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Departamento de Engenharia Geográfica, Geofísica e Energia

Enabling solar electricity with electric vehicles in future energy systems

Pedro Rudolfo Martins Nunes

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Tese orientada pelo Prof. Doutor Miguel Centeno Brito e coorientada pelo Prof. Doutor Tiago Lopes Farias, especialmente elaborada para a obtenção do grau de doutor em Sistemas Sustentáveis de Energia

2015

Para

A Mónica.

Os meus pais.

Todos os outros que me são queridos nesta vida.

Sem esquecer o Fagulha.

"What concerns me is less the mechanics of the transition – the shift from brown to green energy, from sole-rider cars to mass transit, from sprawling exurbs to dense and walkable cities – than the power and ideological roadblocks that have prevented any of these long understood solutions from taking hold on anything close to the scale required."

"…climate change changes everything."

Naomi Klein, *This Changes Everything*

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Resumo

As alterações climáticas estão na agenda dos líderes mundiais e dos decisores políticos, pois contê-las é fundamental. Neste quadro, a União Europeia traçou metas ambientais exigentes, como a redução das emissões de gases com efeito de estufa em 80-95% até 2050. Para isso, os sistemas de energia terão de assentar em energias renováveis, particularmente em energia fotovoltaica, uma vez que no futuro esta parece ser a forma com maior potencial de geração de electricidade limpa. Porém, esta situação contribuirá para o desfasamento entre a produção e o consumo, com geração de energia solar em excesso durante o dia. Esta energia em excesso pode ser convenientemente canalizada para a mobilidade eléctrica, aproveitando a capacidade das baterias dos veículos eléctricos a funcionar como armazenamento controlável e distribuído.

Na presente tese, com base em cenários do ano 2050 para o caso de Portugal, exploram-se as sinergias entre a energia fotovoltaica e os veículos eléctricos, determinando-se os níveis mínimos de penetração que permitem o cumprimento das metas na área do ambiente. Analisa-se em que medida a energia fotovoltaica permite uma maior integração do veículo eléctrico, e vice-versa. Os impactos na rede de energia eléctrica são determinados quantitativamente, assim como a penetração necessária de uma tecnologia que permite a implantação da outra.

Os resultados do modelo mostram que as metas para as emissões de CO_2 só podem ser alcançadas com elevadas penetrações de energia fotovoltaica e veículos eléctricos, o que reforça a necessidade da existência de infraestruturas para carregamento dos veículos durante o dia, tal como nos locais de trabalho. Mostra-se que 100% de energia eléctrica renovável é possível com determinadas combinações entre as duas tecnologias e que as metas ambientais para redução de emissões de CO_2 são apenas alcançáveis com pelo menos 40% de penetração de veículos eléctricos no mercado.

A presente tese contribui para a literatura sobre a integração na rede eléctrica de elevados níveis de energia renovável e sobre a interacção entre energia renovável e veículos eléctricos.

Palavras-chave: Veículos eléctricos; Cenário energético; Energia fotovoltaica; Sistema de energia; Carregamento inteligente

Abstract

Climate change is on the agenda of many world leaders and policy makers, and its containment is of exceptional importance. Within this frame, ambitious environmental targets have been established by the European Union, including the reduction in greenhouse gases emissions by 80-95% until 2050. To do so, energy systems will require a large share of renewable energies, particularly solar photovoltaic power, since it appears to have the greatest potential for decarbonized electricity generation. However, relying on such renewable energy sources is expected to generate a mismatch between production and consumption, namely considerable excess solar electricity during day time. This excess power may be conveniently used to power electric mobility, taking advantage of the battery capacity of the electric vehicles acting as distributed controllable storage.

In this thesis, based on 2050 scenarios for the case study of Portugal, the synergy between photovoltaics and electric vehicles is explored, determining the minimum penetration levels that allow fulfilling the climate and energy targets. It is analyzed the extent to which photovoltaic energy can further transport electrification integration, and vice-versa. The technical impacts on the electricity system are determined quantitatively, as well as the required penetration of one technology that enables the deployment of the other.

Model results show that CO_2 emissions targets can only be achieved with high levels of photovoltaics and electric vehicles, reinforcing the need for day time charging infrastructures, presumably at or near work facilities. It is shown that a 100% renewable energy based electricity supply is possible for certain combinations of these technologies and that the environmental targets to reduce CO_2 emissions can only be reached with at least 40% of electric vehicles market share.

The present thesis contributes to the literature on integration of high levels of renewable energy sources on the electric grid and on interactions between renewable energy and electric vehicles deployment.

Keywords: Electric vehicles; Energy scenario; Solar photovoltaics; Energy system; Smart charging

Publications list

This doctorate is sustained by the following original publications. The submitted manuscript of Article I and Articles II-IV are reproduced at the end of the thesis.

Publications on the basis of the thesis and included on it:

I. Pedro Nunes, Tiago Farias, Miguel C. Brito, "Enabling solar electricity with electric vehicles smart charging", submitted to *Energy* journal (Jan. 2015).

II. Pedro Nunes, Tiago Farias, Miguel C. Brito, "Day charging electric vehicles with excess solar electricity for a sustainable energy system", *Energy*, 80, 263–274 (2015). doi:10.1016/j.energy.2014.11.069

Other authored or co-authored publications during the doctorate included in the thesis:

III. Miguel C. Brito, Killian Lobato, Pedro Nunes, Filipe Serra, "Sustainable energy systems in an imaginary island", *Renewable and Sustainable Energy Reviews*, 37, 229–242 (2014). doi:10.1016/j.rser.2014.05.008

IV. Pedro Nunes, Maria Lerer, G. Carrilho da Graça, "Energy certification of existing office buildings: Analysis of two case studies and qualitative reflection", *Sustainable Cities and Society*, 9, 81–95 (2013). doi:10.1016/j.scs.2013.03.003

Other selected publications during the doctorate not included in the thesis:

V. Pedro Nunes, Tiago Farias, Miguel C. Brito, "Synergies between electric vehicles and solar electricity penetrations in Portugal", *EVS27 Conference Proceedings* (2013). doi:10.1109/EVS.2013.6914942

VI. Pedro Nunes, Tiago Farias, Miguel C. Brito, "Photovoltaic and electric vehicle large scale deployments: opportunities and complementarities", *EU PVSEC28 Proceedings* (2013). doi:10.4229/28thEUPVSEC2013-6CV.5.42

VII. Pedro Nunes, Maria Lerer, G. Carrilho da Graça, “Building Energy Certification System: Application to a Building in Lisbon and Paths to a Future Enhanced Scheme”, *Energy Engineering*, 110 (4), 37–41 (2013). doi:10.1080/01998595.2013.10707933

VIII. Pedro Nunes, Maria Lerer, G. Carrilho da Graça, “Building Energy Certification System: Application to a Building in Lisbon and Paths to a Future Enhanced Scheme”, *International Conference for Enhanced Building Operations (ICEBO) 2011 Proceedings*. ESL-IC-11-10-52

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List of abbreviations and nomenclature

AC	Alternating Current
CCGT	Combined Cycle Gas Turbines
$C_{charging}$	Maximum charging power of the entire V2G fleet
CEEP	Critical Excess of Electricity Production
C_{V2G}	V2G connection capacity
$(\delta_{V2G})_i$	Transport demand at hour *i*
d_{flex}	Flexibility factor
DSM	Demand Side Management
DSO	Distribution System Operator
d_{stab}	Minimum grid stabilization demand
D_{total}	Total electricity demand
D_{V2G}	Annual transport demand
EEP	Excess of Electricity Production
E_{source}	Energy produced by the source in question
e_{stab}	Electricity production from regulation capable sources
e_{th}	Total electricity production from sources with flexibility constraints
E_{total}	Total electricity produced on the system
EU	European Union
EV	Electric Vehicle
GHG	Greenhouse Gases
η_{charge}	Charging efficiency
HEV	Hybrid Electric Vehicle
ICE	Internal Combustion Engine
IEA	International Energy Agency
INE	Instituto Nacional de Estatística (the national statistical office)
M	Million
MIBEL	Mercado Ibérico de Electricidade
NEP	Annual number of hours at full power

OECD	Organization for Economic Co-operation and Development
PES	Primary Energy Supply
PEV	Pure Electric Vehicle
PHEV	Plug-in Hybrid Electric Vehicles
PP	Power Plant
PV	Photovoltaics
RES	Renewable Energy Sources
SO	System Operator
SOC	State Of Charge
T&D	Transmission and Distribution
Toe	Ton of oil equivalent
TSO	Transmission System Operator
UK	United Kingdom
US	United States
USD	United States Dollar
V2G	Vehicle-to-grid
VPP	Virtual Power Plant

1. Introduction

On the context of the need of developed countries to drastically reduce world greenhouse gases (GHG) emissions, with the goal of limiting climate change below 2ºC[1] [1], the European Union (EU) envisages a low carbon footprint society for the future. Ambitious environmental targets have been established, such as those from the Energy 2020 strategy [2] and the longer term goals from the Energy Roadmap 2050 [3], in which it is proposed reducing overall GHG emissions by 80-95%, compared to 1990 levels. More recently, an intermediate binding milestone of at least 40% reduction in GHG emissions by 2030 was adopted [4].

The energy sector is responsible for the biggest share, approximately 30%, of GHG emissions in the EU [5] and transport is right after, responsible for around a quarter, with the road transport alone answering for a fifth of total emissions [6]. Consequently, such reduction target can only be achieved by the intensive use of renewable energy sources (RES) and major alterations to the transport sector, still a growing source of GHG emissions with a substantial 36% increase over the past two decades, putting it presently 8% above the 1990 level [6]. The Roadmap 2050 shows that the targeted GHG emissions reduction will have to be met largely domestically within the EU and, thus, within each member state [3].

[1] Compared to pre-industrial levels.

Electricity will play a major role in the decarbonisation of society, given its increasingly importance as an energy vector in modern societies [7], [8] and its potential cleanliness when produced using RES.

In particular, solar electricity generated from photovoltaic (PV) technology appears to be in the future the most attractive form of decarbonized electricity generation, due to its ample resource available [9], noiseless nature, scale flexibility, simple operation and maintenance [10], [11] and price competitiveness trajectory [9], [12], [13]. Hence, solar PV is projected to be the dominant source of electricity in a global warming limiting scenario [14].

This is particularly true for Portugal, with one of the highest insolation levels among Europe [15] and, at the same time, very dependable on external energy supply, with imports accounting for about 80% of internal energy demand in 2011 (mostly oil, coal and natural gas) [16]. With other RES installed capacity or planed installed capacity almost tapped, namely hydro and onshore wind, and not having bet on nuclear power, PV in Portugal is the most promising source of clean, abundant and free of concerns of security of supply[2] energy.

Nevertheless, Portugal just started to explore its solar potential, having only 282 MW of solar PV installed [17][3]. The reasons have to do with a low price competitiveness of the solar PV energy when compared to other electricity sources, but this is changing. Since 2008 solar system prices have decreased by two thirds in most markets [18] and grid parity[4] has already been partially reached in Spain, Germany and Italy [19] and it is expected that the same happens gradually in the rest of the European countries [20].

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[2] Given the universally deployable and distributed nature of solar PV energy.

[3] As a comparison, Germany had 35.7 GW of PV installed at the end of 2013. With a resource of 1200 $kWh/m^2/year$ [197], it has 438 W/person of solar PV installed [198] and Portugal, with a resource of 1900 $kWh/m^2/year$ [197], has 28.2 W/person [17].

[4] Competitiveness is assessed by grid parity: PV will reach it when the electricity produced by a PV system throughout its lifetime has the same cost as buying electricity from the grid [12].

Comparing to the present, by 2050 the cost of solar technology is estimated to have lowered 65% [18].

On the other hand, in the context of the EU environmental targets, in particular the intention to reduce transport-related emissions of CO_2 by at least 60% by 2050[5], electric vehicles[6] (EVs) are a key technology. The EVs are potentially much cleaner than internal combustion engine (ICE) models, because the carbon footprint of EV driving is directly related to the electricity used to charge the batteries, which, on the limit, can be 100% carbon free. Portugal is well positioned to adopt this technology, given its governmental plan of electric mobility, with the deployment of a public recharging infrastructure with 1300 normal charging stations (3.7 kW) and 50 fast charging stations (50 kW) [21], and a green taxation system promoting the adoption of EVs [22].

For these reasons, PV and EVs are expected to have mass adoption in the coming decades across the globe [12], [14], [23]–[25], leading to well-known and relevant impacts on the national energy systems, e.g. possible mismatch between production and consumption of solar electricity and higher electricity demand for EV mobility. Abundant non-dispatchable renewable energy, whose output is conditioned by meteorology and therefore variable, is difficult to articulate with existing base load power generation capacities, that possess limited flexibility and ramp rates (i.e., limited ability to balance rapid changes in renewable generation and demand by adjusting their output) and high minimum output levels[7], leading to an endogenous electricity production superavit, which may have to be curtailed or, when similar amounts of

[5] Compared to 1990 levels.

[6] In this study, when EV is referred it means electric vehicles in general, comprehending pure electric vehicles, i.e., vehicles propelled solely by electricity, with no internal combustion engine used for propulsion, and plug-in hybrid electric vehicles. These technologies are discussed in Section 2.1.2.

[7] Moreover, sufficient load following capable generating power has to be available ahead of periods with high load and low non dispatchable renewables output, reducing the overall system efficiency and increasing the energy cost [26].

variable generation are installed in surrounding markets, exported at low prices[8] [26]. There are thus critical challenges to integrate large-scale PV in the electricity grid, limiting ultimately its contribution to the electricity sector if the deployment is done without articulation with other technologies and careful planning [27], [28][9].

Hence, the installation of storage devices to absorb this energy is highly beneficial [29]. The EVs, with their large battery capacity[10], if seen as a whole, acting as distributed controllable loads and storage [30], may be an answer to avoid increasing worldwide excess of energy [31]–[33]. Indeed, the most significant impact on the electricity system of EVs is their ability to assist the integration of renewable energy into existing power grids [34]. That is, their benefits lie outside the transport sector, since the vehicles storage capacity can serve the upstream electric grid [30]. Additionally, storing energy on EVs batteries should be cheaper than using dedicated grid-scale energy storage technologies, since the cost involved is just the marginal cost of using the batteries because they have been paid for its other purpose: the electric vehicle.

For the particular case of a PV-EV based energy system, there are also other relevant benefits to the transport sector. For example, mid-day solar charging has the potential to increase the daily driving range for commuters' vehicles, important for diminishing driver's range anxiety, a phenomenon seen as a barrier to the EV market uptake [35]. For the particular case of plug-in hybrid EVs (this technology is addressed in Section

[8] It can be exemplified by peak wind generation hours, usually overnight, which do not match the peak load periods that happen during the day, hence leading to negative electricity prices in energy markets. Another example is on sunny days, when PV combined with wind pushes down mid-day demand for fossil fuels power, again leading to negative energy prices, in particular at weekends, when demand is lowest, something which has been anticipated [27], [28] and has already happened [199], [200].

[9] Recently, a non-binding target of interconnection reinforcement between Iberia and France until 2030 [4] has been settled, which may facilitate PV deployment, but it is not a PV enabler per se, rather than one measure among several others that contribute to integrate fluctuating RES [117].

[10] Electrochemical batteries are the most common option for current EVs [201].

2.1.2), this would increase the fraction of miles driven electrically, hence decreasing traveling on ICE mode and petroleum use [36], contributing to the accomplishment of environmental goals.

However, the effects of uncontrolled EV charging are negative, with consequences both at the distribution and generation levels, particularly if the additional electricity demand occurs during peak hours. It is usually assumed that small scale EV introduction (up to 5% of a national fleet) will not pose a significant threat to advanced distribution grids [37], but beyond that the effects may be significant.

1.1. Research questions and purpose

In spite of the scientific and societal relevance of the interactions between PV and EV, in the literature there seems to be a lack of depth of analysis on it, as it has been recently highlighted in [34] and as discussed in detail in Section 2.2, particularly within the scope of the EU environmental goals. Thus, the following research questions, addressed in this thesis, emerge:

1. What are the synergies between PV and EV?
2. How can PV and EV be articulated to better explore their synergies?
3. What is the best EV charging strategy?
4. What levels of PV and EV, individually and separated, are needed to comply with the EU energy-climate targets?

Therefore, the purpose and object of this thesis is to explore the synergies and conflicts between the large penetration of PV and the widespread deployment of EVs in future sustainable energy systems, using energy scenarios for Portugal in 2050 as case study. The analysis considers the effect of different EV charging strategies, including smart charging.

The extent to which PV energy can further transport electrification integration, and vice-versa, is analyzed, providing an overview of the possible impacts of the introduction of PV in articulation with EVs. The technical impacts on the electricity system are determined quantitatively, as well as the required penetration of one technology which enables the deployment of the other, combining and simulating several alternative scenarios representing combinations between both technologies.

This research concerns Portugal, but qualitatively the conclusions may well be generalized to other similar contexts. It contributes to the literature on integration of high levels of renewable energy sources on the electric grid and on the interactions between renewable energy and electric vehicles deployment.

1.2. Contents outline

This thesis comprises five chapters and four articles, referred to in the text as Articles I–IV. See the list of publications for complete references.

Chapter 1 provides an introduction to the European and Portuguese context and, within it, to the positive and negative effects on the electricity grid of mass deployments of photovoltaics and electric vehicles, individually and combined. It also explains the purpose of this thesis and the research questions addressed.

Chapter 2 provides the necessary background on the topic before proceeding, explaining the main concepts. It includes a state of the art overview with a summary of the most important works existing in the literature.

Chapter 3 contains a detailed explanation of the methodology used to conduct the work. It is composed of a presentation of the energy tool used and of descriptions of the general approach, the model calibration, the scenarios modelling process and the charging strategies tested.

Chapter 4 presents and discusses the results of the simulations, divided according to the charging strategy.

Chapter 5 provides a wrap up, with the main conclusions, limitations and suggestions for future work.

Article I, "Enabling solar electricity with electric vehicles smart charging", has been submitted to *Energy* journal, being currently under review. It explores the synergy between PV and EV technologies, determining the minimum penetration levels that allow fulfilling the climate and energy targets based on an EV smart charging strategy.

Article II, "Day charging electric vehicles with excess solar electricity for a sustainable energy system", has been published in *Energy* journal, vol. 80, pages 263-274 (2015). It explores the possible complementarities between wind and solar power and electric vehicles charging using a day and night EV charging profiles.

Article III, "Sustainable energy systems in an imaginary island", has been published in *Renewable and Sustainable Energy Reviews* journal, vol. 37, pages 229-242 (2014). It presents an overview of the state of the art sustainable energy systems methodologies for isolated systems and describes the complete analysis of the energy system of a fictional case study, including electricity supply and demand, heating and mobility. It details the methodology used to build a 100% renewable energy system from scratch. This methodology requires reviewing the different renewable energy technologies, energy demand conditioning tools and energy storage alternatives, which are extensively discussed. It shows from first principles how to integrate and coordinate electric vehicles in a renewable energy based system. It is a work developed for an Energy Systems module lectured at the University of Lisbon on the context of the MIT Portugal Sustainable Energy Systems doctoral program.

Article IV, "Energy certification of existing office buildings: Analysis of two case studies and qualitative reflection", has been published on *Sustainable Cities and Society* journal, vol. 9, pages 81-95 (2013). It presents the application of the Portuguese building energy certification system to two large office buildings in Lisbon, and a cost–benefit analysis of different energy optimization scenarios based on calibrated building thermal simulation models. The results are used to examine the principles and energy indicators of the Portuguese energy certification scheme, resulting in a qualitative reflection about its limitations and opportunities for improvement. It was published following the line of research that first was embraced in the doctorate, before a divergence to the topic of the present thesis.

2. Background and state of the art

To have a proper understanding about the research issue addressed in this work, it is essential to know the background and to have an insight on previously existing reference literature. This background along with a summary of the most important works in this field, which served as backbone to outline, design and perform this study, are presented in this chapter.

2.1. Introduction

2.1.1. Solar photovoltaics

The sun is an inexhaustible resource worldwide, constantly delivering to the Earth's upper atmosphere 1366 W/m^2, the solar constant, which is reduced to 1000 W/m^2 by atmospheric scattering and absorption and to 125-305 W/m^2, or 3-7 kWh/m^2/day, by latitude, seasonal and diurnal variations [42]. The planet has an average PV generation potential of 3.6×10^4 TW, compared to an average demand of 17 TW [38]. In Portugal, the annual value of average irradiance is of 250 W/m^2, which, considering weather factors, such as cloud cover, diminishes to 210 W/m^2, or 5 $kWh/m^2/day$ – still around 650 fold more than the country's total primary energy consumption.

However, the solar resource is inherently variable, posing a challenge for satisfying constant human energy needs with solar power. There are two types of variability: (1) deterministic variability, which is the result of diurnal and seasonal variation as well as local climate, thus predictable; (2) stochastic variability, which is the result of cloud cover and weather. It is predictable just to a certain degree.

The variability is managed according to time and length scale: local, short-term variations are smoothed by geographical averaging, i.e., power distribution over geographical areas larger than clouds and weather systems, or by demand management. Larger or longer-term variation requires grid-scale energy storage or deployment of dispatchable complementary energy sources [39].

In spite of this variability, it is consensual that solar PV is the most promising form of sustainable electricity generation in the future [10]–[12], [40], [41]. The conversion of sunlight into electricity is done without the help of machines or any moving parts, providing PV systems with long lifetime (>25 years) and minimum maintenance cost. The systems are simple to design and their stand-alone installation can provide outputs from W to MW, making the technology suitable to both distributed and centralized production. Unlike thermal generators or wind turbines, which lose efficiency with reduced scale, small PV arrays are no less efficient than the large ones [39]. Photovoltaic cells absorb photons and produce free electrons through the PV effect, generating electricity. Multiple PV cells form a PV module and multiple PV modules connected in series or in parallel form a PV system. The present average commercial module efficiency is 14.5%, expected to grow to 20.5% by 2020 [41].

Today there are mainly two types of technologies involved in solar PV, crystalline and thin semiconducting films. Crystalline solar cells represent about 90% of the world market, divided between mono-crystalline (35%) and multi-crystalline (55%) [39], with China and Taiwan as the largest cell and module producers. In the future, thin film type multi-junction devices, operating in a wide range of the solar irradiation spectrum and suitable for large-scale production, may increase their market share [38]. The same for other emerging PV technologies, based also on thin film cells (organic, polymeric, etc.), due to their potential for very low cost and acceptable efficiencies. For a complete insight on PV cells and modules technology, see [39].

The PV industry is rapidly developing, and is the fastest industry growing worldwide [38]. The global PV cumulative installed capacity has been growing exponentially in the recent years: it was 2.6 GW in 2003, 15.8 GW in 2008 and 138.9 GW in 2013, i.e., a fifty-fold growth in ten years and a nine-fold growth in the last five years [42]. In spite of that, in 2013 it produced 160 TWh, only 0.5% of the global electricity demand [38]. It is projected that will rise to 16% in 2050 [18]. In Europe, with the largest share of PV installed in the world (55%), PV in 2013 covered 3% of the electricity demand. In a business as usual scenario, it is projected to grow to between 7% and 11% by 2030 [42].

The price of the kWh produced from PV is steadily declining, putting it on a competitiveness trajectory. This is due to: (1) the PV module production costs have been decreasing, from 10 EUR/W_p in 1990 to less than 0.8 EUR/W_p in 2013 [43]; (2) innovation in materials technology; (3) increase in the PV module production, leading to economies of scale; (4) improvements in cell efficiency; (5) PV systems longer lifespan; (6) favorable public policies for renewable energy [41].

However, large scale deployment of PV requires support by public policies to promote carbon emissions reduction and technological innovation. The main support mechanisms to finance renewable energy development are described in [8], where the authors compare feed-in-tariffs, tax incentives and tradable green certificate as support mechanisms to finance RES development programs. The energy policies to promote PV deployment are reviewed in [44] and in [10] and, more recently, in [45], which also gives an updated perspective on the solar PV energy developments. For a discussion on how high PV quotas will affect electricity markets, see [13]. For a complete discussion on global prospects, progress, policies and environmental impact of solar PV power generation, see [38].

2.1.2. Electric vehicles

There are three main types of EVs: hybrid electric vehicles (HEVs), plug-in hybrid electric vehicles (PHEVs) and pure electric vehicles (PEVs). Among other differences addressed below, in the HEVs the battery is not externally rechargeable while in the PHEVs and PEVs it is.

The HEV combines two distinct power sources in order to provide driving power, a conventional internal combustion engine (ICE) and an electric motor coupled with a battery, as Figure 1 shows. Typically, the low efficiency ICE is used in combination with a much higher efficient electric system, achieving better fuel economy and better performance than a conventional ICE. It has a hybridization ratio defined as the division between the maximum power of the electric motor and the maximum power of the power train. Full HEVs are able to drive in conventional vehicle transmission mode by utilizing the ICE or in electric power mode or both. The HEVs have an electric motor/generator system which operating as a generator produces electricity, through the ICE or regenerative braking, to charge the battery; when used as a motor, propels the vehicle [46]. As stated, the HEV does not have a plug-in connection to the electricity network.

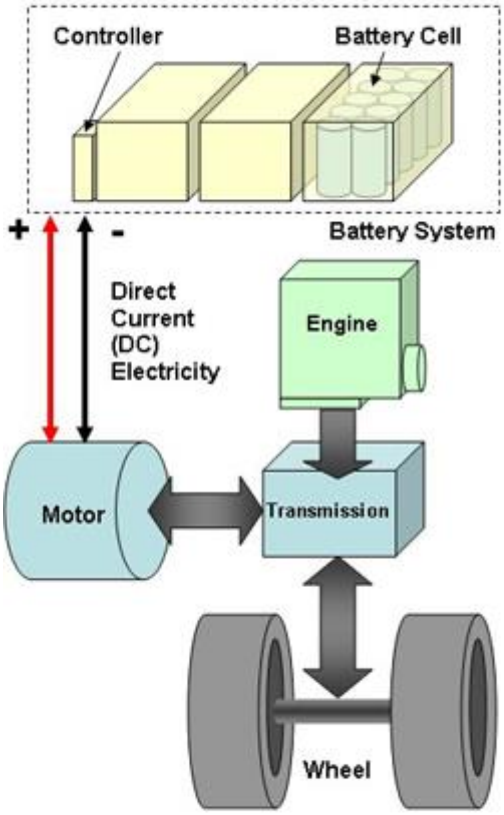

Figure 1. Outline of a typical parallel HEV. Adapted from [47]

The PHEVs, introduced in the market later than the HEVs, are similar to the latter to the extent that both have an ICE and an electrical drive-train. By definition, PHEVs are HEVs that have a battery of at least 4 kWh, a means of recharging it from an external source and the ability to drive 16 km or more in pure electric mode [48][11]. They can run on gasoline/diesel or on electricity or on a combination of both. They are more efficient than HEVs since a more limited use of the ICE increases the overall vehicle efficiency, allowing at the same time the ICE to be used closer to its peak efficiency by operating only at high speeds – which leads to several advantages such as reduced dependence on oil, increased fuel economy, increased power efficiency, lower GHG emissions and the ability to be smart charged[12] [46], [49].

[11] Today's maximum driving range for PHEVs in pure electric mode is 20-60 km [46].

[12] Smart charging is addressed in Section 2.1.2.1.

These vehicles have a battery pack that can be completely charged by plugging the vehicle into a standard European electrical outlet of 230 V AC. In addition, as with HEV, regenerative braking also provides an on-vehicle battery charging alternative. When charged from the power grid, over a well-to-wheels life cycle PHEVs may emit less CO_2 and other pollutants than ICE vehicles and HEVs [50], provided that the grid electricity is cleaner than gasoline or diesel [36]. This electricity may come from any energy sources, including RES with zero-emissions, in this case turning PHEVs GHG emissions close to zero [51].

There are three designs of PHEVs: series, parallel and combo. In the series design the wheels are propelled just by the electric motor, as Figure 2 shows, fueled by electricity from a generator turned by the ICE [49]. The battery stores any charge produced in excess by the ICE. In the parallel design, similar to the HEV design of Figure 1, both the ICE and the electric motor can propel the wheels, independently or simultaneously through mechanical coupling. The combo design allows the vehicle to operate in either series or parallel mode [46].

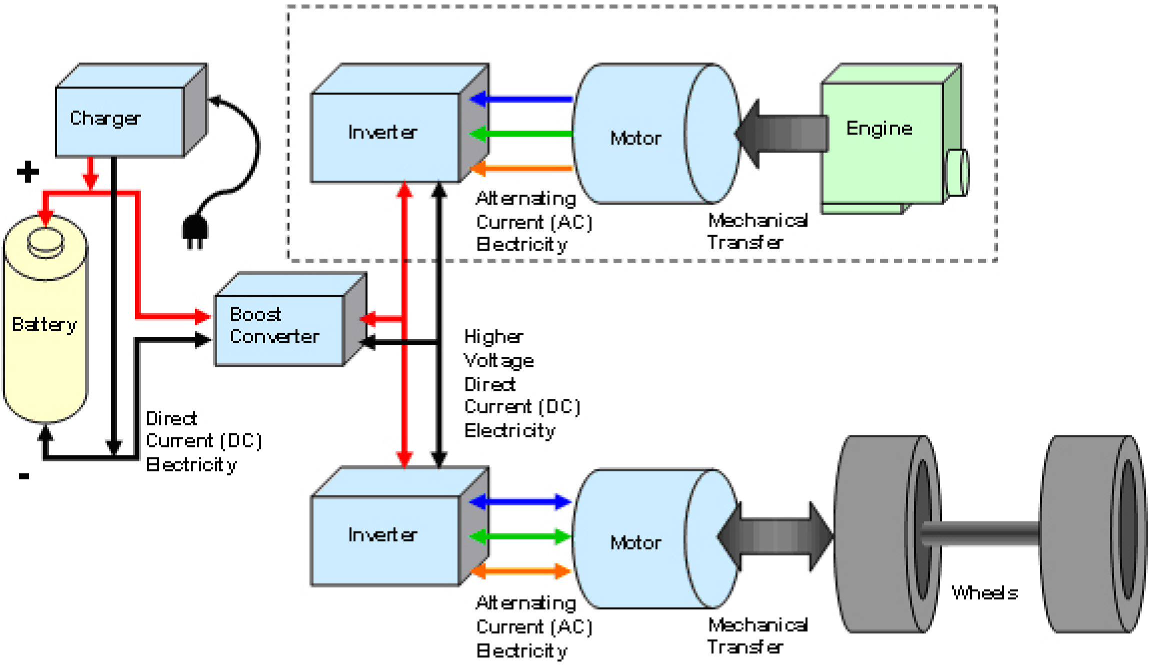

Figure 2. Outline of a typical series PHEV [52]

Pure electric vehicles are propelled only by an electric motor (Figure 3). Part of the electricity used is generated onboard through regenerative braking, but most of it comes from the power grid, since the battery can be charged using a standard electrical outlet or at charging stations. It means that, compared to ICE vehicles, PEVs provide a significant decrease of GHG emissions if charged from green electricity. Comparing to PHEVs, the reductions are also potentially much higher [46], [53]. Pure electric vehicles also have some advantages in performance compared to ICE vehicles, such as higher torque at low speeds without the need of transmission or clutch system.

All major vehicle manufacturers have, or plan to have, PEVs on the market [54]. The more recent models use state-of-the-art Li-ion type batteries[13], having improved performance compared to NiMH vehicles or older Li-ion technology. The drive range of PEVs is 120–390 km, with a typical top speed of 200 km/h [46].

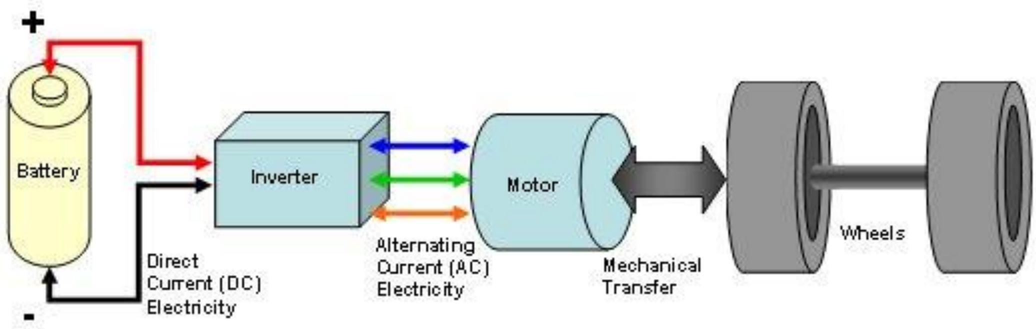

Figure 3. Outline of a typical PEV [55]

Since PEVs do not have an ICE, their battery is operated across the whole range of speeds, increasing its demand. Additionally, to minimize driver range anxiety, the battery capacity needs to be high enough to guarantee at least a driving range sufficient

[13] The great advantages of Li-ion batteries compared to other technologies are longer lifespan and higher energy and power densities. Nonetheless, Li-ion batteries research and development needs to be carried further to match enough energy and power densities for EVs. For a review on the potential of this technology, see [186].

to cover a daily routine driving [56][14]. These requisites imply the need for high-power and high-energy batteries[15] able to withstand high charging and discharging currents, being at the same time light enough, which is a costly technology. This is the most significant factor contributing to the high cost of PEVs today, representing the central barrier to their market uptake [46], [57].

Presently, battery charging is done mostly using conventional household outlets. A 230 V outlet with a 16 A fuse allows a present day PEV such as the Nissan Leaf, with a battery of 24 kWh, to fully recharge in 6-7 h. It is a long period, a factor that together with the need for vehicle charging outside has resulted in the project and/or implementation of public charging stations, such as [21], some offering high-speed charging mode with much reduced charging times. A mass provision of charging points, strategically located, is essential to facilitate the EVs penetration and their establishment as a competitive alternative to conventional vehicles [46].

The existing power grid has its electricity generation capacity mostly sitting idle as operating reserve during off-peak demand hours, and during RES generation peak-hours power production may be higher than the power demand. By articulating EV charging with these periods, the EVs may allow for a more efficient use of the installed capacity, leading to both improved operating efficiencies and use of generating units. However,

[14] In [56] a fleet of 484 gasoline vehicles was monitored in the United States to infer the potential market share for EVs with limited-range, assuming that EV drivers have the same driving patterns and that they charge their vehicles once a day. The authors found that 9% and 21% of the vehicles never exceeded 160 km and 240 km in one day, respectively. It means that these drivers could substitute their current ICE vehicles with EVs existing now on the market without any adaptation in their driving. If drivers are willing to make adaptations on two days per year, the 160 km EV range would meet the needs of 17% of drivers, and if they are willing to adapt six times per year it would serve 32% of drivers. The authors conclude that even EVs with today’s limited battery range, if marketed to segments with appropriate driving behavior, comprise a large enough market for substantial EV market sales uptake.

[15] As a disadvantage, an increased battery energy density increases largely the charging time [46].

EV charging pose some concerns about possible negative impacts on the power grid. The major issues identified during EV charging are increased transformer loading, thermal loading of conductors, unbalance of network, reductions in voltage levels, power losses and harmonic distortion [46], [58].

The EV charging most concern is about exceeding grid power and grid infrastructure capacities. In case of a large load of uncontrolled EV charging, e.g. a large quantity of EVs charging at the same time, there is a substantial increase in power demand, which can be higher than the available local transformer power supply, causing transformer overload, or higher than the current capability of the transmission and distribution grid infrastructures, causing thermal loading of conductors. When vehicle charging takes place during peak periods or in the case of fast charging, the issue is aggravated. As an example, presently in the United Kingdom (UK) the high voltage transmission network can manage the demand of about one million of EVs, but not above that, according to [46].

Even though unregulated EV charging tends to be random, decreasing the risk of transformer overloads, it may cause imbalance on distribution networks, especially when charging is through single phase electric outlets, resulting in increased voltage drops and power losses. These impacts need to be quantified to preserve the reliability of the grid. Increased power harmonics related to EV charging can pose an additional impact on distribution grid transformers, widely diverse in across different parts of the power grid. Thus, future distribution network planning needs to assess EV market uptake scenarios and adapt the local grids accordingly [46]. This issue will be discussed in further detail in Section 2.2.

Future market penetration of EVs has been targeted more or less ambitiously by national governments and other entities. For Portugal, in 2011 it has been established by the government an over ambitious market share of 10% by 2020 [59]. For other countries targets, see Table 1. However, EVs are at the moment noncompetitive with conventional vehicle technology [60], since costs are still high and battery technology is still under developing. To foster EV penetration, a set of policies is essential. In [61] the authors identified ten concrete measures to support the adoption of electric vehicles in the urban environment and classified them according to their effectiveness, efficiency and feasibility. According to this classification, the most urgent measure is the adoption at European level of a standard charging plug. In [62] the EVs challenges and opportunities are addressed in the context of Lithuania, where it was found that significant positive impact on the local EVs market can be created using policies such as tax reliefs or rebates, income tax relief for purchasing an EV and free of charge EV charging points.

Table 1. Electric vehicles penetration targets according to country [54]

Country (EU)	**target**	**Country (non EU)**	**target**
Germany	1M EVs on the road by 2020	USA	62% market share by 2050
UK	350.000 EVs on the road by 2020	Japan	50% in sales by 2020
Sweden	600.000 EVs on the road by 2020	Canada	500.000 EVs on the road by 2018
France	2M EVs on the road by 2020	New Zealand	60% market share by 2040
Belgium	30% market share by 2030	China	5M EVs on the road by 2020
Ireland	40% market share by 2030	South Korea	10% of small vehicles market by 2020

The notion that policies are essential to promote EV sales take-off is reinforced in [63] for China, in which the factors explaining the timid EV sales on that country are identified: (1) protectionism by regional governments; (2) uncertainty over what EV technology is to be promoted and what consumers are willing to pay; (3) lack of investments in charging infrastructure; (4) conservative investment behavior by automakers and battery manufacturers.

Besides policies, for an EV market uptake the technology has to have consumer acceptance. In [64] the authors measured the extent to which real experience of drivers with EVs may affect their preferences and attitudes towards it. The study included attributes regarding purchase price, driving costs, driving performance, environmental performance, driving range, charging possibilities and battery lifetime. The results found that low driving range is a major concern related to EVs, not due to misconceptions but to a true mismatch between the range the drivers wish to have available in their everyday life and what the EVs provide. The results also show that top speeds below 120 km/h are not acceptable – it is not an obstacle for the EV adoption, since the majority of the commercialized EVs have top speeds above that. The possibility to charge at work, the number of charging points along travel roads and in the general public space are important attributes to increase the demand for EVs [64].

As detailed in [65], there are two main strategies for EV charging: (1) uncoordinated charging, in which the EVs start charging as they park, leading to potential critical impacts on the grid; (2) coordinated charging, in which charging is at a convenient time, such as during off-peak hours. It can be based on a simple set of rules, such as delayed charging (i.e., pre-programed charging), or it can be smart charging, i.e., an optimized charging under the command of an operator, based on price, load or regulation [66].

2.1.2.1. Smart charging

The EVs shift the energy source from petroleum to electricity – but their potential is beyond: the EV batteries makes them a form of controllable distributed energy storage. This is the concept of vehicle-to-grid (V2G). Since EVs are parked more than 90% of the time [36], [67], they offer the possibility for demand response in smart grids, namely load shifting. As a whole, they can be seen as a nation sized battery [68]: (1) they can charge when it is more convenient for the system operator, substituting large-scale energy storage systems (namely hydro-pumping); (2) they can provide ancillary services (explained below) to the power system, substituting dedicated units for that; (3) they can supply electricity to the grid (battery-to-grid), substituting traditional power generation[16]. Vehicle-to-grid implies: (1) a smart-grid type distribution infrastructure, with a unidirectional or bidirectional connection to the grid; (2) a control device

[16] The typical example of battery-to-grid is to supply electricity to the grid when it is convenient, such as during peak demand or during low RES production.

communicating with the system operator and following its signals; (3) an on-board meter device. It should be noted that in this study the V2G concept implies the provision of an EV service to the grid, such as load shifting or ancillary services, not implying necessarily electricity flow from the batteries to the grid.

The V2G concept was already addressed in 1997 by Kempton and Letendre [69], when the nomenclature and the acronym did not yet exist. The authors conceptualized the EVs fleet from an analytical perspective normally used by electric utilities, modelling EVs as a peak power resource. They concluded that, if a fraction of the United States' (US) vehicle fleet becomes electrified, the electro-producer systems will be less concerned with real time match between generation and load. Therefore, the system would be more receptive to intermittent renewables, though the implications of the needed modifications on it are profound [69]. Since then, V2G was amply addressed in the literature, such as in [66], [67], [70]–[77].

The V2G concept depends on the smart grid, which, as defined by [78], is an electricity network that efficiently delivers sustainable, economic and secure electricity supplies integrating intelligently the actions of all users connected to it – generators, consumers and those that do both. It relies on a combination of hardware, management and reporting software built atop a communications infrastructure, constituting a great sophisticated and intricate network. This structure can be unidirectional or, to fully exploit the smart grid potentialities and enable the electric vehicle battery as an energy and power buffer of the grid, bidirectional. It gives to consumers, system operators and utilities tools to manage, monitor and respond to energy issues [72]. In Figure 4 it is shown schematically the smart grid scheme with V2G functionality operating under the virtual power plant[17] (VPP) approach. The VPP control center dispatches the aggregated battery power whenever requested by the Distribution SO (DSO) and Transmission SO

[17] Virtual power plant is defined as an aggregation of different type of distributed resources which may be dispersed in different points of medium voltage distribution network. It can be used to make contracts in the wholesale market and to offer services to the system operator [202].

(TSO) and centralizes the energy and communication flow management between energy market players (i.e., producers and consumers) and the operators.

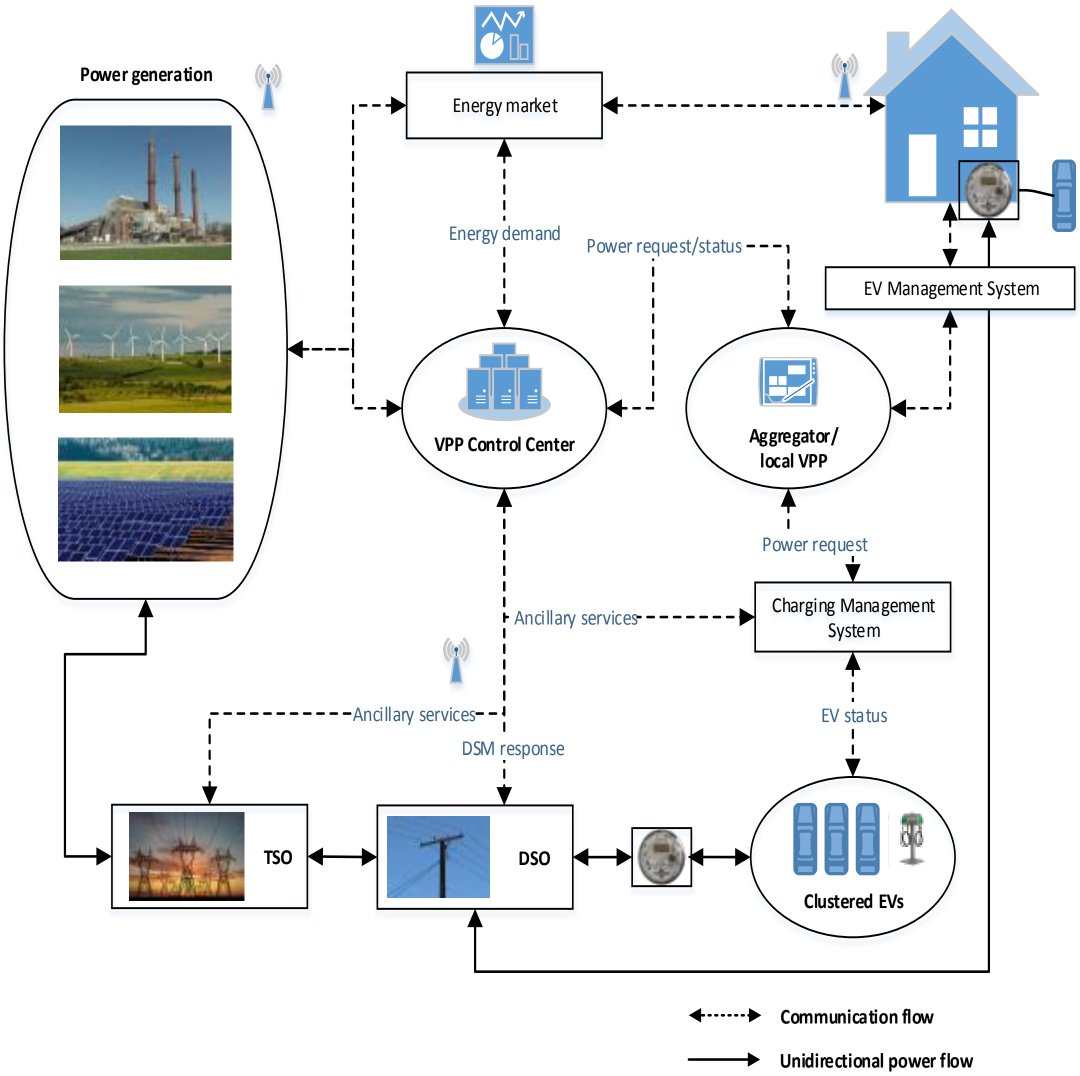

Figure 4. Smart grid scheme with V2G functionality operating under the VPP approach (adapted from [57])

The smart grid technology is getting increasing attention from the academia, industry, public and private entities, since it can be an answer to safely integrate more RES, EVs and distributed generators into the electricity grid. It needs an advanced metering infrastructure, constituting a collection point, i.e., an interface between buyer and seller where data can be gathered and analyzed. These systems capture data, typically at the meter, to provide information to utilities and to consumers. The smart grid can shape the load curve and enables consumers to have greater control over their electricity consumption and to actively participate in the electricity market. At this stage it is not yet a mature technology or widely deployed, existing only in pilot projects in Europe – in essence, the electrical grid today may be considered to be mostly dumb [79]. For an inventory on the smart grid research, development and demonstration projects in Europe, see [80].

One of these projects is the InovGrid [81] in Portugal, implemented by the local DSO. Its main purpose is to develop an advanced metering system and define a set of functionalities to provide the distribution grid with the necessary intelligence. It has a strong focus in the management of small distributed generation and control of the low voltage network, while providing to the customers the conditions to access innovative services. This project has an intrinsic extension, the REIVE project [82], with a purpose to develop an enhanced technical and market integration of small RES distributed generation and EVs. It is focused on the identification, specification and testing of solutions which allow that goal. The main outcomes of both InovGrid and REIVE projects are presented in [83].

Previous studies have found that, in addition to suppress power fluctuations from RES, advanced EV charging smart techniques can also mitigate and better control overloads on the distribution network [46]. Such techniques include stagger charging, i.e., controlled charging of batteries across household outlets to allow load balancing and prevent overloads, and household load control, i.e., postponement of non-essential loads to recharge EVs more rapidly [46]. Studies have additionally found that smart charging is advantageous in reducing technical issues concerning grid power quality [84]. Therefore, EV charging should be coordinated by operators and other multi-agent systems.

Figure 5 schematizes the integration into a power system of both EV and RES. It is assumed that all necessary communication and control schemes are available, as described previously and shown in Figure 4. The electric vehicles are considered aggregated at the charging stations located in public or office parking spaces [57].

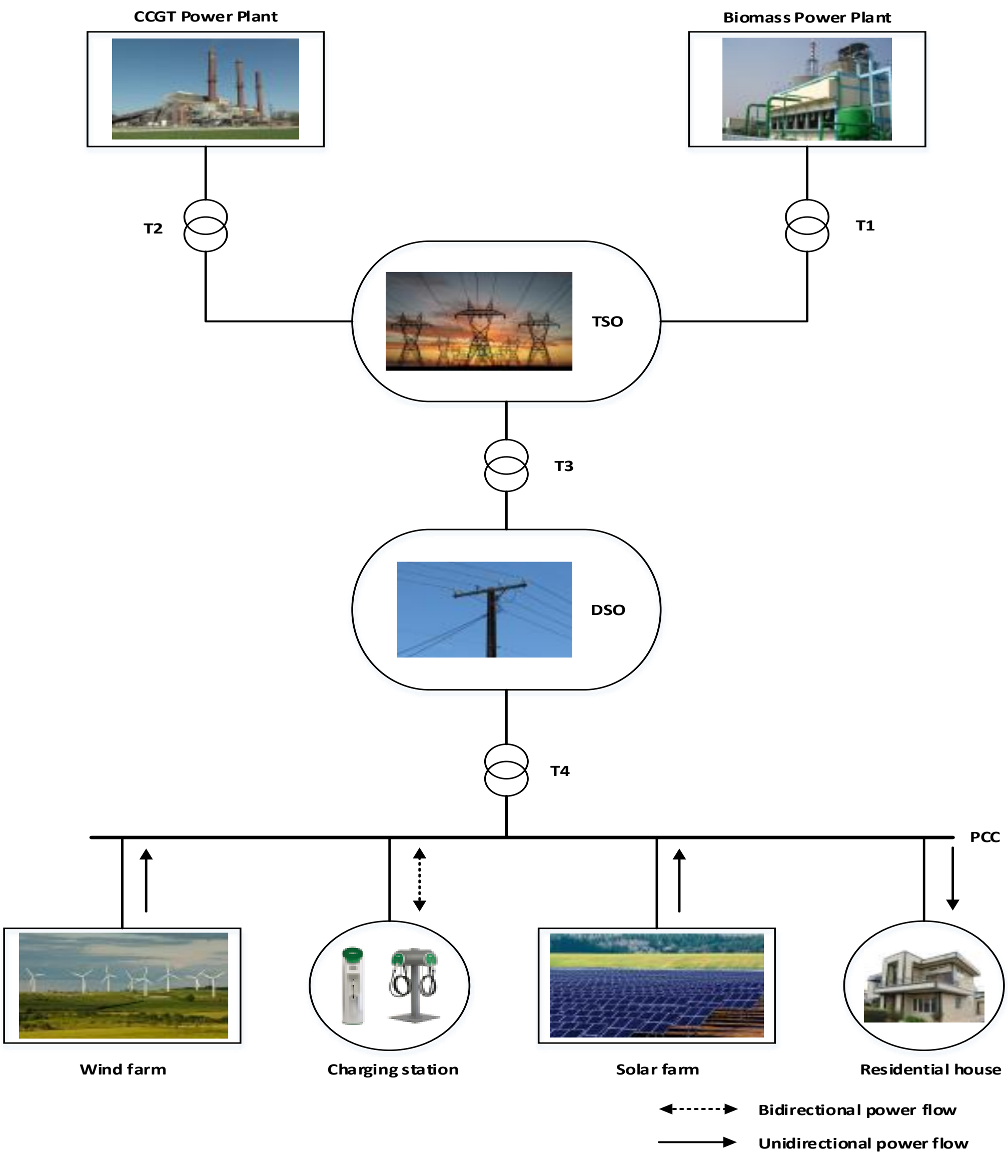

Figure 5. RES and EVs integration into the smart grid with V2G capability. Ti stands for power transformer and PCC for Power Control Center (adapted from [57])

The provision of V2G services to the SO is ultimately determined by its profitability for the parts. There are four power markets where V2G can be integrated, as it was analyzed by [73] and [74]:

1. Base load, i.e., power generation paid on an energy basis that is running most of the time at low cost to cover for constant demand. However, the authors concluded that V2G is not suitable for this market, because cannot be price

competitive due to EV limited energy storage, limited battery lifespan and high energy cost;

2. Peak power, i.e., power generated during times of predictable higher demand, e.g. cold periods. It is paid also on an energy basis. Normally, it is provided by combined cycle gas turbines (CCGT) power plants, which can be switched on for short periods of time. This energy is relatively expensive, making in some cases V2G competitive for peak power. Units operating in peak power mode work sometimes up to 5h, posing difficulties for V2G operate in this market because of storage limitations of each vehicle, which can be overcome drawing power sequentially from different sets of vehicles;

3. Spinning reserves, i.e., energy supplied promptly by permanently online rapid expensive generators in case of loss of programmed generation, e.g. equipment failure or failure of a power supplier to meet contract conditions. Typically, this generation is called for a few minutes a few times per year and is paid for the time available online. These conditions make spinning reserves market especially attractive for V2G;

4. Frequency regulation, i.e., generators that are used to keep the grid frequency and voltage stable. Typically, they are called for up to a few minutes several times per day. By contract, the calls could be limited in number and in duration for each individual EV. The authors concluded that V2G is highly competitive in this market. From the electrical utility perspective, this is a new source of high quality grid regulation and, from the EV buyer perspective, a revenue source that further encourage the purchase [75].

These conclusions are in agreement with [85], where the economic feasibility of using PHEV batteries for V2G aggregated as a grid-scale energy storage is analyzed according to [76]. The authors pointed out that the different uses of V2G technology in the various types of energy markets are not mutually exclusive, since, in fact, they can exist simultaneously. They propose that it is especially profitable for PHEV owners to use V2G for regulation on a daily basis and for peak reduction just on exceptionally high electricity demand days.

In [86] the authors studied the cost-benefit of regulation service provided from unidirectional (power flowing from the grid to the vehicle) and bidirectional (power flowing in both ways) charging of EVs[18]. They found that EVs can participate in the energy market even working with just a unidirectional configuration. In fact, even though bidirectional flowing allows for extra revenues, if one considers the costs from the increased battery fading (battery-to-grid operation substantially increases the number of battery cycles and generally shortens its lifetime), increased protection and sophisticated metering systems, that extra revenue can become negative. The authors conclude that almost all the V2G benefits from a bidirectional power flow can be achieved by a unidirectional power flow, although requiring about twice EV penetration to match the same level of regulation service.

Unidirectional V2G was also explored in [66], in particular optimal charging strategies using the concept. The authors developed an algorithm for unidirectional regulation for use by an EV aggregator, combining the capacity of many EVs to bid into energy markets. The conclusions were that the optimal algorithms maximize the charge of the batteries while minimizing the charging cost to the customers. For the aggregator, they maximize the profits and for the utility they have the potential to improve power system operation and control, by providing additional flexibility to counteract the variability of RES [66].

Another study on unidirectional V2G is presented in [87]. The authors found that when EV charging responds to frequency deviations increasing or diminishing the EV load, the average net effect is to increase the total charging time, since on average the charging power is reduced by 1% (given that the most demanding is related to loss of

[18] In a traditional electrical systems, reserves have to cover for the variability of RES and for any losses of conventional dispatchable generation. This requirement may lead to constraints in the maximum allowed RES penetration, since dispatch depends on fossil fuel based thermal units to perform ancillary services. Since EVs can be seen as active participants in primary providers for these services, then the reserve requirements can be met recurring to loads instead of generation. In this way the dependence on conventional ancillary services providers is reduced, enabling a higher share of RES integration [87].

primary resource availability). This represents a few extra minutes of charging, negligible, given that the charging period of an EV typically is of several hours. Overall, the results prove that EVs are efficient providing this task.

It must be stated that V2G technology, especially bidirectional with battery-to-grid capability, represents a new paradigm of EV charging, requiring an expensive and technologically state of the art structure. At the present, this is a technology that has not concrete deployment plans to be introduced in Portugal, or, as far as is of known, in any country at nation scale, even when smart grids are planned. There are mainly three factors contributing to this:

1. The present date lack of EV significant market uptake – V2G will only be deployed in the long term when sufficient vehicle adoption rates justify the implementation of new control architectures;
2. The lack of joint investment and revenue models between EV industry players [88];
3. The necessity to develop standards and test several smart grid and V2G technologies (e.g. battery technology, communication and power interfaces) to implement efficiently the concept [80];
4. The lack of regulation to ensure that loads and requirements of EVs have limited negative impact on the distribution infrastructure [60].

As examples, in the state of California, US, the Pacific Gas and Electric Company has currently underway a smart grid deployment plan, to be concluded in the horizon of 2020, which does include EV smart charging readiness without battery-to-grid [89]. In what concerns practical demonstration of the V2G principle, see [70], where it is described a pilot project consisting in a practical demonstration of V2G power providing real-time frequency regulation. However, a single vehicle is involved, and thus extrapolation for a large fleet of EVs is not linear [57].

Additionally, in [77] the results of load shifting using EVs in V2G models of large power systems were investigated. It evaluated, with scenarios based on the International Energy Agency (IEA) BLUE Map scenario [24], the grid stabilization needed when using RES and PHEVs. It was found that the primary benefit of load shifting via V2G is reducing the capacity needed to ensure power quality on the electric grid systems with large proportions of intermittent energy generation, such as wind and PV. Moreover, special good results were obtained for Western Europe, characterized by a low share of middle load power, i.e., the traditional power capable of stabilization. The authors have identified some issues of special relevance that must solved before EVs load shifting concept can be fully realized, namely:

1. Forecast of demand and supply of RES: precise weather forecast is a key to predicting with high accuracy the supply of RES. Accurately predicting the demand for the next day is also a key from the viewpoint of load shifting;

2. Guarantee of controllable generating capacity of EVs: stable and controllable energy storage capacity, namely from EVs, is important to perform load shifting. For the system operators, large capacities of EV generation should be guaranteed;

3. Creating implementation incentives: in the early stage of V2G, EVs will be charged when electricity is inexpensive as an incentive. With EV market uptake, new supportive incentive policies should be developed;

4. Competitiveness with large-scale energy storage systems, including large-scale batteries: energy storage systems for buildings and other large structures employing large-scale batteries will likely exist and will be competing with V2G.

Additionally, in [77] it is found further issues that must be solved if V2G is going to provide electricity to the grid (battery-to-grid):

1. Guarantee of controllable battery-to-grid capacity: the cumulative energy storage capacity of all EVs is operated as if it was a virtual pumped storage power plant. Therefore, it is crucial the guarantee of a stable and controllable capacity. It requires, therefore, statistical data of EV driving modes, because a certain number of EVs with enough stored energy should be confirmed to be available and secured;

2. Decreased lifetime of EVs batteries due to frequent charge-discharge cycles: batteries lifetime heavily depends on the number of charge and discharge cycles and battery-to-grid operation substantially increases the number of it, shortening battery lifetime. This not be acceptable to EV owners, since the main purpose of EVs is transportation. This is seen as be the most critical issue to solve;

3. Transparency of business model: the required level of stored energy to guarantee travelling depends on each owner. To perform battery-to-grid it is necessary to monitor the owner driving modes, to measure and to analyze the momentary stored energy and the availability to supply battery-to-grid. The EV owners should be informed of this with transparency to clarify their contribution to the battery-to-grid operation.

It is important to remind that significant penetration on the electrical systems of EVs and non dispatchable RES (PV and wind) together raises power quality concerns to operators of the transmission and distribution systems. In fact, when planning for these scenarios, severe threats such as frequency and voltage fluctuations, voltage drop (related to power reactive flows), harmonic distortion and power factor reduction can arise and must be addressed [90]. Several studies in this field have been conducted, such as [87], [90]–[96], with conflicting findings on the effect of EVs on the distribution networks [34]. Some of these studies are detailed below. Generally, however, it has been observed that EV smart charging, if managed properly, can provide ancillary services to the grid such as frequency and voltage regulation, peak shaving and reactive power support to enhance the operational efficiency, secure the electric grid and reduce power system operating costs [57]. That is, EVs may act as solution for the problems posed by high RES penetration, as long as they have a storage capability that can be used to help managing the network in extreme conditions. At a technical level, the EV batteries together with power electronic interfaces capable of answering very fast to frequency deviations in small increments and in a distributed manner can contribute to improve the global system dynamic behavior in a smart charging environment [75], [97]. But clear and adequate formulation of grid codes is indispensable to guarantee a smooth integration of RES and EVs into the electrical systems [93] along with careful and consistent long term planning and implementation of integration strategies [91].

2.2. Relevant studies[19]

The effects of a high penetration of RES and EVs on the power systems, isolated or in conjunction, have been widely addressed at different levels, and the most relevant literature of the state of the art is presented below. These works summarize well the most recent research and, thus, are helpful to researchers, policy makers, energy producers and governments in their action [10], [44].

A review on power system stability challenges of large scale PV integration is made by Shah et al. [98], a topic also addressed by the same authors in [99], where they found that dispersed penetration of PV is better than concentrated. The authors identified a number of factors that affect the impact of PV penetration on the power system: (1) plant size, location and character (distributed or centralized); (2) availability of backup reserve in the system; (3) dispatch and displacement of conventional generators by PV; (4) reactive power compensation method; (5) control loops of PV. The paper concludes that to increase the PV penetration to large-scale it is important to overcome the bottlenecks of voltage, frequency and angle stability and to develop necessary standards.

In the discussion of RES integration on the electricity grid, it is often discussed the role of storage, since it is regarded as one of the possible solutions to deal with the variability of RES. The applicability, advantages and limitations of various electrical energy storage technologies for large scale RES integration are surveyed by Beaudin et al. in [100], where it is found that flywheels, capacitors and batteries are the most suitable to maintain power quality and grid stability. However, different RES requires different sets of energy storage systems characteristics to address the issue. Yekini et al. [101] reached the same conclusions. An overview of the operation principles, technical and economic performance features and the current research and development of energy storage technologies is presented by Luo et al. in [102], where a detailed comparison

[19] Given the nature of a literature review, in this section the authors are named, besides referenced.

and summary of the existing and promising technology options for different power system applications along with their technical specifications can be found.

Another review on storage was done by Castillo and Gayme in [103], this one giving emphasis to methods to evaluate grid-integrated storage and the regulatory framework. It is found that technology is not anymore the only major barrier to storage integration, since market and regulatory challenges are becoming equally pressing. It points to a critical need for new models that can provide understanding of the interplay between the technical, economic and regulatory questions. Concerning a review on energy storage for application in the transportation sector, Ren et al. [104] present a classification and comprehensive description of the applicable technologies. The authors observed that presently most battery energy storage systems cannot simultaneously meet the requirements of power charge and discharge, efficiency and long cycle life.

An important review is the one by Richardson [34] about modeling approaches, impacts and renewable energy integration of EVs and the power grid, in which several studies assessing the ability of EVs to integrate RES are addressed. It covers four areas: (1) the EVs as a technology, giving an overview of key concepts that are relevant to vehicle interaction with the grid; (2) the existing models, where the modeling approaches existing in the literature to analyze EVs and the electric grid are discussed and compared; (3) the EVs impacts and performance, where general impacts and benefits of EVs on the electricity system are presented, according to economic, environmental and grid perspectives; (4) EVs and renewable energy integration, where a thorough review of the literature divided by wind, solar and biomass is presented. It concludes stating that the existing literature is consensual and conclusive that EVs can increase the amount of RES that can be integrated on the grid while reducing their negative impacts. However, this is better documented for wind energy than for solar; indeed, there is a lack of depth of analysis on the integration between PV and EVs if compared with wind and EVs. The interaction between solar energy and EVs is an area requiring detailed analysis, as solar energy charging stations could be a focus of future infrastructure investment. The author also highlights the importance of smart charging, as it is a common topic of research on EVs and the power grid. The literature points that smart charging can reduce system costs by avoiding extra investment in peak generating units, transmission and distribution systems, allowing EVs to be used as distributed storage mechanism for absorbing excess renewable energy[20]. However, a comprehensive economic rationale in favor of smart charging has yet to be produced.

The smart charging approaches are discussed by García-Villalobos et al. in [105], where the authors review comprehensively the different strategies, algorithms and methods to implement smart charging control systems. The authors address the main architectures of smart charging, centralized and decentralized control, concluding that both can be effective, although at low penetration levels of EVs the decentralized control scheme should be preferable due to its low communication requirements. In contrast, with high market uptake of EVs the centralized control architecture may be the best solution. In both architectures the EVs are able to provide voltage and frequency regulation. However, the authors conclude that the active integration of EVs can be a very complex task and that issues such as voltage deviations and transformers overloading should be addressed by power systems simulation tools.

A detailed review on the potential undesirable impacts of uncontrolled EV charging is presented by Mwasilu et al. in [57], along with a comprehensive assessment of the research and advancement of EVs smart charging and RES interaction. Several EV smart charging strategies under the V2G approach are examined, concluding that the smart grid will foster the perspectives of EVs as grid supporters and RES penetration enablers, although further research and analysis are required to justify the adoption of EV storage over other grid-scale energy storage technologies. An advanced technology allowing real time communication and power measurement needs to be developed and standardized, and further research on its main challenges and limitations, such as communication delays, routing protocols and cyber security, is critical for the reliable and efficient adoption of the smart charging framework. Under the light of recent pilot projects, the smart charging feasibility is assessed, being found that the adoption of the EV as an energy market player is hindered by the low penetration of EVs with V2G capability and by the need of low cost and high efficient EV charger power converters.

[20] More on this in Section 2.1.2.1.

The idea that an effective and reliable V2G support of the electrical grid needs prior a clear understanding of its dynamic behavior is reinforced.

2.2.1. Modelling high RES penetration in the electrical system

Denholm and Margolis [27] examine in the context of a transmission constrained grid the limits to large-scale deployment of solar PV in traditional power systems, i.e., systems with a large incorporation of thermal power plants with limited operative flexibility, defined as the fraction of peak load below which conventional generators can cycle. The authors compare for different levels of system flexibility the hourly output of a simulated large PV installed capacity to the amount of electricity usable. One interesting conclusion is that, to achieve a 30% share of PV in an 80% flexible system, the average cost of PV would be 1.5 times the base cost. They found that the limited flexibility of base load generators is responsible for increasing unusable PV generation for PV shares above 10-20% of the electricity demand.

A follow-up analysis by Denholm and Hand [28] discuss and quantify how to increase PV penetration beyond this range, simulating different mixes of wind, PV and concentrating solar power with a combined share of 80%. They found that a highly flexible system, close to 100%, i.e., virtually without conventional base load generators, allows for penetrations of about 50% of RES with unusable rates below 10%. For RES shares between 50% and 80%, keeping unusable energy below 10% requires a combination of load shifting with storage equal to about one day of average demand.

In a similar approach, Nikolakakis and Fthenakis [106] calculated the optimum mix of electricity from wind and solar PV, based on the case of New York state in the US. They modeled penetrations in the grid of PV only, wind only and PV and wind together, considering four flexibility scenarios: 70%, 80%, 90% and 100% – even though 90% and 100% flexibilities are unrealistic for contemporary power systems, they were included to show the absolute limits of wind and solar penetration. It was found that, since PV produces only within a relatively narrow window throughout the day, although its output coincides well with demand, increasing PV capacity beyond a certain level increases the amount of unusable energy that needs to be curtailed in the absence of storage capacity. On the other hand, wind provides intermittent electricity in a larger window throughout the day, but it blows stronger during the night, when the demand is low. It was shown that when PV and wind are used together they achieve much higher total penetration of RES than individually, especially at penetration levels above 20%. For example, with 70% of grid flexibility, by integrating 14.5 GW of PV and 11.1 GW of wind a total penetration of 25% of wind and solar can be achieved without having to curtail more than 9% of energy. If this was to be met by wind alone, 19.7 GW of wind capacity would be required and 26% of energy would be curtailed. Another example, for a 100% flexibility scenario, if no more than 10% of energy is allowed to be curtailed, the maximum RES penetration with a combination of PV and wind is 59% (compared to 47% for the only-wind scenario). Without curtailing any energy, PV achieves 5.9%, 8.9%, 11.9% and 14.8% penetration for a 70%, 80%, 90% and 100% flexible grid, respectively. The authors conclude that a PV and wind combination fits best the load curve and gives maximum penetration whilst curtailing less energy.

In [107], Solomon et al. discuss the appropriate amount of storage for high penetration of solar PV, discussing the available technologies for achieving it. These technologies are classified under three categories, based on their response time, power capacity and duration, i.e., suitable for power applications (such as ultra-capacitors and fly wheels), employed as buffer or emergency systems (such as batteries) and used for bulk power (such as hydropump and compressed air), respectively. They conclude that no single existing storage technology has all of the required properties; nonetheless, hybrid storage systems, such as batteries combined with hydropump, may have appropriate properties to allow high PV penetration. The authors also define an index, which, for a certain grid flexibility, leads to a PV-storage combination that allows high PV penetration without storage systems being too large. They employ this methodology to the case study of Israel, founding that the appropriate amount of storage is below the daily electricity demand, in accordance to what was found in [108].

Krajačić et al. in [109] presented some insights on energy system planning and technical solutions for achieving 100% RES electricity production in Portugal. The analysis was based on modelling results of three electricity production scenarios: a reference scenario representing the year 2006, a 2020 scenario built according to the, at the time, energy strategy for 2020 [110] and a 100% RES scenario. These last two scenarios also consider the 2006 electricity demand. The analysis was performed for a closed system, i.e., without considering interconnection capacity, enabling a better overview of the available energy technologies but pointing limitations to the model: they used the H2RES model [111], that accepts only a single reversible hydro installation, not allowing different control of different hydropump systems, thus limiting the analysis. It was found that 100% RES solution favors hydro and wind power, but it would require larger wind turbines and larger pumped hydropower plants. Assuming technology developments with proper combination with transportation, batteries and hydrogen could become the storage solution. The authors conclude stating that a 100% RES supply should only be possible with additional grid expansion and international exchange of RES electricity.

Fernandes and Ferreira [112] analyzed different possible future strategies for a RES based system for Portugal, each one characterized according to the expected electricity consumption and renewable share. It was found that a 100% RES scenario is theoretically possible, but a significant increase on the total capacity of the system would be necessary to ensure no shortfalls during summer. An outcome is the existence of excess of electricity generation during the winter and also a significant increase of the total cost of the system. The authors conclude that a complementarity between resources and inclusion of storage systems are essential to 100% RES systems.

MacKay [32] took a different approach to analyze the range of sustainable energy options for the UK in the future, looking in particular to the potential role of solar PV. The author did an analysis from first principles focused on collecting, converting and delivering sustainable energy. Departing from the average rate of 5000 W per capita of energy consumption in the UK, he found that it corresponds to 1.25 W per square meter of land, which compares with the solar PV potential in Germany, 4 W/m^2, or with the potential in sunnier locations, up to 10 W/m^2. The author concludes that decarbonization of the UK and other similar countries will only be possible through a combination of several options: installing large RES power generation facilities, namely solar PV; large-scale RES energy imports, namely solar from sunny countries; installing

RES facilities in other countries; population reduction; drastic energy efficiency improvements and lifestyle changes; non-renewable low carbon sources, such as nuclear power. He highlights that large scale solar PV deployment either needs to be combined with electricity storage or it needs to be coupled with large flexible demand for energy. He finishes stating that it is very hard to achieve the climate change targets without significant deployment of solar PV in sunny locations, and points some issues such as the area required, the challenge of transmitting energy, the additional costs of handling intermittency and the need for high decline in the whole-system costs of PV and energy storage.

Brito et al. [Article III] followed also an approach from first principles to tackle the problem of designing an imaginary isolated fossil free energy system. It serves to illustrate the methodologies to plan sustainable energy systems for isolated systems, which is given an overview. Using detailed hourly balance between supply and demand, it shows how electricity, heat and mobility can be fulfilled with sustainable and renewable energies only, highlighting the importance of energy storage.

Weitemeyer et al. [29] considered the role of storage in the integration of RES in future power systems. They used long-term PV and wind energy power generation data series to present a modelling approach that assesses the role of storage size and efficiency on 100% RES electricity scenarios, applying it for the case study of Germany. They found that up to 50% of the electricity demand could be met by RES without storage, but only on the condition of an existing ideal mix between wind and solar PV generation and if the remaining power plants, namely nuclear and fossil fuel based, are fully flexible. Although at the moment only limited parts of the German generation portfolio is flexible, a scenario with flexible backup power plants was tested, showing that a share of 80% by RES is possible with small but highly efficient storage devices. The authors conclude that the transformation of the European power supply system to one based on RES is challenging, but achievable if balance between the installation of additional RES capacity and storage capacity is found.

How hydropump energy storage can assist the integration of wind energy on the power grid is addressed by Connolly et al. in [113], using Ireland as a case study. The authors define the maximum wind penetration as occurring when the energy in excess surpasses

5% of the total annual wind energy produced. The results show that hydropump can increase wind penetration and, at current prices, reduces its operating costs; however, under expected 2020 fuel prices and interest rates, the savings may not be enough.

2.2.2. Modelling interactions between the RES and EV

The ability of EVs to assist the integration of renewable energy into existing power grids is arguably their most significant impact on the electricity system [34]. The literature on this subject is primarily focused on the analysis of wind energy and solar energy, with wind energy receiving much greater attention and a more detailed analysis, as Richardson [34] points out.

Kempton and Tomić [74] conducted a technical analysis to assess to what level the primary function of EVs, transport, is compromised if they provide services to the grid. The authors investigated the electricity markets in which EVs have the highest potential and developed an analytical approach to quantitatively describe the available power, duration, costs and market value of these power forms. It was found that EVs probably will not generate bulk power, due to their fundamental engineering characteristics and because the energy from EVs is more expensive than bulk electricity from centralized power plants. Indeed, V2G may be able to be cost competitive for energy market only when electricity prices are unusually high, as in occasions in peak power markets. However, V2G is price competitive in power markets based on on-line and available power, with an added energy payment when power is actually dispatched. These quick response services are purchased to balance constant fluctuations in load and to adapt to unexpected equipment failures, representing 5–10% of market value. Electric vehicles are thus suitable to provide ancillary services of spinning reserves and regulation. In fact, operating in these markets may be profitable for EV owners: the price paid for reserve availability is attractive even if there is loss of money for the dispatched energy. The authors conclude that V2G can improve the reliability of the electric system, reducing its costs.

In a companion article, Kempton and Tomić [73] examine the systems and processes needed to implement V2G. They quantitatively compare the US light vehicle fleet with the electric power system: the former has 20 times higher power, less than one-tenth the utilization and one-tenth the capital cost per kW. On the other hand, utility power plants have 10–50 times longer operating life and lower operating costs per kWh, suggesting that V2G can be virtuously used to complement needs of the driver and grid manager. The article suggests some strategies and business models and the steps necessary for the implementation of V2G. The authors consider that there may be a point where the costs of V2G drop enough to make it competitive, providing storage for RES generation. They calculate that 3% of the fleet dedicated to regulation is enough to stabilize large-scale wind power, and that 8–38% of the fleet is enough to provide for it operating reserves or storage.

In the same article the authors describe policy and legal frames that may motivate faster V2G development, such as: (1) promotion of electric grid improvements, higher reliability and frequency stability avoiding construction of new power plants and transmission lines; (2) market regulation guaranteeing competitive markets for regulation and spinning reserves or, instead, recognition of the value of V2G providing these ancillary services; (3) policies favoring the development of new industry, technology and employment; (4) existence of single or coordinated government units; (5) existence of commitments to growth of RES or reduction of GHG emissions or both. These measures should be applied especially in geographic areas with high vehicles concentration and with transmission constraints and where regulation and spinning reserves have high costs.

Tomić and Kempton [75] used two fleets of PEVs, with 100 and 252 vehicles, to evaluate the economic potential providing power for the regulation power markets in four US regulation services markets. They tested two regulation methods, regulation-up, with the vehicle providing power to the grid (battery-to-grid), and regulation-down, with the vehicle decreasing or increasing its power demand, i.e., unidirectional V2G. Regulation-up has the advantage of more time availability from the fleet to provide the service, since the result is no net change in battery charge, comparing with regulation-down, in which, if the batteries are fully charged, they stop being able to provide the service. However, this should be manageable preventing the fully charge of the batteries. Nonetheless, the best approach would be to simplify controls and approval by providing regulation-down only. The authors conclude that V2G grid regulation is economically feasible, providing significant revenues that would improve the economics of EVs and further encourage their adoption, improving at the same time the stability of the grid. The most relevant variables are: (1) the value of the ancillary services; (2) the power capacity of the electrical connection and wiring; (3) the available capacity of the vehicle battery. The amount of time the vehicles are on the road is not a relevant variable. The technical V2G barriers are identified, namely batteries are not specifically designed and optimized for EVs. For example, battery life cycle number needs to be higher to support a greater number of charge and discharge cycles. As for institutional barriers, the following are identified: (1) nonexistence of vehicles aggregators to manage multiple fleets and individual vehicles; (2) regulation signal is not broadcasted by all operators; (3) rates for regulation services are not available at the retail level; (4) yet inexistent mass production of V2G enabled vehicles; (5) need for V2G provision quality standards.

Another study addressing V2G is from Lund and Kempton [67], which discuss the integration of wind energy into the transport and electricity sectors in the Danish system. Assuming a national fleet constituted entirely by EVs, 10 kW connections and batteries with a capacity of 30 kWh, the impacts are calculated for a range of wind power, from 0 to 100% of the electricity demand, and for three EV charging scenarios, non-smart night charging, simple smart charging and bidirectional V2G. No international electric transfers are considered to allow an understanding on how to minimize the need for them. The results show that EVs with night charging improve the efficiency of the electric power system, lower CO_2 emissions and improve the ability to integrate wind power, and more so with smart charging and bidirectional V2G – although the latter does not allow for significantly better results comparing with the former. The results may be conservative, since smart charging and V2G were not modelled to provide grid stability and since their controllers are not smart about the drivers' operating schedule. The authors conclude that intelligent EVs can help minimize electricity excess and CO_2 emissions, constituting thus a carbon-free and lower-cost alternative to construction or expansion of fossil fuel power plants for balancing the grid or to dedicated centralized storage.

In [114] Freire et al. discuss the impacts on the Portuguese electric grid of non-smart EV charging and smart charging (one and two ways) considering a 100% EV fleet scenario. The authors perform at first some macro annual calculations, establishing that the increased electricity demand of such scenario is below 36.5%, and a 25% EV penetration scenario increases electricity demand less than the 2009 wind production. For the present electricity portfolio, an EV gives origin to about 82 g/km of CO_2 in an ordinary year and 102 g/km in a dry year, not an over ambitious value, since the 2021 EU target for new vehicles is of 95 g/km [115]. With more incorporation of RES on the grid, this value may drop to 41 g/km by 2020. Freire et al. proceed with a more detailed analysis of a one week period for illustrative purposes, not addressing power quality issues or EV ancillary services provision. For 100% EV fleet, the authors found that non-smart charging with a late afternoon/night charging profile might create very high peak demand on the grid, circa 8 GW, which can be avoided with smart charging. In this mode, the maximum power that the EV fleet has to absorb is about 4.5 GW, or about 26% of the smart charging connection capacity if each EV is connected to a standard household outlet. It was also found that in bidirectional V2G mode the fleet will be charging from the grid most of the time, not supplying it.

Fasugba and Krein in [86], a reference also presented in Section 2.1.2.1 and further detailed here, address the cost benefits and regulation services capability of unidirectional V2G charging. The possible ancillary services level is quantified using different charging strategies, and the impacts on the electricity prices of various power-draw schedules and EV participation as a demand response load are evaluated, both for owners and system operators. The study considers that EVs are plugged-in for charging in the work period 9:00-10:00 and at home in the period 21:00-7:00. The authors found that a battery with a bidirectional charger and 20 kWh of stored energy have a maximum regulation of 6.6 kW, the maximum power of the connection. On the other hand, an EV equipped with a unidirectional charger has a maximum regulation capacity of 3 kW, i.e., about twice of unidirectional V2G penetration is needed to reach the same provision of ancillary services. The authors highlight that utilities may not be willing to pay for EV energy dispatch, but only for capacity, because the net energy dispatch should be zero, i.e., by the time of disconnection the battery should be at least with the same amount of energy as in the beginning. Nonetheless, a bidirectional EV may generate 480 USD/year in revenue, with an equivalent of 335 USD/year in battery degradation, and thus a net profit of 146 USD. A unidirectional EV can generate 130 USD annually in revenue, 11% less, but if costs associated with safety and complex metering issues of bidirectional V2G are considered, the difference should become in favor of unidirectional V2G.

Denholm et al. [36] studied the co-benefits of large scale PHEV and solar PV deployment, using as case study the Texas state in the US, which has limited interconnection. It considers a large scale deployment of both PHEVs and solar PV, respectively a 30% penetration and 15% energy share. It addresses the ability of the combination of these technologies to reduce overall vehicle petroleum use and consumption of electricity from fossil fuels, comparing with scenarios where the technologies are deployed alone. It considers two charging scenarios, unrestricted and restricted after 15:00 charging. The first co-benefit is that adding PV reduces or eliminates the increase in peak capacity requirements due to the PHEV demand. The second co-benefit is to avoid curtailed energy during period of PV peak production and low simple demand. The amount of curtailment will however also be determined by the flexibility of the grid. A minimum generation point is determined by the need to keep thermal generators online to provide operating reserves, which potentially could be provided by the PHEV charging (not explored). One of the conclusions is that allowing PHEVs to charge during mid-day increases the fraction of travel distance driven electrically, decreasing petroleum use. It finishes observing that to avoid curtailment of mass PV deployment the flexibility of the grid needs to be increased and alternative uses for the electricity generated in the middle of the day must be found, such as the one explored in the article and others including load shifting, energy storage and increased electrification.

Dallinger et al. [116] studied the RES supply integration on the grid using EVs for the case studies of California state in the US and Germany in a 2030 scenario. The study uses an agent-based simulation model, including real time market prices as control charging signals and a detailed simulation of driving behavior. It considers an EV market uptake greater than 80% in both cases, divided into PHEVs and PEVs, and three charging strategies: after the last trip (end of the day, i.e., uncontrolled charging), time-of-use tariff based and smart charging. One finding is that the ramping of the residual load, i.e., the total system load minus the RES generation (it represents the generation needed from dispatchable power plants), is strongly influenced by RES generation, nearly doubling if RES generation is included. However, EVs smart charging contribute to a less residual load fluctuation in both power system scenarios. On the other hand, uncontrolled charging and time-of-use tariff charging do not significantly improve RES grid integration, because only a small proportion of energy in excess from RES is consumed by EVs – in the first case due to time disparity between EV consumption and RES generation and in the second case because time-of-use rates are not flexible enough. It is found that the peak load increases even with smart charging, since the consumers want to maximize the electric range of their vehicles to redeem the investment, although with significantly lower ramp rates. The authors conclude that the daily pattern of PV generation favors the storage capabilities of EVs if a charging infrastructure is available where the vehicles are parked during the day, highlighting the importance to consider load and RES generation in detail when analyzing future power systems.

Hennings et al. [51] surveyed the use of excess wind power to charge EVs, using Germany 2020 and 2030 scenarios with 1 million and 6 million EVs, respectively. They used EV models based on real driving patterns and car usage considering a controlled charging scheme, i.e., shifting the charging into off-peak times during the night. Only home charging is modelled, and the study is divided considering the grid transfer capacity to be unlimited or limited by potential bottlenecks. It is shown that a substantial part of the charging demand of EVs can be met by otherwise unused wind power, depending on the requirements for stabilization of the grid. The wind power use is limited by the charging demand of the EVs and the bottlenecks in the transmission grid. For example, with and without grid restrictions, in 2030 about 30% and 50% of the EV demand can be met by excess wind power, respectively, considering an existing minimum share of grid stabilization from load following power plants. With no minimum grid stabilization, in 2030 most wind power can be absorbed with simple load. In 2020 the share of excess wind energy useable in EVs is limited to 7.5% with grid bottlenecks, compared to 8.4% without them. For the same conditions, respectively, in 2030 that share is 8% compared to 15%, since the grid connection capacity does not keep up with the increased wind turbine capacity installed. The authors conclude stating that 1 million EVs have barely any effect on the energy balance and 6 million have a clear but not dramatic effect.

Lise et al. [117] assessed the required share for a stable EU electricity supply until 2050. The paper addresses the limitations of relying on flexibility in generation as the future shares of intermittent RES supply increase, identifying flexibility measures to accommodate it and ordering them by merit. The analysis allows to draw a number of conclusions, including: (1) increasing intermittent supply decreases the role of base load power and the share of flexible supply. Reduced availability of flexible supply combined with increasing load-following capability requires the need to apply further alternative flexibility measures; (2) decreasing importance of base load power is however counteracted by demand side management (DSM) and storage, since with them the resulting residual demand is flattened, leading to a continuity of the importance of base load power technologies; (3) in 2050 intermittent supply is expected to be larger than demand in certain periods, providing incentive for DSM; (4) strengthening interconnection reduces the need for load-following power. Additionally, six measures contributing to balancing demand and production were identified to include intermittent RES in the power system: DSM, interconnection, storage, backup, curtailment, power outage. The first three have lower costs than the cost of backup capacity, a commonly applied solution.

Liu et al. [118] studied the co-benefits of large scale EVs and wind power in Inner Mongolia, the region in China with more wind power installed, already dealing with excess production. It considers an EV market uptake of 100%, corresponding to 2.6 million EVs, testing five charging modes: uncontrolled (after last trip), night, morning, afternoon and bidirectional smart charging. The results are that EVs have the ability to balance the electricity demand and supply, furthering wind power integration by 8% and saving both energy system and fuel costs. Between the charging strategies, EVs with afternoon charge have the most excess electricity reduction potential, allowing to integrate slightly more wind power than the bidirectional smart charging. The authors found, however, that the EV integration with a low level of wind power struggles to reduce CO_2 emissions, i.e., simply electrifying transport in a fossil fuel dominated energy system may not help to reduce the CO_2 emissions. Renewable energy development is thus crucial for transport electrification.

Lund and Münster [119] studied strategies to control CO_2 emissions integrating transportation and the energy sector for the case of Denmark. Two 2020 scenarios with 40% EV penetration have been considered. One is PEVs combined with fuel cell vehicles and the other is the use of biofuel and synthetic fuel from ICE vehicles. Both scenarios lead to a substantial decrease of the excess of wind power: if 50% of the electricity production is fluctuating, the excess electricity production is reduced by 70%. Calculations on CO_2 show that the two scenarios cause circa 5% emissions saving.

Zhang et al. [120] evaluated the impacts of integrating PV power into future electricity systems through EVs and heat pumps using a region of Japan as case study. They used several scenarios consisting on the combination of different penetrations of the three technologies, testing 0-30 GW of installed PV, 0-5 million EVs and 0-5 million houses equipped with heat pumps. The EV charging method is bidirectional V2G and it is considered that the heat pumps serve to heat water for sanitary uses. The region has pumped hydropower capacity installed for energy storage, but the model considers that it is completely replaced by the EV batteries. The flexibility of the natural gas power plants is considered to be 100%. The results show that one million EVs combined with one million heat pumps can reduce excess electricity by 3 TWh, 2% of total electricity. When 30 GW PV is integrated into the electricity system with 5 million EVs and 5 million heat pumps, 11.6 Mt of CO_2 emissions are reduced, 43% of total CO_2 emissions.

Pillai at al. [121] highlight the importance that V2G may have in order to improve the reliability of models simulated on an hourly-basis, such as EnergyPLAN. For small scale systems, they found that the amount of wind power that could be integrated in future electricity grids is lower for dynamic simulations (with a timescale of seconds) than for hourly simulations. They simulated a Danish island with around 100 MW of total system installed capacity with EnergyPLAN and DIgSILENT PowerFactory [122], which addresses fast dynamics in the grid, and compared the results, concluding that the wind power that could be integrated is much lower for the dynamic simulations than for the hourly simulations. In particular, without V2G providing for frequency regulation, they found that the hourly simulation foresees the use of 65% of the wind capacity while the dynamic simulation foresees 39%; with V2G providing for regulation, the wind energy used is 82% and 70%, respectively. This has to do with large wind power penetration causing frequency instability due to fluctuations in the generation. However, in nation sized energy systems, as the case of the object of this work, this difference is reduced due to smoothing effects when summing diverse RES sources spread along the country. In conclusion, due to their fast response in comparison to conventional generators, EVs may have an important role in future energy systems.

Tuffner et al. [123] used power flow simulation to perform a comprehensive distribution-level analysis on the leveraging potential of household rooftop PV electricity generation and EV charging, one of the first studies on the matter. They found that the overload of existing distribution system components caused by high EV penetration, which is mainly in the secondary transformer, is relieved by distributed residential PV acting as an electricity source downstream of this component. Furthermore, EV charging consumes the generated energy from the PV and reduces the reversal of power flow in the distribution system, which may cause voltage violations. For example, in the case of an EV using uncontrolled charging, the reduced transformer overloading was 11% when 20% of the homes were equipped with PV. With bidirectional V2G charging, high voltage problems on the grid due to high PV penetration was worsened with EV, since V2G injects electricity upwards the grid. These issues were not observed with unidirectional EV smart charging, since the EV charger never acts as a generator.

Interesting results were presented by Speidel and Bräunl [124], where the authors show findings of a trial conducted between 2010 and 2012 in Western Australia in which 11 EVs and 23 charging stations were monitored. It is thus a study confined to a small EV sample and a particular region, therefore generalizations require caution. They found that with a non-smart charging strategy the daily EV charging power profile aggregated over the charging stations closely resembles a solar PV curve, meaning that EV demand can be counterbalanced by solar PV. The data shows that most charging is conducted at work and home locations, whereas charging stations were used for a third of charging events. Of the total energy supplied, 79% of the energy is consumed during daytime, in the period 8:00-18:00. They found also that EVs spend significantly more time at a charging station than what is technically required for the charging process.

Fattori et al. [30] published a study addressing specifically the combination between PV electricity and EVs. The analysis is focused on the presence of non-PV energy sources in the mix and on the ramps their power has to face in order to satisfy the overall electricity demand. They tested different charging types: uncontrolled charging and smart charging with and without battery-to-grid capability. The aim of this study was to understand what advantages these two intelligent control strategies can provide relative to uncontrolled charging. For that, they used a linear optimization model named EVLS [125], which simulates the interactions between the electric vehicles and the electricity system for a circumscribed area, in their case a province of Northern Italy with about 0.5 million inhabitants and an overall fleet of 400000 cars. Only the PV electricity is considered among the existing generation technologies of the area, i.e., the individual remaining power plants are virtually excluded and their generation is generically included. They studied PV penetrations of up until 500 MW in combination with an EV fleet share up to 50%. Since the study is constrained to the residential sector, the possibility of charging the vehicles at work during the hours of PV generation was not considered, and an environmental analysis was not performed. The conclusions were that a high penetration of EVs under uncontrolled charging can make the generation face higher peaks. With an EV fleet share of about 50%, the increase in the value of the peaks can vary from 10% up to 16%, depending on the presence of PV. The PV electricity, in this case, can cover only a small fraction of this additional demand, since they are not correlated. They also found that the same level of EV penetration does not imply additional peak if smart charging strategy is adopted, with battery-to-grid allowing for -35% of net load in case of high penetration of both EVs and PV. As for ramps, the analysis established that the combined penetration of EVs and PV can strongly increase the ramping of the demand of non-PV capacity under uncontrolled charging, again because EV demand and PV production do not fit each other in the tested scenarios. The results are better with smart charging strategies and battery-to-grid, since the ramps are much reduced even for low EV penetrations. Charging the EVs during the day would likely lead to more positive results. Generally, the authors conclude that the smart control strategies bring significant flexibility to energy systems where the presence of non-dispatchable RES generation is relevant [30].

2.2.3. Summary

In summary, the introduction of EVs into power systems with high RES penetration has potentially several advantages, including grid support, enhanced power quality and reduced carbon emissions from both the power generation and transportation sectors. Smart charging allows EVs to be used as distributed storage for absorbing excess renewable energy, leading to additional benefits. As for battery-to-grid, it has limited role in improving the penetration of RES because it causes excessive battery degradation. Table 2 shows an overview of the literature classified according to subjects.

While there is some extensive literature about the effects on the power systems of individually large amounts of RES and EVs, and even in combination, it focuses more and is more detailed for wind energy than for solar, as EV charging is traditionally viewed as a solution to use useless off-peak time wind energy. In particular, there are no studies on: to what extent substantial hydro-pumping capacity, like it is planned for Portugal, is enough to absorb the energy excess in a 2050 scenario with high solar PV penetration; how to articulate the environmental synergies between PV and EV to reach the EU 2050 CO_2 emissions reduction target; what is the best EV charging strategy to adopt in the Portuguese system and other systems alike. That is, there is still a lack of long term analysis between solar energy and electric mobility, which is precisely the main goal of the present study.

Table 2. Overview of the literature according to subjects

Authors	Impacts of high RES penetration on the electrical system			EV integration on the electrical system			Grid support and power quality
	Wind	PV	Grid scale storage	Non smart charging	Smart charging		
					One way	Two ways	
Connolly et al. [113]	✓		✓				
Dallinger et al. [116]	✓	✓		✓	✓		
Denholm and Hand [28]	✓	✓	✓				
Denholm and Margolis [27]		✓					
Denholm et al. [36]		✓		✓	✓		
Fasugba and Krein [86]					✓		✓
Fattori et al. [30]		✓		✓	✓	✓	
Fernandes and Ferreira [112]	✓	✓	✓				
Freire et al. [114]	✓			✓	✓	✓	
Hennings et al. [51]	✓			✓	✓		
Kempton and Tomić [74]						✓	✓
Kempton and Tomić [73]	✓					✓	✓
Krajačić et al. [109]	✓	✓	✓				
Lise et al. [117]	✓	✓	✓	✓		✓	
Liu et al. [118]	✓			✓		✓	
Lund and Kempton [67]	✓			✓	✓	✓	
Lund and Münster [119]	✓		✓	✓			
Mackay [32]	✓		✓				
Nikolakakis and Fthenakis [106]	✓	✓					
Pillai at al. [121]	✓					✓	✓
Solomon et al. [107]		✓	✓				
Speidel and Bräunl [124]				✓			
Tomić and Kempton [75]						✓	✓
Tuffner et al. [123]		✓		✓	✓	✓	✓
Weitemeyer et al. [29]	✓	✓	✓				
Zhang et al. [120]		✓				✓	

3. Methodology

This chapter presents and explains the methodology adopted in this work and comprises: a presentation of the energy tool used and its functioning (Section 3.1); a description and outline of the general approach (Section 3.2); the model calibration, including a brief description of the Portuguese electric power system in order to characterize the reference year and the base from which the scenarios further presented evolved (Section 3.3); a presentation of the scenarios, and how they were constructed (Section 3.4); the EVs charging methods and their fundaments (Sections 3.5 and 3.6).

For the simulation of the Portuguese electricity and transport systems and integration of electricity sources, different simulation tools were considered and, in the end, EnergyPLAN [126] was chosen. For a comprehensive review of energy systems modelling tools, see [127]. EnergyPLAN is a validated computer model designed for energy systems analysis that optimizes the operation of a given energy system on the basis of inputs and outputs defined by the user. The reasons behind the choice are:

1. The purpose of this research is to understand how PV and EVs facilitate each other their large-scale integration into a country level electricity system, and EnergyPLAN is a simulation model at regional and national levels including the major primary sectors of an energy system, namely electricity and transport;

2. EnergyPLAN has the capability to simulate EVs smart charging;
3. It was required an instrument with a temporal fine analysis, instead of an aggregated annual demand and production analysis, and EnergyPLAN, being an hourly simulation computer tool, satisfies that condition, making it suitable to model solar power integration (and power from other renewable sources), considering its variability;
4. Ample previous research about integration of fluctuating RES has been carried out using this tool[21].

These features indicate that EnergyPLAN is appropriate to this study.

3.1. The EnergyPLAN software

The EnergyPLAN computer tool was created in 1999 and it is developed by the Sustainable Energy Planning Research Group at Aalborg University. It is currently in version 11, the one used for this work, which can be downloaded from [126]. It is programed in Delphi Pascal and, although it is available free of charge, it is not open source, in the sense that the code cannot be edited. It is used for the simulation of entire energy systems, thus including electricity, heat and transport sectors. It works by optimizing the operation of the system according to what is described in Section 3.1.1. Its purpose is to give the possibility to look to a complete energy system as a whole, e.g. addressing the challenge of integrating fluctuating power from RES into the power grid, allowing to identify energy, environmental and economic impacts of various energy strategies. It is not, however, a bottom-up model, that is, it does not seek optimal energy and technological paths departing from pre-defined conditions such as energy needs of a region; it allows, instead, the analysis of a variety of paths so that they can be compared with one another [126].

[21] See more on this in Section 3.1.

The EnergyPLAN has been used before in numerous studies, including to analyze in the context of a European project the integration of fluctuating RES into local and regional electricity systems in Germany, Estonia, Poland, Spain and the UK, specifically with the aim to balance wind power by use of combined heat and power [128]. In [129] it was used to analyze different strategies to solve the problem of excess of electricity production during certain periods in Denmark in a 2020 scenario. In [130] to identify the ability of different energy systems and regulation strategies to integrate wind power, again in Denmark. It was used in [131] to perform a comparative energy system analysis of different technologies using organic waste for heat and power production and as fuel for transportation, while in [132] it was used to assess the effectiveness of storage and relocation options in RES based systems. In [133] the EnergyPLAN was used to assess in China the potential of up to 100% renewable energy based systems, and in [134] to study the wind energy integration into future energy systems based on conventional power plants in Croatia.

In what concerns works related to or including the transport sector using EnergyPLAN, it is relevant to mention: [135], assessing the problems and perspectives of converting present energy systems into a 100% RES based systems; [119], addressing CO_2 emissions control strategies through integrated transportation and energy sectors; [67] and [118], analyzing the integration of wind energy into the transport and electricity sectors; [136], analyzing the design of a 100% RES system by the year 2050 in Denmark. These studies are reviewed in Section 2.

None of these works, however, concern Portugal. Currently there are scarce applications of EnergyPLAN to this country. One of the few is [137], which proposes a modeling framework to optimize the investment in new renewable generation capacity on long-term scenarios while taking into account the hourly dynamics of electricity supply and demand. For that, the authors used an hybrid approach, combining EnergyPLAN and TIMES [138]. They used both models iteratively: the TIMES investment optimization model was used to optimize the investment in new generation capacity while the EnergyPLAN operation optimization model was used to calculate the energy balances with an hourly time resolution. Another study having Portugal as a case study is [112], already described in Section 2.2.1.

Published studies concerning the impacts of PV and EVs using EnergyPLAN are yet to this moment inexistent, except the publications derived from the present work. For an updated online list of studies completed with EnergyPLAN sorted by subjects, see [139].

It should be stressed that the EnergyPLAN model corresponds to an aggregate computation with a one hour resolution. Therefore, it does not account for the shorter term dynamic of the electrical system, in the range of seconds, meaning that parameters such as frequency stability are not computed. Hourly simulation by itself thus provides insufficient criteria to ensure the feasibility of an energy scenario, and therefore should be coupled with dynamic simulations. As mentioned in Section 2.2, Pillai et al. [121] emphasis the discrepancies between the two types of simulations, especially when applied to small isolated regions. At a nation size systems, the differences are reduced by the smoothing effect of the sum of numerous and geographically spread sources of RES. If EVs can provide short term power balancing, the differences are further reduced, again suggesting that EVs may have an important role in energy systems scenarios due to their fast response in comparison to conventional generators. Still, dynamic simulations are important to ensure stable power system operations and control and to justify the technical feasibility of hourly simulations, like EnergyPLAN performs [121].

3.1.1. Model functioning

A summarized description of the functioning of the model is given below. It is restricted to the parts of EnergyPLAN that were applied to this work and how the model was set up; other configurations or functionalities, e.g. district heating, are not covered. A detailed description, including formulation, can be found in [67], [140] and [141].

3.1.1.1. General aspects

The EnergyPLAN performs annual deterministic analysis, i.e., for the same input one always has the same output, working, as already mentioned, with a time-step of one hour. The output can be also accessed on an hourly basis if the user defines it. The model works under one of two different main types of optimization, technical and market-economic, chosen by the user according to the type of analysis desired.

The technical optimization serves to help in the design and analysis of large and complex energy systems, at a regional or national level, under a set of possible technical regulation strategies. It needs as input detailed data from the system being simulated, such as power plants installed capacities, import/export capacity, regulation strategy and hourly datasets of available renewable resource and demand. The outputs are detailed energy balances, energy generation, fuel consumption and CO_2 emissions. The algorithm behind the technical-optimization minimizes the import/export of electricity and seeks to identify the least fuel-consuming solution.

The market-economic optimization performs an analysis of trade and exchange on international electricity markets. The model requires input to calculate market prices and to determine the market response to the hourly import-export balance. A set of economic data related to energy production is needed to determine marginal production costs of the individual electricity production units. The algorithm works optimizing each power plant functioning, identifying the least-cost solution to maximize the business-economic profits. The program procedure analysis is schematized in Figure 6.

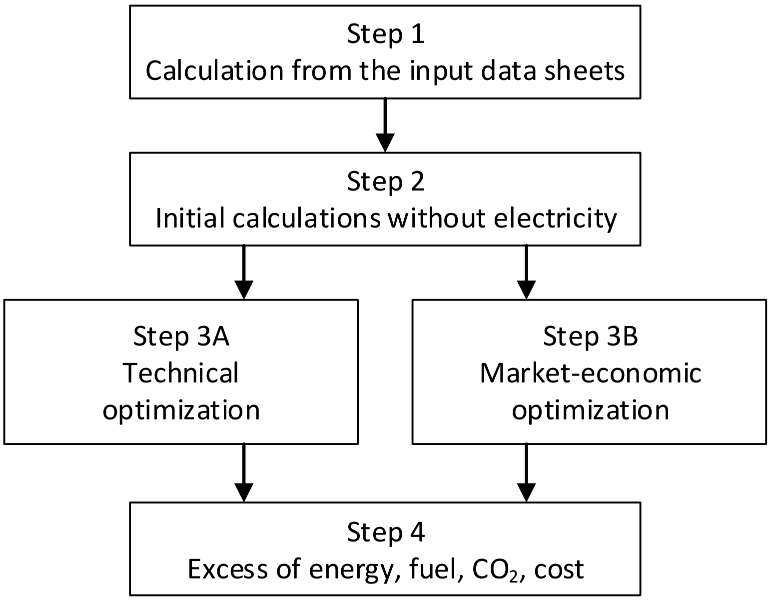

Figure 6. EnergyPLAN procedure analysis. Adapted from [140]

For reasons addressed further below, in Section 3.2, this work requires the technical optimization approach, and for this reason one will focus on it from this point on.

The electricity demand is defined by an annual value (TWh/year) and an annual hourly distribution data set. Part of this electricity can be made flexible, on the scale of a day, a week or a month, in order to simulate consumer demand side response. It is also possible to simulate the import/export balance with external regions specifying its hourly distribution. Beyond the restriction posed by the interconnection capacity, defined by the user, the model accounts separately additional import and export values. These are the hourly deficits and surpluses in the system after considering the fixed import/export.

The electricity generation from variable RES is found by multiplying the RES capacity by the respective hourly distribution. Since future technologically improved renewable technologies with the same installed capacity can lead to higher productions for the same year, one can specify a correction factor to change the distribution and increase the annual generation. This factor changes the production in such a way that the production remain the same at hours with either no production or maximum production, while the other values are adjusted according to that factor, resulting in an increased capacity factor. It is also possible to use RES to contribute to grid stabilization, assigning a share of their production to it.

The model accounts for excess electricity production (EEP), which is the difference between the generation and the total load[22]. It can be totally absorbed by hydroelectric pumping if there is enough pump capacity and storage available and used at a more convenient time in spite of losses due to system inefficiencies (see Table 8 further below). Otherwise, the rest can be used for additional smart charging. If there still exists EEP, the remainder is exported or, in the absence of interconnection capacity, it becomes critical excess of electricity production (CEEP) and must be curtailed. In other words, CEEP is energy in excess in the system.

A share between 0 and 1 should be set to define the minimum percentage of the total electricity production coming from grid-stabilizing units and a flexibility level should be allocated to thermal power plants to account for their restricted ability to operate below certain levels.

The production of thermal power plants is determined as the difference between (1) the demand and the sum of the other generation, (2) the minimum production needed in order to fulfil the stabilization requirements of the grid or (3) the thermal minimum load level, whichever is larger.

The hydropower is adjusted as function of the water supply, water storage, potential for replacing thermal power plants and reducing CEEP, and it is considered to contribute to grid stability.

The model assumes that dispatchable production units can change output from one hour to another without ramp rates constraints, thus considering that the system has capacity to accommodate sharp changes in the output of wind and solar power.

---

[22] Total load is the simple consumer load plus non-smart EV charge plus part of EV smart charge (i.e., the charge to assure that the vehicles that will drive shortly are charged – see Section 3.1.1.2.).

Table 3 presents an overview of the components involved in the modelling made for this work and the operation of each one under the technical-optimization approach.

Table 3. Input and operation of the EnergyPLAN components [140]

Component	Input	Operation (technical regulation)
Energy sources		
Wind onshore Wind offshore Photovoltaic River hydro	Electric capacities Hourly distributions	Are given priority in the electricity production
Hydropower	Electric capacity Efficiency Storage capacity Annual water supply Hourly distribution of water	Firstly, best possible utilization of all water input Secondly, hydropower is relocated in the best possible way to avoid excess electricity production
Reversible hydropower	Pump capacity Pump efficiency	Pump is used in order to avoid excess electricity production and the turbine to substitute fossil power plants
Thermal power plants	Electric capacity Efficiency Minimum capacity Fuel specification	Solely used after all other electricity production units, if the demand is still higher than the supply (or for grid stabilization)
Transport		
Gasoline vehicles Diesel vehicles	Fuel demand	n.a.
Electric vehicles (non-smart charge)	Electricity demand and hourly distribution	Fixed electricity demand defined by the hourly distribution
Electric vehicles (smart charge)	Electricity demand and hour distribution Maximum share of parked cars Share of cars connected Charge efficiency Battery capacity Grid-to-battery capacity	Charging is distributed with the aim of decreasing excess electricity production and the quantity of fossil power in the overall system[a]

[a] more on this in Section 3.1.1.2

3.1.1.2. Smart charging

Smart charging in EnergyPLAN involves an optimization problem to manage the EV load in order to decrease the network's existing excess of energy production, allocating EV demand to that periods. The smart charging inputs are, as all of other parameters, expressed for the entire utility system and for the entire vehicle fleet. It means that, for example, the total V2G capacity at a given time is calculated multiplying the power available from a single car by the number of vehicles plugged in at that time, i.e., the V2G fleet follows the big battery concept[23] [68]. Since a number of cars will be driving and can neither discharge to nor charge from the grid, the total capacity of the batteries is never available.

The model assumes that a user defined fraction of the fleet will need to drive during the next few hours and therefore cannot be discharged. The model also considers that the batteries should be fully loaded when the respective cars disconnect from the grid to start driving. This is not an adjustable parameter in the EnergyPLAN v11, meaning that even before short journeys the model assures the full load of the batteries.

As a rule, the model charges the batteries (e_{charge}) in the case of existent EEP (e_{EEP}) and available battery capacity (S_{battery}), considering the power limits of the V2G connection (C_{V2G}) and its efficiency (μ_{charge}). That is, the model uses the minimum of the values in Eq. (1):

[23] The aggregation of vehicles follows the virtual power plant concept model, meaning that they are clustered and controlled as a single distributed energy sink and source, easing the centralized control by the system operator. At the virtual power plant control center, the aggregated battery power is dispatched according to the needs of the system operator, which manages the communication and energy exchanges between the energy market players (the producers and the consumers) [203].

$$e_{\mathrm{charge}} = MIN\left[e_{\mathrm{CEEP}}; \frac{S_{\mathrm{battery}}}{\mu_{\mathrm{charge}}}; \mathrm{C}_{\mathrm{V2G}} \right] \tag{1}$$

This mode of functioning implies that the system operator (SO) is aware of the schedule for each car, anticipating when the car will be driven. Then, the SO gives priority to charge the cars that will drive shortly, so any existent EEP is directed first to those cars and only afterwards to the remaining of the fleet. Later, when applicable, if the state of charge (SOC) of the batteries allows for it, i.e., if there is energy available from the cars that will be parked in the next hours, V2G cars are told to help the grid when they can replace production or stabilization or both from thermal fossil based units.

Even when there is no EEP, every hour the model inspects the next few hours of driving needs and forces the charging as needed. In this case, the algorithm calls for whatever dispatchable sources are available to fully charge the batteries prior to driving periods, with an order of merit favoring the less carbon intensive sources, i.e., fossil fuel power plants are ramped up or switched on only as a last resource. The model does not consider wear out of the batteries over time.

3.2. General approach

The analysis is constrained to mainland Portugal, since the Portuguese islands are not interconnected with the continent. The transport analysis is constrained to the light passenger vehicles, thus excluding buses and trains. This is the segment where EVs have the most market potential. Since fuel cell vehicles have expected limited share on market sales until 2050 [24], this technology was not considered.

In order to ensure the model is simulating the Portuguese energy system correctly, a reference model was created and validated representing the year 2011 (see Section 3.3). The model approach is schematized in Figure 7 and in the following sections more details are provided.

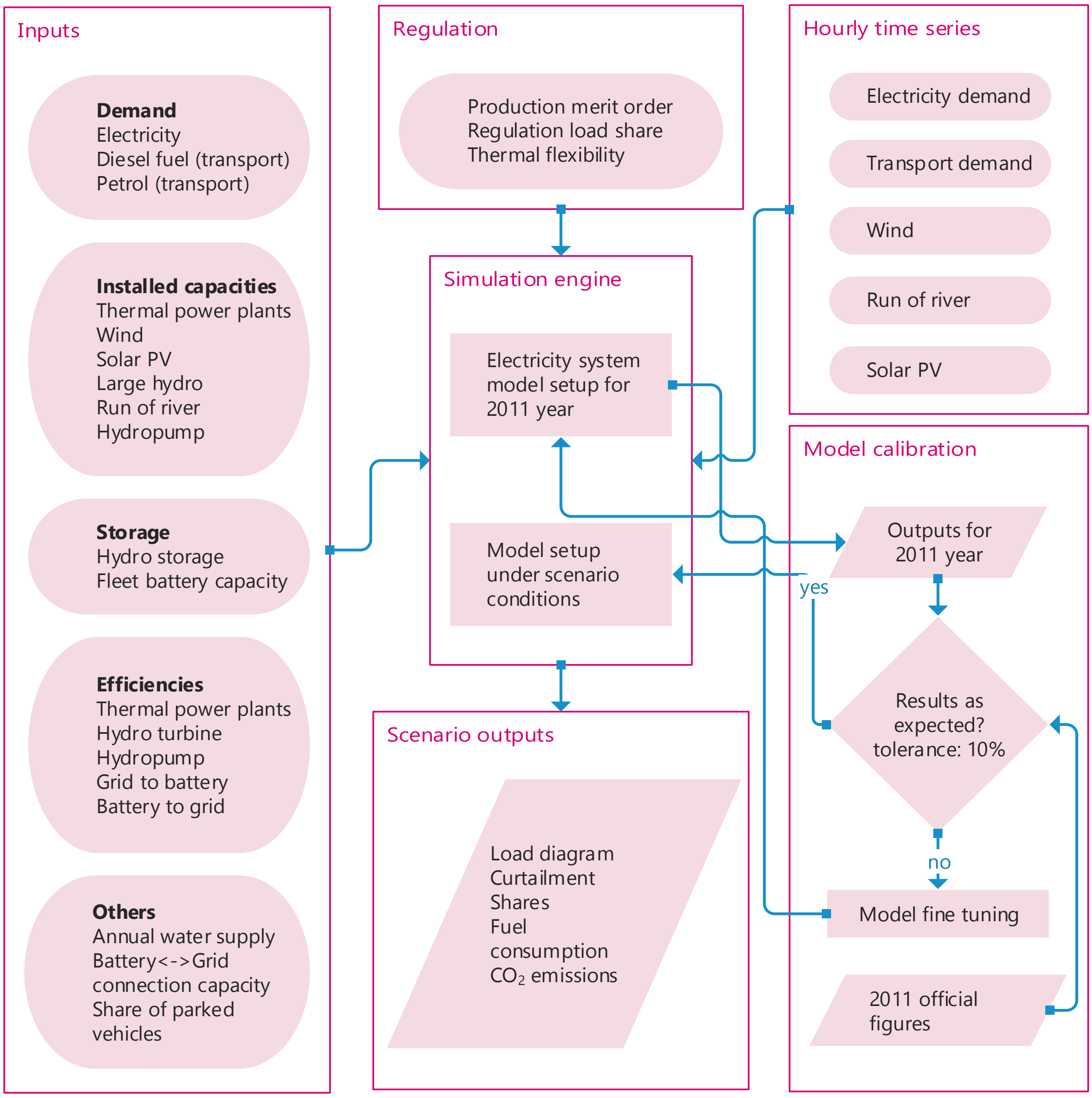

Figure 7. Model approach

To understand the PV impacts on the system, the shape of the daily and inter-seasonal load profiles is important, as already noted in Section 2. On the course of decades, they can change due to alterations in the climate, society, technology, policy and regulation, etc., and are therefore hard to anticipate. Consequently, for the sake of the simplicity in this work, one did not model different load profiles. For the same reason, and because it was out of the scope, flexible simple electricity demand was not considered[24].

The water distribution to the hydro reservoirs was available from the TSO on a daily basis, not on an hourly basis, as it is needed by EnergyPLAN. The transformation to an hourly basis was made from the run-of-river output distribution, which, on a national scale, is correlated with the overall country water supply (5.26 TWh in 2011 [142]), since run-of-river plants do not store a significant amount of energy. The total large hydro storage available in 2011 was around 3081 GWh [143], never reaching below 40% of that capacity in that year [142], meaning that the energy buffer was always relatively high. On an hourly basis, the algorithm of the model always counts for the storage available and dispatches large hydro production considering this constraint, which means that fine alterations in the distribution of water have no direct implications on the hourly model behavior.

Although it is possible that future RES generation may provide some grid stabilization, as it has been argued regarding wind turbines [144], conservatively this option was not considered in the present work.

The analyses do not consider possible transmission constraints, in part because some of the PV generation is used at or close to the generation point and partly because it is considered that the TSO assures the deployment of the transmission capacity needed in the future, as planned in [145]. It should also be mentioned that transmission and distribution (T&D) power losses are already included on the network energy figures. A PV system generating at the load site would offset the losses associated with delivering electricity, meaning that, in a future with a significant share of PV, energy T&D losses are expected to be lower. Conservatively, in all the scenarios discussed below those losses are as in the present. It ought to be stressed that to plan at such levels of penetration of solar PV it will be important to perform detailed load flow analysis

[24] Simple electricity demand is the simple load, excluding EV demand. Demand side management is considered in the total load, since EV smart charging is fundamentally a DSM mechanism.

quantifying the T&D loss offsets as well as the possible T&D constraints and the ability of the utility to handle the aggregated power flows from thousands of individual small generators [27].

As mentioned above, a technical optimization strategy was chosen as opposed to a market economic optimization. Also, no interconnection capacity with the exterior is considered. Five different reasons are behind these choices:

1. From a techno-economic viewpoint it is desirable that electricity production is consumed locally, not incurring this way in losses and costs due to transportation over long distances;
2. Establishing technical feasibility should precede the analyses of the business driven operation [146];
3. There is a great uncertainty in market behavior modeling in an horizon of about 35 years from now;
4. A closed system analysis enables a better overview of the available energy sources and possibilities and constraints to their internal use, helping to understand how to minimize the need for interconnection capacity [67];
5. For a scenario with high penetration of solar electricity, it is likely that the gross of the exports will be at the time of higher solar irradiance, which will be low valued in the energy markets because at the very same time other trading partners (e.g. Spain) will have eventually their own excess of solar electricity.

3.3. Model calibration

Calibration to a past period is an iterative process of adjustments whose goal is to obtain simulation predicted outputs that are similar to the corresponding registered parameters, thus validating the model. For this purpose, the year 2011 served as a reference, as it was at the time of preparing this work the most recent year with the detailed technical data needed available from the TSO (REN) and the national energy authority (DGEG).

For this reason, and also to give an insight over the existing electric power supply in Portugal, this year is characterized next.

3.3.1. The Portuguese electric-power system in 2011

The electricity consumption in 2011 was 50.5 TWh, with a peak power demanded from the grid of 9192 MW and a minimum load of 4966 MW. Figure 8 shows the electricity generation shares according to the production sources. It can be seen that electricity production from RES supplied 46% of consumption, 18% coming from wind, 22% from hydro and 8% from other renewables, e.g. biomass, waste and biogas. Solar PV produced 262 GWh of electricity, a share of 0.5%. The import balance represented 6% and the thermal generation accounted for 54.3%, with 18.2% from coal, 28.0% from natural gas and the remaining from oil (<2%) and renewable sources, such as biomass [147].

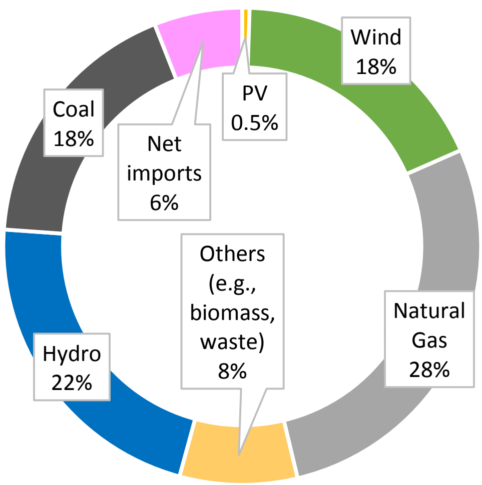

Figure 8. 2011 electricity shares

The annual load diagram with energy production and demand divided by weeks is shown in Figure 9. One can see that RES production starts to grow in the end of the summer and is highest in the first months of the year, mainly due to high water availability in this period, reaching its lowest levels during the summer, for the opposite reason. As a consequence, thermal electricity share is higher during the dry season. The coefficient of hydroelectric productivity for the all year of 2011 was 0.92 [143], meaning that that year was 8% below the average of hydro resource availability.

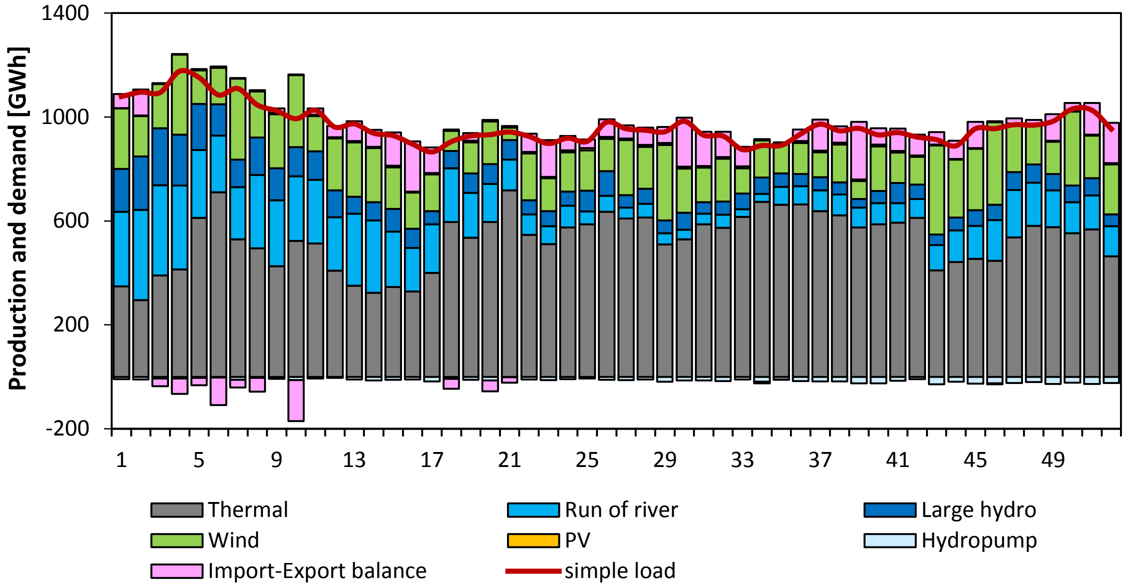

Figure 9. Registered 2011 weekly energy production and demand

The shapes of the daily and seasonal load profiles and the load duration curve are critical to understand how PV interacts with the system. They are analyzed having as basis the next figures. Figure 10 shows the inter-seasonal average load in the system. For the whole year, average load was 5768 MW, with a higher average demand during the heating period as opposed to a lower demand during the summer. Typically, due to the mild Mediterranean temperate climate, with temperature amplitude damped by the sea at coastal places where most of the consumption takes place, and due to a historical low level of air conditioning installed in residences, cooling demand is small. The month with the highest average demand was January (6600 MW); on the other hand, August was the month with the lowest (5378 MW, less 19%). The annual peak load was 9167 MW.

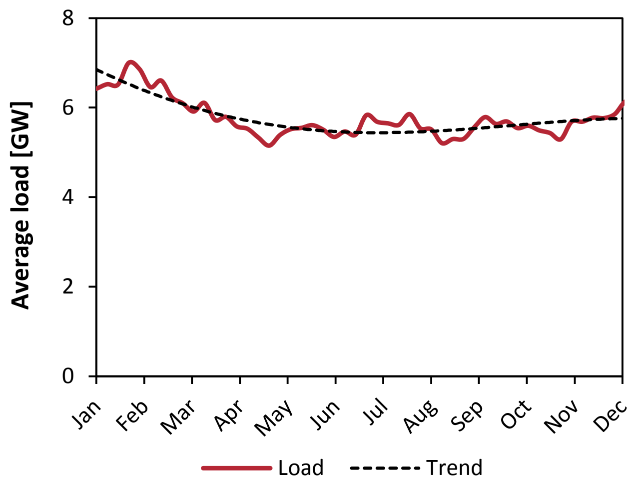

Figure 10. Inter-seasonal average load along 2011

A further insight into electricity demand and the electric-power system operation is obtained reordering the annual demand data into a load duration curve diagram. It translates the total annual number of hours a system is required to provide a certain amount of load. Figure 11 shows the normalized duration curves for 2011 for the entire electric-power park and for PV and wind generation individually, being the power normalized to the peak load. Most of the bottom half of the load duration curve is fulfilled with base load plants, designed for continuous operation close to their optimum efficiency output. For this reason, they have limited ability to cycle or vary output, but they present low operating costs[25]. In Portugal, base load is provided mostly with natural gas fired and coal fired power plants. It is worthwhile to notice the shape of the PV curve, with a steeper zone (daylight) and an essentially flat zone (corresponding to night periods). The overall capacity factor for 2011 was 0.29.

[25] See Section 3.4.2.2.1 for more on this.

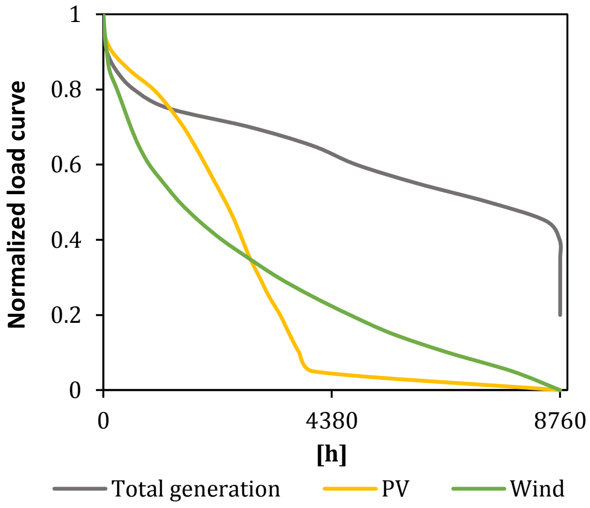

Figure 11. 2011 normalized load duration curve

Figure 12 shows the load of two weeks of the year, those with the highest and the lowest average demand, in January (7000 MW) and April (5580 MW), respectively. It is evident the night valley period, starting at around 22:00 and extending to about 7:00, corresponding to a low demand period due to diminished activity during those hours. From 7:00 on weekdays, the starting of household activity, services and industries are responsible for an increasing in the demand, forming from about 9:00 till 17:00 a midday plateau, with a depression around noon due to lunch interruption in services, where the load slightly decreases. Later, there is a peak in the demand around 20:00 due to an increase of domestic load, associated to lighting and domestic appliances after the work period. On the weekends the demand is around 15% less, but the pattern is not fundamentally different, except for the lunch period depression.

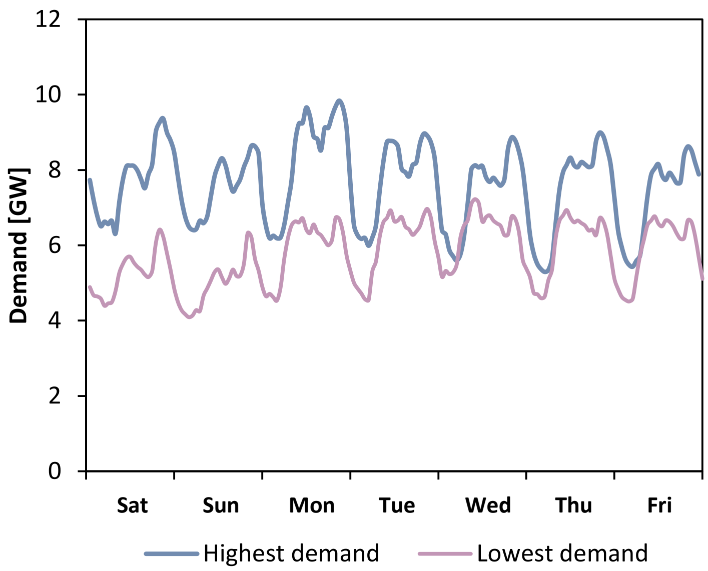

Figure 12. Demand for the two weeks of the year with highest and lowest consumption

Figure 13 shows the daily averaged load patterns for all weeks and their average, giving an overview on the weekly demand distribution along the year.

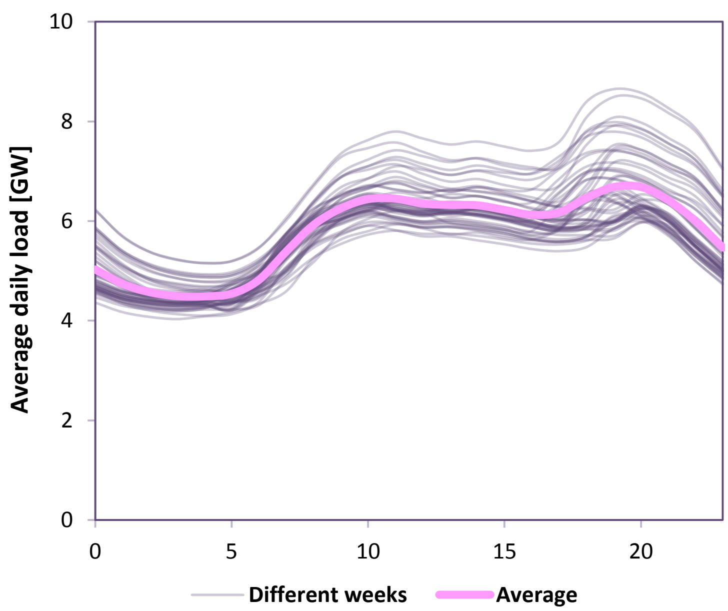

Figure 13. Averaged daily load patterns along the year

To have an insight on the solar variability along the year, Figure 14 shows the PV production profiles corresponding to the days with the highest and the lowest irradiation, which occurred on the 7th of July and on the 23rd of January, respectively – the first registered around fifteen times more generation than the latter.

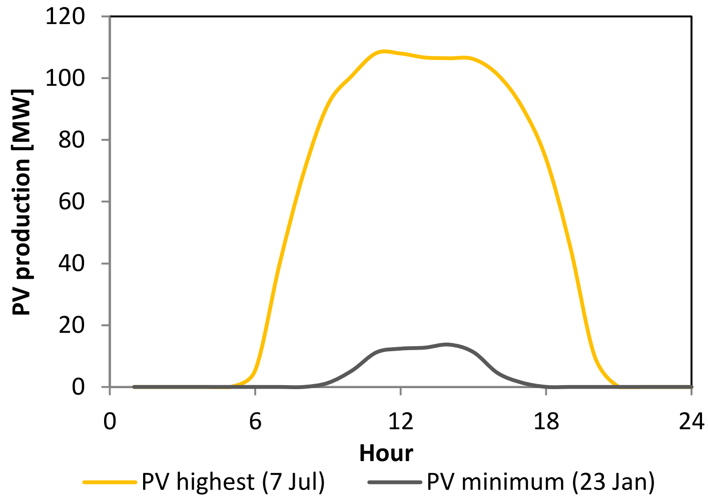

Figure 14. PV maximum and minimum productions for the entire year

3.3.2. 2011 Simulation

The main variables to be calibrated are: electricity demand, electricity production by source, RES share, primary fuel consumption, monthly average power and CO_2 emissions. The results obtained are shown in Table 4. The average of the module of the individual annual differences is 0.36%.

Table 4. Model calibration results

	2011 figures [16], [147], [148]	**2011 simulation**	**Difference to reference (%)**
Final energy (GWh)			
Electricity demand	50503	50630	+0.3
Electricity production			
Thermal PP	27336	27300	-0.1
Large hydro	4213	4210	-0.1
Run of river	7638	7650	+0.2
Wind	9003	9030	+0.3
PV	262	260	-0.8
RES electricity share	46.0%	45.4%	-1.3
Primary Fuel (Mtoe)			
Natural gas	2.870	2.862	-0.3
Coal	2.201	2.194	-0.3
Oil	0.249	0.248	-0.5
Biomass	0.380	0.379	-0.2
Diesel	4.013	4.013	0.0
Gasoline	1.319	1.319	0.0
CO_2 emissions (Mt)			
Electricity sector	16.36	16.31	-0.3
Transport sector[a]	15.65	15.78	+0.8

[a] passenger + light duty vehicles fleets

Figure 15 presents the monthly evolution of the real and simulated average power demand; the average of the module of the differences is 0.29%. The registered import/export balance in 2011 was 2051 GWh, while the model outputted 2180 GWh, i.e., +6.3%. This difference is mainly explained by the strategic behavior of the electricity players in the Iberian electricity market (MIBEL) and other constraints, which are not entirely captured by the technical optimization of the EnergyPLAN [112][26].

[26] For example, operative maintenance or failure of power plants and strategic withholding of capacity by market players affect the energy exchanged [204].

Since the main purpose of the study is to compare and analyze the technical feasibility and impacts on the grid of mass deployments of EV and solar PV, the model is considered valid and the reference year formed the basis for the study of the projected scenarios presented in the next sections.

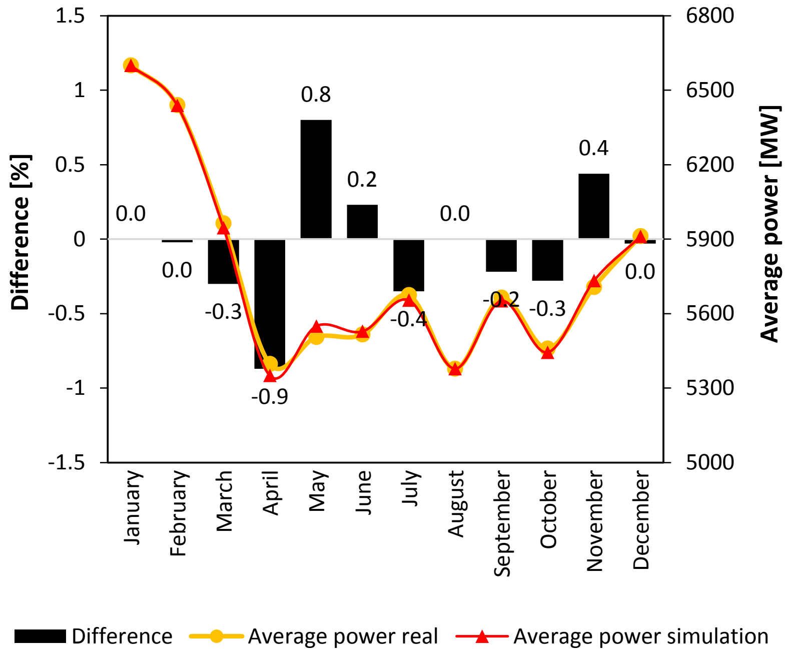

Figure 15. Monthly basis real and simulated average power demand for 2011

3.4. 2050 Scenarios

Scenarios are essential to describe possible development paths, to provide to decision-makers a broad overview and show how far they can shape the future mobility and electricity systems. To study the impacts of the greater or lesser articulation, i.e., the synergies and conflicts, between solar PV and EV deployments, several combinations between solar PV installed capacity and EV market penetration in 2050 were conceived and simulated.

3.4.1. Scenarios modelling

The scenarios in this work are built upon long term EU objectives for the climate-energy area and upon different reference scenarios presented in the literature, some of these derived from partial equilibrium technical-economic models of the evolution of the energy systems over a defined time horizon, such as MARKAL/TIMES [138].

Data temporal extrapolation was applied to the scenarios with a time horizon shorter than 2050. The criteria for choosing the considered scenarios were:

1. European Union or, preferably, Portugal scope;
2. Scenarios built 2009 onwards, in order to reflect the effects of the financial crisis that started in 2008 and lead the EU and particularly Portugal to an economic downturn;
3. Scenarios or objectives that met the above criteria but comprise future conditions that have already been achieved in Portugal were discarded.

The path of a new technology market uptake and the forecast of stock of vehicles or the prospective sales of new products may be modeled using univariate time series sigmoid growth curves, referred as S-shaped curves. The curve follows this shape since the initial growth is often very slow (e.g. a new technology replacing a mature one), followed by rapid exponential growth when barriers to adoption relax and then falls off as the market saturation is approached [149], [150]. The curve also identifies an inflection point, where growth stops to increase and starts to diminish (see Figure 16).

The majority of technology growth curves have been developed to forecast its adoption rate using the simple logistic model and the Gompertz model. The latter is the most referenced. The main difference between the two kinds of curves is that the logistic curve is symmetrical and, thus, the inflection point is at the center of symmetry; as for the Gompertz curve, it has no center of symmetry and the late growth stage can reach several times of early growth stage, as Figure 16 shows, more in line with the market uptake of several technologies. The inflection arises before half the saturation is reached. The Gompertz model was previously used to successfully predict several trends in market demand, such as car ownership within 26 countries until 2015 based on data from the period 1960-1992 [151]. In [152] the authors used it to predict the EV ownership in China in the coming years. Both model types imply an estimation for the market share growth capacity.

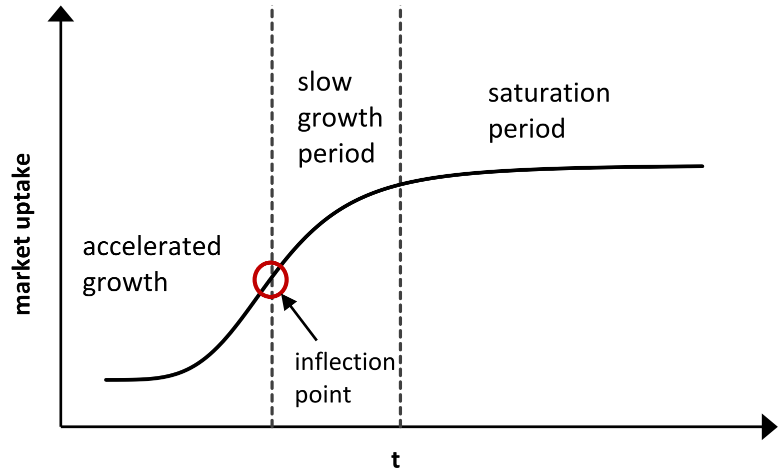

Figure 16. Development of technology penetration. The curve shape is of a Gompertz growth model

One third model adopted in some studies is the extended logistic model, which differs from the simple logistic in the fact that the saturation value becomes dynamic, i.e., the upper limit varies over time [149]. An explanation and evaluation of these models is presented in [149].

The selection of an appropriate type of S-curve is important, and a method to select between logistic and Gompertz models is proposed in [153]. Following this, the choice of the model to use in this work was made using criteria based on forecasting errors and on the plausibility of the estimated saturation levels.

The best fitting results to the real data were obtained with the following Gompertz function:

$$y = a \exp\left[-\exp\left(-k\left(x - x_c\right)\right)\right] \tag{2}$$

where a, k and x_c are unknown positive-valued numbers, a representing the saturation level.

3.4.2. Electricity system

3.4.2.1. Solar PV scenarios

The European Photovoltaic Industry Association (EPIA) has found that, in a business as usual scenario, a share in the range of 7% to 11% of PV in European electricity by 2030 is realistic [42]. With policy incentives, it increases to 10-15% [12], and in a paradigm shift scenario, where all barriers are lifted and specific boundary conditions are met, it is foreseen that PV can have a penetration of 25% by 2030 [12]. Building on these trends, two extreme scenarios and a third that is their average constitute the three solar PV deployment levels in Portugal by 2050 studied in this work (Figure 17). They correspond to a share of PV in the energy mix of 25% to 33% (see Section 4.1.4). Table 5 contains the capacity installed and the annual energy production for these PV scenarios.

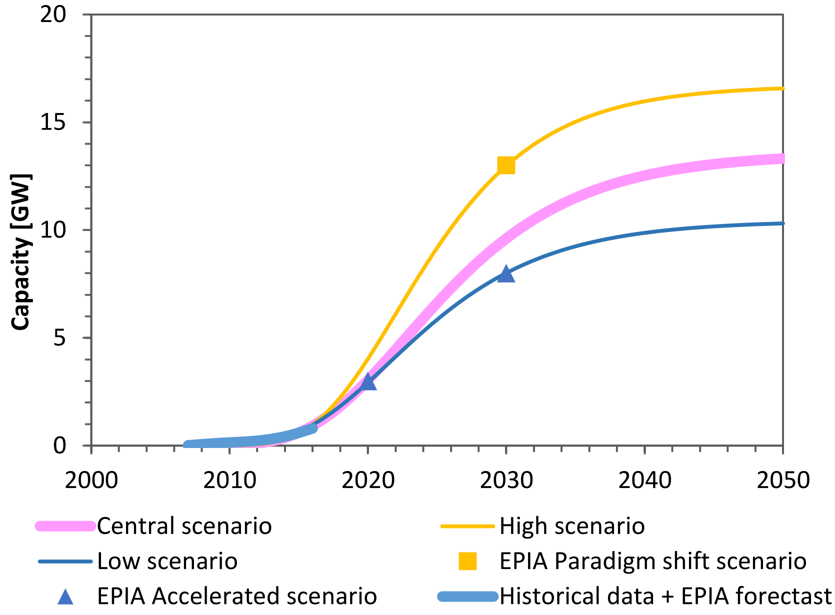

Figure 17. Scenarios of evolution of the PV installed capacity [12]

Table 5. Capacity installed and yearly energy productions for the different PV scenarios considered in this study

		Low scenario	**Central scenario**	**High scenario**
Capacity installed	**MW**	10308	13316	16669
Production	**TWh**	17.46	22.56	28.24

3.4.2.2. Common assumptions

The scenarios projected differ between each other in the level of PV and EV deployments, which means that several common projections about the utility system were used in all of them. These common assumptions are discussed in this section.

Natural gas is viewed by some as a bridging energy to a sustainable energy future [154], and, even in future scenarios that foresee a high share of RES, natural gas is expected to grow in the following decades, mainly because it can substitute coal with technical and environmental advantages. In Portugal, the evolution until 2050 of the installed capacity of natural gas power plants, based on CCGT, is derived from [155], [156] and is shown by the thickest line in Figure 18. It constitutes a 22% increment in capacity, from 4687 MW to 5723 MW.

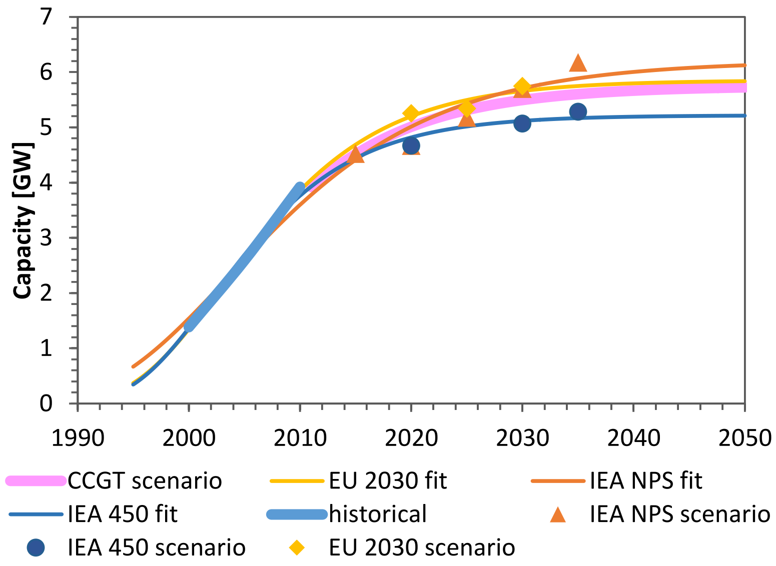

Figure 18. Modeled evolution of the total installed capacity of natural gas fired based power plants [155], [156]

Taking in consideration the expected marked decline in coal electricity generation in the EU, no electricity generated by coal was considered [157]. In Portugal, due to mandatory compliance with environmental legislation, it is foreseen as plausible the decommissioning until 2022 of the Sines power plant [145], which has been in operation since 1985 and is the biggest coal fired power plant in Portugal, representing most of the total coal fired installed generation capacity in the country (~70%). In this work it is assumed that the rest of this capacity will also be decommissioned until 2050, and gradually substituted with CCGT type power plants.

Although the present capacity of fuel-oil fired based power plants is significant (see Table 6), these plants are seldom operated, and fuel-oil based electricity production in Portugal in 2011 was very small (<2%) [16]. It was also assumed the total decommissioning of this type of generation until 2050, with its role in the system assumed by CCGT technology, cleaner and less carbon intensive.

Besides natural gas, all scenarios consider that thermal generation in 2050 is provided by biomass, urban solid residues (waste) and biogas type power plants. The projected evolution of these together is derived from [155] and [156] and is shown by the thickest line in Figure 19. It is a 124% increment in capacity, from 603 MW to 1348 MW. Overall, thermal capacity is reduced 24%, and fossil fuel based power-plants diminishes 34%.

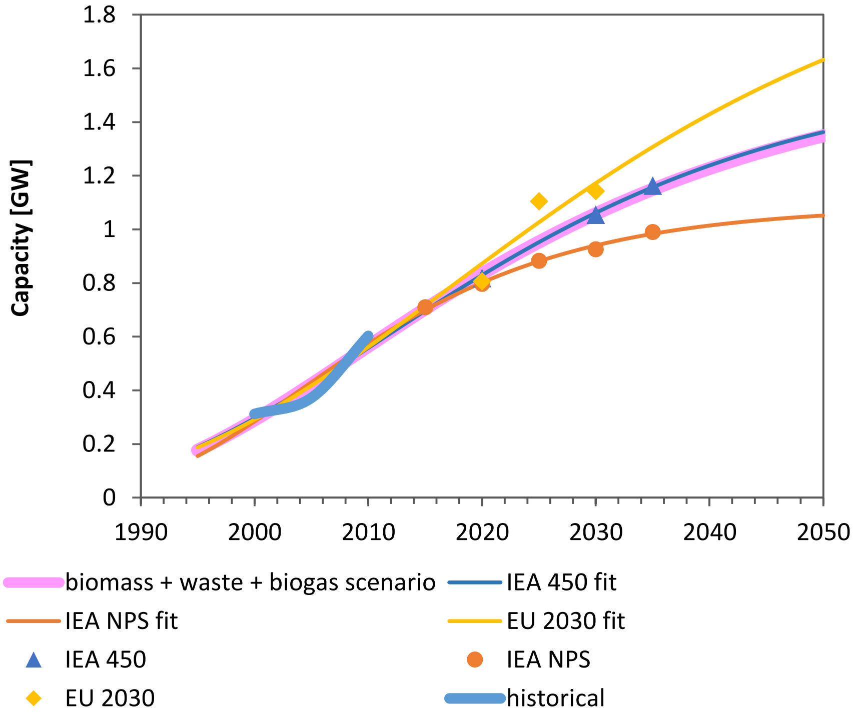

Figure 19. Modeled biomass, waste and biogas based fired capacity evolution until 2050 [155], [156]

As for hydropower, all the new large hydro capacity determined by the *Programa Nacional de Barragens com Elevado Potencial Hidroeléctrico* [158] is considered to be fully implemented in 2050, including its pumping capacity. This represents a growth in the installed capacity from 5392 MW to 8536 MW. Hydropump capacity almost quadruplicates from 1020 MW to 4004 MW, justified by the need to absorb wind energy in excess during the night. One did not consider additional installed hydropower capacity, since the potential is considered to be virtually depleted in 2030 [159].

Concerning wind energy, Portugal has seen notable deployment of onshore wind power capacity that currently puts it in the top list of countries with both high growing rate and accumulated capacity. This is illustrated by the line corresponding to the historical penetration in Figure 20, showing an installation of about 4 GW of wind in a period of about ten years. The projected evolution, that corresponds to the average of three scenarios [12], [155], [160], foresees a capacity in 2050 of 7674 MW, an increment of 88%. This evolution is in accordance with the perception that onshore wind potential starts to be depleted from 2020 [159]. The 2011 capacity factor was 0.25 and for 2050 it was adjusted to 0.29, a 15% increase due to expectable technological improvements [161].

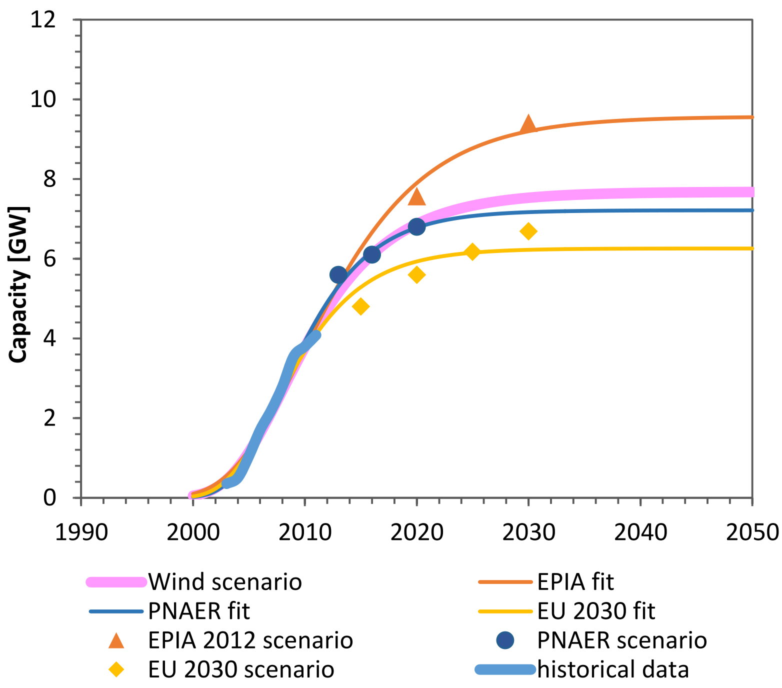

Figure 20. Evolution of onshore wind installed capacity [12], [155], [160]

Offshore sustainable potential for Continental Portugal was accessed in 2010 [162] and it was found to be 3500 MW, if one considers the offshore feasibility ensured by a NEP (annual number of hours at full power) of 2700 h/year or more. If one considers a restrictive scenario where the economic viability requires a NEP of 2900 h/year or more, the offshore potential is reduced to 1400 MW. Conservatively, the latter was considered for the 2050 scenarios, again including a 15% improvement on the capacity factor (to 0.38) due to technological improvements.

In what concerns evolution of overall electricity demand, it is assumed to follow a linear increase, partly due to EV, modelled according to [12], [155] and [156]. It foresees an increment from 50.5 TWh in 2011 to 62.3 TWh in 2050 (Figure 21). The approximation was as if the EV electricity demand of the Central EV penetration is incorporated in this growth, meaning that total electricity demand for the other EV penetrations is different[27].

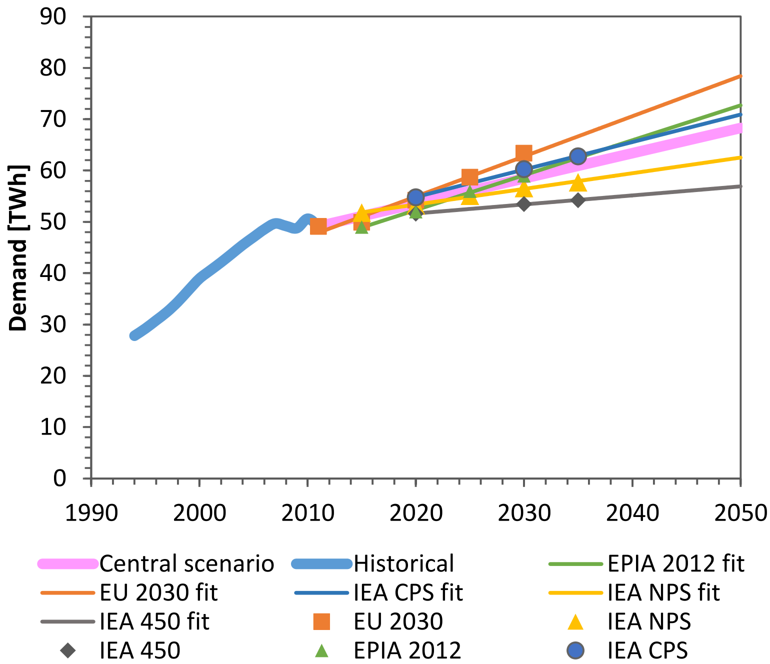

Figure 21. Evolution of electricity demand [12], [155], [156]

[27] See Section 3.4.3.1 for the details on this.

3.4.2.2.1. System flexibility

Conventional fossil fuel power plants are restricted in their ability to change generation levels due to technical-operation limits. Furthermore, they incur in significant economic penalties when running under a certain level below the nominal output, due to efficiency losses and increased preventive and corrective maintenance needs when fossil power generators work in part load operations. The comfortable operational range of these power plants define the grid flexibility, or flexibility factor, which, according to [27], is the fraction below the annual peak load until which flexible sources can operate. The flexibility of current systems can be difficult to assess since the minimum load is not technically rigid, but determined by the costs of thermal units cycling [28]. The flexibility factor can be inferred using Eq. (3), where e_{th} represents the total electricity production from sources with flexibility constraints and i is the annual hourly values, from 1 to 8760.

$$d_{flex} = \frac{MIN\left\{\left(e_{th}\right)_1,\ldots,\left(e_{th}\right)_i,\ldots,\left(e_{th}\right)_{8760}\right\}}{MAX\left\{\left(e_{th}\right)_1,\ldots,\left(e_{th}\right)_i,\ldots,\left(e_{th}\right)_{8760}\right\}}\times 100 \qquad (3)$$

The overall system flexibility is dependent on the energy mix (e.g. grid flexibility is smaller for grids with a high share of fossil fuel fired power) and on the technology used (e.g. coal power plants are less flexible than natural gas fuel fired power plants, and new generation natural gas fuel fired power plants are more flexible than older ones). Figure 22 shows the relative load level of the aggregation of the existent thermal electric power plants for 2011 year, 57% on average. One can see that the minimum load levels of functioning are around 15%. Following Eq. (3), the absolute minimum was found to be on the early morning of a Sunday in January, when the demand was around 50% of the annual peak value and wind was satisfying 61% of that demand. At that hour, thermal power plants were operating at 730 MW of load, corresponding to a flexibility level of 86.7%, meaning that the thermal Portuguese electric power structure is operated in a rather flexible manner. This is possible because CCGT based power plants dominates the installed thermal electric power capacity that in practice operates[28], with a share of circa 66%, and because coal power plants are constituted by generator groups that can be turned off, albeit not without economic penalties. Indeed, the true cost of on/off operations are often not known or not well understood by the system operators [163]. Although future generations of CCGT based power plants are expected to provide increased levels of flexibility to the system because they offer significant ramp up and ramp down capabilities [164], [165], the 2050 scenario assumes the present flexibility, as it is already high.

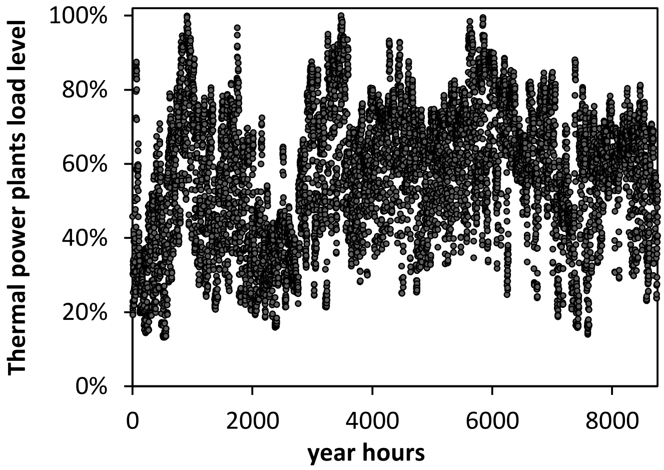

Figure 22. Load level of the thermal power plants aggregate relative to their annual peak production

3.4.2.3. System stabilization share

In order to maintain real-time balance between generation and load, it is necessary that a minimum part of generation comes from load following capable plants, i.e., plants that offer ramp up and ramp down operating reserves. In the Portuguese electric power system these are provided by thermal and large hydropower plants. The minimum grid stabilization demand is calculated as function of e_{stab}, the electricity production from

[28] See Sections and 3.3.1 and 3.4.2.

regulation capable sources, and e_{total}, the total electricity production, according to Eq. (4), where, as usual, *i* represents the annual hourly values.

$$d_{stab} = MIN\left\{\left(\frac{e_{stab}}{e_{total}}\right)_1, \ldots, \left(\frac{e_{stab}}{e_{total}}\right)_i, \ldots, \left(\frac{e_{stab}}{e_{total}}\right)_{8760}\right\} \times 100 \tag{4}$$

Figure 23 shows the load level of the grid stabilization capable power plants aggregate relative to total production on an hourly basis throughout the year. On average, it was 62.4% with a registered minimum of 18.3%. This is the value used in the EnergyPLAN 2011 model. Correlation between the two series shown in Figure 22 and Figure 23 is 0.868, which means that ~87% of stabilization share is on average provided by thermal power plants.

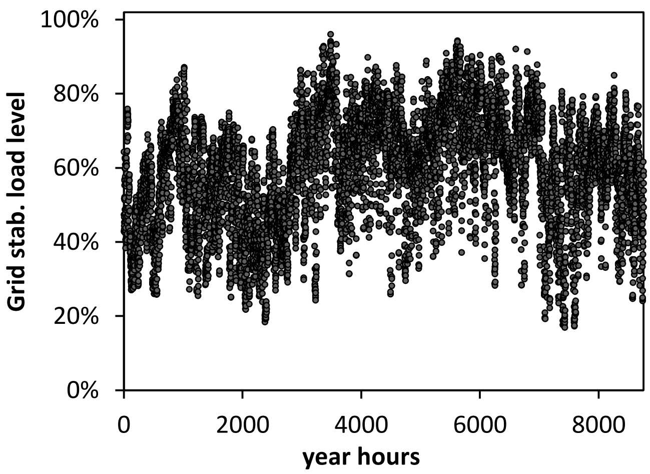

Figure 23. Load level of the grid stabilization capable power plants aggregate relative to total production

Higher shares of non-dispatchable generating capacity impose greater needs for the remainder of the power generation capacity to flexibly complement its variable output, and this is not totally obviated by increasingly precise forecast models [166]. With a growing share of RES in an electricity system, the net load, i.e., the RES generation subtracted to the electricity demand, is increasingly volatile in absolute amounts and in frequency and amplitude of changes (ramp rates), requiring an increase of the stabilization share and flexibility levels [166], [167]. Electricity systems with high RES penetration overtime tend to incorporate CCGT based power plants as base load supply because they fulfill the two requirements: they offer a technical capability of load following better than other types of power plants, such as coal and nuclear, implying additionally less capital investment; they also provide increased levels of flexibility to the system because they offer significant ramp up and ramp down capabilities [164]. Based on existing IEA and EU projections [155], [156], it is expected that dispatch of supply to cover the net demand in 2050 in Portugal will rely in flexible capacity provided by CCGT power plants and in hydropower plants with storage. That is, in a way, base load power plants will have to be run down to very small part load regimens, or even will have to be completely shut down, in order to avoid significant overcapacities – namely during peak wind and solar periods; on the other way, they have to provide for substantial operating reserves available online to cope with increased load following requirements. This work considers that in 2050 these two conditions have similar but opposite effects, and therefore the level of required stabilization share is maintained.

3.4.2.4. Summary

Table 6 summarizes the modeled installed capacities described along this section. In the Central PV scenario, the total installed capacity for the electro producer system for 2011 is 18902 MW and for 2050 it is 37911 MW, a 100% increase. The evolution of the installed capacity according to source is illustrated in Figure 24. Table 7 gives the division of the system in 2050 according to the type of generation and the scenario. Finally, Table 8 gives the summary for the modeled efficiencies, grid flexibility and stabilizations levels of the power plants.

Table 6. Modeled installed capacities in 2011 and 2050. All numbers in MW.

	2011	2050	References
Production Installed capacity	**18902**	**37997**	
Thermal	**9274**	**7071**	
CCGT	4687	5723	[147], [155], [156]
Coal	1756	-	[147][145]
Fuel-oil	2228	-	[147]
Biomass, urban residues, waste	603	1348	[147], [155], [156]
Wind onshore	**4081**	**7674**	[12], [147], [155], [168]
Wind offshore	**-**	**1400**	[162]
Solar (Central Scenario)	**155**	**13316**	[12], [147], [169]
Hydro	**5392**	**8536**	
Large hydro	2537	5681	[168], [170]
Run of river	2855	2855	[147], [168]
Hydropump	1020	4004	[168], [170]

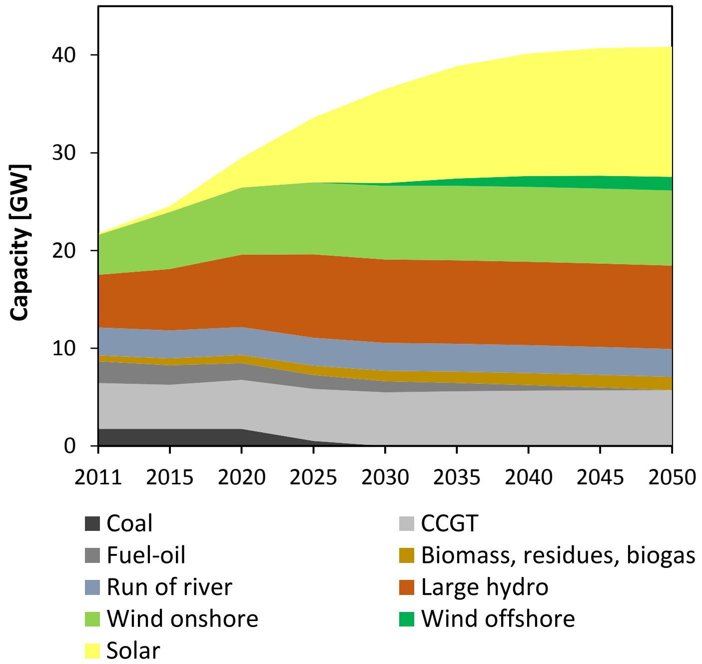

Figure 24. Evolution of the electric power capacity installed (PV Central scenario)

Table 7. Total capacity installed in 2050 according to the type of generation

	Low Scenario		Central Scenario		High Scenario	
	MW	**%**	**MW**	**%**	**MW**	**%**
Dispatchable	12752	36.4	12752	33.6	12752	30.8
Non-dispatchable	22237	63.6	25245	66.4	28598	69.2
Renewable	29266	83.6	32274	84.9	35627	86.2
Non-renewable	5723	16.4	5723	15.1	5723	13.8

Table 8. Modeled power plants efficiencies and grid flexibility and stabilizations levels

	2011	2050	References
Power plants efficiencies			
CCGT	43.0%	60%	[16], [147], [171]
Oil fired	44.0%	N/A	[16], [147]
Coal fired	35.7%	N/A	[16], [147]
Biomass	20.1%	30%	[16], [147], [172]
Hydro plants (turbine/pump)	80%	80%	[173]
Flexibility and stabilization			
Overall thermal power plants flexibility	86.7%	86.7%	[147], [165]
Minimum grid stabilization share	18.3%	18.3%	[a]

[a] See Section 3.4.2.3

3.4.3. Mobility

3.4.3.1. EV market uptake

The passenger car stock evolution until 2050 is the product between the evolutions of the passenger car ownership per capita and the population. The first was obtained following [174], [175] and is shown in Figure 25. Since 2008 the passenger car density has seen a pronounced decline from 474 to 406 vehicles per 1000 inhabitants due to the economic downturn, but the fit to the historical trend since 1975 foresees a recovery from this drop to 484 vehicles per 1000 inhabitants by 2050. As in the EU-15, it is expected that passenger car demand reaches saturation in Portugal [176].

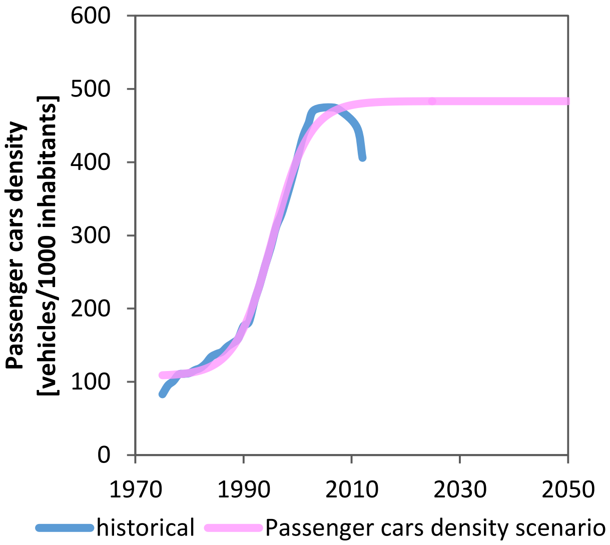

Figure 25. Modeled passenger cars density evolution until 2050 [174], [175]

The central scenario for the population evolution of the national statistical office (INE) [177], shown in Figure 26, is applied to these figures to compute the passenger car stock evolution, also shown in Figure 26. It departs from a fleet of 4.78 M vehicles in 2013 reaching 2050 with 4.18 M vehicles, a loss of 13% in the fleet size, correlated with the decline in population.

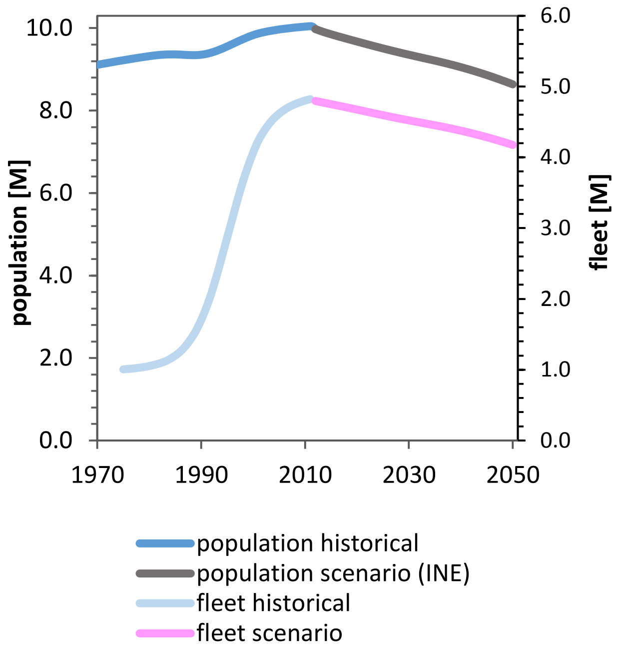

Figure 26. Population projections [177] and modeled passenger car stock evolutions until 2050

For 2050, the EU targets for the transport sector a minimum of 60% reduction of GHG[29] [6], and the IEA has developed a scenario for market uptake of PEV and PHEV technologies, called BLUE Map scenario, reflecting an overall target of a 50% reduction in global energy-related CO_2 emissions compared to 2005 levels, to which transport contributes with an emissions reduction of 30% [24]. The assumptions in this work for EV technology market penetration are based on the IEA BLUE Map scenario for OECD Europe. Three passenger vehicles scenarios for Portugal were developed as shown in Figure 27: (1) Central Scenario, which is an adaptation to the Portuguese context of the IEA scenario; (2) Low Scenario, with half the penetration in sales of PEVs and PHEVs; (3) High Scenario, with double penetration in sales of PEVs and PHEVs.

[29] Having as reference 1990.

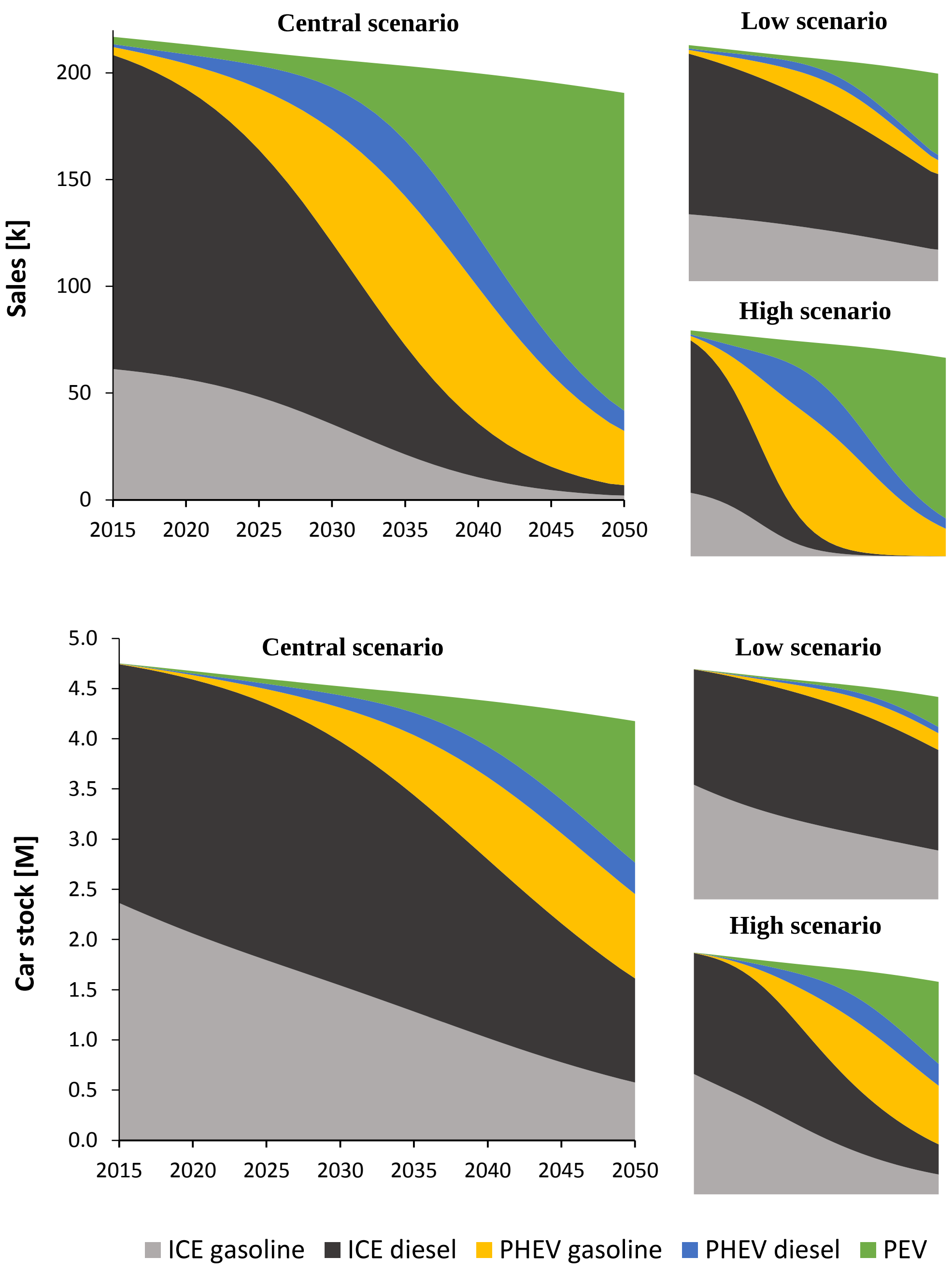

Figure 27. Sales and total car stock evolution until 2050 for the different EV scenarios

3.4.3.2. Common assumptions

It is assumed that partially charging the EVs on a daily basis will not be an obstacle. The PHEVs were modeled as if driving mode is full electric until total depletion of the battery, with an electrical range of 98 km. This way, PHEVs offer the opportunity to rely more on electricity while retaining the driving range of an ICE vehicle. In the UK, 97% of the trips are estimated to be less than 80 km and, more generally, in Europe, half of the trips are less than 10 km, being 80% less than 25 km [24]. Considering the same patterns for Portugal and assuming that they do not change significantly in the future, this means that the vast majority of future trips in PHEV will be made in full electric mode. The model assumes that only 5% of the distance traveled by PHEVs is in ICE mode.

For the ICE fleet modeling, one have started from average present consumption values of 2.56 MJ/km for gasoline cars and 2.52 MJ/km for diesel cars [178] and applyed a 20% improvement in efficiency until 2050. This increased efficiency is due to future technological improvements, including less vehicle weight, less rolling resistance coefficient and more efficient powertrains [179].

In 2011 in Portugal, gasoline cars traveled on average 8647 km and diesel cars traveled 23470 km [178]. In the long run, this difference is expected to disappear for passenger cars. These is due to two reasons: (1) vehicle's acquisition price of ICE gasoline and diesel cars tends to converge; (2) prices per km traveled with both fuels tend also to converge, due to aggravation in diesel fuel taxation [180]. In the modeling it was assumed that this approximation happens gradually over a period of 35 years and by 2050 vehicle travel distance is the same for both vehicle types.

Average daily travel distance for passenger cars in Portugal is 35 km [178]; it is assumed that mobility in 2050 is as in the present.

For the EVs, it was assumed that travel distances are the same as for ICE vehicles, i.e., mobility is the same for all vehicles. Table 9 presents a summary of the common assumptions to all vehicles scenarios.

Table 9. Common assumptions to all EV scenarios

		References
PEV and PHEV (electric mode) consumption	0.2 kWh/km	[24]
ICE gasoline consumption	2.05 MJ/km	[178]
ICE diesel consumption	2.02 MJ/km	[178]
Annual mileage	12662 km	[178]
Battery efficiency	95%	[181]
Vehicle average lifespan	17 years	[182]

3.4.3.3. Summary

Table 10 contains a summary of the relevant fleet and electricity demand parameters for the vehicles scenarios. For the Low, Central, High and 100% scenarios, EV electricity demand represents 4.7%, 10.4%, 12.6% and 15.9% of total electricity demand, respectively. It should be highlighted that, even in an unrealistic scenario of EV total market uptake, EV demand is still below one fifth of the national electricity requirements.

3.4.4. PV and vehicle scenarios combined

Considering the previously discussed different PV and EV penetration scenarios, there are fifteen possible arrangements constituting the set of electricity-transport realities simulated for this work, as shown in Table 11. For an easy identification of each scenario, nomenclature is using two letters, the first referring to the PV scenario and the second referring to the EV scenario. The correspondence is: 0 for 0%, L for Low, C for Central, H for High and 100 for 100%. For example, LC scenario is the combination between the Low PV and the Central EV scenarios.

Table 10. Fleet and demand characterization of the different EV scenarios

	0% EV		Low EV		Central EV		High EV		100% EV	
	# M	share %	# M	share %	# M	share %	# M	share %	# M	share %
ICE gasoline	1.392	33.3	1.008	24.1	0.576	13.8	0.390	9.3	-	-
ICE diesel	2.783	66.7	2.075	49.7	1.037	24.8	0.592	14.2	-	-
PHEV gasoline	-	-	0.345	8.3	0.840	20.1	1.151	27.6	1.566	37.5
PHEV diesel	-	-	0.129	3.1	0.314	7.5	0.431	10.3	0.522	12.5
PEV	-	-	0.618	14.8	1.409	33.7	1.611	38.6	2.088	50.0
Demand					TWh					
Total electricity	55.81		58.57		62.30		63.90		66.38	
EV	-		2.77		6.49		8.09		10.57	
Gasoline	10.02		7.26		4.15		2.81		-	
Diesel	19.74		14.71		7.35		4.20		-	

Table 11. Arrangements between PV and EV scenarios

		L0	LL	LC	LH	L100	C0	CL	CC	CH	C100	H0	HL	HC	HH	H100
PV	**Low**	✓	✓	✓	✓	✓										
	Central						✓	✓	✓	✓	✓					
	High											✓	✓	✓	✓	✓
Vehicles	**0% EV**	✓					✓					✓				
	Low		✓					✓					✓			
	Central			✓					✓					✓		
	High				✓					✓					✓	
	100% EV					✓					✓					✓

3.5. Day and night charging

People in an urban society typically commute in the early morning and late afternoon, meaning that there are two time blocks in the 24h of the day, during the night and daytime, in which there is opportunity to refuel the vehicles. They correspond to very different practices of EV usage: charging at home and charging at work. These two charging approaches were tested, not only chosen according to social behaviors but also according to their suitability to the dominant RES.

As discussed above, electricity demand decreases during the night, from 22:00 to 7:00, and, typically, during the night wind blows with higher intensity due to existing higher pressure gradients in the atmosphere. These two conditions make nighttime a period with possible excess of energy, leading to the definition of a EV charging pattern, called 'night charging profile' (Figure 28), corresponding to the charging at home approach. Actually, night charging EV is advocated in a number of studies, such as [51], and government documents defining future energy strategies, such as [160]. For instance, night excess electricity serves as a reason in Portugal to the implementation of a program of reversible hydropower with an horizon of 2020 [158].

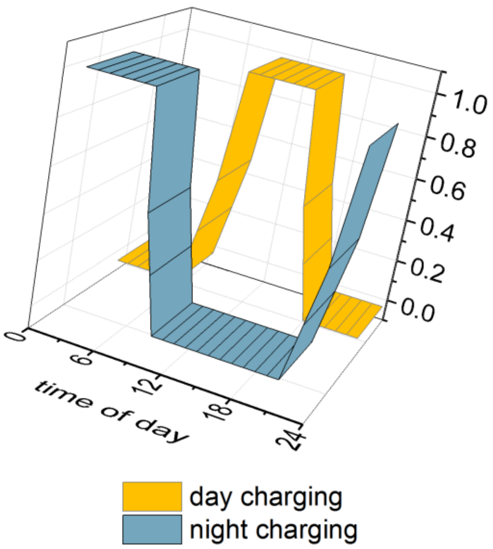

Figure 28. EV normalized night and day charging profiles

On the other hand, solar PV production takes place during the day with a highly predictable pattern, as illustrated in Figure 29, so in a scenario of high PV share it is likely that the daily profile for excess of energy production can follow the same pattern. A second EV charging pattern is thus defined, called 'day charging profile', corresponding approximately in time duration and schedule to the middle of the winter and summer PV production profiles, as shown in Figure 28 and in Figure 29. The latter also highlights the differences in solar energy generation between summer and winter (73% more energy in the former). Day charging corresponds to the charging at work approach, for example at the commuters' worksite parking lot or at a park & ride site, a change in the way EV charging is habitually advocated.

Both charging types correspond to a dumb charging strategy [183], i.e., there is no intelligent managing of charging, which means that batteries will start charging immediately after plugging and will keep charging until necessary level is reached. Charging using a smart strategy is explored below (in Section 3.6).

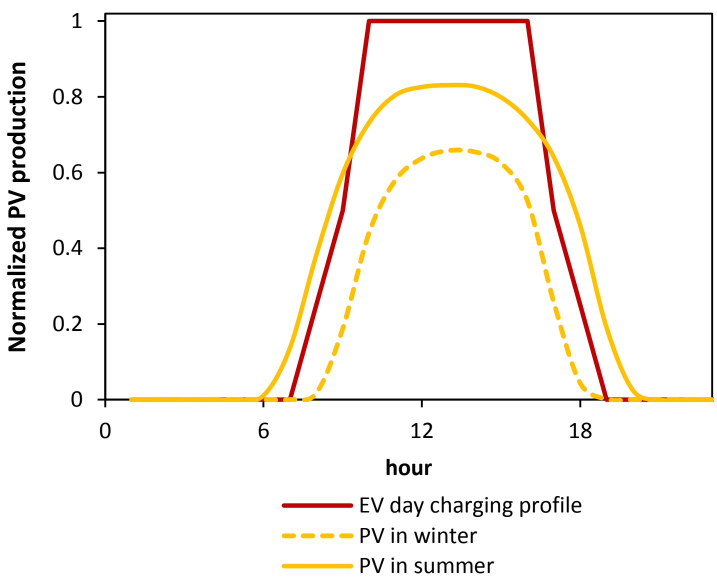

Figure 29. Normalized daily average PV production for summer and winter and normalized EV day charging profile

3.6. Smart charging

The smart charging scenarios differ from the day and night charging scenarios just in the charging strategy. That is, the scenarios are equal, except the non-smart delayed charging is replaced with smart charging. The assumptions made for it are described next.

3.6.1. General assumptions

It was decided to take the conservative approach and it is assumed in the model that smart charging operation is unidirectional, providing thus for unidirectional V2G services to the power system. As stated in Section 2.1.2.1, unidirectional V2G is especially attractive because it requires little if any additional infrastructure other than communication between the EV and an aggregator and it does not imply interconnection issues or battery degradation, having more customer acceptance [66]. Thus, in the model V2G does not provide for base load or peak power, i.e., it does not provide for battery-to-grid.

Present average battery sizes are of 13.0 kWh for PHEV and 26.7 kWh for PEV [184]. It is expectable that energy density will be much higher in the future [185] and that lithium-ion (Li-ion) batteries will be the first choice for energy storage [186], due to their high specific energy, large number of charge-discharge cycles and reasonable cost [187]. This technology depends however on a robust battery management system to ensure safe and reliable battery operations, accurately calculating the battery state of charge [188]. It is assumed EVs equipped with Li-ion type batteries with twice the energy density as in the present [186] while maintaining the weight of batteries installed in each vehicle, thus extending twofold the current driving range, a crucial condition for the successful mass EV technology deployment. Currently, Li-ion technology batteries have an efficiency of 80-95% [181], and is assumed that on average they will operate at the top limit of this range.

This means that, according to the EV penetration scenario, the total fleet storage capacity is in the range of 38.5-108.9 GWh (see Table 12) if one considers a SOC window of 85% [189], which in any case corresponds to less than the average daily national electricity demand (circa 137 GWh)[30].

Table 12. Battery storage overall size and power capacity of grid to battery connection

		Available capacity	Grid connection bandwidth	
			Max	**Min**
		GWh	**MW**	**MW**
	0%	-	-	-
	Low	38.5	2829	2263
EV Scenarios	**Central**	89.5	6638	5310
	High	108.1	8270	6616
	100%	140.9	10814	8651

Charging of vehicles was modeled considering charging at a rate of 3.7 kW/car (230 V, 16 A), the present normal charging mode [21]. Since a number of cars will always be driving and can neither contribute to decrease nor increase the grid load, the total capacity of the connection is not always available. Although studies for large fleets have shown that at any given time less than 10% of the cars are driving, like [36] for the US and [67] for Denmark, conservatively it is assumed that in Portugal in 2050 a share of 20% of the entire fleet is circulating at rush hour. It is also assumed that 70% of the parked cars are connected to the grid [67]. This means that for the electrical fleet in the Central EV scenario the overall grid-to-battery will have a maximum of capacity of 6.64 GW and a minimum of 5.31 GW, as Table 12 details. Table 13 presents a summary of the assumptions made for the V2G model.

[30] In order to achieve high RES penetration, it has been shown for Israel and California in the US that the maximum threshold for energy storage in need is significantly less than the daily average demand [107], [108].

Table 13. Assumptions made in the V2G model

		References
Fraction of the EV fleet with V2G capability	100%	[a]
Useable state of charge window for batteries	85%	[189]
PEV battery size	53.4 kWh	[184]–[186]
PHEV battery size	26.0 kWh	[184]–[186]
Vehicle charging power (unidirectional)	3.7 kW	[21]
Grid-to-battery efficiency	90%	[67]
Max. share of cars driving during rush hour	20%	[67]
Share of parked fleet connected to grid	70%	[67]

[a] It is assumed V2G capability as a standard EV feature in the future. See Section 3.6.2 for more on this.

3.6.2. Ancillary services

EnergyPLAN ancillary services provision are comprised in the minimum grid stabilization production share input parameter, which was set to 18.3%[31]. It corresponds to the percentage of grid stabilizing units injecting power into the grid each hour, calculated relative to production, not demand[32]. Since the EVs short term power balancing enhances the reliability of energy systems scenarios, a grid stabilization share should be allocated to V2G similar to that of other regulation units[33] [121]. On the other hand, stabilization requirements can be met recurring to loads instead of just generation, increasing and reducing the EV load [87]. The difference between the time needed for actual charging and the duration of time the vehicles are plugged in yields time flexibility that can be exploited to provide grid stabilization [86]. Based on this, the

[31] See Section 3.4.2.3.

[32] See Section 3.4.2.3 for details on this.

[33] Tomić and Kempton [75] concluded that EVs can provide regulation of higher quality than the currently available, because it is of fast response to a signal, distributed and available in small increments.

V2G model considers that the entire EV fleet is available for unidirectional V2G stabilization using up to 100% of the connection capacity to provide for that service[34].

3.6.3. Driving patterns

Electric vehicles travel distances and trip patterns are assumed as those for the ICE vehicles, meaning that mobility is considered the same for all types of vehicles. The period of day during which a car is driven, and, consequently, is not connected to the grid and is draining energy from the battery, is an important element for modelling an energy system with a V2G component. The amount of potential gains for the system heavily depends on the V2G availability and, thus, to appreciate the V2G concept, a certain number of EVs should be available and secured. Therefore, statistical travelling patterns should be included in the model. These patterns are typically different from region to region and, therefore, at a nation level, they should be weighted to obtain an average national travelling pattern that is sufficiently representative. Thus, monitoring and analysis of these patterns is a key point [77].

In the EnergyPLAN the distribution of the transport demand is provided in 8784 hourly values (a leap year). This time series is used to calculate the energy drain from the batteries in every hour along an entire year and therefore the input data file should be based on an hourly resolution travel survey. These surveys are usually carried out by national or local bodies (e.g. statistical offices, transport ministries) or by research centers, like in [190]. It is a study that departs from the driving time periods and assesses the EV availability in Denmark, showing how many cars are available for charging and discharging in each hour of the day. The average driving distance was obtained for weekdays, weekends and holidays to illustrate the EV users' driving requirements in different days. On another study [191], the driving behavior of car drivers from six European countries – not including Portugal – is investigated also by

[34] The traditional power grid ancillary services adapt the power supply to demand. V2G unidirectional ancillary services adapt demand to supply [114].

means of a survey. It aims to provide some insights on how electric vehicles could fit mobility habits, but hourly driving patterns are not provided in the report. Both studies have national scope within the respective countries.

In Portugal for the time being there is not a countrywide study of this kind, but INE made a survey with a geographical scope of Porto metropolitan area [192], the second biggest population center in the country, and adjacent areas. It gathered information from about 200000 individuals in order to characterize the mobility of the resident people using a number of parameters such as the number, time and duration of the journeys carried. The distribution of trips by time of day is probably different across regions in Portugal, and the average national pattern may not be exactly the same as the one of the region studied, but it is expected a sufficiently common similarity, as it was observed in [191] between other countries and in the INE study among the different areas in analysis. Given that premise and in the absence of a broader study, the INE's survey is considered sufficiently representative of the national driving patterns and it is used to construct the V2G model inputs.

The transport demand input is split in weekdays and weekends, since these are periods with significantly different driving patterns. The probability distribution of each car to travel during weekdays is shown in Figure 30. Three periods with stronger traffic intensity can be highlighted: 7:00-9:00, 12:00-14:00 and 18:00-19:00, corresponding to the periods of commuting to and from work.

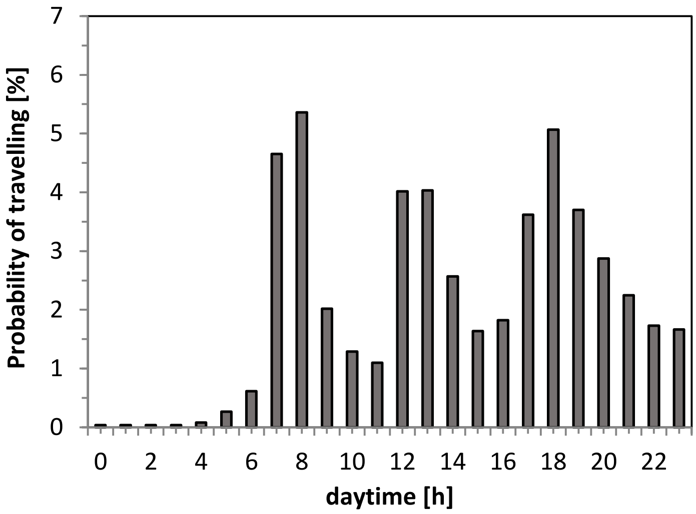

Figure 30. Probability distribution used to define the EV daily journeys during weekdays [192]

Figure 31 shows the driving patterns for the weekends, which has an important distinction between the weekdays driving behavior, since during the weekends there is a greater irregularity in the dislocations. Also, as it would be expected, morning mobility is lower and starts later (the share of trips made before 9:00 is basically halved), increasing gradually until 10:00.

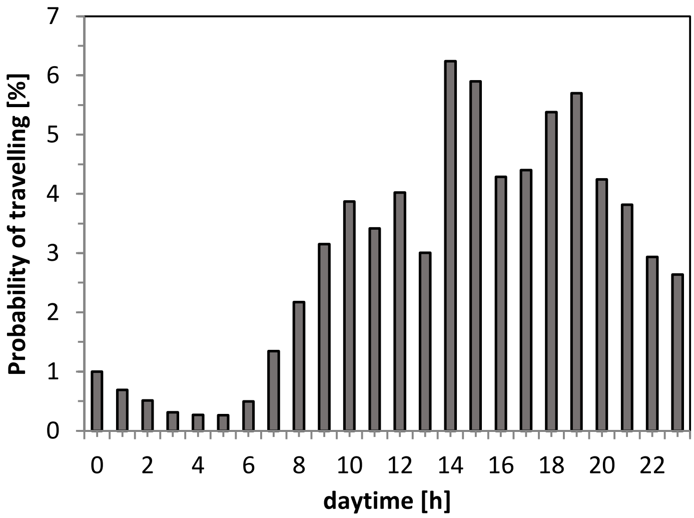

Figure 31. Probability distribution used to define the EV daily journeys during the weekends [192]

Overall, contrary to what could be a common perception for mobility during the weekend, i.e., less mobility, on the weekends there is an increased car use, especially between 14:00 and 16:00. Nevertheless, it does not signify necessarily increased driving distances during the weekend. The travel distances were not accessed in the INE survey, but they were in [191] for other EU countries. It was found that the average daily driving distance does not significantly increase over the weekends, with the authors pointing out that EVs could not only cover the typical driver needs during weekdays but also the weekends. This is likely the case of Portugal, and so the same assumption was taken in this work.

During weekends the cars are not as spatially concentrated as in weekends, because they are spread along more diversified geographical zones. Statistically, for the entire period analyzed, the daily number of trips is 2.5 and each journey takes 22 minutes. In urban areas the journey time is aggravated 4 minutes comparing to more rural areas.

3.6.4. Battery draining

A higher probability of a car being travelling at a certain time means that more cars are travelling at that time and, accordingly, a corresponding higher drain from the batteries is occurring. In other words, battery draining from V2G at *i* hour, $(t_{V2G})_i$, is proportional to the probability of travelling at the same hour and can be calculated by [140]:

$$\left(t_{V2G}\right)_i = \left(D_{V2G} \times \frac{\left(\delta_{V2G}\right)_i}{\sum_{1}^{3784} \delta_{V2G}} \right) \times \eta \tag{5}$$

In Eq. (5), D_{V2G} is the annual transport demand of V2G cars, $(\delta_{V2G})_i$ is the transport demand at hour *i* (given by the probability of traveling) and η_{charge} is the grid-to-battery efficiency (see Table 13). The weekly battery-to-wheel demand for the Central EV scenario obtained from applying the equation is shown in Figure 32.

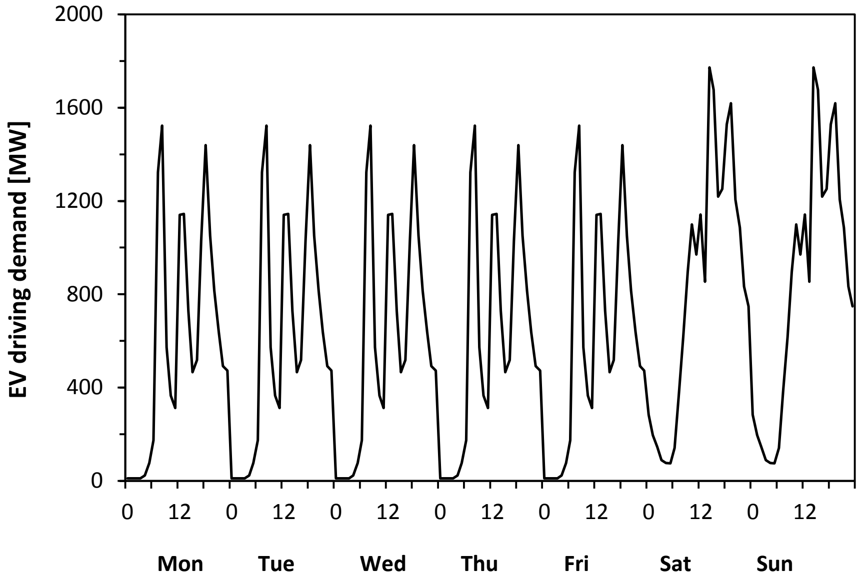

Figure 32. Weekly EV battery-to-wheel demand for the EV Central scenario

3.6.5. V2G connection

The V2G connection capacity at *i* hour of the total V2G fleet, $(C_{V2G})_i$, is calculated by the model applying Eq. (6), where C_c is the maximum charging power of the entire V2G fleet, $V2G_{cs}$ is the share of the parked fleet that is connected to the grid and $V2G_{Max}$ is the maximum share of cars driving during rush hour.

$$\left(C_{V2G}\right)_i = C_{\mathrm{C}} \times V2G_{\mathrm{CS}} \times \left[\left(1 - V2G_{\mathrm{Max}}\right) + V2G_{\mathrm{Max}} \times \left(1 - \frac{\left(\delta_{V2G}\right)_i}{Max\left(\delta_{V2G}\right)}\right)\right] \tag{6}$$

In the expression there are three factors: the first factor represents the power capacity of the entire V2G fleet; the second factor is the share of grid connected V2G fleet, in order to determine the maximum available capacity, not time dependent; the third factor, between brackets, calculates the share of V2G fleet on the road at *i* hour and is the sum of two terms: the first term represents the minimum fraction of parked vehicles and the second term the additional fraction of vehicles parked during non-rush hours [140]. The relevant parameters for the calculation are given in Table 12 and Table 13. Figure 33 shows the EV weekly V2G available connection capacity for the Central EV scenario. For this scenario, the capacity of V2G ranges between 5310 MW and 6629 MW, averaging 6112 MW.

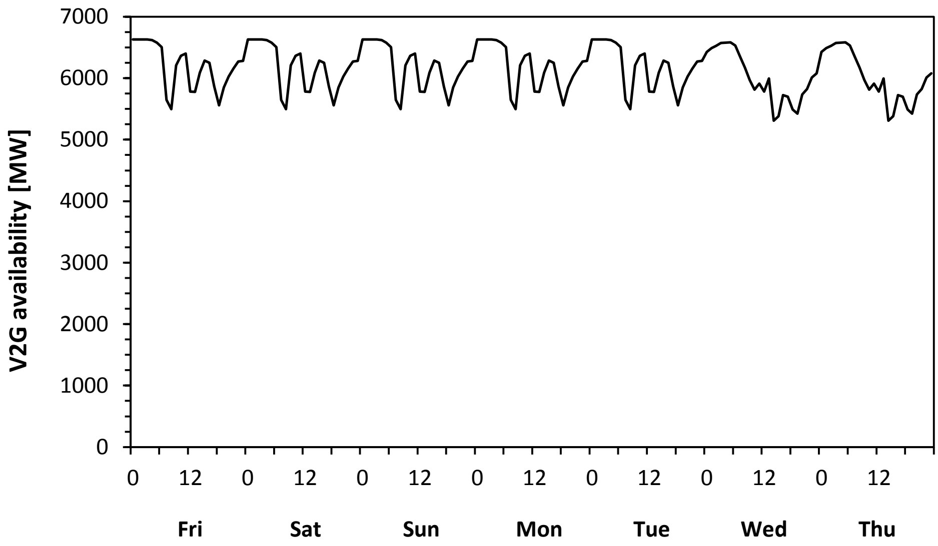

Figure 33. Weekly V2G connection available for the Central EV scenario

4. Results

From a technical and operational perspective, criteria such as fuel savings, CO_2 emissions, fossil fuel thermal power generation, minimization of import/export and excess of power generation may be applied in assessing how well a system integrates RES [193]. According to this, the evaluation of the different scenarios is based on the most relevant parameters, including EEP in the system, average load, RES shares, CO_2 emissions and primary energy.

Unless otherwise stated, the CO_2 emissions and primary energy results concern the electricity system and the passenger vehicles sector together while RES share concerns only the electricity system. The results are distinguished between day and night charging and smart charging, thus being presented separately.

Excess production is a measure of whether solar PV in articulation with EV is effectively leading to advantages without the need for more inter-country electricity bandwidth. Its amount is an important parameter for power grid planning, construction, operation management, dispatching and CO_2 emissions reduction. Quantifying it and find possible strategies to reduce it or utilize it is critical for the energy system optimization [33], and so emphasis is given to CEEP in the results analysis.

The total CEEP for a given period of time, e.g. one entire year, is obtained from the sum

$$CEEP_{Total} = CEEP_{S1} + CEEP_{S2} + \ldots + CEEP_{Sn} \tag{7}$$

with *S*1, *S*2,…, *S*i describing the individual sources of energy production. CEEP of each source for a certain given time period must be calculated on an hourly time basis:

$$CEEP_S = \sum_i \left(Esource_i \times \left(1 - \frac{Dtotal_i}{Etotal_i} \right) \right) \tag{8}$$

It corresponds to the sum of the CEEP from each hour *i* of that period, being *Esource* the energy produced by the source in question, *Etotal* the total electricity produced on the system and *Dtotal* the total demand, including simple demand, EV demand and energy for hydroelectric pumping. From $CEEP_S$ it is possible to calculate the share of that energy source in the electricity mix for the entire period:

$$Share_S = \frac{Etotal_S - CEEP_S}{Dtotal} \tag{9}$$

In the equation $Etotal_S$ is the total of electricity production from that source and *Dtotal* is the total demand during the period.

The shown reductions in CO_2 are relative to 1990, as the EU 2050 climate-energy target is [3]. This goal was set for the energy system and for the GHG as a whole, but is assumed that it is the same for its individual components.

4.1. Day and night charging

In this section two charging scenarios are explored: day charging, corresponding to a high PV penetration, and night charging, corresponding to a high share of wind power.

4.1.1. General insights

A general first qualitative insight on the effects of a large scale deployment of solar PV in the electricity system can be gained through the observation of the load diagram of a sufficiently short time period to allow a fine analysis. For that, a week from mid of April was chosen, simulated for the Central PV scenario without integrating EV (C0 scenario). This is illustrated in Figure 34, where it is seen that in five of the seven days shown there is a substantial amount of CEEP in the middle of each day. On those days, one can observe that hydropump capacity is working on the limit from the morning until the afternoon for ten or more hours each day, in coincidence with solar PV production. Notice that CEEP occurs only on the weekdays, due to a cloudy weekend registered that week. Since weekends correspond to a period of lower demand, if it was not this particular cloudiness on this weekend CEEP would be especially critical on that two-day period. To have an insight on the EV charging effects with day charging profile on the network over the same period and the difference that it produces in load diagram, the Central EV scenario was then added (resulting in CC scenario), shown in Figure 35. It is evident the lower CEEP and the greater use of solar PV electricity, eliminating most of the CEEP on Monday and Tuesday, although even on these days hydropump is working close to or at its maximum for several hours of the day. Nonetheless, the amount of CEEP is still considerable on the other days. Without EV, if the order of merit of electricity entering the grid has solar in last place, PV curtailment is 202 GWh, corresponding to 20% of demand and 48% of PV production during that week. With EV, the curtailment is reduced to 123 GWh, or 11% of demand and 29% of PV production during that week.

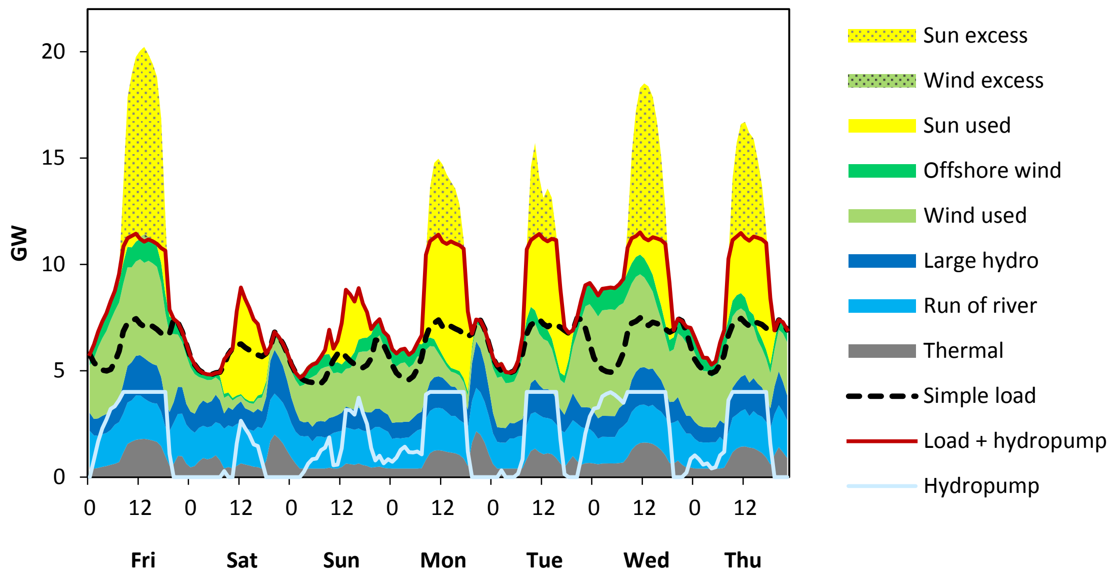

Figure 34. Simulated 2050 hourly load diagram for the C0 scenario in a selected 7-day period in mid of April

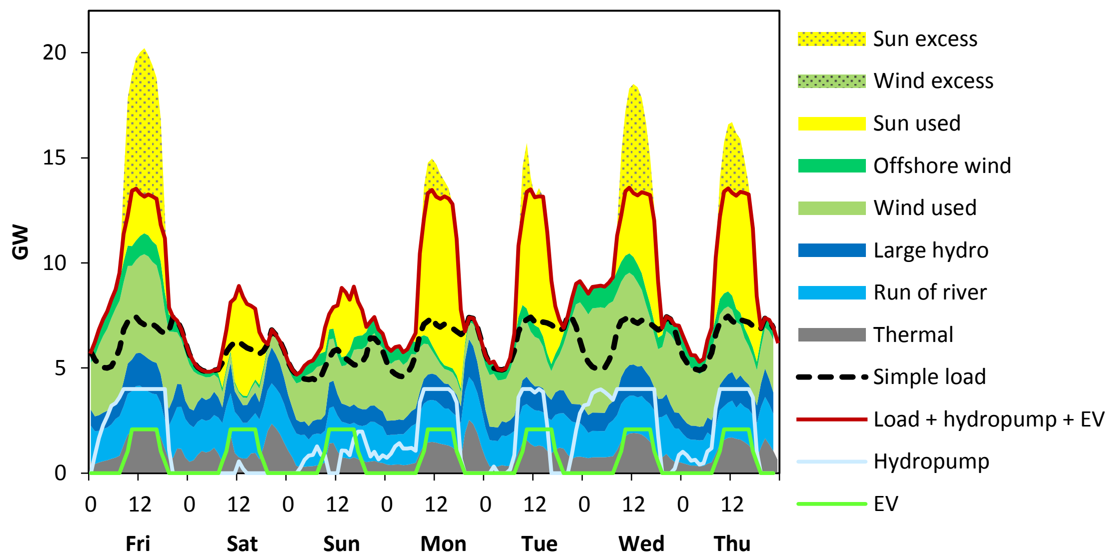

Figure 35. Simulated 2050 hourly load diagram for the CC scenario for the same 7-day period of Figure 34 (day charging)

A broader but less detailed insight can be gained through the analysis of the load diagram for the entire year, in Figure 36. It presents the weekly energy production and consumption for the CC scenario with EV day charging, and may be compared with the analogous figure for 2011 (Figure 9) for an analysis of the effects in the load diagram that the assumptions described in Section 3.4.2 produce. It is evident the much less prominence of the thermal based energy. Secondly, one can see that the energy produced in surplus is much greater, with emphasis for solar if the merit order of electricity entering the grid puts it in last place. The negative energy values on the figure translate how this surplus is used, the CEEP being denoted in red: it occurs less during the winter and more during the rest of the year, confirming that the solar PV is the responsible for the CEEP.

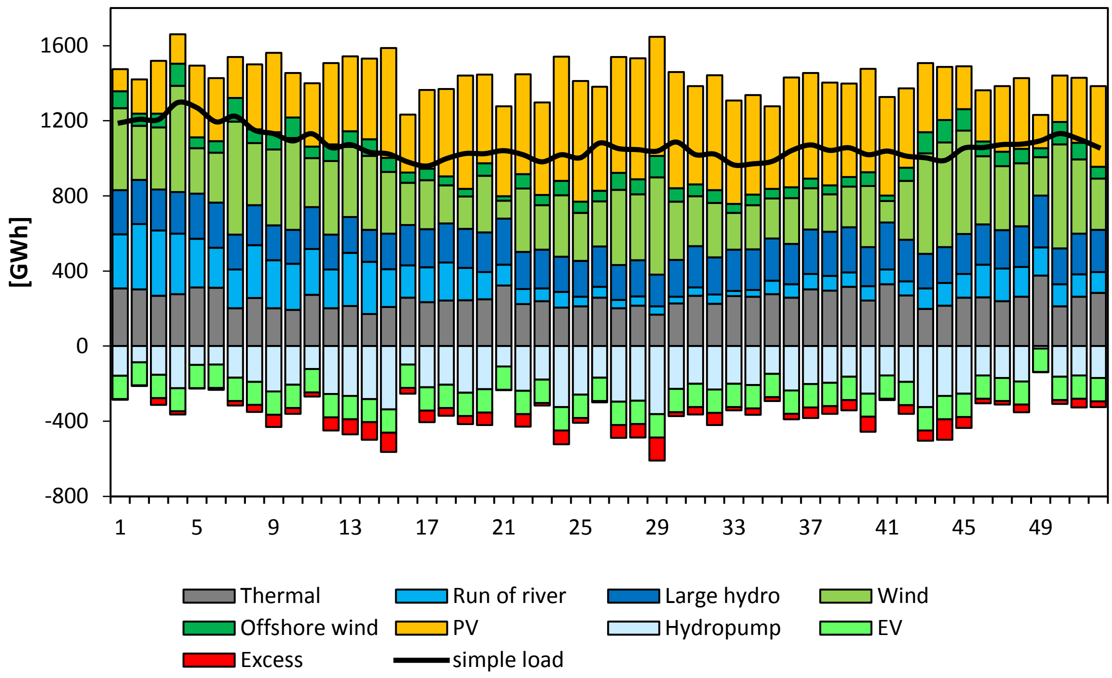

Figure 36. Simulated 2050 weekly energy production and consumption for the CC scenario (day charging)

4.1.2. Day charging *vs.* night charging

In Figure 37 one can see the CEEP, as share of total production, and the CO_2 emissions as function of the PV installed capacity. The graph shows the results for the day and night EV charging profiles in relation to the Central EV scenario. It is possible to observe the optimal level of PV penetration from the stand-point of CO_2.

For the day charging profile, its minimum is found to be in the range of 16-17.5 GW of installed capacity, where CO_2 emissions stabilize at a level of 3.85 Mt. It corresponds to a 83.5% reduction. Above those PV levels, emissions grow up because marginal penetration of internally usable renewable electricity in the grid starts to decrease, yet stabilization share by CCGT power plants, with associated emissions, must still be assured. Since one also wants to minimize CEEP, one can say that the optimum level of PV penetration is 16 GW with a corresponding CEEP of 5.35 TWh, or 7.1% of total demand, with a RES penetration in the electricity mix of around 96.5%. This PV penetration level is around 700 MW below the PV High Scenario.

For the night charging profile, CO_2 reaches a minimum of about 5.4 Mt at around 14 GW of PV penetration, i.e., on a point that corresponds to 700 MW of more installed capacity than the one from the Central PV Scenario. It corresponds to a 77.0% reduction in CO_2 emissions. This means that the targeted 80% reduction level cannot be attained with this charging profile. The corresponding CEEP was found to be 8.3% of total demand. With the same PV penetration, the CO_2 emissions attained with the day charging profile are of 4.02 Mt, i.e., a reduction of 82.8%.

It is thus possible to say, from the standpoints of CO_2 emissions and CEEP, that the day charging profile is more advantageous than the night charging profile, and, in fact, the only one that permits to attain the targeted reduction in CO_2 levels. The results for the other EV penetration scenarios are not shown, but they are qualitatively similar. Hence, subsequent results and analyses, unless otherwise stated, concern solely the day charging profile.

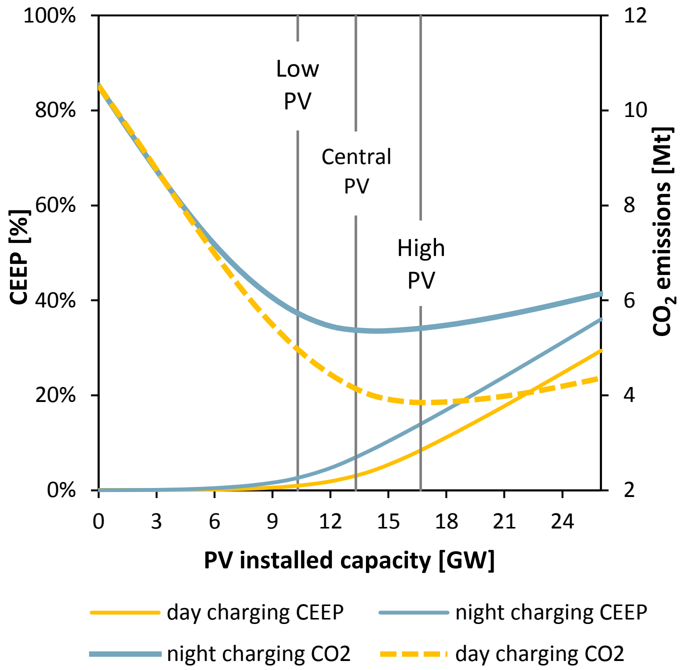

Figure 37. CEEP given in share of total production and CO_2 emissions as function of PV installed capacity and EV charging profiles for the Central EV scenario

4.1.3. Impacts of different EV market shares

4.1.3.1. CEEP

For an insight on the effects of the different EV scenarios on the grid, daily profiles for the average power demand and production are shown in Figure 38 for different EV market uptakes. One can see that the total power production and its shape do not change significantly, meaning that the introduction of EV, on an aggregated base analysis, do not imply major changes in the average load diagram and that the increasing electricity demand of higher shares of EV can be fulfilled with the anyway produced electricity. Table 14 shows the average and peak CEEP for each of the EV scenarios. Between the 0% and the 100% EV scenarios the average surplus power is reduced 4.4 times.

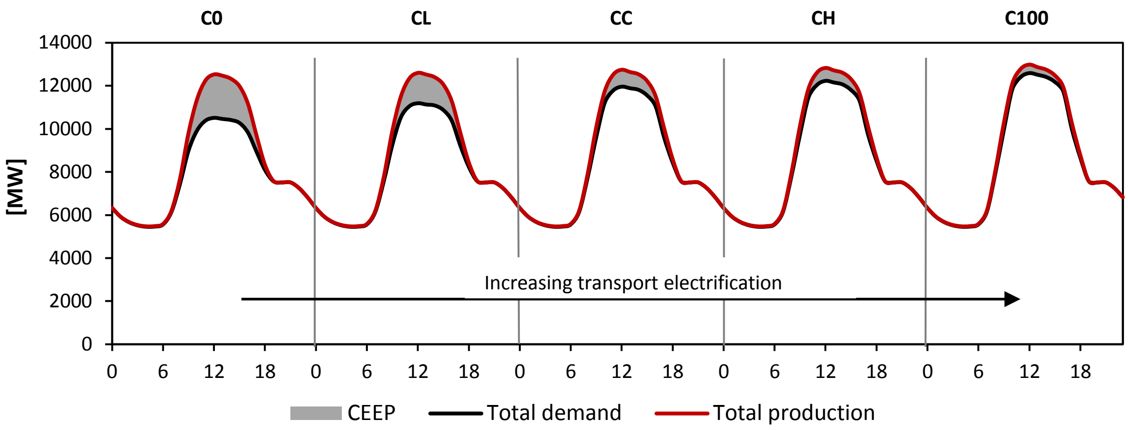

Figure 38. Daily average power demand and production profiles for the whole year for different EV scenarios combined with the Central PV scenario (day charging)

Table 14. Average unusable power for the different mobility scenarios (day charging). All figures in MW.

	C0	CL	CC	CH	C100
average daily CEEP	605	430	254	200	137
average peak CEEP	2019	1410	786	600	395

Figure 39 illustrates the relative CEEP as function of the EV market share for the different PV scenarios, showing that the introduction of EVs leads to a reduction in excess production of electricity. It was obtained based on simulations of each of the EV scenarios combined with each of the PV scenarios. The lines are steeper for higher PV penetrations, meaning that the marginal positive effects of the EV penetration on the CEEP are higher for higher solar PV capacity installed. The flatter lines toward the right means that the advantages of the EVs growth is increasingly smaller as the fraction of the market share increases. The High PV scenario allows for relatively stable benefits from EV increments throughout the entire EV deployment range, since that even at high EV shares, close by 100%, the marginal benefit of adding EV is still high (i.e., not much smaller than in the beginning).

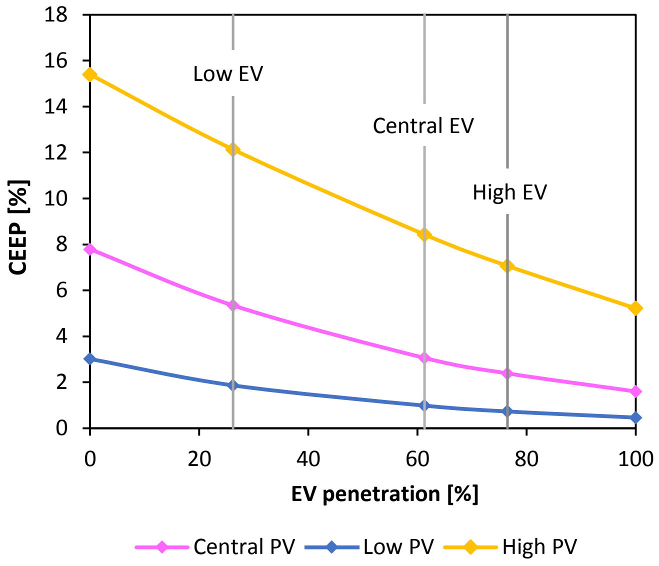

Figure 39. Unusable energy production as functions of the EV market share for the three PV scenarios (day charging)

4.1.3.2. CO_2 reductions

Figure 40, obtained as Figure 39, illustrates how reduction in CO_2 emissions evolves with increasing EV penetration for the three solar PV scenarios. Because higher shares of EV allow for more use of solar PV energy, which increases the RES share in the electricity mix, the CO_2 reductions are higher for higher EV shares.

At low EV penetrations, the different PV scenarios do not lead to much different CO_2 reductions because in the Low PV scenario the solar CEEP is already above a level that do not allows for further CO_2 reductions. However, the reductions start to diverge with increasing EV market share (note that the height of the gap between curves increases to the right) because solar CEEP starts to decrease. The green band between the 80 and 95% CO_2 reductions represent the EU 2050 target [3]. One can see that this goal can only be reached with at least 50% EV market share in the High PV scenario and scenarios with less solar PV need even higher EV market share to accomplish the 80% reduction (53% and 67% for Central and Low PV scenarios, respectively).

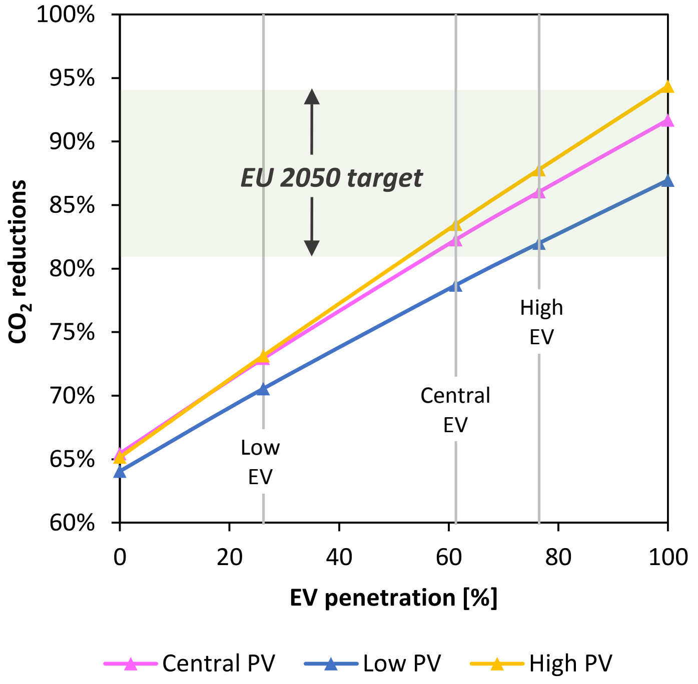

Figure 40. CO_2 reductions as function of EV market share for the three PV scenarios (day charging)

4.1.4. Impacts of different solar PV deployments

4.1.4.1. PV share

It is shown in Figure 41 the PV share and the PV energy in excess in the electricity mix as function of the PV installed capacity for the Central EV scenario. It can be seen that until around 6 GW of installed PV virtually all its energy is integrated into the system. Above that, the PV in excess increases rapidly and, as a consequence, the PV share growth starts to decrease, i.e., it starts to take place diminishing returns of additional PV installed. In the High PV scenario, the PV share is 32.6% and the PV in excess is 13.3%, i.e., almost a third of the demand can be covered by PV in this scenario, although with a significant excess of energy.

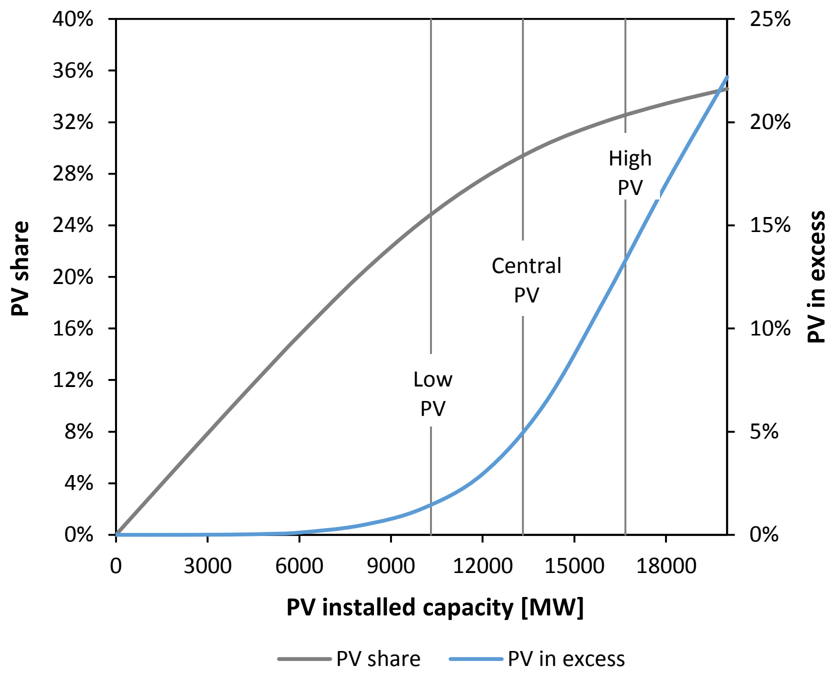

Figure 41. PV share and PV in excess in the power system varying with the PV installed capacity for the Central EV scenario (day charging)

In Figure 42 is shown the PV share as function of the CEEP in the system, varying the capacity of PV installed. It is insightful to see that from up around 4% CEEP the PV share starts to increase very slowly. For this 4% CEEP, the PV share is between 25% and 33%, corresponding to the 0% EV and 100% EV scenarios, and to around 12 GW and 16 GW of PV capacity (as seen below in Figure 43), respectively. Finally, it is worthwhile to note that the Central, High and 100% EV scenarios allow PV shares up to 20% with less than 1% of CEEP in the system.

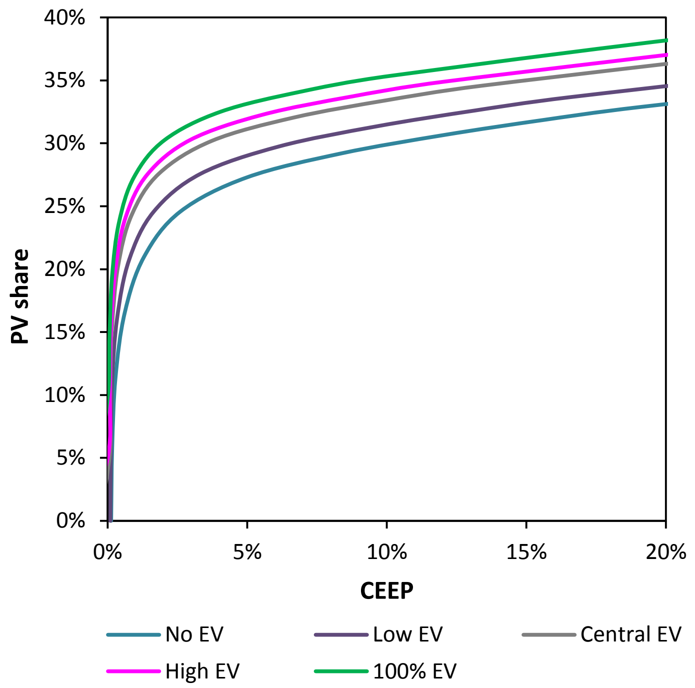

Figure 42. PV share in the system as function of CEEP (day charging)

4.1.4.1. CEEP

Figure 43 shows the existing CEEP for each of the EV scenarios resulting from different installed PV capacities. As expected, the CEEP increases with increasing PV capacity, increasing more, i.e., with higher increasing rates, with lower EV quotas. In the Low PV scenario, there is negligible CEEP (<1%) for the Central or higher EV scenarios. Following the lines indicating the PV scenarios, it can be seen that the CEEP is tripled or more going from the 100% EV to the 0% EV scenarios, being the difference higher with higher PV capacity installed.

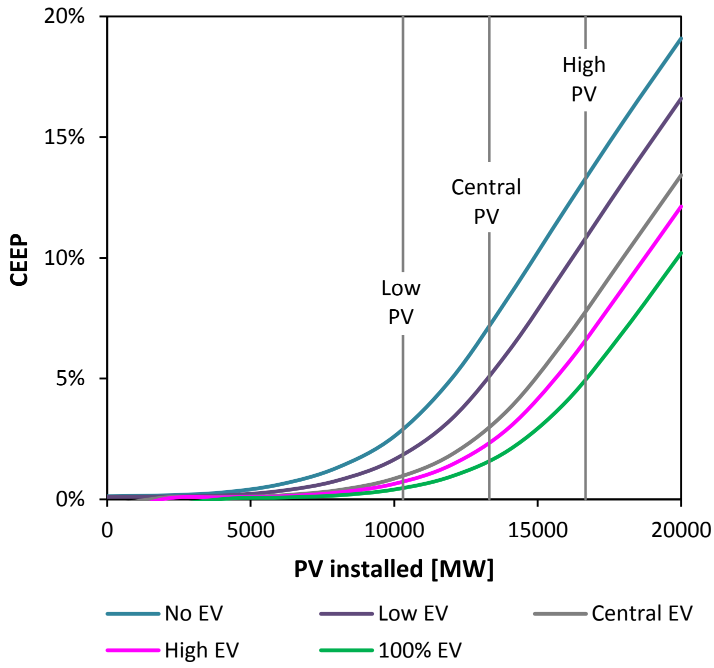

Figure 43. Total CEEP in the system as function of the installed PV capacity (day charging)

4.1.4.2. CO_2 reductions

Figure 44 relates the PV installed capacity with the CO_2 reductions achieved in each of the five EV scenarios and should be analyzed in conjunction with Figure 45, which gives the respective CO_2 marginal reductions. Without any PV capacity installed and 0% EV market share, the CO_2 reductions are of 43.7%. From here on, increments in PV capacity or EV market share or both lead to increased CO_2 reductions until a certain level of PV (that varies with the EV scenario), and the gains start to be negative, as shown in Figure 45. From this inflection point, the emissions start to increase because marginal penetration of RES electricity in the system starts to decrease, yet stabilization share by CCGT power plants must be maintained, as discussed in Section 4.1.2. The diminishing returns of additional PV capacity in CO_2 reductions start earlier for the scenarios with lower EV penetration (where the slope of the lines in Figure 45 starts to be negative), becoming negative at 17 GW for the Central EV scenario. For the High and 100% EV scenarios, the returns become negative later, after the values of 18 and 19 GW of PV, respectively. For the 0% and Low EV scenarios, the returns become negative earlier, from approximately 14 and 15 GW of PV, respectively. The largest CO_2 reduction attained is of 94.7%, meaning that the 95% top limit of the 2050 EU target is not achievable, but almost.

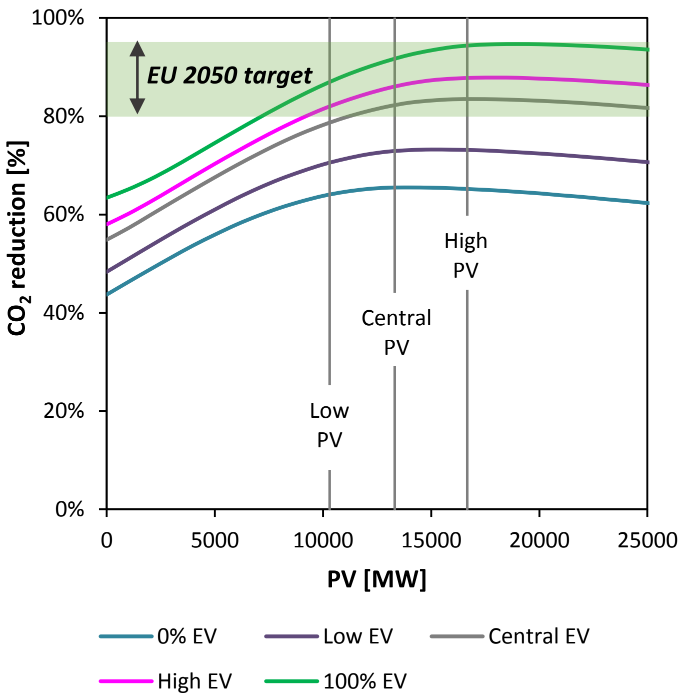

Figure 44. CO_2 reductions as functions of the PV penetration (day charging)

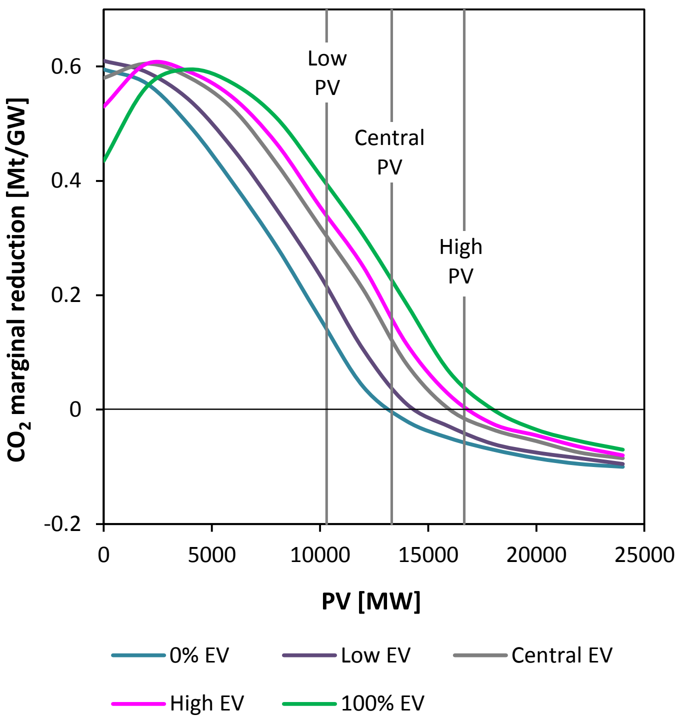

Figure 45. CO_2 reductions rate as function of the PV penetration (day charging)

In Figure 44 it is also worthwhile to note that the 80% EU 2050 target is not possible to achieve in any circumstances with the 0% and Low EV scenarios. In the Central EV scenario, a minimum PV installed capacity of 11.5 GW is needed to fulfill the EU target and in the 100% EV scenario this number decreases to 7.3 GW.

4.1.5. Arrangements between PV and EV scenarios

Figure 46 identifies the arrangements that lead to less than 80%, 80% and more than 80% reductions in CO_2. The basis for the simulations of the several EV penetrations is the Central EV scenario, from which the EV quota is changed maintaining constant the ratio between diesel and gasoline ICE vehicles and between PEVs and PHEVs. That is, for the sake of simplicity, here are simulated different EV quotas that derive from the Central EV scenario and not directly from the application of the IEA BLUE Map scenario with different premises, as it is the case of the Low, Central and High EV scenarios, as explained in Section 3.4.3.1. Several of mobility cases are simulated with several PV penetrations in order to identify the arrangements plotted. All the combinations in the area corresponding to more than 80% CO_2 reductions imply excess of electricity.

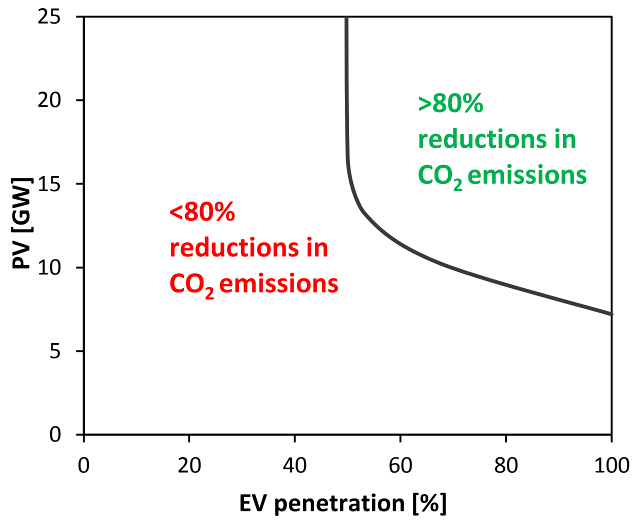

Figure 46. Arrangements between EV market share and PV capacity that lead to 80% reductions in CO_2 (day charging)

In order to reach 80% reductions in CO_2 it is worth to note that:

1. The minimum 50% EV market share is maintained even with extreme PV penetration levels, higher than the High PV scenario. With this EV penetration, it should be installed around 15 GW of PV; higher PV than this does not lead to additional CO_2 reductions;
2. With 100% EV market share, a minimum of 7.2 GW of solar PV is required.

Figure 47 identifies the scenarios ordered by their merit concerning fossil fuel consumption (natural gas, diesel and gasoline) and absolute reductions in CO_2 emissions. One can see that between L0 and H100 scenarios the fuel consumption is reduced significantly, from 32.0 TWh to 6.5 TWh (due to the more efficient electric drive-trains than the ICE ones and due to increased PV share in the mix), i.e., a fivefold reduction. The reduction in CO_2 between these two scenarios is from 14.9 Mt to 22.0 Mt, about 30% difference. The scenarios that accomplish the EU 2050 goal of 80% CO_2 reductions are from the LH scenario onwards.

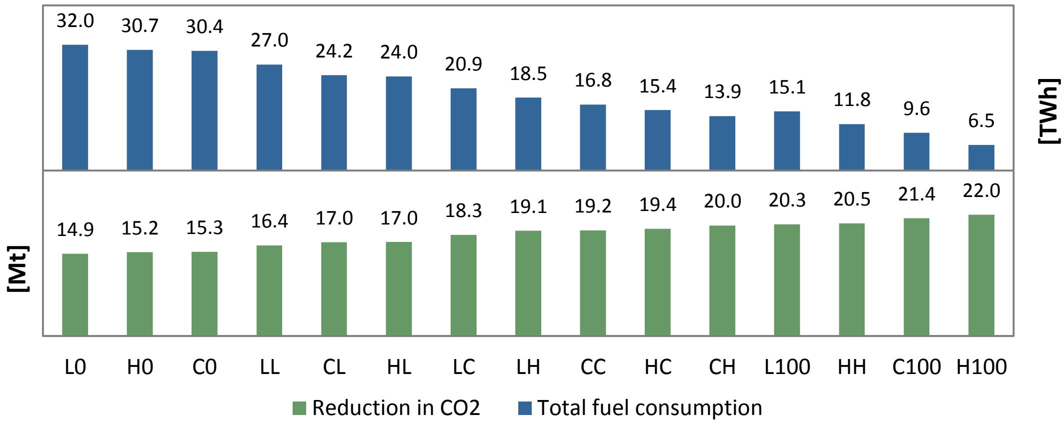

Figure 47. Scenarios ordered by its merit concerning fossil fuel consumption (natural gas, diesel and gasoline) and reductions in CO_2 emissions (day charging)

The RES share in the electricity mix, RES share in the primary energy supply (PES), CO_2 reductions, CEEP, PV share in the electricity mix and PV energy used of all the possible arrangements between the PV and EV scenarios are summarized in Table 15. A color scale from red (worst results) to green (best results) is used to facilitate its interpretation. One can observe that the best results concerning CO_2 emissions are reached with the high PV in conjunction with high EV penetration scenarios. As for the CEEP, the best results are obtained with the high EV scenarios in combination with the Low PV scenarios. The minimum percentage of CEEP is 0.5%, reached with the L100 scenario. The highest level of RES electricity share is attained in scenario C0, with 99.4%, and one can see that high levels of PV with low levels of EV reach the higher values. The highest level of RES share on the primary energy supply is achieved with the H100 scenario, with 92.1%, and L100 is the scenario that allows for more PV use, with 99.4%.

Table 15. RES share in the electricity mix, RES share in the primary energy supply, CO_2 reductions, CEEP, PV share in the electricity mix and PV energy used for the scenarios arrangements (day charging)

	RES electricity share [%]					**RES share on PES [%]**				
High PV	99.1	98.2	96.6	95.9	94.7	70.9	75.8	83.1	86.4	92.1
Central PV	99.4	97.9	95.4	94.2	92.2	69.6	74.3	80.8	83.6	88.1
Low PV	97.9	95.4	91.9	90.3	87.8	67.2	71.0	76.1	78.3	81.7
	CO_2 reductions [%]					**CEEP [%]**				
High PV	65.1	73.1	83.5	87.8	94.3	15.4	12.1	8.4	7.1	5.2
Central PV	65.4	72.9	82.3	86.0	91.7	7.8	5.3	3.1	2.4	1.6
Low PV	64.0	70.5	78.7	82.0	86.9	3.0	1.9	1.0	0.7	0.5
	PV share on electricity mix [%]					**PV used [%]**				
High PV	31.1	31.8	32.6	32.8	33.1	77.1	81.4	86.7	88.8	91.7
Central PV	28.6	29.1	29.4	29.4	29.3	87.3	91.2	95.1	96.2	97.5
Low PV	25.0	25.1	24.8	24.7	24.3	95.2	97.1	98.6	98.9	99.4
	0%	**Low**	**Central**	**High**	**100%**	**0%**	**Low**	**Central**	**High**	**100%**
			EV					**EV**		

Attaining higher levels in RES share or in CO_2 reductions than the ones obtained in this section, close or equal to 100%, should just be possible with:

1. Providing for grid ancillary services, i.e., frequency regulation, load following capacity and contingency reserves, with electric vehicles batteries in a smart charging model or other energy storage technologies [28], [167], [181] and higher RES share[35]. As shown in [109], with the introduction of these technologies a 100% renewable electricity supply for Portugal is achievable;

2. By means of demand side management, such as load shifting [194], in particular EV load shifting.

Results from scenarios using some of these assumptions are presented in Section 4.2.

[35] Namely by means of future generations of wind turbines comprising advanced power electronics [205], [206].

4.1.6. Sensitivity analysis

As seen in Section 3.4.2.2, as the potential for additional hydroelectricity is limited in Portugal [159], most future RES penetration is only achievable by deployment of solar PV and wind power. Each one has its own merit and they should be articulated in order to achieve the highest technical efficiency, i.e., enabling the larger renewable energy share by dumping less electricity compared to the exclusive PV and wind scenarios. This is a topic addressed in a number of studies, as [106] and [195]. To contribute to this discussion, a sensitivity analysis to evaluate the differences in CEEP and CO_2 between implementing more or less PV as opposed to onshore wind was performed, having as reference the CC scenario. Because wind energy is produced mostly during the night and solar energy is produced exclusively during the day, the analyses were performed with EV night charging profile for wind and with EV day charging profile for solar PV.

The results for the CEEP are shown in Figure 48, where it can be seen that additional installed capacities lead to faster growth of CEEP for PV. This means that marginally there is less dumped energy installing more wind than solar PV; however, the total CEEP is always lower with additional solar PV.

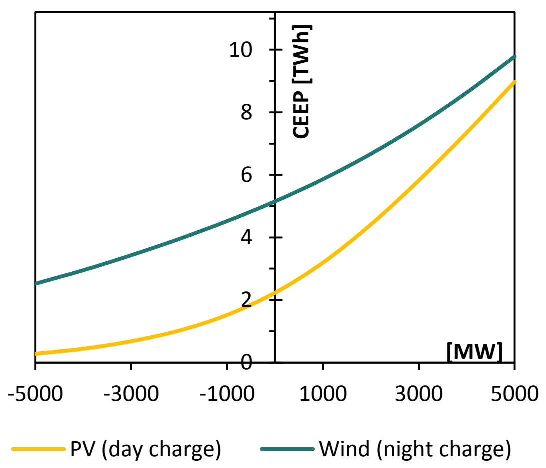

Figure 48. Unusable energy as function of deviations in the PV and wind installed capacities in the CC scenario

If one focuses this analysis in the CO_2 emissions, it can be seen in Figure 49 that incrementing wind capacity as opposed to incrementing solar PV capacity leads to greater reductions in CO_2. From the marginal point of view, it is thus more favorable extra wind than solar PV, but, again, consistently until very high levels of penetration (about 17.3 GW for solar PV and 11.7 GW for wind) the total emissions are lower with a daytime EV charge[36].

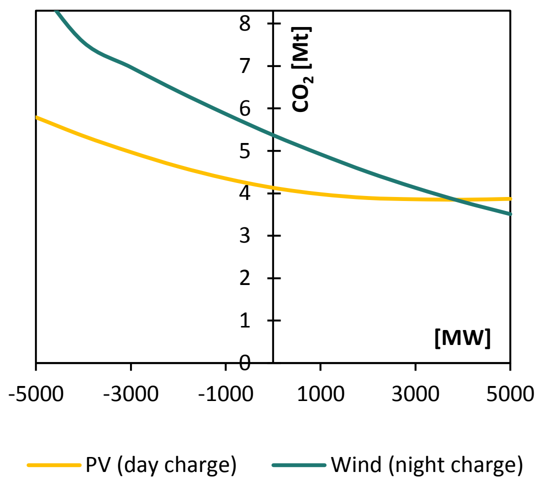

Figure 49. CO_2 emissions as function of deviations in the PV and wind installed capacities in the CC scenario

[36] It should be highlighted that it is more realistic to install additional PV capacity than wind, since the former has for now non-significant capacity installed and the latter has already close to 5 GW.

4.2. Smart charging

The charging methods tested before, day charging and night charging, are considered dumb charging because they are based on a simple set of rules. On the other hand, smart charging manages EV load in order to decrease the grid peak load, transferring that demand to valley periods, and to substitute as much as possible non-carbon free ancillary services with V2G[37].

The previous scenarios were tested with smart charging, according to the premises of Section 3.6, and the results are presented and discussed in this section. For the sake of clarity and distinction between the two charging methods, the analysis is in a similar fashion but independent, although comparisons with day charging are made.

4.2.1. General insights

A first insight on the effects of EV smart charging on the electricity system is given by the load diagram shown in Figure 50. It corresponds to the CC scenario on a week in mid of April, the same from Figure 35, for comparative purposes with day charging. In the figure, grid-to-battery refers to the EVs battery charging, i.e., the battery inflow from the grid, and battery-to-wheels refers to the EV driving demand from the battery, directly correlated with the driving patterns. It can be seen that there is CEEP just on the first day; on the other days, the line representing the total production adjusts perfectly to the total load. It is interesting to note that during the cloudy weekend registered, with low solar PV production, the model does not charge the EVs until Sunday night. This is possible since the model is solely based on statistical information, from which is derived that everyday charging is not mandatory since the autonomy of the EVs is

[37] As detailed in Section 3.1.1.2.

higher than the average daily travel distance[38]. Hence, the model does not account for unpredictable EV charging demand, due to driver's unplanned or longer trips, for example, something that would force some everyday EV charging. Considering the entire week, the energy in excess is 7 GWh, 0.45% of the entire demand, and the PV surplus production is 1.6%[39]. During this week, the use of smart charging reduces CEEP in 6% when compared to day charging (123 GWh).

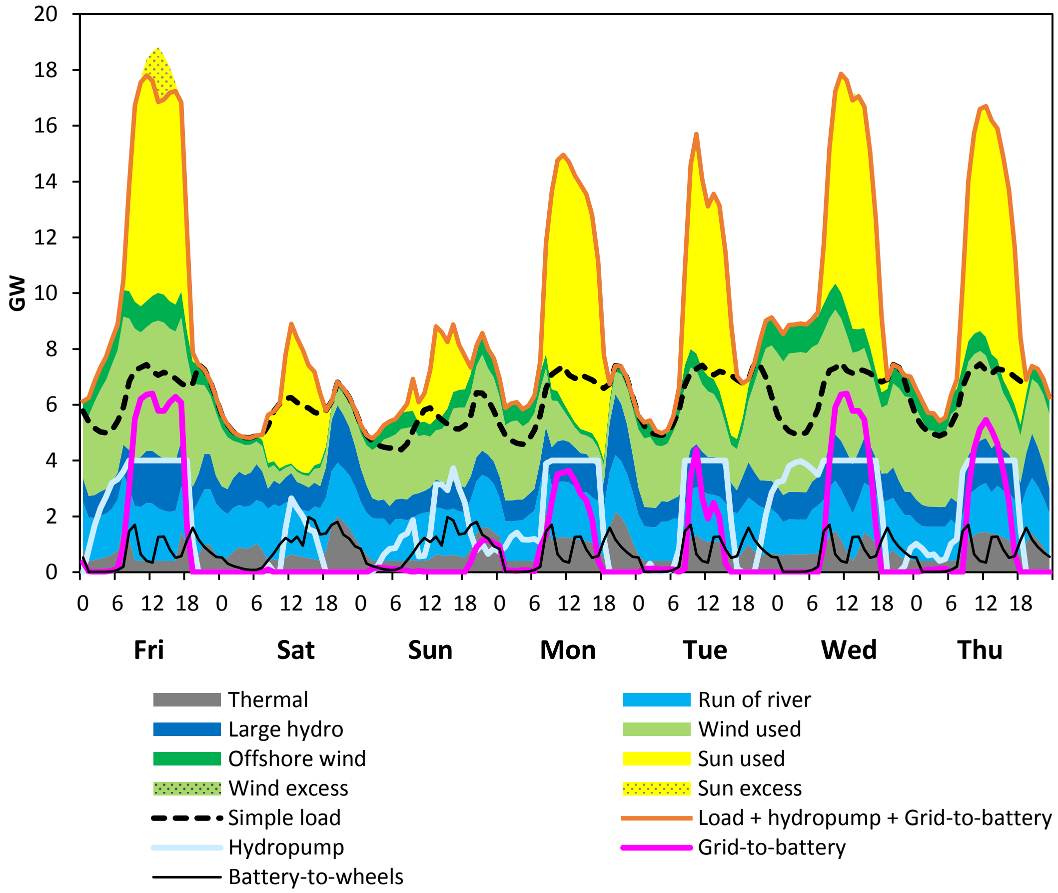

Figure 50. Simulated 2050 hourly load diagram for the CC scenario in a selected 7-day period in mid-April (smart charging)

[38] This in accordance with [207], which gathered data from 25 EV users from Lisbon over a period of one year. The users on average travelled 39.9 km/day and the charging routines show 0.6 daily charges.

[39] Considering that PV energy is the last in the merit order of sources injecting energy into the power grid.

The load diagram for the entire year on a weekly basis is shown in Figure 51. It corresponds to the CC scenario with EV smart charging and may be compared with Figure 36 for an insight on the effects in the load diagram of the smart charging in relation to the day charging profile. One can see that the energy produced in surplus, i.e., EEP, given by the area of the bars above the simple load line, is, as expected, the same in the two cases, because the simple load does not account for the EV charging. However, how this EEP is used, given by the negative energy values in the figures, is different, and perceived even with a timescale of one week. Even though the EV smart charging adaptation to the production profile is on an hourly basis, it has graphically perceived effects on a daily basis and even on a weekly basis, since the average autonomy of fully charged PEVs and PHEVs in electrical mode is on average 5.5 days. That is, the fleet charging management allows for some compensation of intra-week variability in the renewable resource available. Generally, it is possible to observe that weeks with higher RES production have higher EV consumption, the opposite also being observed. The result is that CEEP is very much reduced with smart charging. For the entire year, the CEEP is 3.1% with day charging and 0.2% with smart charging.

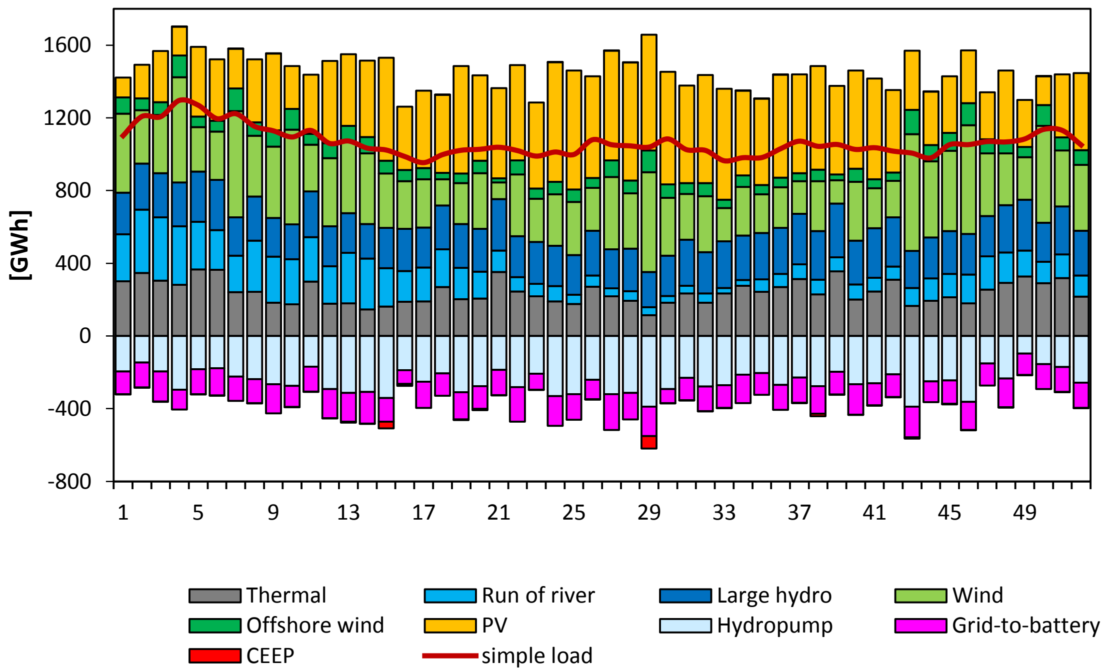

Figure 51. Weekly energy production and consumption for the CC scenario (smart charging)

4.2.2. V2G charging profile

An insightful result is the one shown in Figure 52, where the annual daily average profiles of the smart EV charging, PV production, total non dispatchable production and day charging are sketched. The figure was obtained averaging and normalizing the hourly outputs of the model for the entire year for the CC scenario. The good correspondence between the PV production and the total non dispatchable sources was expected, since the former represents 44% of the latter. More interesting is to note the good correspondence between the EV smart charging and the PV production profile. It should be highlighted that the model algorithm optimizes the EV charging according to the premises described above (Section 3.1.1.2), i.e., in order to reduce CEEP and GHG emissions. That is, in the absence of a pre-determined EV charging pattern, the model adjusts the EV charging to a pattern very similar to the PV production and, by inherence, to the non-flexible day charging profile, reinforcing the conclusion that most of the electric vehicle charging will have to take place during working hours. Table 16 presents the correlation factors between the different curves.

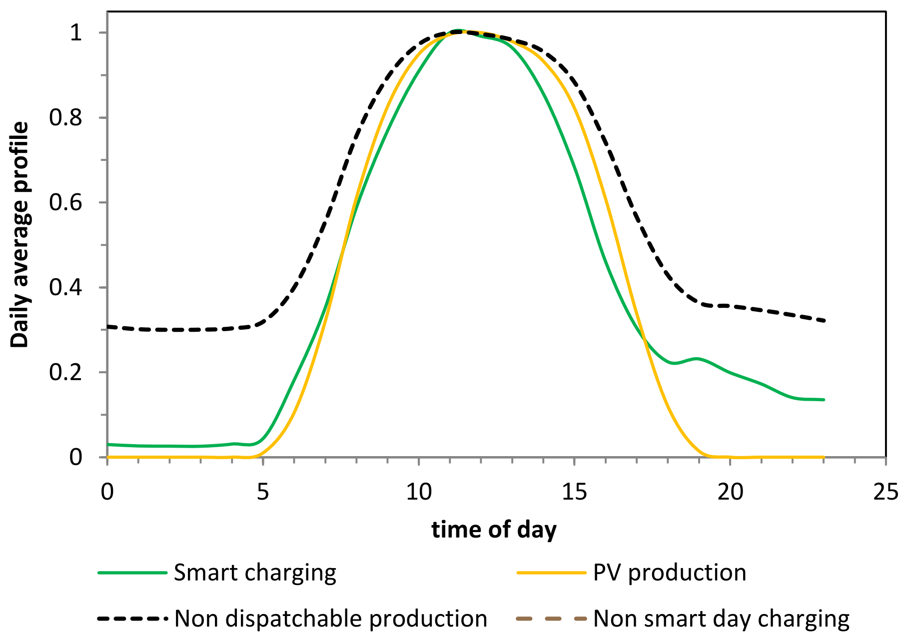

Figure 52. Normalized annual daily average profiles in the CC scenario of EV charge, PV generation and total non dispatchable generation

Table 16. Correlations factors between the profiles shown in Figure 52

Grid-to-battery – PV production	0.981
PV production – Non dispatchable sources	0.998
Grid-to-battery – Non dispatchable sources	0.986
Smart charging – Day charging	0.968

4.2.3. Impacts of different EV market shares

4.2.3.1. CEEP

The daily profiles of the average power demand and production for different EV market uptakes are shown in Figure 53. It concerns the High PV scenario, the one with the most potential to produce energy surplus, and the results were obtained averaging the hourly outputs of the model for the whole year. One can see that the CEEP is drastically reduced with increasing transport electrification. As with day charging, the total power production and its shape do not change significantly with increased transport electrification. Table 14 presents the average and peak CEEP for each of the EV scenarios, where it can be seen that between the 0% and the 100% EV scenarios the average power in surplus is reduced around sixteen fold. Results from an additional scenario, HC', corresponding to the HC scenario tested with the non-smart day charging, is included. Comparing HC with HC', one can see that the smart charging more than halves the average CEEP.

Also interesting is to note that between the H0 and the HL scenarios, despite the additional demand from the EVs, the total energy production during midday is slightly reduced (around 5%), which is due to the transference of stabilization share from thermal units to V2G.

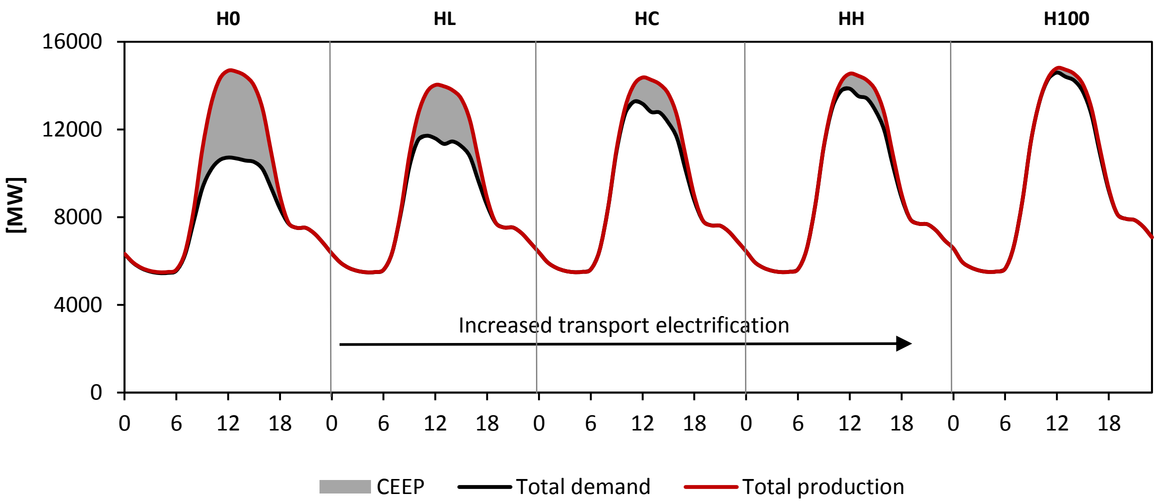

Figure 53. Daily average power demand and production profiles for the whole year for different EV scenarios combined with the High PV scenario (smart charging)

Table 17. Average unusable power for different mobility scenarios (smart charging). All figures in MW.

	H0	HL	HC	HH	H100	HC'
average daily CEEP	1227	682	346	224	77	722
average peak CEEP	3963	2627	1463	933	336	2341

Figure 54, obtained based on simulations of each of the EV scenarios combined with each of the PV scenarios, shows the CEEP reducing with EV market uptake for the different PV scenarios. The lines are steeper for higher PV penetrations, meaning that the marginal positive effects of the EV penetration on the CEEP are higher for higher solar PV capacity installed. The flatter lines toward the right shows the EV growth diminishing returns on CEEP avoidance. Finally, it can be seen that in the Low PV and Central PV scenarios a 0% CEEP is reached with around 30% and 65% of EV market share, respectively.

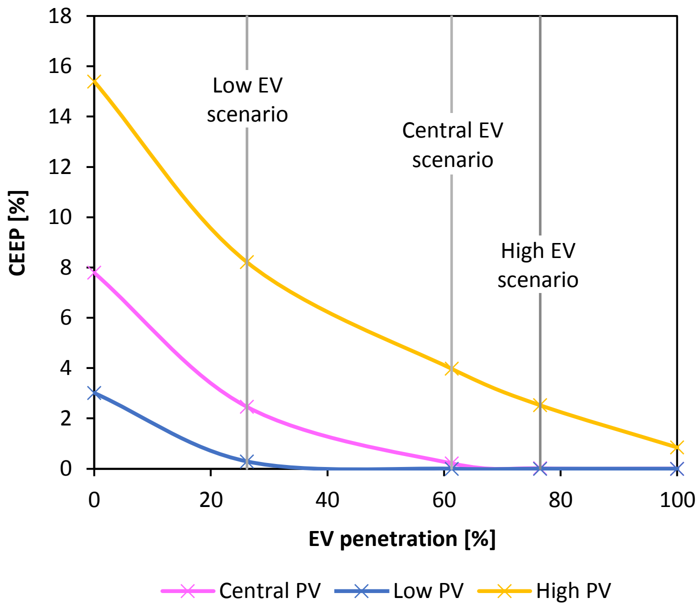

Figure 54. Relative CEEP as function of EV market share for the different PV scenarios (smart charging)

4.2.3.2. CO_2 reductions

Figure 55, obtained as Figure 54, illustrates how reductions in CO_2 emissions evolves with increasing EV penetration for the three PV scenarios. The green band between the 80 and 95% CO_2 reductions represents the EU 2050 target [3]. Because higher shares of EV imply less ICE vehicles and allow for more use of solar PV energy, increasing the RES share in the electricity mix, the CO_2 reductions are higher with higher EV shares. The height of the gap between curves increases to the right, meaning that the marginal benefit of additional EV market share is higher for higher PV scenarios. One can see that in the High PV scenario the EU goal can only be reached with at least circa 41% of EV market share. To reach it in the Low PV and Central PV scenarios it is needed around 84% and 50% of EV market, respectively. It is noteworthy to compare the High PV scenario with the Central PV scenario: it is seen that for low EV penetration the former does not leads to further CO_2 reductions in comparison with the latter, because the additional solar energy produced in the High PV scenario is wasted until around 32% of EV penetration.

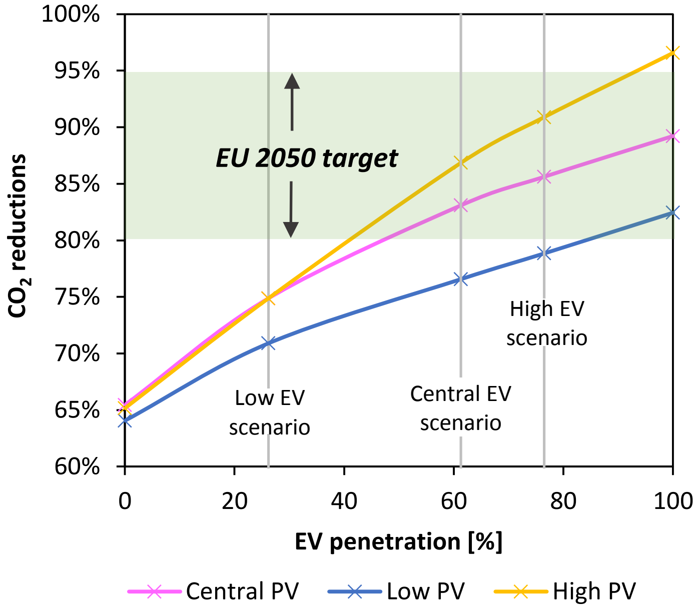

Figure 55. CO_2 reductions attained in the PV scenarios as function of EV market share (smart charging)

4.2.4. Impacts of different solar PV deployments

4.2.4.1. PV share

Figure 56 shows the PV share and the PV energy in excess in the power system varying with the PV penetration for the Central EV scenario. One can observe that up to 12 GW of PV there is virtually no energy in excess. From that point onwards, the energy in excess grows steadily and the capacity to include PV energy in the system begins to decrease. In the High PV scenario one has 34.0% of PV share with 7.0% of PV in excess.

Comparing with the analogous figure for day charging, Figure 41, one sees that with smart charging it is possible to double the PV capacity without excess of energy in the system. For the High PV scenario, the PV share is 34%, with an excess of 7%.

Recalling that with day charging for the same scenarios the PV share was 32.6% and the PV in excess was 13.3%, it means that with smart charging one can fit in the system more share of PV because its excess is almost halved. That is, the solar PV share on the electricity mix and the corresponding excess depends on the changing variables PV and EV, but also on the EV charging strategy.

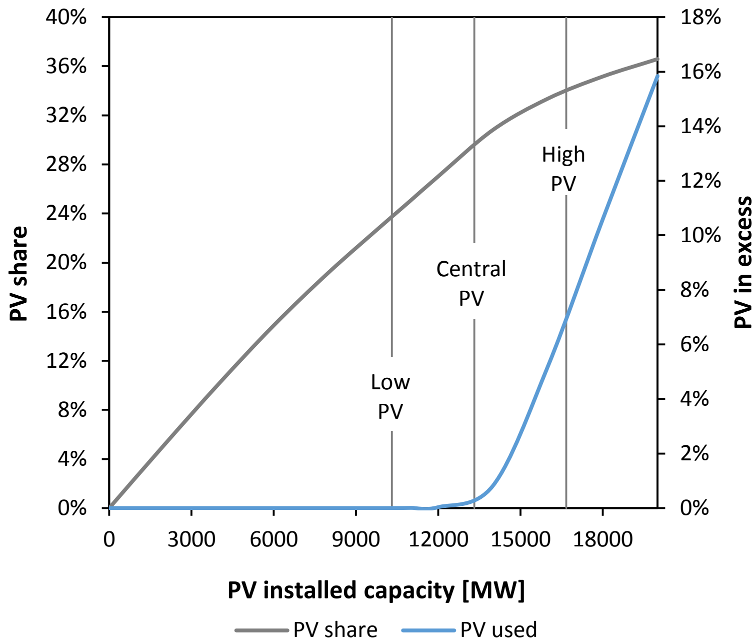

Figure 56. PV share and PV in excess in the power system varying with the PV installed capacity for the Central EV scenario (smart charging)

The PV share varying with the CEEP for each of the EV scenarios is shown in Figure 57. Without EV penetration, CEEP arises above 10% PV share. In the Low EV scenario that happens for PV shares above 23%, while with higher EV quotas it is possible to have a power system with 30% of PV share or more without PV in excess. Comparing with the analogous figure for day charging, Figure 42, it is possible to see that smart charging is very effective absorbing the energy in excess. For the same level of CEEP, it allows more PV share in the system; more important, it allows greater PV shares without excess, due to the very precise allocation of EV demand to periods when there is energy in excess.

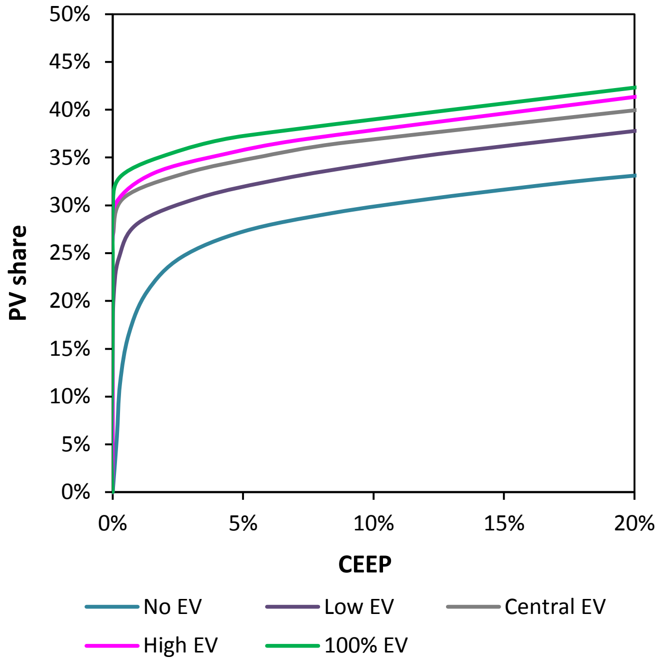

Figure 57. PV share in the system as function of CEEP (smart charging)

4.2.4.2. CEEP

Figure 58 presents the relative CEEP in the system for each of the EV scenarios resulting from different installed PV capacities. As with day charging (see Figure 43), for the lower EV quotas the CEEP grows larger. With EV penetration, the Low PV scenario has negligible (<1%) or none CEEP. In the High PV scenario, the CEEP is around seven times higher for the 0% EV scenario than for the 100% EV scenario. Comparing with the analogous results for day charging, Figure 43 overall results are much better. It is interesting to note the great reduction in CEEP between day charging and smart charging in the Low EV scenario, showing that even a relatively low number of EVs using smart charge provides great benefits to the system.

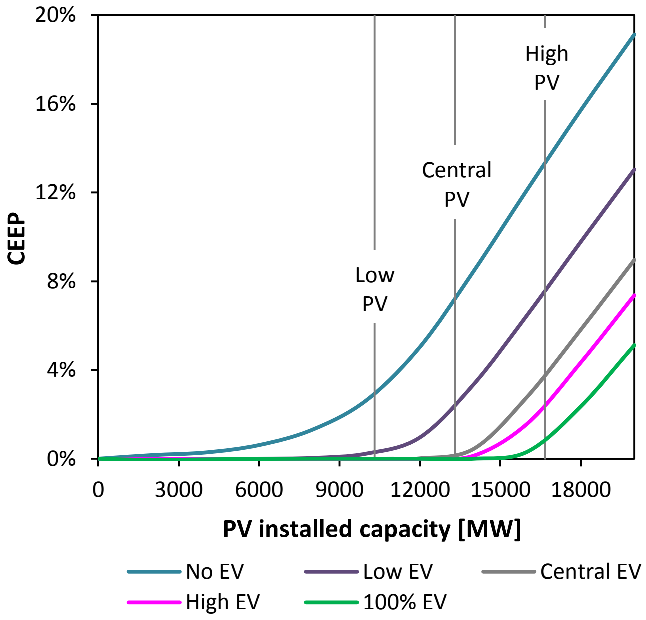

Figure 58. Total CEEP in the system as function of the installed PV capacity (smart charging)

4.2.4.3. CO_2 reductions

Figure 59 graphically shows the relation of the PV installed capacity with the CO_2 reductions achieved; it should be analyzed in conjunction with Figure 60, which gives the respective CO_2 marginal reductions of PV penetration. As with day charging, the increments in PV capacity or EV market share or both lead to increased CO_2 reductions until a certain PV level, depending on the EV scenario. Above that level there is no gain, as shown in Figure 60. That is, from this point on, the emissions reduction stabilize – a significant difference to day charging (see Figure 44 and Figure 45), where the emissions increased. This difference is because the EV provide for stabilization of additional PV, and no additional CCGT power is needed to provide for that service.

Another difference between day and smart charging is that with the latter it is possible to exceed the 95% top limit of the 2050 EU CO_2 reduction target and even it is possible a 100% RES based primary energy supply, but with extreme PV deployment (>22 GW).

As with day charging, with smart charging higher EV penetration allows for higher CO_2 marginal reductions of PV increment.

It is interesting to note in Figure 60 that generally the marginal gains start to increase from around 8 GW of installed PV in the scenarios with EV, being higher and longer with higher EV market shares. This may be understood by noting that when there is EEP in the system the model primarily channels this energy to hydro-pumping, a process involving greater losses in the posterior energy use, which is given by $\left[1-\left(effiency_{pump} \times efficiency_{turbine}\right)\right]$. Since the hydropump and turbine systems are both modelled with an efficiency of 80% (see Table 8), this means that overall the process implies 36% energy losses, higher than the 10% losses (see Table 13) involved in the EV charging process. That is, only after hydro-pumping capacity is exhausted the model starts to take advantage of the EV flexible smart charging. Because direct use of solar electricity is more efficient than its deferred use by hydro storage, it would be interesting to test a model giving priority to EV smart charging over hydro-pumping, which is not possible to test in EnergyPLAN.

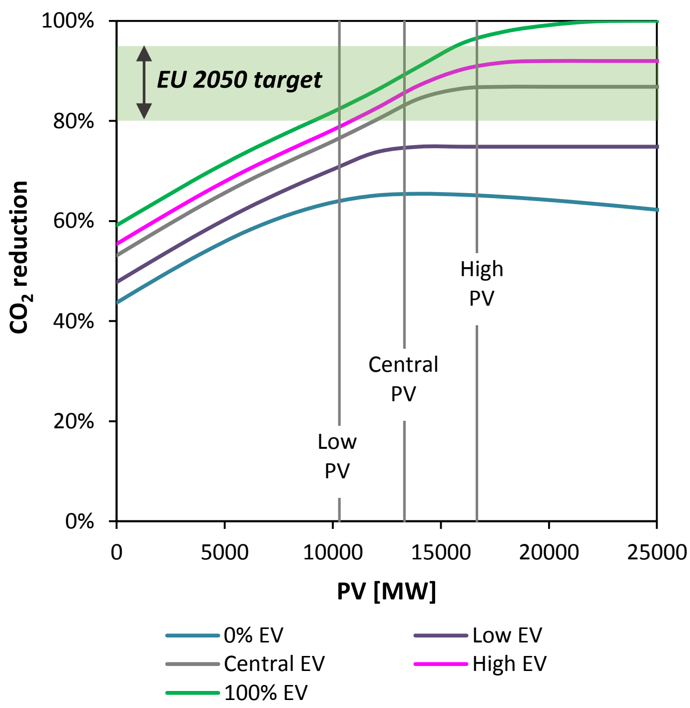

Figure 59. CO_2 reductions as functions of PV penetration (smart charging)

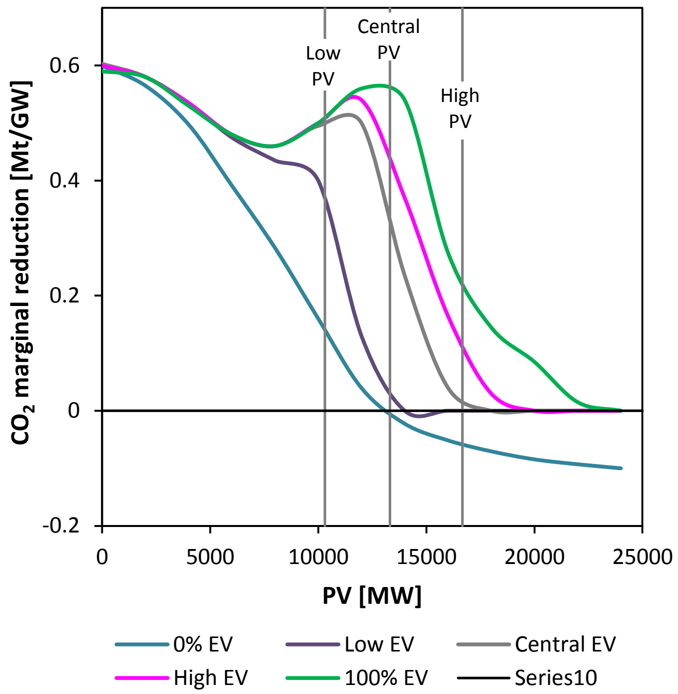

Figure 60. CO_2 reductions rate as function of the PV penetration (smart charging)

4.2.5. Grid stabilization of V2G

In Figure 61 the stabilization services provided with V2G for the whole year is represented. Due to the model functioning described before, it corresponds to a direct substitution of thermal units. In energy, it amounts of 1252 GWh, corresponding to 0.49 Mt of CO_2 avoided. On average, V2G provides for 142.6 MW of stabilization at every hour with a peak value of 2815 MW.

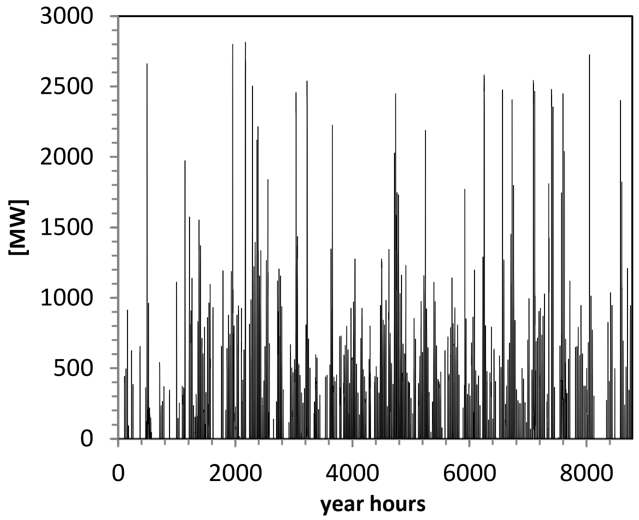

Figure 61. V2G stabilization services provision along the year in the CC scenario

From the different PV scenarios studied in this work, the one that requires more stabilization is the High PV scenario because it accounts for more non dispatchable capacity installed and thus for more energy production. On the contrary, the EV scenario that offers the least capacity of V2G to provide for stabilization is the Low EV scenario (excluding the 0% EV scenario). The two combined form the HL scenario, which on average produces 9308 MW of power, meaning that it requires an average of 1703 MW of stabilization. In Table 12 one can see that the Low EV scenario offers a grid connection with a bandwidth of at least 2263 MW, meaning that even in this scenario a great part of stabilization is provided with V2G.

4.2.6. Arrangements between PV and EV scenarios

Figure 62 identifies the arrangements between PV and EV deployments that lead to 80% reductions in CO_2 emissions and no CEEP (defined as less than 0.01 TWh/year). As the results of Figure 46 (day charging), the mobility has as basis the EV Central scenario, from which the EV penetration is changed maintaining constant the ratio between diesel and gasoline ICE vehicles and between PEVs and PHEVs. Several of mobility cases are simulated with several PV penetrations in order to identify the arrangements plotted.

In order to reach 80% reductions in CO_2 it is worth to note that:

1. With extreme PV penetration levels, higher than the High PV scenario, the minimum 41% EV market share is maintained. With this EV level, around 15 GW of PV should be installed;
2. With 100% EV market share, a minimum of 9.1 GW of solar PV is required (it corresponds to a PV share in the electricity mix of 19.9%).

In order to avoid CEEP it is noteworthy that:

1. A PV penetration level of 14.7 GW is the maximum allowed in the system, requiring an EV market share of 100%;
2. A minimum share of 2% of EV is always needed, even in the absence of PV penetration. This is because the EVs DSM is used to very accurately absorb existing EEP.

Lastly, the lower vertex of triangle shaped zone where the two conditions are met corresponds to penetrations of 61% of EV and 15 GW of PV.

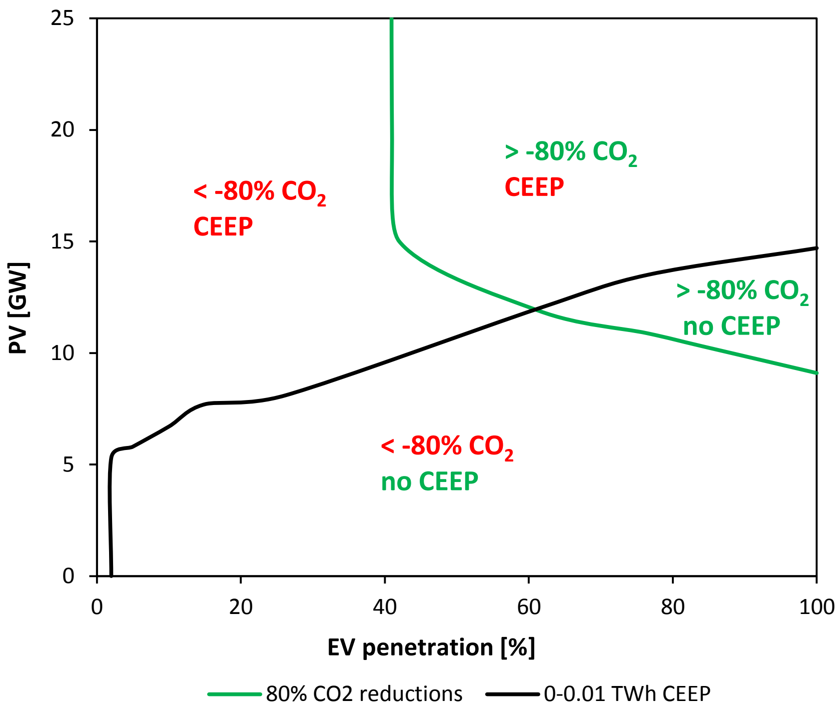

Figure 62. Arrangements between EV market share and PV capacity that leads to 80% reductions in CO_2 and to 0-0.01 TWh/year of CEEP (~0% CEEP)

Figure 63 presents the scenarios ordered by their merit concerning fossil fuel consumption and absolute reductions in CO_2 emissions. One can see that between L0 and H100 scenarios the fuel consumption is reduced more significantly than with day charging (Figure 47), i.e., an eightfold reduction vs. a fivefold reduction. The reduction in CO_2 between these scenarios is from 14.9 Mt to 22.5 Mt, about 30% difference. The scenarios that accomplish the EU 2050 goal of 80% CO_2 reductions are from the L100 scenario onwards.

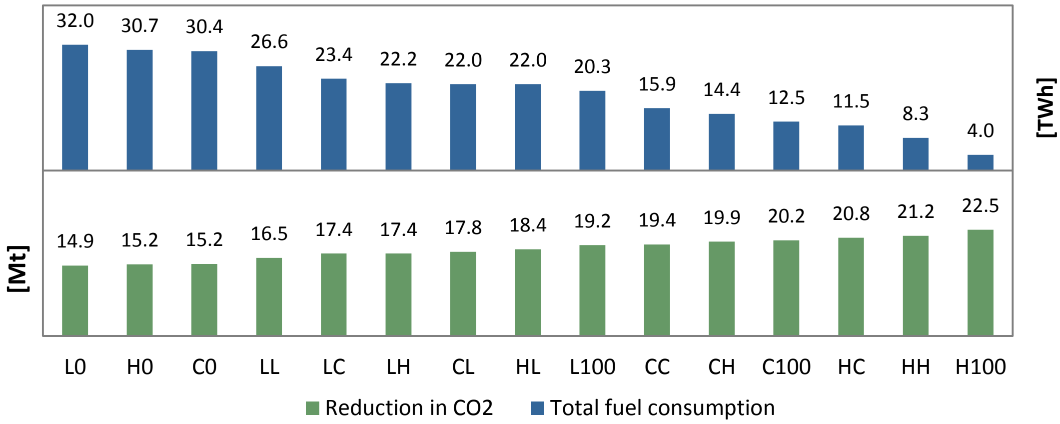

Figure 63. Scenarios ordered by its merit concerning fossil fuel consumption (natural gas, diesel and gasoline) and reductions in CO_2 emissions (smart charging)

Finally, a summary of the results concerning the most relevant parameters that were analyzed is presented in Table 18. One can see that a 100% RES based primary energy supply is not attainable (the highest reduction is of 95.0% for the H100 scenario), and, consequently, a 100% of CO_2 emissions reductions is also non attainable (the highest reduction is of 96.6% for the same scenario). On the other hand, there are scenarios that lead to very high shares of RES on the electricity mix[40], including 100% covering (scenarios CL, HL and HC), though they imply some CEEP. In fact, they are complementary to the 0% CEEP scenarios, i.e., they are the ones with higher CEEP, in line with [112]. The maximum PV share in the electricity mix is around 34%, which is for the scenarios with simultaneously higher PV and EV penetrations. This is in accordance with [27] and [196], which found that high PV contributions in a traditional power system would require enabling technologies, such as EV smart charging. As expected, the scenarios with the maximum CO_2 reductions are those with higher EV market uptake and higher levels of RES share on the primary energy supply. The average EV CO_2 emissions are 12.9, 7.9 and 2.5 g/km for the L100, C100 and H100 scenarios, respectively.

[40] Very high shares of RES on the electricity mix occurs with less EV market uptake since the RES weight is higher with lower overall electricity demand

If one compares Table 18 with the analogous table for day charging, Table 15, it is possible to see that there are certain scenarios that lead to better results with day charging (except for CEEP, which is always better with smart charging). This is due to an already addressed issue in Section 4.2.4.3, i.e., the smart charging model primarily channels EEP to hydro-pumping, which has greater losses than EV charging. If all the EEP is absorbed by hydro-pumping, as happens with some Low and Central PV smart charging scenarios, that is worse than directly absorb EEP with EV charging, as happens with the day charging model.

Table 18. RES share in the electricity mix, RES share in the primary energy supply, CO_2 reductions, CEEP, PV share in the electricity mix and PV energy used for the scenarios arrangements (smart charging)

	RES electricity share [%]					RES share on PES [%]				
EV	0%	Low	Central	High	100%	0%	Low	Central	High	100%
High PV	99.1	100	100	98.8	96.2	70.9	76.8	86.7	90.1	95.0
Central PV	99.4	100	95.8	92.9	88.0	69.6	75.9	81.5	82.9	84.8
Low PV	97.9	95.6	88.5	85.3	80.4	67.2	71.1	73.7	74.7	76.3

	CO_2 reductions [%]					CEEP [%]				
EV	0%	Low	Central	High	100%	0%	Low	Central	High	100%
High PV	65.1	74.8	86.8	90.9	96.6	15.4	8.6	4.3	2.8	1.0
Central PV	65.4	74.8	83.1	85.6	89.2	7.8	2.6	0.2	0.0	0.0
Low PV	64.0	70.9	76.5	78.8	82.4	3.0	0.3	0.0	0.0	0.0

	PV share on electricity mix [%]					PV used [%]				
EV	0%	Low	Central	High	100%	0%	Low	Central	High	100%
High PV	31.1	33.3	34.0	34.1	34.0	77.1	86.2	93.0	95.5	98.4
Central PV	28.6	30.0	29.6	29.0	28.0	87.3	95.6	99.6	100	100
Low PV	25.0	25.0	23.7	23.2	22.4	95.2	99.5	100	100	100

5. Closure

5.1. Conclusions

This thesis has presented different possible pathways and their technical consequences for the electricity and passenger vehicles sectors. Emphasis was given to the articulation between the electric vehicles (EV) market share and photovoltaics (PV) deployment and analyses and comparisons on a set of important parameters were conducted, such as critical excess of electricity in the grid, CO_2 emissions and allowed renewable energy penetration in the system.

It tries to address important research questions such as how can PV enable the electrification of the transport sector while EV storage allows a larger penetration of renewable energy sources (RES) in general, and solar in particular.

Long term scenarios with large penetrations of PV and electric mobility were explored for the particular case study of Portugal in 2050. The methodology is naturally generalizable for other energy systems. However, any generalizations of the particular results obtained require some caution. Nevertheless, it is expected that these scenarios qualitatively represent other similar energy systems. Although one always sought conservative options when defining the different model parameters, it should be noted that the scenarios are not predictions, just possible realities.

Model results show that the introduction of EV demand on the grid leads to a reduction of excess production of electricity in the system but does not imply major changes in the average load diagram. In other words, the majority of the extra electricity demand from the EV can be fulfilled with the otherwise excess electricity.

Two non-smart EV charging patterns were tested: a night charging profile, corresponding to the nighttime when overall electric demand is lower and there is typically stronger wind power potential, and a day charging profile, corresponding approximately to the average PV daily production profile. The latter constitutes a significantly different paradigm of EV usage, where its charging takes place during work hours and therefore at the worksite and park & ride parking lots. It was found that the minimum level of CO_2 emissions was reached with the day charging profile and 16 GW of PV, with a reduction of 83.5% in emissions relative to 1990 and a 7.1% excess of energy. The night charging profile with 14 GW of PV leads to a maximum of 73.5% in CO_2 reductions, with 8.3% energy excess, meaning that the European Union (EU) 2050 target of 80% CO_2 emissions reductions cannot be attained with this type of charging.

The analysis on the impacts of different EV market shares has shown that marginal EV penetration lowers the energy excess for higher solar PV capacity installed and that the CO_2 emissions decrease with the increasing EV market share for any level of PV penetration.

With daytime charging, the EU 2050 target can be reached for a scenario with at least 50% EV market share. It was seen that, up to 12 GW of PV installed, higher PV shares in the electricity mix are attained with lower EV market shares, happening the opposite above that point. Without any PV capacity installed and 0% EV market share, the CO_2 reductions are 43.7%, the minimum reduction. The largest is 94.7%, meaning that the 95% top value of the 2050 EU target is not achievable, but almost. A required minimum PV installed capacity between 7.3 and 11.5 GW is needed to fulfill the 80% goal, depending on the EV market share. The highest values of renewable electricity share in the electricity mix were attained with high levels of PV combined with low levels of EV, being the highest 99.4%. A 92.1% renewable share can be achieved with 100% EV market uptake.

To decide between implementing more or less PV as opposed to onshore wind, it should be taken into account that total excess of energy is always lower with additional solar PV. As far as CO_2 emissions are concerned, incrementing wind capacity (as opposed to incrementing solar PV capacity) leads to greater reductions in CO_2, but, again, consistently until very high levels of penetration (about 17.3 GW for solar PV and 11.7 GW for wind) the total emissions are lower with PV.

A third EV charging strategy was tested: smart charging. Comparing to non-smart charging, it was found that increasing levels of EV market share lead to additional reductions in the energy excess. It is possible to attain 0% energy excess using smart charging, needing a minimum of 2% EV market share. The 80% EU 2050 target to reduce emissions can be reached with at least 40% of EV market share and 15 GW of PV. The same is possible with a 100% EV fleet coupled with at least 9.1 GW of solar PV, which, until a level of 14.7 GW, does not lead to energy in excess. In order to simultaneously reach the EU 2050 target and not produce energy excess, the combination with least EV and PV is 61% and 15 GW, respectively.

A 100% RES based electricity supply is possible with certain smart charging EV and PV combinations, though they all imply excess of energy. The allowable PV share in the electricity mix is 34% and a good correspondence between the EV smart charging and the PV production profiles was found, which is to say that most of the charging is during daytime to maximize petroleum displacement, not nighttime.

Finally, certain smart charging scenarios lead to worse results than day charging, because the smart charging model primarily channels excess energy to pumped hydropower, a less efficient process than EV charging. Energy planners and grid operators should have this in mind when defining their strategies.

Summarizing, this thesis has fundamentally addressed the imbalance of supply and demand, which represents the ultimate limit for system penetration of variable renewables in the electric power grids. The concentration of solar PV output during the day can produce unusable excess electricity, increasing costs and requiring non-optimized installed capacity, thus preventing the ability to achieve very high PV generation share. As a result, if solar PV is to provide a large fraction of a system's electricity, some valuable use must be found for its excess output. It was seen that electric mobility offers an opportunity to use that excess electricity, reducing external energy dependency and greenhouse gases emissions. However, given that most of the solar excess electricity will naturally be generated during daytime, the coupling of solar photovoltaic and electric vehicles will require that most of the electric vehicle charging will have to take place during working hours, having significant impact on social habits and infrastructures, namely the existence of charging spots for commuting vehicles at or near the work facilities.

5.2. Limitations and future work

In the course of this work came across some limitations which are pointed out below, and may consist in improvement opportunities, furthering the study. Some of them can be overcome in the future with the inclusion of functionalities or increased flexibility in the EnergyPLAN modelling tool.

Short timescale power dynamics, affecting grid power quality, were out of the scope of this work, and thus were not considered. Moreover, they cannot be covered by hourly energy planning tools such as the EnergyPLAN. Nonetheless, they should be addressed to ensure stable power system operation and validity of electric grid scenarios, by using dynamic simulations of short time-step, in the order of a second. This coupling between energy planning tools and dynamic simulation tools ensures the technical feasibility of energy scenarios and, thus, it would be of great interest to enhance this study that way.

The model does not consider minimum startup and shutdown times of thermal power plants, neither their ramping rates, since these constraints cannot be modelled in EnergyPLAN. However, due to high ramping of variable renewable generation, they should be accounted for. Though in the simulations performed this issue may be of minor importance, since in the future the thermal power flexibility may increase, it would be interesting to further the study in this direction.

Additionally, the EnergyPLAN tool does not account for the restraints posed by power transmission lines within the modelled system. When planning high penetration levels of solar PV, it is important to perform detailed load flow analysis, quantifying the transmission and distribution losses and constraints and the ability of the utility to handle the aggregated power flows from thousands of individual small generators. Therefore, the consideration of these issues with another energy tool would be useful to enhance this study.

To make EV modelling more authentic, the EV charge in EnergyPLAN could allow for a stochastic component, allowing to replicate the unpredictable character of some of the EV charging demand, due to e.g. drivers unpredictable traveling, such as longer trips that give origin to forced charging. Also, an interesting refinement of the model would be to allow the vehicle controller to be able to predict how much charge is needed, not always fully charging the battery if there is no energy in excess.

Also, it would be of interest to test a model with a controllable dispatch of individual power plants. In particular, with a controllable dispatch of hydropump, allowing for instance to give priority to EV smart charging, since direct use of solar electricity is more efficient than its deferred use by hydro storage. Additionally, only a single reversible hydro installation is accepted by the model, which could be reprogrammed to better replicate the dispatch of dispersed units. This is not possible in the current EnergyPLAN.

The existence of national reliable, representative and detailed statistical data of the EV driving patterns and distances travelled along with their availability to charge and support the grid is vital for studies like this. Such data is a key to further discuss the feasibility of the scenarios presented. In Portugal, however, there is no study of this type so far, and therefore it is left as a suggestion to conduct one.

Since the methodology presented in this study is generalizable and applicable to other situations, it would be of interest to extend it to other energy systems and other contexts, in order to have an insight on how the results would fit other realities.

It would be also of interest to enhance the study evaluating the economic implications of the scenarios.

Finally, a number of assumptions have been made for this work. Although one tried that they are as credible as possible, they are not certain. Therefore, a sensitivity analysis of the scenarios main assumptions, testing and simulating alternatives, would be worthwhile, something that has not been done for the sake of simplicity – yet.

Another prospect for furthering the work could be the examination of intermediate years over the coming decades until 2050. It would be valuable for policy makers to prepare the energy transition required to achieve the scenarios that have been shown to achieve a sustainable, robust, clean and integrated energy system in 2050.

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Article I

Enabling solar electricity with electric vehicles smart charging

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(submitted to *Energy* journal)

Abstract

It has been shown that a long term sustainable energy system based on a high penetration of solar photovoltaics requires massive deployment of day charging electric vehicles to make use of the excess solar electricity generation at sun peak hours. In this paper the synergy between these technologies is further explored, determining the minimum penetration levels that allows fulfilling the climate and energy targets. Simulations for a case study of Portugal in 2050 using an electric vehicles smart charging approach show that a 100% renewable energy based electricity supply is possible with certain photovoltaics and electric vehicles combinations and that the environmental targets to reduce CO_2 emissions are just reachable with significant electric vehicles market share. The notion that vehicle charging will have to take place during working hours to maximize petroleum displacement is reinforced.

Highlights

- An energy system with significant electric mobility and solar electricity is modelled.
- The extent to which smart charging of electric vehicles allows photovoltaics integration is quantified.
- A small electric vehicle market share is needed to avoid excess of energy.
- Certain electric vehicles and photovoltaics combinations allow 100% renewable electricity supply
- CO_2 reduction targets can only be achieved with significant electric vehicles penetration

1. Introduction

This article analyses the positive interactions between a high penetration of solar photovoltaics (PV) and the deployment of electric vehicles (EVs) in future energy systems [1] having as departure the European context. To contribute to limit climate change below 2ºC[1] [2], the European Union (EU) targets an overall greenhouse gas emissions reductions by 80-95% until 2050[2] [3]. It is only achievable by the intensive use of renewable energy sources (RES) and major alterations in transportation, since energy and transport sectors are the two biggest greenhouse gases (GHG) emitters in the economy[3] [4].

In the economy's decarbonisation, electricity will play a main role, given its increasingly importance as an energy vector in modern societies [5] and its potential cleanliness when produced using RES. In particular, solar electricity generated from PV technology appears to be in the future the most attractive form of decarbonized electricity generation due to its noiseless nature, scale flexibility, simple operation and maintenance [6] and price competitiveness trajectory [7][4], bringing PV on the verge to compete with household electricity prices [8]. For this, solar PV is projected to be the dominant source of electricity in a global warming limiting scenario [9].

Within this framework, EVs[5] are a key technology from the demand side, since they are much more efficient than the internal combustion engine (ICE) [10] models and potentially much cleaner on a well-to-wheel analysis [11]. Carbon footprint of EV driving is directly related to the electricity from which the batteries are charged, which,

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[1] Compared to pre-industrial levels.

[2] Compared to 1990 levels.

[3] The energy sector presently is responsible for the biggest share, approximately 30%, of GHG emissions in the EU [82] and transport is right after, responsible for around a fourth, with the road transport alone answering for a fifth of total emissions [4]. For the time being, transport sector is still a growing source of GHG emissions, with a substantial 36% increase over the past two decades, putting it presently 8% above the 1990 level [4].

[4] Competitiveness is assessed by grid parity: PV will reaches it when the electricity produced by a PV system throughout its lifetime is at least as profitable as buying electricity from the grid [7]. Grid parity has already been partially reached in Spain, Germany and Italy [83] and due to the declining PV levelized cost of energy it is expected that the same happens gradually in the rest of the European countries [84].

[5] In this paper, EV refers to electric vehicles in general, comprehending pure electric vehicles, i.e., vehicles propelled solely by electricity, with no internal combustion engine used for propulsion, and plug-in hybrid electric vehicles.

on the limit, can be 100% carbon free, making EVs the most promising solution to reduce emissions form vehicles [12].

For these reasons, PV is expected to undergo mass adoption in the following decades across the globe [7], [9] while EV use is also expected to take off [13]–[15], which will lead to well-known and relevant impacts on the national energy systems, e.g. possible mismatch between production and consumption of solar electricity and higher electricity demand for EV mobility. Abundant non-dispatchable renewable energy, whose output is conditioned by meteorology and therefore fluctuating, may have to be curtailed or, when similar amounts of variable generation are installed in surrounding markets, exported at low prices [16]. Hence, the installation of storage devices to absorb this energy is highly beneficial [17]. Within this frame, the EVs, with their large battery capacity[6] if seen as a whole, may be an answer to avoid increasing worldwide excess of energy [18]. In fact, the most significant impact on the electricity system of EVs is their ability to assist the integration of renewable energy into existing power grids [19]. For a review on this subject, see Richardson [19]. Previous works addressing specifically the integration of solar PV and EVs are for example [20]–[23].

In this work this topic is addressed building upon [1], which may be seen as a companion article. It explored the possible complementarities between wind and solar power and EV deployment using a non-smart day and night charging strategies. It was shown that CO_2 emissions targets can only be achieved with high levels of PV penetration and EVs day charging, reinforcing the need for day time charging infrastructures [24], presumably at or near work facilities [1]. A future energy scenario for Portugal in 2050 was used as case study. This country is especially appropriate to test the interaction of these two technologies, since it has a substantial solar resource availability[7] [25], a public EV recharging infrastructure [26] and a green taxation system that promotes the adoption of EVs [27].

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[6] Electrochemical batteries are the most common option for current EVs [85].

[7] However, Portugal did not do yet the leap in order to start exploring its solar potential, having just 282 MW of solar photovoltaic installed [86]. As a comparison, despite of Germany having only 1200 kWh/m2/year of solar resource available and Portugal 1900 kWh/m2/year [87], the former has 438 W/person of solar PV installed against 28.2 W/person in the latter [88]. The reasons for this have a great amount of deal to do with a still lack of competitiveness in the price of the solar PV unit of energy when compared to other electricity sources, but that is changing. Competitiveness is assessed by grid parity: PV will reach it when the electricity produced by a PV system throughout its lifetime is at least as profitable

This article explores some research prospects that arose in [1]. In particular, a smart charging strategy is tested, which requires detailed modelling of mobility. This approach enables reaching the CO_2 targets for 2050 with virtually no excess of energy. Furthermore, the extent to which PV energy can further transport electrification integration, and vice-versa, is explored in detail: the required penetration of one technology to enable the deployment of the other is determined quantitatively. To avoid repetitions, in this paper details are provided just for the new parts of the work.

2. Smart charging of electric vehicles

As detailed in [28], there are two main strategies for EV charging: (1) un-coordinated charging, in which the EVs start charging as they park, leading to potential critical impacts on the grid; (2) coordinated charging, in which charging is at a convenient time, such as during off-peak hours. It can be based on a simple set of rules, such as delayed charging (i.e., pre-programed charging), or it can be smart charging, i.e., an optimized charging under the command of an operator, based on price, load or regulation [29]. A delayed type EV charging, programmed for certain times of the day, was tested in [1]; this paper focuses on the smart charging strategy, which relies on the smart grid technology. As defined in [30], a smart grid is an electricity network that efficiently delivers sustainable, economic and secure electricity supplies integrating intelligently the actions of all users connected to it – generators, consumers and those that do both. It is based on a combination of hardware, management and reporting software built atop a communications infrastructure, constituting a great sophisticated and intricate network. At the moment it is on early stages. For an inventory of the smart grid research, development and demonstration projects in Europe, see [31].

In this context, the EV batteries may act as a form of distributed controllable energy storage and possible supply of power. This is the concept of vehicle-to-grid (V2G). Since EVs are parked more than 90% of the time [32], they offer the possibility for demand side response (DSM), namely load shifting. Conceptually, they can be seen as a nation sized battery [33]: (1) they can charge when it is more convenient for the system

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as buying electricity from the grid [7]. Grid parity has already been partially reached in Spain, Germany and Italy [83] and due to the declining PV levelized cost of energy it is expected that the same happens gradually in the rest of the European countries [84].

operator (SO), substituting large-scale energy storage systems (namely hydro-pump); (2) optionally, they can supply electricity (battery-to-grid) and ancillary services to the power system[8]. V2G implies: (1) a smart connection to the grid[9]; (2) a control device communicating with the SO and following its signals; (3) an on-board meter device.

The V2G concept was already approached in 1997 by Kempton and Letendre [34]. Since then, V2G was amply addressed in the literature, such as in [32], [35]–[37], [21], [38]–[40], [29], [41] and experimentally tested in pilot projects, such as [35], [42], [43]. For a comprehensive review on the topic, focused on V2G and RES integration, see Mwasilu et al. [44]. For a review of smart charging approaches, see García-Villalobos [45].

Fig. 1 schematically represents the smart grid scheme with V2G functionality operating under the virtual power plant (VPP)[10] approach. The VPP control center dispatches the aggregated battery power whenever requested by the Distribution SO (DSO) and Transmission SO (TSO) and centralizes the energy and communication flow management between energy market players (i.e., producers and consumers) and the operators.

[8] EVs could charge during off-peak hours, when the price of electricity is low, and sell to the electric companies under contract payments during those periods and, thus, more expensive, representing a profit for the EV owner. If this payment is lower than the cost of centralized power generation, the electric power companies will also realize profits [41].

[9] It should be noted that, in our meaning, V2G concept does not imply necessarily electricity flow from the batteries to the grid.

[10] Virtual power plant is defined as an aggregation of different type of distributed resources which may be dispersed in different points of medium voltage distribution network. It can be used to make contracts in the wholesale market and to offer services to the system operator [89].

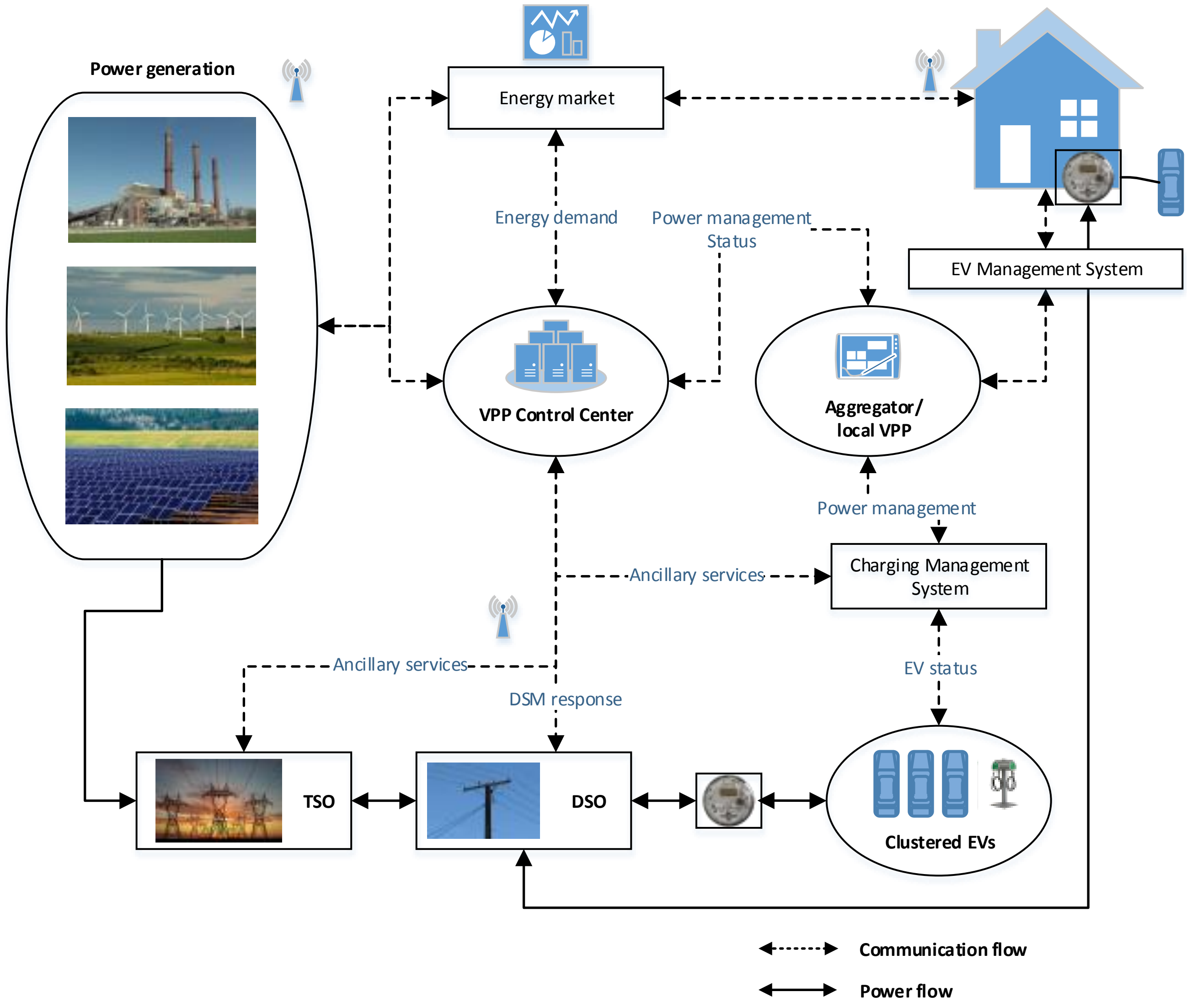

Fig. 1. Smart grid scheme with V2G functionality operating under the VPP approach. Adapted from [44]

The provision of V2G services to the SO is ultimately determined by its profitability for the parts. The power markets where V2G could be integrated are: (1) base load, i.e., power generation paid on an energy basis that is running most of the time at low cost to cover for constant demand. V2G is not suitable for this market because cannot be price competitive due to EV limited energy storage, limited battery lifespan and high energy cost; (2) peak power, i.e., power generated during times of predictable higher demand, e.g. cold periods, paid also on an energy basis. Normally, it is provided by combined cycle gas turbine (CCGT) power plants, which can be switched on for short periods of time. This energy is relatively expensive, making in some cases V2G competitive for peak power. Units operating in peak power mode work sometimes up to 5h, posing difficulties for V2G operate in this market because of storage limitations of each vehicle; (3) spinning reserves, i.e., energy supplied promptly by permanently online rapid expensive generators in case of loss of programmed generation, e.g. equipment failure or failure of a power supplier to meet contract conditions. Typically, this generation is called for a few minutes a few times per year and is paid for the time available online. These conditions make spinning reserves market especially attractive for V2G; (4) frequency regulation, i.e., generators that are used to keep the grid frequency and voltage stable. Typically, they are called for up to a few minutes several times per day. By contract, the calls could be limited in number and in duration for each individual EV. V2G is considered highly competitive in this market [38]. From the electrical utility perspective, this is a new source of high quality grid regulation and, from the EV buyer perspective, a revenue source that further encourage the purchase [39].

To help with the economic rationale of V2G, in [46] the authors studied the cost-benefit of regulation service provided from unidirectional (power flowing from the grid to the vehicle) and bidirectional (power flowing in both ways) charging of EVs. They found that EVs can participate in the regulation market even working with just a unidirectional configuration. In fact, even though bidirectional flowing allows for extra revenues, if one considers the costs from the increased battery fading (battery-to-grid operation substantially increases the number of battery cycles and generally shortens its lifetime) and the increased sophisticated infrastructure, that extra revenue can become negative.

It is worth to note that significant penetration in the electrical systems of non dispatchable RES, i.e., PV and wind, and EVs raises concerns to SOs related to the power quality, as mentioned in [1]. Several studies in this field have been conducted, such as [47]–[54], and more are desirable [45]. Nonetheless, generally, it has been observed that smart charging of EVs can enhance the operational efficiency, secure the electric grid and reduce power system operating costs [44].

3. Approach

An energy model for the Portuguese electricity and transport systems with integration of electricity sources using the EnergyPLAN [55] computer tool was developed in [1]. That model serves as a basis in the present work. It is calibrated for the reference year

2011 and the mobility analysis is constrained to light passenger vehicles, i.e., the segment where EVs have the most market potential.

For the present work a whole new EV smart charging strategy was thought and applied in the model. Smart charging in EnergyPLAN involves an optimization problem with aim to manage the EV load in order to decrease the network's existing excess of energy production (EEP), allocating EV demand to that periods. When applicable, the model maximizes the replacement of fossil based stabilization of the grid with V2G. In the case of lack of EEP, the model inspects the next few hours of driving requirements and forces the charging as needed. In this case, the algorithm calls for whatever dispatchable sources are available to fully charge the batteries prior to driving periods, having as priority the less carbon intensive sources. As a last resource, fossil fuel power plants are ramped up or switched on. The model does not consider wear out of the batteries over time. For a more detailed description of the V2G EnergyPLAN algorithm, see its manual [56] or [32].

It should be mentioned that issues concerning power quality, such as frequency and voltage fluctuations, are not accounted by one hour time step simulations, like in EnergyPLAN. Although EVs contribute positively for a better accuracy of hourly simulations, to justify their technical feasibility they should be coupled with dynamic simulations [57].

For a further detailed description of the methodology, including model calibration, see [1].

4. 2050 scenarios

A reference 2050 scenario for Portugal that included one EV and one PV penetration levels is presented in [1]. In the present study further levels of PV and EV penetrations are conceived and then combined, giving origin to several scenarios which were simulated. They are crucial to outline possible development paths and give to the decision-makers a broad overview and show how far policies can shape the evolution in energy and mobility sectors. As in [1], they are built upon long term EU objectives for the climate-energy area and upon different reference scenarios presented in the literature. Data temporal extrapolation was applied for the scenarios with a time horizon shorter than 2050 using a Gompertz function fitting [58]. See [1] for a detailed description on this.

4.1. Power grid

4.1.1. Solar photovoltaics deployment

Based on the average of the European Photovoltaic Industry Association (EPIA) trends, a PV deployment level of 13.3 GW for Portugal in 2050 was assumed in [1]. It constitutes the Central PV scenario, as is called from now on in this paper. Additionally, building on the same trends, two additional scenarios, Low PV scenario and High PV scenario, are studied. Table 1 presents the capacity installed and the annual energy production for these scenarios.

Table 1 Capacity installed and yearly energy productions for the different PV scenarios considered in this study

		Low scenario	Central scenario	High scenario
Capacity installed	**MW**	10308	13316	16669
Production	**TWh**	17.46	22.56	28.24

4.1.2. Other assumptions

Several other projections about the utility system common to all the scenarios were made in [1], namely installed capacities, power plant efficiencies, electricity demand, system flexibility and system stabilization. Table 2 summarizes some of these assumption for the years 2011 (reference year) and 2050. For its fundaments and details, see [1].

Table 2 Modeled demand, installed capacities and system flexibility and stabilization in 2011 and 2050

	2011	2050	References
	MWh		
Electricity demand	50.5	*	[7], [59], [60]
	MW		
Production Installed capacity	**18902**	**37997**	
Thermal	**9274**	**7071**	
CCGT	4687	5723	[61], [59], [60]
Coal	1756	-	[61][62]
Fuel-oil	2228	-	[61]
Biomass, urban residues, waste	603	1348	[61], [59], [60]
Wind onshore	**4081**	**7674**	[7], [61], [59], [63]
Wind offshore	**-**	**1400**	[64]
Hydro	**5392**	**8536**	
Large hydro	2537	5681	[63], [65]
Run of river	2855	2855	[61], [63]
Hydropump	1020	4004	[63], [65]
	%		
Overall thermal power plants flexibility	86.7	86.7	[61], [66]
Minimum grid stabilization share	18.3	18.3	[1]

* Electricity demand varies according to the mobility scenario. See Section 4.2 for details.

4.2. Mobility

4.2.1. EV market uptake scenarios

The IEA BLUE Map scenario for OECD Europe [14] is the basis for the assumptions for the evolution of the EV market penetration. It was considered different EV technologies: Pure EV (PEV) and gasoline and diesel plug-in hybrid EVs (PHEV). The total EV market share or penetration corresponds to the sum of individual market shares of these technologies. Three passenger vehicles scenarios were developed, which are adaptations to the Portuguese context of the IEA scenario: (1) Low EV Scenario (EV share of 26.2%), with halved EV sales of the IEA scenario; (2) Central EV Scenario (EV share of 61.4%), with the same EV sales as in IEA scenario; (3) High EV Scenario (EV share of 76.5%), with doubled EV sales of the IEA scenario. To enhance the study, two additional extreme scenarios are considered: none EV market share (0% EV scenario) and full EV market share (100% EV scenario). The characteristics of the scenarios are presented in Table 3. More details about the modeling of the fleet are provided in [1].

Table 3 Fleet and demand characterization of the different EV scenarios

	0% EV		**Low EV**		**Central EV**		**High EV**		**100% EV**	
	# M	**share %**	**# M**	**share %**	**# M**	**share %**	**# M**	**share %**	**# M**	**share %**
ICE gasoline	1.392	33.3	1.008	24.1	0.576	13.8	0.390	9.3	-	-
ICE diesel	2.783	66.7	2.075	49.7	1.037	24.8	0.592	14.2	-	-
PHEV gasoline	-	-	0.345	8.3	0.840	20.1	1.151	27.6	1.566	37.5
PHEV diesel	-	-	0.129	3.1	0.314	7.5	0.431	10.3	0.522	12.5
PEV	-	-	0.618	14.8	1.409	33.7	1.611	38.6	2.088	50.0
Demand					**TWh**					
Total electricity	55.81		58.57		62.30		63.90		66.38	
EV	-		2.77		6.49		8.09		10.57	
Gasoline	10.02		7.26		4.15		2.81		-	
Diesel	19.74		14.71		7.35		4.20		-	

4.2.2. Other assumptions

Table 4 presents a summary of general assumptions common to all vehicles scenarios. For the fundaments, see [1].

Table 4 Common assumptions to all EV scenarios

		References
PEV and PHEV (electric mode) consumption	0.2 kWh/km	[14]
ICE gasoline consumption	2.05 MJ/km	[67]
ICE diesel consumption	2.02 MJ/km	[67]
Annual mileage	12662 km	[67]
Battery efficiency	95%	[68]
Vehicle average lifespan	17 years	[69]

4.2.3. Smart charging

A conservative approach recommends the adoption in the model of a unidirectional V2G operation. As stated in Section 2, unidirectional V2G is especially attractive because it requires little, if any, additional infrastructure other than communication between the EV and an aggregator and it does not imply interconnection issues or battery degradation, having more customer acceptance [29]. Thus, the V2G model does not provide for base load or peak power.

In what concerns ancillary services provision, in the EnergyPLAN tool they are comprised in the minimum grid stabilization production share input parameter, which was set to 18.3% [1]. Since the EVs short term power balancing enhances the reliability of energy systems scenarios, a grid stabilization share should be allocated to V2G similar to that of other regulation units [57]. On the other hand, stabilization requirements can be met recurring to loads instead of just generation, increasing and diminishing the EV load [47]. The difference between the time needed for actual charging and the length of time the vehicles are plugged in yields time flexibility that can be exploited to provide grid stabilization [46]. Based on this, the V2G model considers that the entire EV fleet is available for unidirectional V2G stabilization using up to 100% of the connection capacity to provide for that service[11].

The present average battery sizes are of 13.0 kWh for PHEV and 26.7 kWh for PEV [70]. It is expectable that energy density will be much higher in the future [71] and that lithium-ion (Li-ion) batteries will be the first choice for energy storage [72], due to their high specific energy, large number of charge-discharge cycles and reasonable cost [73]. This technology depends however on a robust battery management system to ensure safe and reliable battery operations, accurately calculating the battery state of charge (SOC) [74]. It is assumed EVs equipped with Li-ion type batteries with doubled energy density as in the present while maintaining the weight of batteries installed in each vehicle. This means that, according to the EV penetration scenario, the total fleet storage capacity is in the range of 38.5-108.9 GWh (see Table 5) if one considers a SOC

[11] The traditional power grid ancillary services adapt the power supply to demand. Unidirectional V2G ancillary services adapt demand to supply [90].

window of 85% [75], which in any case corresponds to less of the average daily national electricity demand (circa 137 GWh).

Table 5 Battery storage overall size and power capacity of grid to battery connection according to the EV scenario

		Available capacity	Grid connection bandwidth	
			Max	**Min**
		GWh	**MW**	**MW**
	0%	-	-	-
	Low	38.5	2829	2263
EV Scenarios	**Central**	89.5	6638	5310
	High	108.1	8270	6616
	100%	140.9	10814	8651

Since a number of cars will always be driving and can neither contribute to decrease grid load nor increase, the total capacity of the connection is not always available for stabilization. Although studies for large fleets have shown that at any given time less than 10% of the cars are driving [32], conservatively it is assumed that in Portugal a share of 20% of the entire fleet is circulating at rush hour. It is also assumed that 70% of the parked cars are connected to the grid [32]. This means that for the electrical fleet in the Central EV scenario the overall grid-to-battery capacity will have a maximum of 6.64 GW and a minimum of 5.31 GW, as Table 5 details. Table 6 presents a summary of the assumptions made for the V2G model.

Table 6 Assumptions made in the V2G model

		References
Fraction of the EV fleet with V2G capability	100%	[a]
Useable SOC window for batteries	85%	[75]
PEV battery size	53.4 kWh	[70]–[72]
PHEV battery size	26.0 kWh	[70]–[72]
Charging power (unidirectional)	3.7 kW	[26]
Grid-to-battery efficiency	90%	[32]
Max. share of cars driving during rush hour	20%	[32]
Share of parked fleet connected to grid	70%	[32]

[a] It is assumed V2G capability as a standard EV feature in the future

4.2.3.1. Driving patterns

For the EVs it is assumed that travel distances as well as trip patterns are the same as for the ICE vehicles, meaning that for all type of vehicles mobility is the same. The period of day during which a car is driven, and, consequently, is not connected to the grid and is draining energy from the battery, is an important element for modelling an energy system with a V2G component. The amount of potential gains for the system heavily depends on the V2G availability and, thus, to appreciate the V2G concept, a certain number of EVs should be available and secured. Therefore, statistical travelling patterns should be included in the model. These patterns are typically different from region to region and, therefore, at a nation level, they should be weighted to obtain an average national travelling pattern that is sufficiently representative. Thus, monitoring and analysis of these patterns is a key point [41].

In the EnergyPLAN the distribution of the transport demand is provided in 8784 hourly values (a leap year). This time series is used to calculate the energy drain from the batteries in every hour along an entire year and therefore the input data file should be based on an hourly resolution travel survey. These surveys are usually carried out by national or local bodies (e.g. statistical offices, transport ministries) or by research centers, like in [76], [77]. In Portugal for the time being there is not a countrywide study of this kind, but the National Statistical Institute (INE) made a survey [78] with a geographical scope of Porto metropolitan area, the second biggest population center in the country, and adjacent areas. It gathered information from about 200 000 individuals in order to characterize the mobility of the resident people using a number of parameters such as the number, time and duration of the journeys carried. The distribution of trips by time of day is probably different across regions in Portugal, and the average national pattern may not be exactly the same as the one of the region studied, but it is expected a sufficiently common similarity, as it was observed in [77] between other countries and in the INE study among the different areas in analysis. Given that premise and in the absence of a broader study, the INE's survey is considered sufficiently representative of the national driving patterns, and therefore it was used to construct the V2G model inputs.

The transport demand input is divided in weekdays and weekends, since these are periods with significantly different driving patterns. The probability distribution of each car to travel during weekdays is shown in Fig. 2a. Three periods with stronger traffic intensity can be highlighted: 7-9h, 12-14h and 18-19h, corresponding to the periods of commuting to and from work. Fig. 2b shows the driving patterns for the weekends, which has an important distinction between the weekdays driving behavior, since during the weekends there is a greater irregularity in the dislocations. Also, as it would be expected, morning mobility is less and starts later (the share of trips made before 9h00 is basically halved), increasing gradually until 10h00. Overall, contrary to what could be a common perception for mobility during the weekend, i.e., less mobility, on the weekends there is an increased car use, especially between 14h00 and 16h00. The cars do not concentrate however as much as when commuting, because they are spread along more diversified geographical zones[12]. Statistically, for the entire period analyzed, the daily number of trips is 2.5 and each journey takes 22 minutes. In urban areas the journey time is aggravated 4 minutes comparing to more rural areas.

[12] Nevertheless, more car travels during the weekend does not signify necessarily increased driving distances. These were not accessed in the INE survey, but they were in [77] for other EU countries, where it was found that the average daily driving distance does not significantly increase over the weekends. It is concluded that EVs could not only cover the typical driver needs during weekdays but also the weekends, which is likely the same case for Portugal.

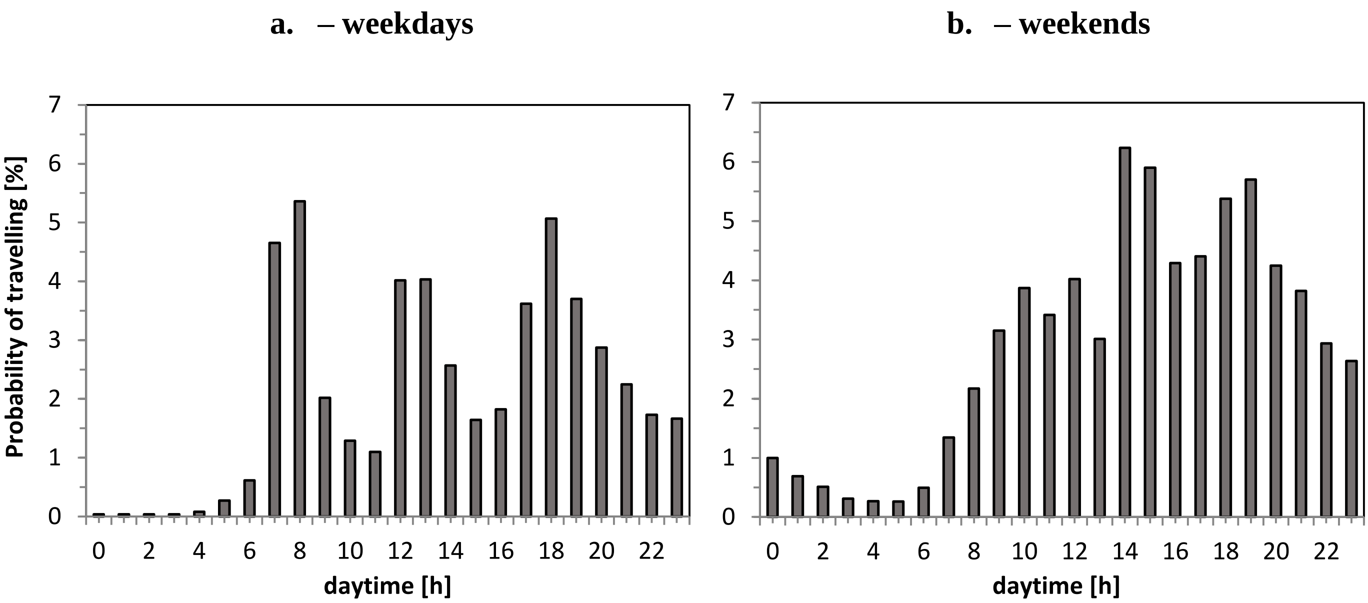

Fig. 2. Probability distribution used to define the EV daily journeys [78]

4.2.3.2. Battery draining

A higher probability of a car being travelling at a certain time means that more cars are travelling at that time and, accordingly, a corresponding higher drain from the batteries is occurring. In other words, battery draining from V2G at *i* hour ($\left(t_{V2G}\right)_i$) is proportional to the probability of travelling at the same hour and can be calculated by [56]:

$$\left(t_{V2G}\right)_i = \left(D_{V2G} \times \frac{\left(\delta_{V2G}\right)_i}{\sum_{1}^{3784} \delta_{V2G}} \right) \times \eta \qquad (1)$$

In Eq. (1), D_{V2G} is the annual transport demand of V2G cars, $\left(\delta_{V2G}\right)_i$ is the transport demand at hour *i* (given by the probability of traveling) and η is the grid-to-battery efficiency (see Table 6). The weekly battery-to-wheel demand for the Central EV scenario obtained from applying the equation is shown in Fig. 3.

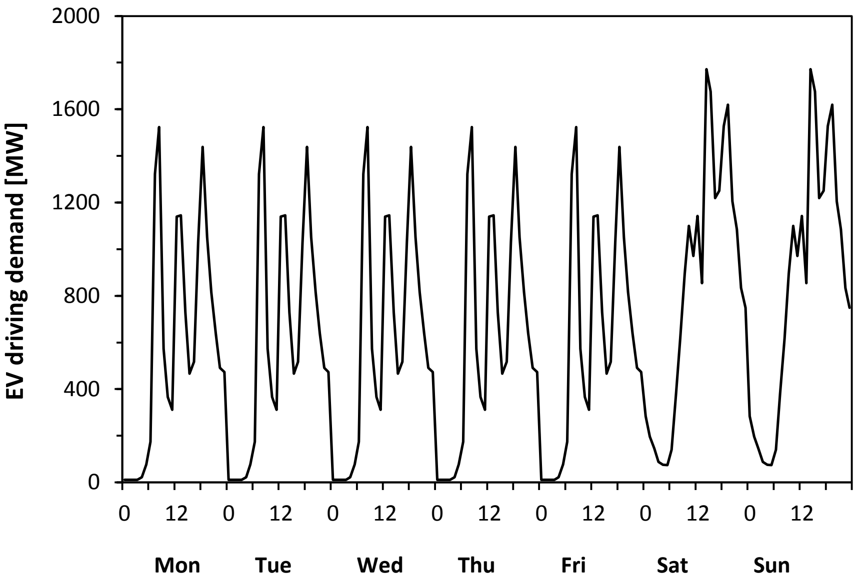

Fig. 3. Weekly EV battery-to-wheel demand for the EV Central scenario

4.2.3.3. V2G connection

The V2G connection capacity at *i* hour ($\left(C_{V2G}\right)_i$) of the total V2G fleet is calculated by the model applying Eq. (2), where *C* is the maximum charging power of the entire V2G fleet, $V2G_{\mathrm{C}}$ is the share of the parked fleet that is connected to the grid and $V2G_{\mathrm{Max}}$ is the maximum share of cars driving during rush hour.

$$\left(C_{V2G}\right)_i = C \times V2G_{\mathrm{C}} \times \left[\left(1 - V2G_{\mathrm{Max}}\right) + V2G_{\mathrm{Max}} \times \left(1 - \frac{\left(\delta_{V2G}\right)_i}{Max\left(\delta_{V2G}\right)}\right)\right]$$

In the expression there are three factors: the first factor represents the power capacity of the entire V2G fleet; the second factor is the share of grid connected V2G fleet, in order to determine the maximum available capacity, which is not time dependent; the third factor, between brackets, calculates the share of V2G fleet on the road at *i* hour and is the sum of two terms: the first term represents the minimum fraction of parked vehicles and the second term the additional fraction of vehicles parked during non-rush hours [56]. The relevant parameters for the calculation are given in Table 5 and Table 6. Fig. 4 shows the EV weekly V2G available connection capacity for the Central EV scenario.

For this scenario the capacity for V2G ranges between 5310 MW and 6629 MW, averaging 6112 MW.

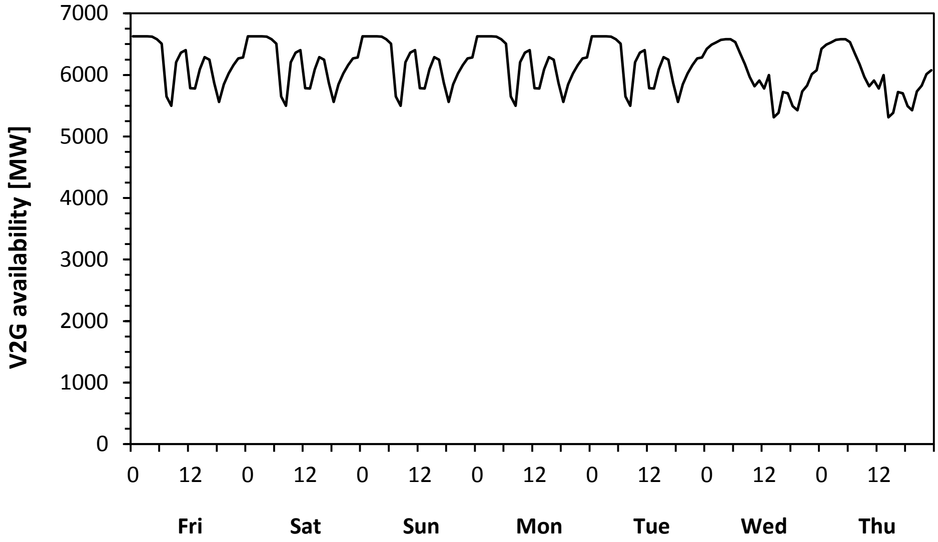

Fig. 4. Weekly V2G connection available for the Central EV scenario

4.3. PV and vehicle scenarios combined

Considering the previously discussed different PV and EV penetration scenarios, there are fifteen possible arrangements constituting the set of electricity-transport realities simulated for this work, as shown in Table 7. For an easy identification of each scenario, nomenclature is using two letters, the first referring to the PV scenario and the second referring to the EV scenario. The correspondence is: 0 for 0%, L for Low, C for Central, H for High and 100 for 100%. For example, LC scenario is the combination between the Low PV and the Central EV scenarios.

Table 7 Arrangements between PV and EV scenarios

		L0	LL	LC	LH	L100	C0	CL	CC	CH	C100	H0	HL	HC	HH	H100
	Low	✓	✓	✓	✓	✓										
Solar PV	**Central**						✓	✓	✓	✓	✓					
	High											✓	✓	✓	✓	✓
	0%	✓					✓					✓				
	Low		✓					✓					✓			
EV	**Central**			✓					✓					✓		
	High				✓					✓					✓	
	100%					✓					✓					✓

5. Results

The evaluation of the different scenarios is based on a set of relevant parameters, such as RES shares, CO2 emissions and EEP in the system. In particular, the amount of EEP is an important parameter for power grid planning, construction, operation management, dispatching and CO2 emissions reduction [18]. It can be totally absorbed by hydroelectric pumping, provided there is enough pump capacity and storage available, and used at a more convenient time. If there is not, the remainder is used to EV smart charging. If it is totally consumed, there is no Critical Excess of Electricity Production (CEEP), otherwise the excess becomes CEEP. Quantifying it and find possible strategies to reduce it or utilize it is critical for the energy system optimization [18].

Unless otherwise stated, the CO_2 emissions and primary energy results concerns the electricity system and the passenger vehicles sector together while RES share concerns only the electricity system.

5.1. V2G charging profile

An insightful result is the one shown in Fig. 5, where the annual daily average profiles of the EV charging, PV production, total non dispatchable production and the non-smart day charging tested in [1] are sketched. The figure was obtained averaging and normalizing the hourly outputs of the model for the entire year, respecting to the CC scenario. The good correspondence between the PV production and the total non dispatchable sources was expected, since the former represents 44% of the latter. More interesting is to note the good correspondence between the EV smart charging and the PV production profiles. It should be stressed out that the model algorithm optimizes the EV charging according to the premises previously described in the model functioning (Section 3), i.e., in order to reduce CEEP and GHG emissions. That is, in the absence of a pre-determined EV charging pattern, the model adjusts the EV charging to a pattern very similar to the PV production and, by inherence, to the non-flexible day charging profile considered in [1], reinforcing the conclusion that most of the electric vehicle charging will have to take place during working hours. Table 8 presents the correlation factors between the series.

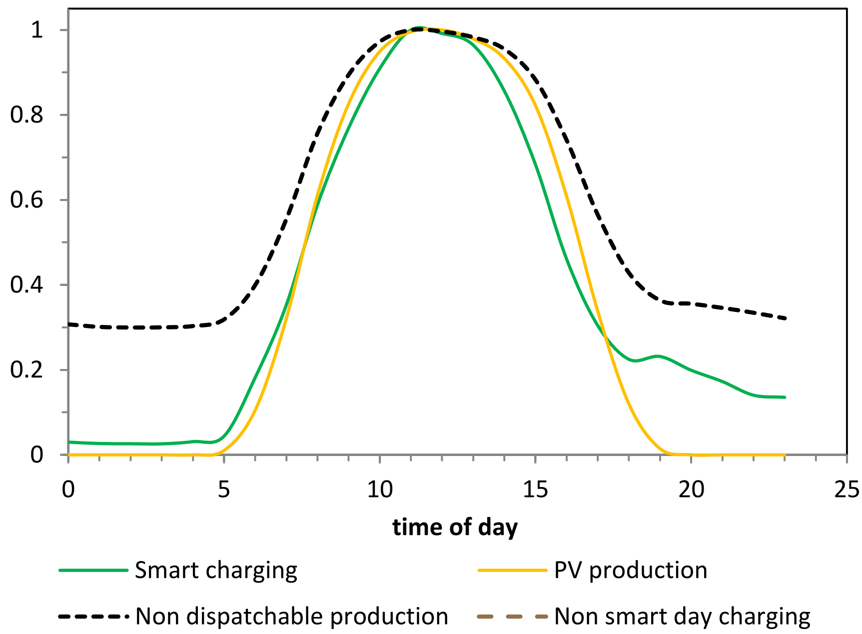

Fig. 5. Normalized annual daily average profiles in the CC scenario of EV charge, PV generation and total non dispatchable generation

Table 8 Correlations factors between the profiles shown in Fig. 5

Grid-to-battery – PV production	0.981
PV production – Non dispatchable sources	0.998
Grid-to-battery – Non dispatchable sources	0.986
Smart charging – Day charging	0.968

5.2. Impacts of different EV market shares

To have a first insight on the effects of the different EV scenarios on the power grid, the daily profiles of power demand and production for different EV market uptakes are shown in Fig. 6. It concerns the High PV scenario, the one with the most potential to produce energy surplus, and the results were obtained averaging the hourly outputs of the model for the whole year. One can see that the CEEP is drastically reduced with increasing transport electrification. The total power production and its shape do not change significantly with increased transport electrification, meaning that the introduction of EV on the network, on an aggregated base analysis, does not imply major changes in the average load diagram and that the increasing electricity demand of higher shares of EV can be mostly fulfilled with the anyway produced electricity. Table 9 presents the average and peak CEEP for each of the EV scenarios, where it can be seen that between the 0% and the 100% EV scenarios the average power in surplus is reduced around sixteen fold. Results from an additional scenario, HC', corresponding to the HC scenario tested with the non-smart day charging shown in Fig. 5, is included. Comparing HC with HC', one can see that the smart charging more than halves the average CEEP.

Also interesting is to note that between the H0 and the HL scenarios, despite the additional demand from the EVs, the total energy production during midday is slight reduced (around 5%), due to the transference of stabilization share from thermal units to V2G.

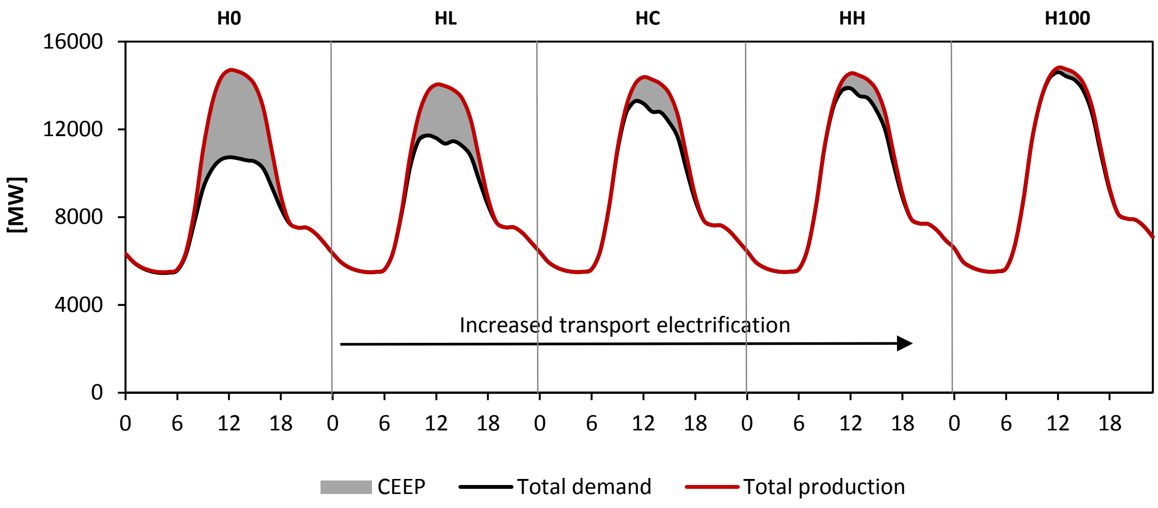

Fig. 6 Daily average power demand and production profiles for the whole year for different EV scenarios combined with the High PV scenario

Table 9 Average unusable power for different mobility scenarios

	H0	**HL**	**HC**	**HH**	**H100**	**HC'**
			MW			
average daily CEEP	1227	682	346	224	77	722
average peak CEEP	3963	2627	1463	933	336	2341

Fig. 7, obtained based on simulations of each of the EV scenarios combined with each of the PV scenarios, shows the CEEP reducing with EV market uptake for the different PV scenarios. The lines are steeper for higher PV penetrations, meaning that the marginal positive effects of the EV penetration on the CEEP are higher for higher solar PV capacity installed. The flatter lines toward the right show the EV growth diminishing returns on CEEP avoidance. Finally, it can be seen that in the Low PV and Central PV scenarios a 0% CEEP is reached with around 30% and 65% of EV market share, respectively.

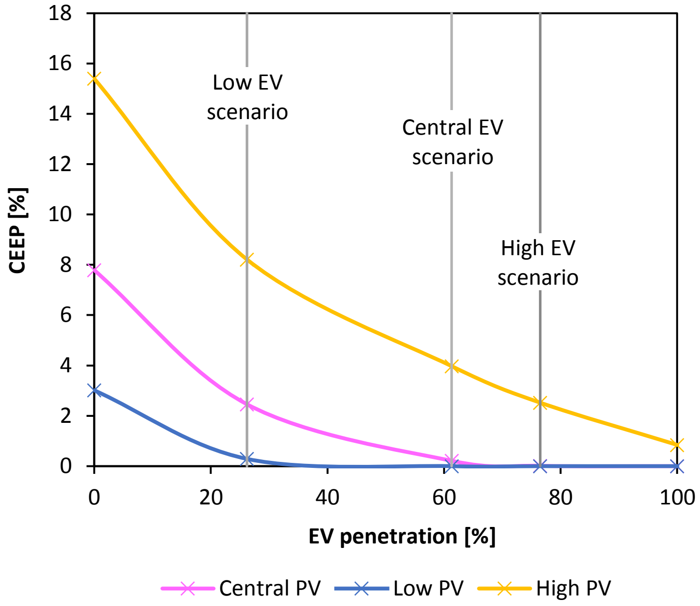

Fig. 7 Relative CEEP as function of EV market share for the different PV scenarios

Fig. 8, obtained as Fig. 7, illustrates how reductions in CO_2 emissions evolves with increasing EV penetration for the three PV scenarios. The green band between the 80 and 95% CO_2 reductions represents the EU 2050 target [3]. Because higher shares of EV imply less ICE vehicles and allow for more use of solar PV energy, increasing the RES share in the electricity mix, the CO_2 reductions are higher with higher EV shares. The height of the gap between curves increases to the right, meaning that the marginal benefit of additional EV market share is higher for higher PV scenarios. One can see that in the High PV scenario the EU goal can only be reached with at least circa 41% of EV market share. To reach it in the Low PV and Central PV scenarios it is needed around 84% and 50% of EV market, respectively. Noteworthy is to compare the High PV scenario with the Central PV scenario: it is seen that for low EV penetration the former does not lead to further CO_2 reductions in comparison with the latter, which is because the additional solar energy produced in the High PV scenario is wasted up until around 32% of EV penetration.

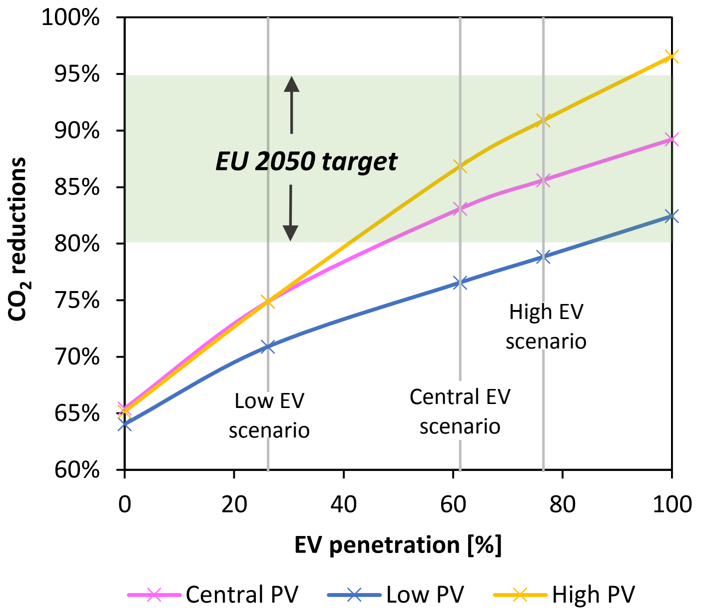

Fig. 8 CO_2 reductions attained (reference: 1990) in the PV scenarios as function of EV market share

5.3. Arrangements between PV and EV scenarios

Fig. 9 identifies the arrangements between PV and EV deployments that leads to 80% reductions in CO_2 emissions and no CEEP (defined as less than 0.01 TWh/year). The mobility has as basis the EV Central scenario, from which the EV penetration is changed maintaining constant the ratio between diesel and gasoline ICE vehicles and between PEVs and PHEVs. Several of mobility cases are simulated with several PV penetrations in order to identify the arrangements plotted.

To reach 80% reductions in CO_2 it is worth to note that: (1) with extreme PV penetration levels, higher than the High PV scenario, the minimum 41% EV market share is maintained. With this EV level it should be installed around 15 GW of PV; (2) with 100% EV market share a minimum of 9.1 GW of solar PV is required (it corresponds to a PV share in the electricity mix of 19.9%). In order to not have CEEP it is noteworthy that: (1) a PV penetration level of 14.7 GW is the maximum allowed in the system, requiring an EV market share of 100%; (2) a minimum share of 2% of EV is always needed, even in the absence of PV penetration. This is because the EVs DSM is used to very accurately absorb existing EEP. Finally, it is noteworthy the triangle shaped zone where the two conditions are met, whose lower vertex corresponds to penetrations of 61% of EV and 15 GW of PV.

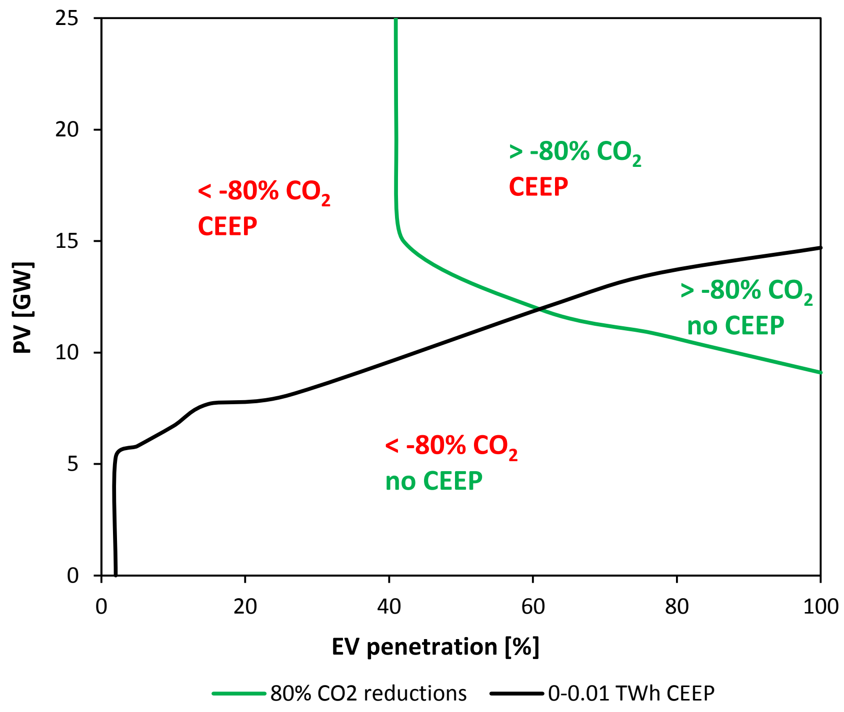

Fig. 9 Arrangements between EV market share and PV capacity that lead to 80% reductions in CO_2 and to 0-0.01 TWh/year of CEEP (~0% CEEP)

Fig. 10 presents a summary of the results concerning the most relevant parameters analyzed. One can see that a 100% RES based primary energy supply (PES) is not attainable (the highest reduction is of 95.0% for the H100 scenario), and, consequently, a 100% of CO_2 emissions reductions is also non attainable (the highest reduction is of 96.6% for the same scenario). On the other hand, there are scenarios that lead to very high shares of RES on the electricity mix[13], including 100% covering (scenarios CL, HL and HC), though they imply CEEP, in line with [79]. In fact, they are complementary to the 0% CEEP scenarios. The maximum PV share in the electricity mix is around 34%, which is for the scenarios with simultaneously higher PV and EV penetrations. This is in accordance with [80] and with [81], which found that high PV contributions in a traditional power system would require enabling technologies, such as EV smart charging. As expected, the scenarios with the maximum CO_2 reductions are the ones

[13] Very high shares of RES on the electricity mix occurs with less EV market uptake since the RES weight is higher with lower overall electricity demand

with the higher EV market uptake, the same ones with higher levels of RES share on PES.

RES electricity share [%]

EV	0%	Low	Central	High	100%
High PV	99.3	100.0	100.0	99.1	97.4
Central PV	99.5	100.0	96.9	94.9	91.7
Low PV	98.2	96.4	91.3	89.1	86.0

RES share on PES [%]

EV	0%	Low	Central	High	100%
High PV	70.9	76.8	86.7	90.1	95.0
Central PV	69.6	75.9	81.5	82.9	84.8
Low PV	67.2	71.1	73.7	74.7	76.3

CO2 reductions [%]

EV	0%	Low	Central	High	100%
High PV	65.1	74.8	86.8	90.9	96.6
Central PV	65.4	74.8	83.1	85.6	89.2
Low PV	64.0	70.9	76.5	78.8	82.4

CEEP [%]

EV	0%	Low	Central	High	100%
High PV	15.4	8.6	4.3	2.8	1.0
Central PV	7.8	2.6	0.2	0.0	0.0
Low PV	3.0	0.3	0.0	0.0	0.0

PV share on electricity mix [%]

EV	0%	Low	Central	High	100%
High PV	31.1	33.3	34.0	34.1	34.0
Central PV	28.6	30.0	29.6	29.0	28.0
Low PV	25.0	25.0	23.7	23.2	22.4

PV used [%]

EV	0%	Low	Central	High	100%
High PV	77.1	86.2	93.0	95.5	98.4
Central PV	87.3	95.6	99.6	100	100
Low PV	95.2	99.5	100	100	100

Fig. 10. RES share in the electricity mix, RES share in the primary energy supply, CO_2 reductions, CEEP, PV share in the electricity mix and PV energy used for the scenarios arrangements

6. Conclusions

The future of the European power networks will heavily rely on renewable energy to comply with the climate-energy targets. In this context, installation of storage will likely be required to balance the fluctuations of power production. This study addressed the research question of to what extent the electric mobility, with its large battery capacity, may enable this transition. Since solar PV is seen as the future dominant source of electricity, this work focused on how transport electrification using a smart charging strategy can further solar electricity integration and vice-versa.

The required penetration of one technology which enables the deployment of the other was determined, analyzing parameters such as existing critical excess of energy, CO_2 emissions and allowed renewable energy penetration. The results obtained are for the electric system and passenger vehicles in Portugal 2050 scenarios and therefore any generalizations require caution. Nevertheless, it is expected that it qualitatively represents similar energy systems.

It was found that increasing levels of EV market share always lead to a reduction in the energy excess. To achieve 0% energy excess, even without any PV penetration, a minimum level of EV market share using smart charging to consume the surplus of energy is required (2% of EV share for the particular case study of Portugal 2050). It is also shown that CO_2 reductions are higher with higher EV shares and that the EU 2050 target to reduce emissions in 80% can only be reached with significant EV market share and PV capacity (respectively 40% and 15 GW for Portugal 2050). The same objective may be reached with a 100% EV fleet coupled with significantly less solar PV (9.1 GW of PV in Portugal 2050). In order to simultaneously reach the EU 2050 target and not produce energy excess, additional EV deployment is required (61% EV share and 15 GW for PV in Portugal 2050).

A 100% RES based electricity supply is possible with certain EV and PV combinations, even though they all imply excess of energy. With simultaneous high levels of EV and PV, the allowable PV share in the electricity mix is around a third. The good correspondence between the EV smart charging and the PV production profiles reinforces the conclusion that most of the electric vehicle charging will have to take place during working hours to maximize petroleum displacement.

The methodology presented in this study is generalizable and applicable to other situations. Thus, it would be of interest, and left as a suggestion for future work, to extend it to other energy systems and other contexts, in order to have an insight on how the results would fit other realities.

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Article II

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Day charging electric vehicles with excess solar electricity for a sustainable energy system

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ABSTRACT

In order to reach significant CO_2 emissions reductions, future energy systems will require a large share of renewable energies, such as wind and solar photovoltaic power. However, relying on such renewable energy sources is expected to generate considerable excess power during certain periods of the day, in particular during night time for wind and daytime for solar power. This excess power may be conveniently used to power electric mobility. This paper explores the possible complementarities between wind and solar power and electric vehicles charging, based on 2050 scenarios for the case study of Portugal. Model results show that CO_2 emissions targets can only be achieved with high levels of photovoltaics penetration and electric vehicles, reinforcing the need for daytime charging infrastructures, presumably at or near work facilities.

1. Introduction

The challenges for future sustainable energy systems will have to address the limits to climate change [1] and therefore GHG (greenhouse gases) emissions reduction targets, as those set, for example, by the EU (European Union) for 2050 [2]. In order to comply with these ambitious targets, energy systems will have to strongly rely on RES (renewable energy sources). The particular optimum portfolio of renewable energy sources will depend on the geographical region and local climate conditions, but in most places will surely include solar PV (photovoltaic), wind, hydroelectric and biomass. A large penetration of RES in the electricity system will introduce new challenges mainly associated to its variability and limited flexibility (i.e., their limited ability to balance rapid changes in renewable generation and demand by adjusting their output).

On the other hand, the transport sector is responsible for a significant share of energy demand, typically about a third of final energy demand, and a relevant source of GHG emissions, about a fourth of total emissions [3]. To change this paradigm, the EV (electric vehicle), being more energy efficient than the ICE (internal combustion engine) vehicle and having the possibility to be fueled by renewable electricity, is expected to play a major role in future mobility systems. The widespread deployment of EVs will also introduce new challenges, including higher electricity demand and significant changes to the load diagram. Conversely, EV batteries may work as a large scale energy storage, required to absorb excess energy peaking on a RES dominant energy grid [4,5].

The purpose of this work is to explore the synergies and conflicts between the large penetration of renewable energy sources, with particular emphasis on solar photovoltaic and wind power, and the widespread deployment of electric vehicles in future sustainable energy systems.

Future energy scenarios for Portugal in 2050 are used as case study. This country is particularly suitable to test the interaction between renewable energy sources and electric vehicles since it has significant solar, hydro and wind power potentials (although the former is mostly untapped) [6–8] and may be considered to be on the forefront in the promotion of the EV, with an ambitious electric mobility program which includes an already deployed public recharging infrastructure [9].

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2. Methodology

2.1. Energy systems modeling

For the simulation of the Portuguese electricity and transport systems and integration of electricity sources, different simulation tools were considered and, in the end, EnergyPLAN [10] was chosen. For a comprehensive review of energy systems modeling tools, see Ref. [11]. EnergyPLAN is a validated deterministic computer model designed for energy systems analysis that optimizes the operation of a given energy system on the basis of inputs and outputs defined by the user. The reasons behind the choice are: (1) the objective of this research is to investigate the ability of PV and EVs to facilitate the large-scale integration into a country level electricity system of each other, and EnergyPLAN is a simulation model at regional and national levels including the major primary sectors of an energy system, namely electricity and transport; (2) it was required an instrument with a temporal fine analysis capability, instead of an aggregated annual demand and production analysis, and EnergyPLAN, being an hourly simulation computer tool, satisfies that condition, making it suitable to model the sun power integration (and power from other renewables), considering its variability; (3) ample previous research about integration of fluctuating renewable energy resources has been carried out by using this tool, such as [12–14]. These features indicate that EnergyPLAN is appropriate to this study.

The transport analysis was constrained to the light passenger vehicles, i.e., it excludes buses and trains. This is the segment where EVs have the most market potential. In order to ensure the model is simulating the Portuguese energy system correctly, a reference model was created and validated representing the year 2011. The model approach is schematized in Fig. 1 and in the following sections more details are provided.

To understand how PV impacts on the system, the shape of the daily and inter-seasonal load profiles are of great importance. On the course of decades, they can change due to alterations in the climate, society, technology, policy and regulation, etc., being these hard to predict. For the sake of the simplicity in this work, we did not model different load profiles.

In our analyses we do not consider possible transmission constraints, in part because some of the PV generation is used at or close to the generation point and partly because we consider that the TSO (transmission system operator) assures the deployment of the transmission capacity needed in the future, with some of that already in project [15]. It should also be noted that transmission and distribution (T&D) power losses are already reflected on the network energy figures. A PV system generating at the load site would offset the losses associated with delivering electricity, meaning that, in a future with a significant share of PV, energy T&D losses are expected to be lower. Conservatively, in the scenarios we assume that losses are the same as in the present. It ought to be stressed that to plan at high levels of penetration of solar PV it will

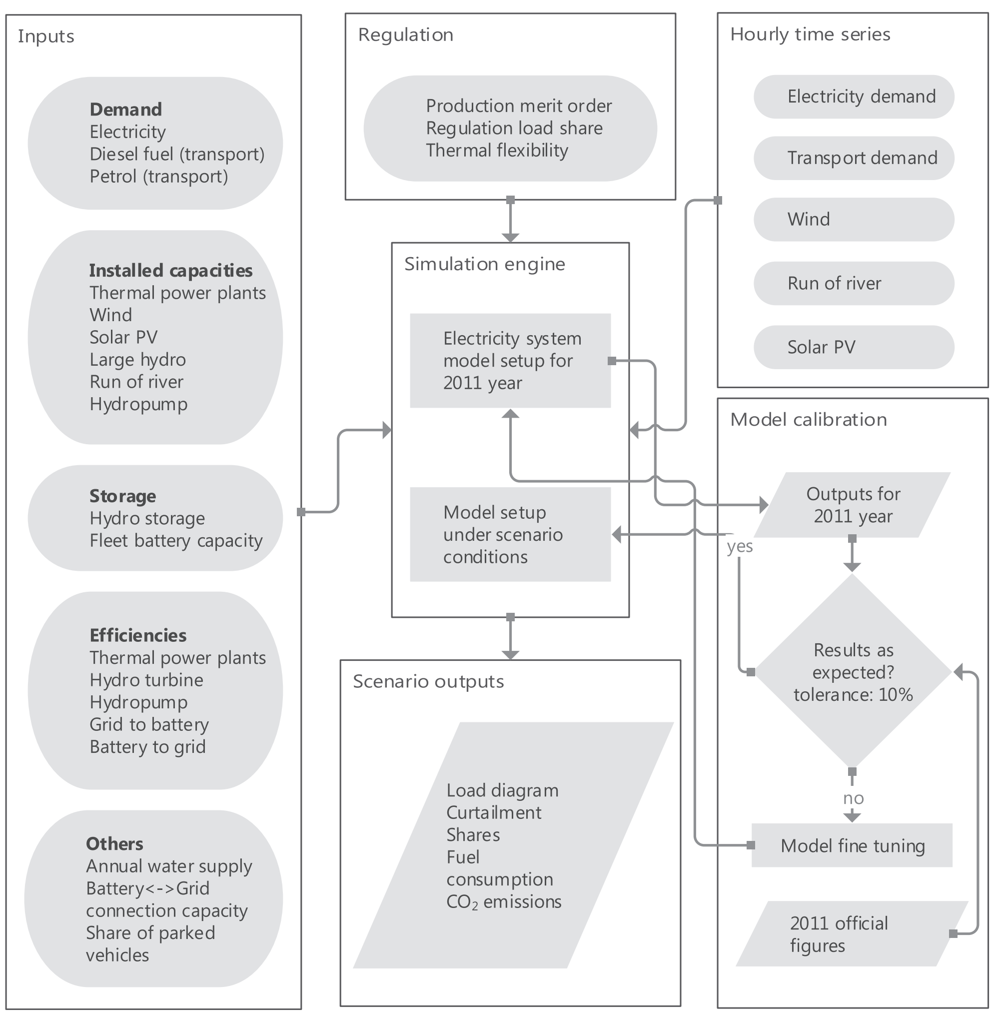

Fig. 1. Model approach.

be important to perform detailed load flow analysis quantifying the T&D loss offsets as well as the possible T&D constraints and the ability of the utility to handle the aggregated power flows from thousands of individual small generators [16].

In particular, significant penetration on the electrical systems of non dispatchable RES, i.e., PV and wind, and EVs raises concerns to operators of the transmission and distribution systems related to the power quality. In fact, when planning for these scenarios, severe threats such as frequency and voltage fluctuations, voltage drop (related to power reactive flows), harmonic distortion and power factor reduction can arise and must be addressed [17]. Several studies in this field have been conducted, such as [17–24], with conflicting findings on the effect of EVs on the distribution networks [25]. Generally, however, it has been observed that EVs, if managed properly, can provide ancillary services to the grid such as frequency and voltage regulation, peak shaving and reactive power support to enhance the operational efficiency, secure the electric grid and reduce power system operating costs [26]. That is, EV may act as solution for the problems posed by high RES penetration, given that they have a storage capability that can be used to help managing the network in extreme conditions. From a technical level, the EV batteries together with power electronic interfaces capable of answering very fast to frequency deviations in small increments and in a distributed manner can contribute to improve the global system dynamic behavior [27,28]. But clear and adequate formulation of grid codes is indispensable to guarantee a smooth integration of RES and EVs into the electrical systems [21] along with careful and consistent long term planning and implementation of integration strategies [18].

It should also be stressed out that our model in EnergyPLAN corresponds to an aggregate computation with a one hour resolution. Therefore, it does not account for the shorter term dynamic of the electrical system, in the range of seconds, which means that parameters such as frequency stability are not computed. Hourly simulation by itself thus provides insufficient criteria to ensure the feasibility of an energy scenario, hence should be coupled with dynamic simulations. Pillai et al. [29] points out that there are discrepancies between the two types of simulations, especially when applied to small regions. At a nation size systems, the differences are reduced by the smoothing effect of the sum of numerous and geographically spread sources of RES. If EVs can provide short term power balancing, the differences are further reduced, which again suggests that EVs may have an important role in energy systems scenarios, due to their fast response in comparison to conventional generators. Still, dynamic simulations are important to ensure stable power system operations and control and justify the technical feasibility of hourly simulations [29].

2.2. Model calibration

Calibration to a past period is an iterative process of adjustments whose goal is to obtain simulation predicted outputs that are similar to the corresponding registered parameters, thus validating the model. For this purpose, the year 2011 served as a reference, as it is the most recent year with the detailed technical data needed available from REN (Rede Eléctrica Nacional), the TSO, and DGEG (Direcção-Geral de Energia e Geologia), the national energy authority. The main variables to be calibrated are: electricity demand, electricity production by source, RES share, primary fuel consumption, monthly average power and CO_2 emissions. The results obtained are shown in Table 1. The average of the module of the individual annual differences presented is 0.36%.

Fig. 2 presents the monthly evolution along the year of the real and simulated average power demand, being the average of the module of the differences 0.29%. As for the registered import/export balance in 2011, i.e., the imports minus the exports, it was 2051 GWh, while the model outputted 2180 GWh, i.e., +6.3%. This difference is mainly explained by the strategic behavior of the electricity players in the MIBEL (Iberian electricity market), which is not entirely captured by the technical optimization of the EnergyPLAN [30]. This type of optimization was chosen as opposed to a market economic optimization for two reasons: (1) because from a techno-economic viewpoint it is desirable that electricity production is consumed locally, not incurring this way in losses and costs due to transportation over long distances and (2) there's a special great uncertainty in market behavior modeling in an horizon of about 35 years from now. For these reasons, in our model imports just take place when technically it is not possible to supply the demand with endogenous production and, similarly, exports just take place when it is not possible to absorb endogenously all the energy produced. Since the main purpose of the study is to compare and analyze the technical feasibility and impacts on the grid of mass deployments of EV and solar PV, the model is considered valid and the reference year formed the basis for the study of the projected scenario presented in the next sections.

Table 1
Model calibration results.

	2011 figures [31–33]	2011 simulation	Difference to reference (%)
Final energy	**GWh**		
Electricity demand	50,503	50,630	+0.3
Electricity production			
Thermal PP	27,336	27,300	−0.1
Large hydro	4213	4210	−0.1
Run of river	7638	7650	+0.2
Wind	9003	9030	+0.3
PV	262	260	−0.8
RES electricity share	46.0%	45.4%	−1.3
Primary fuel	**Mtoe**		
Natural gas	2.870	2.862	−0.3
Coal	2.201	2.194	−0.3
Oil	0.249	0.248	−0.5
Biomass	0.380	0.379	−0.2
Diesel	4.013	4.013	0.0
Gasoline	1.319	1.319	0.0
CO_2 emissions	**Mt**		
Electricity sector	16.36	16.31	−0.3
Transport sector (passenger + LDV fleets)	15.65	15.78	+0.8

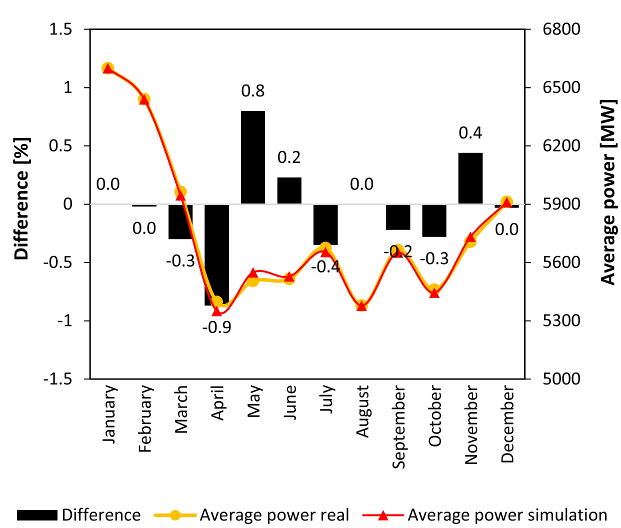

Fig. 2. Monthly basis real and simulated average power demand for 2011.

3. 2050 scenarios

Scenarios are essential to describe possible development paths, to provide to decision-makers a broad overview and show how far they can shape the future mobility and electricity systems. To study the impacts of the synergies and conflicts between solar PV and EV deployments, a 2050 scenario was conceived and simulated. It is built upon long term EU objectives for the climate-energy area and upon different reference scenarios presented in the literature, some of these derived from partial equilibrium technical-economic models of the evolution of the energy systems over a defined time horizon, such as MARKAL/TIMES [34].

Data temporal extrapolation was applied for the scenarios with a time horizon shorter than 2050. The criteria for choosing the considered scenarios were: (1) European Union or, preferably, Portugal scope; (2) scenarios built 2009 onwards, in order to reflect the effects of the financial crisis that started in 2008 and lead the EU and particularly Portugal to an economic downturn; (3) scenarios or objectives that met the above criteria but comprise future conditions that have already been achieved in Portugal were discarded.

The path of a new technology market uptake and the forecast of stock of vehicles or the prospective sales of new products are modeled using univariate time series sigmoid growth curves, referred as S-shaped curves. The curve follows this shape since the initial growth is often very slow (e.g. a new technology replacing a mature one), followed by rapid exponential growth when barriers to adoption relax and then falls off as the market saturation is approached [35,36]. The selection of an appropriate type of S-curve is important and the choice between a set of models considered was made using criteria based on forecasting errors and on the

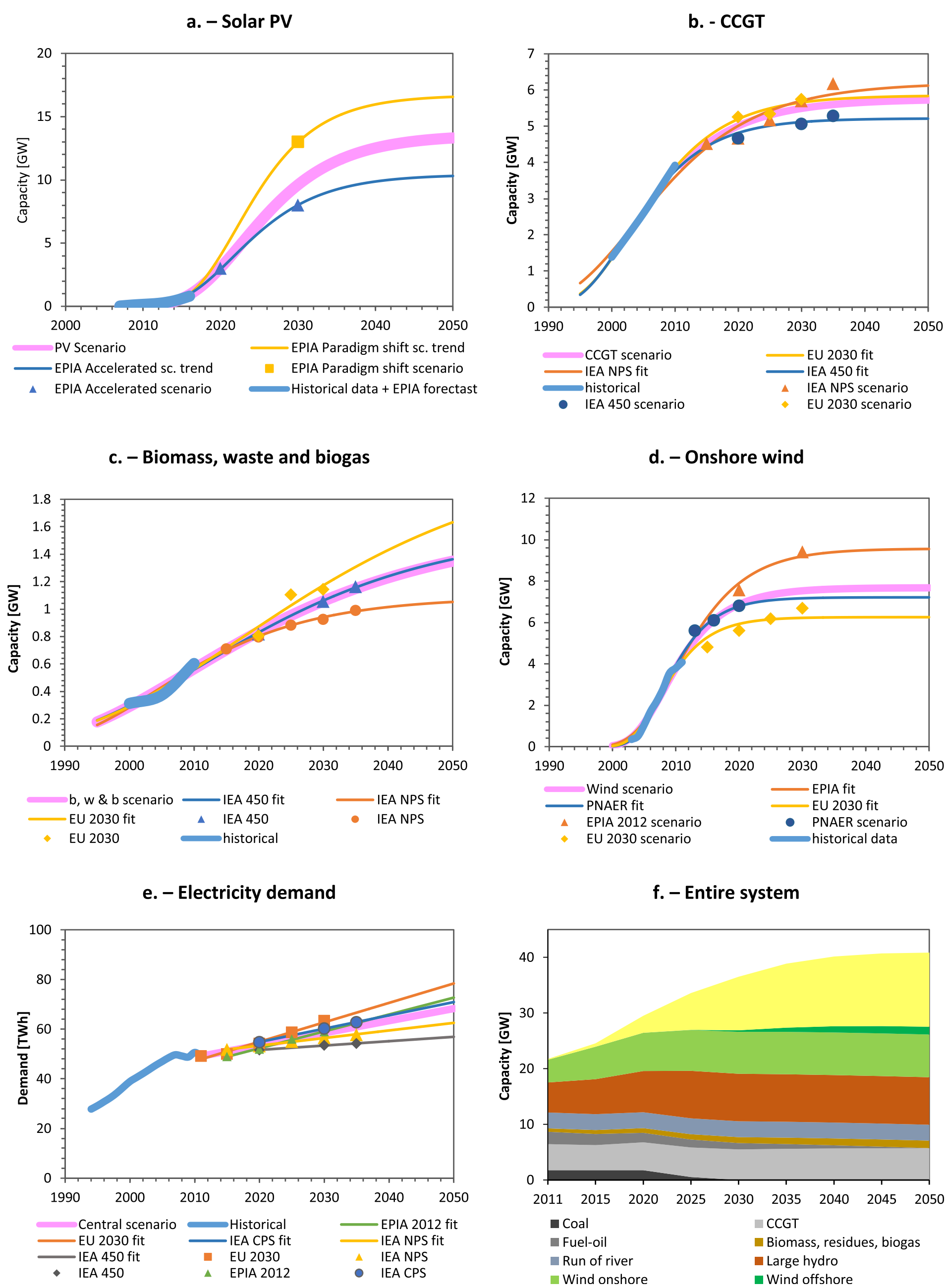

Fig. 3. Modeled evolution of the installed capacities according to source and for the entire electric system [38,40,41,44].

plausibility of the estimated saturation levels. The best fitting results to the real data were obtained with the following Gompertz function:

$$y = a\exp(-\exp(-k(x - x_c))) \tag{1}$$

where a, k and x_c are unknown positive-valued numbers and a representing the saturation level. It produces a curve with an inflection point, i.e., where the rate of growth stops to increase and start to diminish, occurring before half the saturation is reached.

3.1. Electricity system

3.1.1. Solar PV scenario

The EPIA (European Photovoltaic Industry Association) has found that, in a business as usual scenario, a share in the range of 7%–11% of PV in European electricity by 2030 is realistic [37]. With policy incentives, it increases to 10%–15% [38], and in a paradigm shift scenario, where all barriers are lifted and specific boundary conditions are met, it is foreseen that PV can have a penetration of 25% by 2030 [38]. Building on these trends, their average constitute the solar PV deployment level in Portugal by 2050 considered for this work (Fig. 3a). It corresponds to an installed capacity of 13,316 MW which translates into a share of PV in the energy mix of 29.3%.

3.1.2. Other assumptions

Several projections about the utility system were made for the scenario. These are briefly discussed in this section.

Natural gas is viewed by some as a bridging energy to a sustainable energy future [39], and even in future scenarios that foreseen a high share of RES it is expected to grow in the following decades, mainly because NG (natural gas) can substitute coal with technical and environmental advantages. In Portugal, the evolution until 2050 of the installed capacity of natural gas power plants, based on CCGT (combined cycle gas turbines), is derived from Refs. [40,41] and is depicted by the thickest line in Fig. 3b. It constitutes a 22% increment in capacity, from 4687 MW to 5723 MW.

Taking in consideration the expected marked decline in coal electricity generation in the EU, no electricity generated by coal was considered [42]. In Portugal, due to mandatory compliance with environmental legislation, it is foreseen as plausible the decommissioning until 2022 of the Sines power plant, which operates since 1985 and is the biggest coal fired power plant in Portugal, representing most of the total coal fired installed generation capacity in the country (~70%). In this work it is assumed that the rest of this capacity will also be decommissioned until 2050, and gradually substituted with CCGT type power plants.

Table 2
Modeled installed capacities in 2011 and 2050.

	2011	2050	References
	MW		
Production installed capacity	18,902	37,997	
Thermal	9274	7071	
CCGT	4687	5723	[31,40,41]
Coal	1756	–	[15,31]
Fuel–oil	2228	–	[31]
Biomass, urban residues, waste	603	1348	[31,40,41]
Wind onshore	4081	7674	[31,38,40,53]
Wind offshore	–	1400	[46]
Solar PV	155	13316	[31,38,54]
Hydro	5392	8536	
Large hydro	2537	5681	[53,55]
Run of river	2855	2855	[31,53]
Hydropump	1020	4004	[53,55]

Although the present capacity of fuel–oil fired based power plants is significant (see Table 2), these plants are seldom operated, and fuel–oil based electricity production in Portugal in 2011 was very small (<2%) [33]. We have also assumed that the total decommissioning of this type of generation until 2050, with its role in the system assumed by CCGT technology, which is cleaner and less carbon intensive.

Besides natural gas, our scenario considers that thermal generation in 2050 is provided by biomass, urban solid residues (waste) and biogas type power plants. The projected evolution of these together is derived from Refs. [40,41] and is shown by the thickest line in Fig. 3c. It is 124% increment in capacity, from 603 MW to 1348 MW. Overall, thermal capacity is reduced 24%, and fossil fuel based power-plants diminishes 34%.

As for hydro, all the new large hydro capacity determined by the *Programa Nacional de Barragens com Elevado Potencial Hidroeléctrico* [7] is considered fully implemented in 2050, including its pumping capacity. This represents a growth in the installed capacity from 5392 MW to 8536 MW. Hydropump capacity almost quadruplicates from 1020 MW to 4004 MW, justified by the need to absorb wind energy in excess during the night. We did not consider additional installed hydro capacity, since the potential is considered to be virtually depleted in 2030 [43].

Concerning wind energy, Portugal has seen notable deployment of onshore wind power capacity that currently puts it in the top list of countries with both high growing rate and accumulated capacity. This is illustrated by the line corresponding to the historical penetration in Fig. 3d, showing an installation of about 4 GW of wind in a period of about ten years. The projected evolution, that corresponds to the average of three scenarios [38,40,44], foresees a capacity in 2050 of 7674 MW, an increment of 88%. This evolution is in accordance with the perception that onshore wind potential starts to be depleted from 2020 [43]. The 2011 capacity factor was 0.25 and for 2050 we have adjusted it to 0.29, a 15% increase due to expectable technological improvements [45].

Offshore sustainable potential for Continental Portugal was accessed in 2010 [46] and it was found to be 3500 MW, if one considers the offshore feasibility ensured by a NEP (equivalent annual number of hours at full power) of 2700 h/year or more. If one considers a restrictive scenario where the economic viability requires a NEP of 2900 h/year or more, the off-shore potential is reduced to 1400 MW. Conservatively, we have used the latter for the 2050 scenario, which, including again a 15% improvement due to technological improvements, translates into a capacity factor of 0.38.

In what concerns evolution of overall electricity demand, it is assumed to follow a linear increase, partly due to EV, and it was modeled according to [38,40,41]. It foresees an increment from 50.5 TWh in 2011 to 62.3 TWh in 2050 (Fig. 3e). Our approximation was as if the EV electricity demand is incorporated in this growth.

3.1.2.1. System flexibility. Conventional fossil fuel power plants are restricted in their ability to change generation levels due to technical-operation limits. Furthermore, they incur in significant economic penalties when running under a certain level below the nominal output, due to efficiency losses and increased preventive and corrective maintenance needs when fossil power generators work in part load operations. The comfortable operational range of these power plants define the grid's flexibility, or “flexibility factor”, which, according to [16], is the fraction below the annual peak load until which flexible sources can operate. The flexibility of current systems can be difficult to assess since the minimum load is not technically rigid, but determined by the costs of thermal unit cycling [47]. The flexibility factor can be inferred using Eq. (2), where e_{th} represents the total electricity production from sources with flexibility constraints and i is the annual hourly values, from 1 to 8760.

$$d_{flex} = \frac{MIN\{(e_{th})_1, \ldots, (e_{th})_i, \ldots, (e_{th})_{8760}\}}{MAX\{(e_{th})_1, \ldots, (e_{th})_i, \ldots, (e_{th})_{8760}\}} \times 100 \quad (2)$$

The overall system flexibility is dependent on the energy mix (e.g. grid flexibility is smaller for grids with a high share of fossil fuel fired power) and on the technology used (e.g. coal power plants are less flexible than natural gas fuel fired power plants, and new generation natural gas fuel fired power plants are more flexible than older ones). The relative load level of the aggregation of the existent thermal electric power plants for 2011 year was, on average, 57%, and the minimum load levels of functioning are around 15%. Following Eq. (2), the absolute minimum was found to be on the early morning of a Sunday in January, when the demand was around 50% of the annual peak value and wind was satisfying 61% of that demand. At that hour, thermal power plants were operating at a 730 MW load, which corresponds to a flexibility level of 86.7%, meaning that the thermal Portuguese electric power structure is operated in a rather flexible manner. This is possible because CCGT based power plants dominates the installed thermal electric power capacity that in practice operates (see Section 3.1), with a share of circa 66%, and because coal power plants are constituted by generator groups that can be turned off, albeit not without economic penalties. In fact, the true cost of on/off operations are often not known or not well understood by the TSOs [48]. Although future generations of CCGT based power plant are expected to provide increased levels of flexibility to the system because they offer significant ramp up and ramp down capabilities [49,50], our 2050 model assumes the present flexibility as it is already high.

3.1.2.2. System stabilization share. In order to maintain real-time balance between generation and load, it is necessary that a minimum part of generation comes from load following capable plants, i.e., plants that offer ramp up and ramp down operating reserves. In the Portuguese electric power system these are provided by thermal and large hydro power plants. The minimum grid stabilization demand is calculated as function of *estab*, which represents the electricity production from regulation capable sources, and e_{total}, the total electricity production, according to Eq. (3), where i represents the annual hourly values.

$$d_{stab} = MIN\left\{\left(\frac{e_{stab}}{e_{total}}\right)_1, \ldots, \left(\frac{e_{stab}}{e_{total}}\right)_i, \ldots, \left(\frac{e_{stab}}{e_{total}}\right)_{8760}\right\} \times 100 \quad (3)$$

The load level of the grid stabilization capable power plants aggregate relative to load demand on an hourly basis throughout the year was, on average, 62.4%, with a registered minimum of 18.3%. This is the value used in the EnergyPLAN 2011 model. Correlation between the system flexibility and system stabilization series is 0.868, which means that ~87% of stabilization share is on average provided by thermal power plants.

Higher shares of non-dispatchable generating capacity impose greater needs for the remainder of the power generation capacity to flexibly complement its variable output, and this is not totally obviated by increasingly precise forecast models [51]. With a growing share of RES in an electricity system, the net load (i.e., the RES generation subtracted to the electricity demand) is increasingly volatile in absolute amounts and in frequency and amplitude of changes (ramp rates), requiring an increase of (1) the stabilization share and (2) flexibility levels [51,52]. Electricity systems with high RES penetration overtime tend to incorporate CCGT based power plants as base load supply because they fulfill the two requirements: they offer a technical capability of load following better than other types of power plants, namely coal and nuclear, implying additionally less capital investments than these ones; they provide increased levels of flexibility to the system because they offer significant ramp up and ramp down capabilities [49]. Based on existing IEA (International Energy Agency) and EU projections [40,41], it is expected that dispatch of supply to cover the net demand in 2050 in Portugal will rely in flexible capacity provided by CCGT power plants and in hydraulic power plants with storage. That is, in a way base load power plants will have to be run down to very small part load regimens, or even will have to be completely shut down, in order to avoid significant overcapacities – namely during peak wind and sun periods – but, on the other way, they have to provide for substantial operating reserves available online to cope with the increased load following requirements. In this work we consider that in 2050 these two conditions are expected to have similar but opposite effects and therefore the level of required stabilization share is maintained.

Table 3
Modeled power plants efficiencies and grid flexibility and stabilizations levels.

	2011	2050	References
	%		
Power plants efficiencies			
CCGT	43.0	60	[31,33,56]
Oil fired	44.0	N/A	[31,33]
Coal fired	35.7	N/A	[31,33]
Biomass	20.1	30	[31,33,57]
Hydro plants average efficiency (turbine/pump)	80	80	[58]
Flexibility and stabilization			
Overall thermal power plants flexibility	86.7	86.7	[31]
Minimum grid stabilization share	18.3	18.3	[a]

[a] See Section 3.1.2.2.

3.1.3. Summary

Table 2 summarizes the modeled installed capacities described along this section. The total installed capacity for the electro producer system for 2011 is 18,902 MW and for 2050 it is 37,911 MW, a 100% increase. The evolution of the installed capacity according to source is illustrated in Fig. 3f. Finally, Table 3 gives the summary for the modeled efficiencies, grid flexibility and stabilizations levels of the power plants.

3.2. Mobility

3.2.1. EV market uptake scenario

The passenger car stock evolution until 2050 is the product between the evolutions of the *per capita* passenger car ownership and the population. The first was obtained following [59,60] and is shown in Fig. 4. Since 2008 the passenger car density has seen a pronounced decline from 474 to 406 vehicles/1000 inhabitants due to the already mentioned economic downturn, but the fit to the historical trend since 1975 foresees a recovery from this drop to 484 vehicles/1000 inhabitants by 2050. As in the EU-15, it is expected that passenger car demand in Portugal reaches saturation [61].

If the INE (Instituto Nacional de Estatística) central scenario for the population evolution [62], shown in Fig. 5, is applied to these figures, one can have the passenger car stock evolution, depicted equally in Fig. 5. It departs from a fleet of 4.78 M vehicles in 2013 and reaches 2050 with 4.18 M vehicles, a loss of 13% in the fleet size, which is correlated with the decline in population.

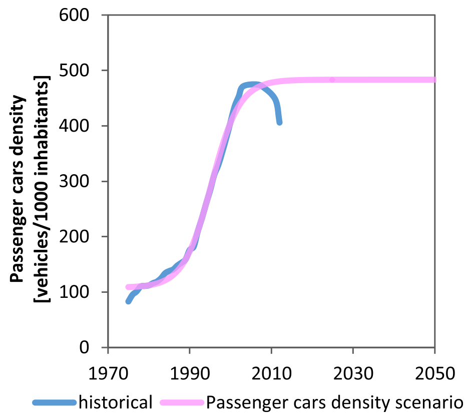

Fig. 4. Modeled passenger cars density evolution until 2050 [59,60].

For 2050, the EU targeted for the transport sector a minimum of 60% reduction of GHG[1] [63], and the IEA has developed a scenario for market uptake of PEV (pure electric vehicle) and PHEV (plug-in hybrid electric vehicle) technologies, called BLUE Map scenario, which reflects an overall target of a 50% reduction in global energy-related CO_2 emissions compared to 2005 levels, to which transport contributes with an emissions reduction of 30% [64]. In our assumptions for EV technology market penetration, we had as basis the IEA BLUE Map scenario for OECD (Organisation for Economic Co-operation and Development) Europe and from it we developed the vehicle scenario for Portugal presented in Fig. 6.

3.2.2. Other assumptions

Present average battery sizes are about 13.0 kWh for PHEV and 26.7 kWh for PEV [65] and it is foreseeable that, due to improvements in existing battery technology and due to introduction of new battery technologies based in new chemistry, e.g. Li–S [66], energy and power densities will be much higher in the future, with a potential for tripling specific energy by 2030 [67]. We have assumed EVs equipped with Li-ion type batteries modeled with doubled energy density while maintaining the weight of batteries installed in each vehicle, thus extending twofold the current driving range, a crucial condition for the successful mass EV technology deployment. Currently, Li-ion technology batteries have an efficiency of 80–95% [68], and we assumed that on average they will operate at the top limit of this range.

PHEVs were modeled as if driving mode is full electric until the total depletion of the battery, with an electrical range of 98 km. This way, PHEVs offer the opportunity to rely more on electricity while retaining the driving range of an ICE vehicle. In the United Kingdom, 97% of trips are estimated to be less than 80 km and, more generally, in Europe, half of the trips are less than 10 km, being 80% less than 25 km [64]. Considering the same patterns for Portugal and that they do not change significantly in the future, this means that the vast majority of the future trips in PHEVs will be made in full electric mode. The model assumes that only 5% of the distance traveled by PHEVs is in ICE mode.

For the ICE fleet modeling, we have started from average present consumption values of 2.56 MJ/km for gasoline cars and 2.52 MJ/km for diesel cars [69] and applied a 20% improvement in efficiency, considering that the power to weight ratio is maintained. This increased efficiency is due to future technological improvements, namely less vehicle weight, less rolling resistance coefficient and more efficient powertrains [70].

[1] Having as reference 1990.

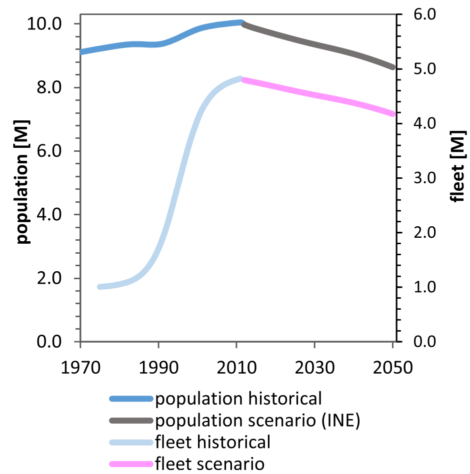

Fig. 5. Population projections [62] and modeled passenger car stock evolutions until 2050.

In 2011 in Portugal, gasoline cars traveled on average 8647 km and diesel cars traveled 23,470 km [69]. In the long run, this difference tends to converge to zero for passenger cars. These is due to two reasons: (1) vehicle's acquisition price of ICE gasoline and diesel cars tends to converge; (2) price in € per MJ of energy content of both fuels tend also to converge, due to aggravation in the diesel fuel taxation [71]. In our modeling, we have assumed that this approximation happens gradually over a period of 35 years and by 2050 vehicle travel distance is the same for both vehicle types.

Average daily travel distance for passenger cars in Portugal is 35 km [69] and we have considered that mobility in 2050 is the same as it is in the present.

For EV, we have assumed that travel distances as well as trip patterns are the same as for the ICE vehicles, meaning that for all types of vehicles mobility is the same.

Table 4 presents a summary of the common assumptions to all vehicles scenarios.

3.2.2.1. Charging profiles. People in an urban society typically commute in the early morning and late afternoon, meaning that there are two main periods in the 24 h of the day, during the night and daytime, in which there is opportunity to refuel vehicles. They correspond to very different practices of EV usage: charging at home and charging at work.

These two charging patterns were tested, not only chosen according to social behaviors but also according to their suitability to the dominant RES. Electricity demand decreases during the night, from 10 p.m. until around 7 a.m, which corresponds to a low demand period due to a diminished activity during those hours, and, typically, during the night wind blows with higher intensity due to existing higher pressure gradients in the atmosphere. These two conditions make night time a period with possible excess of energy, so we tested a similar EV charging pattern, called night profile (Fig. 7), which corresponds to the charging at home approach. Actually, night charging EV is advocated in a number of studies, such as [73], and government documents defining future energy strategies, such as [44]. For instance, night excess electricity serves as a reason in Portugal to the implementation of a large hydro dam program with pumping capability with a horizon of 2020 [7].

On the other hand, solar PV production takes place during the day with a highly predictable pattern, and in a scenario of high PV share it is likely that daily profile for excess of energy production can follow the same pattern. A similar EV charging pattern is tested, called *day charging profile* (Fig. 7), corresponding approximately in time duration and schedule to the middle of the winter and

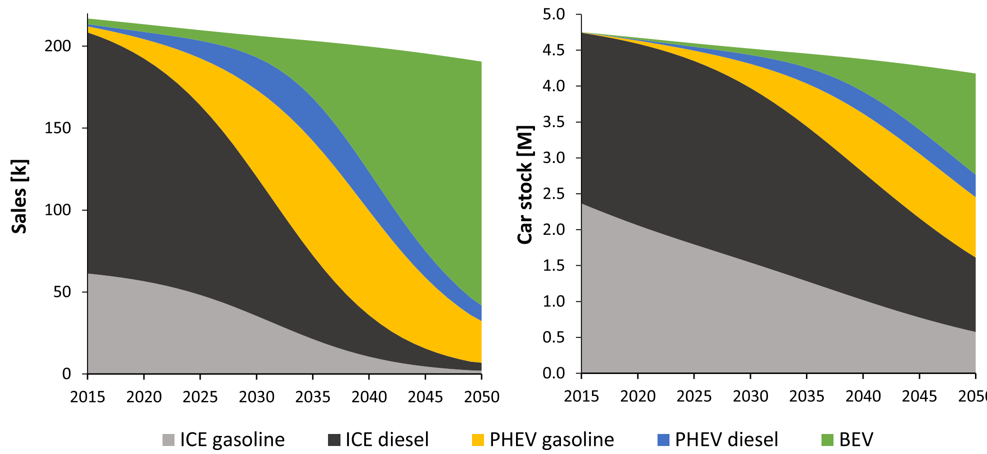

Fig. 6. Sales and total car stock evolutions until 2050 for the EV scenario.

Table 4
Common assumptions to all EV scenarios.

		References
PEV and PHEV (electric mode) consumption	0.2 kWh/km	[64]
ICE gasoline consumption	2.05 MJ/km	[69]
ICE diesel consumption	2.02 MJ/km	[69]
Annual mileage	12,662 km	[69]
Battery efficiency	95%	[68]
Vehicle average lifespan	17 years	[72]

Table 5
Scenario fleet and demand parameters.

	#	Share
	M	%
ICE gasoline	0.576	13.8
ICE diesel	1.037	24.8
PHEV gasoline	0.840	20.1
PHEV diesel	0.314	7.5
PEV	1.409	33.7
Demand	TWh	
Total electricity	62.30	
EV	6.49	
Gasoline	4.15	
Diesel	7.35	

summer PV production profiles. Day charging corresponds to the charging at work approach, for example at the commuters' work-site parking lot, which is a change in the way EV charging is usually advocated.

3.2.3. Summary

Table 5 contains a summary of the relevant fleet and energy demand parameters. Notice that EV demand is just about one tenth of the national electricity requirements.

4. Results

The evaluation of the scenario is based on the most relevant parameters, including excess of electricity in the system and CO_2 emissions. Unless otherwise stated, the CO_2 emissions concern the electricity system and the passenger vehicles sector together.

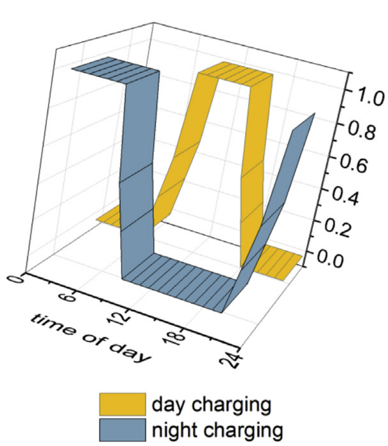

Fig. 7. Normalized night and day EV charging profiles.

Excess production is a measure of whether solar PV in articulation with EV is effectively leading to advantages without the need for more inter-country electricity bandwidth. Below, EEP refers to the Excess of Electricity Production in relation to the simple consumer load, EV demand included, that at a given time the system is injecting into the grid. This EEP can be totally absorbed by hydroelectric pumping if there is enough pump capacity and storage available and used at a more convenient time in spite of losses due to system inefficiencies (see Table 3). In this case, there is no CEEP (Critical Excess of Electricity Production). If there is no hydroelectric pumping capacity installed or the existing is not enough to absorb totally the EEP, the remainder becomes CEEP, and must be exported or curtailed. The total CEEP for a given period of time, e.g. one entire year, is obtained from the sum.

$$CEEP_{Total} = CEEP_{S1} + CEEP_{S2} + \ldots CEEP_{Sn} \quad (4)$$

with $S1, S2, \ldots Si$, corresponding to the individual sources of energy production. CEEP of each source for a certain given time period must be calculated on an hourly time basis:

$$CEEP_S = \sum_i \left(\mathrm{Esource}_i \times \left(1 - \frac{\mathrm{Dtotal}_i}{\mathrm{Etotal}_i} \right) \right) \quad (5)$$

It corresponds to the sum of the CEEP from each hour i of that period, being *Esource* the energy produced by the source in question, *Etotal* the total electricity produced on the system and *Dtotal* the total demand, including simple demand, EV demand and energy for hydroelectric pumping. From $CEEP_S$ it is possible to calculate the share of that energy source in the electricity mix for the same period:

$$Share_S = \frac{Etotal_S - CEEP_S}{Dtotal} \tag{6}$$

being $Etotal_S$ the total of electricity production from that source and Dtotal the total demand.

4.1. General insights

A general first qualitative insight on the effects of a large scale deployment of solar PV in the electricity system can be gained through the observation of the load diagram of a sufficiently short time period to allow a fine analysis. For that, we have chosen a week from mid of April, which was simulated without integrating EV. This is illustrated in Fig. 8, where we can see that in five of the seven days shown there is a substantial amount of CEEP in the middle of each day. On those days, one can observe that hydropump capacity is working on the limit from the morning until the afternoon for ten or more hours each day, in coincidence with solar PV production. Notice that CEEP occurs only on the weekdays due to a cloudy weekend registered that week. Since weekends correspond to a period of less demand, if it was not this particular cloudiness on this weekend CEEP would be especially critical on that two-day period. To have an insight on the EV charging effects with day charging profile on the network over the same period and the difference that it produces in load diagram, the EV scenario was then added, shown in Fig. 9. It is patent the less CEEP and the greater use of solar PV electricity, eliminating almost of the CEEP on Monday and Tuesday, although even on these days hydropump is working close to or on its maximum for several hours of the day. Nonetheless, the amount of CEEP is still considerable on the other days. Without EV, if we consider as order of merit of electricity entering the grid that solar is in last place, PV curtailment is 202 GWh, which corresponds to 20% of that week demand and 48% of PV production. With EV, the curtailment translates into 123 GWh, or 11% of that week demand and 29% of PV production.

A broader but less detailed insight can be gained through the analysis of the load diagram for the entire year (Fig. 10). It presents the weekly energy production and consumption with EV (day charging) and it is evident the low prominence of the thermal based energy. Also, one can see that the energy produced in surplus is of great amount, with emphasis for solar if the merit order of electricity entering the grid puts it in last place. The negative energy values on the figure translate how this surplus is used, the CEEP being denoted in red (in the web version): it occurs less during the winter and more during the rest of the year, confirming that the solar PV is the responsible for the CEEP.

4.2. Day charging vs. night charging

In Fig. 11 one can see the CEEP, as share of total production, and the CO_2 emissions as function of the PV installed capacity. The graph shows the results for the day and night EV charging profiles. It is possible to observe the optimal level of PV penetration from the stand-point of CO_2.

For the day charging profile, its minimum is found to be in the range of 16,000–17,500 MW of installed capacity, where CO_2 emissions stabilize at a level of 3.85 Mt. Relative to 1990 levels, it corresponds to a 83.5% reduction. Above those PV levels emissions grow up because marginal penetration of internally useable renewable electricity in the grid starts to decrease, yet stabilization share by CCGT power plants, with associated emissions, must still be assured. Since one also wants to minimize CEEP, one can say that the optimum level of PV penetration is 16,000 MW with a corresponding CEEP of 5.35 TWh, or 7.1% of total demand, with a RES penetration in the electricity mix of around 96.5%.

For the night charging profile, CO_2 reaches a minimum of about 5.4 Mt at around 14,000 MW of PV penetration, i.e., on a point that corresponds to 700 MW of more installed capacity than the one from the PV Scenario. Relative to 1990 levels, it corresponds to a 77.0% reduction in emissions. This means that the desired 80% reduction level (it is for the entire energy system and we consider that it is the same for the energy sub-sectors) cannot be attained with this charging profile. The corresponding CEEP was found to be 8.3% of total demand. With the same PV penetration the CO_2 emissions attained with the day charging profile are of 4.02 Mt, i.e., a reduction of 82.8% relative to 1990.

It is thus possible to say, from the standpoints of the CO_2 emissions and the CEEP, that the day charging profile is more advantageous than the night charging profile, and, in fact, the only one that permits to attain the targeted reduction in CO_2 levels.

Additionally, mid-day charging has the potential to increase the daily driving range for commuters' vehicles, which can important for diminishing driver's range anxiety, a phenomenon seen as a barrier to pure electric vehicles (PEV) market uptake [74]. For the particular case of PHEVs, this would increase the fraction of miles driven electrically, hence decreasing traveling on ICE mode and

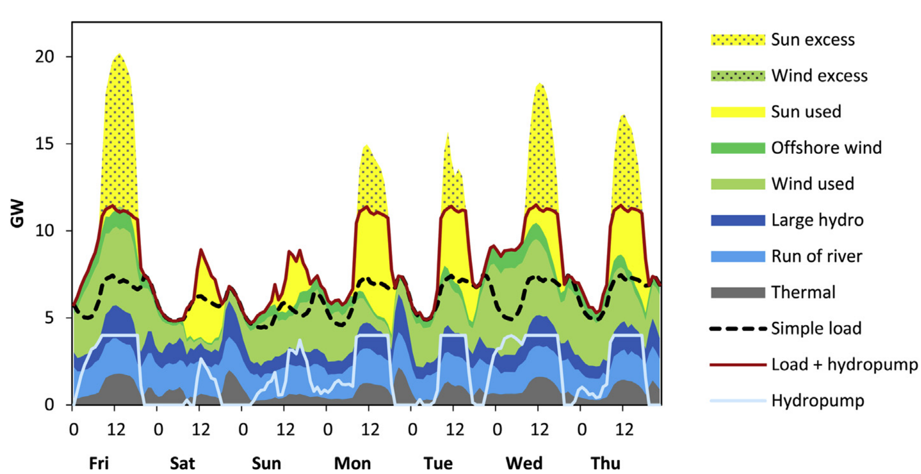

Fig. 8. Simulated 2050 hourly load diagram without EV in a selected 7-day period in mid-April.

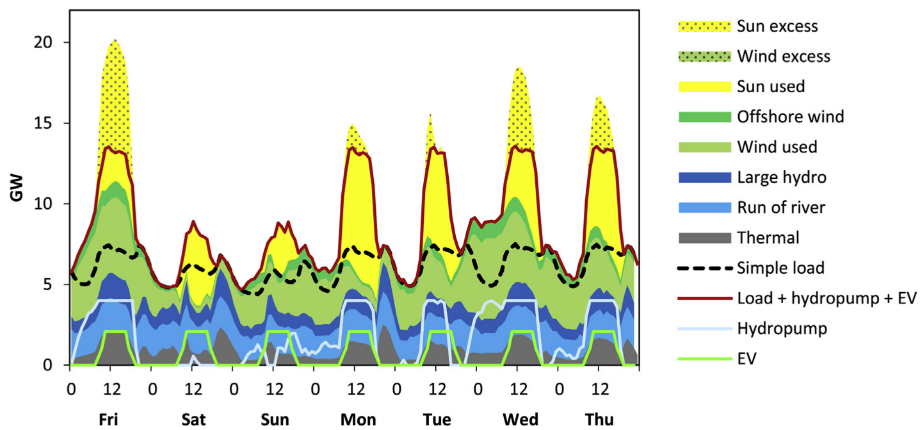

Fig. 9. Simulated 2050 hourly load diagram with EV for the same 7-day period of Fig. 8.

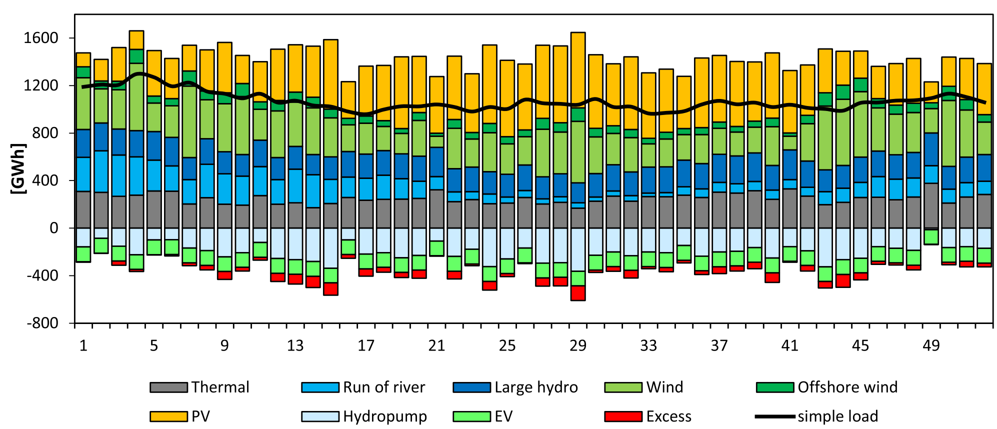

Fig. 10. Simulated 2050 weekly energy production and consumption.

petroleum use [75], contributing to the accomplishment of environmental goals.

4.3. Sensitivity analysis

As the potential for additional hydroelectricity is limited in Portugal [43], most future RES penetration is achievable by deployment of solar PV and wind. Each one has its own merit and they should be articulated in order to achieve the highest technical efficiency, i.e., enabling the larger renewable energy share by dumping less electricity compared to the individual PV and wind scenarios. This is a theme addressed in a number of studies, like [76,77]. To contribute a little for the discussion, we have performed a sensitivity analysis to evaluate the differences in CEEP and CO_2 between implementing more or less PV as opposed to onshore wind. Because wind energy is produced mostly during the night

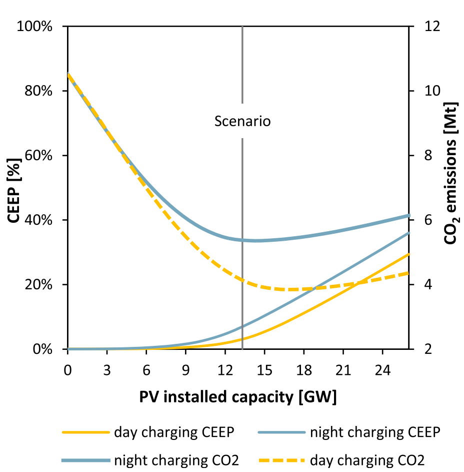

Fig. 11. CEEP given in share of total production and CO_2 emissions as function of PV installed capacity and EV charging profiles.

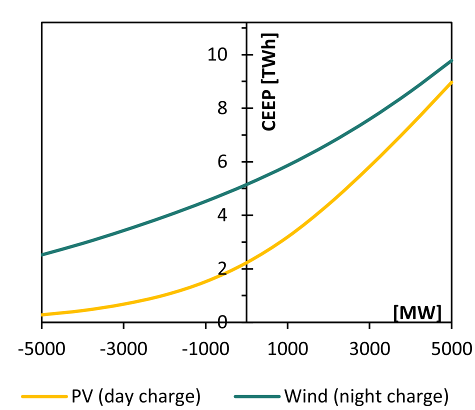

Fig. 12. Unusable energy as function of deviations in the PV and Wind installed capacities.

and solar energy is produced exclusively during the day, the analyses were performed with EV night charging profile for wind and with EV day charging profile for solar PV.

The results for the CEEP are shown in Fig. 12, where it can be seen that additional installed capacities leads to faster growth of CEEP for PV. This means that marginally there is less dumped energy installing more wind than solar PV; however, the total CEEP is always lower with additional solar PV.

If one focuses this analysis in the CO_2 emissions, one can see in Fig. 13 that incrementing wind capacity as opposed to incrementing solar PV capacity leads to greater reductions in CO_2. From the marginal point of view, it is thus more favorable extra wind than solar PV, but, again, consistently until very high levels of penetration (about 17.3 GW for solar PV and 11.7 GW for wind) the total emissions are lower with a day EV charge.

5. Conclusions

The fundamental imbalance of supply and demand represents the ultimate limit for system penetration of variable renewables in the electric power grids. The concentration of solar PV output during the day can produce unusable excess electricity, increasing costs and requiring non-optimized installed capacity, thus preventing the ability to achieve very high PV generation share. As a result, if solar PV is to provide a large fraction of a system's electricity, some valuable use must be found for its excess output. Electric mobility offers an opportunity to use that excess electricity. However, the fact that most of the solar excess electricity will naturally be generated during daytime, the coupling of solar photovoltaic and electric vehicles will require that most of the electric vehicle charging will have to take place during working hours, which will have significant impact on social habits and infrastructures, namely the existence of charging spots for commuting vehicles at or near the work facilities.

This long term scenario with electric mobility and large penetration of photovoltaics was explored for the particular case study of Portugal in 2050. Model results show that the introduction of EV demand on the network leads to a reduction of excess production of electricity in the system but does not imply major changes on the average load diagram. In other words, the majority of the extra electricity demand from the EV can be fulfilled with the otherwise excess electricity.

Two EV charging patterns were tested: a night charging profile, corresponding to the night period when overall electric demand is lower and there is typically stronger wind potential, and a day charging profile, corresponding approximately to the average PV daily production profile. It was found that the minimum level of CO_2 emissions was reached with the day charging profile and 16 GW of PV, with a reduction of 83.5% in emissions relative to 1990 levels and a corresponding 7.1% of excess of energy. The night charging profile with 14 GW of PV leads to a maximum of 73.5% in CO_2 reductions, which means that the desired 80% CO_2 emissions reductions level cannot be attained with this type of charging.

If one should decide between implementing more or less PV as opposed to onshore wind, the total excess of energy is always lower with additional solar PV. As far as CO_2 emissions is concerned, incrementing wind capacity (as opposed to incrementing solar PV capacity) leads to greater reductions in CO_2, but, again, consistently until very high levels of penetration (about 17.3 GW for solar PV and 11.7 GW for wind) the total emissions are lower with PV.

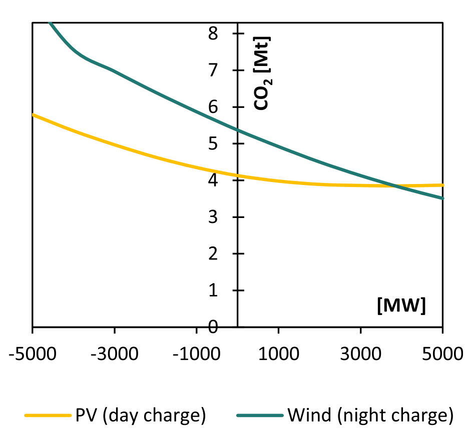

Fig. 13. CO_2 emissions as function of deviations in the PV and Wind installed capacities.

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Article III

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Sustainable energy systems in an imaginary island

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ABSTRACT

The study of sustainable energy systems is an interdisciplinary endeavour which entails the analysis of a large amount of diverse data and complex interactions that are better understood if developed from first principles. This paper reviews the approaches to this analysis and presents as a general case study, a fossil free imaginary island whose electricity, heat and mobility demand are fulfilled with sustainable and renewable energies only. The detailed hourly balance between supply and demand highlights the importance of energy storage, which is achieved by reversible hydropower and storage in electric vehicles.

Contents

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1. Introduction

The analysis of a sustainable energy system is a complex interdisciplinary exercise that involves a thorough understanding of technology, physics, electrical engineering, modelling, economics and sociology. Teaching energy systems, in particular to a heterogeneous audience, thus becomes a challenge which can be facilitated by the development of particular case studies that illustrate the most relevant issues that can emerge in this area.

Sustainable energy systems are usually approached with the support of software packages designed for that purpose [1]. However, from the educational point of view, it is more interesting to tackle the problem from scratch. The results will certainly be less realistic as assumptions will be made to make the problem more tractable in the available time frame. This methodology may also be useful at the early stages of a feasibility analysis for a particular project. It provides a comprehensive view of the problem, of its variables and constraints, which is a crucial requirement for choosing the most suitable software package for further in-depth studies. Additionally, hidden parameters and variables are exposed to those outside the renewable energy circle, such as policy makers and investors.

Our study departs from a fictional case study, which has served as the backbone of a course on sustainable energy systems for engineering students at the University of Lisbon. Its overall purpose is to design a fossil free energy system for an isolated region, an imaginary remote island whose main characteristics were arbitrarily set and are presented in Table 1. Besides this, the only data used are the solar radiation, wind speed, temperature and precipitation time series, and typical load diagrams for the corresponding climate data.

This paper presents an overview of the state of the art Sustainable Energy System (SES) methodologies for isolated systems and describes the complete analysis of the energy system of the fictional case study, including electricity supply and demand, heating and mobility, thus detailing the methodology used to build a 100% renewable energy system from scratch. This methodology requires reviewing the different renewable energy technologies, energy demand conditioning tools and energy storage alternatives, which are extensively discussed.

2. Overview of SES analysis

Sustainable energy systems with 100% renewable energy share require an understanding of the renewable energy resource characteristics and availability and how can the different available technologies be integrated and managed in order to meet the energy demand. A well cemented understanding of the problem should be built upon a gradual approach, starting from basics and preferably without the use of a dedicated computer tool for the purpose that, more often than not, acts as a black box to the user. This approximation allows gaining sensibility to the subject, which enables the proper choice of the appropriate tool for a particular application, helping in the preparation of the input data and the critical analysis of the outputs.

An approach of this type is presented by Mackay in 'Without the hot air' [2], a well-known and fruitful discussion of sustainable energy systems from first principles. Here, the potential of different renewable sources for the UK are individually analysed and are then articulated to match energy demand. The potential of energy storage is briefly reviewed, but it is only considered on an annual scale and not on a more detailed level, such as on an hourly scale. It concludes that in UK around 92% of the energy demand can be fulfilled by renewables. However, an integrated sustainable energy plan requires temporal simultaneity of energy consumption and production, an analysis not performed in 'Without the hot air'.

Jebaraj and Iniyan [3] present a broad review of energy models. They identify various emerging issues related to the energy modelling, covering models of energy planning, energy supply and demand, forecasting, renewable energy, emission reduction and optimization. Also, models based on neural network and fuzzy theory are reviewed and discussed. On the other hand, Connolly et al. [1] review computer tools for analysing the integration of renewable energy into energy systems. In order to aid the selection of a suitable energy tool for a particular application, 37 different software tools are comprehensively analysed. The paper contains individual descriptions of each of the energy tools reviewed, outlining the context of the information provided, and provides a sample of the existing studies completed by each of the energy tools in consideration. The authors conclude that there is no energy tool that addresses all issues related to integrating renewable energy.

Wide analyses of particular 100% renewable energy systems have been conducted in many studies and a review of them is presented by Lund et al. in [4]. The range of applicability goes from the town level to global scenario level, including countries of different sizes although none is focused on small isolated regions. Østergaard and Lund [5] outline the energy situation of the Danish city of Frederikshavn, including all electricity, heating and transportation demands, developing a technical scenario for the transition to an energy system based on locally available RES such as geothermal, wind off-shore, biogas and waste. Special focus is given to the impacts of geothermal energy on the energy system dynamics. Also in Denmark, Lund and Mathiesen [6] and Mathiesen et al. [7] present a methodology including hourly computer simulations and propose a series of required changes to the "business as usual" reference scenario to achieve 50% of RES in 2030 and 100% of RES in 2050. It includes a socio-economic feasibility study of the 2030 system, the marginal feasibility of each individual proposal, socio-economics costs, health costs, commercial potential and job creation, and the energy balances

Table 1
Island general assumptions.

Population	50,000
Population density	100 person/km^2
Average family size	2.5 person
Number of cars	0.5 car/person

by source, fuel consumptions and CO_2 emissions for both 2030 and 2050 scenarios. Connolly et al. [8] focuses on three different scenarios (biomass, hydrogen and renewable generated electricity based systems) and a fourth one combining all three together, to achieve a 100% RES supply system for Ireland. A similar approach is developed by Krajačić et al. [9] for Portugal. Three scenarios are tested, including one 100% RES, and the authors conclude that if all the exchanged electricity with the exterior is RES based, it will be possible to achieve a 100% RES electricity supply within a 10 years frame. A long term sustainable solution for China is analyzed by Liu et al. in [10]. The article presents the current development of RES in the country and discusses its potential. Then, it makes a comparison with Danish situation and it determines that it is suitable to adopt a similar methodology of RES implementation in China. Considering that the renewable energy resources in the country are abundant and can cover the demand, the authors conclude that proposing a 100% renewable energy system in China is not unreasonable.

At the global and regional levels, Føyn et al. [11] perform a modelling exercise aiming to test ETSAP-TIAM energy system model in order to achieve a 100% global renewable energy system. A 100% RES system is not achieved, but the model comes close to exploit several of the RES limits, which indicates that the data on renewable resources potentials must be refined. Another conclusion is that the IPCC 2C target [12] will be very expensive to reach.

In Australia, Elliston et al. [13] discuss 100% renewable energy systems to meet 2010 hourly electricity demand. It is shown that the most challenging issue is how to fulfil demand on non-windy winter evenings after periods of consecutive clouded days when concentrated solar thermal storage is at low levels. Reduction in peaking capacity through demand response strategy was assessed, concluding that a significant reduction in peaking capacity can be achieved with carefully designed demand-side policies. Another approach to simulate a 100% renewable energy sources (RES) based system at a country level (New Zealand) is presented by Mason et al. [14]. Here the authors removed the fossil fuel based production from a 3 year data set of half-hourly historic electricity production and replaced it by modelled electricity production from wind and geothermal energy sources. Peaking management was modelled using demand side response, biomass gas generation, pumped storage hydro and additional conventional hydro. Again, demand-side policies were shown to have considerable advantages over installation of new peaking plants. On another study, Ćosić et al. [15] analyses the implementation of two renewable scenarios designed for the years 2030 and 2050 in Macedonia with 50% and 100% RES shares, respectively. Special emphasis is given to the articulation between intermittent RES and storage technologies. The authors conclude that the RES 50% scenario could be easily achieved with new energy efficiency measures leading to demand reduction.

Table 2
Summary of literature overview of energy systems with a high share of renewable energy.

	Back of envelope approach	Isolated systems[a]	Hourly or thinner analysis	Economic analysis	*Notes*
Large scale					
MacKay [2]	✓	✓		✓	Simple and meaningful approach to energy planning in the UK context. Detailed analysis of match between supply and demand is not performed
Østergaard and Lund [5]			✓		100% RES supply of the Danish city of Frederikshavn is simulated using EnergyPLAN. Special focus on the use of geothermal energy. Primary energy consumption can be reduced by 26%, mainly through changes in the production system
Lund and Mathiesen [6] and Mathiesen et al. [7]			✓	✓	100% Renewable energy system by the year 2050 is simulated for Denmark using EnergyPLAN and incorporating a socio-economic analysis
Connolly et al. [8]			✓		Four 100% renewable energy systems using EnergyPLAN were simulated for Ireland with each three focusing on a different resource and a fourth being a combination of each
Krajačić et al. [9]		✓	✓		Study is for Portugal using H_2RES software and RenewIslands methodology, being conducted an analysis as if the country was an isolated system
Liu et al. [10]				✓	RES potential and objectives for China are analysed, being compared with Danish situation. Detailed analysis is not performed
Føyn et al. [11]				✓	ETSAP-TIAM global energy system model (TIMES based partial equilibrium model) is tested towards a 100% RES global supply
Elliston et al. [13]			✓		Simulation was performed using a program written in Python programming language developed by the lead author
Mason et al. [14]		✓	✓		Simulations were performed half-hourly using Matlab.
Ćosić et al. [15]			✓	✓	Authors conclude that biomass needed for a 100% RES based system may not be available. Simulations were carried on EnergyPLAN
Islands					
Krajačić et al. [26]			✓		Application of the H_2RES model [22] to the island of Mljet. Several scenarios, with different choices of renewable technologies (PV and wind), hydrogen for transport and storage, grid connection, are presented. A 100% renewable island scenario is feasible
Kaldellis et al. [27]		✓	✓	✓	Estimation of energy (electricity and thermal), water demand and RES potential (solar, wind and biomass). HOMER simulation to ensure energy autonomy. The proposed system includes wind turbines, PV panels, batteries and a biogas electrical generator
Singal et al. [28]	✓	✓		✓	Sizing of a RES system on an annual average basis, without software optimization. It is suggested to replace the existing diesel generating plant by a biogas power plant, a biomass gasification plant, a PV system and batteries for storage
Praene et al. [29]		✓			Assessment of current energy situation and consumption of Reunion island and evaluation of renewable energy potential. Description of the PRERURE energy plan, aiming for a 100% RES supply on 2030
Bağcı [30]	✓				Study about Peng Chau Island, Hong Kong. The combination of solar, wind and wave energy are shown to be the most suitable option to achieve energy autonomy from mainland

[a] With isolated systems we mean systems with limited or absent energy trades with other regions, like most of islands.

Table 3
Overview of reviews on energy systems with a high share of renewable energy.

	Models review	Computer tools review	100% renewable systems	RES integration	Notes
Connolly et al. [1]		✓			37 tools were analysed and compared but just four have been used previously to simulate 100% renewable energy-systems
Jebaraj and Iniyan [3]	✓				It gives a brief overview of the various methods for energy modelling
Lund et al. [4]			✓	✓	Provides a review of the works presented at the 2009 SDEWES Conference [31]
Duic et al. [32]			✓	✓	RenewIslands methodology for the assessment of alternative scenarios for energy and renewable resource planning
Duic et al. [22]			✓	✓	H2RES model for optimisation of integration of hydrogen usage with intermittent RES in island energy systems

On a smaller scale, several studies about integrating RES in remote islands have also been performed. Most of the cases studies consist on hybrid renewable energy systems, where the integration of new RES is made upon existing energy supply systems, typically a diesel power plant connected to a small distribution grid. The increase of RES share can help mitigate the raising costs of fossil fuels and gain autonomy from mainland energy imports, which ultimately leads to higher levels of system reliability and supply security. An extensive review on hybrid renewable energy systems is presented by Neves et al. [16].

Evaluating the renewable potential and modelling possible scenarios for increasing RES share is the goal of several articles: Andaloro et al. [17] addresses the case of Salina Island near Sicily, Italy, with special emphasis on summer months due to the higher demand from tourism; Katsaprakakis et al. [18] proposes a 90% renewable system with PV, wind turbines, batteries and a diesel generator as a backup for Dia Island in Greece; Kaldellis et al. [19] presents an optimal wind-hydro solution for a couple of islands in the Aegean Sea near Greece, with a renewable energy sources penetration exceeding 85% of total demand; Babarit et al. [20] studies the Yeu Island in France, to be supplied by marine renewables (offshore wind and waves), balancing the size of local battery storage with grid import from mainland; Bueno et al. [21] develops a wind powered pumped hydro storage system to increase the RES share in Canary Islands, reducing fossil fuel imports; and, finally, the application to the H_2RES model for optimisation of integration of hydrogen usage with intermittent RES [22] in the case studies of the islands of Porto Santo, Portugal [23], Corvo Azores, Portugal [24] and Cape Verde [25].

More ambitious targets of 100% RES supply, are addressed by Krajačić et al. [26], which draws different scenarios for Mljet Island, Croatia, where energy autonomy could be obtained using fuel cell, electrolyser and hydrogen storage technologies; Kaldellis et al. [27] describes the HOMER software optimization of a RES system to satisfy electricity, water and thermal demands, in Agathonisi Island, Greece; Singal et al. [28] shows that it would be environmental and economically advantageous to replace the existing diesel generating plant with biomass, PV and batteries, and they can fulfil the energy demands of five isolated villages in the remote Neil Island, India; Praene et al. [29] makes an assessment of the available RES and their current contribution for the energy system and also describes the energy plan for the French Reunion Island, in which the main objectives are to diversify the energy mix and make it 100% renewable until 2030; and finally Bağcı [30] proposes a solar, wind and wave energy system to gain energy autonomy In Peng Chau Island, Hong Kong. A common denominator in all these case studies is the need for a backup system, whether it be batteries, hydrogen fuel cells or a biomass-fired steam power plant.

Table 2 presents a systematic summary of the most relevant analysis of sustainable energy systems aiming for 100% renewable energy existing in the literature. Emphasis is given to the share of renewables, if the system is isolated in the sense that it does not allows for energy trade with neighboring systems, which is the case of most isolated islands, if an hourly analysis between energy demand are supply is performed and if it includes an economic analysis. Also, Table 3 includes a summary of other existing reviews on these subjects.

3. Energy supply

In this section we analyse the energy supply potential from the local renewable resources of the imaginary island. We consider production of electricity, heat and also biofuels for transport. The resources are diverse such as biomass, solar, wind and hydro.

3.1. Island characteristics

In order to assess the potential of the different technologies, one has to survey the available energy resources. For an imaginary island one may produce synthetic data sets for a typical climate. Instead, we provide real time series for temperature, solar, wind and rain from an unspecified location. Fig. 1 shows these time series and Table 4 summarises its main features. Due to the association between the cold and rainy seasons and the mild Winter and Summer, one can easily observe that these time series are typical of a southern European temperate climate, which will of course determine the particular final solution. Nonetheless, we do not believe the generality of the approach described below is lost.

The river flow time series may be determined from the precipitation time series by defining two time constants. This first ($\tau_1 = 1$ day) is due to surface water flow and the second ($\tau_2 = 6$ months) due to ground water flow. The river flow is then determined by the fraction of surface and ground water flow (assumed to be 20% and 40% of the precipitation, respectively); these need not necessarily add up to one, as losses, such as evaporation, can also be considered. The overall magnitude of the river flow is determined by the size of the river basin (assumed to be 100 km^2). Using these assumptions, the river flow time series on the nth day is calculated using:

$$\Phi_n = \sum_{i=n-365}^{n} \left(\frac{C_1}{\tau_1} \Phi_i \, e^{-(T(i,n)/\tau_1)} + \frac{C_2}{\tau_2} \Phi_i \, e^{-(T(i,n)/\tau_2)} \right) \quad (1)$$

where $T(i,n)$ is the time difference (in days) between day i and day n.

3.2. Electricity supply

The renewable electricity supply is determined using the solar radiation, wind and rain time series. We focus only on mature

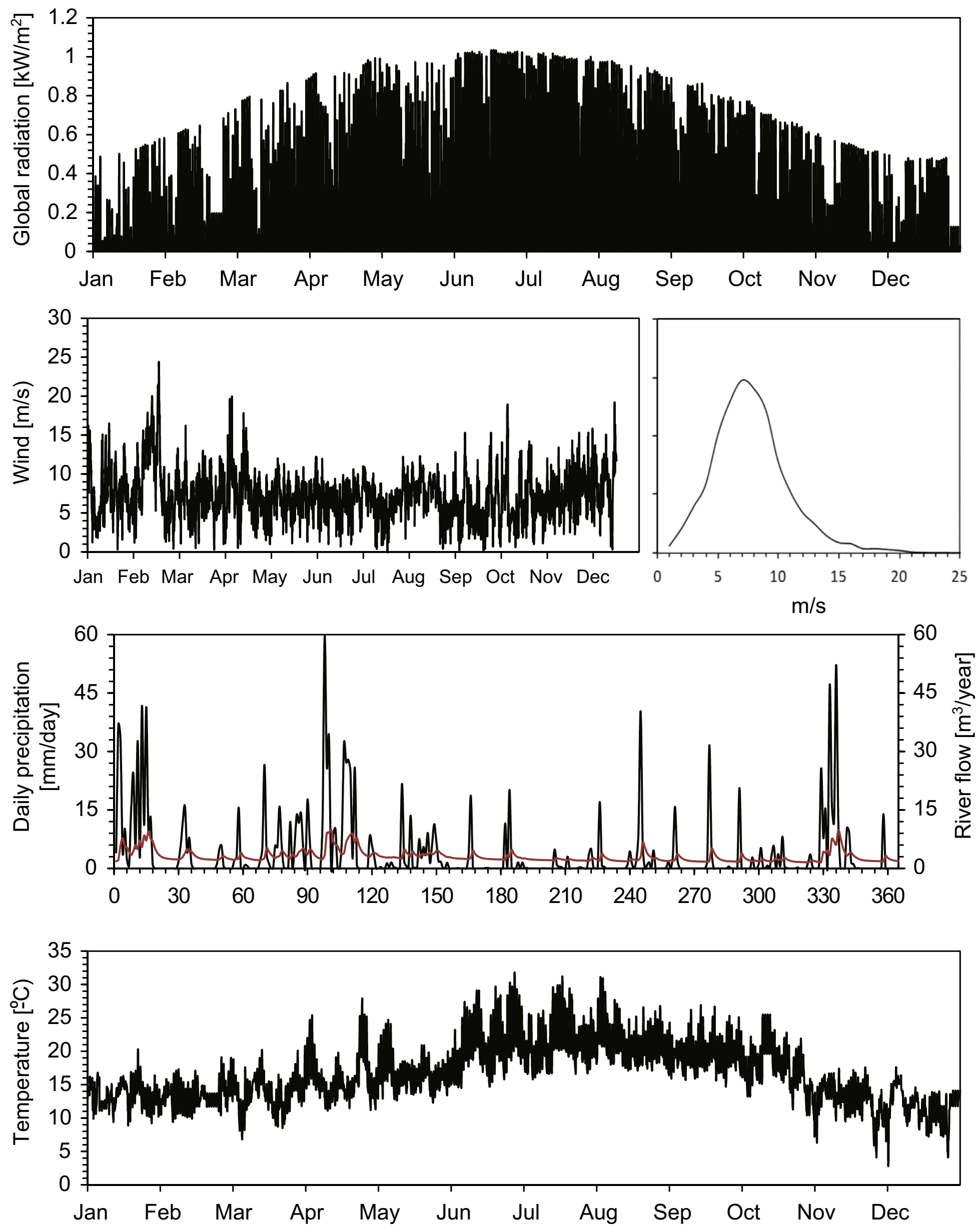

Fig. 1. Input time series: hourly global radiation, wind velocity, precipitation and temperature for a full year. Inset in the wind plot is the wind speed distribution frequency. Red line in precipitation plot shows river flow. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

Table 4
Parameters characterising the input time series.

	Global radiation	Wind speed	Precipitation	Temperature (°C)
Maximum	1.0 kW/m^2	24.4 m/s	24.3 mm	31.8
Average	0.177 kW/m^2	7.3 m/s	0.17 mm	16.4
Minimum	–	–	–	2.8
Total	1.6 MW h/m^2/year	–	1.47 m	–

technologies that have proven conversion efficiencies and known costs. Interesting technologies which are site-dependent (e.g. geothermal) or still in development (e.g. offshore wind, tidal or wave power) are not considered.

First, the available energy density (kW h/m^2/year), the total resource potential and the cost are estimated for each of the technologies/resources. Then the hourly energy available is determined using the time series described in Section 1.

3.2.1. *Solar power*

Standard commercial photovoltaic (PV) installations have an overall efficiency of about 12% [31] and therefore, given that the total annual radiation is 1.6 MW h/m^2/year (see Table 4), the density of PV electrical energy production is 186 kW h/m^2/year. Assuming a typical installation cost of 3 €/Wp and a lifetime of 25 years [32], the energy cost[1] is 0.08 €/kW h. A more complete approach would be to assess the levelized cost of electricity for a PV system [33,34]. The hourly PV electrical energy is straightforwardly calculated using the solar irradiance time series.

The PV modules may be installed on rooftops. Assuming 20% of the total roof area is used for photovoltaics, and that each family

[1] All the cost estimates in this section assume a unitary capacity factor which means that all the energy produced is fed to the grid and thus costs are determined by dividing the energy produced by the cost of the equipment and its O&M. If, as discussed in detail in Section 4, at certain times some of the energy is not dispatched for whatever reason, the unitary cost of energy will be higher.

(2.5 people) has an average roof area of 70 m^2 then the island may have 28 ha of PV panels, which correspond to an annual production of 52 GW h/year, or 2.9 kW h/person/day. If a larger production of PV is required, one may envisage municipal power plants, such as concentrated photovoltaic (CPV) [35,36] or concentrated solar power (CSP) plants [37,38], which have similar cost and energy potential per unit area.

3.2.2. Wind power

The power density of wind on a plane perpendicular to the airflow is given by

$$P = \frac{1}{2}\rho\, v^3 \qquad (2)$$

where ρ is the density of air and v the wind velocity. Applying Eq. (2) to the probability distribution of wind speeds, we have a power density of 458 W/m^2.

Spacing between turbines in wind farms is typically five times the rotor diameter. This spacing is one which minimises the turbulence felt between adjacent turbines. Following [2] and assuming a typical windmill constant efficiency of $\eta = 50\%$, the wind power per unit area of footprint is

$$P = \eta \frac{1}{2}\rho \frac{\pi d^2}{4} v^3 / (5d)^2 = \frac{\pi}{200}\frac{1}{2}\rho\, v^3 \qquad (3)$$

where d is the diameter of the windmill. Using the annual probability distribution of wind speeds, by computing the power for each wind speed range and summing all with the respective range frequency, yields an annual production of 64 kW h/m^2/year. More importantly, from Eq. (3) and the wind speed time series, one can calculate the hourly wind power available. Wind energy cost is estimated at 0.05 €/kW h [39,40]. A more detailed evaluation of the wind potential is possible by considering a wind turbine power curve since the wind turbine efficiency η is also dependent on wind speed [41].

3.2.3. Run of the river hydropower

The power one can extract from flow of water through a turbine due to a vertical drop is

$$P = \eta\rho\Phi g h \qquad (4)$$

where η is the turbine power conversion efficiency[2] (typically about 80% [42,43]), ρ is the density of water, Φ is the water flow[3], g is the acceleration due to gravity and h is the vertical fall height. Considering the river flow time series calculated in Section 3.1 and assuming $h = 50$ m, we have an average power of 1.1 MW yielding 9.3 GW h/year. The energy density of hydropower in this example is 0.02 kW h/m^2. This value is obtained if we divide the annual energy production by the total area of the island.

Costs of hydropower are always very dependent on location, size and power of turbines, etc. Assuming a typical cost of 2 €/W and a lifetime of 25 years, the energy cost is 0.04 €/kW h [44]. Electricity costs can be higher in places with less favourable characteristics [45].

3.2.4. Biomass

The biomass co-generation power conversion efficiencies considered here are 30% for electricity production and 80% for combined electricity and heat production [42,46]. When the fuels employed are residues from agricultural crops and forestry, where biomass production is 0.5–1.5 t/ha/year and the lower heating value (LHV) is 15 GJ/t, the energy production is 0.0125 kW h/m^2/year. When dedicated energy crops are employed, biomass production increases to about 20 t/ha/year and therefore the resultant values of energy production increase to 0.25 kW h/m^2/year [47,48]. A reasonable estimate for the cost of electricity from biomass is about 0.10 €/kW h [49,50].

3.2.5. Waste

Domestic waste may be incinerated or used to produce biogas which in turn is used to produce electricity in a thermal power plant. According to [2], the production of non-recyclable waste is 1 kg/person/day and has an energy content of about 2.6 kW h/kg. If we assume a power conversion efficiency of 20%, the energy production for the island is 9.5 GW h/year or 0.5 kW h/person/day. The cost is estimated at 0.04 €/kW h [51]. The environmental advantages of waste-to-energy processes must also be highlighted, since CO_2 equivalent emissions are around 3 times lower than those from buried waste on landfills [52,53].

3.3. Heat supply

3.3.1. Heat from solar energy

The yield of hot water using solar thermal systems depends critically on the demand profile, unlike the other technologies discussed above. For simplicity one may assume a constant and relatively low conversion efficiency of 50%, which is a typical value when heat loss and unused solar hot water are taken into account. By taking the solar irradiation time series, as for solar PV, the average production of solar hot water is 2.1 kW h_{th}/m^2/day. This value is very similar to the daily hot water demand per person and thus one could state that 1 m^2/person is sufficient (see Section 4.2). However, because of the mismatch between the summer high insolation and winter high hot water demand, 1 m^2/person would only satisfy hot water needs for about half of the days of the year. If the collectors' area is doubled to 2 m^2/person, the solar fraction[4] is increased from 75% to 90%, resulting in the hot water demand being satisfied in 78% of the days. This increase in panel size will not only result in higher costs but also in almost 60% of the heat being wasted during the summer (Fig. 2). Assuming a lifetime of 20 years and an installation cost of 800€/m^2, the thermal energy production cost is 0.12 €/kW h_{th} for 2 m^2/person and 0.07 €/kW h_{th} for 1 m^2/person.

3.3.2. Heat as a by-product of electric production

A co-generation power plant will produce both electricity and heat. Assuming a heat conversion efficiency of 50%, the production of heat is 0.21 kW h_{th}/m^2/year for agricultural/forestry residues and 4.2 kW h_{th}/m^2/year for energetic crops. The cost for this type of heat generation is difficult establish, since it is a by-product of electricity generation. This will be discussed in further detail in Section 5.3.

3.4. Transport

Vehicle transport must be powered by electricity or biofuels, since the challenge is to develop a fossil fuel free energy system. For assessment of biofuels potential and cost we consider two bioethanol options (sugar beet and wheat) and two biodiesel options (rapeseed and sunflower). The relevant data is summarised in Table 5. The LHV values considered are 21.4 and 38 MJ/l for bioethanol and biodiesel, respectively [54]. One can observe that bioethanol production has a significantly higher yield but at the expense of cost.

[2] This depends on turbine technology and the water flow rate.

[3] One ought to reserve a fraction (e.g. 20%) of the river flow for ecological reasons [80] and therefore one may consider an extra 0.8 × factor in Eq. (4).

[4] Solar fraction is the amount of energy provided by the solar technology divided by the total energy required.

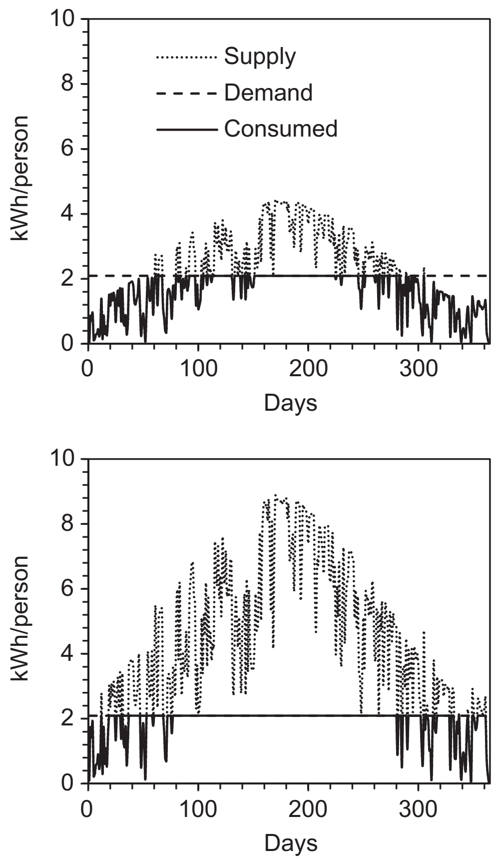

Fig. 2. Solar hot water production, demand and consumption time series for 1 m²/person (left) and 2 m²/person (right). Demand is constant at 2.1 kW h/person/day. Production above this value (dotted line) is wasted.

Table 5
Biofuel yield and cost.

	Crop yield		Fuel yield		Cost	
	Crop	t/ha/year	l/ha/year	kW h/m²/year	€/l	€/kW h
Bioethanol	Sugar beet	66–78	6600–7800	0.111–0.131	0.6	0.10
	Wheat	3.5–9	1225–3150	0.021–0.053		
Biodiesel	Rapeseed	2.8–3.8	1120–1520	0.011–0.014	0.7	0.07
	Sunflower	1.5–3.0	705–1410	0.007–0.013		

3.5. Summary

Table 6 summarises the energy density, total potential and cost for the different renewable energy technologies analysed. Although all energy units are kW h, one should not directly compare electricity with heat or energy from transport. From an educational point of view, the introduction of this table is perhaps an appropriate time for the discussion of the concept of exergy [55,56] [57].

One should highlight that, unlike common perception, solar power actually has the lowest footprint per unit of electricity produced. The island potential for wind power and biomass (and biofuel) does not depend on urban or population characteristics. Their potential depends on the areas assigned to wind parks, forests and agriculture and will be discussed further below.

4. Demand

4.1. Load diagram

The electricity demand is characterized by the load diagram. The simplest approach would be to take a national load diagram and adjusting it according to the population ratio between the island and the country. However, since power demand for a small island may be quite different than that of a larger and much more industrialized region, the island of Faial load diagram is used here. [58] Faial is a small island in the Northern Atlantic with about 15,000 inhabitants, a population density of 87 habitants/km² and therefore similar to our imaginary island. The normalization of the load diagram and extrapolation to our imaginary island results in an electricity demand of 8.2 kW h/person/day.

Fig. 3 shows the island average load diagram for three typical days, in different seasons. The overall increase in the power demand for the month of August may be due to an increase in activity and population associated to incoming tourism during summer. The peak observed in the evening in December may be due to increased lighting (as days are shorter) and heating. The data characterising these load diagrams are summarised in Table 7.

There is a repertoire of tools to reduce/shift the load diagram. The most relevant ones are discussed.

4.1.1. Daylight saving

The use of daylight saving strategies (shifting the clock for an hour before the summer/winter) is common in many economies and has other positive impacts beyond the energy discussion

Table 6
Summary of the relevant results for the energy supply.

	Energy density	Total potential		Cost
	kW h /m²/year	GW h/island/year	kW h/person/day	€/kW h
Solar PV[a]	186	52.2	2.86	0.077
Wind	35.0	–	–	0.023
Hydro	0.02	9.9	0.54	0.009
Biomass	0.26	–	–	0.100
Waste	0.02	9.5	0.52	0.040
Solar hot water[b]	780	32.2	1.8	0.12
Biomass heat	0.42	–	–	n/a
Biofuels	0.01–0.13	–	–	0.07

[a] Considering 20% of the roof area.
[b] Considering 2 m²/person.

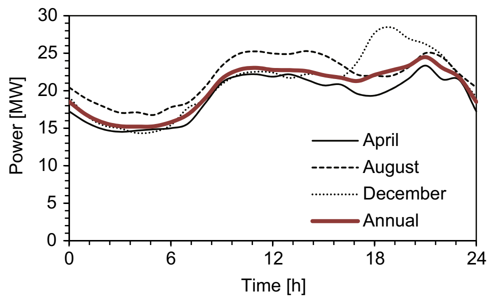

Fig. 3. Load diagrams for three typical days, in three different seasons.

Table 7
Characterization of load diagrams.

		April	August	December	Annual
Energy	GW h/year	167.96	190.85	183.45	177.56
P_{avg}	MW	19.17	21.79	20.94	20.27
P_{min}	MW	14.52	16.78	14.36	15.21
P_{max}	MW	23.35	25.29	28.44	24.48

Table 8
Timetable for differentiated electricity rates.

	Hours
Lower rate	0–8; 22–24
Higher rate	8–22

(e.g. decrease of car accidents in the morning). The impact on energy demand is, however, not as relevant as it is usually presumed [59] and in some situations it may even be counter-productive as a decrease in morning demand may be overcompensated with an increase in the evening demand due to e.g. electricity for cooling. Since there are no cooling needs in our imaginary island, this pernicious effect is not to be expected. Also, since the Faial Island has an ongoing daylight saving scheme, the demand load curve shown in Fig. 3 already takes this measure into account.

4.1.2. Pricing

Price is arguably the most efficient way to condition electricity demand. The increase of the flat rate of the electricity price is known to reduce the demand. However, if the increase is too aggressive it may have a significant negative impact on the local economy [60]. In the scenarios below, an arbitrary increase in flat rate price will be considered to lead to a uniform overall 10% reduction in demand. Realistically, this decrease in demand may be achieved by a careful use of electricity and/or by use of more energy efficient appliances.

Another option is the introduction of pricing according to the time of use [61]. This approach leads to a shift of demand from peak hours (higher rate) to the base load. This will be assumed to result in a 10% shift away from the peak hours, according to the timetable shown in Table 8.

4.1.3. Demand response

In this paper we define demand response as a general term that includes dynamic pricing (electricity rate depends on the instant or near term balance between demand and available supply) and particular customer contracts that reward reducing demand at critical times. For a review of these tools for demand conditioning and its impact see [62]. Here, we assume that the elasticity of demand (the maximum value that a consumer is willing to reduce/increase its demand at a particular time of the day) is 10% of its total demand.

4.2. Heat demand

Heat demand is mainly driven by hot water use and thermal comfort. For the sake of simplicity, we shall ignore other uses of heat, such as those associated to industry. For the estimation of heat demand for hot water we can assume that each person requires 45 l of water at 60 °C per day. Thus the heat required is

$$Q = m\,C_p\Delta T = 2.1\ \text{kW h}_{th}/\text{person/day} \tag{5}$$

where ΔT is the temperature difference between the inlet (assumed to be equal to the annual atmospheric average temperature) and outlet (60 °C) water temperatures. This accounts to about 38.2 GW h_{th}/year for the whole island.

To determine the heat requirements for space heating, the indoor thermal comfort range is considered to be from 18 °C to 25 °C. For our island, the result is that there is essentially no need for cooling, since temperatures rarely exceed 25 °C (see Fig. 1). However, as almost half of the days in the year have an average temperature below 18 °C, heating will be required[5].

For a rough estimate of the heat requirements for a typical home one may assume the following:

- heat losses by conduction with an average U value of 2 W/m^2 K for a $10 \times 10 \times 2$ m^3 home;
- heat losses due to air replacement (ventilation) of 1 ach;
- solar gains of 2.33 kW h/m^2/day and 0.83 kW h/m^2/day for south facing and east/west facing walls, respectively;
- internal gains of 100 W/person considering 2.5 people/home for 12 h/day plus 2 W/m^2 from appliances;

We can thus determine the daily net heat required to keep homes within the comfort temperature range. The annual net heat required is almost 2 MW h_{th}/year per home, which leads to 38.5 GW h_{th}/year for the whole island, quite similar to the heat demand for the hot water. This heat demand is obviously concentrated in the cold season.

4.3. Transport scenarios

The imaginary island is designed to be fossil fuel free and therefore the transport needs will be addressed by electric vehicles (EV) and/or biofuels. Electric vehicles will obviously add demand to the load diagram discussed in Section 4.1 while biofuels will compete with biomass and food, etc., for available land.

The first step for the analysis of the energy required for the transport sector is the assessment of the energy demand per km-person for the different transport options[6] (cf. Table 9).

As expected, public transport has lower energy consumption due to the number of people on board. It should be noted however that the difference between individual cars and buses running on biofuel (almost a factor of 4 ×) is much higher that the equivalent difference for electric vehicles (only a factor of 2 ×), thus showing

[5] One may argue that by considering average day temperature instead of hourly temperature we are taking into consideration the building thermal inertia.

[6] It is also interesting to compare the amount of energy used by a car throughout its lifetime and its embodied energy. The latter may be estimated by assuming that the cost of the car is only due to its embodied energy: assuming a low cost of electricity at the manufacturing site of, say, 0.05 €/kW h, and a total cost of 15 k€ we get 300 MW h/car. Assuming that a car uses 1 kW h/km and drives about 10,000 km/year, it would take 30 years for the car to spend on fuel as much energy as it was required to make it in the first place.

Table 9
Energy needs for transportation.

Type	Fuel	Vehicle	l/100 km	kW h_e/km	No. passengers	kW h/km-person	Refs.
Passengers	Biofuel	Car	10		1.5	0.667	[81]
		Bus	52		30	0.173	[82]
	Electric	Car		0.20	1.5	0.140	[83]
		Bus/trolley		2.83	30	0.094	[84]
		Subway		2.39	80	0.030	[84]
Goods	Biofuel	Truck	32		n/a	n/a	[85]

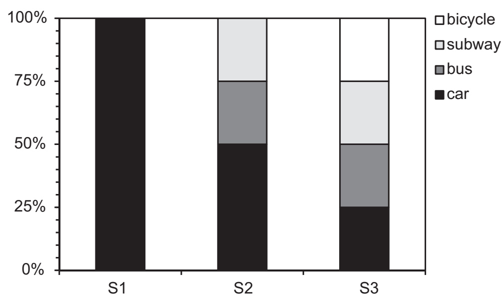

Fig. 4. The different mobility scenarios.

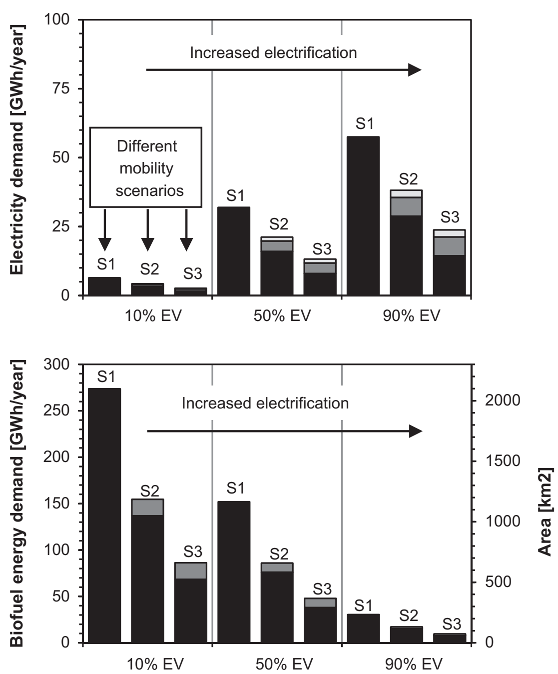

Fig. 5. Energy demand for the transport sector: electricity (top) and biofuel energy (bottom) demand for different mobility scenarios (S1–S3) and increased levels if electrification.

that new electric cars have indeed an overall very good energy efficiency. For simplicity, the transport of goods within the island is not considered.

The purpose of this section is to determine the energy demand for the transport sector. We shall define 3 possible mobility scenarios (S1, S2, S3) for different use of individual car, public transport (bus or subway) and walking/biking (cf. Fig. 4). It is also assumed that local habitants travel on average 25 km/day.

Using the data from Table 9, and assuming 3 levels of penetration of electric vehicles (replacing both individual cars as well as buses running on biofuels) we can calculate the energy demand for the transport sector, as shown in Fig. 5.

The results confirm that the use of public transport leads to lower energy demand. Also obvious, the higher the level of electrification of the fleet, the higher will be the electricity demand and the lower will be the demand for biofuels.

The left vertical axis on both plots of Fig. 5 refers to final and not primary energy and therefore may not be directly compared. However, it is interesting to note that the maximum energy demand for biofuels (everyone driving individual cars running on biofuel) is significantly higher than the maximum electricity demand (everyone driving individual electric cars). This statement holds even if all electricity were to be produced from biomass (cf. Section 3.2) thus asserting the relative high efficiency of electric cars.

Also, the right vertical axis of the biofuel plot shows the land demand for the growth of energy crops for transportation (assuming the production of bioethanol with the highest yield, cf. Table 5 in Section 3.4; for biodiesel the required area would be 10 $\times$ larger). Remembering that the island total area was set to be 500 km^2, it is evident that a significant level of electrification of the transport sector is required, together with efficient mobility scenarios.

Finally, it is also interesting to note that even for the most favourable mobility scenario (when half of the population uses public transportation and 25% only use energy from metabolism to move around) with 90% of electrification, leads to demand of electricity of the order of 1.3 kW h /person/day, adding about 1/6 to the average daily electricity demand in the island.

It is thus essential to review some of the management tools to promote a more favourable mobility scenario, which leads to lower energy demand (regardless of the 'fuel'). The most common solutions available to decision makers are based on penalizing the individual transport by taxation or expensive parking rates, implementing bus lanes [63] or park & ride solutions [64,65]. These may have a significant impact on the shift of usage from private to public transport. Nevertheless, as one considers the energy intensity for transport in Table 9, and in particular for EVs, it is very clear that a small increase in the occupancy rate of individual cars has a huge impact on the energy demand. Thus, car pooling solutions [66] ought to be implemented in the imaginary island to achieve scenario S3.

The energy demand for these mobility scenarios could be further reduced if the averaged travel distance was to be reduced, which could be achieved by concentrating the population in the urban area. This fact serves as a good opportunity to highlight and discus with the students the energy sustainability of urban vs rural populations [67].

5. Storage and transmission

5.1. Electricity storage

There are different technological approaches for electricity storage. For a review see [68]. Here, for simplicity, only the following are considered: large scale storage dam with pumping storage and decentralized small scale using electrochemical batteries in homes and/or in cars.

Table 10
Main characteristics of electrochemical batteries.

		Lead	Li-ion
Specific power	W/kg	130	300
Specific energy	W h/kg	33	140
Efficiency		80%	90%
Cost	€/W h	0.09	0.13
Lifetime	cycles	1500	3000

5.1.1. Hydroelectric storage

Pumping water up a dam at low demand hours is a well established procedure for electricity storage [69]. Assuming a $2 \times 2\ \text{km}^2$ reservoir area with an average depth of 20 m and a conversion efficiency (for the generation of hydroelectricity) of 90%, one can hold the equivalent to about 0.7 GW h of electricity in the reservoir (for a pumping efficiency of 80% this would correspond to almost 0.9 GW h of electricity required to fill the reservoir).

When the pumping station is introduced, one may increase the installed power (in Section 3.2 the installed power was limited by the available water flow). The sizing of the new turbines will therefore have to take into account the needs for energy storage of the island. Assuming a ten-fold increase of the installed power (21 MW), using Eq. (4) we get a water flow of 121 m^3/s and therefore a discharge time[7] of about 184 h.

Regarding costs, the added cost for a pumping loop to a dam during construction is around 30% of the total investment cost on the hydroelectric plant, which leads to a storage cost of 0.47 c€/kW h.

5.1.2. Batteries

Small scale decentralized electrochemical batteries will be available in electric cars (Li-ion) and perhaps in the homes (lead acid) coupled to solar home photovoltaic systems. Table 10 summarizes their most relevant characteristics.

Lithium-ion batteries are more expensive, but they have higher energy density, higher efficiency and last longer. Either way, costs are orders of magnitude higher than the pumping storage and thus the use of batteries cannot be economically viable if its primary use is as energy storage for the grid; hence the use of these coupled to PV systems does not hold economically.

For electric vehicles, the battery technology of choice is lithium-ion due to the advantages mentioned above. We assumed for each car a total battery capacity of 24 kW h, from which 70% is effectively used (to consider for deep discharge prevention and capacity losses that happen over time) and that, on average, 90% of the fleet is parked [70] and connected to the grid. Thus, for a 100% EV fleet (25,000 cars, scenario S1) one has 0.28 GW h available for vehicle-to-grid (V2G), which corresponds to a buffer of about 15 h, considering the average load on the island of 19 MW. The maximum storage capacity in the batteries is thus about 6% of the pumping storage capacity. As far as costs are concerned, one may assume that the use of the EV batteries for grid back up will lead to an accelerated aging of the battery and therefore its precocious replacement. In the model we considered that the lifespan of the battery is reduced by 3 years (7 years instead of the normal 10 years) [71]. If the cost of the battery is €20,000 [72], this leads to a V2G cost of 0.19 €/kW h.

5.2. Electricity transport

The construction and maintenance of the electric grid on the island will lead to energy losses and added costs. These are difficult to estimate, in particular for a small island, since they depend on the distribution of the population on the island, the number of substations, the percentage of underground lines, the voltage use, etc. For our imaginary island one will assume average energy losses of 8% [73,74] and an added cost of 0.01 €/kW h.

[7] This is equal to total volume divided by maximum flow.

5.3. Heat transport

The co-generation biomass plant will produce excess heat that could be used for water or space heating and therefore it is interesting to analyse the costs and energy losses associated to district heating. The distribution of heat may be achieved by water vapour or hot water. This second option, suitable for lower temperature uses, leads to lower costs (0.01 €/kW h for a 10 km line) [75] and lower losses (about 15%) [76]. However, for the mild climate of the island the district heating option cannot be economically competitive and has been discarded. Thus, the solution for the heat supply and demand is based on 1 m^2/person solar thermal panel complemented by electricity heating. For hot water one can assume a coefficient of performance (COP) equal to 1, which is basically Joule heating, whilst for spacing heating one can assume heat pumps with typical COP values of the order of 3. This electricity demand for heating has been factored in for the electricity demand time series discussed below.

6. Results

Considering the data described in the previous sections, one can now build an energy system model for the imaginary island. All calculations below were performed on a spread sheet using the built-in optimization engine. For all optimizations, the free variables are the area available for biomass and photovoltaics, the number of wind turbines and the dam installed power.

The first approach, named Model 1, focuses on the annual net electricity production, i.e. how much electricity one would have to produce annually in order to cope with the annual demand? The main characteristics of this model are:

- The selection criterion for the supply portfolio is cost and therefore the implementation area for the different electricity supply technologies can be such that they are set to their maximum local potential according to Table 6 above.
- Transports are assumed to be driven by biofuels and thus do not add electricity demand.
- As discussed in Section 5.3, heat demand is satisfied by solar hot water complemented by electrical appliances.
- In order to avoid situations where demand surpasses local supply, one may assume for this first model that the island is connected to a wider electricity system, e.g. the continental grid, via an underwater cable with an electricity cost of 0.15 €/kW h.

The results are summarised in Table 11. The cost criterion leads to the focus on the least expensive technologies and therefore the optimized energy mix does not include solar or biomass.

In Model 1 the annual energy imported/exported reaches 74.5 GW h/year with a maximum power of 22.5 MW. Assuming no energy storage, if there was no connection to the continental grid then the local electricity supply would have to satisfy all the electricity demand at all times during the year, and the installed power would be severely oversized. In fact, there are some windless hours when the sum of all other electricity sources is unable to fulfil the demand unless almost 15% of the island was used for the growth of biomass. This *brute-force* approach would of course be clearly unrealistic.

Table 11
Model results: energy portfolio, power and costs.

	Model 1 Annual net Import/export	Model 2a Hydro storage no import/export	Model 2b EV storage no import/export
Solar	–	–	52.1 GW h
Wind	130.1 GW h	190.9 GW h	1136 GW h
Hydro	9.3 GW h	9.3 + 40.7 GW h	9.3 GW h
Biomass	–	–	49.9 GW h
Waste	9.5 GW h	9.5 GW h	9.5 GW h
Total power installed	46.8 MW	86.5 MW	400 MW
Annual electricity demand	150 GW h	159 GW h	218 GW h
Annual electricity supply	207 GW h	250 GW h	1256 GW h
Capacity factor	41%	33%	5%
Cost	10.5 c€/kW h	4.7 c€/kW h	25.0 c€/kW h

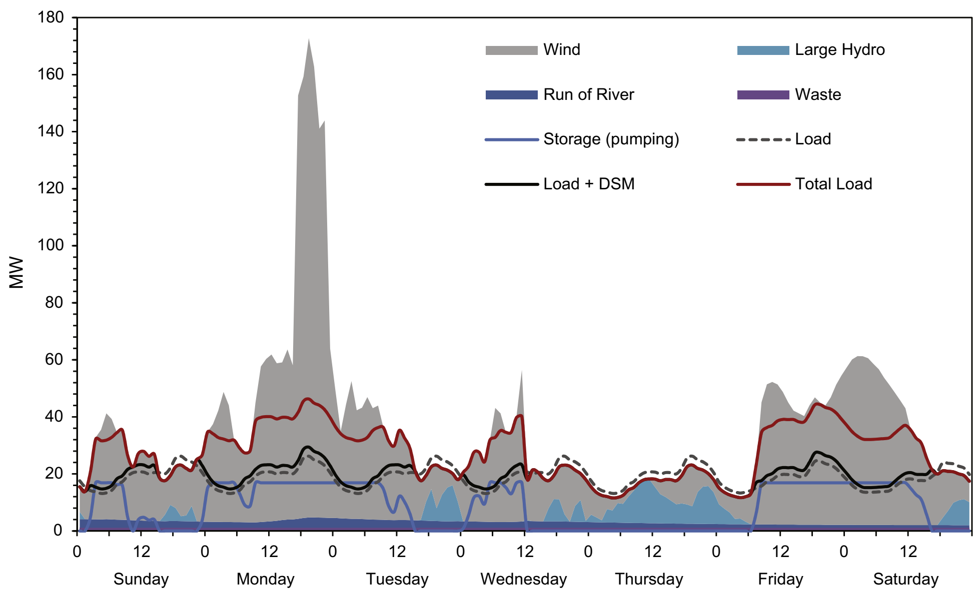

Fig. 6. Load diagram for a week in January for the island energy system with hydro storage (Model 2a).

From these results it is clear that some sort of energy storage is required. Models 2a and 2b describe two extreme scenarios for energy storage:

- Model 2a considers storage in a reversible dam, while transport is still mostly guaranteed by biofuels (scenario S3 with 10% electric vehicles that add to the electricity demand but are not used as backup for the grid);
- Model 2b considers a 100% fleet of electric vehicles (also in scenario S3) whose batteries are used as back-up for the grid.

Furthermore, both models consider the implementation of demand response mechanisms in order to reduce demand at peak times. As above, the optimizing criterion was final cost of electricity.

Fig. 6 illustrates the renewable energy mix calculated for a typical week in January using Model 2a. One can note the over-supply of wind power in about half of the time. The effect of the demand side management (solid black line, compare with dotted black line) is insufficient to overcome the wind power variability and therefore the energy stored in the dam becomes critical for the management of the energy system. The massive wind power oversupply on the second day is followed by two windless days that require power from the dam.

Since it does not require the import of expensive electricity from abroad, Model 2a is able to halve the final cost of electricity. Comparing with Model 1, the installed capacity is increased (to pump water to the reservoir when excess energy is available) and therefore the capacity factor is slightly reduced.

On the other hand, Model 2b uses the EV batteries for back up of the grid. Of course, this option leads to an increased electricity demand. A simple algorithm for energy management of the EV batteries was developed, taking into account the electricity supply/demand balance of the following 24 h: EV batteries are charged at the most favourable times of the day. This method assumes that the energy levels of the EV batteries are controlled by the grid but guaranties an autonomy of 25 km/day for all cars. Notice that, with this simple model, EV charging patterns are not optimized according to their driving needs (e.g. morning drivers may be upset if the most favourable charging time is noon). Furthermore, it assumes that wind and solar power variability are predictable 24 h ahead and other simplifications that are not necessarily realistic. For a detailed discussion of energy management of EV batteries see [77].

Fig. 7 shows the load diagram of a week in July for Model 2b. Since the capacity of the V2G buffer is much lower than the dam reservoir, the energy system requires larger installed capacities (in particular wind power) leading to a much lower capacity factor (cf. Table 11). The added cost allows for the introduction of biomass and solar PV, which now become cost competitive with storage.

In order to increase the storage capacity one can increase the number of EVs. On the other hand, increasing the number of vehicles will lead to increased electricity demand. Thus, there must

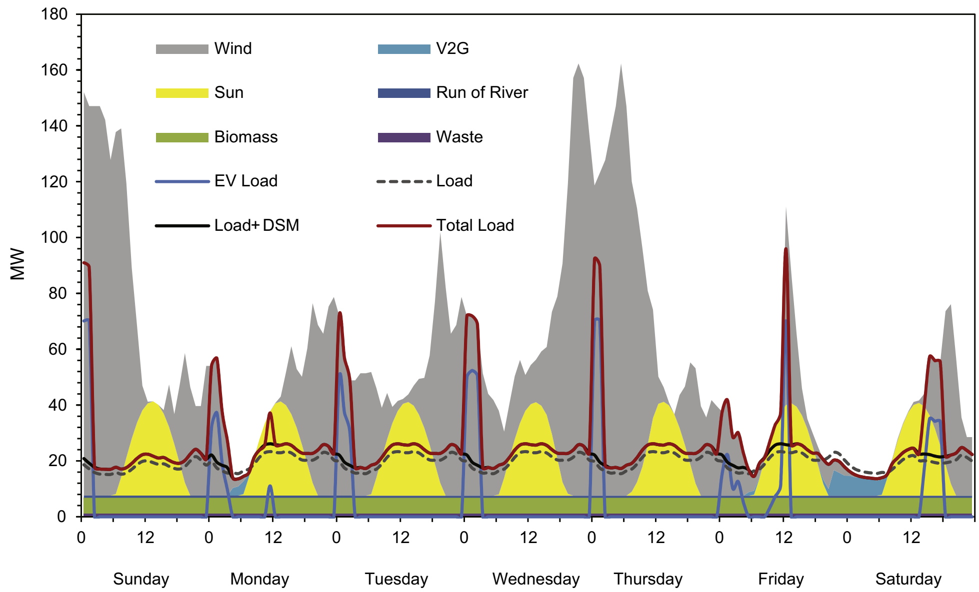

Fig. 7. Load diagram for a week in July for the island energy system with EV storage (Model 2b).

be an optimum of EVs which will minimize electricity cost whilst maximizing the capacity factor. This optimum is shown in Fig. 8.

It is interesting to notice that if we take the values shown in Table 9, where the energy consumption for EVs and biofueled vehicles is 0.14 kW h/(km person) and 0.667 kW h/(km person) respectively, and then using the respective energy cost of electricity of at most 0.30 €/kW h (as shown in Table 11) and biofuels of 0.667 €/kW h (see Table 6), the transport cost is 0.042 €/(km person) and 0.047 €/(km person). This suggests that that transportation in EV can always be economically viable for the user.[8]

Finally, it is important to mention that a complete discussion of sustainable energy systems for a remote island ought to consider some other discussion topics such as:

- Need for redundancy in an isolated energy system in order to increase the robustness of the energy system for unfavorable weather conditions (such as long cold spells, unusual windless or sunless weeks) or interruptions for maintenance;
- Any discussion of biofuels for mobility ought to analyse their impact on the food crisis and in developing countries [78,79];
- Costs of de-fossilizing the energy system;
- Climate change impact on renewable energy resources.

7. Conclusions

We have developed a model for the energy system for an imaginary island, including electricity, heat and transport. The system ab initio required to be fossil-free and sustainable and it is thus based on renewable energies and local resources only. Different mobility scenarios, energy storage alternatives and demand management instruments are discussed in detail.

The most relevant results are:

- Due to the relative mild winters, district heating is not cost competitive and therefore the heat demand is satisfied via solar hot water complemented by electricity for both hot water and thermal comfort.

[8] A typical diesel powered vehicle consumes 5l/(100 km). If we assume a cost of 1.5 €/l, then the transport cost of the vehicle associated to fuel consumption is 0.075 €/km. If the vehicles transports on average 1.5 people, the cost is then 0.05 €/(km person). However, diesel is a heavily taxed commodity with the actual cost being far less.

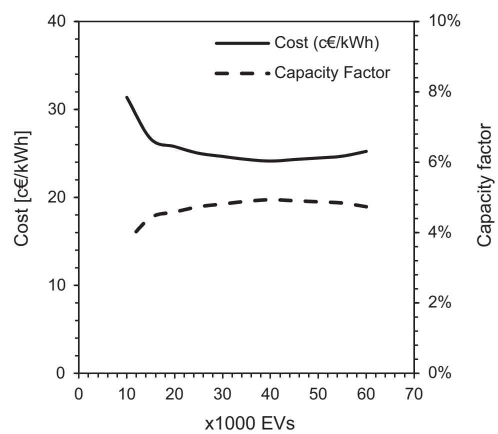

Fig. 8. Electricity costs and overall capacity factor as function of the number of EV.

- Mobility scenarios based on individual transportation are very energy intensive and therefore it is essential that city planning and energy policies focus on the development of public transportation, car pooling schemes, etc.
- Electricity storage is of paramount importance for an energy system based on renewable, and therefore varying resources. The energy storage may be achieved by either pumping storage or large scale deployment of electric vehicles acting as a back-up to the grid.
- Using present day costs for the technology, the cost of electricity was estimated to be below 0.05 €/kW h, or 150 €/person/year, which is more expensive than today's typical electricity bill but still should be manageable without too many economic and/or social consequences. Learning curves for the different technologies considered show that these costs will surely decrease in the near and medium term, making renewable energy systems even more cost competitive.

However, more important than these particular results discussed above, which of course depends on the different assumptions described above, this paper proposes a methodology for the analysis of energy systems that can be used in class in order to present the most relevant issues regarding energy systems, energy management and renewable energies.

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Article IV

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Energy certification of existing office buildings: Analysis of two case studies and qualitative reflection

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ABSTRACT

Energy efficiency in buildings is of particular importance in the pursuit of international objectives in the area of climate and energy, as it is a sector that represents approximately 40% of the total primary energy demand in the world, with expected strong growth. In Portugal, the current Building Energy Certification and Indoor Air Quality System (known as SCE) is intended to be an important step in the promotion of energy efficiency and reduction of greenhouse gas emissions. This work presents the application of the SCE system to two large office buildings in the Lisbon area: an historical building (the Lisbon City Hall, built in the late XIX century) and a contemporary office building. In the context of the SCE energy audits to these two buildings, a cost–benefit analysis of different energy optimization scenarios was performed based on calibrated building thermal simulation models. The two case studies, being very different between themselves, represent opposite contexts in which the SCE can be applied to existing buildings and thus the results constitute a suitable basis to examine the principles and energy indicators used in this and other certification schemes, resulting in a qualitative reflection on the limitations of the SCE and opportunities for its improvement.

1. Introduction

In the European Union (EU), increased building energy performance is a central tool to reduce energy dependency, having the imports in 2010 represented about 54% of the total internal consumption (European Commission, 2012a), and comply with existing carbon dioxide emission targets (European Commission, 2011a, 2011b). The building sector represents approximately 40% of the total final energy demand, with strong growth prospects in a business as usual scenario (Buildings Performance Institute Europe, 2011). Buildings typically have a lifespan of several decades and therefore refurbishment of existing buildings is an important element of the EU energy and climate strategy. In Europe, in each year about 1.2% of the building stock is renovated and 0.1% is demolished (EuroACE, 2011). In this context, building energy certification and labeling is a key policy instrument that provides decision makers in the building construction and refurbishment industry with objective information on a given building, either in relation to achieving a specified level of energy performance or in comparison to other similar buildings (International Energy Agency, 2010). EU has currently an ambitious strategy for deep renovations supported by the 2012/27 Energy Efficiency Directive (European Commission, 2012b). Theoretical framework and a practical tool for its implementation is provided in (BPIE, 2013).

Energy certification schemes can be applied to both new and existing service and residential buildings. These schemes are a subset of whole building environmental assessment schemes. The most well-known whole building qualitative assessment voluntary schemes are the Building Research Establishment Environmental Assessment Method in the UK (BREEAM, Environmental Assessment Method, 2012) and Leadership in Energy and Environmental Design (LEED) in the United States (USGBC, 2013). Both these voluntary schemes are increasingly being used internationally, e.g. by government agencies, as a basis for specifying minimum building environmental performance. Compared to mandatory schemes, voluntary schemes tend to be easier to implement because they are typically introduced in developed markets and are based in well-established quality assurance methods (Mlecnik, Visscher, & Van Hal, 2010). To date, most countries have chosen to adopt voluntary rather than mandatory whole building certification schemes. Mandatory schemes can be implemented in order to include all buildings, while voluntary certification schemes tend to include only buildings that have high energy performance ratings (International Energy Agency, 2010) that then tend to act as a benchmark for those markets.

In the EU, whole building environmental assessment is voluntary but energy certification is mandatory. It is the result of the transposition into national law of the EU Energy Performance

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of Buildings Directive (EPBD) (European Commission, 2002). This directive promotes the adoption of measures that maintain or raise indoor comfort levels while reducing building energy consumption. The guidelines for achieving these improvements are based on (1) adopting a common methodology to verify the energy performance of buildings, (2) defining minimum levels of energy efficiency applied to new and existing buildings that are submitted to large retrofitting, (3) creating energy certification schemes and (4) implementing mandatory periodical inspections for boilers and HVAC systems. More recently the European Commission considered the EPBD requirements should be extended through a recast (European Commission, 2010). This recast extends the existing directive by promoting the construction of nearly zero-energy buildings (nZEB) with a high incorporation of renewable energy. The nZEB definition adopted is vague, having the term "nearly" the possibility to be interpreted in several ways. This lack of definition is a direct result of the fact that the nZEB concept still requires a clear single definition and a commonly agreed energy calculation procedure (Marszal et al., 2011). Within the EU, the Comission is meanwhile promoting the reaching of a common nZEB understanding (BPIE, 2011). The work presented in this paper was developed within the framework of the 2002 EPBD and is unaffected by the guidelines introduced in 2010.

The introduction of the SCE energy certification scheme in Portugal (Ministério da Economia e da Inovação, 2006a) is the result of the transposition into Portuguese law of the 2002 EPBD. There are two main decrees that support the application of this system: RCCTE (Ministério da Economia e da Inovação, 2006b) and RSECE (Ministério da Economia e da Inovação, 2006c). RCCTE is applicable to residential and small service buildings (<1000 m^2 of net floor area) equipped with heating, ventilation and air conditioning (HVAC) systems of up to 25 kW (thermal power). RSECE is applicable to large services buildings (>1000 m^2) and small buildings equipped with HVAC systems with more than 25 kW of thermal power. Both regulations have certain limitations that should be addressed. (Ferreira & Pinheiro, 2011) analysed the flaws of the current version of RCCTE using a case study. In the present study we will focus on RSECE faults.

The aim of this paper is to analyze the application of the Portuguese energy certification system and regulation to the existing tertiary sector through the examination of two case types. This paper presents comprehensively the methodology and, after, the results of the application of the SCE energy certification scheme to two large existing buildings, the Lisbon City Hall (5400 m^2), a historical building, and tower five of the Arquiparque complex (6548 m^2), a contemporary building, both under RSECE. Surveys were conducted and documentation consulted in order to characterize all relevant aspects of the energy demand of these buildings (construction and geometry, HVAC, lighting, electrical appliances, occupancy and habits of use). Different optimization energy scenarios were tested.

The buildings are chronologically apart about 130 years from each other, thus are very different in constructive solutions, space use, etc. (see Section 3), representing each one the archetype of a service building from its own time. These particular buildings were chosen because they represent opposite contexts in which the SCE can be applied; for this reason, they constitute a fruitful basis to examine the principles and energy indicators used in this and other alike certification schemes. Their similarities and differences are exploited, resulting in a qualitative reflection on the limitations of the SCE and opportunities for its improvement. Findings and lessons learned are discussed within sections.

1.1. Structure

Since RSECE is the legislation that it is in the basis of the present work, in Section 2 it is presented a brief overview of the method of application of RSECE to existing buildings, including the definition of its main parameters. The methodology followed in this study is presented here. Section 3 begins with a description of the most relevant characteristics of the two case studies (Sections 3.1 and 3.2). It continues with a description of the simulation models, including its main inputs and calibration process (Sections 3.3 and 3.4). Results obtained in the different sets of simulations, with discussion, are presented in Sections 3.5–3.7. In Section 4 are presented the energy saving measures proposed and its impacts in different scenarios. After these sections, when the reader it is already in known of the particularities of RSECE, it is opportun to present in Section 5 a qualitative approach to the limitations found in the SCE system. Some of the improvements discussed are sustained with the use of the results from earlier sections. In Section 6 conclusions of the work are presented as well as concrete perspectives for further development of the concepts proposed.

2. Adapted approach

The methodology followed in this study and calculation of parameters has as basis the SCE framework. Under RSECE, the overall energy performance of a building is summarized by an index of primary energy consumption, the Energy Efficiency Index (EEI), in kgoe/m^2.year (where *oe* stands for oil equivalent). The index is obtained using detailed thermal simulation. There are four types of EEIs, as seen on Table 1.

Depending on the value of these indexes, existing buildings may have to undergo an energy rationalization plan (ERP), as shown in Fig. 1. The $EEI_{STANDARD}$ index is used in the end of the certification process to define the building energy certification rating (see Section 3.7).

In addition to the energy component, SCE has an indoor air quality component that is meant to ensure minimum air change rates and compliance with the maximum concentrations of a set of pollutants, microorganisms and radon. The indoor air quality (IAQ) component of the certification process was not performed in the present study. An interesting example of the application of this component of the method is presented by (Asadi, Costa, & Gameiro da Silva, 2011).

The approach method we took can be schematized as Fig. 2 illustrates. In this figure ARC stands for Annual Registered Consumption; ASC for Annual Simulated Consumption; M_iRC for Monthly *i* Registered Consumption and M_iSC for Monthly *i* Simulated Consumption, being *i* the months from January till December.

3. Case studies

To present the applicability of the SCE to existing buildings and, from there, critically appreciate the system we have chosen two buildings that symbolize opposite contexts in which the SCE can be applied. As previously introduced, the two buildings that constitute the case studies on focus are chronologically apart about 130 years from each other (one from mid XIX century and another one from late XX century), thus are very different in constructive solutions, space use, etc. (details are provided in the next subsections), representing each one the archetype of a service building from its own time. Table 2 presents an overview of the features of the two buildings analyzed. One can see that the useful areas of the buildings are not very different (contemporary building net floor area is about 20% higher than the historical), but the same does not happen with occupation density: contemporary building

Table 1
Different types of Energy Efficiency Indexes (EEIs).

$EEI_{STANDARD}$	Calculated value, based on standard conditions of use, defined according the typology (e.g., schools, hotels, etc.) of the building. More about standard conditions in Section 3.7
EEI_{REF}	Reference limit according to the typology
$EEI_{REAL,\ INVOICES}$	Calculated by simple analysis of the last three years building energy consumption invoices (including HVAC consumptions)
$EEI_{REAL,\ SIMULATION}$	Corresponds to EEI obtained through dynamic thermal simulation of the building using the real conditions of use

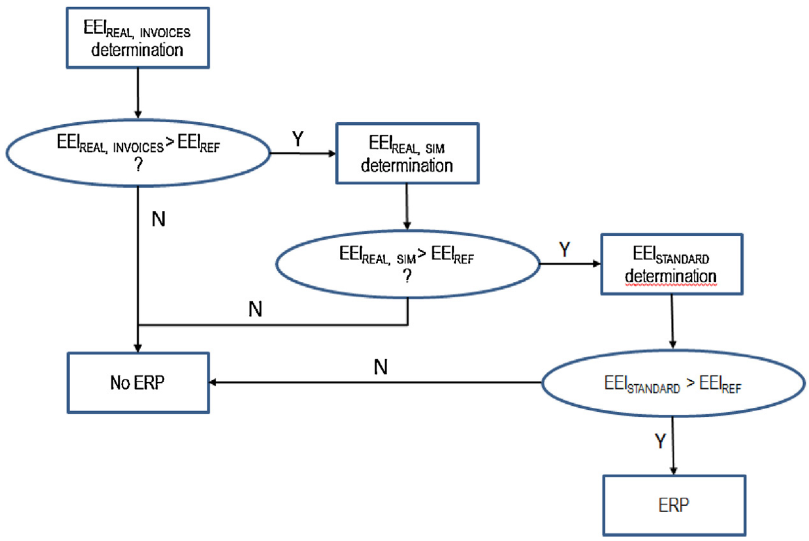

Fig. 1. Definition of the need to submit an existing building to an ERP in the SCE system.

presents almost the double of occupants per unit of net floor area. Concerning electrical appliances density (most of which is office equipment), we can also see that the contemporary building more than doubles the value of historical building. On the other side, lighting density is about 2.5 times less in contemporary building. These differences are due to different strategies of space use management and architectural reasons, each one typical from its own time.

3.1. Historical building (Lisbon City Hall)

This large services building is located in downtown Lisbon (Fig. 3), near the Tagus river. It was built in 1863 with a net floor area of 5 400 m^2 distributed by 4 floors, providing services to the general public, municipal meetings and offices.

3.1.1. Construction

The building has stone masonry walls (*tout-venant* type stone of various sizes bonded with mortar), typical of the late XIX century, with massive thick exterior walls (approximately 1.0 m, $U = 0.84\ W/m^2\ K$) and interior partitions that can reach 0.5 m thickness (providing the building with high thermal inertia).

Single glazing wood frame windows occupy less than 50% of the façade area. Shading is provided by internal roll down curtains (manually operated).

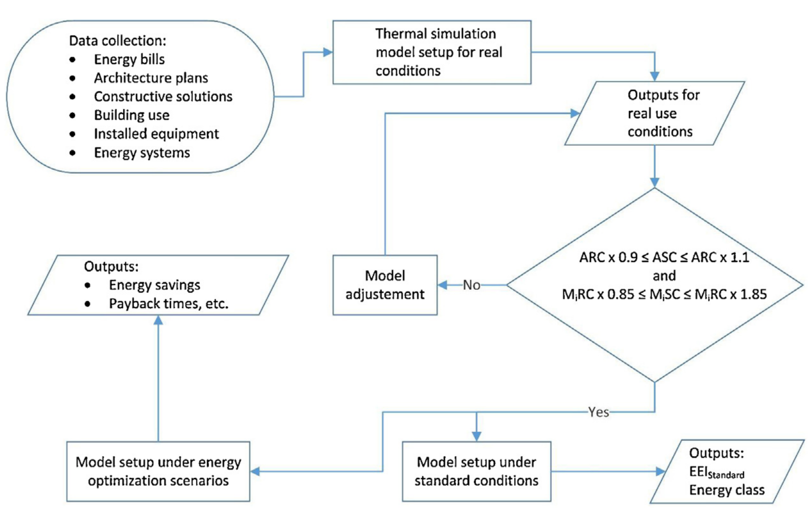

Fig. 2. Approach method.

Table 2
Summary of characteristics of the two buildings.

		Historical		Contemporary
Building use		City-hall/offices		Offices
Net floor area		5400 m^2		6548 m^2
Average occupancy		209 occupants 25.8 m^2/occupant		353 occupants 13.7 m^2/occupant
Lighting density		35.3 W/m^2		13.3 W/m^2
Equipment density		5.5 W/m^2		13.5 W/m^2
Average energy consumption		104 kWh/m^2 year (electricity)		128.5 kWh/m^2 year (electricity) 23.1 kWh/m^2 year (natural gas)
HVAC	System 1	Two fresh air treatment units, total 9300 m^3/h (fixed) One chiller (65 kW) and one heat pump (73 kW), air–water, two pipe distribution	System 1	Two fresh/extracted air treatment units, total 19 300 m^3/h each (fixed) An air–water chiller (182 kW) and two boilers (137.5 kW each). Four pipe distribution
	System 2	26 fan–coil terminal units plus a VRV system with condensers installed in the roof cavity and 61 fan–coil units (the evaporators) in the office spaces.	System 2	172 fan–coil terminal units (28 on average per floor) installed in the office spaces.

3.1.2. *HVAC system*

The building has a centralized HVAC system, composed of two subsystems, with the following characteristics:

- *System 1*: two fresh air handling units, total 9300 m^3/h (fixed), one chiller (65 kW) and one heat pump (73 kW), both air–water;
- *System 2*: split A/C with 26 VRV type HVAC units with the condensers installed in the rooftop and the evaporators (61) inside the offices (System 2). The temperature setpoints are 21–25 °C (winter and summer, respectively);
- The system was installed in 1997.

3.1.3. *Lighting and equipment*

A site survey revealed that most of the lighting is indirect, from fluorescent lamps. In most formal spaces there are incandescent lamps installed in chandeliers (see Fig. 3, right). The average lighting power density for the whole building is 35.3 W/m^2. The average equipment power density is 5.5 W/m^2.

3.1.4. *Available energy consumption data*

The sole energy source for this building is electricity. The energy consumption survey was based on 36 monthly electricity bills (the three years before the audit). There is only one electricity meter for the entire building, so there is no disaggregated information about consumption for different uses, such as HVAC systems. The average yearly consumption is 559 MWh/year, which corresponds to 104 kWh/m^2 year. As expected for a services building located in a temperate climate, electric consumption during summer for cooling is much higher than in winter for heating. Using a conversion factor of electricity to primary energy (F_{pu} = 0.00029 toe/kWh$_e$) results in an $EEI_{REAL,\ INVOICES}$ = 30 kgep/m^2 year (see Section 2).

3.2. *Contemporary building*

The second case study is a seven storey office building built in 1996, located in the outskirts of Lisbon. Left and center pictures in Fig. 4 show a south view of the building. The office floors have a total net floor area of 6548 m^2. It has three levels of underground car parking (3243 m^2) and a top level technical area under a partially closed rooftop (170 m^2). At the time of the audit about 75% of the office spaces of the building were occupied.

3.2.1. *Construction*

The building has a concrete structure and concrete block façades, insulated from the outside (U = 0.45 W/m^2 K). The façades are approximately 50% glazed. Metal frame windows in the offices have double glazing (partially reflective, with low emissivity coating). Internal curtains (manually operated) are used for shading in the offices, except for a narrow glazed area near the ceiling in each floor. The entrance hall is five storey high with double glazing and external venetian blinds (also manually operated).

3.2.2. *HVAC system*

The HVAC system has the following characteristics:

- An air–water chiller (182 kW) and two gas boilers (137.5 kW each). Four pipe water distribution system is used;
- One fresh air handling unit with total flow 19 300 m^3/h (fixed);
- One exhaust fan unit with total flow 19 300 m^3/h (fixed);
- 172 fan–coil terminal units (28 on average per floor) installed in the offices and open spaces;
- The thermal plant is located in a technical area on the rooftop.

3.2.3. *Lighting and equipment*

The majority of lighting systems use fluorescent tubular bulbs installed in direct fixtures on the false ceiling. Average lighting power density for the leased spaces is 13.3 W/m^2. The average equipment power density for all building, including circulations, is 13.5 W/m^2.

Fig. 3. The historical building (Lisbon City Hall).

Fig. 4. Left and center: south view of the contemporary building; right: window in the lobby with external shading (venetian blinds).

3.2.4. Available energy consumption data

This building uses electricity and natural gas (in the thermal plant for heating). We analyzed a total of two years of monthly bills. The average total consumption of electricity for the analysis period is 842 MWh/year. Natural gas consumption occurs typically between November and April, with an average consumption of 14 300 m^3/year for the analyzed period (two complete heating seasons), which corresponds to about 151 MWh/year. Average specific consumption for the whole occupied spaces of the building (unoccupied spaces were not considered), is $EEI_{REAL,\ INVOICES}$ = 32.8 kgoe/m^2 year.

3.3. Simulation models

The building thermal simulations were performed using EnergyPlus (E+) (U.S. Department of Energy, 2009). This simulation tool complies with ASHRAE 140-2004 standard, as the regulation obliges to, but other simulations packages could been used. For a review on the capabilities of building energy simulation programs see (Crawley, Hand, Kummert, & Griffith, 2005). Graphical user interface DesignBuilder (DesignBuilder Software Ltd., 2009) for E+ was employed. The weather data used in the simulation is representative of a typical year in Lisbon (INETI, 2009). The construction of a simulation model representative of reality is an iterative process, where the analysis of results generates sequential modeling refinements (see Fig. 2). Fig. 5 shows 3D rendered images of the two building models. As a result of: geometry, orientation, glazing surface, HVAC installed, internal loads, etc., the building models were divided into thermal zones (19 zones for the historical building and 79 zones for the contemporary, see example in Fig. 6).

All the relevant data collected in the surveys was introduced in the models. Infiltration of outside air was defined according the existence, or not, of mechanical fresh air supply in the spaces and level of envelope tightness. The HVAC systems were modeled according to the HVAC projects that were supplied by the buildings' managers. Comparison between the simulation results and the energy consumption obtained from the invoices allowed for an estimation of the overall efficiency of the HVAC systems. The results of detailed surveys by questionnaire were introduced in the simulation as 24 h schedules (of occupancy, lighting, equipment, HVAC system operations including ventilation, etc.) for weekdays, weekends and holidays.

Two sets of simulations were performed for both buildings: (1) in real conditions of use and (2) in standard conditions of use. Measures of energy optimization were included in simulations, separately or combined. Their applicability was always analyzed in a cost–benefit perspective.

3.4. Calibration of the thermal simulation model

Calibration of the simulation model is an iterative process of adjustment, whose goal is to obtain simulation predicted outputs that are similar to the equivalent measured parameters. In the present case, the focus is on simulation predicted energy consumptions, versus energy bills (invoices). Despite the numerous published case studies, there is still no accepted standard method for calibrating a model. Examples of proposed methodologies include (Raftery, Kean, & O'Donnell, 2011), (Yoon, Lee, & Claridge, 2003) and (Heo, Choudhary, & Augenbroe, 2012). In the present case the variable evaluated in the calibration of the model is the total predicted energy consumption. The process leads to a series of adjustments in various parameters of the model. Under RSECE, a model is considered calibrated if the total predicted energy consumption is within ±10% of the total consumption data from the energy bills, on an annual basis.

3.4.1. Historical building model calibration

Initial thermal simulations for the historical building showed that corrections were required, such as a more detailed assessment of the building usage schedule. One example of these adjustments was the occupancy of offices until late hours in the evening that happens in a typical week, not identified in previous surveys. Although this type of occupancy has no predefined pattern, it leads to lighting energy consumption until 23:00 h every weekday.

The calibration process also refines the prediction of real coefficient of performance (COP) of HVAC systems, i.e., overall COP including distribution losses and reduction in equipment efficiency due to use. Results of calibration are shown in Fig. 7. Typical COP of the installed HVAC system with no losses is approximately 2.5 while the overall COP determined was 1.5 (a substantial 40% reduction). One should note that climate data used in our simulation models are the typical meteorological year (TMY in Energy Plus Weather format), based on a 30 years series of hourly data. The energy bills analyzed cover a period of two or three years. This means that substantial differences can occur between the climate in the weather file and the actual climate that occurred in the period respecting the energy bills. And the differences are bigger for small periods of time, like one month, which explains the relatively bigger differences in some months (see Fig. 8). Use of actual meteorological data for the analyzed period could be advantageous in this case. However, it was not performed because freely available sources lack essential parameters such as hourly solar radiation. Overall, for the total yearly energy consumption, there is a 3% difference, with all months within 15% difference.

3.4.2. Contemporary building model calibration

For the contemporary building, the initial simulation results showed very low heating requirements when compared to the consumption of natural gas recorded in the gas bills. As a result, the following model adjustments were made:

- The setpoint of air temperature during the heating season was adjusted to 21 °C, instead of the 20 °C initially defined;

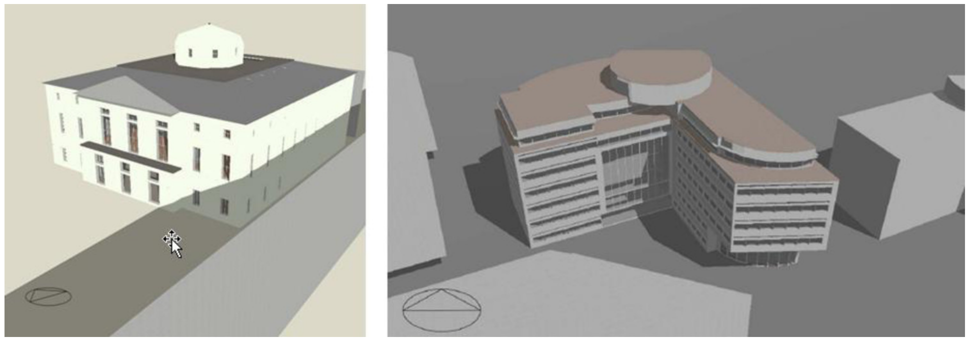

Fig. 5. Visualization of the 3D models: left, historical building (from SW, 15th December, 14:00 h); right, contemporary (S, 15th March, 10:00 h).

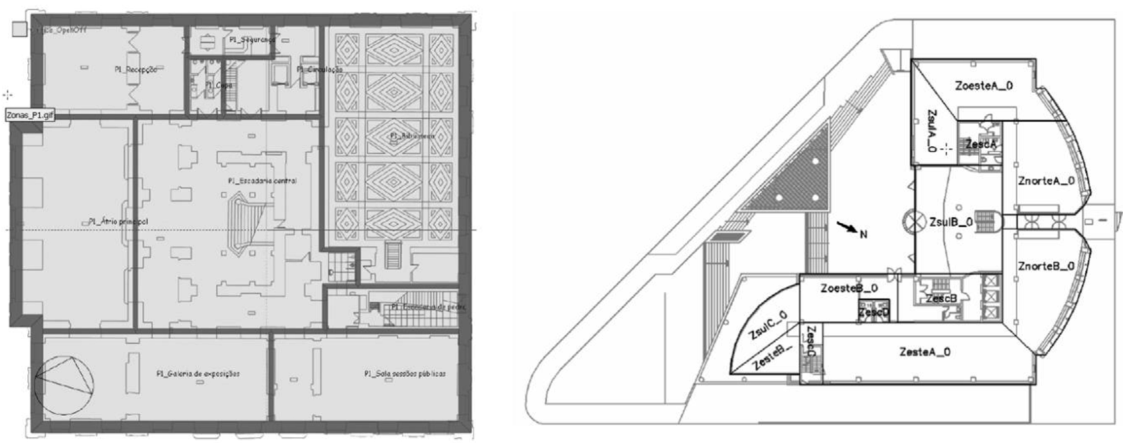

Fig. 6. Example of model thermal zoning. Left, historical building (1st floor); right, contemporary building (entrance floor).

- Effective efficiency, including efficiency in production and distribution, of heating process was adjusted to 0.4 and cooling processes to 1.3 (COP).

Results of the calibration of the contemporary building simulation are presented in Fig. 7 as well. For the total annual energy consumption there is a 5% difference, with some months reaching 15%. In addition to the above mentioned weather data related discrepancies, another factor that contributes to the difference verified is the changing in tenants of the building between the moment in which the audit was performed and the period of the invoices.

3.5. Simulation in real conditions of use

The results of the thermal simulation using real conditions are summarized in Table 3. From these values, $EEI_{REAL,\ SIMULATION}$ values can be calculated (see Section 2): 30.0 kgoe/m^2 year for historical building and 32.8 kgoe/m^2 year for contemporary building. Profiles of monthly heat and cool demand are shown in Fig. 9.

3.6. Discussion of results

Calibration of both models has permitted to obtain accurate computational representations of the real buildings, with error margins of 3% and 5% for the historical and contemporary building, respectively. For the historical building, it follows from the simulation that lighting is responsible for the largest share of the total electrical consumption (54.6%). Offices and circulations share 34% and 27% respectively of this consumption. These high figures make lighting a priority area for intervention. The HVAC system (including fans) accounts for less than a third of the overall building consumption, a typical value for this type of building.

For the contemporary building, lighting accounts for approximately 29% of total electricity, with clear predominance for lighting

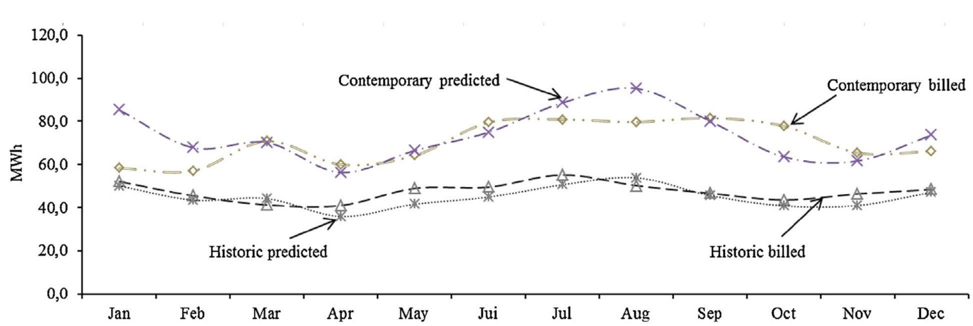

Fig. 7. Evolution along the year of the foreseen consumption by the simulation and the energy consumption registered.

Table 3
Annual energy consumptions (electricity or natural gas) by type of usage.

	Historical building			Contemporary building		
	MWh	toe	Share of total (primary energy)	MWh	toe	Share of total (primary energy)
Lighting	297.5	86.3	54.6%	244.0	70.8	29%
Electrical appliances	57.1	16.6	10.5%	227.7	66.0	26%
Heating	56.3	16.3	14.0%	147.3	12.7	5%
Cooling	83.9	24.3	17.8%	217.3	63.0	25%
Others	16.9	4.9	3.1%	140.1	40.6	16%

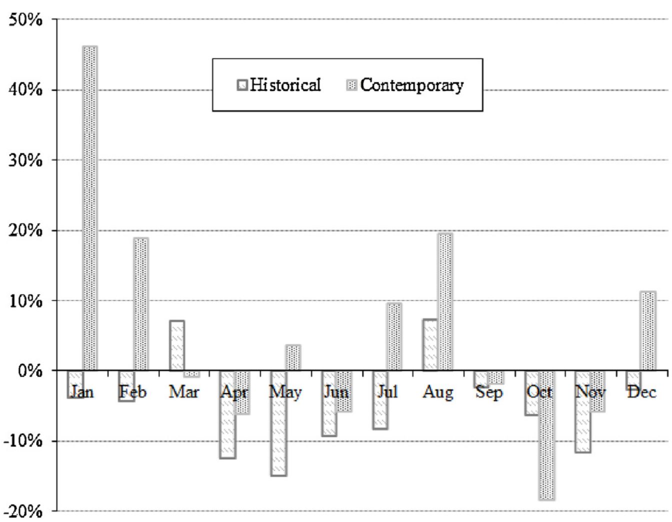

Fig. 8. Percentage monthly differences between registered and simulated consumption.

of working areas on the office floors (24% of total electricity consumption). In total, lighting in offices, parking and outdoor spaces are responsible for approximately 28% of the annual primary energy consumption of the building. Thus, in contemporary building, as in the case of the historical, lighting is identified as an area in which to propose a reduction in energy consumption.

3.7. Simulation under standard usage conditions

As discussed above, the RSECE/SCE system analyses building energy performance using a methodology that is meant to be independent of building use. The goal of this system is to be able to compare the energy efficiency of different buildings that can have in reality very different conditions. Standard usage conditions are listed in the regulation and consist of densities of occupancy and electrical appliances, fresh air ventilation rates, schedules of occupancy, electrical appliances and lighting (Fig. 10 shows an example of this last type of schedule), that vary with building use. The office typology is therefore a pattern of use (densities and schedules) that represents a typical office. Lighting is not a standard condition: the actually installed lighting power density should be used in this simulation. For the two buildings examples of standard parameters use are shown in Table 4.

Finally, for comparing the buildings, we applied correction factors for winter and summer heating and cooling demand to compensate for the effects of climate variation between the different locations (Ministério da Economia e da Inovação, 2006b).

The results of the simulations in standard conditions are summarized in Table 5. One should note that lighting consumption in the historical building is much lower in standard conditions due to the lower usage profile, which is more reasonable than the real profile (operation of offices until 23:00 h, etc.); consumption for heating is higher in standard conditions because of less heat generated by lighting. The same is conversely true for cooling demand.

The values for the $EEI_{STANDARD}$ are 20.5 kgoe/m^2 year for historical building and 30.9 kgoe/m^2 year for the contemporary. Energy class of both buildings is C, in a scale from A+ (the better) to G (the worst) (Fig. 11). The historical building houses the City Hall, and since for this typology the reference maximum value that is legislated is 15 kgoe/m^2 year, the implementation of a plan for reduction of energy consumption is mandatory (see Fig. 1). The same for the contemporary building, which has a limit value of 30.7 kgoe/m^2 year (value obtained by the weighted average by the net floor area of the limit values of the usage types that exist in the building: Offices and Car Park). The plan for reduction of energy consumption must consist of energy saving measures that have a simple payback period inferior or equal to eight years, determined by simulation or other method for the real conditions of usage of the building.

4. Reduction of energy consumption

Effective energy management requires methodologies that support the selection of energy saving measures, which are viable and environmental friendly. (Doukas, Nychtis, & Psarras, 2009) presented a decision support model for such measures in a typical existing building based on the existing energy management systems. (Iqbal & Al-Homoud, 2007) investigated the impact of alternative energy conservation measures on energy requirements in office buildings in hot–humid climates using parametric analysis. In the present case, we tried to identify and analyze potential measures to improve energy efficiency of the two buildings. The measures analyzed were: improved lighting, installation of photovoltaic (PV) panels and improvement of the HVAC systems.

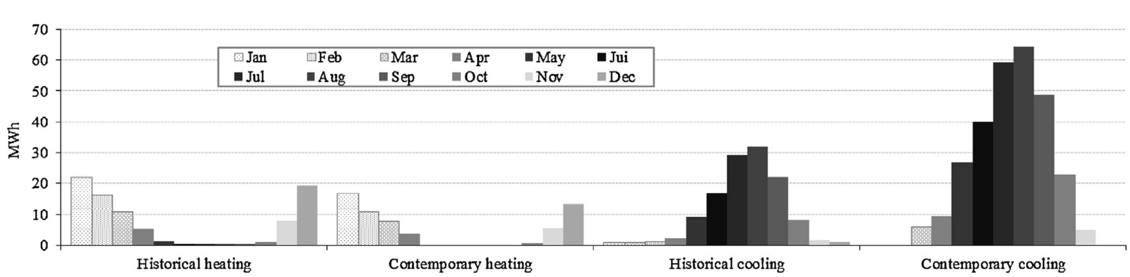

Fig. 9. Monthly heating and cooling demand.

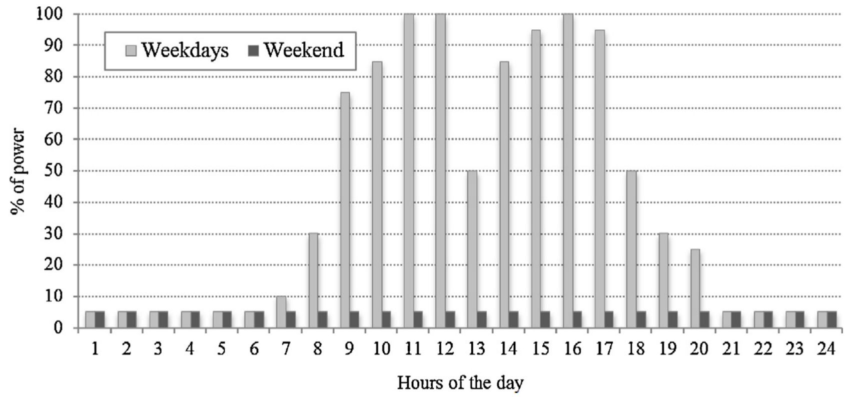

Fig. 10. Lighting schedule for the Offices typology as defined in the regulation.

Table 4
Standard parameters and comparison with real parameters.

	Occupancy (m^2/occupant)		Equipment (W/m^2)	
	Real	Standard (City Halls typology)	Real	Standard (offices typology)
Historical building	25.8	15	5.5	5
Contemporary building	18.5	15	13.5	15

Table 5
Electrical consumptions in standard conditions of use.

	Historical		Contemporary	
	MWh	Variation from real conditions	MWh	Variation from real conditions
Lighting	182.8	−38.6%	236.6	−3.1%
Electrical appliances	51.2	−10.3%	314.8	+27.7%
Heating	65.0	+15.4%	99.7	−32.3%
Cooling	75.6	−9.9%	297.2	+36.8%

4.1. Improved lighting scenarios

There is a great potential for intervention in the lighting installations as shown by the predominance of lighting consumption displayed in Table 3. For office buildings, different case studies showed that it is possible to obtain both good visual quality and low installed power. In particular, a normalized power density of $2\,W/m^2$. 100 lux is feasible with currently available technology. Also, development of LED technology is growing, being already well suited to task lighting applications. Identification of the locations where it was possible to improve lighting systems obeyed three criteria: compatibility between possible intervention and the character of the space; existing lighting density; share of the zone in the total lighting consumption. Two lighting optimization scenarios were defined for each building.

4.1.1. Lighting scenario: historical building

The “Light1” optimization scenario consists of:

1. Substitution of incandescent lamps by compact fluorescent lights (CFL) with the same total amount of lumens. This

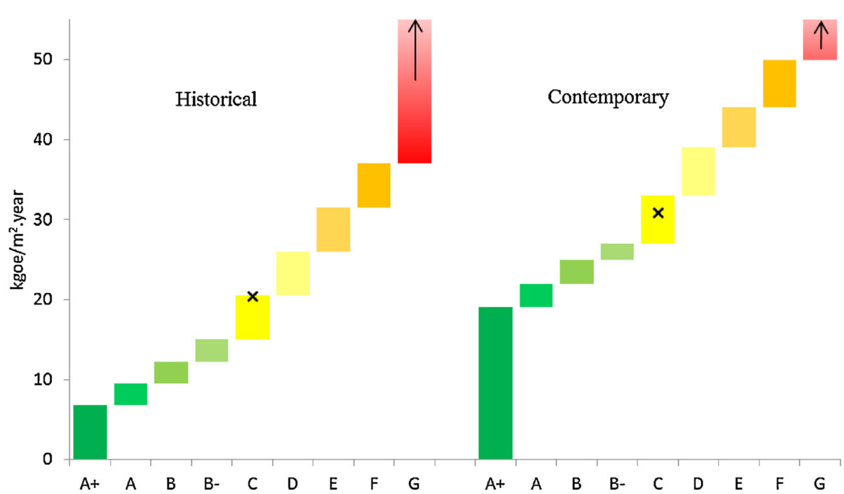

Fig. 11. Energy classes for the buildings (“×” marks the actual value).

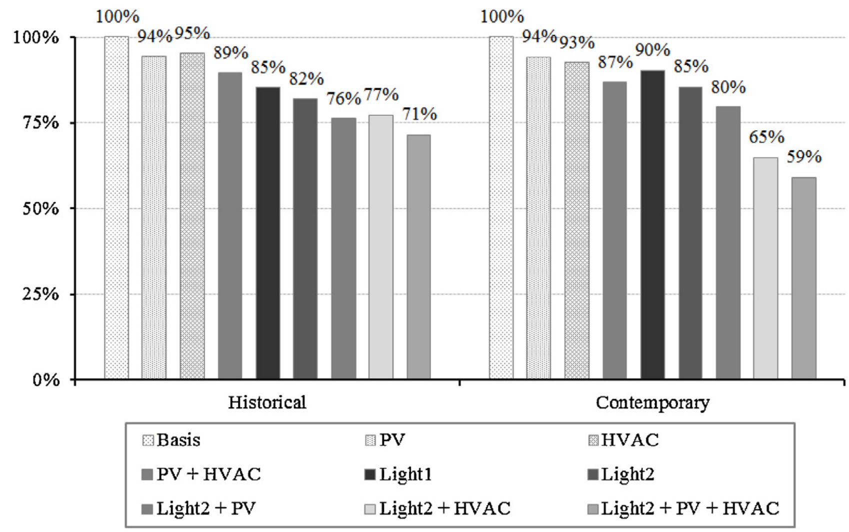

Fig. 12. Net total electrical relative consumptions from the grid for the projected scenarios.

measure must always be applied given the UE prohibition of sale of incandescent lighting bulbs, started in 2012;

2. In the offices: elimination of lighting in the false ceiling cavities (indirect light), given low luminous efficiency of this solution. The offices currently have a lighting density of 20 W/m^2, which is clearly high. It is advisable therefore a lighting solution in a plane directly below the ceiling, allowing for 350–400 lux (Veitch & Newsham, 2000). The implementation of such measures leads to a reduction in lighting density to 8 W/m^2. The possibility of installing lamps in the work plan should not be dismissed given its greater efficiency;
3. Substitution of existing halogen lamps by low consumption alternatives with equal luminous.

The "Light2" scenario differs from "Light1" in the lighting schedules for the offices, which become equal to the occupancy schedules. The survey showed that even in the absence of workers (lunch time, etc.) the lights are not turned off. Therefore, the "Light2" scenario considers that lighting follows occupancy, and its implementation may be through consciousness of the employees of the importance to turn off the lights when they leave (or, alternatively, can be implemented by adoption of motion detectors in the offices). The spaces affected by these measures represent 80% of total lighting consumption and 44% of total electrical consumption in the building. Daylighting measures were not considered in historical building because of existing shadowing by adjacent buildings.

4.1.2. Lighting scenario: contemporary building

The "Light1" optimization scenario consists in a reduction of installed lighting power in offices to 8 W/m^2. This is a reduction of approximately 40% of the installed lighting power, which allows a further reduction on energy consumption for cooling, with a marginal increase in the energy consumption for heating.

The "Light2" scenario combines the Light1 scenario with daylight responsive luminous flux adjustment in the office spaces and replacement of outdoor lighting fixtures. In this scenario 80% of the room lighting is adjusted continuously by the natural light levels detected by installed sensors, which are set to 400 lux (indicative value), and the remaining 20% subject to the general control. This measure has higher costs because it requires for a change of equipment: continuous adjustment of artificial lighting levels is only possible with the use of electronic ballasts with adjustable flux. For the payback calculations, we considered an average cost of 35 €/m^2. Outdoor lighting corresponds to approximately 8% of annual electric consumption of the building. Overall, 85% of the outdoor lighting fixtures use halogen lamps that, in this scenario, are replaced by fluorescent lighting with the same output. Lighting schedule following occupancy in contemporary building was not considered since discrepancy between lighting and occupancy was found to be small.

4.2. PV scenarios

The scenarios of installation of photovoltaic panels considered grid connected systems with a kWh sale cost equal to purchase cost. In the historical building, the south facing portion of the building roof allows for the installation of PV panels with a total area of approximately 220 m^2 (11° inclination and an azimuth of 17° relative to the south in SE direction). For architectural reasons, the panels should be installed in a plane parallel to the roof (a slope of 11° penalizes production by approximately 6.1% when compared with the optimal inclination, which, for Lisbon, is 32° (JRC European Commission, 2013). Monocrystalline modules were chosen with a total installed power-peak of about 24 kWp. Simulation showed that the average annual net output would be 31.3 MWh (considering losses in the system due to temperature, wiring and inverter). For the contemporary building, it is considered 300 m^2 of panels installed on the roof with 32.7 kWp of power, with optimal orientation and inclination (south oriented, 32° slope). Annual production is estimated to be around 56.7 MWh.

4.3. HVAC optimization scenarios

4.3.1. HVAC scenario for historical building

An efficient solution for production of thermal energy for ambient heating and cooling is the use of a ground connected heat pump to obtain energy from low enthalpy geothermal resources (Hepbasli & Tolga Balta, 2007). In this area of downtown Lisbon, the ground water level is quite high, due to the proximity of the river (this part of the city is built in terrain that was once part of the river bed), typically water can be found at approximately 3.5 m depth (Farinha, 1995). For this reason we studied a scenario that replaces the air source heat pump with a geothermal water source heat pump (this scenario is called HVAC). We considered that the replacement heat pump has an average COP of 4.5 (Hepbasli & Tolga Balta, 2007). In the simulations, an effective COP of 3.15 was used to account for losses in the distribution network. The VRV system with fan–coils

Table 6
Annual savings and payback periods for the scenarios.

	PV	HVAC	PV + HVAC	Light1	Light2	Light2 + PV	Light2 + HVAC	Light2 + PV + HVAC
Historical								
Annual savings	3.6 k€	3.0 k€	6.6 k€	9.2 k€	11.3 k€	14.9 k€	14.3 k€	17.9 k€
Relative annual savings (energy)	6%	5%	11%	15%	18%	24%	23%	29%
Investment cost	110 k€	31 k€	141 k€	65 k€	74 k€	184 k€	105 k€	215 k€
Payback	24 years	11 years	21 years	7 years	6 years	12.3 years	7 years	12 years
Contemporary								
Annual savings	6.5 k€	8.4 k€	14.9 k€	10.9 k€	15.7 k€	22.9 k€	39.4 k€	45.9 k€
Relative annual savings (energy)	6%	8%	13%	10%	15%	20%	35%	41%
Investment cost	150 k€	43 k€	193 k€	130 k€	237 k€	387 k€	280 k€	430 k€
Payback	23 years	5.1 years	13 years	11.9 years	15 years	17 years	7.1 years	9 years

cannot be connected to this equipment, because of the intrinsic different principle of operation. Because we did not consider replacing the VRV system, for the whole building the overall COP increases from 1.5 to 1.84 (a 23% improvement).

4.3.2. HVAC scenario for contemporary building

In the contemporary building we have studied a conversion of the HVAC system in order to increase the efficiency of the heating and cooling processes. This is difficult to assess given the complexity of the existing system and the quantity and variety of equipment involved. To identify the most appropriate intervention it is necessary to investigate in more detail the various components and evaluate the need for replacement or rehabilitation of equipment, piping, insulation, etc. Therefore, we have chosen to consider as objective the increase of overall efficiency of heating (boiler) and COP of cooling (heat pump) in 30% (an increase, respectively, to 0.52 and 1.69). The costs for this intervention were very difficult to estimate; therefore, an investment value such that the payback period is not more than 8 years was used.

4.4. Results for real conditions

Fig. 12 shows the results of predicted electrical consumption of the buildings in real conditions of use. Table 6 shows the annual savings and payback periods calculated for both buildings for each scenario.

In historical building, the simultaneous adoption of the all optimization scenarios (Light2, PV and HVAC), results in a decrease in the annual electricity bill of approximately 30% (17.9 k€ of annual savings), with a payback period of 12 years. Light1, Light2 and Light2 + HVAC scenarios are of mandatory application (they have a payback inferior to 8 years, see Section 3.7).

For the contemporary building, the adoption of all the scenarios leads to a decrease in the energy bill of almost 46 k€ on an annual basis (a 41% reduction in energy consumption, with an estimated payback of 9 years).

4.5. Results for standard conditions

The previously defined optimization scenarios were also simulated in standard usage and load conditions. This allowed for an evaluation of possible changes in building energy class (or rating). Fig. 13 summarizes the results obtained ($EEI_{STANDARD}$ for each scenario). For the historical building, the energy demand calculation in standard conditions requires that the standard schedule is used for the Light 2 scenario. For historical building, the Light2 scenario was replaced by the Light3 scenario, which is a variant of the Light2 scenario with modified lighting density in the dinner room (which is a formal space rarely used but with a very high lighting density, 191 W/m^2). Substitution of fiber optic existing illumination by LEDs is proposed in this scenario, which leads to a 2/3 reduction in lighting density. This scenario was not simulated for real conditions of use because, as said, this space is rarely used, and the modification proposed would have in real conditions a very high payback period.

For contemporary building, the system proposed on Light2 scenario (see Section 4.1.2) implies an operation profile with a power fraction that is dependent on the natural levels of illumination, thus it is a more efficient system in the sense that same level of illumination is obtained with less energy consumption. Thus, we consider that is a valid strategy to simulate its impact in standard conditions, overriding the standard profile regarding power, but maintaining the standard operation schedule (see Fig. 10).

These results for the historical building show that:

- The simultaneous application of scenarios Light3, PV and HVAC results in an improvement in energy class, from C to B−;
- Overall, the $EEI_{STANDARD}$ can improve by 25% (a decrease in 5.5 kgoe/m^2 year);

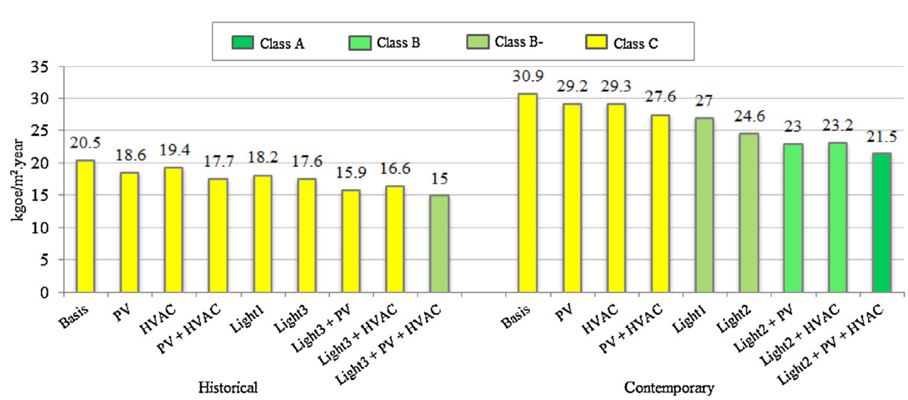

Fig. 13. Results in the EEI of the energy optimization measures.

- Despite Light2 having negligible effects on real consumption, it allows for, in standard conditions, an improvement of 0.6 kgoe/m^2 year, 2.9% in the overall value of the indicator. The additional cost of the intervention is estimated at about €3000, and based on these assumptions the payback period for this measure is calculated to be 2.65 years.

The results for the contemporary building show that:

- The simultaneous application of scenarios Light2, PV and HVAC results in an improvement in energy class, from C to A;
- Overall, the $EEI_{STANDARD}$ improves by 31% (a decrease in 9.4 kgoe/m^2 year).

5. Proposed improvements to the SCE system

The application of the SCE system should result in tangible energy savings compared to what the industry would be without this regulation. This section presents a qualitative approach to the limitations of the SCE system. A set of possible improvements is discussed. Some of the proposed improvements are already in use in other certification systems, such as LEED [7] or BREEAM [6].

5.1. Improvement of the EEI

Given the purpose of the SCE to limit overall consumption in the buildings sector (in toe/year or kWh/year), the units adopted (kgoe/m^2 year) may appear, in a first instance, appropriate. However, it may be more effective to normalize energy consumption using the number of building occupants rather than the currently used gross floor area, given that services buildings are "designed for people". Thus, we propose an indicator with units of kgoe/occupant.year. A limit may be set on the number of occupants/m^2 to guarantee that buildings which exceed a reasonable density of occupancy (function of typology) do not have that excess accounted in the EEI calculation. This type of indicator would impose worse energy classes on houses or services buildings with low occupancy densities, and thus would prove more effective from an overall sustainability perspective. Finally, this indicator is directly proportional to the building energy costs per occupant (as opposed to *per square meter* in the case of the standard indicator).

We have performed an exploratory exercise with the buildings studied. The historical building has a relatively low real occupancy density (25.8 m^2/occupant). This number includes occasional occupants, for example citizens who attend city hall meetings, and therefore it is inappropriate for comparison with other buildings with other types of occupancy, like the contemporary building. For a correct assessment, it is necessary to normalize patterns of occupancy. This normalization can be carried out for working weeks of the year on the basis of 8 h/day on working days (40 h/week), generating a correction factor *Fc*. This factor will be function of the various types of space utilization, each corresponding to one type of use profile *i*. The expression of the correction factor takes the form

$$F_C = \frac{\sum_{i=1}^{n}(\text{occupants})_i \times ((\text{yearly hours})_i/47 \times 40)}{N} \quad (1)$$

where (occupants) is the total number of occupants with the usage profile *i*; (yearly hours) is the total number of hours per year that each occupant with real *i* use profile remains in the building; *N* is the total number of occupants; 47 is the average number of working weeks *per year*; 40 is the number of weekly working hours (8 h/day).

Thus, normalized number of occupants in a building is calculated with the expression

$$\text{occupants}_{\text{normalized}} = F_C \times N \quad (2)$$

Table 7
Relevant parameters of the two buildings for comparison.

	Historical	Contemporary
Area (m^2)	5398	4602
Occupants	209	353
F_C	0.69	1.00
Occupants normalized	145	353
Real occupancy density normalized (m^2/occupant)	37.2	13.0
Lighting density (W/m^2)	35.3	13.3
Real electrical appliances density (W/m^2)	5.5	13.5
EEI_{REAL} (kgoe/m^2 year)	30.0	53.9
$EEI_{REAL,\,OCC}$ (kgoe/occupant$_{NORM}$ year)	1117	703

Adopting this methodology in the historical building, which has an occupancy of 105 employees during work hours and about 208 occasional visitors *per week* (for calculations, we used 104 at a time, two times per week, 8 h/day), we obtain a normalized value of 145 occupants. Since $EEI_{REAL,\,INVOICES}$ of the building is 30.0 kgoe/m^2.year, we obtain

$$EEI_{REAL,OCC} = 30.0 \times \frac{5398}{145} = 1117\,\text{kgoe} \quad \text{occupant}_{\text{norm}}\,\text{year} \quad (3)$$

In order to understand the meaning of this indicator, a comparison between historical and contemporary building, which has a substantial superior occupation (13.7 m^2/occupant), should be performed. For comparison of the buildings in standard conditions, the historical building was simulated for the same type of use that was used for the contemporary building (Offices). Fig. 14, left, presents the results for the $EEI_{STANDARD}$ and the results using the indicator that is based on occupancy density.

The relevant parameters for the comparison between the two buildings are summarized in Table 7. Fig. 14, right, presents a comparison of the EEI_{REAL} for the two buildings using the standard and the newly introduced criteria. Despite the difference in typology between the two buildings, the end use type is not fundamentally different as they are both service buildings. Historical building has values of specific consumption *per* square meter that are substantially lower than the contemporary building. However, there is a reversal of this ranking if we use an indicator based on normalized occupancy.

Using the $EEI_{STANDARD}$ indicator, the historical building is rated as being approximately 10% more efficient than the contemporary building (both buildings are in the same energy class, C). Using the $EEI_{REAL,\,OCC}$ indicator (Fig. 14, right) leads to a different ranking where the historical building is approximately 37% less efficient (due to its lower occupancy density). So, in terms of annual energy cost per occupant we conclude that that the contemporary office building is more efficient than the Lisbon City Hall building.

Another useful type of indicator would use occupancy and cost indicators, taking into account energy costs *per* occupant, rather than primary energy consumption per unit of floor area. An indicator of this type would be advantageous and more intuitive in some sectors, such as services, allowing building owners and management companies to have immediately a clear picture of the energy cost per occupant. The results of the application of this indicator to the two buildings are shown in Table 8. Also in this case the contemporary building outperforms the historical building (as expected).

Table 8
Energy costs *per capita* for both buildings.

	Historical	Contemporary
Real occupancy (€/occupant$_{REAL}$ year)	307	285
Normalized occupancy (€/occupant$_{NORM}$ year)	443	285

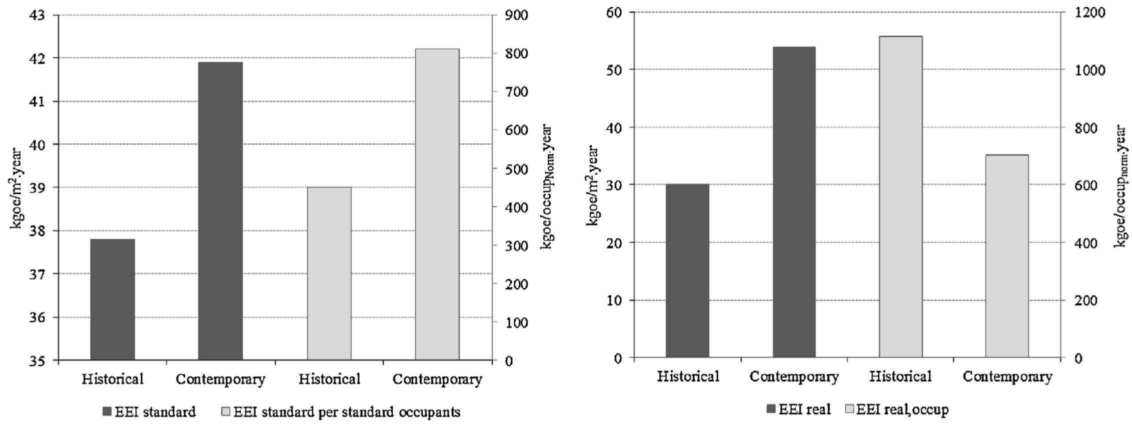

Fig. 14. Left: $EEI_{STANDARD}$ values for the two buildings using same typology; right: EEI_{REAL} values for the two buildings in useful footage area basis and in normalized occupancy basis.

5.2. Audit costs

When calculating economic payback of energy optimization measures, usually energy audit costs for the owners are not taken into account, although these costs are not negligible. In fact, they can represent the money savings of several years of certain energy consumption reduction measures. This is the same to say that the economic payback for those measures is extended by the same period of time.

In the cases where the building energy certification is voluntary, it is legitimate that owners of buildings include the price of the energy certification in the balance that they do in order to decide if they opt for it or not. Thus, despite the energy certification being mandatory in some cases, it is also legitimate in that cases that owners have the same reasoning, not seeing as a sunk cost the price of the certification.

Standard simple economic payback (*SSEP*) time is calculated by

$$SSEP = \frac{IC}{AS} \tag{4}$$

where IC is the investment cost and AS is the cash annual saving of the energy saving measure. If we take into account the audit price (AP), new simple economic payback (NSEP) is calculated by

$$NSEP = \frac{IC + AC}{AS} = \frac{IC}{AS} + \frac{AC}{AS} = SSEP + \frac{AP}{AS} \tag{5}$$

This means that NSEP is the SSEP plus a term that depends on the relation of the audit cost to annual saving.

We used the case studies to calculate new payback (Fig. 15) taking into account the audit prices for the owners, which were around 4 €/m^2 excluding VAT. This value is according the current market prices for RSECE energy certification in Portugal. On average, aggravated payback time is of 3 years (+16%).

Because energy certification price varies with the area of the building, a brief survey was conducted among a company that offers that service (Natural Works), with the goal of identifying possible prices for a wide range of net floor areas that large existing buildings in Portugal may have (Fig. 16). It is not a representative sample, but it fits the purpose of this study.

With this information it is possible to perform a sensitivity analysis of the payback time of the audit price for building owners with a dependence on the attained reduction in consumption and building specific consumption (Fig. 17). It can be seen that audit payback times are lower for bigger buildings. For buildings with the same net floor area, lower payback times happen for big specific consumptions that may allow big relative reductions in consumption. One concludes from here that smaller buildings with smaller energy consumption (thus probably with small reductions in consumption after the audit) are extremely penalized.

5.3. Life cycle energy analysis (LCEA)

The overall energy impact of a building is more than just its operational energy consumption. Buildings consume energy directly or indirectly in all phases of their lifecycle and there is

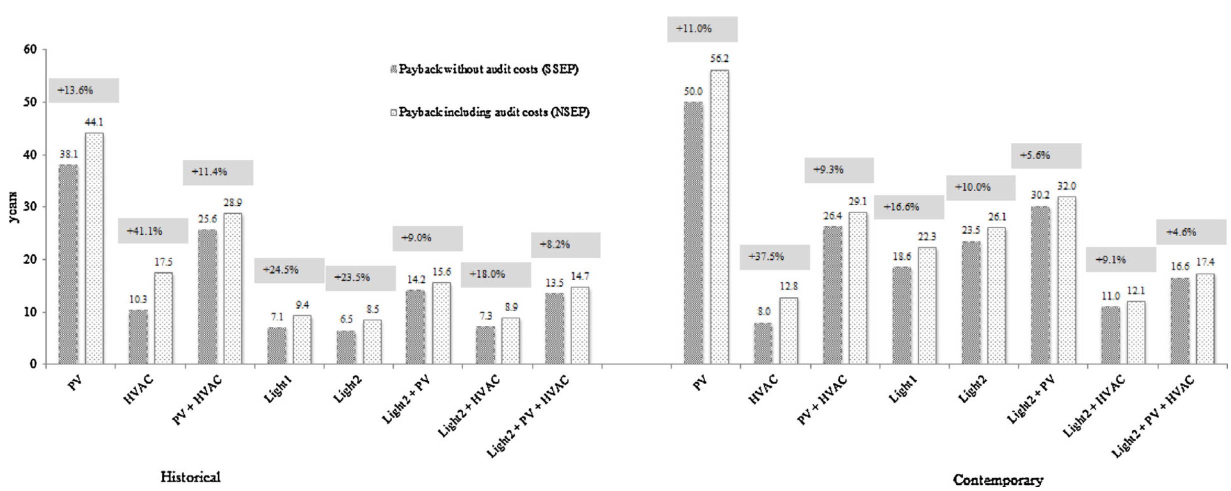

Fig. 15. Comparison between economic payback times without and with account of the audit costs for the owner of the buildings.

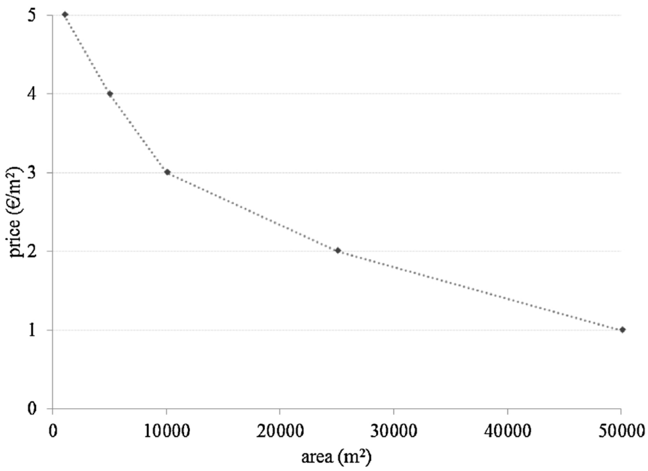

Fig. 16. Variation of price of energy certification of large office buildings with the net floor area.

interplay between phases of energy use (embodied and operating energy) (Ramesh, Prakash, & Shukla, 2010). Hence, for an adequate assessment of the overall impact it is necessary to perform a comprehensive analysis of the energy used in all stages of lifecycle of the building. This is a suitable method for analysis of energy and use of other natural resources as well as the impact on the environment (Bekker, 1982).

The SCE system is limited to accounting energy consumption during building use, leaving aside the embodied energy in the materials and equipment that results from manufacturing processes, transportation, assembly, decommissioning and recycling. (Ramesh et al., 2010) compiled data sources adopted by different authors to evaluate lifecycle analysis of buildings. It is concluded from the case studies the authors revised that, under a life cycle perspective, operating energy has a major share (80–90%) in energy utilization in buildings, followed by embodied energy (10–20%), whereas demolition and other process energy has negligible or little share. Since operating energy has the largest share in LCEA, reducing it is the most important aspect for the design of buildings which demand less energy. Embodied energy should then be addressed in second instance. Even though it constitutes only 10–20% in a LCEA, opportunity for its reduction should not be ignored. There is potential for reducing embodied energy requirements using materials in the construction that requires less energy during manufacturing (Yohanis & Norton, 2006). And this potential becomes more important as the energy efficiency of the building increases, thereby increasing the relative weight of the embodied energy in materials. In the lack of LCEA, building energy regulation and certification schemes are not able to reach their main objective, and become limited or even market distorting mechanisms (Casals, 2006).

Another possible evolution in certification schemes like the one adopted in Portugal is the extension of its scope to non-intrinsic parameters to the building, but important in assessing its energy sustainability in a wider way. In particular, the extent of the certification system to the energy consumption that is inherent to the average daily commute of the building users. However, since this is not a parameter intrinsic to the building, and changes in accordance with a number of factors (new roads, technological developments in the automotive sector, etc.), its introduction into the energy certification system lacks a careful analysis. American LEED (USGBC, 2013) and English BREEAM (BREEAM, Environmental Assessment Method, 2012) systems can serve as case studies for this possible evolution of the SCE and systems alike.

5.4. Limitations to the consumption of renewable energy

The importance of choosing an appropriate indicator of energy efficiency is critical to the success of any energy certification system. In the current context of limitations of energy consumption at national and international level, such indicator should establish consumption limits for fossil energy, but as well for renewable energy, i.e., should impose a limit for the overall energy use in a building. However, for the time being, this is a not a common practice. In fact, these limits are only applied to energy from conventional sources, with no imposition of maximum consumption of renewable energy. This may allow for misuse use of renewable resources (Casals, 2006).

For example, under the SCE system, an inefficient building with high energy consumption can still obtain, and do obtain frequently, an A+ rating if significant part of its energy consumption is from renewable energy systems incorporated in the building (e.g., PV, solar-thermal). In this context, there may be an inadequate use of a natural resource, which, despite being renewable, must be used sustainably.

5.5. Other limitations of the SCE

In the exercise of application of the SCE, we encountered another limitation which can reduce the success in containment of consumption in existing buildings. In the calculation of the energy class and EEI there are parameters that are simulated using conditions defined by regulation (standard conditions), such as: occupancy density, equipment density and all schedules of usage. This option

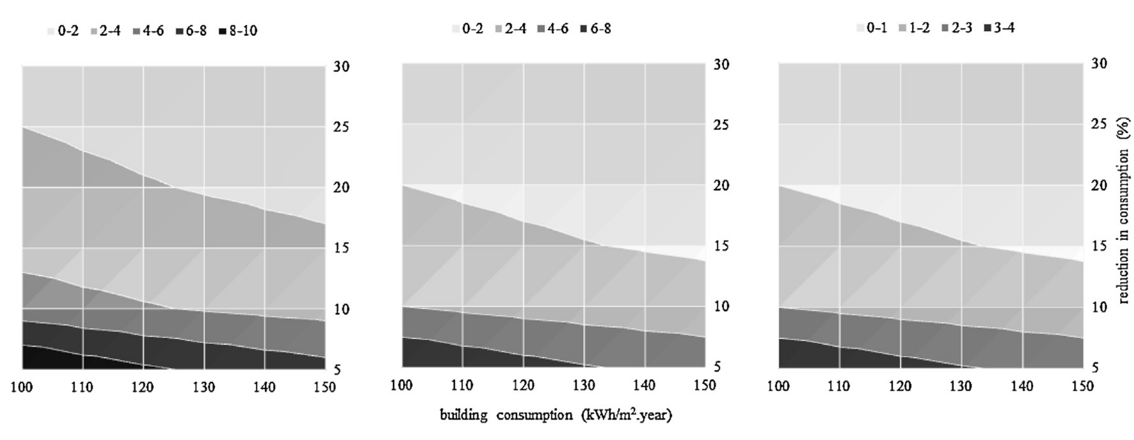

Fig. 17. Sensitivity analysis of aggravated payback time (in fraction of a year) if audit price is included in the economic analysis.

can distort the results because, for example, a building with obsolete equipment is not penalized, which is not desirable. On the other hand, an owner or tenant of a building that invests in the latest equipment with state of the art energy performance does not see his building benefited under the current SCE system or any other system alike.

6. Conclusions

This paper presented comprehensively the application of the Portuguese energy certification system (SCE) to two office buildings located in Lisbon region. These buildings are chronologically apart about 130 years and very different from each other, representing each one the archetype of a service building from its own time. They are representative of opposite contexts in which the SCE can be applied and, for this reason, they constituted a fruitful basis to examine the principles and energy indicators used in SCE and other schemes alike. Their similarities and differences were exploited, which resulted in the presented qualitative reflection on the limitations of the SCE and opportunities for its improvement.

Energy consumption of each building was predicted using a computational simulation model calibrated against the available energy consumption data. The results of the calibrated building thermal simulations have shown that lighting is a major contributor to the overall energy consumption of both buildings (55% for historical and 29% for contemporary). In both buildings, HVAC systems are responsible for about 30% of the overall energy consumption. The buildings were both classified with an energy rating of C (on a scale that goes from G to A+). Calibrations lead to an annual discrepancy of 3% on historical and 5% on contemporary between models and existing consumption data.

A set of energy consumption reduction measures was analyzed, including: improved lighting, introduction of onsite renewable energy production using photovoltaic panels and improvement/substitution of the existing HVAC systems, resulting in a better overall COP. If all studied energy reduction measures are implemented simultaneously, for historical building the energy consumption is reduced by 30%, with an overall payback of 12 years, and the energy rating is improved to B− (meeting the minimum acceptable level for new buildings). For the contemporary building, energy consumption is reduced by 41%, with an overall payback of 9 years, and the energy rating is improved to A.

The SCE system is meant to promote building energy efficiency. However, we have found that in SCE's current format there are criteria that have been overlooked and are of special importance in the evaluation of the energy efficiency of a building. We have developed a simple calculation procedure for of an alternative energy efficiency index, normalized by the total number of building occupants (as opposed to net floor area), that showed that it may be a more representative parameter. The refinement of this concept and the development of a more evolved index are encouraged by the authors as future research.

Also we pointed out that the embodied energy in the materials that compose a building is not accounted for, representing a weakness that will became more important with the ongoing improvement in building energy efficiency. European certification processes based on Directive 2002/91/EC do not usually consider aspects related to the life cycle of the building. Because of this, in some cases it may give rise to the paradox of obtaining a better energy classification while producing a higher energy consumption, as (Bribián, Usón, & Scarpellini, 2009) pointed out. These authors proposed a simple LCA approach that can, along with other future studies of the same character, be used to introduce the LCA concept on the legislation.

Also the regulation as it is presently does not impose a limit on the consumption of renewable energy, leading to undisciplined use of natural resources. An inefficient building with large energy consumption can be rated "A+" if it has large incorporation of renewable energy systems. In the view of the authors this constitutes a theme of worthwhile further thinking.

We pointed out that, when calculating economic payback of energy optimization measures, the energy audit costs for the owners are not taken into account. In some cases, these costs can represent the money savings of several years of a given energy consumption reduction measure. For the cases studied, taking this cost into account, led to an average payback time increase of 3 years. It is advisable to foster thinking about if and how a revision in the regulation should consider audit/certification costs. The exploration performed in this study is based on a non-representative sample and a broader set of samples in different contexts of the code application are worth to analyze. Ideally, energy LCA methods should be used on parallel with the economic analysis.

Finally, it was also noted that energy class does not take into account the equipment installed on a building. A building with energy inefficient equipment is not penalized this way, which is not desirable. In the author's opinion, these findings and lessons learned can constitute a basis for future research in order to refine certification energy systems like the one studied.

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