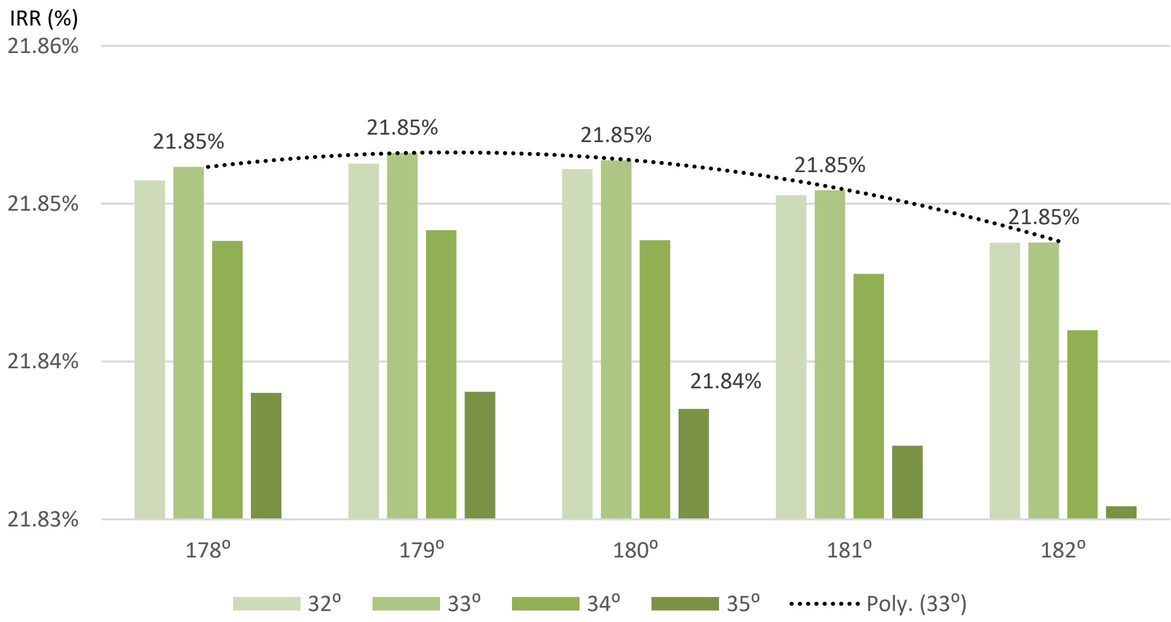

Figure 22: IRR's for the optimal configurations of the systems with orientation angles of 178 to 182 degrees in combination with tilt angles of 32 to 35 degrees.

Table 8 provides an overview of the key performance indicators of the optimal and 'expected-optimal' solution for the ground-mounted PV system – for this specific case-study. The table also lists the key performance indicators of the optimal system configuration of the roof-mounted system of scenario 1 for easy comparison. As can be seen, the year-1 savings of the optimal ground-mounted system are slightly higher than the expected optimal configuration while their total cost is equal, resulting in a slightly larger IRR for the former system.

When comparing the ground-mounted system with the roof-mounted system it can be seen the production on the roof (in kWh per kWp per year) is lower due to the suboptimal orientation and inclination. The cost of installing on the roof however, is lower than installing on the ground which makes that the IRR does not differ to a large extent, only by 0.3%. This indicates that there is a trade-off between the extra cost of installing on the ground as compared to on the roof, and the higher savings per kWp per year that are generated.

System	**Orientation - Inclination**	Production (MWh/yr)	Production (kWh/kWp)	Year-1 Savings (€)	Cost (€/kWp)	Total cost (€)
210	**179º - 33º**	356	1,696	42,916	874	183,565
210	**180º - 35º**	357	1,698	42,887	874	183,565
0 + 280	**225º - 15º**	453	1,616	52,155	821	225,056

System	**Orientation - Inclination**	IRR	NPV (€)	Payback	Self-consumption	Self-sufficiency
210	**179º - 33º**	21.85%	184,689	4.54	93%	22%
210	**180º - 35º**	21.84%	184,421	4.54	93%	22%
0 + 280	**225º - 15º**	21.50%	218,957	4.60	90%	27%

Table 8: Overview of the key performance indicators of the optimal configuration of the ground-mounted system and of the roof-mounted system.

5.4. Sensitivity analysis

In this section a sensitivity analysis is performed regarding the optimal system configuration of scenario 1 (roof-mounted). There is a large number of inputs to the model which affect the outcome of the optimal solution but, four main inputs were selected. The selection of these four factors is based on their probability to occur and on the extent to which they affect the optimal system configuration and the economic viability of the original optimal system configuration. More specifically, in the remainder of this Section the effects of a change in the annual consumption, a change in the electricity prices, a change to the PV installation cost, and a change to the inclination of the roof are examined.

5.4.1. Change of consumption

In this section the effects of a change in the consumption are investigated on the key financials of the ideal system configuration of scenario 1, as described in Section 5.1.1, consisting of 280 kWp installed on the roof with SW orientation and a 15-degree tilt angle. The consumption is reduced to 50%, 70% and 90% of the original consumption and increased to 110% of the consumption. This change of annual consumption is assumed to happen right after the installation of the system. The reduction in consumption is assumed to consist of a reduction of consumption for every 15-minute interval. This has the effect of replacing part of the self-consumption by feeding in to the grid (which implies lower benefits). This creates a negative effect on the economic viability of the project.

Initially – without a change to the consumption – the IRR amounts to 21.5% with a self-consumption rate of 90%. In the case of a 10 and 30% reduction of the consumption, the IRR is reduced to about 21% and 20%, respectively. The NPV is reduced from about € 219,000 down to € 212,000 and € 184,488 respectively, while the self-consumption rate is reduced to 87% and 79%. When the consumption is only half, the self-consumption rate reduces to 65%, inducing a reduction of the IRR to about 17% with a NPV of € 133,748. On the contrary, when the consumption is increased by 10%, the self-consumption rate rises to 92%, resulting in a larger IRR of 21.8%. A graphic representation of these effects is provided in the form of a graph in Figure 23.

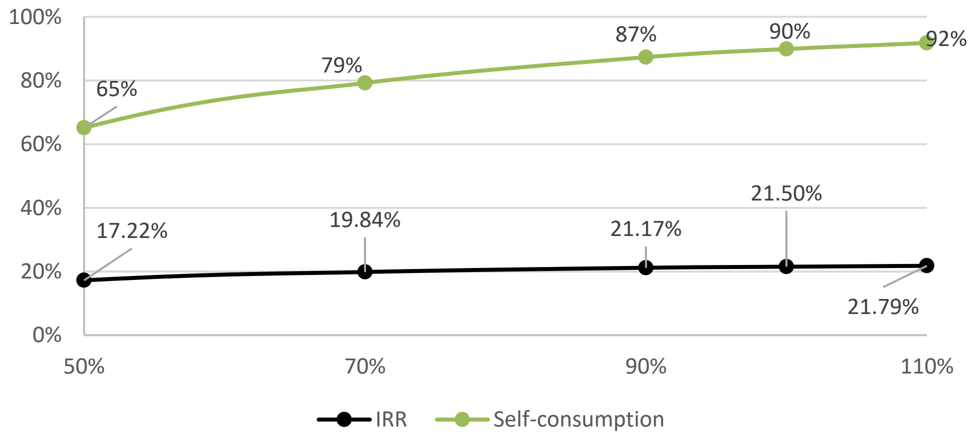

Figure 23: The effect of changes in the consumption on the IRR and the self-consumption rate of a 280 kWp roof-mounted system with SW orientation and a 15-degree tilt angle.

5.4.2. Change of the electricity price

As it is difficult to predict future electricity prices, a sensitivity analysis has been performed on the ideal system configuration of scenario 1. As mentioned in Section 4.1, the savings for the consumer stem from three main sources: avoided cost of buying electricity from the grid, remuneration for feeding in surplus electricity to the grid, and the avoided cost of peak-power consumption remunerations. In this section the effect of price changes to the electricity cost and to the feed-in remuneration are examined, although separately. More specifically, the electricity price is assumed to vary between 50% and 110% of the current price (as used in the model) in order to account for a worst-case scenario and for a positive scenario. The remuneration for feeding in surplus electricity is based on monthly averages of the electricity price on the wholesale market. Also this price is difficult to predict. The effects on the systems profitability are examined for feed-in remunerations ranging from 2 to 8 cents per kWh, with 4 being the current price used in the model. This means that the worst-case and best-case scenario are the feed-in remuneration falling by 50% and the remuneration being doubled. In line with Section 5.4.1, it is assumed that these changes come in effect during the first year of operations (and therefore, are not taken into account in the sizing decision).

As expected, a reduction in the electricity price negatively affects the first-year savings and the IRR of the project. The IRR goes down to 11.6% for electricity prices that are only half of the current prices as used in the model. In the case electricity prices increase by 10%, the overall project IRR increases to 23.4%. When looking at the first-year savings, it can be seen that they do not follow the change in electricity price exactly. For example, a 50% reduction in electricity price only reduces the first-year savings by about 38% from € 52,155 to € 31,945. This is because the first-year savings for the reference system is made up for 78% by the avoided cost of buying electricity, while the remaining 22% stems from the grid revenues and the reduction of peak-power consumption fees. This means that only 78% of the savings are affected by a change in the electricity price.

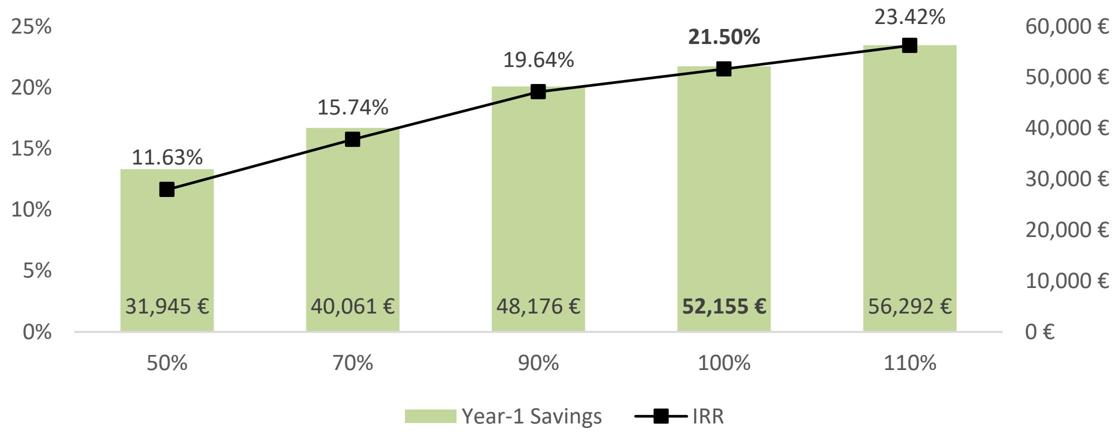

Figure 24: The effect of changes in the electricity price on the first-year savings that stem from using the PV system and the effect on the IRR of the system.

A change to the remuneration received for feeding in surplus electricity has a smaller effect than the change in the electricity price because for the reference system only 10.13% of the produced electricity is fed into the grid. The amount of electricity fed into the grid remains unchanged so the annual revenues from feeding in to the grid follow a linear trend based on the change in the feed-in remuneration. If the feed-in price is reduced by one eurocent, the IRR reduces by 0.17% while the IRR increases by 0.25% when the feed-in price is increased by one eurocent. When the feed-in price is halved, the IRR reduces to 21.11% while the IRR increases to 22.39% when the feed-in price is doubled as illustrated in Figure 25.

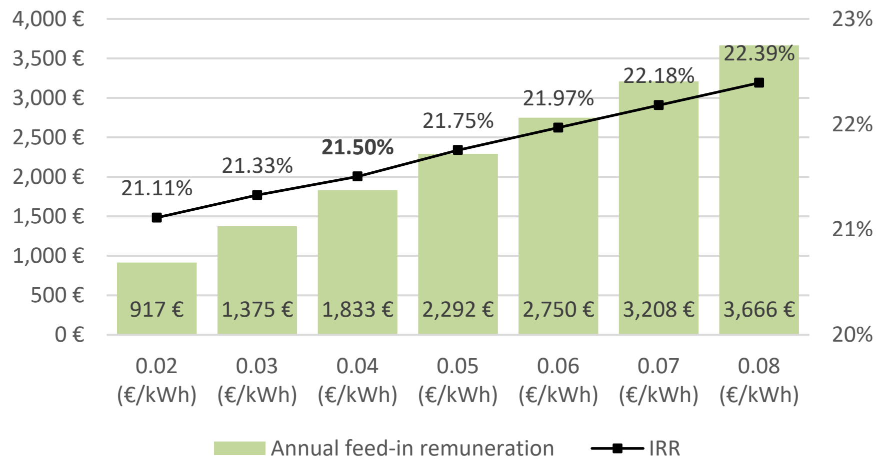

Figure 25: Change in annual feed-in remuneration and project IRR for different feed-in remunerations (in € per kWh).

Changes in the feed-in price directly make surplus electricity more or less valuable. This means that it will directly affect the optimal system configuration for the different feed-in prices when this is taken into account during the sizing of the system. The original system (based on a 0.04 € per kWh feed-in price) has a self-consumption rate of 90%. If the feed-in price is increased, this balance of self-consumption and surplus electricity is changed. Practically this means that by increasing the feed-in price, the system size will be increased which increases the absolute amount of electricity that is self-consumed, decreases the self-consumption rate, and increases the amount of electricity fed into the grid. As illustrated in Figure 26, the optimal system configurations increase in size with an increasing feed-in price but, still all of the modules are put on the SW-facing side of the roof. The SW-facing roof is limited in size, allowing for maximum 350 kWp of installed capacity, which explains the system-size stagnation starting from a feed-in price of 7 eurocents per kWh. The share of surplus electricity (that is sold to the grid for the feed-in price) ranges from 8% for a feed-in price of 2 eurocents up to 16% for feed-in prices of 7 and 8 eurocents per kWh. This implies that the self-consumption rates range from 92% down to 84%.

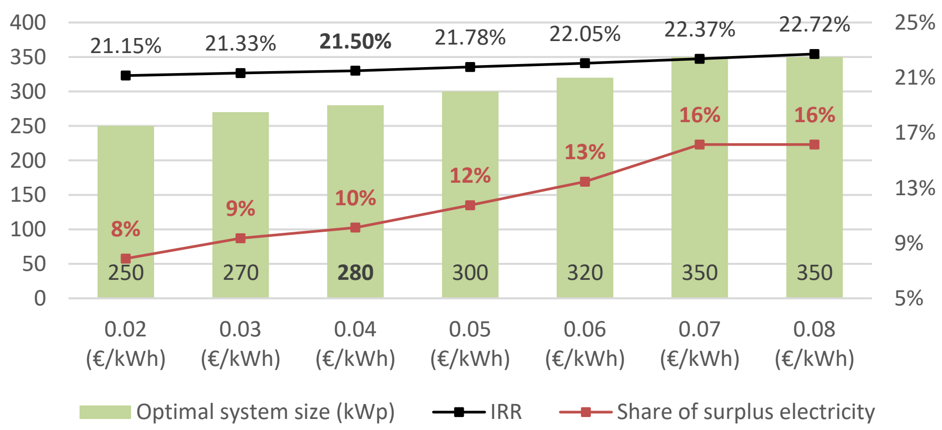

Figure 26: Indication of the optimal system size (kWp), the corresponding project IRR, and the share of surplus electricity production for different feed-in remunerations (in € per kWh).

5.4.3. Change in the installation cost

As mentioned in section 4.3.1, the cost for the PV systems used in this model are based on low-end estimates by PV project developers. For this reason, it is important to assess the effect of increased capital investment requirements on the economic viability of this case. More specifically, the effects of price increases of 10% to 50% in steps of 10% are examined.

As the increase in cost only changes the annual savings to a small extent, through the increase of the annual insurance cost, there is no change to the optimal system configuration as compared to the base case of scenario 1. The key performance indicators that are affected are the initial investment cost, the NPV and the IRR. If the installation cost rises by 10%, the project IRR is reduced by 2%, if the installation cost rises by 50%, the project IRR is reduced down to 13.8% as illustrated in Figure 27. In line with the expectations, the NPV of the system decreases with an increase in the PV installation cost as illustrated in Figure 27. A 10% increase of the PV installation cost, induces a reduction in the NPV of the project of 11.4 %. The change in NPV is more profound than the change in the PV installation cost, as it also takes into account the change in the annual insurance cost.

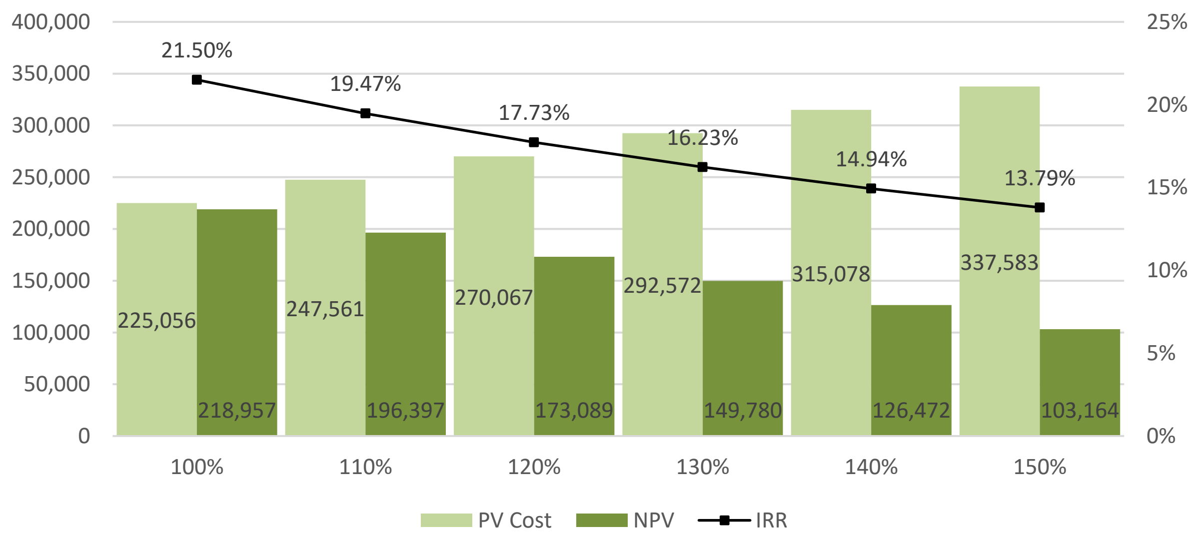

Figure 27: The IRR, payback period (in years) for a 280 kWp system for different percentual increases in the PV system cost.

5.4.4. Change of the roof inclination

The inclination of the roof of the logistics warehouse under study is 15 degrees. As different inclinations are possible for different buildings, it is interesting to see what would be the effect of different inclinations of the roof on the projects viability. Also, this allows to identify whether for some roof-inclinations, a roof installation can achieve a higher IRR than a ground mounted installation as opted in Section 5.3. More specifically, the roof inclination is varied between 10 and 30 degrees in steps of 5 degrees. The orientation of the building is maintained the same, with one side of the roof facing NE (45-degree orientation) and the other side facing SW (225-degree orientation). The same analysis has been performed for a roof with NS-orientation, with half of the roof size facing North, and half of the roof size facing South.

In line with the expectations, increasing the roof's inclination angle – and therefore, the module tilt angle – reduces the size of the optimal system configuration for both roof orientations. For the original roof orientation, the IRR values range between 21.2% for a 10-degree inclination up to 21.8% for a 25-degree inclination. These IRR's are very close to the highest IRR obtained from a ground mounted system (21.84%) as described in Section 5.3, although the investment cost for these roof-mounted systems are lower. When looking at the South-oriented roof, the optimal system size is smaller than that of the original roof for every inclination angle. This is due to the higher productivity of modules facing South rather than SE. The IRR's obtained for this roof are larger than the IRR values obtained for the best-performing ground-mounted system for inclinations of the roof ranging from 15 to 30 degrees. This is because the orientation is the same, and the inclinations are close to the optimal inclination for the ground-mounted system, making that the AC output of the systems are very close but, the roof-mounted system requires a lower installation cost. A graphical presentation of these two cases is provided in Figure 28.

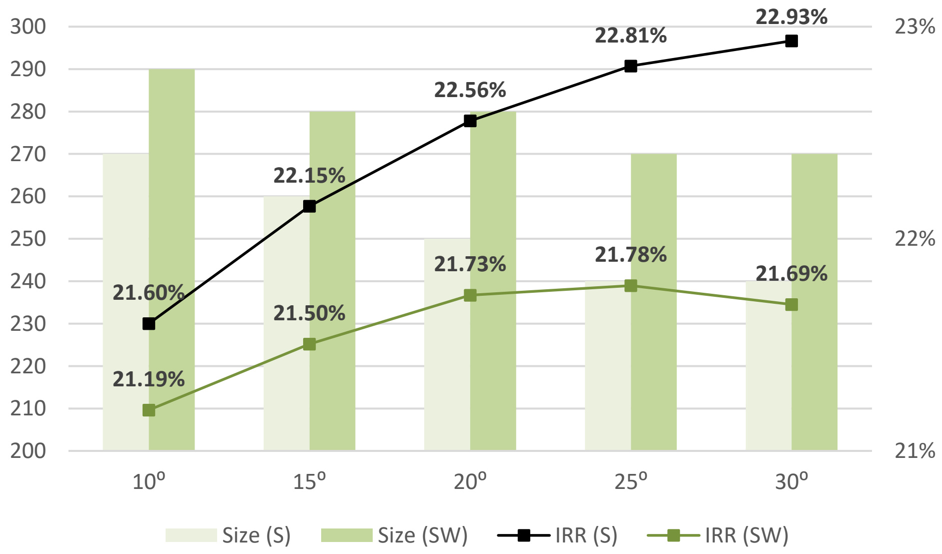

Figure 28: Size of the optimal roof-mounted system for different roof inclinations along with the project IRR for roofs oriented NE-SW and N-E. The size on the NE- and N-sides of the roof is 0, the size on the other roofs is expressed in the graph in kWp.

6. Conclusion

Portugal's regulatory framework for PV self-consumption, UPAC, stimulates the choice for PV system sizes that correspond to the consumption source it is connected to. This approach allows the increase in the overall installed PV capacity through decentralized generation. From the perspective of an electricity consumer, with connected capacity ranging from BTE to MAT, the relatively high electricity cost in Portugal as compared to the rest of the EU and lowered PV system cost make a PV self-consumption unit an attractive way of reducing their electricity cost and in turn, to increase their competitiveness.

The optimal size of a system is a delicate balance between the capital expenditure – which shows economies of scale but of course, increases with the size in absolute terms –, the applicable electricity tariff scheme, the remuneration for excess electricity which varies with the wholesale price on the market, the solar irradiation, and the consumption profile. All of these factors are subject to variability, which induces risk associated with the investment. As the lifetime of a PV system typically ranges from 25 to over 30 years, it is important to take into account this variability when deciding on the optimal PV system.

Depending on the case, it is not always the best option to maximize the energy output of the system through the orientation and inclination (35-degree inclination due South), as the peak-price periods do not align with the peak of the PV production but are rather before noon and in the late afternoon. Additionally, as a system's self-consumption rate depends strongly on the consumption profile, it is important to analyze this profile. High consumption levels during peak hours in the afternoon throughout the year might make that an orientation more towards the west can be a better option than an orientation perfectly to the South.

Overall it can be concluded that a self-consumption unit tends to be a good investment as it is possible to achieve attractive IRR's of well over 15% for the Northern part of Portugal and over 20% for the Southern part of Portugal. Larger systems with a capacity of over about 150 kWp tend to be more cost-effective (assuming the electricity consumption is large enough to obtain a self-consumption rate of around 90%) due to the strong decrease in the per-kWp system cost for capacities over 150 kWp.

It is important to note that the optimization of the system configuration in this thesis did not take into account all the risks associated with a project with a lifetime of about 30 years. Additionally, the results will differ when applying to different case studies, so the results in this thesis should not be used as absolute indicators for other projects. The results show however, that for a lot of businesses in Portugal it is worthwhile investigating possible cost reductions through solar energy but, to be aware of the importance of the system size in a possible project assessment.

Generally, it is advisable to be rather conservative when deciding on the size of the PV system, based on a sensitivity analysis. In order to reduce risk for these larger systems through a conservative approach, it is a good option to undersize the system in order to achieve a self-consumption rate that is closer to 100%, especially for system with capacities that remains larger than the 150 kWp. Doing this, the effect of fluctuations in the wholesale market is mitigated and, the investment is less exposed to possible future changes in the amount of consumption and its profile as there is a certain margin. Another way of reducing the risk – which has not been performed in this thesis – is a detailed analysis of the actual sources of consumption and their variability, which in term can be considered when making an investment decision.

Future work consist of the development and comparison of methodologies to determine the optimal system configuration based on hourly and monthly consumption data. Additionally, the work can be extended with the addition of battery storage to the system configuration. In order to promote the widespread use of the methodology and the model, a user friendly interface is to be developed that allows to vary all parameters that affect the optimal configuration.

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Annex

Overview of the Python code for the main part of the model, excluding the code to load the consumption, weather data, and the production of the reference PV system.

```
import Excel_import
import Excel_import2
import Determine_tariff
import Specific_production
import Load_tmy
import pandas as pd
import numpy as np
import matplotlib.pyplot as plt
from datetime import datetime
import time
import openpyxl as opy
from matplotlib import cm

PV1_type = "Roof"
PV2_type = "Roof"

PV1_maxsize = 401
PV2_maxsize = 5
PV_size_steps = 10

Orientation_min = 180
Orientation_max = 181
Orientation_steps = 1

Inclination_min = 10
Inclination_max = 31
Inclination_steps = 5


# Path for newer data format
path = r'C:\Users\Vince\cons_warehouse'

# Change the tariffs
Vazio = 0.0698
SV = 0.0685
Cheia = 0.1049
Ponta = 0.1137
Potencia_cost = 0.2641   # (Euro/kW*dia)
OMIE = 0.04

# Parameters
Discount_rate = 0.1
Infl = 0.015
Degradation = 0.01
#cost_kWp_PV1 = 787.5
#cost_kWp_PV2 = 787.5
cost_inv_kWp = 70
cost_oper_main = 10 # (Euro/kWp x kWp/kW)
insurance_cost = 0.0035 # 0.35% of the installation cost

```

```
# Load consumption
Annual_cons = Excel_import.load_cons(path)
Annual_cons = Annual_cons

# Load TMY data and sort it to follow the consumption dates
tmy = Load_tmy.tmy('Lisboa15min-DST.csv')
tmy_ordered = Load_tmy.reorder(tmy, Annual_cons)

# Determine the tariff for every 15 min interval
Cons_tariff = Determine_tariff.get_tariff(tmy_ordered, Vazio, SV, Cheia, Ponta)
Cons_tariff.to_csv('consXtariff.csv',header=True)

pv1_colnames = [0]
pv2_colnames = [0]
pv_tot_colnames = [0]
System_size = pd.Series([0])

for i in range(0,PV1_maxsize,PV_size_steps):       # Size range of PV system 1
    for l in range (0,PV2_maxsize,PV_size_steps):  # Size range of PV system 2
        print(i)
        print(l)
        pv1_colnames.append(i)
        pv2_colnames.append(l)
        name = str(i) + ' + ' + str(l)
        pv_tot_colnames.append(name)

        size = i + l
        System_size = System_size.append(pd.Series(size))

revenue_delta = [1]
colnames = [1]
Inflation = [1]
for i in range(1,25):
    revenue_delta.append(((1 + Infl) * (1 - Degradation))**i)   # Create a list containing the changes in revenue every year for 25 years
    colnames.append(i + 1)                                        # Make a list of column names indicating the years
    Inflation.append((1 + Infl)**i)                               # List with adaptations of inflation for every year

# Dataframe with maintenance costs for 25 years, adapted for inflation
Maint_cost_matrix = pd.concat([System_size] * len(colnames), axis = 1)
Maint_cost_matrix = Maint_cost_matrix * Inflation * cost_oper_main
Maint_cost_matrix.columns = colnames

def single_type_pv_cost(size, pv_type):
    if size == 0:
        cost = 0
    else:
            if pv_type == "Roof":
                cost = 1749.2 * size ** (-0.158)
            elif pv_type == "Ground":
                cost = 1429.6 * size ** (-0.092)
            else:   # Inclined on roof
                cost = 1739.6 * size ** (-0.122)
    return cost


# To be used when PV1 is Roof and PV2 is Roof-INCLINED
# Calculates the extra cost that stems from PV2 being inclined on the roof
def adapt_cost_inclined(pv2_size):
    if pv2_size == 0:
        cost_adapt = 1
    else:
        cost_adapt = 3*(10**(-10)) * pv2_size**3 - 4*(10**(-7)) * pv2_size**2 + 0.0002 * pv2_size + 1.0469
    return cost_adapt

pv1_size = pd.Series(pv1_colnames)
pv2_size = pd.Series(pv2_colnames)

Specific_cost_PV = System_size.apply(single_type_pv_cost, pv_type = PV1_type)

# If pv1 and 2 of same type, just calculate overall cost based on total size
if PV1_type == PV2_type:
    PV1_cost = Specific_cost_PV.mul(pv1_size.values)
    PV2_cost = Specific_cost_PV.mul(pv2_size.values)
    System_cost = PV1_cost + PV2_cost
# If Roof + Roof-Inclined, for PV1 apply baseline price, for PV2 apply baseline price + adaptation for inclination
else:
    cost_adapt_inclined = pv2_size.apply(adapt_cost_inclined)
    PV1_cost = Specific_cost_PV.mul(pv1_size.values)
    PV2_cost = Specific_cost_PV.mul(pv2_size.values)
    PV2_cost = PV2_cost.mul(cost_adapt_inclined.values)
    System_cost = PV1_cost + PV2_cost

# Insurance cost
Insurance_cost_matrix = pd.concat([System_cost] * len(colnames), axis = 1)
Insurance_cost_matrix = Insurance_cost_matrix * Inflation * insurance_cost
Insurance_cost_matrix.columns = colnames

# Inverter replacement cost (for years 10 and 20)
Inverter_replace = System_size * cost_inv_kWp

def Fin(Cashflow):
    # If no cashflows, set all fin indicators to 0
    CashflowList = list(Cashflow)
    if sum(CashflowList) == 0:
        payback_period_Undiscounted = 0
#        payback_period_Discounted = 0
        NPV = 0
        IRR = 0
    # Calculate NPV, IRR, discounted and undiscounted payback period
    else:
        NPV = np.npv(Discount_rate, Cashflow)
        IRR = np.irr(Cashflow)

        # Dataframe containing the cashflows (26 values, rows 0 to 25)
        cf_df = pd.DataFrame(CashflowList, columns=['UndiscountedCashFlows'])
        cf_df.index.name = 'Year'
        cf_df['CumulativeUndiscountedCashFlows'] = np.cumsum(cf_df['UndiscountedCashFlows'])
        # Last year when no positive cumulative cashflow
        final_full_year_Undiscounted = cf_df[cf_df.CumulativeUndiscountedCashFlows < 0].index.values.max()
        # Fractional year: cumulative CF of last year where negative (converted to positive) divided by cumulative CF of the year after, when it is firs
        fractional_yr_Undiscounted = -cf_df.CumulativeUndiscountedCashFlows[final_full_year_Undiscounted]/cf_df.UndiscountedCashFlows[final_full_year_Un
        payback_period_Undiscounted = final_full_year_Undiscounted + fractional_yr_Undiscounted
```

```python

    return pd.Series([NPV, IRR, payback_period_Undiscounted])




counter = 0
for orientation in range (Orientation_min,Orientation_max,Orientation_steps):
    for inclination in range(Inclination_min,Inclination_max,Inclination_steps):

        print('Production PV1 and PV2')
        print(counter)
        PV_prod1 = Specific_production.spec_prod(inclination,orientation,tmy_ordered)
        PV_prod1.fillna(0, inplace=True)
        PV_prod1[PV_prod1 < 0] = 0
        PV_prod2 = PV_prod1.copy()


        # Add specific production and consumption to main dataframe
        Cons_tariff = Cons_tariff.assign(Spec_prod1 = PV_prod1)
        Cons_tariff = Cons_tariff.assign(Spec_prod2 = PV_prod2)
        Annual_cons.index = Cons_tariff.index
        Cons_tariff = Cons_tariff.assign(Consumption = Annual_cons)

        # Create 3 dataframes that will represent the production of PVsystem 1, 2
        # and the two of them together for all the possible sizes of the individual systems
        Production1 = pd.DataFrame(0*Cons_tariff['Spec_prod1'], index = Cons_tariff.index).copy()
        Production1.rename(columns = {'Spec_prod1' : 0}, inplace = True)
        Production2 = pd.DataFrame(0*Cons_tariff['Spec_prod2'], index = Cons_tariff.index).copy()
        Production2.rename(columns = {'Spec_prod2' : 0}, inplace = True)
        Production_total = pd.DataFrame(0*Cons_tariff['Spec_prod2'], index = Cons_tariff.index).copy()
        Production_total.rename(columns = {'Spec_prod2' : 0}, inplace = True)


        # Multiply specific production of the pv systems with their sizes to obtain
        # the electricity output for all sizes (both PV1, PV2 and for the two together)
        print('start pv1')
        PV1_matrix = pd.concat([Cons_tariff['Spec_prod1']] * len(pv1_colnames), axis = 1)
        PV1_matrix.columns = pv1_colnames
        Production1 = PV1_matrix.mul(pd.Series(pv1_colnames).values)
        del PV1_matrix
        print('start pv2')
        PV2_matrix = pd.concat([Cons_tariff['Spec_prod2']] * len(pv2_colnames), axis = 1)
        PV2_matrix.columns = pv2_colnames
        Production2 = PV2_matrix.mul(pd.Series(pv2_colnames).values)
        del PV2_matrix
        print('PV totaal')
        Production_total = Production1 + Production2.values
        Production_total.columns = pv_tot_colnames

        # Dataframe with same size as the production dataframes in which all columns
        # represent the actual consumption (so all columns are the same)
        print('start generatie consumptionmatrix')
        Consumption_matrix = pd.concat([Annual_cons] * len(Production_total.columns), axis = 1)
        Consumption_matrix.columns = list(Production_total.columns)

        Autoconsumo = (Consumption_matrix.gt(Production_total) * 1 * Production_total +
                       (Consumption_matrix.gt(Production_total) - 1) * (-1) * Consumption_matrix)
        # If more produced than (auto)consumed, than that amount is fed into the grid
        Feedin = (Production_total.gt(Autoconsumo) * (Production_total - Autoconsumo))
        # If more consumed than produced, that amount is bought from the grid
        Buy_grid = (Consumption_matrix.gt(Production_total) * (Consumption_matrix - Production_total))
        # Savings_energy (because of autoconsumption) are Autoconsumo (in kW) divided
        # by 4 (transform kW to kWh) and multiply by the appropriate tariff
        Savings_energy = Autoconsumo.multiply(Cons_tariff['Tariff'], axis = 'index') / 4
        # Revenue from grid is Feedin divided by 4 (kW to kWh) multiplied with feed-in tariff
        Revenue_grid = Feedin.copy() / 4 * OMIE

        Current_power_ponta  = Annual_cons.multiply(Cons_tariff['Tariff_Pot'], axis = 'index')
        Current_annual_ponta_cost = 0
        Reduction_power_ponta = Autoconsumo.multiply(Cons_tariff['Tariff_Pot'], axis = 'index')
        Savings_Power = pd.DataFrame(np.zeros(shape = (1,len(Reduction_power_ponta.columns))))

        print('start savings potencia berekening')
        for j in range(1,13):   # Loop through the 12 months

            energy_ponta = pd.DataFrame(np.zeros(shape = (1,len(Reduction_power_ponta.columns))))

            Current_monthly_energy_ponta = 0
            hours_ponta = 0
            energy_ponta = 0
            days_in_month = 0

            for i in range(0,len(Reduction_power_ponta)):

                month = Cons_tariff.iloc[i]['index_copy'].month

                if month == j:
                    days_in_month = days_in_month + 1 # Every row is 15 minutes which is 1/96 of a day
                    if  Cons_tariff.iloc[i]['Tariff_Pot'] > 0:   # Savings_power.iloc[i][colname] > 0:

                        hours_ponta = hours_ponta + 0.25
                        energy_ponta = energy_ponta + (Reduction_power_ponta.iloc[i].values / 4)
                        Current_monthly_energy_ponta = Current_monthly_energy_ponta + (Current_power_ponta.iloc[i] / 4)

            days_in_month = (days_in_month / 4 / 24)
            Ponta_value = energy_ponta * Potencia_cost * days_in_month / hours_ponta
            Current_annual_ponta_cost = Current_annual_ponta_cost + Current_monthly_energy_ponta * Potencia_cost * days_in_month / hours_ponta
            Savings_Power = Savings_Power + Ponta_value

        del Ponta_value

```

```python
        Export_power = pd.DataFrame({'PV1':Production1.sum().values,
                                     'PV2':Production2.sum().values,
                                     'Total_Prod':Production_total.sum(),
                                     'Size': System_size.values,
                                     'Consumption': pd.Series(Annual_cons.sum(), index = list(Autoconsumo.columns)),
                                     'Autoconsumo': Autoconsumo.sum(),
                                     'Feedin': feedin.sum(),
                                     'Buy_grid': Buy_grid.sum()},
                                     columns = ['PV1','PV2','Total_Prod','Size',
                                                'Consumption','Autoconsumo','Feedin','Buy_grid'])

        Export_financial = pd.DataFrame({'SC_Energy':Savings_energy.sum(),
                                         'Revenue_grid':Revenue_grid.sum(),
                                         'Savings_power':pd.Series(Savings_Power.iloc[0].values,
                                                   index = list(Autoconsumo.columns))}, columns = ['SC_Energy','Revenue_grid','Savings_po

        Export_financial['Savings_total'] = Export_financial['SC_Energy'] + Export_financial['Revenue_grid'] + Export_financial['Savings_power']


        # Dataframe containing the savings for 25 years, adapted for degradation and inflation
        Revenue_matrix = pd.concat([Export_financial['Savings_total']] * len(colnames), axis = 1)
        Revenue_matrix = Revenue_matrix * revenue_delta
        Revenue_matrix.columns = colnames

        # Dataframe with cashflows
        CashFlow = Revenue_matrix.duplicated()
        CashFlow = Revenue_matrix.copy()

        CashFlow = CashFlow - Maint_cost_matrix.values
        CashFlow = CashFlow - Insurance_cost_matrix.values
        CashFlow[10] = CashFlow[10] - Inverter_replace.values
        CashFlow[20] = CashFlow[20] - Inverter_replace.values
        CashFlow[0] = System_cost.values * - 1
        CashFlow = CashFlow.reindex_axis(sorted(CashFlow.columns), axis = 1)


        PV1_cost.Index = Export_financial.Index
        PV2_cost.index = Export_financial.index
        System_cost.index = Export_financial.index

        Export_financial['PV1_cost'] = PV1_cost
        Export_financial['PV2_cost'] = PV2_cost
        Export_financial['PV1 & PV2 Cost'] = System_cost

        Key_financials = CashFlow.apply(Fin, axis = 1)
        Key_financials.columns = ['NPV', 'IRR', 'Payback']

        Export_financial = pd.concat([Export_financial, Key_financials], axis = 1)


        counter = counter + 1

        Export_all = pd.concat([Export_financial, Export_power], axis = 1)
        Export_all['Orientation'] = orientation
        Export_all['Inclination'] = inclination

        Optimalconfig1 = Export_all.loc[Export_all['IRR'].idxmax()]
        Export_all.drop(Export_all['IRR'].idxmax(), inplace = True)
        Optimalconfig2 = Export_all.loc[Export_all['IRR'].idxmax()]
        Export_all.drop(Export_all['IRR'].idxmax(), inplace = True)
        Optimalconfig3 = Export_all.loc[Export_all['IRR'].idxmax()]
        Export_all.drop(Export_all['IRR'].idxmax(), inplace = True)

        Optimal_indiv_config = pd.concat([Optimalconfig1,Optimalconfig2,Optimalconfig3],axis = 1)

        if counter == 1:
            Optimal_configurations = Optimal_indiv_config.copy()
        else:
            Optimal_configurations = pd.concat([Optimal_configurations,Optimal_indiv_config], axis = 1)


wb = opy.load_workbook('Exportfile_template.xlsx')
sheet1 = wb["Power and Energy"]
sheet2 = wb["Savings"]
sheet3 = wb["Production"]
print('part 1')
for row1 in range (0,len(Export_power)):
    c1 = sheet1.cell(row = row1 + 2, column = 1)
    c1.value = Export_power.index[row1]
    c2 = sheet2.cell(row = row1 + 2, column = 1)
    c2.value = Export_power.index[row1]
    for column1 in range(0,len(Export_power.columns)):
        # write (0,0) to Excel (2,1) and repeat
        c3 = sheet1.cell(row = row1 + 2, column = column1 + 2)
        c3.value = Export_power.iloc[row1,column1]
    for column2 in range(0,len(Export_financial.columns)):
        c4 = sheet2.cell(row = row1 + 2, column = column2 + 2)
        c4.value = Export_financial.iloc[row1,column2]

wb.save('Exportfile.xlsx')
```