PV Self-Consumption and Tariff Design Impact on Retail Energy Markets

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Abstract

The rapid decline on PV technology costs, the attractive efficiency increase on PV panels available for the residential sector and European Parliament public policies on energy in order to address the climate change issue have substantially increased the number of consumers that have decided to start producing energy, coining a new term: the PV prosumer.

The main goals of the present work are to identify the main challenges posed by prosumers to the system and the current issues that are arising in energy markets due to PV prosumers integration. Additionally, one methodology have been developed to quantify cross-subsidization among customers and another already existing method has been adapted to this work's data and requirements for the system loss of welfare analysis. In both methodologies, different markets and retail tariff designs have been considered being able to assess the impact of these different tariff structures in energy markets.

Results obtained showed that cross-subsidization exists among ratepayers, being more subsidized prosumers with higher PV installed capacities and under the Dual Rate Tariff Structure in the Free Market. In that sense, when the retail tariff fixed component is increased, cross-subsidization tend to diminish. It has also been observed that in all cases there is a loss of welfare in the system when a prosumer is integrated, whatever its PV installed capacity is. Additionally, this work tariff proposal is able to mitigate cross-subsidization and significantly reduces system loss of welfare.

Keywords:

Energy Economics, Energy Markets, PV Prosumers, Cross-Subsidies, Loss of Welfare.

Resumo

A rápida queda dos custos das tecnologias PV, um aumento significativo da eficiência dos mesmos e um conjunto de Políticas Públicas para energia no nível Europeu fizeram que o número de consumidores de eletricidade que começou a produzir a sua própria energia incrementasse substancialmente até criar um novo termo no setor energético: o PV prosumer.

Os principais objetivos de este trabalho são a identificação dos desafios mais importantes que os prosumers estão a pôr na rede e os problemas que estão a surgir nos mercados energéticos por causa da sua integração. Nesse sentido, este trabalho desenvolveu uma metodologia para quantificar a subsidiação cruzada entre clientes e adaptou outra para também quantificar a perda no bem-estar do sistema. Nas duas metodologias, diferentes tipos de mercado e tarifas de comercialização foram considerados para posteriormente poder analisar o impacto de os diferentes tipos de estruturas tarifarias no mercado.

Os resultados obtidos mostram que atualmente existe uma subsidiação cruzada entre clientes, sendo os mais subsidiados aqueles que têm mais capacidade instalada de PV e que estão sujeitos a uma estrutura tarifaria bi-horária no mercado livre. Além disso, também foi observado como um aumento na componente fixa da tarifa de comercialização diminui a subsidiação cruzada. Também pode-se concluir que em todos os casos em que um prosumer é integrado no sistema existe uma perda de bem-estar. Por último, é importante dizer que estrutura tarifaria proposta por este trabalho mitiga a subsidiação cruzada e reduze a perda de bem-estar do sistema.

Palavras-chave:

Economia da Energia, Mercados Energéticos, PV Prosumers, Subsidiação Cruzada, Perda de Bem-estar

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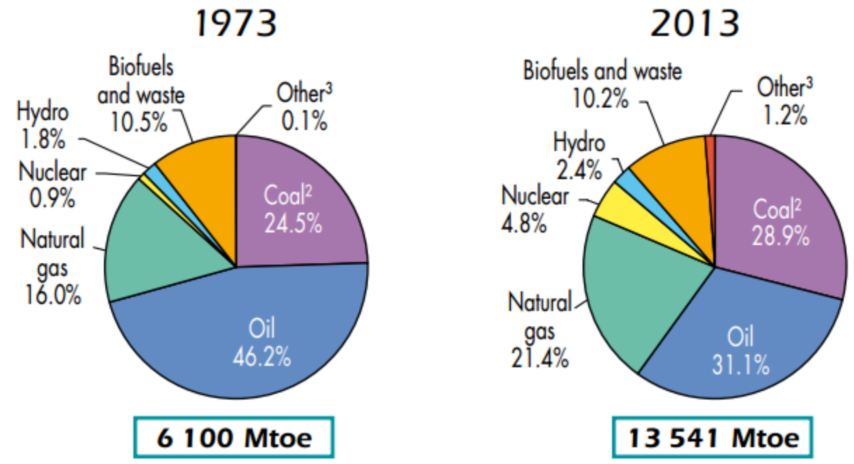
1. Introduction

1.1. Energy Overview and EU Energy Policy

In December 2015, a worldwide agreement was reached on climate change at the Paris climate conference (COP21). 195 countries settled the basis for a universal legally binding global climate deal. The agreement consisted on a global action plan to keep global warming below 2°C, above pre-industrial levels, among other measures to prevent climate change. Other important measures taken during the Paris conference on emissions mitigation were the need for global emissions to peak as soon as possible and to drastically reduce them thereafter (1).

The Paris agreement is considered a milestone in the energy transition to a sustainable future. A transition that already started by the end of the XX century and that now is being seen as the only way out for human sustainable development as society. In 1973, coal and oil together represented 70.7% of world energy primary supply. However, despite the energy generation increase, in 2013, coal and oil stood for 60% of world energy primary supply, as it can be observed in Figure 1 [Source: International Energy Agency]. The increase in other energy sources such as nuclear, hydro and natural gas, and the embryonic implosion of renewables can explain this new scenario, although fossil fuels are still predominant.



1. *World includes international aviation and international marine bunkers.*
2. *In these graphs, peat and oil shale are aggregated with coal.*
3. *Includes geothermal, solar, wind, heat, etc.*

Figure 1. World Energy Primary Supply. Comparison of values from 1973 and 2013 (2).

Regarding the world electricity generation, it must be highlighted that the electricity production by means of burning fossils fuels was about 75%, while 40 years later, in 2013, fossil fuels in electricity production represented 67.4%, as shown in Figure 2 [Source: International Energy Agency]. Considering that the electricity production in 2013 was four times the produced in 1973, the decrease in fossil fuels sources has been, at least, significant.

In the EU-28, combustible fuels, including waste and biomass, accounted for almost 50% of the electricity production in 2013, which represents a significant difference when compared at worldwide level, as non-EU developing countries are using more fossil fuels to run their economies. In Figure 3 [Source: EUROSTAT], it can be observed that for the EU-28, almost 25% of the electricity production came from renewable energy sources (RES) in 2013.

Portugal renewable energy share in 2014 reached 57.25% when it comes to electricity generation. For a reference, in 2004, the renewables share represented 27.47% of the total electricity production (3). The Portuguese energy mix will be explained further on into more detail.

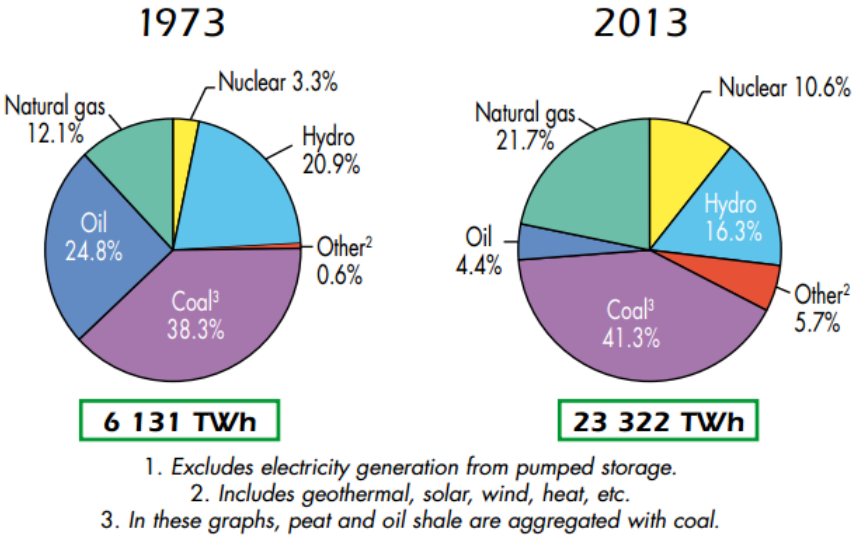


Figure 2. Electricity generation by fuel. Comparison of values from 1973 and 2013 (2).

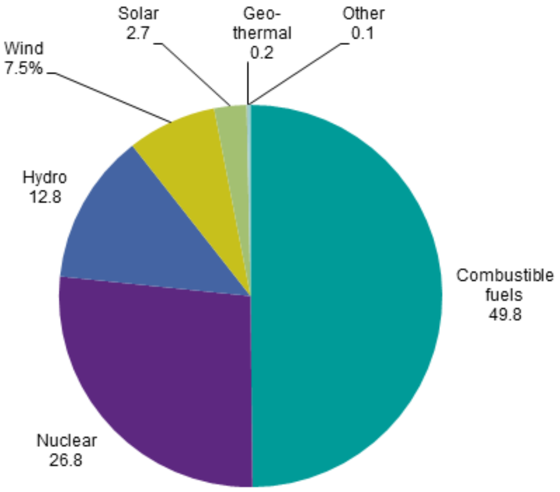


Figure 3. Net-Electricity Generation in the EU-28, 2013 (4).

Furthermore, the EU relies on energy imports for 53% of its total energy consumption, rising concerns on the energy security of its member states and the consistency of the energy supply. The cost of importing energy represents more than €1 billion per day, and energy imports account for around 20% of total imports. More in detail, the EU imports 90% of its crude oil, 66% of its natural gas, 42% of its coal and other solid fuels and 40% of its uranium and other nuclear fuels (5).

Renewable Energy Sources (RES) are considered a key factor in the energy transition and can effectively deal with the two main energy issues explained above: climate change, as they do not emit carbon dioxide, or they are carbon neutral sources (biomass); and, energy security, as they are available in EU land. In order to address global climate change and energy security raising concerns, the EU Parliament approved in 2008 a European directive to develop renewable energy and energy efficiency within the EU.

The 2020 climate & energy package introduces three main targets to be achieved by 2020: 20% cut in greenhouse gas emissions compared to the 1990 levels, 20% of EU energy produced by renewable energy sources and 20% improvement in energy efficiency (6). The goals for 2030 are far more ambitious and the EU aims to reduce greenhouse gas emissions by a minimum of 40%, increase renewable energy production by 27%, and improve energy efficiency by at least 27% (7). However, there has not been so far a particular assignation per country on these goals. Not having clear goals to achieve per country could lead to a gap between the goal and what it has been done by 2030, forcing the EU to take extra measures to fill in that gap and avoid free-rider situations and a general drop off in policies for achieving the 2030 targets in the EU members.

In Portugal, the European Commission’s 20-20-20 goals were integrated as the National Action Plan for Renewable Energy under the 2009/28/CE directive (PNAER, Plano Nacional de Acção para as Energias Renováveis). The PNAER considers an Energy National Strategy (ENE 2020), approved by the government in April 2009, which targets several sectors and assumes important goals to be achieved by 2020.

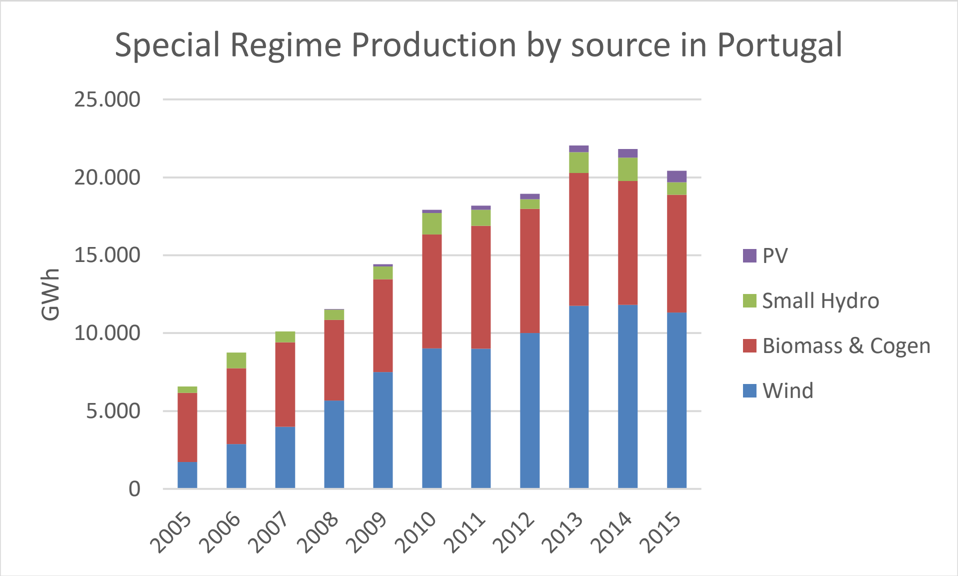
According to the ENE 2020, and considering the RES contribution, the main objectives are (8):

- 31% of gross final energy consumption, 60% of total electricity generated, and 10% of energy consumption in transport by 2020.
- Reduce energy dependency to 74% of the dependency in 2009.
- Reduce on 25% the energy import balance, reducing the oil imports on about 60 million barrels.
- 25% reduction of primary energy consumption and 30% reduction of energy consumption by the State.

The policy deployment for achieving the previous mentioned targets was based on boosting RES by means of Feed-in tariffs (FiT) or subsidies. Between 2001 and 2012, the Portuguese Government subsidized wind power generators with maintained average feed-in tariffs at around 100€/MWh, although levelized cost of energy (LCOE) for wind was in a sustain scale back. In addition, subsidies were provided in 2007 for distributed RES and co-generation facilities. For solar PV generation, the guaranteed subsidy for the first eight years of the system’s lifetime was 630€/MWh. Consequently, the Net Present Value of the FiT was kept above 4€ per W of installed capacity (9). Although the government had made some reduction in the FiT for PV distributed generation, the FiT duration period was raised from eight to fifteen years.

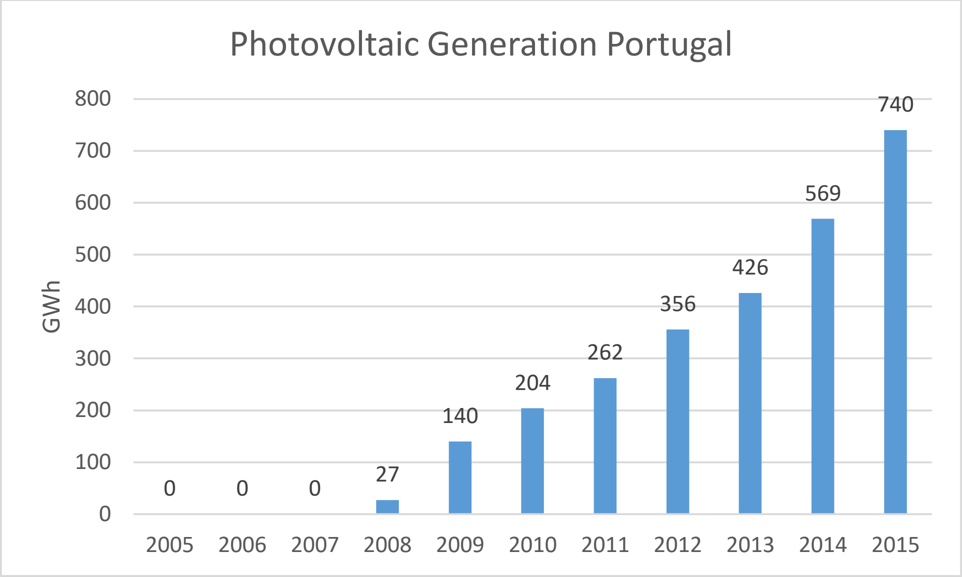
Nowadays, the current FiT for wind is around 74-75€/MWh for 15 years. For PV systems with less than 5kW of installed capacity the FiT is between 310 and 317€/MWh; and, for those over 5kW of capacity a FiT of 450€/MWh is given. When PV systems are considered as micro generation and installed on residential, commercial or industrial building rooftops, the FiT for less than 5kW is 470€/MWh and for systems with more than 5kW is 355€/MWh (10).

After the implementation of energy policies for boosting renewable energy, in 2014 Portugal reached 57.25% of electricity production by RES, as it has been previously mentioned, although that high share of renewable can also be explained by the fact that it was a rainy year, increasing hydroelectric production substantially. In 2015, the special regime electricity production reached 20,426GWh, representing 40.52% of the total electricity generated (taken into account the electricity imported through the interconnection with Spain). The special regime production considers all the technologies that generate energy in a cleaner way: renewables, biomass combustion and co-generation. The most important energy source producing under the special regime is wind (not considering large hydro power plants), accounting for more than half of the production. In 2015, wind power provided to the Portuguese grid 11,332GWh, which represented 55.48% of the special regime production and 22.48% of the total electricity generation. Biomass combustion and co-generation thermal plants are the second most used technologies in special regime production as it can be seen in Graph 1 [Source: REN].



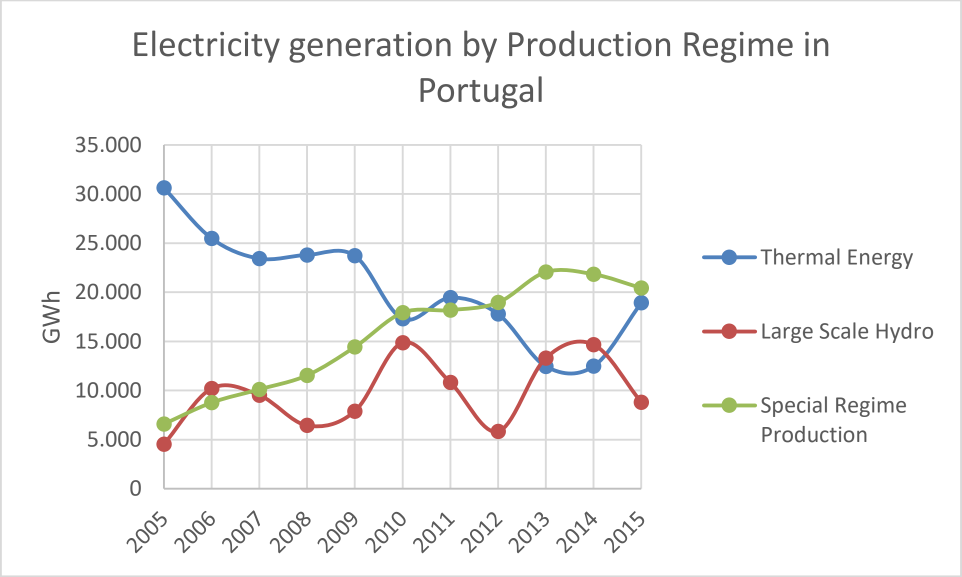
Graph 1. Special Regime Production by technology. Portugal 2005-2015.

Special attention must be addressed to the PV electricity generation in the last four years. The rapid decline of its LCOE has driven the PV market, contributing in 2015 with 740GWh to the electricity consumption, as it is shown in Graph 2 [Source: REN].



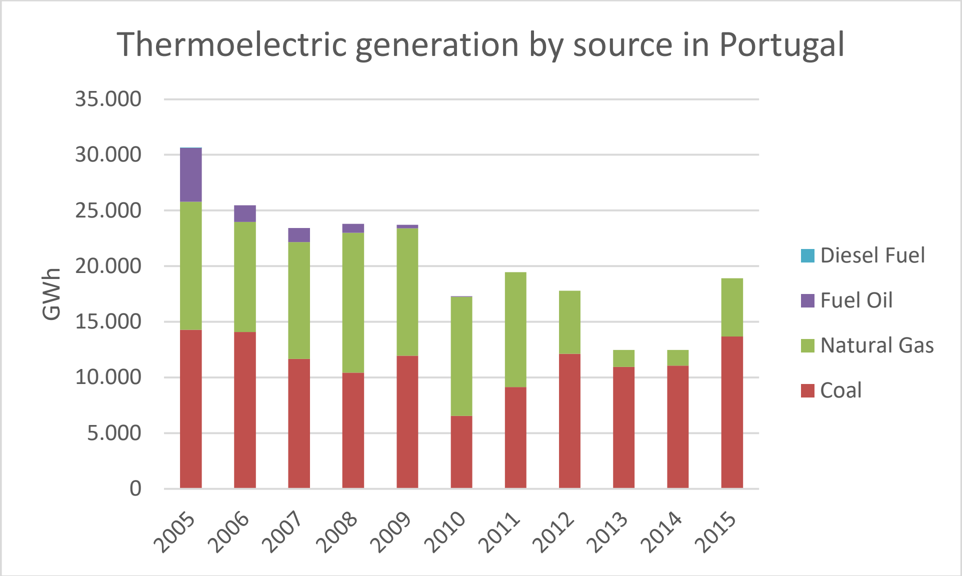
Graph 2. Photovoltaic Electricity Generation. Portugal 2005-2015.

There has been a sustained decline on the electricity production by means of combustion technologies (conventional thermal energy) in the last 10 years. On the other hand, large-scale hydro power plants and special regime production have experienced a sustained growth, as observed in Graph 3 [Source: REN]. In 2015, it is important to highlight the substitution of large scale hydro for thermal energy due to climate conditions, as it was an exceptional dry year in Portugal.



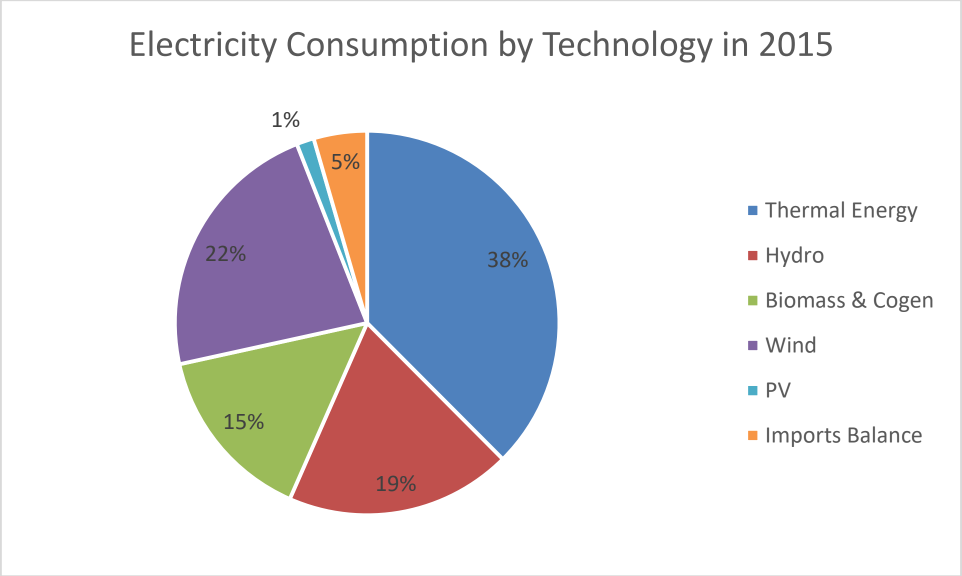
Graph 3. Electricity Generation by Production Regime. Portugal 2005-2015.

The decline on the use of convention thermal energy sources can also be seen in Graph 4 [Source: REN]. There was a scale back on coal consumption until 2012, when coal recovered consumption levels of three and four years ago. Diesel fuel consumption in electricity generation is non-existing, and fuel oil was residual and currently not used. Regarding natural gas, there has also been a reduction on its consumption for electricity generation purposes and, in 2015, accounted only for 28% of the total conventional thermal energy production, as it can be observed in Graph 4 [Source: REN]. The drought in 2015 forced to use more natural gas, although pre-crisis levels were not reached.



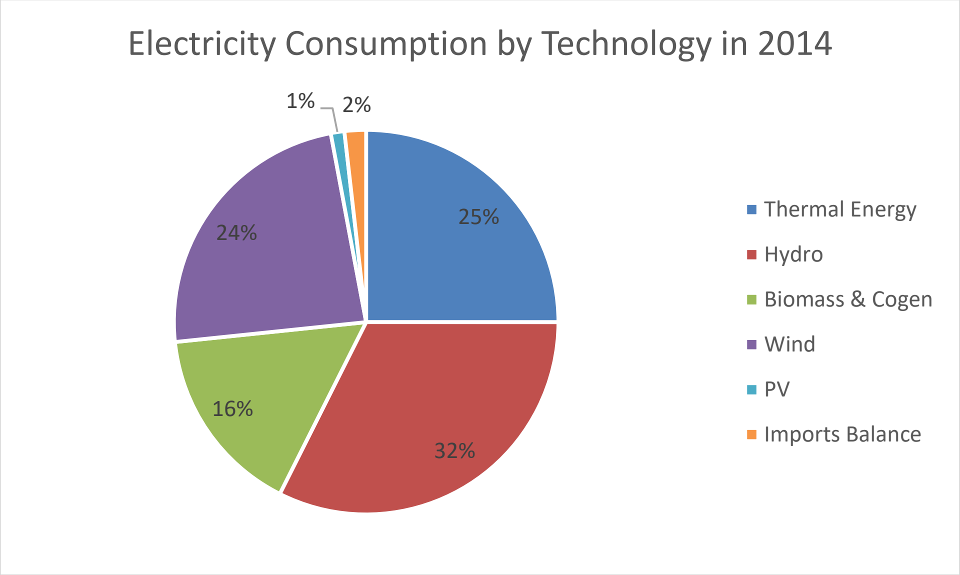
Graph 4. Thermoelectric generation by source. Portugal 2005-Feb 2016.

The application of the already mentioned energy policies in Portugal has caused a major presence of renewable energy in the energy mix, as well as reduction in the use of conventional thermal energy technologies. In Graph 5 [Source: REN], the energy balance for Portugal in 2015 is presented. Although thermal energy sources still represent a high percentage on the electricity generation, wind and hydro stand for an important percentage of the energy mix.



Graph 5. Electricity Consumption Balance by Technology. Portugal 2015.

In order to present, more realistic values, and to avoid the influence of exceptional weather conditions in 2015, the energy mix of 2014 for Portugal is also given in Graph 6 [Source: REN]. In 2014, wind and hydro accounted for more than half of the energy produced for electricity consumption. In that year, the hydro productivity index was 1.20, while in 2015 was 0.84 due to the extremely dry weather condition. Regarding wind, its productivity index was also higher in 2014 than in 2015, 1.10 and 1.02 respectively.



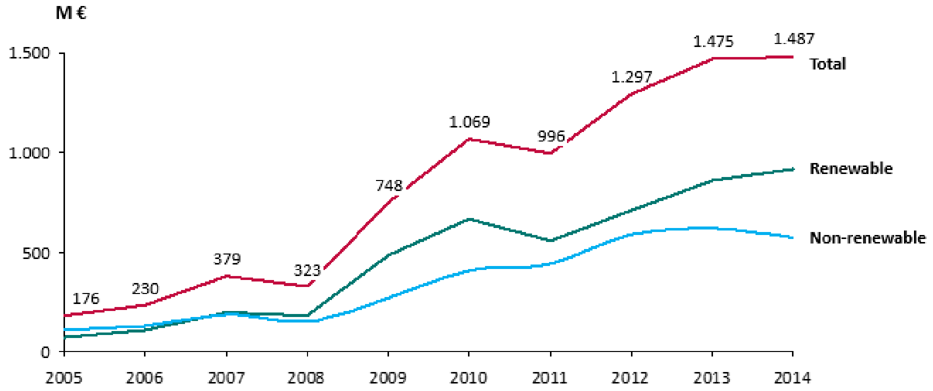
Graph 6. Electricity Consumption by Technology. Portugal 2014.

On the other hand, subsidies and taxes required for applying energy policies can also have cost implications and can be quite controversial. Wealth transfers and cross-subsidization, technology favouritism and entrenched political dependencies are a few examples of decisions standing behind subsidization and taxation.

The Energy International Administration (EIA) pointed out that subsides are aimed to lower the energy production costs, raising the price received by energy producers and lowering the price paid by consumers (11). The International Energy Agency estimated that in 2014 fossil fuel were subsidized with $490 billion, and renewable energy only received $135 billion in subsidies.

In Portugal the surcharge of the special regime generation accounted for €1,487 million. In 2008, there was a drastic increase, which stopped in 2010. From there on, the growth has been sustained, but slightly less pronounced, as it can be seen in Figure 4 [Source: ERSE for data until 2013. EDP for 2014 data] (12). On the other hand, the surcharge associated to renewable energy is a subjective indicator, as the market price decreases when more energy is produced by renewables (marginal cost is zero) and that surcharge is surely needed to achieve 2020 and 2030 EU goals.

Shifting towards a low carbon economy and driving this transition on renewable energy has its pros and cons. Several studies have attempted to estimate the costs and benefits involved in getting over the carbon based economy. In 2006, Stern estimated in ‘The economics of Climate Change’ that the energy transition costs would equal 1% of the GDP per year, rising the number up to 2% one year later in a subsequent review. On the other hand, Stern pointed out that energy transition could benefit the economy on $2.5 trillion, contrasted with costs of 5 to 20% of the GDP if no change is made in the energy model (13).



2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	
6,5	8,8	10,1	11,6	14,4	18,0	18,3	19,0	22,1	21,9	Special Regime (TWh)
86,3	92,2	94,6	101,3	96,2	97,0	105,2	112,4	107,7	107,1	Purchase price (€ / MWh)
59,4	65,9	57,4	73,2	44,6	38,7	50,8	44,1	41,0	39,1	Selling price (€ / MWh)

Figure 4. Special Regime Generation Surcharge. Portugal.

1.2. Prosumers: a key driver in the energy transition

Within the energy transition scope, an emerging phenomenon is changing the game's rules for Distribution System Operators (DSOs) and Transport System Operators (TSOs), and causing a significant increase on the amount of Distributed Generation (DG) in distribution grids. This new scenario is characterized by the surfacing of more empowered new customers willing to have an active role in the electricity markets. First, it was through market liberalisation that customers assumed a more active role in the energy market by being allowed to choose different energy suppliers. Nowadays, that degree of freedom has increased to another level where customers can decide whether they only want to buy and consume electricity or they want to participate in the production process as well by generating part of the electricity they consume.

The Union of the Electricity Industry-EURELECTRIC presented four cases to exemplify the DG level of penetration in the grid in February 2013 (14). In those cases, DG is considered not only to be prosumers or small producers, but all kinds of distributed generation. If prosumer's penetration into the grid achieves higher levels, DG problem can be exacerbated.

- In Galicia (Spain), the DG installed capacity connected to the Unión Fenosa Distribución grid represents 120% of the total peak demand, being wind power the most deployed technology accounting for 62.10% of DG installed capacity. In addition, DG responds to more than 30% of the energy demand of Unión Fenosa Distribución in the area.

- In Italy, 10GW were connected to the grid in 2011, being the highest yearly integration of DG worldwide.

- In northwest Ireland, DG installed capacity already connected to the grid (307.75MW) surpasses peak demand (160MW). Furthermore, 186MW are planned to be installed and 640MW in different applications have been presented.

- In south Germany, DG almost accounts for the peak load, and in several locations already surpasses local load. In high RES production period, the DSO network is seen as large generator from the TSOs perspective.

For a fully understanding of prosumer's impact, a proper definition must be provided. Regarding the energy market and the energy production, a prosumer is a consumer that it also produces its own energy. Several types of prosumers could be identified according to their level of dependency on the electricity supplier and the grid.

Firstly, the prosumers that are able to produce their own electricity, but still need the grid to purchase power when they need it. They reduce the total amount of energy a regular customer buys by producing their own. They are known as self-consumption prosumers.

Secondly, those who are able to generate all the electricity they need. They have their own DG systems, storage devices and other technologies in order to be disconnected from the grid. They are known as grid defection prosumers.

Thirdly, prosumers that produce enough electricity to sell it at large scale to the grid, although they might be still connected to the grid, which is considered as commercial electricity production and they are known as such.

Prosumers could be characterized by owning a DG system, that could be backed up with energy storage equipment, and that could be monitored, controlled and operated through smart meters and other equipment for this special purpose (15). Small DG systems are usually under control of the owners (prosumers). The DG technologies include different fuelled engines, combined heat and power generation (CHP) based on biomass or fossil fuels, wind turbines, fuel cells, PV systems and a large variety of micro-generation technologies. The energy produced is consumed partially or totally on site, although any excess can be fed into the grid (with the exception of CHP, as heat transport is not feasible due to its large transport losses, although electricity produced in CHP pants can).

The focus of this work is on prosumers using PV panels for producing their own electricity that still need to be connected to the grid, in order to buy electricity due to intermittency of renewable DG systems and to sell it when there is an excess. From now on, the term prosumer/s will be used for referring to the PV panel owners, although some analysis and conclusions could also be valid for prosumers using other DG technologies.

1.3. Problem Identification

The identification and analysis of all the consequences that large integration of PV prosumers could cause to the distribution network and to energy markets is a challenge itself. In other words, identifying all the prosumers current issues is an issue itself. Therefore, this study will also attempt to identify and quantify the major issues in the prosumers scenario, regarding their impact in the distribution network and the energy markets.

Despite the obvious difficulties to define how prosumers are affecting the energy system, some areas must be put into analysis, so the problem identification gets simple.

First, the energy efficiency approach. Prosumers are consumers that generate their own electricity and, consequently, they reduce their energy consumption from the grid. However, most of them still need the grid and in peak hours they withdraw energy from the system, so they still have the option to get that electricity. This is the reason why PV panels are seen somehow as an energy efficiency measure. On the other hand, part of the fixed costs are included in the tariff variable or volumetric part. Hence, if consumption is reduced, fixed costs are not recovered and other customers must assume extra costs. This phenomenon is a particular kind of cross-subsidization that will be explained further on. In addition, taxes and levies are also included in some countries in the tariff volumetric part, causing the same problem. This work will pay special attention to the particular phenomenon of cost allocation distortion due to the energy efficiency effect of PV panels owned by prosumers.

In that sense, the tariff design and structure will play an important role on the mitigation of this effect. The main issue of fixed costs recovery underlies on a non-realistic tariff design that does not allocate costs properly. Challenges could arise when determining the non-volumetric weight on the overall tariff, but also on the charge structure for the volumetric part.

Second, the seller effect. Selling electricity to the grid at large scale using the DSOs distribution networks may have some adverse consequences that must be analysed. Distributed generation sometimes can be positive to the system, but it may also have some negative effects. In this particular case, distribution losses, levelized cost of energy (LCOE) for PV and access fees to the grid must be analysed to identify the main challenges. When it comes to compensation of PV fed into the grid, different models for rewarding the energy generated by prosumers could have different impacts on the grid. Net-metering has different positive and negative consequences from both the grid and the prosumer perspective, than Self-Consumption or FiT. Hence, identifying what issues come about when applying different compensation models is within this project scope.

Third, the impact on the energy markets in terms of subsidies and FiT for PV is another must in this study purpose. Together with DG distortion to energy markets in a more general perspective, PV subsidization impact on investment identification signs and on the energy market equilibrium has to be properly studied.

Regarding cross-subsidies, as it will be the dominant and primary interest of this study, it must be said that no general accepted definition or quantification method has been established. It is not easy to define cross-subsidies because they are difficult to measure, and they are challenging to measure because it is hard to define them (16). Therefore, a specific approach for a particular type of cross-subsidies will be given in order to define and solve that quandary.

1.4. Goals

The goals of this work will be settled according to the issues PV Prosumers entail to the energy system. The main objectives of the study are presented below.

First, identify the main challenges posed by the integration of small-scale PV generation into low-voltage distribution networks, both from the operational and economical points of view.

Second, identify the current issues in today's retail energy market and analyse their relation to actual tariff designs, focusing on the Portuguese case.

Third, quantify cross-subsidies between PV prosumers and regular ratepayers in the Portuguese energy market and propose alternative tariff designs to mitigate subsidization impacts.

2. PV Prosumers in Energy Markets

In 1921, Albert Einstein was awarded a Nobel Prize for discovering the photoelectric effect. Since that discovery, solar or photovoltaic cells, as they are known now, have experienced a rapid technology development, allowing photovoltaic energy to be considered one of the future technology in the energy sector.

In this section, a market overview of PV energy is presented. The aim is to understand the rapid growth of PV technology and its fast emergence in the market significantly reducing costs within few years. The understanding of PV energy role in the market will provide a better perspective when analysing PV prosumers dynamics and future expectations.

2.1. PV Market Overview

Despite PV solar energy is not the most produced in the EU-28, as it represents a share of 5,5% of the total renewable energy produced (17), the market for PV has developed more rapidly than expected and far more than other markets for other renewable energy sources. Several factors have driven this growth.

First, the rapid evolution of PV technology reaching higher efficiencies within shorter periods has been a key factor for the sector breakthrough. Second, the favourability of conditions for PV market growth has helped the sector expansion. Ultimately, the rapid and sustained decrease on the LCOE of PV has driven the prices down making PV a feasible cheap option for energy generation.

2.1.1. PV technology step up

According to the Centro de Investigación de Recursos y Consumos Energéticos (CIRCE) from Spain, PV technology, can be classified as follows (18):

- Wafer-based cell (1st Generation PV)
  - Crystalline Silicon
    - Single Crystalline silicon
    - Multi Crystalline silicon
  - GaAs & III-V single junction
- Thin-film cell
  - Conventional thin-film (2nd Generation PV)
    - Hydrogenated a-Si (a-Si:H)
    - Cadmium telluride (CdTe)
    - Copper indium gallium diselenide (CIGS)
    - Copper zinc tin sulphide (CZTS)
  - Emerging thin-film (3rd Generation PV)
    - Dye-sensitized solar cell (DSSC)
    - Perovskite
    - Organic PV (OPV)
    - Quantum dot PV (QD)

Two good indicators for calibrating the current status of PV technology are: PV cells and modules efficiency and Energy Payback Time (EPBT). The first is referred to the amount of solar energy converted into electricity by the solar cell or by a module. The second concept measures the time that a PV system has to operate in order to recover all the energy that was used in its production process, also accounting for pollution and CO_2.

With regard to energy efficiency, commercial PV systems have experienced a significant increase in the past ten years. For silicon wafer-based cells, efficiency has risen from 12% to 16% within this short period. Cadmium telluride (CdTe) cells efficiency increase has not been less moderate than silicon-wafer based cells by jumping from a 9% in 2005 to 13% last year (18).

Under laboratory conditions, efficiencies reached are outstandingly higher. Silicon wafer-based cells achieved an efficiency of 25.6% and 20.8%, for single crystalline and multi crystalline in that order. Regarding thin-film cells, Cadmium telluride (CdTe) efficiency equalled 21% and Copper indium gallium diselenide (CIGS) performance passed along 20%. The higher efficiency reached in 2015 was accomplished by high concentration multi-junction cells getting to 46%, going down to 38.9% in module (18) (19).

The National Centre for Photovoltaics (NCPV), at the National Renewable Energy Laboratory (NREL), latest chart for research cell efficiency records shows the rising tendency in PV efficiency throughout the last decades, as it can be observed in Figure 6.

On the other hand, energy payback time will depend on the conditions of the location chosen for its installation. Therefore, EPBT will be different for each location. For southern Europe, the EPBT is 1.5 year and could be less depending on the technology and the location. For instance, in Sicily using Multi Crystalline Silicon cells, the EPBT is 1 year. That means that the rest of its lifespan will be net-generating energy. For northern Europe, the EPBT is slightly higher ascending to 2.5 years (18). The decreasing tendency of EPBT for PV technology is shown in Figure 5.

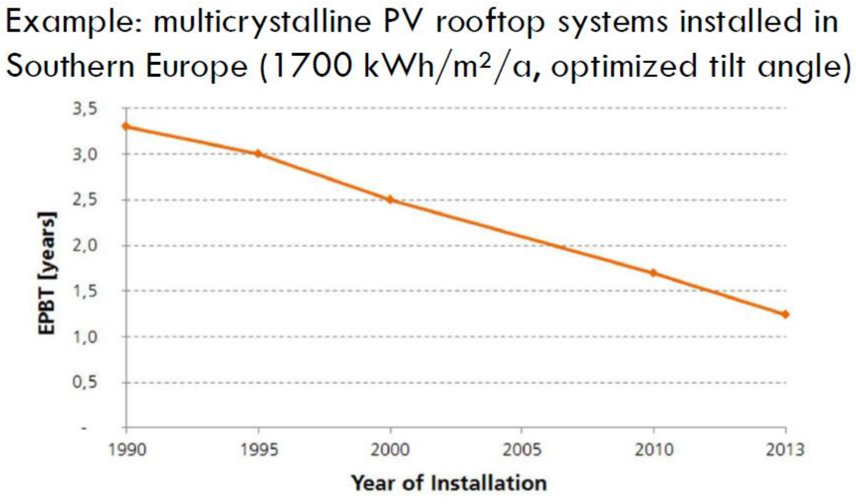


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Figure 5. EPBT for Multi Crystalline PV rooftop systems in Southern Europe (18) (19).

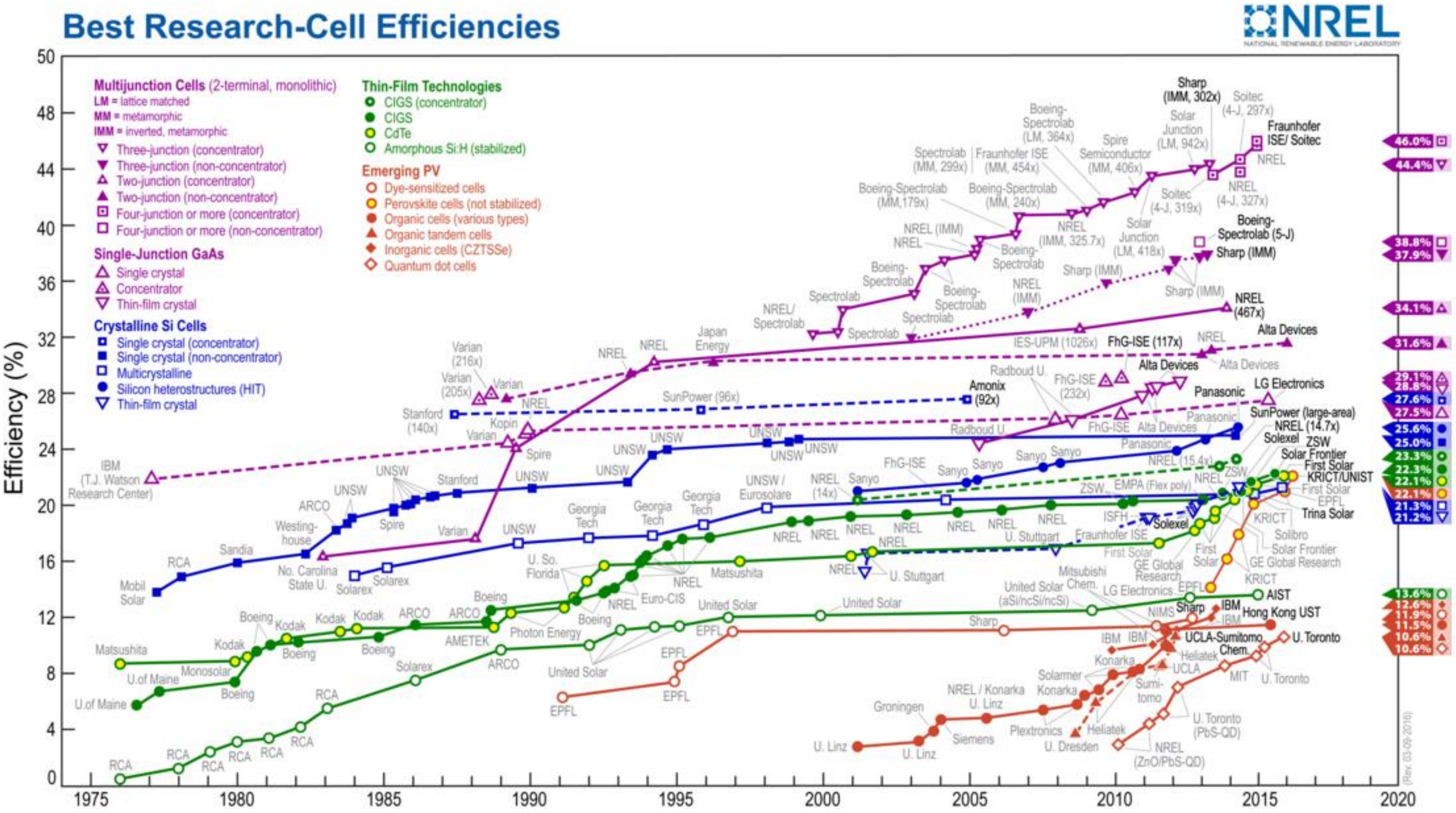


Figure 6. Best Research-Cell Efficiencies latest chart (April 2016) (20).

2.1.2. PV Market Analysis

PV market grows 44% per year and, as a result, the cumulative amount of PV capacity has increased significantly. In Figure 7, the world rapid increase in the cumulative capacity from more than 23GW in 2009 to 138.9GW in 2013 can be observed (21). That amount of PV energy produced in 2013 could have been able to generate 160TWh, covering the annual power supply needs for 45M European households and equivalent to the electricity produced in 32 coal large power plants (22).

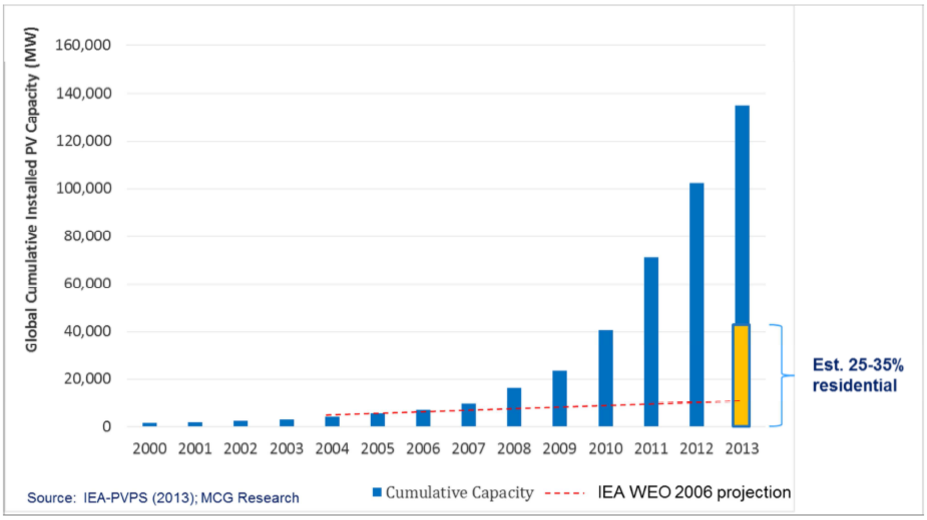


Figure 7. Cumulative PV Capacity (MW). Residential share calculated only for 2013 (21).

A non-trivial proportion of the world's PV Capacity consists in PV systems at a household level. That generates a decentralized PV deployment, where the electricity is consumed nearby its place of production, in contrast with the coal or oil centralized power plants. It is estimated that around 25 to 35% of the total cumulative PV capacity was installed at a residential level in 2013 (21).

More recent data points out that, in 2014, PV module production accounted for 40GWp, being China and Taiwan the leaders on the sector with a share of 69%, followed by Europe with 6% and Japan, USA and Canada with 4% each. Regarding the cumulative PV installations in 2014, they reached 180GWp. Europe stood for 48%, decreasing its share of 58% in 2013. On the other hand, China and Taiwan jumped from 13% in 2013 to 17% the following year (18).

In addition, 91% of the PV technology produced in 2014 were Si-wafer based cells, while 9% of the production were thin film cells.

With respect to European PV market development, there has been a sustained growth since the early 2000s. However, punctual booms followed by a drastic deceleration in the coming years have characterized the PV cumulative installed capacity expansion in Europe. In 2008, Spain's PV boom drove the PV market in Europe by increasing its installed capacity from 2GW to almost 6GW. In 2009, Spain could not keep up with that cadence and Germany took the lead. The Spanish boom in 2008 and bust the year after is an example of overheated market development, showing that is not an adequate model for a sustainable and continuous integration of renewables in the system, and that excessive high values for FiTs are not adequate. In 2010, there was a major growth mainly due to German installations keeping its levels from previous years, and a first boom in Italy and Czech Republic, adding around 3.8GW together. Italy experienced another rise in 2011 that combined with German new installations, led to a significant growth in the installed capacity. In 2012, a deceleration of the European market started and it was Germany alone who helped to maintain slightly lower levels than in 2011. In 2013, the decline in German new installations confirmed the decrease in the market with only 11GW of new PV capacity in the grid (22). In Figure 8, the evolution of new connected PV capacities to the grid is shown.

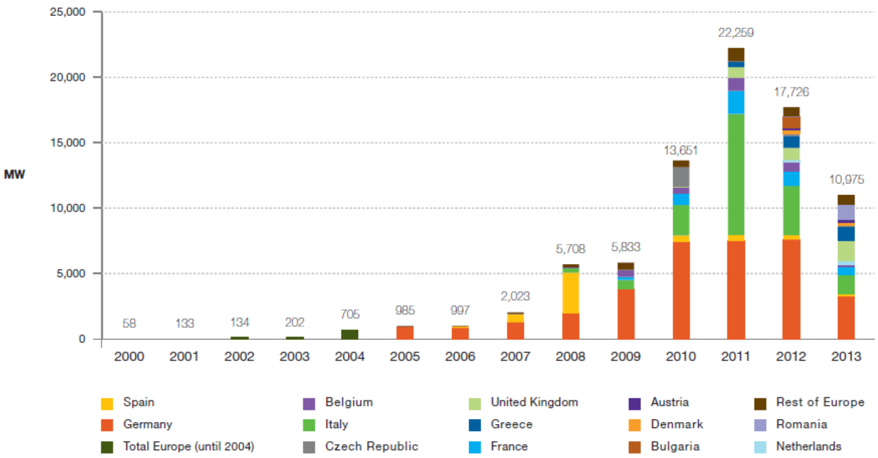


Figure 8. New PV Capacities connected to the grid. 2000-2013 (22).

The cumulative European installed capacity was driven by punctual booms of particular countries, by the sustained increase in German PV capacity until 2012 and by a deceleration starting in 2012. The rapid growing tendency until 2011 and a slow on the rate of increase the following years are the main characteristics for PV deployment in Europe and for the ability to increase PV penetration levels in the following years. European PV cumulative capacity expanded until 80GW in 2013, being Germany the most developed market. In Figure 9, the evolution of European installed capacity from 2000 to 2013 can be observed.

In Portugal, despite its high potential for developing a large PV sector, the growth has been relatively slow and by the end of 2015, the total PV installed capacity reached 429MW. Comparing values of 2013, Portugal had 283MW of installed capacity, representing a 0.8% of the PV installed capacity in Germany. France installed in 2013 more PV capacity than the total installed capacity of Portugal. Portuguese PV market is one of the less developed if the PV potential is considered. One possible explanation to that fact is that investors have assembled their efforts on wind technology within the renewable energy sector. Higher return rates and profitability for wind technology could have been drivers of this phenomenon. However, the PV market has grown in the last years and a clear tendency on cumulative installed capacity growth can be observed, as it is shown in Graph 7 [Source: EDP].

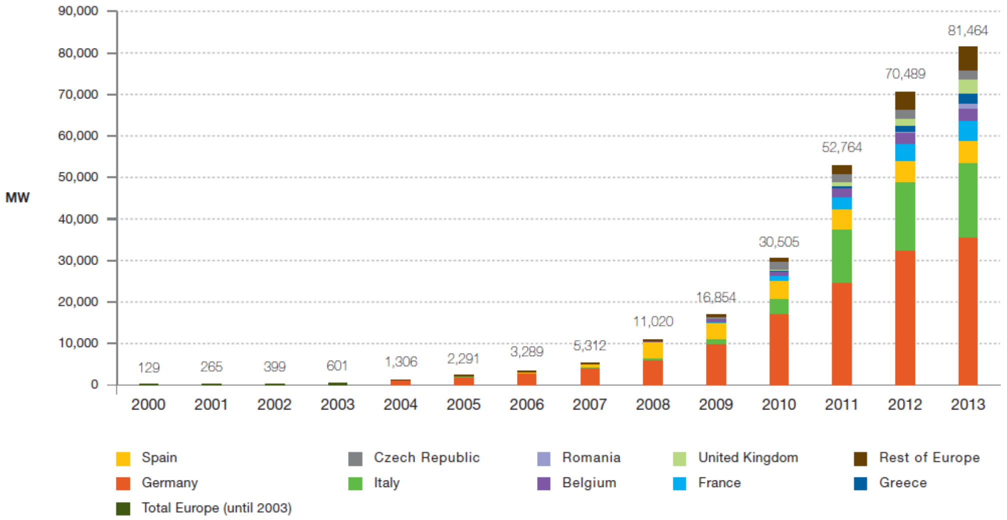
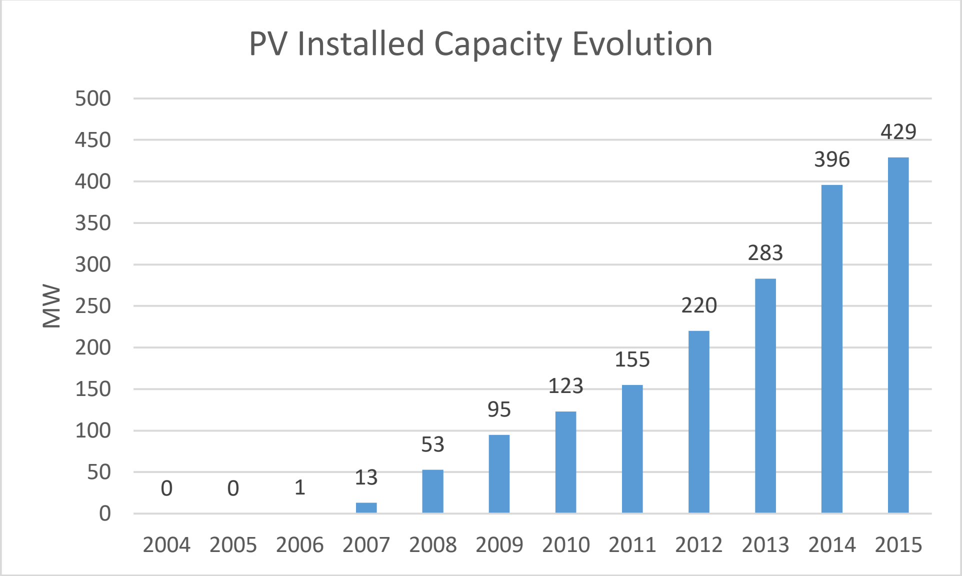


Figure 9. European PV installed capacity evolution. 2000-2013 (22).



Graph 7. PV Installed Capacity Evolution. Portugal 2004-2015.

According to the system size, the electricity prices regime and the nature of the investor, the market can be classified into ground-mounted systems, residential PV applications and industrial and commercial rooftop applications.

Commercial and industrial rooftop applications are the larger segments in the European PV Market. PV residential applications have experienced a rapid growth and have started to represent an important share in some European countries. In Figure 11, the PV market segmentation per country based on the cumulative capacity in 2013 is presented.

It can be observed, that the countries with a higher level of PV penetration have a more balanced market segmentation, like Germany, France and Italy. In these countries, PV share in different segments has similar weights, reaching a higher penetration by diversifying its installation purposes. On the other hand, countries with a not very large PV deployment are more concentrated in a particular segment. Romania has almost 100% of the PV market based on ground-mounted systems and a low level of PV penetration. The Romanian case can be explained due to the entry of large European Utilities willing to invest in PV electricity generation and installing large PV farms. The same can be applied to the Spanish case: energy policy on boosting the PV market with very favourable FiT and substantial subsidies attracted large PV producers and drove the market growth.

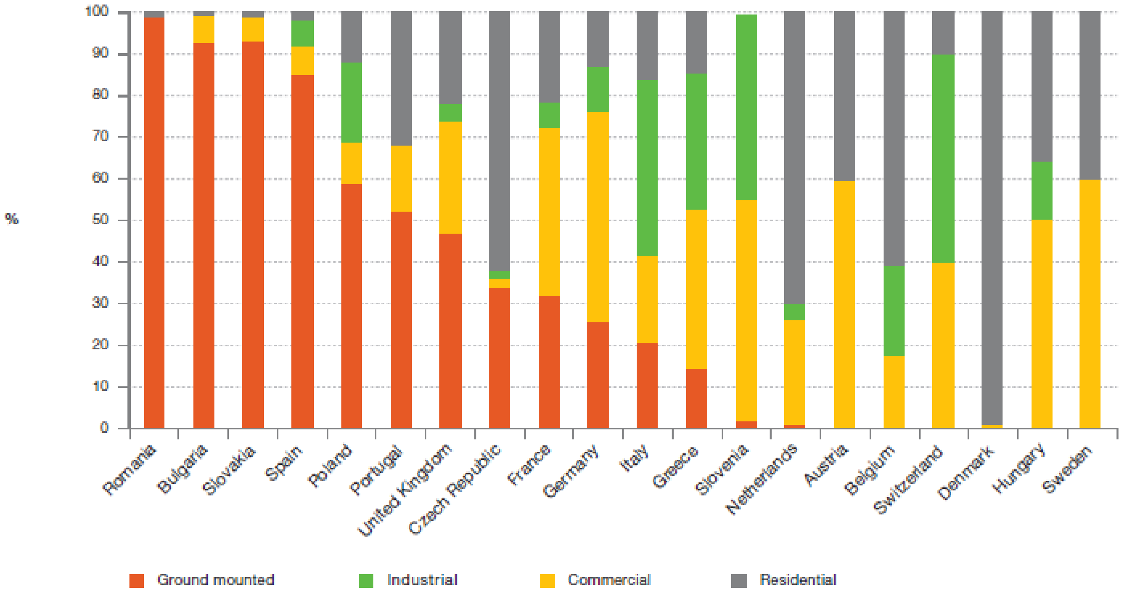


Figure 10. European PV cumulative capacity market segmentation in 2013 (22).

With regard to Portugal, it must be highlighted that the most important segment, by reaching more than 50% of the market share is ground-mounted systems. If compared with the rest of southern European countries (Spain, Greece, Italy, etc.), Portugal is the country with a larger PV share at a residential level.

Furthermore, in 2013, the 80% of the total PV installed capacity in Portugal was in the residential sector. Prosumers represented the largest market segment and the PV integration level was drove by the individual initiative. That makes the purpose of this study very interesting and timing from the Portuguese PV market perspective. With regard to the ground-mounted system, it must be said that it was insignificant and that large-scale PV farms model is still not attractable for investors in the Portuguese market.

In Figure 11, PV market segmentation in 2013 can be observed for several European countries. The German integration of PV pursuing a more balanced model is verified. On the other hand, the large-scale PV farms in Romania by means of ground-mounted systems still drives the PV sector in the country. PV deployment in Spain was more equilibrated in 2013, although ground-mounted systems were still leading segment.

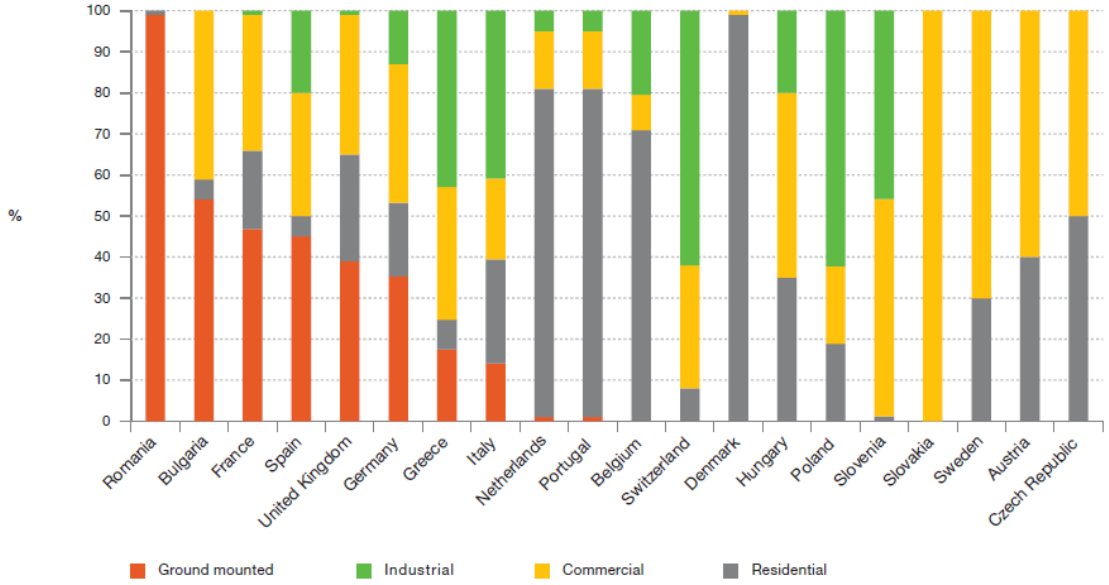


Figure 11. European PV Market Segmentation in 2013 (22).

Ultimately, the European PV market projections are very uncertain due to the changing boundary conditions. Unexpected energy policies and market responses to those policies can be determining for the future of the PV sector in Europe. Projections until 2018 show a growth tendency, although slightly slower than in the previous years. It is projected that for 2018, the total cumulative PV capacity in Europe will be around 156GW (22).

Popularity of PV will be the key for its development at a residential level. Already eight European countries are adopting support schemes for PV electricity compensation when injected to the grid. On the other hand, only one country (Spain) has adopted non-supporting measures for PV, in order to stop a massive reduction of consumption and problems in recovering grid and system costs.

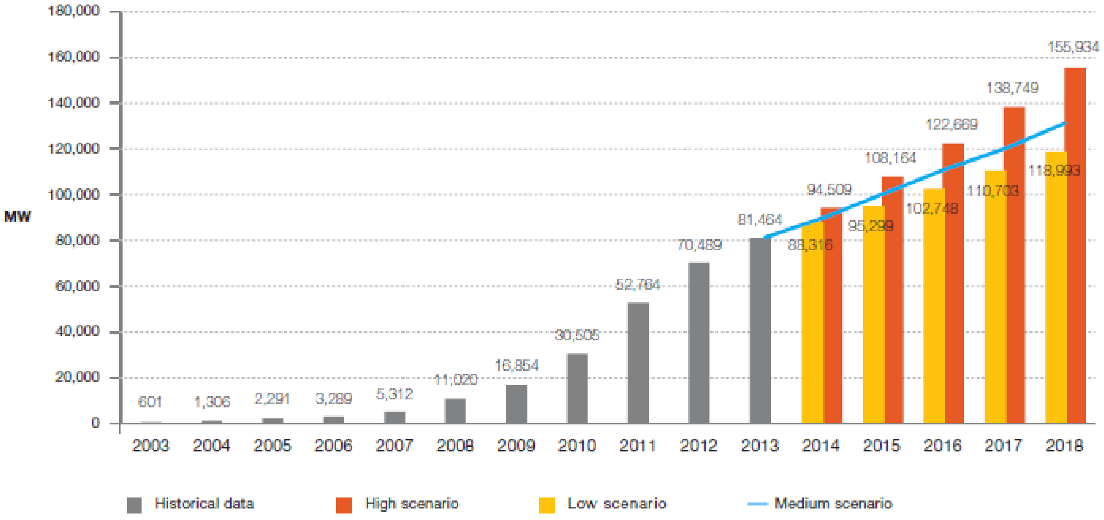


Figure 12. PV cumulative installed capacity in Europe by 2018 (22).

2.1.3. PV price development

A rapid decline on solar energy technology costs has favoured the acquisition of energy generation systems by consumers in order to start producing their own energy, as seen in the previous section. The decrease in the LCOE of solar PV has been the major driver for large investments in the sector and for bringing solar technology to large-scale production making the residential sector a potential customer.

In 1975, the price of PV Crystalline Silicon technology was around 100USD/Wp. Within approximately 10 years, there was a contraction on PV module prices of around 90%, reaching in 1986 10USD/Wp. The following years the decrease on prices was slightly less pronounced and another 90% reduction on price took around 30 more years until reaching 1USD/Wp in 2014. In 2008, CdTe Thin Film got into the market at price over 1USD/Wp and it followed a similar tendency than Crystalline Silicon technology by going down 1USD/Wp in 2014 (18). In addition, price decreases as PV cumulative installed capacity increases. Considering that PV installed capacity has increased over the years, comparing PV price evolution over time or over cumulative installed capacity is practically the same.

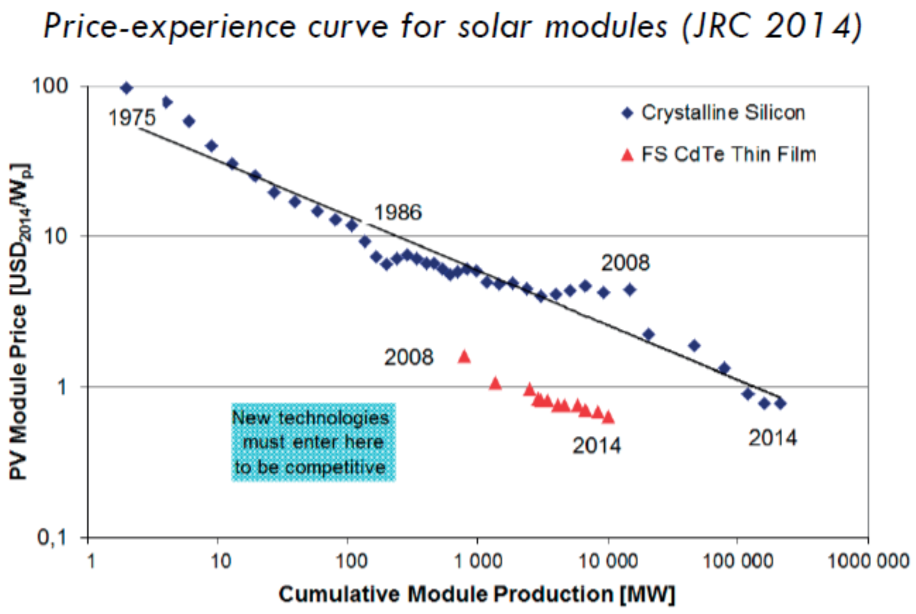


Figure 13. Price-experience curve for solar modules (18).

PV module prices have experienced a price reduction of 22% every time the market was doubled, known as a learning rate of 22% (23). Therefore, the increase in the PV competitiveness has been outstanding. However, depending on the PV panel model and purpose substantial changes in the LCOE occur. For instance, the LCOE for solar PV in rooftop residential applications goes from $180 to $265 and for commercial and industrial rooftop systems from $126 to $177. While at Utility Scale using Crystalline Silicon and Thin Film cells, LCOE is reduced until a low end of $72 and a high end of $86 (24).

If compared to wind energy, both have experienced a similar LCOE reduction and have increased their competiveness significantly. While wind decreased its LCOE 58% from 2009 to 2014, solar PV experienced a LCOE reduction of 78%.

With regard to the price structure, LCOE cost share are presented in Figure 14*Figure* . For a 3% Return on Investment (ROI) it can be seen that the most important share is O&M, followed by the PV module itself. The capital cost is around 18%. If the ROI is increased until 10%, the LCOE cost structure is modified. The capital cost becomes the most important share on the LCOE standing for a 45%, while O&M and the PV module represent lower portions both with a 16%. A higher maturity of PV technology will provide lower ROIs and lower capital costs. It can be observed that with a 3% ROI, considered as a safe investment, the LCOE is reduced around 33%.

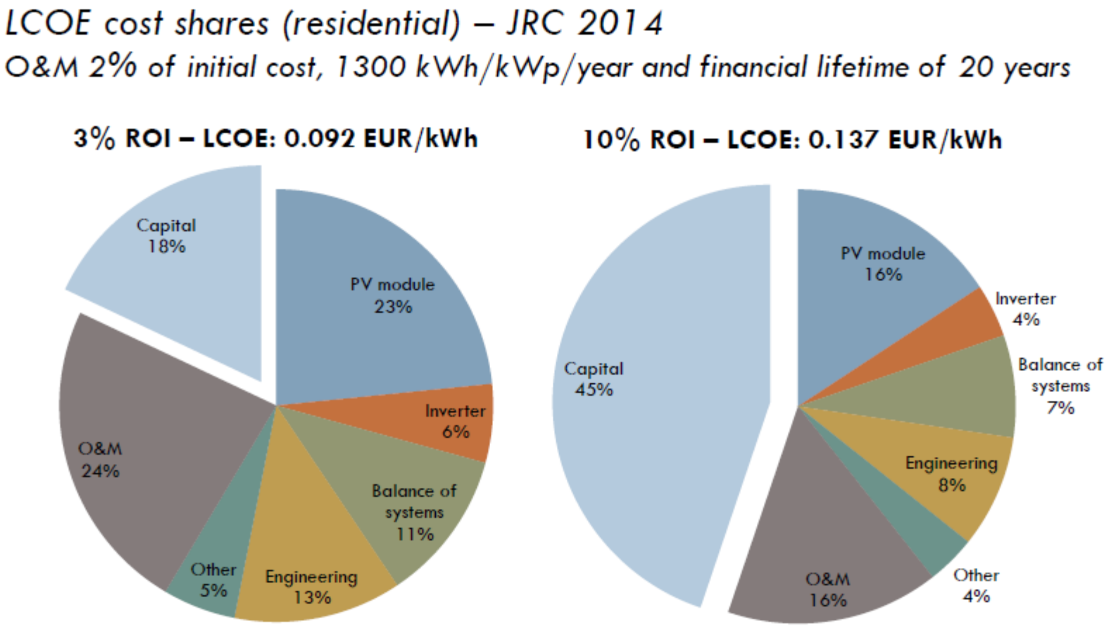


Figure 14. Residential PV LCOE cost shares (18).

2.2. Integration of PV Prosumers in Distribution Networks

The etymological meaning of Distributed Generation (DG) implies a decentralized generation scheme connected to the grid. In fact, DG consists in a decentralized deployment of small energy generation units with rather small or medium installed capacities that are connected to the distribution network. Generally, the term DG is used to refer renewable energy generation units more in particular. DG is more likely to be operated by a large number of smaller energy producers, which are also known as prosumers, although large producers are also operating DG systems. The system is taking on another scheme by transiting from a centralized generation system towards a more decentralized energy production scheme, where smaller producers are substituting large generators. PV prosumers take part on the large scale integration of DG in the distribution networks.

The EU defines briefly and in a wider perspective what DG is about. The European Directive 2003/54/EC defines as Distributed Generation ‘generation plants connected to the distribution system’. Other institutions provide several other definitions. However, this study will define DG as in the previous paragraph and it will be referred to a particular kind of DG, which are prosumers. (a definition is also provided in section 1.2.) (25). The term DG will be used to broaden the concept and not to limit the discussion to prosumers, although in this section prosumers and DG will be used indistinctively.

In DG units, energy is generated close to the loads, which could benefit the system on increasing the security of supply, providing better power quality, reducing peak load and congestion in transmission and distribution networks, reducing long distance energy transmissions, avoiding network overcapacity, deferring network investments and reducing distribution grid losses. However, DG production based on RES, like prosumers, is non-dispatchable, meaning that the energy generation cannot be controlled or planned. In addition, it is not necessarily close to the load, especially in low-demand periods with high production of energy by RES when excess of supply must be sent to feed farther loads increasing transportation losses. When energy production is left to randomness, it is said that production is under a stochastic regime. In these situations, production matching demand in real time (as energy sector requires), is a matter of luck. In that sense, two hypothetical situations must be addressed: DG not necessarily generating when the network is constrained and DG production exceeding local loads, which will require higher voltage levels (14).

In addition, distribution networks have been designed to operate the energy flow in only one direction, from large central generation to the final customer. With the integration of DG, energy flows can bi-directional.

Hence, new challenges are posed by DG, and particularly prosumers, on the distribution network and will have to be handled by DSOs and TSOs.

2.2.1. Network capacity

Distributed Generation, PV prosumers included, can certainly reduce the need to use the transmission and distribution network capacities for electricity transport over long distances. Does that implies a reduction in networks costs? To address this question, consumption peak (peak load) and production peak must be regarded. In the particular case of PV presumption, PV production peak does not match with consumption peak at a residential level. In Figure 15, PV self-generation impact on local demand is shown. As prosumers require the grid services in peak hours for their consumption, overall network costs remain the same.

Furthermore, distribution network must be designed for guaranteeing no line congestions in the network area where DG is integrated. In transmission networks it is easy to find multiple pathways in case of congestion due to its meshed scheme. On the other hand, in distribution networks, its looped and radial design, not allowing many options for the energy flow, makes it more difficult (25).

Strategic location of DG units, if flexibility in that sense is possible, will help to reduce congestions in production peak periods and will be more efficient in terms of energy supplying for near loads.

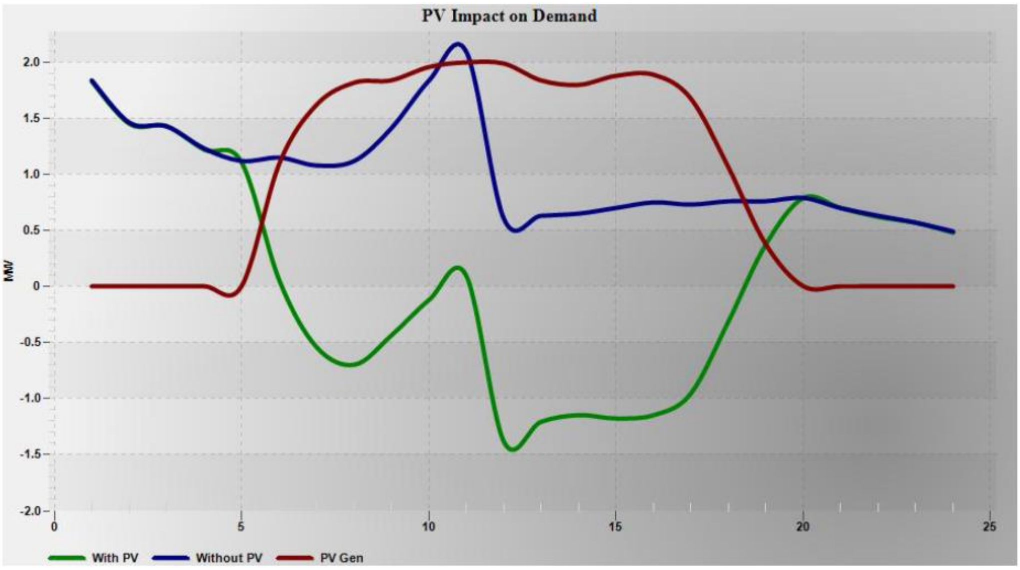


Figure 15. PV self-generation impact on local demand (26).

2.2.2. Losses

DG impact on network losses will strongly depend on the DG location and production profile. Losses are proportional to the distance the electricity goes through. Therefore, if the DG units are near the load and there is no congestion, so the electricity generated does not need to be send to some further load, losses are reduced. On the other hand, even if the load is closer to the DG generator, if there are many DG units able to assume local demand, the electricity excessing local demand will be transported to cover other loads, increasing network losses.

Bi-directional power flows can increase network losses, if they are not manged efficiently and in a smart way. In October 2005, DG-GRID, carried on one study concluding that a low DG penetration level contributed to reduce network losses, while network losses were augmented with a high DG penetration level, (25) (27).

2.2.3. Network protection

Integration of DG increases the number of short circuit currents. This can generate thermal and mechanical stress problems in some elements of the distribution network. Many protection systems must be checked when integrating DG. Overcurrent relays used for protecting the distribution line have to be checked, as well the dimensioning of the overcurrent relays protecting lines coming from the primary substation. In addition, bi-directional flow must be considered in case of fault and a proper selectivity in protection must be developed for avoiding unnecessary DG disconnections.

Other common situation is an uninterrupted DG supply to a network portion that has been unintentionally isolated to clear a fault. That could generate an uncoordinated response to the fault, as well as some difficulties in tracking it down. When a problem arises, it is easier to identify it, monitor it and solve it in a centralised system.

Network robustness is also important when considering to integrate DG, as it can cause variation in voltage levels if the network is weak (25).

2.2.4. Voltage profile and fluctuations

Distribution network voltage profiles might be affected by DG integration, increasing their levels on the connection lines. This increase depends on the power rate of the DG unit and location where it is connected. Generally, the higher the resistances near the local connection point, the higher the local voltage. Voltage control is done at distribution level, making very difficult an efficient correction over local voltage levels (25).

Furthermore, voltage fluctuations (flickers) and distortions (harmonics) can occur when integrating a DG unit using interfaces like power electronic converters (25).

2.3. PV Prosumers Market Features

The integration of prosumers into the energy grid will definitely have some consequences regarding the current market structure. These will be associated mainly with higher demand for flexible consumption and production, higher price volatility and higher balancing costs. The tariff design applied to prosumers and the chosen model to compensate the energy they inject into the grid can help to mitigate or exacerbate these problems.

The intermittent nature of prosumers, the distributed generation (wind, solar) and the possibility prosumers now have to perform profit-maximizing behaviour based on option for flexible demand and optimal use of private generation and storage capacities are the main drivers for the previous challenges (28). With regard to that new role of the customer being demand-flexible, smart-metering systems will have to take part actively in order to enhance this two-way communication.

In addition, a large-scale integration of prosumers into the market will directly affect price-time frames as known. Systems to deal with the volatility of price due to the peaks and valleys of the renewable generation will be needed. However, it is true that prosumers will also help to decrease price volatility, as they are part of the demand response. A projection of the impact that a large-scale integration of prosumers will have in the market will help to apply the right policy.

However, the current market model it is not fully shaped to fit demand response or the efficient integration of prosumers, which are economically encouraged to consume, produce and store energy and optimize their decisions when it comes to their energy utilization.

2.3.1. Tariff designs' impact on prosumers

Energy is a unique good. Supply and demand must match in real time, making the energy sector very capital intensive in terms of long-time investment for providing energy security to households, commerce and industries. It is not only the electricity that the customer ends up consuming what it costs money, but the possibility to have access to it by a deployment of reliable energy system able to provide that service. Therefore, the system's capacity plays a major role on determining costs and designing tariffs.

Network costs generally included in tariffs are given below (26):

- CAPEX
  - Incurred when investing in assets for providing the service, such as overhead lines and underground cables, substations, control centres, information and communication technologies, metering systems and other assets.
- OPEX:
  - Operations and maintenance
  - Procurement of network losses
  - Customer service (mostly fixed)
  - Overhead costs

Network tariffs design is complex. Cost allocation among several users with different consumption profiles is demanding. DG introduces even more challenges, as isolating DG costs and benefits and assigning them to different user's category is not simple at all. Accordingly to different studies, this situation ends up in DG units not paying networks tariffs or the application of tariff schemes to DG designed for load-only grids (compensation schemes) (29) (30).

Electricity tariffs are generally characterized by three elements (29) (31):

- Fixed charge (€/period), related to the connection costs and the metering of the customer's consumption.
- Capacity charge (€/kW·period), proportionate to the contracted installed power or, not very often, to a specific maximum power used over a period; covers the fixed costs of the infrastructure required for providing the system's overall capacity.
- Energy o volumetric charge (€/kWh), collected on the energy commodity consumed by each customer; covers the costs related to the variable network costs, transport and distribution of energy.

A cost reflective tariff structure will balance these three elements allowing an effective collection of revenues. Evolution of peak demand will be a key indicator for future investments and for monitoring the evolution of capacity based costs.

The main challenge within the energy sector is to recover the system's fixed costs, like network utilisation and access costs, through current tariff designs. Nowadays, most of the network tariffs within the EU-28 are mainly based on volumetric charges.

Table 1 and Table 2 show how the previous introduced elements (energy charge, fixed charge and capacity charge) are distributed in terms of percentage in distribution networks tariffs for households and small industries.

Households

	Energy Charge (%)	**Fixed + Capacity Component (%)**
0%	NL	
0-25%	ES, SE	AT, CY, CZ, FR, DE, GB, GR, HU, LU, RO
25-50%	NO	IE, IT, PL, PT, SK, SI
50-75%	IE, IT, PL, PT, SK, SI	NO
75-100%	AT, CY, CZ, FR, DE, GB, GR, HU, LU, RO	ES, SE
100%		NL

Table 1. Household distribution network tariff (26).

Small Industries

	Energy Charge (%)	**Fixed + Capacity Component (%)**
0%	NL	RO
0-25%	IT, LU, ES	CY, DE, GB, GR, SK
25-50%	AT, PL, SI	CZ, FI, FR, HU, SE
50-75%	CZ, FI, FR, HU, SE	AT, PL, SI
75-100%	CY, DE, GB, GR, SK	IT, LU, ES
100%	RO	NL

Table 2. Small Industries distribution network tariffs (26).

From Table 1 and Table 2, it is inferred that many EU member states have high volumetric percentages in the network tariff at a residential level (households). On the other hand, the situation is slightly different for small industries, as the fixed and the capacity component represent a larger share.

2.3.1.1. Volumetric share on tariff structures

Volumetric charges are dependent on the amount of electricity that the prosumer, or any consumer, buys. Therefore, increasing the weight of volumetric charges in the electricity bill will benefit prosumers, as higher retail rates increase the value of the savings achieved by the PV system and improve the return on investment. That means that for each kWh produced, the savings will be equal to the full retail rate. On the other hand, non-volumetric charges are not affected by the PV output and, therefore, are not favourable for the prosumer.

However, a further analysis must be carried on in order to know how the utility would be affected by that charge structure. A larger volumetric charges structure reduces utility revenues, increase the rates to other ratepayers and cross-subsidization could occur. A cross-subsidization situation could be dangerous for a utility, as regular consumers would pay part of the generation that the prosumers are consuming. There is a wealth transfer from the regular costumer to the prosumer, which is not a favourable situation to the prosumer because it is not sustainable.

A contradictory situation is found: at one hand, electricity transmission and distribution network costs are characterized for being extremely non-volumetric; on the other hand, network tariffs are highly volumetric in most of the EU member states, as seen in Table 1 and Table 2. When a consumer becomes a prosumer, the net electricity withdrawn from the grid is reduced, and the prosumer contributes less to grid costs.

Fixed network costs are unlikely to reduce, as PV prosumers would still need the grid at peak hours and the necessary capacity for these periods. The grid is still designed to cover peak demand, but costs are not recovered due to the reduction on consumption and the volumetric based tariffs.

When network tariffs fail to recover network costs, two scenarios may arise. First, there could be a revenue erosion if the utility assumes the unpaid network costs. That could be likely to happen if the regulator does not allow the total recovery of network costs through tariff rises. Second, regulators rise tariffs to meet network costs, being regular ratepayers the most affected due to the volumetric tariff structure. Here is where cross-subsidization comes about. Prosumers end up paying less than other customers pay if network usage by both is compared (26).

This could lead to an unstable situation in network tariffs. Paul Simshauser explains this phenomenon referring the Queensland (Australia) experience with PV prosumers integration in the network. In five years, a spiral of tariff rises followed by demand response, increased tariff network prices in 112%.

Therefore, a balance between a fairly allocation of network costs and making the customer efficient in consumption must be found. However, is clear that a more capacity-based tariff is required to ensure the system’s sustainability.

2.3.1.2. Network tariff structure designs

Network tariff structures can be designed to reflect the changes occurring in the energy market during the period the electricity is consumed. The period can be from a year (flat retail rate) to a very small time scale (real time pricing).

Different designs for network tariff structures regarding the retail price are presented (32):

- **Fixed Rate**
  Prosumers are charged a fixed rate for all the energy they produce and consume. It is a very simple method that only requires a meter. The model is known, deterministic and constant.
- **Time-of-use (ToU)**
  It is a known deterministic model that is variable in time. The price of energy is known but fluctuates based on the time the energy is prosumed. Therefore, the prosumer is encouraged to shift from high-price periods to low-price periods. However, if a large-scale change in the prosumers behaviour happens and most of them respond to this pricing scheme, there would be a drastic modification of the internal load of the system when the prices change. As the price depends on the time the energy is prosumed, a smart metering device will be required.

- **Real-time pricing (RTP)**
  The electricity price varies based on supply and demand reflecting the real cost of producing electricity. As supply and demand are uncertain, price is not known and the model is non-deterministic. However, some retailers could provide fixed prices ahead of the consumption time. Smart metering and a forecasting device will be required in order to make smart decisions on when to consume or produce. Usually, utilities give a deterministic price to the prosumers for all hours of the day, so it is not a clear reflection of the market state. It is an unknown, stochastic and variable in time model.
- **Variable Peak Price (VPP)**
  VPP is a type of ToU tariff, but the peak period prices vary on a daily basis. The VPP price is given one day ahead to the consumer. The model is known one day ahead, but before the only unknown is the VPP price.

From the tariffs described above, it is clear that a fixed tariff will mitigate cross-subsidization among customers as PV production period is charged the same as the non-production period. Prosumer savings come from PV production periods that are usually charged higher. There is a risk for the Utility on loosing prosumer customers if this tariff is applied.

The relationship between prosumers and ToU tariffs is not well defined yet, and it is contradictory depending on the study, analysis or work done on it. There is one opinion that states that ToU rates reward PV prosumers as the peak of energy production by PV technology matches the high-price periods (21). On the other hand, a recent study carried on by the National Renewable Energy Laboratory (USA) pointed out that ToU rates will improve the PV prosumers economy, but will negatively affect 20% of the households' economies (33).

With regard to RTP, it must be said that, under smart grid scenarios, the prosumer will be able to decide whether to inject or store and whether to increase or decrease the onsite load. That would be a very favourable scenario for prosumers as they could maximize their benefits by means of smart metering and could be more energy efficient. However, time-based pricing in general and RTP specially, could diminish the price peak during the day when energy is more expensive due to the fact that at that period PV output is higher. Therefore, PV compensation rates will be affected by the fact that their own PV output is crushing the wholesale price. In other words, PV output will be reducing PV economy and investment. Nevertheless, on long-term perspective, renewable larger penetration may cause peak prices to happen at less time coincident with PV output (21). From the Utility perspective, RTP may help to avoid bottlenecks or congestion by changing network conditions through demand response, although it can also be more effective on terms of consumption reduction, which would increase the cross-subsidization issue if the volumetric share on the tariff structure were important.

When compared to ToU, RTP presents the following issues: the cost of real time metering and billing, the large potential wealth transfer among customers by means of removing current cross-subsidization in ToU (arising from other issues, not fixed cost allocation) and the potential volatility of bills (34).

The first area of concern is that RTP requires the installation of sophisticated meters and a more complex billing system (34). That could be a problem for small consumers, but could attract large consumers to RTP. It may also be a problem for a non-energy-familiarized consumer, as the complexity of the bill raises and could create some fears.

The second issue would be the wealth transfer that may occur among customers due to the implementation of RTP. In ToU billing, low-quantity consumers at high-pricing periods are subsidizing larger consumers (35). RTP could remove the existing cross-subsidies to those customers consuming much more energy when wholesale prices are higher. On the other hand, under RTP, customers may reduce consumption when prices are high and increase when prices are low. This price responsiveness, which offsets the loss of consuming large quantities at high-pricing periods, could reach real time elasticities of -0.1, but it will never overcome transfers due to the lost cross-subsidy for larger consumers at high-pricing periods (35). It might be said that it is very important to mitigate the impact of wealth transfer when adopting RTP.

The third area of concern is the potential volatility of bills. The main issue is that prosumers could need to buy electricity at extremely high prices and, therefore, they would face dramatically expensive electricity bills. Fluctuations on RTP could derive in that ridiculous situation causing a fall in PV prosumers economies. However, to mitigate the impact of these unpredictable price fluctuations, hedging in advance to cover some of their energy demand could be a feasible solution (34). The opportunity for the customer to buy fixed-quantity or fixed-price contracts in advance to cover part of their demand and then pay or get the real time price for deviations from the contracted quantity could certainly reduce the bill volatility.

2.3.2. PV support schemes

Regarding the compensation models for PV prosumers, meaning the way they are economically or energetically compensated for injecting electricity to the grid, some of the most common models must be studied (36).

- **Self-Consumption - Feed-in tariff (FiT)**
  The prosumer is charged one rate for electricity consumption and is compensated with another rate for energy production. Usually, the feed-in tariff has a known constant electricity price. In this case, consumption and production may be metered independently. For instance, in Ontario (Canada), the electricity consumption of prosumers is tracked on a ToU tariff and PV output is guaranteed a higher fixed rate (32).
- **Self-consumption - Market Value**
  Market value model is a real-time compensation mechanism. Prosumers are paid the wholesale market price for the electricity injected into the grid. In Portugal, prosumers receive 90% of the wholesale market price.

- **Net Metering**

  The prosumer is charged for the net energy prosumption. Therefore, the electricity is sold to the utility at the same price that it has been bought. Those systems consist in connecting your PV system to the grid and when consuming the power that you are producing it offsets the electricity bill. Therefore, if the prosumer does not produce as much electricity as it is demanded, the grid will supply the difference and that will be reflected in the bill. The compensation the consumer receives in the excess PV generation is energetic, meaning that the meter goes backwards every time energy is produced, it is a way of storing energy. If you are a net producer, you will receive the amount of kWh in excess further on time. It is applied in long billing periods and all the kWh that must be compensated have the same price.
- **Net Billing**

  In Net Billing, the compensation the prosumer receives from the excess generated energy is done by means of monetary credits. In case the prosumer is a net user, positive costs would have to be assumed in the electricity bill. Every kWh is valorised at the price corresponding when it was imported from or exported to the grid.

When comparing Net Metering or Bill Metering with Feed-in tariffs, it must be said that Net Metering model acts like a hedging system that prevents the potential bill volatility. In addition, the prosumer only pays for the electricity that is consuming in excess. However, for net-producers, Net Metering models do not totally ensure payments due to the usually shorter periods of credit banking for the excess generation.

On the other hand, Feed-in tariffs provide a stable contract to sell the electricity the prosumer produce in excess. In these cases, price is usually indexed with inflation. Nevertheless, there is no hedging system able to offset a rapid rising of electricity prices. In addition, prosumers could buy the electricity at higher prices than what they sell to the grid. That could a create non-logic situations where the prosumer is buying electricity at a higher price that he or she is producing it, so it ends up in a losing money situation. Contrarily, they could buy cheaper than they sell, creating another non-logic scenario. On the other hand, FiT have negative consequences to energy markets that will be discussed in this study further on.

Regarding the Net Metering and Market Value tariffs comparison, it must be said that again Net Metering will provide an extra security to the consumer as it hedges part of the excess electricity generation or consumption. However, the prosumer cannot maximize its profits from the PV output as all the kWh are worth the same. In addition, the whole model will be less efficient.

By offering a lower tariff for electricity injections into the grid during certain parts of the day, prosumers will be encouraged to consume more of their electricity onsite. Price-based incentives could increase the generation and consumption in a more optimal way for the grid. In this sense, Market Value tariffs are seen as favourable for prosumers.

2.4. European PV Prosumers Regulation

As seen in Section 2.3., different support schemes can be adopted to compensate prosumers for the energy injected to the grid. The aim of this section is to screen the different schemes applied in different EU-28 member states.

In Table 3, Self-Consumption specific features for each member state are presented (37).

Self-Consumption (SC)

State	***Remuneration***	***Cost contribution***
Austria	Private Purchase Agreement (PPA)	>25MWh/y: 1.5c€/kWh on SC electricity
Croatia	PV system <300kWp: 80% FiT rate	Exempted
Cyprus	PV system<500kWp: 5MW yearly cap, no compensation.	HV: 1.31c€/kWh MV: 1.63c€/kWh LV: 2.01c€/kWh RES levy: 0.5c€/kWh Public service obligation: 0.134c€/kWh
Denmark	FiT: 0.08€/kWh	<50kW: no taxes or PSO charge >50kW: no RES surcharge
Germany	< 90% production: applicable FiT or FiP (FiT premium) rate > 90% production, either: a) average spot market price for solar energy (4-5 c€/kWh) b) income from electricity sale (market or PPA) plus management premium of 1.2 c€/kWh (decreasing to 0.7 c€/kWh in 2015) PV system>100kWp (from 2016): market price	Before 01/08/2014 : exempted After 01/08/2014 : exempted if < 10 kWp and < 10 MWh/year If >10 kWp or > 10 MWh/y : subject to reduced RES-surcharge: 30% by end 2015 35% by end 2016: 40% by end 2017
Finland	PPA	<100kVA or 800MWh: exempted from electricity tax, transfer fee and VAT. Fixed part of the grid charge applies.
France	No specific policy still applied (under discussion)	
Italy	<20MWe: PPA	<20kW: exempted 20-200kW: partially exempted >200kW: system cost exemption
Latvia	Still to be adopted	
Malta	PPA	Exempted
Portugal	90% average MIBEL price	System capacity <1% total power capacity (TPC): exempted. >1% and <3%: 30% grid fees >3% 50% grid fees
Spain	<100kWp: regulation still to be adopted	
Slovakia	Household with voltage level <0.4/0.23kV, connection capacity <16A: no compensation for excess power.	Still to be adopted
UK	<50kWp: generation tariff + export premium: 4.77 £/kWh for up to 50% excess power. >50kWp and <5MWp: FiT	Exempted

Table 3. Self-Consumption EU Member States specific features (37).

In Table 4, Net-Metering different adopted schemes in EU member states are presented. Requirements for being elected, period of netting, compensation in energy terms and capacity cap are given as specific features.

Net-Metering

State	***Requirements***	***Period***	***Compensation***	***Capacity Cap***
Belgium	+/- 12kWp for PV systems with <10kVA connections (5kVA in Brussels)	Annually	All PV owners	N/A
Cyprus	Household and municipal PV systems <3kW	Annually	Retail price 900€/kW for vulnerable consumers	10MW/year
Denmark	Non-commercial PV systems <6kW	Hourly	Retail price	N/A
Greece	PV systems <20kWp	Annually	Retail price	N/A
Italy	Until 2015, PV systems <200kW From 2015, PV systems <500kW	Annually	Net-Billing based on ToU	N/A
Hungary	Household and commercial PV systems <50kW, connection size <3x63A	Negotiated with DSO	Retail price, free from system charges	N/A
Latvia	Household PV systems <11kW, with installation <400V and <16A per connection	Annually	Retail price	N/A
Netherlands	Connection size <3x80A	Annually	Retail price	N/A
Poland	PV systems <40kW	Every 6 months	<10kW: FiT (15 years): ~ 0.18€/kWh for below 3 kW, 0.11€/kWh for below 10 kW. >10kW and < 40 kW: 100% of the average sales price of electric energy on the competitive market in the preceding quarter	300MW for systems <3kW 500MW for systems <10kW
Sweden	PV systems connection size <100A	Annually	Tax reduction: 0,60 SEK (~6 c€) per kWh of PV reduction, but at least an equal amount of electricity should be bought from the grid. Tax reduction for delivery up to 30 MWh/y	Up to 30000kWh or 18000 SEK/year

Table 4. Net-Metering EU Member States specific features (37).

3. The need for new Energy Markets

Energy Markets are not regular markets. It has been previously pointed out the uniqueness of energy as a good. Supply must match demand instantly. That statement implies that either supply or demand must be flexible to match the other. So far, flexibility has been reached in the supply side by using fossil fuels or nuclear energy. Hydropower will depend on long term weather conditions and renewable energy sources, like wind or solar energy, will depend on short term weather conditions. Therefore, based on energy forecast and on demand intraday tendencies, supply load will be varied by adding or subtracting more or less units of energy, which means by burning more or less fossil fuels or by using more or less uranium. In case the demand is higher, more fuel should be used, which is not possible when it comes to RES like wind or solar as the wind speed or the solar irradiance at the peak demand period cannot be modified. This flexibility in the production of an extra unit of energy requires an investment and a fair revenue to the energy supplied and the security provided.

When energy markets were liberalized, the continuous supply to customers in a multi-supplier environment, having to determine a share for each one became more demanding. Energy markets were designed based on this previous concept: marginal cost (MC) as the main driver, defining the cost of producing an extra unit of electricity. When using conventional energy sources, MC can be associated with the fuel used.

However, when it comes to RES, MC lose its meaning as wind and solar energy, for instance, cannot be charged.

However, flexibility could also be reached from the demand side. An empowered customer having a more active role in the energy market could be a key factor in that sense. Making the customer more aware of its consumption patterns, being able to take smart and informed decisions on when and how much to consume, will help to increase flexibility in the demand side. The transition to a RES based energy system could rely on the customer as an active part of the system itself.

In this section, current issues in energy markets, the impact of RES support models and the new role of a more empowered customer are discussed.

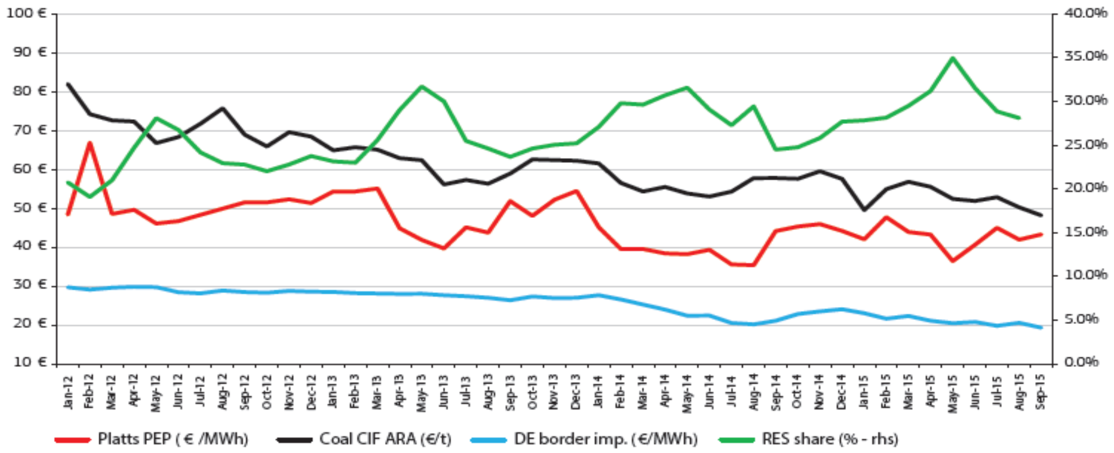
3.1. Current issues in European Energy Markets

Electricity markets have been designed taking into account the technology used in the XX century. As mentioned, electricity prices are determined by marginal cost and are largely expressed in kWh. Usually, energy markets are compared to mobile and internet markets where there are very few suppliers charging by GB or minute, which would be the MC in the energy case, and most of them offer flat rate tariffs.

New technologies brought to the market are not based on MC to recover their costs as they are using wind or sun, which are free of charge. Therefore, when energy is produced by RES, MC is zero. That fact can generate some distortions in the current market structures, specifically regarding the electricity price. Technologies with MC equals to zero push the supply curve to the right and cause a decrease in the wholesale market price. This and other main issues in European Energy Markets are briefly described below. A more detailed explanation will be given in Section 3.2 along with the impact of RES (particularly PV) in the energy markets.

Wholesale prices decrease

Generally, wholesale electricity price have been in a constant fall for the past years (38). In Europe, some markets have been more affected than others have, although the general tendency has shown a slight decrease since 2012, as it can be seen in Figure 16.

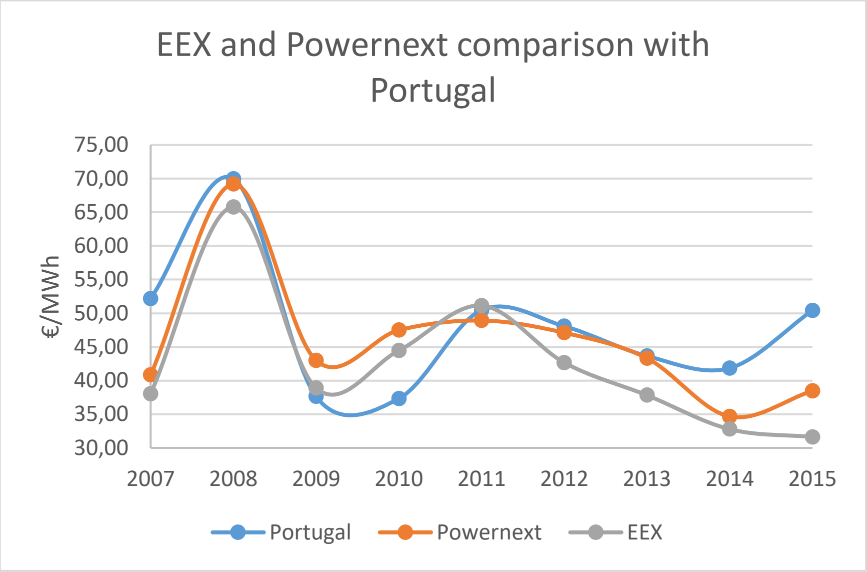


Platts PEP: Pan European Power Index (in €/MWh)
Coal CIF ARA: Principal coal import price benchmark in North Western Europe (in €/Mt)
DE border imp. stands for long term contract based import natural gas price on the German border (in €/MWh)
RES (renewables) includes hydro, wind, solar and biomass; RES share in the total power generation estimation for the EU-28 as a whole (right hand scale)

Figure 16. Evolution of wholesale power price in Europe compared to coal and gas prices and share of RES (39).

The average price for wholesale electricity between 2012 and autumn 2015 has experienced a slight decrease moving from 50€/MWh to around 40€/MWh. Probably, the average price for all the European Energy Market it may not be very accurate, as in some markets the price has declined significantly and in others the shrinkage has not been that drastic. For instance, EEX (energy market where Germany takes part) has seen a decrease in the electricity price from 60.68€/MWh in 3rd April 2011 to 20.85€/MWh in 16th February 2016 (40).

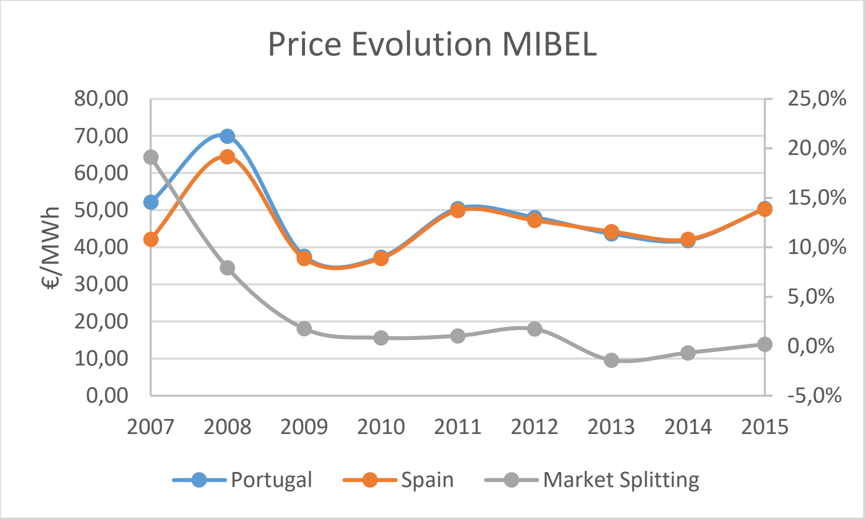
On the other hand, MIBEL (Mercado Ibérico de Electricidad) has been more volatile and the decrease has not been that significant as it can be seen in Graph 9 [Source: EDP]. There was a slight decrease, from 52.17€/MWh in 2007 to 50.43 in 2015, regarding the Portuguese price after considering the market splitting. In 2016, that decrease has been more significant and for the first four months of the year the price has gone from 36.4€/MWh in January to 22.5€/MWh in April. When comparing the Portuguese market with EEX or Powernext, it must be highlighted that Portuguese electricity price has been always above the EEX and Powernext prices except for the recession years, when electricity prices in Portugal were drastically reduced. In Graph 8 [Source: EDP], differences on EEX, Powernext and Portuguese can be observed. However, many factors determine the electricity price and it would not be accurate to point at RES integration as the only responsible element.



Graph 8. EEX and Powernext price comparison with Portugal.

It is a fact that RES integration in the market reduces the wholesale electricity price, although it cannot be determined how important that impact is. Certainly, if technologies are producing electricity and the marginal cost is zero the wholesale price in the spot market will be reduced. On the other hand, significant changes in the demand side can also be dominant. A clear example of that situation would be the significant decrease on electricity prices in MIBEL during the economic and financial crisis that led to a recession and a subsequent slow growth in the economy activity. As seen in Graph 9 [Source: EDP], the impact of the economic crisis sunk electricity prices, from 69.98€/MWh in 2008 to 37.63€/MWh in 2009 in Portugal.

Low or negative electricity (not possible in MIBEL as there is a floor at 0) prices would mean that there is an excess in the supply side and that further investment on energy facilities is not presumably required, when it actually is. The issue is that conventional power plants are still required for providing flexibility and balance the system, and RES power plants are needed for fastening the energy transition. Market fails to give a proper response in that sense. However, low prices could also mean that it has been a rainy and windy year, although that can change from one year to another, so market spot price is not a precise investment indicator itself.



Graph 9. Price Evolution MIBEL 2007-2015.

Wholesale and retail price mismatch

In addition, as it has been said in previous sections, system's existing infrastructure is the main driver for determining its costs. In a time of decreasing prices, investment in conventional power plants to ensure the capacity required has increased the system costs, as well as the RES deployment. Total system cost is driven by fixed costs, while retail price is dominated by a variable structure.

Furthermore, indirect taxes and levies in the electricity bill equalled in 2014 the energy part. According to EURELECTRIC, since 2008, taxes and levies have augmented in 48% and the energy part has diminished in 6% (41), as it can be observed in Figure 17.

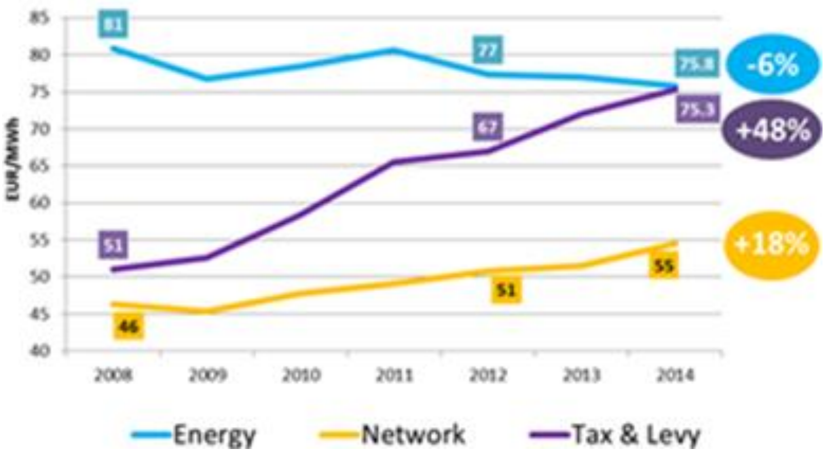


Figure 17. Electricity bill price components (41).

Projections show prices still to grow as system fixed costs will not be reduced and demand is decreasing. Estimations point out that the recovery of system costs from end consumers will rise about 24% by 2030, around €340 billion per year for the EU-28. CAPEX will represent 57% of the full cost of the system in 2030, spending almost 50% of it in RES deployment (41).

The increase in fixed costs and a larger deployment of DG, including households and business, threats the fair recovery of fixed costs and puts the most vulnerable consumers in a loss of wealth situation, also known as “consumer divide”. The consumers not able to invest in self-consumption systems will assume the fixed costs in the form of volumetric charges of the customers that are reducing consumption and are avoiding to them.

Inefficient investment signs and operational behaviour

A consequence of the two problems discussed above is that there are no efficient signs for operation or investment in the current energy market. Low prices, or even negative in other European energy markets, show that there is an excess of supply and discourages investment for new capacity, when, in fact, it is still required.

In addition, incentives for investment in demand reduction appliances are strongly encouraged, but there are no incentives on flexibility on the demand side and rising prices in electricity are favouring fuel substitution in particular energy applications. No signals on demand-side pricing do not encourage shifting consumption from one time frame to another. In times when demand response is in the core of the energy transition, energy markets are failing to provide real signs for that purpose.

3.2. PV Support Models Impact

There is no doubt on the efficiency of PV support schemes to boost the PV market. Different PV support schemes have been explained in section 2 and have been briefly discussed from the prosumer perspective. In this section, consequences of the most applied schemes (feed-in tariffs and net-metering) are discussed.

Feed-in Tariff (FiT)

Some particular problems caused by FiTs can also be extended to other Solar PV support schemes. FiT ensures a periodic payment independent of the market revenue for the supported plants or systems distorting market signals when integrated in market together with plants not receiving this support. FiT supported plants reduce prices and blur the link between wholesale and retail energy price.

In addition, FiT provide inefficient signs for investment as they do not ensure the minimum-cost solution for the energy system by deploying not the most effective long-term mix of plants and demand-side resources (38). However, FiT can be competitive if decided by auction and will provide stability to the investors ensuring the sustainability of the investment.

FiT support schemes do not wipe out cross-subsidization among customers and neither they help in providing a real fair value for solar energy. Definitely, FiT schemes are very effective in attracting investors, although the market impact makes FiT not the best support scheme to apply in some situations and depending on the goal to achieve.

Net-metering (NM)

As it was explained in previous sections, net-metering is a compensation system for RES, particularly PV, which remunerates DG owners in energy terms when they inject electricity to the grid. NM equals the price for each kWh consumed or produced disregarding the time frame.

Solar PV is non-dispatchable and, therefore, its value depends on the time when it is produced and its capacity is marginal depending on weather conditions (42). Hence, the time when it is produced is a key factor for providing efficient incentives for determining its productivity and supply reliability, which will determine its real value for investment. Net-metering distorts the value of solar DG by subsidizing it inefficiently and misrepresents solar PV real value in the market.

In addition, NM freezes flexibility on the demand side and provides no sign for energy efficiency, as all the kWh are equally valued.

As a conclusion, NM is not an efficient scheme to support Solar PV integration in the energy market, as it creates cross-subsidization deteriorating financial position of less affluent customers and distorting signs for energy efficiency and real value of generated solar energy

After analysing, the most applied PV support schemes some conclusions could be withdraw. Brown, A. and Bunyan, J. discuss in (42) the main issues of supporting Solar PV distributed generation with net-metering models. They come to the conclusion that support schemes applied for PV depending on the goal to achieve and other factors like the implementation methodology (for instance, by auction) can bring the following negative consequences (42):

- Produce cross-subsidization among customers, creating wealth transfers from less affluent customers to more affluent customers, as PV panel owners avoid paying a fair share of system’s fixed costs.
- Distort the efficiency of small-scale solar PV in comparison with other RES, unfairly benefiting it economically.
- Negatively impact the energy sector competitiveness.
- Fail to reflect the price of solar and its supply reliability, by not considering different values for solar depending on the generation time frame (particularly for NM). Consequently, distorts price signals for energy efficiency.

3.3. Empowered customers as a new market driver

Renewable energy explosion in the energy market has brought a new feature: a more active customer consuming energy in a smart way based on informed decisions. Technological shift towards a more energy efficiency and self-consumption perspective has allowed the empowerment of customers able now to control their consumption and, in some cases, even production. Outstanding step-up of mobile technologies and smart meters into the energy scene is settling the basis for a totally informed consumer on his consumption patterns able to modify them and be flexible. It is estimated that around 72% of energy customers in 17 Member States will be using smart meters by 2020 (41).

This new scenario will allow a better integration and proliferation of prosumers in the energy system. As explained in Chapter 1 and 2, integration of prosumers in the system can have many good consequences, but a few cons that must be mitigated, like for instance cross-subsidization. The prosumer fits perfectly in this new profile of a more empowered customer. Therefore, a brief explanation of the new features of this type of consumer are given in this section.

A more empowered customer will allow higher flexibility on the demand side that could help to compensate the growing supply inflexibility due to RES integration. There are different approaches when it comes to tariff designs to match non-dispatchable generation with flexible demand and the other way around. In February 2016, EURELECTRIC proposed two possible tariff structures that could help to mitigate the problem (41).

The first approach would include a fixed rate based on contracted capacity valuing flexibility in demand to be supplied by RES. According to EURELECTRIC, increasing the tariff capacity share would keep moderate the demand and would provide incentives for greater consumption when more renewable energy is produced. Favouring flexible demand to be served by non-dispatchable generation would also encourage customers to get energy smart management equipment. This would probably bring costs down and offer a lower retail price.

Secondly, under low-production conditions for renewable technologies, promote dynamic rates to serve non-flexible demand with dispatchable technologies. Contrarily to the first approach, this structure would rise retail prices.

Ultimately, a transition to an energy system based mainly on RES would need in its core an empowered customer able to be demand flexible to ensure efficient utilization of non-dispatchable energy generation. For that purpose, providing real price signs for RES generated energy would be key if a change on customer behaviour is pursued.

3.4. Alternative Market Models

Problems discussed in sections above spin around one main issue that is the mismatch in conventional market design and performance of new technologies. New RES technologies are non-dispatchable generation, while the current market model is based on flexible production. In this section, an overview of the most accepted suggested solutions for this particular issue and other problems within energy markets are presented, taking as reference the document from the Oxford Institute for Energy Studies where some alternate energy market model are proposed (38).

First, it has been demonstrated the inconvenience of subsidizing RES with compensation support schemes that distort prices, signals for investment and prevent changes towards a more flexible demand side. Therefore, the first alternative would be to drop the support for RES and low carbon technologies that are distorting the market. However, this straightforward measure would probably prevent reaching EU targets in carbon reduction and RES deployment. Although some RES technologies have reached LCOE lower than the energy price, which is known as achieving ‘gird-parity’ (38), it would be unlikely for them to remain self-sustained and survive only based in market revenue. On the other hand, one other possible solution would be substitute current support models to less distorting tools like economic instrument such as high carbon taxes, cap-and-trade limits and carbon intensity targets (38).

Second, introduce capacity mechanism and shift towards a more balanced market, focusing on the reliability of the system to provide energy. However, this alternative only solves one issue of many occurring in energy markets.

Third, introduce a more flat rate or demand-related elements into the pricing structure. Energy system is becoming more capital intensive and so reflects the cost structure. On the other hand, costs recovery still undergoes mainly through volumetric pricing, failing to reflect the system’s cost composition. In that sense, addressing fixed costs recovery through more demand-related elements into pricing could be a possible alternative. Cost recovery through kWh pricing fails to reflect cost structure and kW pricing could provide a more realistic price structure. Action should be addressed in two main areas: end of supply chain and the consumer side. With regard to supply end, revenue support (FiTs and other support models) could be substituted by investment capital support. The idea underlying in this alternative is that plants should be efficient and financially feasible when operating under regular market conditions and only before operating could receive government support to overcome possible market barriers. On the other hand, regarding the consumer side, a more capacity based tariff would help to recover system’s fixed costs. In addition, and particularly regarding prosumers, a more capacity based tariff could avoid fixed costs sharing issues arising among customers, like the consumer divide, and could erase unfair wealth transfers. However, some studies on this matter warn that this could aggravate problems of vulnerable consumers, reduce incentives for consumption efficiency and will not erase market distortions on the supply side.

Fourth, to address stable cost recovery, shift to a more transactive pricing unbundling the market for energy generation and electricity transmission or distribution, taking the liberalisation of energy market until its full extend. Two primary products, electricity and transmission capacity, would be traded between producers, consumers and prosumers either separately or together, leading to a decentralised energy market based on forward and spot transactions for these two products. The main advantage would be that consumer would be involved in the investment decision-making, rather than just passing on large fixed cost charges and the fixed costs would be easy to recover. On the other hand, demand-side would become more complex, as it requires a fully informed consumer and a proper technological equipment. It is also very likely that long-term contract arise giving few space left for new investment on the supply side. In addition, this measure does not totally avoids distortions caused by subsiding discrimination on only low carbon technologies. Ultimately, this alternative would benefit more affluent customers or parts involved, as they would have a stronger position in the decentralized market and could exacerbate less affluent customer’s energy issues.

Fifth, centralise planning decisions and control of the system would bring together operation and investment decisions allowing a more efficient coordination and lowering transaction costs. This approach could avoid some inefficiencies in the investment stage. On the other hand, this model increases substantially the pressure on the political authority in charge of the decisions and, consequently, rises risk in decision-making, leading to an inefficient operation.

Sixth, consolidate two separate markets: a long-term investment market and a short-term market for energy. This solution would accept that short-term markets do not include main cost drivers for the system and that the price in these markets fails to reflect the real cost structure. On the other hand, customer's involvement in the investment market would be highly restricted to those with sufficient information and capacity to commit with long-term contracts. In addition, this system opposes liberalisation core element, as it reduces the importance of short-term markets in the energy competition.

Seventh, and ultimately, the two market solution has become a trendy choice for substituting current market models. This alternative market model is composed by two markets based on the energy availability. There would be one 'as available' market that would supply energy at lower prices at times when enough supply was provided to the market. The other would be 'on demand', available at all times but at a higher price. This solution hives off non-dispatchable technologies from the current market and creates a two-side market based on different technology flexibility degrees. In recent studies carried by experts in the matter, two-side market is considered as the best solution for a market in transition as it erases subsidies distortions in a global market, provides signals for operation and investment, incentivises demand-response and optimises the system (38).

4. Quantifying cross-subsidies from consumers to prosumers in the Portuguese Energy Market

Cross-subsidies in the energy sector is one of the most currently discussed issues in the industry. Integration of RES has arisen the controversy of cross-subsidization and, nowadays, there is an important discussion on that topic involving industry experts, utilities and prosumers. Identifying and calculating cross-subsidies coming from the integration of prosumers in the system will be the main goal of this section. Therefore, a definition of cross-subsidization, an overview of different methodologies on how to approach cross-subsidies and calculations and results obtained from EDP data will be provided.

4.1. Previous studies and analyses

Paul Simshauser proves in *'Distribution network prices and solar PV: Resolving rate instability and wealth transfers'* (43) that solar households use slightly less peak capacity than non-solar houses and, therefore, cross-subsidies are rapidly arising. Simshauser approaches the prosumers cross-subsidization issue by applying different tariffs structures from more variable to a more fixed cost based composition revealing cross-subsidies by comparing them. Hence, he defines four customer profiles, two with PV and two without, and then applies different tariffs rates and compares the values with the other profiles showing cross-subsidization among them. Simshauser concludes that demand-peak capacity drives the network costs, which generates cross-subsidies if prosumers reduce consumption in non-peak hours and that different tariff structures more fixed costs based could remove wealth transfers among customers.

In November 2015, Picciariello, A. et al., presented in *'Electricity distribution tariffs and distributed generation: Quantifying cross-subsidies from consumers to prosumers'* (29) a Reference Network Model to analyse the effect of different tariff structures on the magnitude of cross-subsidies from consumers to prosumers in twelve simulations on different networks in the USA with eight different PV penetration levels. Picciariello, A. et al., developed an algorithm to quantify the estimated amount of money transferring from regular customers to prosumers. They concluded that the more volumetric the tariff and the more support schemes applied, the more cross-subsidies grow.

Gilbraith, N. et al., quantified the Net Present Value (NPV) for PV panel owners, regular customers and the overall customers when a PV panel is integrated in the grid in *'Evaluating how Demand Side Resources Affect the Environmental and Economic Performance of Energy Systems'* (9). They first calculate the present value of the cost of installing and operating a distributed solar PV array, the present value of the avoided grid electricity purchases and the present value of the cost of grid electricity that solar PV displaces. Then NPV is calculated for every stakeholder. The work's conclusions are presented below:

- Solar PV is net present value positive for the average Portuguese electricity ratepayer that owns a solar array

- Distributed solar PV generation has a higher cost than using the grid to produce and deliver a marginal unit of electricity during periods that solar PV arrays generate electricity
- Ratepayers as a whole pay 900-2600€ more in total costs for each kilowatt of distributed solar PV capacity that panel owners install; the 500 W solar array increases total system costs by 1600€.
- Panel owners also avoid paying sunk grid costs, such as revenue guarantees to other renewable generators and the costs of grid infrastructure.
- Non-panel owners will pay an additional 1600€ in bills (total across all non-panel owners) for each 500W array that panel owners install. This is equivalent to a 140€/MWh subsidy to panel owners, which is larger than the subsidy that many other Portuguese generators receive but smaller than the subsidy for existing solar PV arrays.

These three studies served for settling the basis for the calculations in this work.

4.2. Cross-subsidies in the energy sector

In economic terms, cross-subsidization refers to a situation where some customers are paying relatively less for some goods at the expense of other customers that are paying relatively more. This situation is generated when there are different outputs/products/services sharing common costs. The allocation of costs to the different outputs/products/services could unfairly reflect the real contribution of each output to the common costs (16).

Regarding the energy sector, cross-subsidies arise when a customer segment able to be identified by particular characteristics (large energy consumer or small consumer, PV panel owner or non-PV panel owner, etc.) is subsidizing another. The cost allocation to customer segments that have not directly caused those costs is the origin for cross-subsidies to arise. From that embryonic definition on cross-subsides, it can be inferred that different causes for unfair cost allocation generate different types of cross-subsidies. One of the main causes is the integration of prosumers to the grid. The fact that customers consume the energy they produce, consequently reducing their consumption and, in some cases, injecting the excess into the grid, is the starting point for defining what kind of cross-subsidies are going to be considered.

However, integration of PV at a residential level in the grid is the common denominator for several sub-causes:

- First, cross-subsidies arising due to the fact that system's fixed costs are not being recovered when PV panel owners reduce the electricity consumption because they are mostly recovered through the tariff volumetric part. This second cause will be the main subject of study and, from now on, the term cross-subsidies will be used to refer this particular kind of cross-subsidization.
- Second, if prosumers do not pay the fair share of their distribution costs and their costs of service when injecting energy in the grid, those would be allocated to other non-solar customers or be absorbed by the utility depending on the regulator. Hence, non-solar

customers will be subsidizing the services that prosumers are enjoying from the system. This type of cross-subsidization only occurs if prosumers are injecting energy into the grid. In this study, this sub-cause will be considered in the system loss of welfare calculation, which will be presented in the following section.

- Third, relying on solar energy in the day-ahead market or not doing so, will generate another type of cross-subsidization among the utility customers. If the utility counts on the availability of solar for making day-ahead purchases and, due to the natural intermittence of this source, solar energy is not available when required, the utility will have to replace this energy in the spot market at the marginal cost price, which is higher than the solar marginal price. Those extra costs will be passed on all customers and not only to the cost-causers, in this case, the DG customers using PV panels. On the other hand, if the utility decides not to rely on solar energy and hedges against it, the cost of hedging is likewise passed on all customers (42). This situation is more likely to occur to commercial PV energy generation than to prosumers, although in some regions where prosumers are injecting energy into the grid in substantial amounts this phenomenon could also happen. In this work, this sub-cause will not be considered.

4.2.1. Definition

In order to quantify cross-subsidies, a proper and more extended definition of what cross-subsidies are needs to be provided. However, it is difficult to define them because it is hard to measure them (16). The methodology used will play then a major role when determining cross-subsidies.

As it has been previously mentioned, tariffs for small and medium customers like households are composed by a large variable part and a smaller fixed part (44). When a prosumer is integrated into the grid, consumption during solar peak-hours production is reduced, due to the solar output self-consumed. However, the system still needs to provide a response to demand in peak-hours, when solar energy is not being produced. The main issue is that solar output curve may not match demand curve for most of the clients, as shown in Figure 18. In addition, no incentives are provided to increase flexibility on the demand side, as mentioned in section 3. Therefore, system's costs are not decreasing because the system requires enough capacity to cover the demand's peak, but revenue is decreasing due to the combination of prosumer's consumption reduction and the large tariff volumetric part.

In that sense, current tariff structures with a large variable part are, in fact, variabilizing fixed costs, meaning that are including fixed cost in the variable part. If fixed costs are not recovered, they will be absorbed by the utility or passed on non-solar customers depending on the regulator. Regular customers would be absorbing fixed costs that were previously paid by the current prosumers (before they installed the PV panel), and cross-subsidization occurs. The mismatch between costs and revenues structure in the Portuguese energy sector is reflected in Graph 10 [Source: EDP].

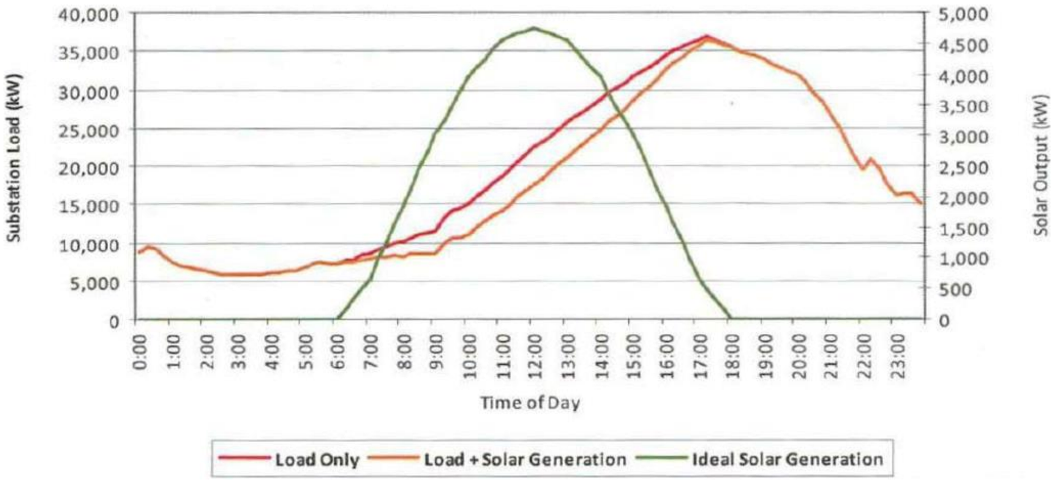
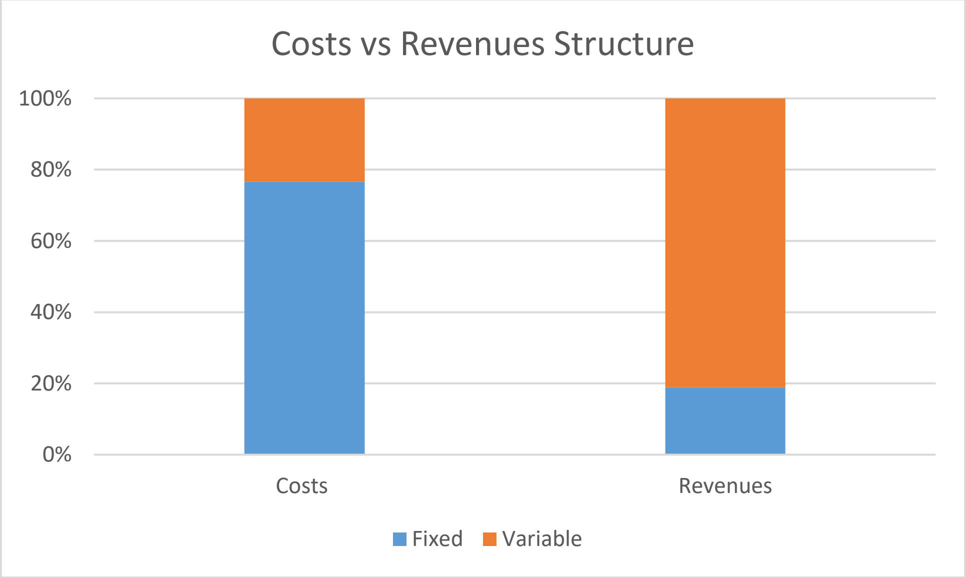


Figure 18. Solar output and demand curve mismatch (45).



Graph 10. Costs vs Revenues Structure in the Portuguese Energy Sector.

According to this work's projections, and taking into account that the electricity demand in Portugal for 2015 was around $45 \cdot 10^6$ MWh and that the current average electricity price is 191.84€/MWh, a demand contraction of 1% would cause a revenue fall of around 85M€. If compared to the data provided in Graph 5, it can be observed that electricity consumption in Portugal served by PV technology represented 1%. In addition, in Figure 11 is shown that the residential PV market segment in Portugal represented in 2013 around 80%. It would not be precise to extract conclusions from this pile of data, although it can provide some insights on how PV prosumers can deteriorate the revenue structure.

In that sense, it must be highlighted that many other factors could cause a demand fall, not only a contraction in consumption due to PV electricity generation. Other factors could decrease demand, such as a GDP reduction or energy efficiency measures.

As a conclusion, and given the fact that most of fixed costs are recovered through the tariff volumetric part, cross-subsidies will be the percentage of fixed costs variabilized in the retail tariff multiplied by the reduction on consumption of the prosumer.

4.2.2. Methodology: PV production as a demand reduction to determine cross-subsidies

This method will approach cross-subsidization from its pure definition perspective according to this work. Cross-subsidies will appear when avoiding fixed costs payments included in the tariff variable component, which has been reduced due to the PV self-consumption. Other wealth transfers will come as a system loss of welfare and will be computed further on.

First, reduction on consumption must be identified. In that sense, two situations are considered: if demand (D) is larger than PV production (P) [1] or if it is smaller [2].

$$if\ D - P \geq 0 \rightarrow \boldsymbol{P} \qquad [1]$$

$$if\ D - P < 0 \rightarrow \boldsymbol{D} \qquad [2]$$

In [2], excess PV energy injected in the grid is not considered, as it will be very difficult to isolate cross-subsidies only arising from the fixed costs payment avoidance. Therefore, costs associated to the distribution network, access tariffs, etc. related to the energy injected will be disregarded, as well as the compensation for the energy injected into the grid. This methodology will be a favourable approximation to the issue, as not all kinds of cross-subsidies are considered. Therefore, it can be said that, in this method, PV energy installed at a household level could be considered as a pure energy efficiency measure.

For the first case, if demand is larger than production, cross-subsidization will be given by [3]. PV production will depend on the year global irradiation, so the average value on a defined period must be used. In this work, two daily radiation profiles per 15 minutes have been considered, one obtained for the month of February and the other for July, both of them in the city of Lisbon. The one obtained for February will be used for all the winter period, from October to March, and the same will occur with the July profile and will be used for the summer period.

$$Cross - Subsidies = PV\ production\ (kWh) \cdot Tariff \left(\frac{€}{kWh}\right) \cdot \%Fixed\ Costs\ Variablized \qquad [3]$$

For the second case, when demand is less than PV production, only the energy demand must be considered. However, to quantify the exact amount of energy reduced, a 15 minutes discrete analysis comparing demand and production in each period must be developed. It can happen that PV production is concentrated in specific periods, eventually not reducing demand further on that period. Cross-subsidies in this scenario are given by [4].

$$Cross - Subsidies = EnergyDemand\ (kWh) \cdot Tariff \left(\frac{€}{kWh}\right) \cdot \%Fixed\ Costs\ Variabilized \qquad [4]$$

4.2.3. Data and Assumptions

In this methodology, four variables must be defined: demand, PV production, tariff volumetric part and the percentage of fixed costs variabilized in the volumetric part. Data discretized in 15 minutes periods is required to analyse dynamics occurring either when PV production is higher than demand and vice-versa.

Demand profiles

Demand profiles were generated using a new method to create low-voltage synthetic load profiles designed by J. A.C Machado, P. M. S. Carvalho and L. A. F. M Ferreira in (46). Load profile simulation can be adapted to different consumer profiles. This method establishes a discrete-time nonstationary Markov process that realistically reproduces high-resolution daily load volatility and time-dependency based on AMI (Advanced Metering Infrastructure) data and specific aggregate load data. For the purpose of this study, 200 daily demand profiles were generated in 15 minutes intervals for an average day of February. This study will assume that consumption profiles remain invariable along the year.

PV Production

First, radiation values have been obtained in the Institute for Energy of the Joint Research Centre for the European Commission (47). The inclination angle considered for the panel is 35º facing south, and the radiation is calculated in this conditions (G_{eff}). Solar Daily Radiation for all days in winter (from October to March, using data from February) remains constant and the same happens for the summer period (from April to September, using data from July). Hence, only two radiation profiles are considered.

The efficiency (η) of the panel is assumed 15% and its degradation is considered 0% annually. The performance ratio of the installation is calculated (PR) assuming that the average solar access is 95%, the inverter efficiency is 96%, the module temperature derate factor is 0.88 and the ratio of converting from DC to AC is 0.94 (48), and it is given by [5].

$$PR = 0.95 \cdot 0.96 \cdot 0.88 \cdot 0.94 = 0.75 \qquad [5]$$

Then, system's PV output will be given by [6]:

$$PV_{output}(kW) = G_{eff}\left(\frac{kW}{m^2}\right) \cdot A_{PV\ system}(m^2) \cdot \eta \cdot PR \qquad [6]$$

The PV system area will be determined by the installed PV capacity. Total installed capacity of the installation must be sized taking into account the customer profile demand and will vary according to the customer needs. Nowadays, complex algorithms optimize the installed capacity in order to maximize self-consumption. The purpose of this study is not to optimize a PV system, and no complex algorithm will be used. Contrarily, it has been designed to be as simple as possible.

The criterion to determine the installed capacity will be that the installed capacity should be equal to the average demand power of the customer taking into account the installation performance ratio, as expressed in [7]. Values found will be rounded off to the lower value in the following scale: 300W, 600W, 900W, 1200W and 1500W. Those are the considered available PV arrays that the prosumer can install according to its demand. PV modules of 300W and 2m^2 of area are the single units to assemble bigger PV arrays.

Demand for daylight hours has been considered, from 5h to 19h as an approximation for the annual average matching the PV production interval in summer given by (47). Additionally, average sunshine hours in winter (from October to March) have been calculated according to EU data in (49). Data is presented in Table 14.

Month	Days	Sunshine (h)	Monthly Av. (h)	Winter Av. (h)
October	31	208	6,71	5,50
November	30	157	5,23	
December	31	142	4,58	
January	31	142	4,58	
February	28	150	5,36	
March	31	203	6,55	

Table 5. Sunshine hours for winter in Lisbon (49).

Once all the data is gathered, the PV system area can be obtained by means of [7].

$$A_{PV\ System}(m^2) = P_{installed}(kW) \cdot A_{specific}\left(\frac{m^2}{kW}\right) = \frac{Winter\ Demand\ (kWh)\ within\ PV\ production\ interval}{Nº sun\ hours\ for\ winter \cdot PR} \cdot \frac{A_{1panel}(m^2)}{0.3\ kW_{1panel}} \qquad [7]$$

Given the fact that the PV output will be calculated in periods of 15 minutes, in order to obtain the energy value, it will be multiplied by 0.25h.

$$PV_{output}(kWh) = PV_{output}(kW) \cdot 15(min) \cdot \frac{1h}{60min} = PV_{output}(kW) \cdot 0.25h \qquad [8]$$

Tariffs

The tariffs structures applied are based in the ERSE’s 2016 tariffs and prices for electricity. Three different tariffs options are considered for a 6.9 kVA demand profile for regular low voltage clients in the regulated market: simple, bi-hourly (dual rate) and tri-hourly (triple rate). The tariff structure has also been discretized in 15 minutes periods to proceed with calculations. In that sense, only the volumetric charges have been considered, as they are the only affected by a decrease on consumption.

Fixed Costs Variabilization Percentage

Regarding the costs structure variable part, only those costs incurred strictly by consumption, those that vary with consumption, have been considered. Hence, exploitation costs that do not vary with consumption in all the sector activities has been taken into account as fixed. The only costs considered as variable are part of the additional costs resulting from non-renewable special regime technologies and part of the energy acquisition. On the other hand, revenues structure has been determined according to the overall revenue coming from the fixed or variable component in the retail tariff. In order to calculate the percentage of fixed costs that are recovered in the retail tariff volumetric part, costs and revenues structures must be compared. According to EDP projections for 2016, and as presented in Graph 10, total system costs structure consists in 75% fixed and 25% variable. With regard to the revenue structure for low voltage normal clients in the regulated market, or BTN (“Baixa Tensão Normal”), the 80% correspond to the variable component and the 20% to the fixed part. Assuming that costs structure for BTN clients reproduces the total system costs scheme, and comparing directly both costs and revenues structures, it can be concluded that 23% (all variable) and 58% (all fixed) of total costs are charged through the retail tariff volumetric part. That fact implies that 75% of fixed costs are recovered in the tariff variable component.

The important value is the percentage in the volumetric part used to recover fixed costs. This value will be the percentage of fixed costs that prosumers are avoiding when reducing their consumption. Considering that the fixed component in the retail tariff is fully allocated to recover fixed costs, 58% of total costs that are fixed will need to be charged in the tariff variable part. Therefore, considering that revenues coming from variable charges represent the 80%, fixed costs will account for 71% of the volumetric part in the retail tariff.

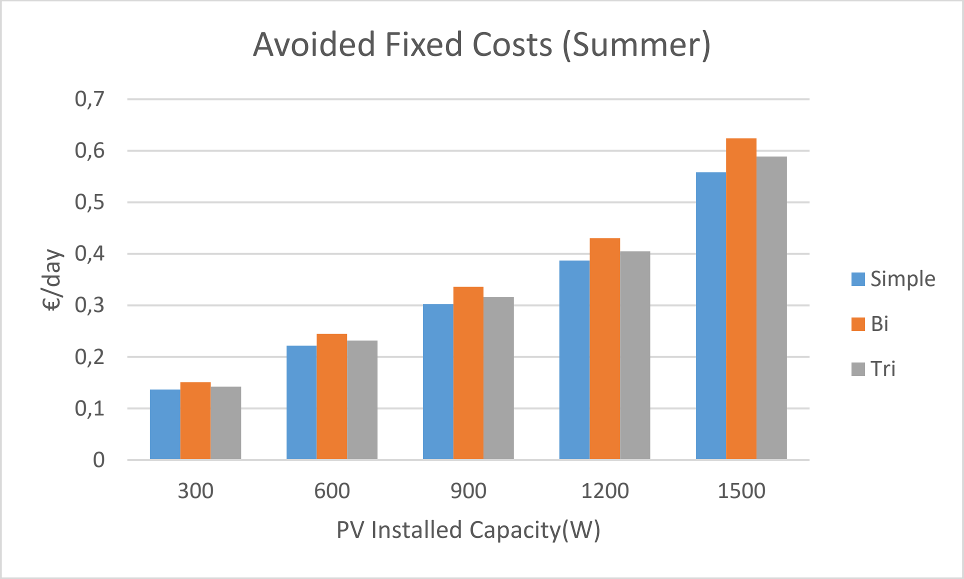
4.2.4. Results

First, the current situation in the Portuguese Energy Market will be analysed. The base case for this study has been the Regulated Market and its corresponding tariffs for BTN clients with 6.9kVA contracted power. However, Free Market and other alternative tariffs and their impact on cross-subsidization are also going to be studied.

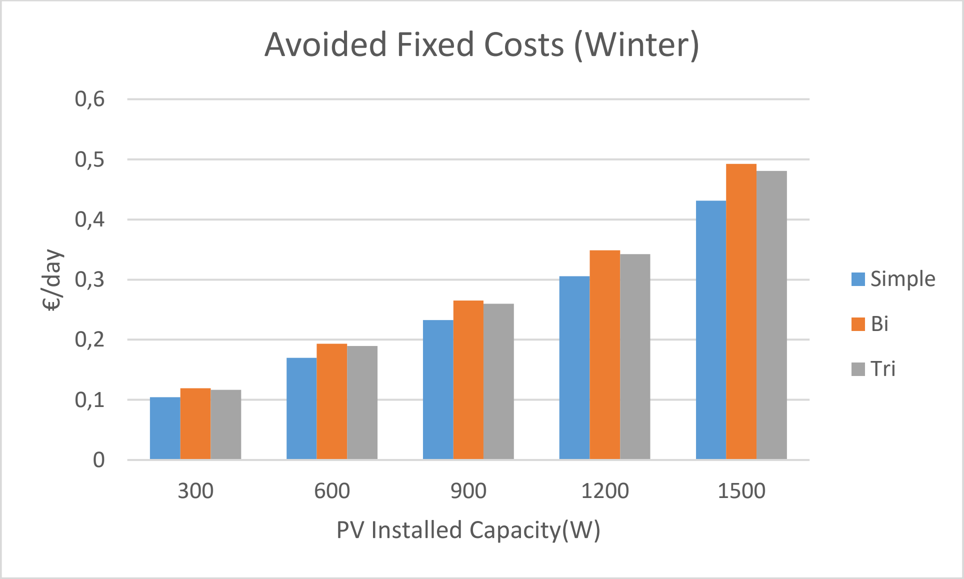
In the regulated market, three different tariffs options are offered to the customer: Simple, Dual Rate (Bi) and Triple Rate (Tri) tariff. Due to their different structure they must be analysed separately. In addition, as seen in the previous section, different consumption profiles will require different PV installed capacities (300W, 600W, 900W, 1200W and 1500W). Cross-subsidies have been studied per installed capacity and per tariff design, as shown in Graph 11. Additionally, due to different tariff designs and different PV production rates in summer and winter, seasonality has been introduced to evaluate cross-subsidies. Cross-subsidies per day that arise in winter are given by Graph 12.

As it can be observed, the most subsidized prosumer will be the customer with 1.5kW of PV installed capacity and subjected to a Dual Rate tariff reaching 0.62€ per day in summer of avoided fixed costs. On the other hand, a prosumer with 300W PV array and a simple tariff will be avoiding 0.14€ per day during the same period. Additionally, a clear tendency shows that there is a sustained growth of cross-subsidies if PV installed Capacity is increased. Logically, as PV energy is more self-consumed, consumption from the grid is reduced and cross-subsidies rise.

Regarding cross-subsidization in winter, presumably cross-subsidization should be smaller as PV output is lower. In Graph 12, cross-subsidies per day in winter are presented per PV installed capacity and retail tariff design.



Graph 11. Avoided Fixed Costs per day in summer.



Graph 12. Avoided Fixed Costs per day in winter.

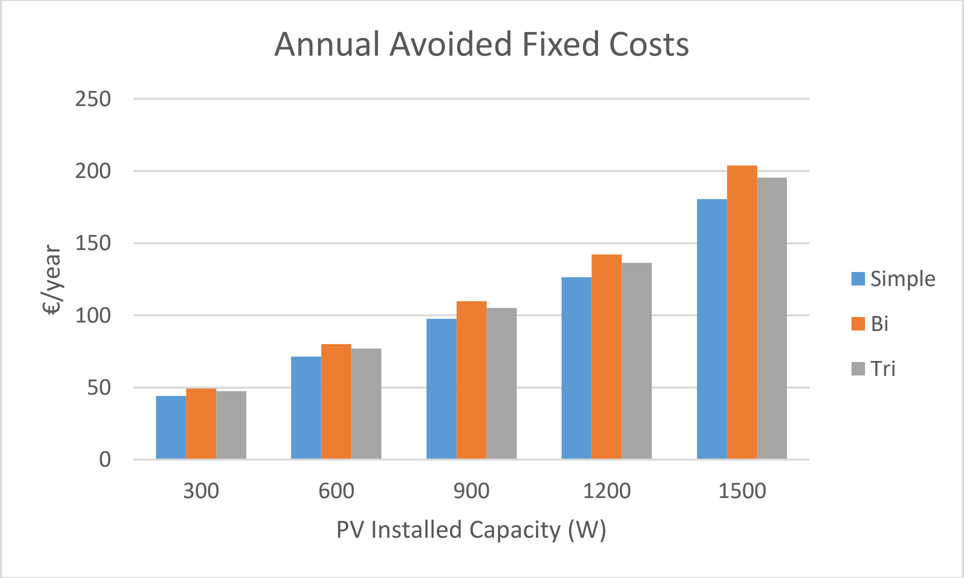
As assumed, winter presents a more unfavourable situation for prosumers. In winter, the highest and lowest cross-subsidization occurs for the same prosumer profiles: 1500W with Dual Rate tariff and 300W with Simple tariff respectively. For the first case, the prosumers avoids 0.48€ in fixed costs per day and, in the second scenario, the subsidizations is about 0.10€ per day. Comparing the values obtained in summer period, the most subsidized prosumer (15000W with Dual Rate) reduces cross-subsidization in 18%. For the less subsidized prosumer, cross-subsidization is reduced in 24%.

The average reduction of cross-subsidies from summer to winter is 20%. All the values obtained are shown in Table 6.

W	Tariff	Summer (€/day)	Winter (€/day)	Difference (%)
300	Simple	0,14	0,10	-24%
300	Dual	0,15	0,12	-21%
300	Triple	0,14	0,12	-18%
600	Simple	0,22	0,17	-23%
600	Dual	0,24	0,19	-21%
600	Triple	0,23	0,19	-18%
900	Simple	0,30	0,23	-23%
900	Dual	0,34	0,27	-21%
900	Triple	0,32	0,26	-18%
1200	Simple	0,39	0,31	-21%
1200	Dual	0,43	0,35	-19%
1200	Triple	0,40	0,34	-16%
1500	Simple	0,56	0,43	-23%
1500	Dual	0,62	0,49	-21%
1500	Triple	0,59	0,48	-18%
AVERAGE		0,34	0,27	-20%

Table 6. Avoided Fixed Costs per day and summer vs winter comparison.

In order to avoid the impact of seasonality, an annual analysis must be carried on by multiplying the values above by 183 days for the summer period and 182 days for the winter period. In Graph 13, annual avoided fixed costs by prosumers are shown depending on the PV installed capacity and the tariff design.



Graph 13. Annual Avoided Fixed Costs in the Regulated Market.

Results obtained annually show the same tendency as in summer and winter. Cross-subsidies rise with PV installed capacity as more energy is self-consumed and less energy is consumed from the grid. According to the graph, a prosumer with 1500W of installed PV and being charged through a Dual Rate tariff is avoiding annually around 204€, while a prosumer with only 300W of installed capacity and Simple tariff design is evading 44€ in terms of fixed costs.

It has been observed in Graph 11, Graph 12 and Graph 13 that for all the PV arrays, the Dual Rate (Bi) tariff is always cross-subsidizing prosumers more than the Simple and Triple Rate designs. If the tariffs designs are analysed into more detail, it can be observed that, within the PV production period, electricity retail prices are higher, which makes more valuable the energy self-consumed by prosumers.

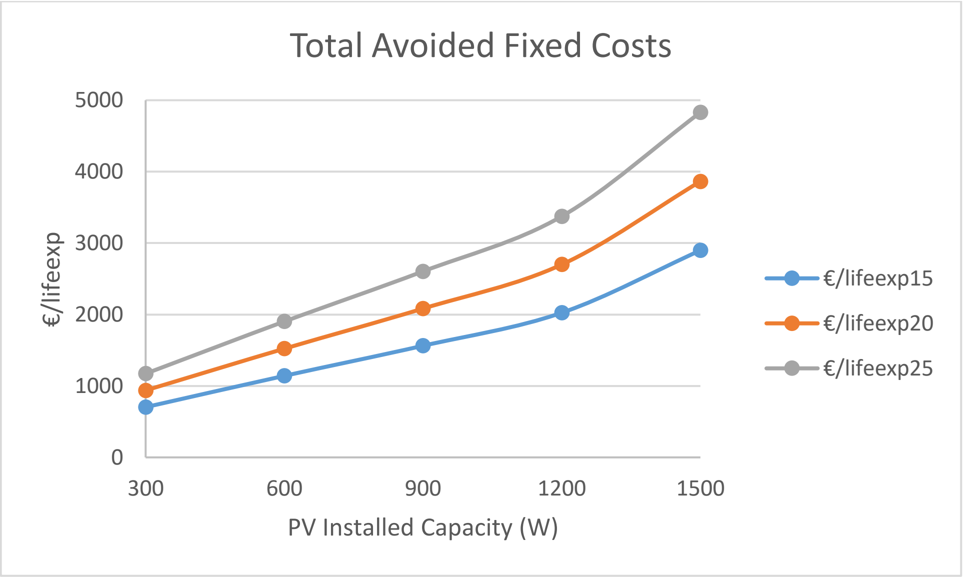
For instance, considering that in summer the PV production period goes from 5am to 19pm and in winter from 7am to 17pm, the average price of electricity within these periods has been calculated, and it is shown in Table 7.

	Summer (€/kWh)			**Winter (€/kWh)**		
Period	Simple	Dual	Triple	Simple	Dual	Triple
PV Production	0,1634	0,1715	0,1644	0,1634	0,1818	0,1758
Non-PV Production	0,1634	0,1274	0,1284	0,1634	0,1326	0,1306

Table 7. Average electricity retail tariff in PV and non-PV periods.

In both cases, for winter and summer, Dual Rate tariff values more the energy consumed within the PV production period. Therefore, self-consumption is more valuable than in other tariff designs. This phenomenon will be assessed further on when proposing different alternatives for the volumetric tariff design.

Another important factor in cross-subsidization will be the life expectancy of the PV panel. In this work, calculations for 15, 20 and 25 years of life expectancy have been performed and results are shown in Graph 14. As it can be seen, if the PV panel is producing energy during longer time, cross-subsidization will definitely increase. In order to calculate the total cross-subsidies per each PV array, the average value for the different volumetric retail tariff designs has been computed.



Graph 14. PV panel life expectancy impact on cross-subsidies.

Ultimately, if prosumers are already in the Free Market, different tariffs will be applied and different results will be obtained. For the Free Market (FM), the retail prices have been obtained from EDP Comercial (public prices in the website (50)), although they have been adapted to the period distribution considered in the Regulated Market (RM) as shown in Table 8.

Active Energy	**FM**	**(€/kWh)**	**RM**	**(€/kWh)**
Simple Tariff <=6,9 KVA	-	0.1634	-	0.1634
Dual Rate Tariff <=6,9 KVA	Normal	0.1990	Out of Valley	0.1909
	Economic	0.0937	Valley	0.1002
Triple Rate Tariff <=6,9 KVA	Normal	0.3182	Peak	0.2169
	Economic	0.1636	Out of Valley	0.1716
	Super economic	0.0936	Valley	0.1002

Table 8. Tariff Volumetric Retail price for the Free Market (adapted).

When comparing the results obtained for the Free and Regulated Market, it can be said that there is not a big difference, although the tendency shows that higher wealth transfers occur from regular ratepayers to prosumers as shown in Table 9. The fact that in the Free Market cross-subsidies are higher it can be explained because of the higher retail price in the PV production period, valuing more the self-consumed energy.

Additionally, as the retail price for the Simple Tariff design is the same in both markets, no difference in cross-subsidization will be found between prosumers in that case.

W	Tariff	RM (€)	FM (€)	Difference (%)
300	Simple	44	44	0%
300	Dual	49	51	4%
300	Triple	47	49	3%
600	Simple	71	71	0%
600	Dual	80	83	4%
600	Triple	77	80	4%
900	Simple	98	98	0%
900	Dual	110	114	4%
900	Triple	105	108	3%
1200	Simple	126	126	0%
1200	Dual	142	148	4%
1200	Triple	136	140	3%
1500	Simple	181	181	0%
1500	Dual	204	212	4%
1500	Triple	195	203	4%

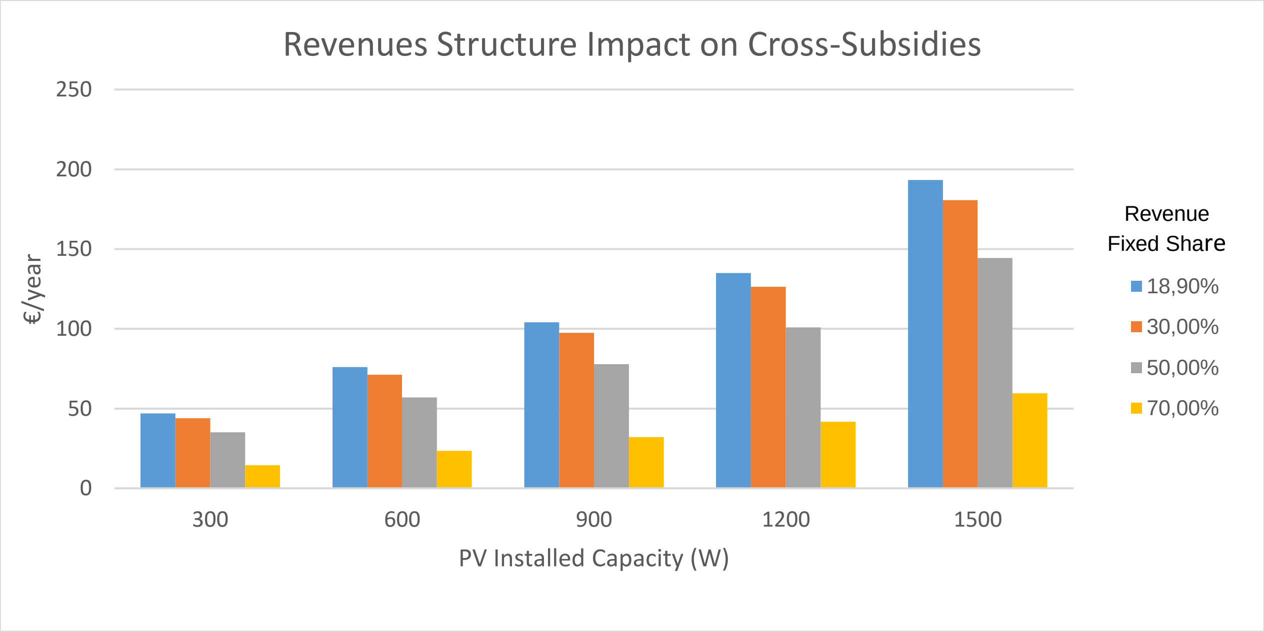
Table 9. Cross-subsidies comparison between Free Market and Regulated Market.

4.2.5. Tariff Assessment

This section aims to assess different tariff designs to mitigate the cross-subsidization issue among ratepayers due to PV self-consumption and the consequently reduction of consumption from the grid. First, as the main goal of this section, different revenues structures will be proposed addressing the fixed costs variabilization. Additionally, and due to the fact that in the previous section has been found out that the volumetric part has also an impact on fixed costs avoidance, a volumetric retail tariff assessment will be also performed.

Non-volumetric retail tariff component

As it has been mentioned in previous sections, the current revenues structure is 18.90% fixed and 81.10% variable, which creates a mismatch with the costs structure (76.58% fixed and 23.42% variable) that variabilizes fixed costs accounting for 71.12% in the volumetric retail tariff component. Therefore, in order to mitigate cross-subsidization, it seems obvious that charges through the retail tariff fixed component must increase. In Graph 15, cross-subsidies for different revenues structures and different PV arrays are shown. The values shown are the average for the different volumetric retail tariff designs.



Graph 15. Revenues Structure Impact on Cross-Subsidies.

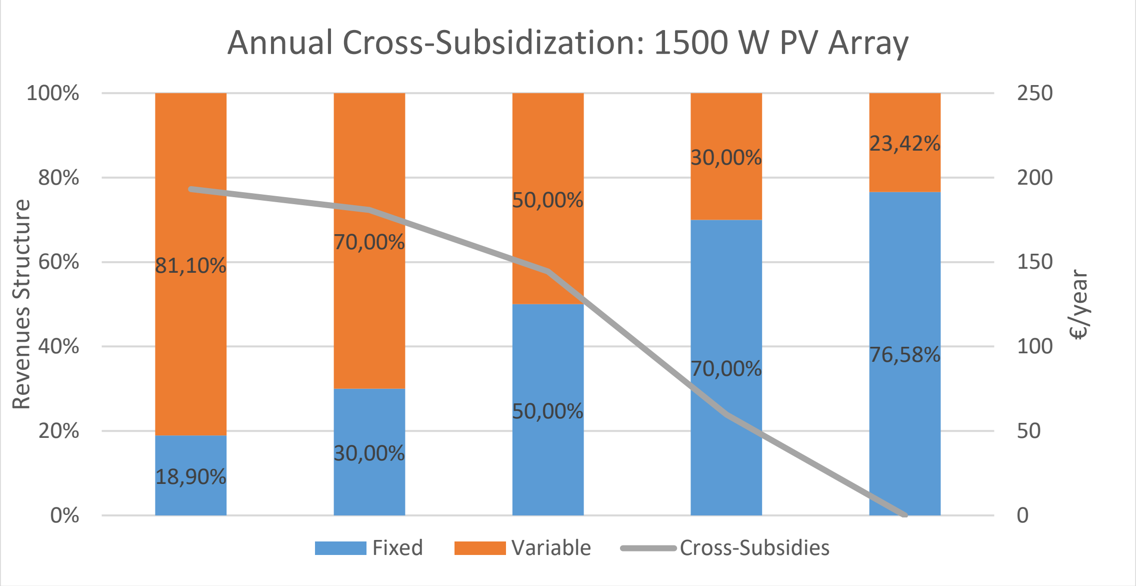
In Table 10, the average difference regarding the current structure is provided, as well as the annual cross-subsidies in each case.

	Annual Cross-Subsidies (€)			
Fixed Component Share	18,9%	30,0%	50,0%	70,0%
300W	47	44	35	14
600W	76	71	57	23
900W	104	97	78	32
1200W	135	126	101	42
1500W	193	181	144	60
Average Difference	-	-6%	-25%	-69%

Table 10. Annual Cross-Subsidies for different fixed revenues component.

As it can be observed, cross-subsidies are substantially reduced when increasing the fixed component in the retail tariff. By making the tariff structure more cost-reflective, cross-subsidies can be reduced up to 69% if increasing the fixed component at 70%. Nevertheless, that will mean an increase in the fixed component of about 270%, which cannot be applied in one-year time. However, moderate reforms in that sense will definitely help to mitigate the problem as shown for the 30% and 50% of fixed component. Despite the avoidance of fixed costs is directly proportional to the consumption reduction as seen in Equation [3] and [4], the cross-subsidies reduction will be different for PV arrays with different capacities due to different consumption profiles.

In Graph 16, evolution of cross-subsidization for a 1500W prosumer is shown for different percentages of fixed revenues. The tendency to clearly decrease until the point when the revenues structure matches the cost structures can be observed.



Graph 16. Annual Cross-Subsidization for different fixed components in the retail tariff for a 1500 PV array.

Volumetric retail tariff component

As observed in section 4.1.4, and particularly in Table 7, different designs for the volumetric retail tariff component will also have an impact on the avoidance of fixed costs by prosumers. If the energy consumed within the PV production period is more valuable than without, then, cross-subsidization will be higher. In that sense, increasing flexibility in the demand side (see Chapter 3) will help to mitigate the problem if alternative tariffs reflecting that phenomenon are applied.

A feasible solution would be to reduce the value of electricity within the PV production period and decrease the value for the rest of the day. In this work, an alternative tariff design has been created according to the following constrains: not affecting the total revenue (making it invariable), not changing more than 30% the price in each period and reducing cross-subsidies by at least 5%.

The proposal is presented in Table 11 and it is compared to the current structure for the Regulated Market BTN clients for 6.9kVA.

	Period	Current (€/kWh)	Proposal (€/kWh)	Difference
Simple	-	0,1634	0,1634	0%
Dual	Out of Valley	0,1909	0,1700	-11%
	Valley	0,1002	0,1300	30%
Triple	Peak	0,2169	0,2300	6%
	Out of Valley	0,1716	0,1420	-17%
	Valley	0,1002	0,1200	20%

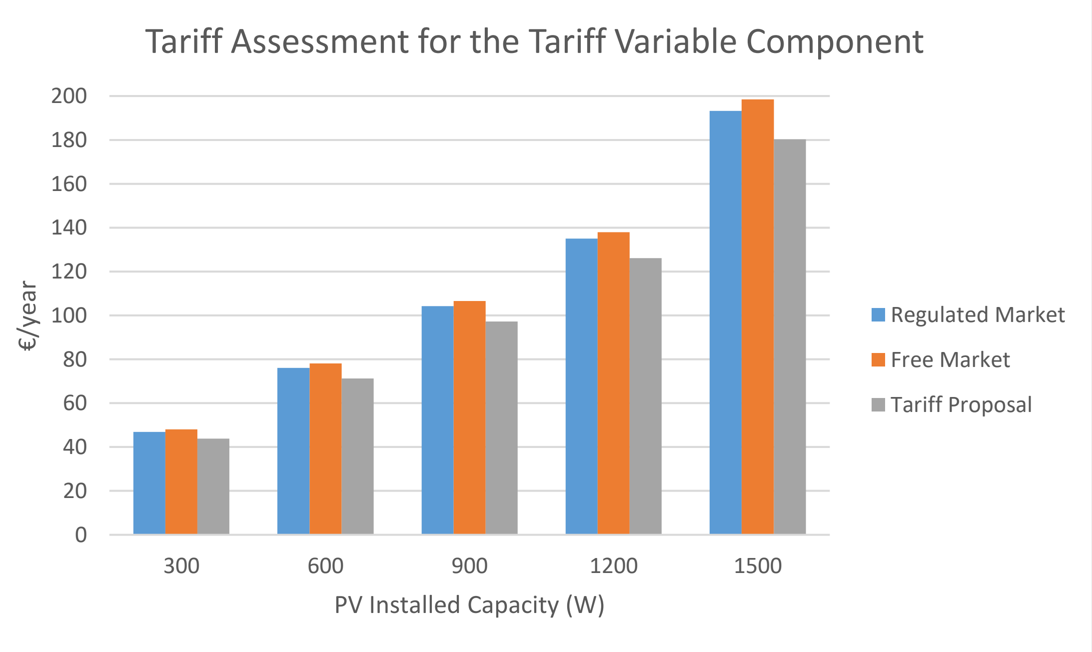
Table 11. Alternative Volumetric Retail tariff design.

The results obtained for that tariff designed are presented in Table 12.

W	RM (€/year)	FM (€/year)	Proposal (€/year)
300	47	48	44
600	76	78	71
900	104	107	97
1200	135	138	126
1500	193	198	180
Average	111	114	104
Difference	-7%	-10%	-

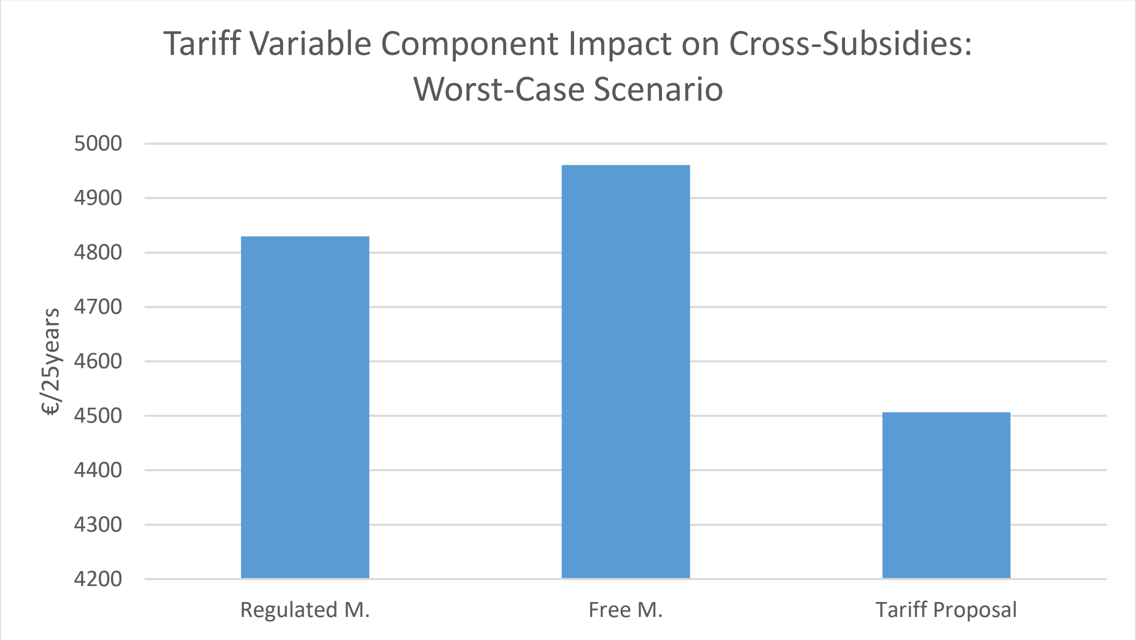
Table 12. Comparison of annual cross-subsidies for the Free Market, the Regulated Market and the Tariff Proposal.

As it can be seen, if the tariff proposal is applied cross-subsidies in the Regulated Market will be reduced by 7% and by 10% in the Free Market. The tariff proposal always reduces the cross-subsidization independently of the PV Installed Capacity as shown in Graph 17.



Graph 17. Cross-subsidies for different volumetric retail tariffs designs.

If it is looked into more detail in the worst case scenario, which would be a prosumer installing a PV array of 1500W considering the average between all tariff volumetric structures, the tariff proposal will reduce cross-subsidization during the PV panel life expectancy in around 325€ comparing it to the Regulated Market retail tariff design and by 450€ compared to the Free Market situation, as shown in Graph 18.



Graph 18. Tariff Variable Component Impact on Cross-Subsidies: Worst-Case Scenario.

4.3. Benefits and Costs of Distributed PV: System Loss of Welfare

The impact of PV goes beyond cross-subsidization and can affect the overall system causing a loss of welfare. This situation is mainly caused by higher costs of the technologies used to generate energy that are substituting cheaper ones, which will charge a higher cost to society. In addition, to strongly incentivise one particular kind of technology will create conflicting incentives that could harm the system (41). In this section, a particular interpretation on the method used by Gilbraith, N. et al. in *'Evaluating how Demand Side Resources Affect the Environmental and Economic Performance of Energy Systems'* (9) is carried on to determine the overall system loss of welfare.

4.3.1. Definition

In the energy sector, loss of welfare could occur as a consequence of taxation (not considered in this study), strong subsidization of a particular technology and substituting current generation technologies by others more expensive.

Increase on generation costs due to the mentioned inefficiencies will be passed to customers. In the PV prosumer scenario, solar PV LCOE is still more expensive than other technologies as seen in Chapter 2.Then, if injected in the grid due to supply excess onsite, the system may generate energy at a higher cost, which will generate a loss of welfare in the system. Additionally, part of the energy generated is not injected into the grid but self-consumed by the prosumer, what can be seen as a demand contraction. The combination of both situation will generate a system loss of welfare, as can be observed in Figure 19. System loss of welfare occurs because the intersection of supply and demand does not take place on the equilibrium point because of market inefficiencies, switching supply curve to the left due to higher generation costs.

Moreover, if the increase on generation costs is passed to the customers as an increase in the retail tariff, demand response of customer could even contract more the consumption and exacerbate the system loss of welfare. Nevertheless, demand response was not considered in the study.

On the other hand, supporting renewable energy integration in the system could reactivate other sectors (renewable energy sector) and will probably generate a positive impact on society, although this study do not quantify it.

In this study, system loss of welfare will be defined as the wealth loss of the overall customer when integrating PV panels in the system. Therefore, three stakeholder will be defined: PV owner, non-PV owner and the overall customer (ratepayers as a whole). Wealth transfers between these three agents will be quantified.

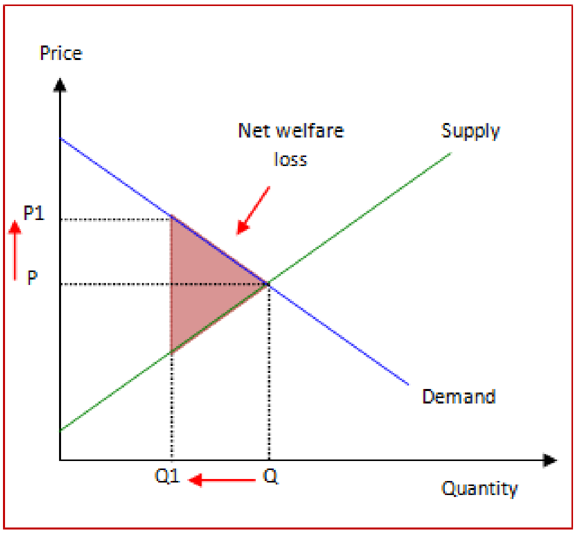


Figure 19. Theoretical scheme for a system in a Loss of Welfare situation (41).

4.3.2. Methodology

Firstly, if the present value (Pv) of buying, installing and operating a distributed PV system is less than the present value of purchasing the same amount of electricity from the grid, then the PV panel owner has a benefit on adopting the solar PV system. Additionally, if the present value of the purchases avoided by the prosumer from the grid is less than the present value of the cost of substituting the system's energy generated by the solar energy, the non-PV owners will be benefitted. From the overall ratepayer point of view, if the present value of buying, installing and operating a PV system is less than the present value of generating and distributing the same electricity, then the system becomes more cost-effective.

In other words, the PV panel owner will be favoured when the savings and the extra money he receives for injecting energy into the grid are higher than the capital costs of the PV panel. The other ratepayer (non-PV owner) will be benefitted when the avoided costs of generating energy with PV panels instead that with other technologies by the system are higher than the prosumer's savings and remuneration. In that sense, the other ratepayer will have a benefit when the avoided costs, which are marginal costs, are higher than the avoided payments and remuneration for the prosumer, meaning that the negative costs would be sunk costs assumed by the other ratepayers. Ultimately, the overall consumer will be advantaged when the costs that solar panels are avoiding to the system are higher than the PV panel capital costs, which means that if the LCOE of PV is higher than the current technologies used by the system, the system will become less cost-effective.

In Table 13, gain and loss situation for the three stakeholders taking into account different values for the present value of solar cost (Pv cost solar), retail price of electricity (Pv price grid) and cost electricity generation (Pv cost grid) are presented.

Stakeholders		PV Owner	Non-PV owner	Overall
Pv cost solar <	Pv price grid < Pv cost grid	+	+	+
	Pv price grid > Pv cost grid	+	-	+
Pv (cost grid) <	Pv cost solar < Pv price grid	+	-	-
	Pv cost solar > Pv price grid	-	-	-
Pv (price grid) <	Pv cost grid < Pv cost solar	-	+	-
	Pv cost grid > Pv cost solar	-	+	+
Benefit if		Pv (cost solar) < Pv (price grid)	Pv (price grid) < Pv (cost grid)	Pv (cost solar) < Pv (cost grid)

Table 13. Gain and loss situation for the several stakeholders (9).

To quantify the wealth transfers among customers (or stakeholders), the Net Present Value (NPV) balance is considered and is explained in the following section.

As it has been said above, this methodology quantifies the loss of welfare in the system by calculating the NPV for all the stakeholders involved: PV panel owners, regular customers and the overall ratepayers. According to the definition previously mentioned, NPV for panel owners, non-PV owners and overall ratepayers are given by [9], [10] and [11].

$$NPV_{owner} = PV_{price\ grid} - PV_{cost\ solar} \qquad [9]$$

$$NPV_{non-PV\ owners} = PV_{cost\ grid} - PV_{price\ grid} \qquad [10]$$

$$NPV_{overall} = PV_{cost\ grid} - PV_{cost\ solar} \qquad [11]$$

Additionally, the NPV for PV panel owners can be further developed by adding zero (Pv cost grid added and subtracted) and expressed as in [12]. It can be observed that the benefit for the PV panel owner can come from the difference between the cost of electricity generation by the system and by the PV panel plus the difference between the retail electricity price and the cost of providing one more unit of electricity, as the PV panel owner could be avoiding fixed costs.

$$NPV_{owner} = \left(PV_{cost\ grid} - PV_{cost\ solar}\right) + \left(PV_{price\ grid} - PV_{cost\ grid}\right) \qquad [12]$$

On the other hand, the NPV for the overall ratepayers can also be calculated as in *[13]*.

$$NPV_{overall} = NPV_{owner} - NPV_{non-PV\ owners} \qquad [13]$$

In order to determine the NPVs for the different stakeholders, the present value (Pv) for the cost of installing and operating a distributed solar PV array, for the avoided grid electricity purchases and for the cost of grid electricity that solar PV displaces are calculated by means of [14], [15] and [19] respectively.

First, present value for the cost of buying, installing and operating a PV panel will be obtained from computing the value evolution over time of the solar panel cost and taxes, the loan acquired and the discount rate on the investment.

$$PV_{(Cost\ Solar)} = \sum_{n=1}^{N} \left(c \cdot (1+r)\right) \cdot \left(\frac{i_L \cdot (1+i_L)^N}{(1+i_L)^N - 1}\right) \cdot \left(\frac{1}{(1+d)^n}\right) \qquad [14]$$

where c stands for the array costs in €, r for the value added tax rate, i_L for the nominal loan interest rate (real loan interest + inflation), d stands for the nominal discount rate (real discount rate + inflation), h for a 15 minutes period and n for the annual index.

Second, present value for avoiding electricity purchases from the grid will consider two situations in each period of analysis, depending if energy demand is higher than PV output. In this case, if PV generation is smaller than demand, the prosumer's benefit will be equal to the volumetric part of the tariff multiplied by the energy generated, which is the monetary savings in purchasing electricity from the grid, as shown in [16]. On the other hand, if PV generation is greater than demand, and can be injected in the grid, the benefit for the prosumer will be the energy not purchased from the grid plus the energy injected, as given in [17]. Portugal rewards PV prosumers with the 90% of the spot market (MIBEL) price at that time. If energy injected in the grid is not remunerated, then the last equation must be used, which represents the same situation that in the first case when demand was greater than PV generation [18].

$$PV_{(Price\ Grid)} = \sum_{n=1}^{N} \left(\sum_{h=1}^{24} b_{h,n}\right) \cdot 365 \cdot \left(\frac{1}{(1+d)^n}\right) \qquad [15]$$

The value of $b_{h,n}$ will depend on the following condition:

Condition	*Value*
$g_h \leq q_{h,i}$	$b_{h,n} = g_h \cdot T_h \cdot (1 + inflation)^n$ [16]
$g_h > q_{h,i}$	$b_{h,n} = \left(q_{h,i} \cdot T_h + \left(g_h - q_{h,i}\right) \cdot 0.9 \cdot LMP_h\right) \cdot (1 + inflation)^n$ [17] $b_{h,n} = g_h \cdot T_h \cdot (1 + inflation)^n$ [18]

Table 14. Compensation of PV energy according to system loss of welfare methodology.

where $b_{h,n}$ is the monetary benefit of each unit of solar PV generation, g_h is the solar PV generation, $q_{h,i}$ is the panel owner electricity demand without considering self-consumed solar PV, T_h is the retail tariff applied at a residential level for BTN clients of 6.9kVA, LMP_h is the MIBEL

Portuguese wholesale daily average price for 2015 in 15 minutes discrete periods, $inflation$ is the annual rate growth for retail tariffs and MIBEL price due to inflation, d stands for the nominal discount rate (real discount rate + inflation), h for a 15 minutes period and n for the annual index.

Third, present value for the system or grid electricity that solar PV substitutes will take into account the distribution and transportation losses to deliver electricity and the average generation cost of the other technologies being displaced, as it is shown in [19].

$$PV_{cost\ grid} = \sum_{n=1}^{N}\left(\sum_{h=1}^{24} g_h \cdot C_{gen,h} \cdot (1 + l_{trans}) \cdot (1 + l_{dist})\right) \cdot \left(\frac{1}{(1+d)^n}\right) \qquad [19]$$

where g_h is the PV generation in 15 minutes intervals, $C_{gen,h}$ is electricity generation cost for the grid minus the benefits obtained by emitting less CO_2, l_{trans} stands for the transportation loss rate, l_{dist} is the average distribution losses rate, d stands for the nominal discount rate (real discount rate + inflation), h for a 15 minutes period and n for the annual index.

4.3.3. Data and Assumptions

In this methodology, many variables are considered. Explanation of data and assumptions are given for each present value calculated. With regard to the demand profiles, tariffs and PV production output, the same procedure as in the methodology to determine cross-subsidies has been applied.

In that section, seasonality has not been taken into account due to the calculations methodology structure, so the impact of summer and winter conditions have been considered in the sensibility analysis, as well as the different tariff structures for each season.

Present value for the cost of buying, installing and operating a PV panel

PV panel cost has been determined through the specific price per watt for different capacities. It is difficult to determine a common established price for commercial PV. However, this study considers the judgments in (9), to determine price in € per watt. A logarithmic equation has been created to approximate the values in (9) to adapt them to the PV capacities considered in this work. The price per watt is given then by [20].

$$€/W = -0.734 \cdot \ln(PV\ capacity) + 6.85 \qquad [20]$$

Representative prices for different PV panel sizes, as well as the total costs after taxes, are presented in Table 15. The array cost could be subjected to modification in a range from -25% to 25%, which will allow to develop a sensibility analysis. Base case is presented in Table 15.

P(W)	**300**	**600**	**900**	**1200**	**1500**
Price (€/W)	2.7	2,2	1,9	1,6	1,5
c	810	1320	1710	1920	2250
r	23%	23%	23%	23%	23%
Total Cost	996,3	1623,6	2103,3	2361,6	2767,5

Table 15. Prices for purchasing and installing a PV panel.

Several cases are considered depending on the PV panel life expectancy (N): 10, 15, 20 and 25 years. Different results collected for each case will serve as a sensibility analysis. Additionally, a real discount rate of 5% has been taken into account, which makes a nominal discount rate for the investment of 7% by means of [21]. Real discount rate can also be modified and take the following values: 1%, 3% and 5%. Regarding the interest loan for purchasing the PV panel, it has been fixed at a real value of 5%, which turns out in a nominal value of 7%. Ultimately, no sensibility analysis has been carried out for the loan interest rate as suggested in (9), due to its low impact in the present value.

$$Rate_{nominal} = (1 + Rate_{real}) \cdot (1 + inflation) - 1 \qquad [21]$$

Present value for avoiding electricity purchases from the grid

For calculating the present value of avoided purchases from the grid, the main variables that are called upon to play an important role are demand profile, PV generation, tariff structure and the spot market price (MIBEL). As the first three variables have been already discussed, only spot market price will be explained.

Demand profiles and PV production output are discretized in periods of 15 minutes for an annually or seasonally average day. MIBEL daily average price for each period of 15 minutes from 0h to 23:59h has been calculated in order to match prosumer's demand and solar production data structure. Data from MIBEL has been obtained from EDP and it belongs to 2015. In case of market splitting, prices are referred to the Portuguese wholesale market.

Sensibility analysis on the MIBEL price has also been performed due to the high volatility of prices, depending on weather and economic factors. Increase and decrease up to ±25% has been considered.

Ultimately, an inflation rate of 2% annually has been considered as the electricity price growth rate and the same annual increase has been considered for the MIBEL price.

Present value for the system or grid electricity that solar PV substitutes

Generation cost for other technologies electricity generation has been set up at 50€/MWh at the base case, although it can be modified from 20 to 80€/MWh to conclude the potential impact on the base case results. The benefits of substituting energy from the grid by solar would be the price of CO_2 in the EUA (European Allowances for emissions) multiplies by the average factor emission of Portugal.

Additionally, it has been assumed that PV generation avoids an average of 10% as distribution system loss rate and 1.5% as transmission losses. Ultimately, it has been assumed that the generation cost grows with inflation (considered as 2% annually).

Sensibility Analysis

The involvement of many factor in this methodology requires a sensitivity analysis to assess the impact of changes in their values. Moreover, these factors or variables are susceptible to be very volatile from one period of analysis to another. Therefore, settling a sensitivity analysis structured in a Low Overall NPV, Base Case and High Overall NPV, is mandatory.

	Low case	Base case	High case
N (years)	15	20	25
Mibel price (€/MWh)	-25%	0%	25%
PV price (€/W)	25%	0%	-25%
Discount rate (%)	3%	5%	7%
Grid generation cost (€/MWh)	20	50	80
Tariff seasonality	Winter	Summer	Summer
Weather conditions	Winter	Summer	Summer

Table 16. Sensibility Analysis Scenarios.

The results presented in the next section are obtained in the Base case Scenario, which includes all the data presented in this section.

4.3.4. Results

Using the methodology presented in the System Loss of Welfare, NPV for the different stakeholders is calculated in order to know who is benefiting or, on the other hand, paying the costs of PV integration into the grid at a residential level. For the Base Case in the Regulated Market, results presented in Table 17 have been obtained.

In all the cases, for all the PV installed capacities and under the same retail tariff structure, there is a system loss of welfare quantified by the NPV for the overall ratepayer, going from the 600€ in the 600W case to 225€ in the 1500W scenario. One of the main reasons for that is that capital costs for PV have an important impact in the system loss of welfare and do not follow a lineal tendency. Table 17 shows that for higher PV installed capacities, the system loss of welfare is diminished, except from 300W to 600W and from 300W to 900W, which as seen in Equation *[11]*, depends on the present value for the system electricity that PV substitutes and on the present value for the cost of a solar PV array. No conclusion can be withdraw without analysing each present value. However, it can be stated that the tariff design will not have an impact on the system loss of welfare, but on the cost or benefit allocation between PV panel owners and non-PV panel owners.

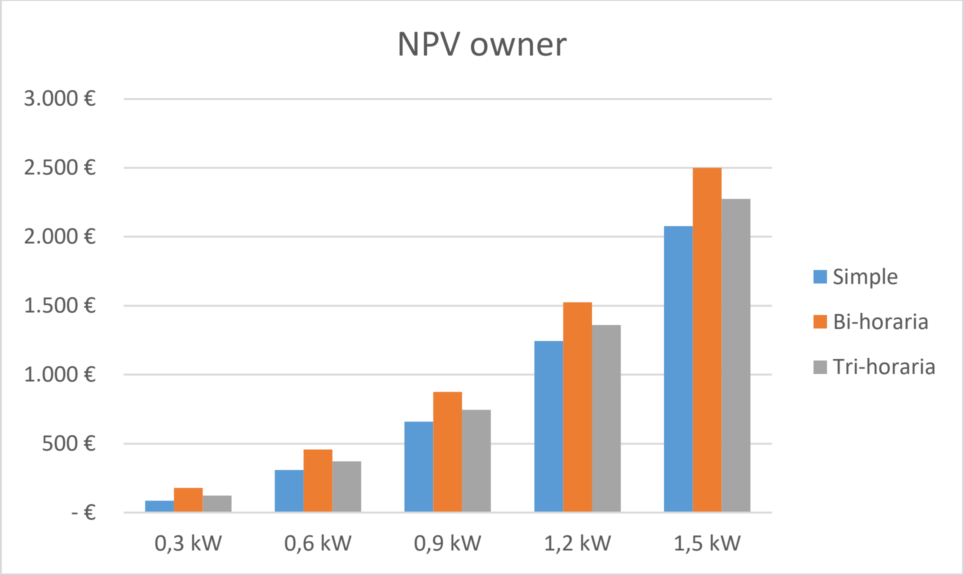
W	Tariff	NPV owner (€)	NPV others (€)	NPV overall (€)
300	Simple	87	-575	-488
300	Dual Rate	179	-667	-488
300	Triple Rate	124	-612	-488
600	Simple	309	-915	-607
600	Dual Rate	458	-1064	-607
600	Triple Rate	371	-978	-607
900	Simple	659	-1237	-578
900	Dual Rate	874	-1452	-578
900	Triple Rate	746	-1324	-578
1200	Simple	1244	-1572	-328
1200	Dual Rate	1525	-1852	-328
1200	Triple Rate	1361	-1688	-328
1500	Simple	2079	-2304	-225
1500	Dual Rate	2499	-2724	-225
1500	Triple Rate	2275	-2500	-225

Table 17. System Loss of Welfare Results for the Base Case in the regulated Market.

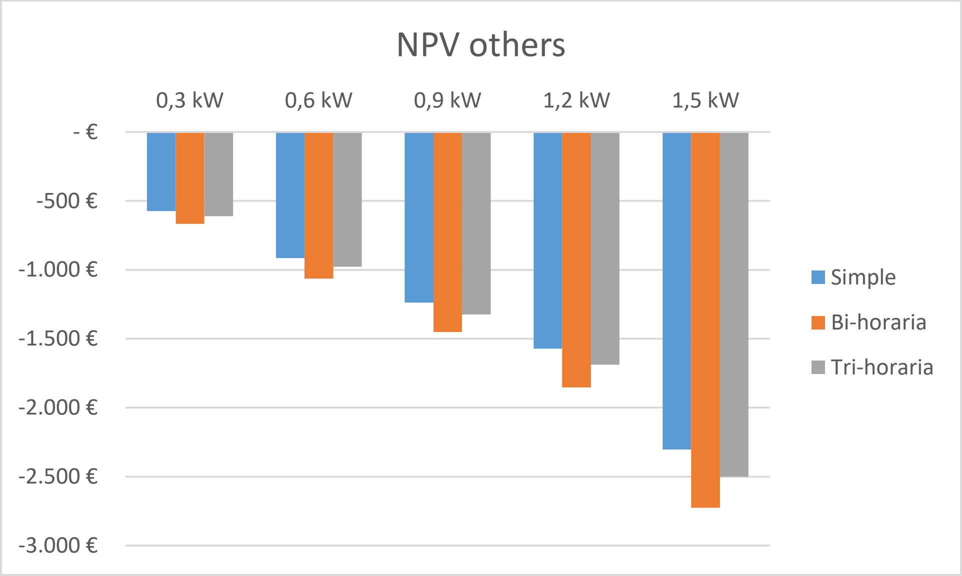
With regard to PV panel owners, the benefit of installing a PV panel array will depend on the capacity installed and on the volumetric retail tariff. For higher capacities, PV panel owners will obtain larger benefits. For instance, a prosumer with 1500W of installed capacity being charged through the Dual Rate tariff will have around 30 times more benefit than a prosumer with 300W and a Simple tariff structure, although it must be highlighted that the installed capacity depends on the consumption and not on the willingness of having a PV array. In Graph 19, it can also be observed that the Dual Rate tariff always provides higher benefits for prosumers with different PV capacities. The reason for that phenomenon is the same given in section 4.1.4, which can be explained for a higher price within the PV production period in that tariff structure.

From Graph 19, it can be inferred that under the given conditions explained in the previous section, PV panel owners are being benefitted with their choice of installing PV in their houses, although for low-capacity prosumers the benefit is clearly less substantial.

On the other hand, in Graph 20, it can be observed a completely different situation for non-PV panel owners (others). In all cases, for each prosumer that installs a PV array at his or her home, the other ratepayer will be negatively affected assuming the costs caused by it. In other words, in all cases the present value for the energy acquisition price from the gird will be higher than the present value for the system electricity that is substituted by solar PV, which can be explained by a higher LCOE for solar PV than other generation technologies. A regular ratepayer will be paying an additional cost valued from 575€ every time a PV array of 300W is integrated to 2304€ when a 1500W PV module is installed, both subjected to the simple tariff.

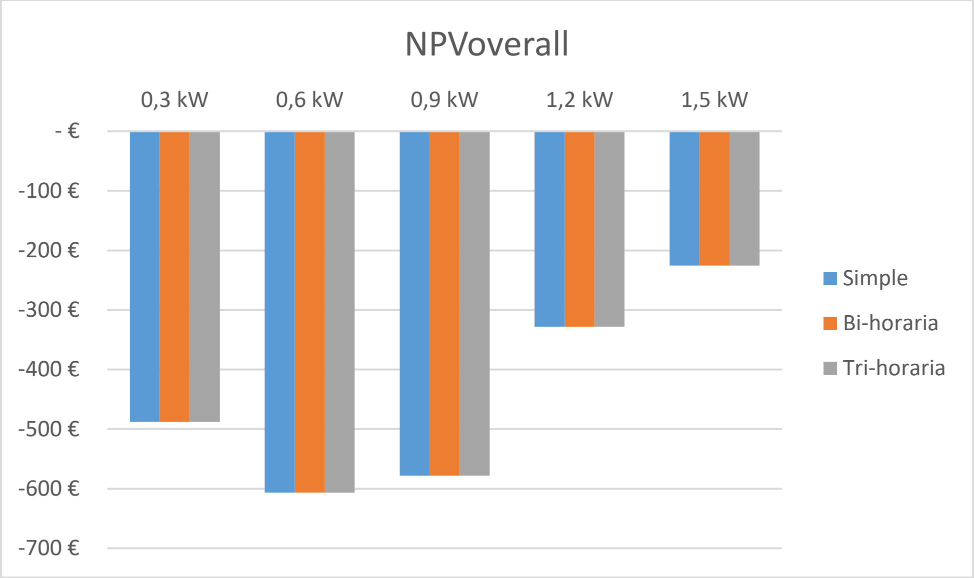


Graph 19. NPV for PV panel owners.



Graph 20. NPV for the non-PV owners (others).

Ultimately, from the overall perspective, or system welfare, results obtained can be observed in Graph 21, although they have been previously discussed. It must be highlighted that system loss of welfare is higher for PV arrays of 600W and 900W than for 300W. One possible explanation would be that the cost of going from 300W to 600W and 900W of PV installed capacity is still greater than the benefit the prosumer will gain.



Graph 21. NPV for the overall ratepayer or System Welfare.

As the NPV values for the different stakeholders depend on the present values for the solar cost, for avoiding solar purchases from the grid and for substituting electricity from the grid for solar PV, a deeper analysis for these factors must be developed to understand the impact of each one into the NPVs.

In Table 18, the present values for the different variables involved in the System Welfare are presented.

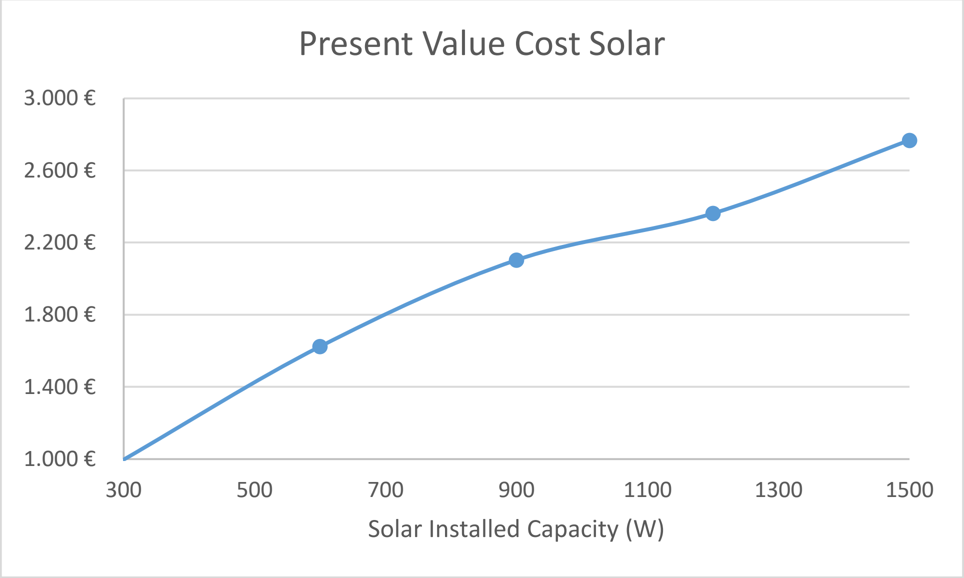
Present values		**300W**	**600W**	**900W**	**1200W**	**1500W**
PV Cost Solar (€)		1107	1624	1993	2362	2768
PV Price Grid (€)	Simple	2066	2782	3482	4194	5240
	Dual Rate	2144	2908	3664	4430	5595
	Triple Rate	2097	2835	3556	4292	5405
PV Cost Grid (€)		508	1017	1525	2034	2542

Table 18. Present Value for the different variable involved in the System Welfare.

Given the data in Table 18, it can be understood why the system loss of welfare is higher for 600W and 900W than for 300W, as prices for 600W (2.2€/W) and 900W (1.8€/W) have a bigger impact on the system compared to the electricity they substitute, according to Equation [11]. However, this presumed inconsistency in the result could be derived from the price assumption for different installed capacities. Additionally, the fact that LOCE for PV is reduced for higher capacities makes the system more cost-effective and reduces the system loss of welfare.

Present value for solar cost evolution is presented in Graph 22. It can be observed there is a sustained growth in the costs for solar along with the PV installed capacity. However, from 300W to 600W and to 900W, the increase is more significant than in between the other values, where the rise is more moderate.

Regarding the present value for prosumer avoided energy purchases from the grid, it can be seen that the present value rises as the PV capacity is higher. This is the value that has a bigger impact on the system welfare. Therefore, as shown in the previous methodology, avoided purchases from the grid can have a dramatic impact and can lead to a situation of unsustainability, so called spiral of death, where tariffs rise due to the PV integration attracting more customers to become prosumers. Additionally, if there is a PV-favourable policy, system loss of welfare will be substantially increased. In this case, it has only been considered that the PV output injected into the grid will be remunerated at the 90% of the MIBEL price. If PV support schemes (see Chapter 2 and 3) had been considered, the present value for avoided grid purchases would have been much higher.



Graph 22. Present Value for solar PV for different installed capacities.

Ultimately, the present value for the system's electricity substituted by solar PV grows with the PV installed capacity, as there is more electricity coming from PV injected into the grid. The difference between present value for the price of avoided purchases and the energy substituted are the sunk costs of the system that prosumers avoid paying, and would be eventually paid by the other ratepayers.

In addition, the difference between the cost of the solar PV array to the prosumer and the cost of solar to the grid would need to be recovered by the regulator by means of increasing the retail tariff.

4.3.5. Sensibility Analysis

The Base Case scenario is based on many assumptions and factors that are subjected to high volatility ratios. Hence, it is necessary to identify how the NPV calculation will be affected by those changes and which variables have a greater impact on the NPV final value. For developing the analysis a PV array of 900W will be used. Additionally, the values used for the present values of avoided purchases from the grid will be the average between the Simple, Dual Rate and Triple

Rate. A sensibility analysis based on tariff structure will be developed further on in the tariff assessment section.

First, a worst and best case scenario are presented in Table 19. To determine high and low case the higher values for the NPV of the overall system has been taken into account. In case of invariance when a variable was modified, the NPV for the owner will determine the high or low case condition.

	Low case	**Base case**	**High case**
N (years)	15	20	25
Mibel Price (€/MWh)	-25%	0%	25%
Pv Price (€/W)	25%	0%	-25%
Discount Rate (%)	3%	5%	7%
Grid Generation Cost (€/MWh)	20	50	80
Tariff Seasonality	Winter	Summer	Summer
Weather Conditions	Winter	Summer	Summer
NPV PV owner (€)	-1081	760	1544
NPV others (€)	-1558	-1338	-538
NPV overall (€)	-2639	-578	1007

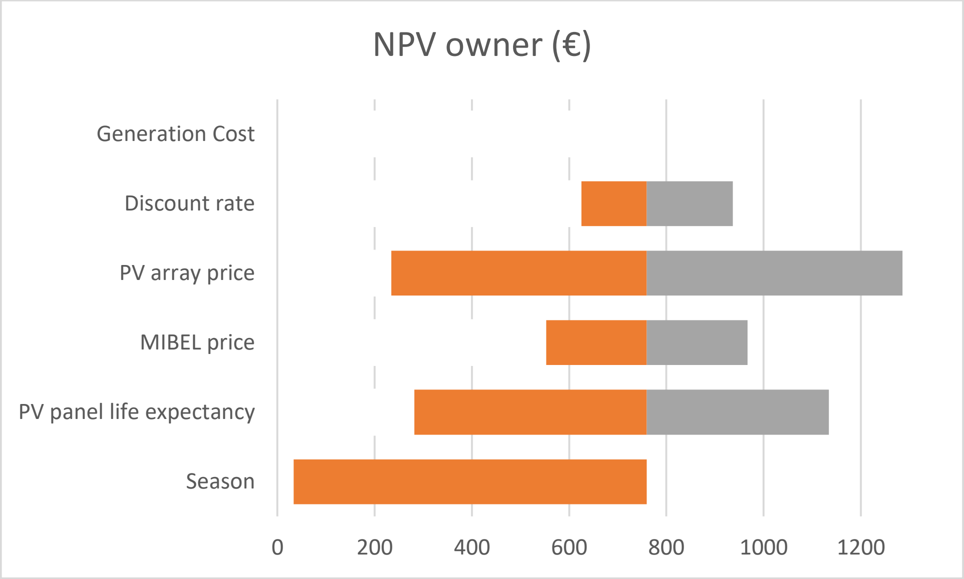
Table 19. Worst and Best Case Scenario for a PV array of 900W.

From the values in the table above, it can be observed that there exist possibilities where installing a PV array could incurred in costs for all the stakeholders in the system: the prosumer, the regular ratepayers and the overall system. However, even under unfavourable conditions, it can be seen that the prosumer does not lose that much compared to the other regular ratepayers, although this price-increase scenario is not likely to occur as prices for PV are expected to keep decreasing, as seen in Chapter 2. Additionally, it is observed that that the other ratepayers are net present value negative for all the scenarios, which reflects that if no changes are made in the energy market model, cross-subsidization will occur even in the best-case scenario.

On the other hand, in the high NPV case, or best-case scenario, a large owner's benefit makes the overall system gain welfare. In that case, the prosumer is more benefitted and the other ratepayers are not losing that much compared to the worst-case. However, for further conclusion a single-variable sensibility analysis must be developed to know the impact of each variable in the net present values for the different stakeholders.

From Graph 23, it can be concluded that the factor that most affects the net present value for prosumers is the season of the year, as the PV output and the retail tariff structure depend on that. The PV panel price and its lifetime also influence a lot the NPV for PV owners. A decrease in the PV panel price, as expected for the next years, will definitely be a driver for more consumers to become prosumers, as the benefits of installing a PV array are obvious. On the other hand, the grid generation costs will not have any impact on the NPV for owners when installing a PV array.

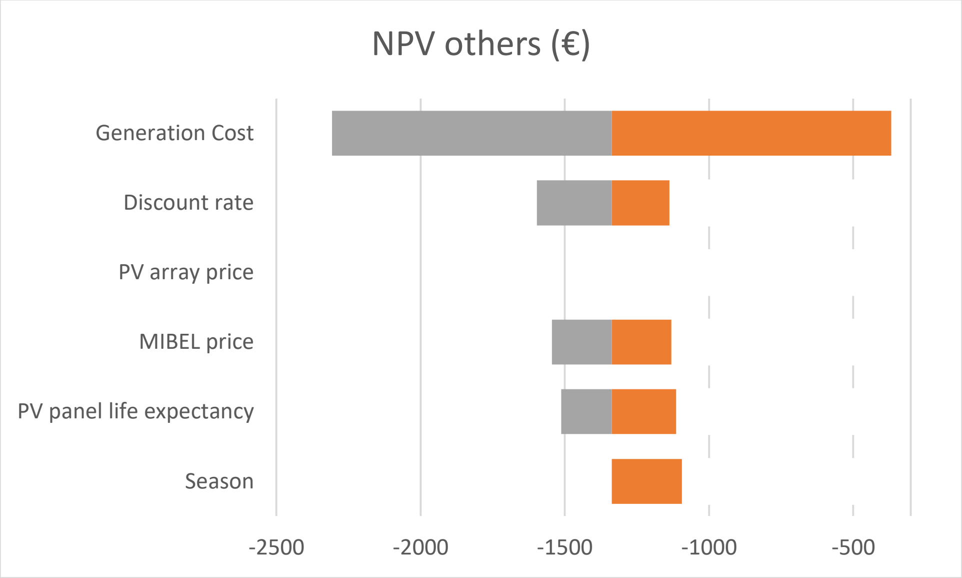
MIBEL price and the investment discount rate are considered to have a moderate impact on the prosumers NPV.



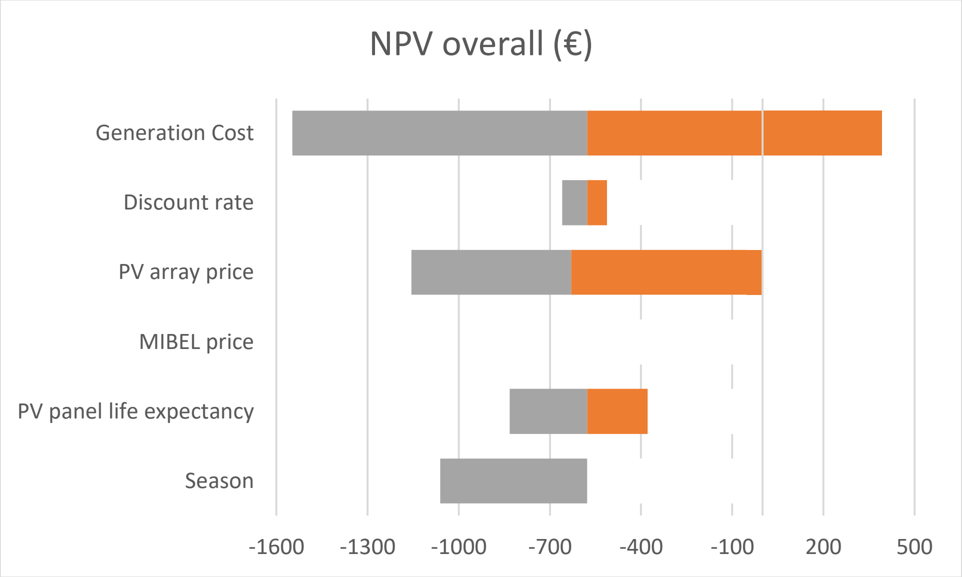
Graph 23. NPV Sensibility Analysis for PV owners.

In Graph 24, it can be observed the NPV for the other ratepayers is mainly driven by the system generation costs. If the generation costs for regular technologies are increased then solar PV becomes competitive and can bring down the costs of the system. Therefore, if generation costs rise, NPV for other ratepayers increases as the system is consuming cheaper energy served by solar PV. On the other hand, if the system generation costs decrease then the energy served by solar PV is more expensive and the system becomes less cost-effective decreasing the NPV for the non-PV owners. The other variables have a moderate impact, with the exception of the PV array price being the only one not affecting the other ratepayers.

In Graph 25, the sensibility is developed for each variable in the NPV overall case. It can be observed that there are mainly two variables dominating the NPV value: system generation costs and the PV array price. In the first case, if generation costs rise, the system will gain fare because the system electricity is being substituted by a cheaper energy source. On the other hand, if prices decrease, then solar is more expensive and is making the system less cost-effective, as mentioned in the previous paragraph. With regard to the PV array price, if it decreases, the system loss of welfare will be almost zero as it is consuming electricity at a lower investment price, and if they increase, the opposite situation will occur. It is important to highlight that an increase in 30€ in the generation costs can make the system gain welfare, as well as for the PV price, which can make the system gain welfare only by decreasing a bit more than 25%. The season considered, meaning the PV output and the tariff structure can also have an impact by decreasing the NPV in winter conditions. Ultimately, the PV panel life expectancy also impacts moderately the system welfare.



Graph 24. NPV Sensibility Analysis for other ratepayers.



Graph 25. NPV Sensibility Analysis for the overall system.

4.3.6. Tariff Assessment

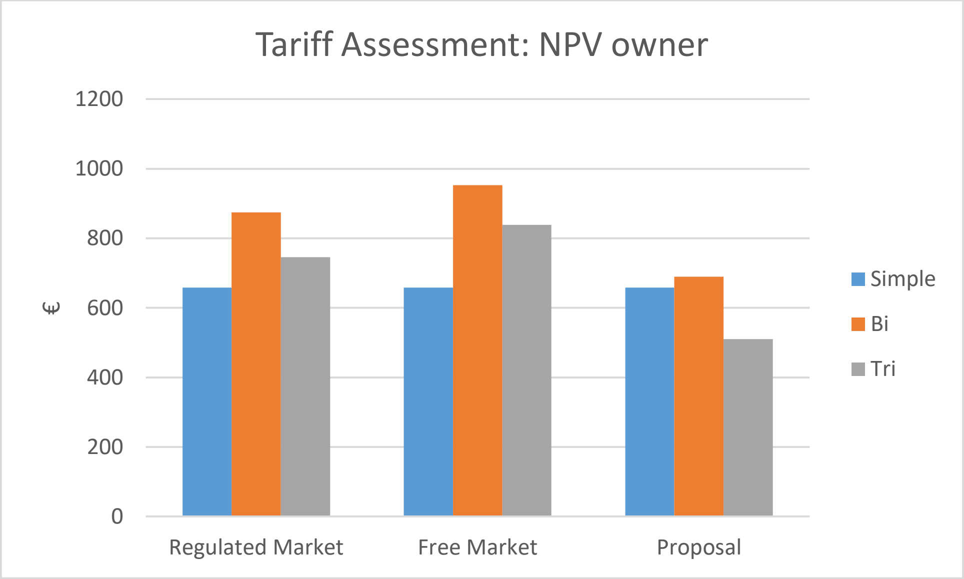
The tariff assessment will be developed for the 900W prosumer case. Tariff structures from the regulated market, the free market and the tariff proposal presented in Table 11, will be compared for analysing the system welfare in each case. Additionally, the tariff assessment will only be done for the base case. In this case, the tariff fixed component is not considered in the methodology, therefore only the volumetric part will be used and analysed.

All the retail tariff structures considered in the tariff assessment are presented in Table 20.

Active Energy	**FM**	**(€/kWh)**	**RM**	**(€/kWh)**	**Proposal**	**(€/kWh)**
Simple Tariff <=6,9 kVA	-	0.1634	-	0.1634	-	0,1634
Dual Rate Tariff <=6,9 kVA	Normal	0.1990	Out Valley	0.1909	Out Valley	0,1700
	Economic	0.0937	Valley	0.1002	Valley	0,1300
Triple Rate Tariff <=6,9 kVA	Normal	0.3182	Peak	0.2169	Peak	0,2300
	Economic	0.1636	Out Valley	0.1716	Out Valley	0,1420
	S.economic	0.0936	Valley	0.1002	Valley	0,1200

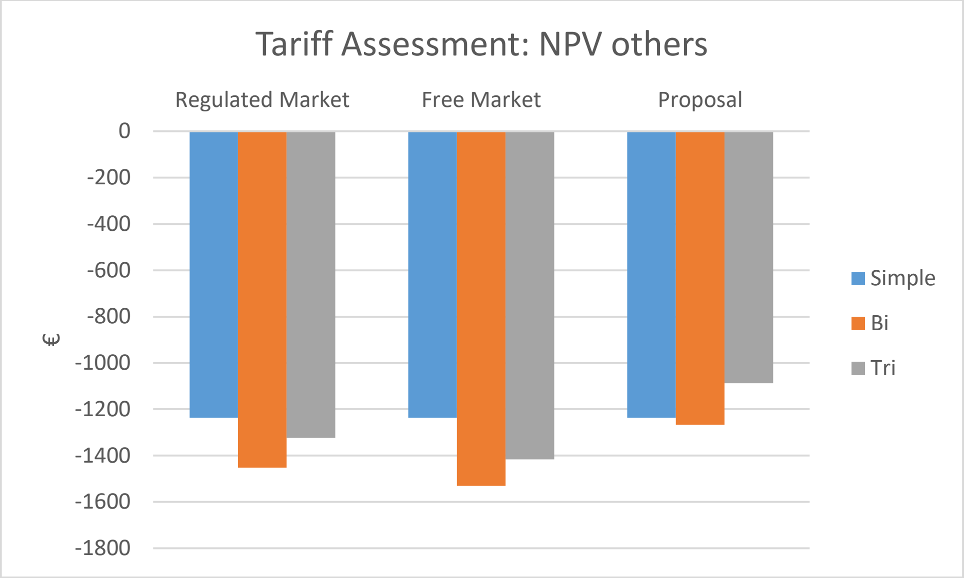
Table 20. Retail tariffs considered in the Tariff Assessment for the system welfare.

Graph 26 shows that for all the markets, even this work's tariff proposal, the Dual Rate structures offer more benefits to prosumers, which means that all the structures are still valuing more the energy consumed in the PV production period. In that sense, the most benefitted prosumer is in the free market with a Dual Rate structure. On the other hand, the less benefitted prosumer is under this work's proposal tariff conditions with a Triple Rate structure. Additionally, it can be observed that generally free market benefits more prosumers, while the alternative proposal reduce prosumer's incentives. It must be highlighted that as the Simple structure is the same for all the retail designs, there are no differences in the benefit of prosumers subjected to a flat rate regardless the market.



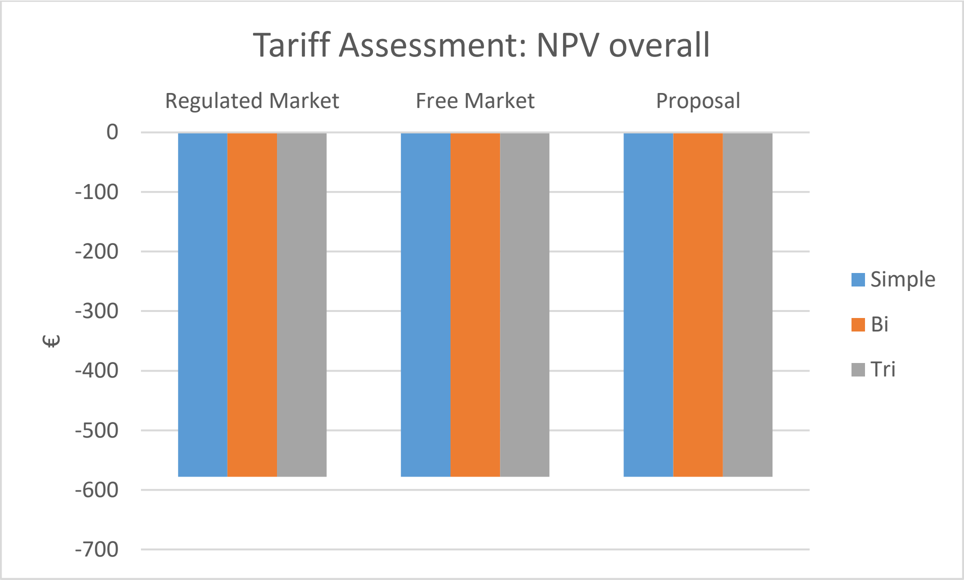
Graph 26. Tariff Assessment: NPV owner.

Graph 27 shows that the other ratepayers are being more disadvantaged by the free market, the regulated market and the alternative proposal in this order. The ratepayers in a Dual Rate tariff structure are also being more badly affected than the other time structures, so a regular ratepayer in the Free Market and with a Dual Rate tariff will be assuming around 1530€ in 20 years for a 900W prosumer, while with the alternative proposal it would be 1260€.



Graph 27. Tariff Assessment: NPV others.

Ultimately, Graph 28 shows that for the overall system welfare there is no difference between markets or tariff time structures. From that, it can be concluded that the tariff structure is only affecting how much the prosumer are being benefitted and how much are the other regular ratepayers being disadvantaged. System Welfare does not depend on the tariff volumetric structure.



Graph 28. Tariff Assessment: NPV overall.

5. Conclusions

PV energy has been called upon to play an important role in the future and its market is growing rapidly. PV market is emerging especially at a household level, configuring a new consumer that besides consuming is also able to produce energy, the prosumer. In Portugal, 80% of total PV installed capacity was at a residential level in 2013. A rapid decrease on PV prices, 78% from 2009 to 2014, and a high efficiency improvement rate, from 12% to 16% in the past ten years, are the two main drivers for this growth together to the climate change awareness arise of people, private and public institutions. However, PV integration in the energy system is posing many challenges both at an operational and at an economical level, and its rapid growth is exacerbating them.

PV prosumers are a particular kind of Distributed Generation based on RES that produce non-dispatchable energy by means of PV panels. Prosumers produce energy under a stochastic regime and in periods when the prosumer has an excess of energy, the destination loads are not necessarily close to the generation point, which can cause some issues on the network. First, the mismatch of PV production peak with the consumption peak, which will make the overall costs of the network remain the same and may cause some congestions in the network. Second, in case that the prosumer has an energy excess and the destination load is not close, network losses could increase. Third, other technical aspects like network protection and voltage profiles can be affected by the integration of PV energy in the grid.

Additionally, PV prosumers integration are arising issues on current energy markets. Firstly, RES integration in the market reduces the wholesale electricity price, as its marginal cost in the spot market auction is zero. The average price of all European Energy Markets has decreased from 50€/MWh to 40€/MWh between 2012 and 2015. Secondly, and consequently, there is a mismatch between the wholesale and the retail price due to the RES deployment and the no-decrease of investment costs in conventional technologies. Thirdly, low or even negative prices in European Energy Markets are not showing efficient signs for investment and operational behaviour, discouraging investment in new capacity. Ultimately, the fact that prosumers are reducing consumption together with the current variabilization of fixed costs in the retail tariff volumetric part creates cross-subsidies among customers, making more vulnerable to an increase in tariffs, phenomenon known as consumer divide. Moreover, cross-subsidization and a higher capital cost for PV compared to other technologies can also produce a system loss of welfare, affecting the overall consumer, prosumers and regular ratepayers.

In that sense, this study has developed a methodology to quantify cross-subsidization caused by the prosumers' reduction on consumption and has adapted another already existing methodology to quantify the system loss of welfare. The conclusions withdrawn from the results obtained are presented in the two following sections.

5.1. Cross-subsidies in the energy sector

It can be concluded that cross-subsidization increases with PV installed capacity, as more energy will be self-consumed and more fixed costs will be avoided due to their variabilization in the retail tariff volumetric. In addition, for each PV installed capacity, the most subsidized prosumers will be those with Dual Rate Tariffs, Triple Rate Tariff and Simple Tariff in that order. The difference between different retail tariff structures can be explained by the fact that, in summer and winter period, the average price for the energy consumed within the PV production is more expensive for the Dual Rate Tariff (0.1715 €/kWh) than for the others (0.1644€/kWh for Triple and 0.1634€/kWh for Simple).

In that sense, for a fixed component share in the retail tariff of 18.9%, a prosumer with 1500W of installed PV and being charged through a Dual Rate Tariff is avoiding annually around 204€, while a prosumer with only 300W of installed capacity and Simple tariff design is evading 44€ in terms of fixed costs. If seasonality is applied, and summer and winter periods are compared, there is an average decrease of 20% in cross-subsidization among customers in the winter period. Additionally, the longer time the prosumer is producing energy, the higher cross-subsidization will be.

On the other hand, when comparing the results obtained for the Free and Regulated Market, it can be said that there is not a big difference, although the tendency shows that cross-subsidization in the Free Market is 4% higher as an average. That can also be explained by a higher retail tariff price within the PV production period in the Free Market.

If the fixed component share is modified, and higher non-volumetric charges are applied, cross-subsidization is obviously reduced. If the fixed component accounts for the 70% in the retail tariff, cross-subsidization could be reduced in 69%. More moderate, increases show that for a retail tariff fixed component of 30% and 50%, reduction will represent 6% and 25% respectively. If the retail tariff reproduces the system’s costs structure, and fixed component in the retail tariff accounts for the same that fixed costs do, cross-subsidization will be eradicated.

Ultimately, if the retail tariff volumetric part decreases the retail price of energy within the PV production period, as in the tariff proposal presented in this work, then cross-subsidization will be reduced in 10% compared to the Free Market and in 7% for the Regulated Market.

5.2. System Loss of Welfare

In the base case, for all the PV installed capacities and under the same retail tariff structure (it has no impact on the overall system welfare), there is a system loss of welfare quantified by the NPV for the overall ratepayer, going from the 600€ in the 600W case to 225€ in the 1500W scenario. It can be concluded that capital costs for PV integrated in the energy system are one of the main drivers for the system welfare. Additionally, it has been observed that the system loss of welfare is not always reduced with the PV capacity as from 300W to 600W it increases. One of the reasons for that could be that PV prices per watt considered in that work do not follow a lineal tendency but a logarithmic one.

Sensibility analysis for the overall consumer showed that there are mainly two variables dominating the NPV value: system generation costs and the PV array price. In the first case, if generation costs rise, the system will gain fare because the system electricity is being substituted by a cheaper energy source. On the other hand, if prices decrease, then solar is more expensive and is making the system less cost-effective. Second, if the PV price array decreases, the system loss of welfare will be almost zero as it is consuming electricity at a lower investment price, and if they increase, the opposite situation will occur.

With regard to PV panel owners for the base case, the benefit of installing a PV panel array will depend on the capacity installed and on the volumetric retail tariff. For higher capacities, PV panel owners will obtain larger benefits and in all cases the Dual Rate Tariff will be more favourable for prosumers. For instance, a prosumer with 1500W of installed capacity being charged through the Dual Rate tariff will have around 30 times more benefit than a prosumer with 300W and a Simple tariff structure.

Additionally, it can be concluded that the factor that most affects the net present value for prosumers is the season of the year, as the PV output and the retail tariff structure depend on that. The PV panel price and its lifetime also have a strong influence on the NPV for PV owners.

When it come to the regular ratepayers, in all cases the present value for the energy acquisition price from the gird will be higher than the present value for the system electricity that is substituted by solar PV, which can be explained by a higher LCOE for solar PV than other generation technologies. A regular ratepayer will be paying an additional cost valued from 575€ every time a PV array of 300W is integrated to 2304€ when a 1500W PV module is installed, both subjected to the simple tariff.

In that case, the sensibility analysis pointed out that the NPV for the other ratepayers is mainly driven by the system generation costs. If the generation costs for regular technologies are increased then solar PV becomes competitive and can bring down the costs of the system. Therefore, if generation costs rise, NPV for other ratepayers increases as the system is consuming cheaper energy served by solar PV.

Ultimately, regarding the impact that Free or Regulated Market and this work’s proposal could have on the system loss of welfare, it can be said that the system welfare does not depend on the retail tariff volumetric part and, therefore, there are no differences. However, prosumers are still more favoured by the Free Market and the Dual Rate Tariff structures. Contrarily, prosumers will not be that advantaged is this work’s proposal is applied. On the other hand, non-PV owners in a Dual Rate Tariff and in the Free Market will be more affected than under other time structures. For instance, a regular ratepayer in the Free Market and with a Dual Rate tariff will be assuming around 1530€ in 20 years for a 900W prosumer, while with the alternative proposal it would be 1260€.

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