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ENERGY PLANNING WITH ELECTRICITY STORAGE AND SUSTAINABLE MOBILITY:
THE STUDY OF AN ISOLATED SYSTEM

PHD PROGRAM IN SUSTAINABLE ENERGY SYSTEMS

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Resumo

A presente tese desenvolve uma metodologia de planeamento energético que visa melhorar a sustentabilidade de um determinado sistema isolado, através de uma avaliação multicritério de estratégias para a integração de fontes de energia renovável, armazenamento de electricidade, mobilidade sustentável e adopção de medidas de eficiência energética.

Inicialmente é apresentada uma revisão dos desenvolvimentos associados ao armazenamento de electricidade e à mobilidade eléctrica, tal como das mais relevantes vantagens e desvantagens de cada tecnologia. É igualmente realizada uma avaliação dos modelos existentes para planeamento energético, através da identificação das principais motivações para a investigação neste tópico.

Nesta tese são apresentados os princípios teóricos inerentes ao planeamento energético, incluindo o impacto ambiental, custos económicos e financeiros, e adequação do sistema electroprodutor. É também elaborada uma perspectiva sobre apoio à decisão multicritério e abordagens para modelizar a incerteza.

No que diz respeito à metodologia proposta para o planeamento energético multicritério, nesta tese é construída uma formulação matemática para os seguintes critérios: impacto ambiental (emissões de carbono do sector dos transportes e do sistema eléctrico de energia); custos económicos e financeiros (custos associados às emissões de carbono, custos de produção de energia eléctrica, custos do armazenamento centralizado de electricidade, custos da mobilidade eléctrica, e custos das medidas de eficiência energética); e adequação do sistema electroprodutor (probabilidade de risco de perda de carga). Esta metodologia beneficia do desenvolvimento de um algoritmo para o escalonamento e despacho económico de grupos térmicos, incluindo fontes de energia renovável, armazenamento centralizado de electricidade, e carregamento de veículos eléctricos, endereçando também o conceito V2G.

A abordagem desenvolvida é aplicada a um caso de estudo, o qual consiste na ilha de São Miguel (Açores, Portugal), atendendo às características do respectivo sistema eléctrico de energia e aos investimentos previstos. Esta tese, para além de identificar as alternativas para o planeamento energético e calcular os atributos seleccionados para o ano 2030, apresenta uma discussão dos resultados obtidos, assim como uma análise multi-attributo e multi-cenário incluindo a incerteza.

Em suma, este trabalho disponibiliza uma nova metodologia de planeamento energético multicritério, para sistemas isolados, a qual supre certos hiatos relevantes do conhecimento, mas também adapta formulações já conhecidas, ao problema de planeamento em questão. Considera-se que a abordagem construída no âmbito da presente tese, oferece contribuições concretas e valor aplicável ao processo de planeamento energético em sistemas isolados, tanto na perspectiva das preocupações do operador do sistema eléctrico, como do ponto de vista das autoridades regionais.

Abstract

This thesis develops an energy planning methodology for enhancing the sustainability of a given isolated system, through a multicriteria evaluation of strategies for renewable energy sources integration, electricity storage, sustainable mobility and the adoption of energy efficiency measures.

Initially, a review is provided on electricity storage and electric mobility developments, as well as on the most relevant advantages and disadvantages of each technology. A survey on energy planning models is also carried out, through the diagnosis of research drivers.

In this thesis, major theoretical fundamentals are exposed for energy planning, including environmental impact, economic and financial costs, and adequacy of the electric generation system. An outline of multicriteria decision aid and approaches to model uncertainty is also provided.

When it comes to the proposed methodology for multicriteria energy planning, this thesis builds a mathematical formulation for the next criteria: environmental impact (carbon emissions from the transport sector and power system); economic and financial costs (carbon-based costs, power generation costs, costs of centralized storage, costs of electric mobility, and costs of energy efficiency measures); and adequacy of the electric generation system (loss of load expectation). This methodology benefits of the development of an algorithm for unit commitment and economic dispatch of thermal power units, including renewable energy sources, centralized electricity storage, and electric vehicles charging, addressing as well the V2G concept.

The developed energy planning approach is applied to a case study, which consists in the São Miguel Island (Azores, Portugal), bearing in mind its power system characteristics and expected investments. This thesis, besides identifying energy planning alternatives and computing the selected attributes for the year 2030, presents a discussion of the obtained results, as well as a multi-attribute and multi-scenario analysis dealing with uncertainty.

To sum up, this work presents a new methodology for multicriteria energy planning, for isolated systems, which fulfils some critical knowledge gaps, as well as adapts, to the current planning problem, already established formulations. The approach built within this thesis is believed to upgrade current approaches and, as a result, bring concrete contributions and applicable value to the energy planning process of isolated systems, either through a utility-oriented perspective, or government-oriented viewpoint.

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List of Abbreviations

AAUs	Assigned Amount Units
AMI	Advanced Metering Infrastructure
AFLC	Average Full Load Cost
CAES	Compressed Air Energy Storage
CAPEX	Capital Expenditures
CCGT	Combined Cycle Gas Turbine
CDM	Clean Development Mechanism
CERs	Certified Emission Reductions
CIMs	Community-wide and fully harmonised Implementing Measures
COPT	Capacity Outage Probability Table
CP	Charging Post
CRF	Capital Recovery Factor
CSF	Centralized Storage Facility
DCF	Discounted cash-flow
DOE	US Department of Energy
DSM	Demand Side Management
DSO	Distribution System Operator
EC	European Commission
ECCR	Economic Carrying-charge Rate
EM	Electric Mobility
ENTSO-E	European Network of Transmission System Operators for Electricity
EPC	Engineering, Procurement and Construction
EPRI	Electric Power Research Institute
ERUs	Emission Reduction Units
ET	Emissions Trading
ETS	Emissions Trading Scheme
EU	European Union
EV	Electric Vehicle
FCR	Fixed-charge Rate
FERC	Federal Energy Regulatory Commission
FIT	Feed-in-tariffs
FOAK	First of a kind

FOR	Forced Outage Rate
GCF	Green Climate Fund
GENCO	Electricity Generation Company
GHG	Greenhouse gases
ICV	Internal Combustion Vehicle
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRR	Internal Rate of Return
JI	Joint Implementation
LOLE	Loss of Load Expectation
MA	Multi-attribute problems
MCDA	Multicriteria Decision Aid
MO	Multi-objective problems
NAP	National Allocation Plan
NIMs	National Implementation Measures
NOAK	Nth of a kind
NPV	Net Present Value
OECD	Organisation for Economic Co-operation and Development
OEM	Original equipment manufacturer
OPEX	Operation Expenditures
OTC	Over-the-counter
pCER	Primary Certified Emissions Reduction
PLC	Power Line Carrier
PHEV	Plug-in Hybrid Electric Vehicle
RES	Renewable Energy Sources
sCER	Secondary Certified Emissions Reduction
SMES	Superconducting Magnetic Energy Storage
SupAg	Supplier/Aggregator
TSO	Transmission System Operator
UCED	Unit Commitment and Economic Dispatch
UNEP	United Nations Environment Programme
UNFCCC	United Nations Framework Convention on Climate Change
V2G	Vehicle-to-Grid

Chapter 1

1 Introduction

1.1 Research Motivation

The world undergoes a demanding Era. Several concurrent crises have unfolded during the last decade: climate, biodiversity, fuel, food, water and, more recently, the global financial system. As it is scientifically demonstrated, the anthropogenic carbon emissions lead to global warming and climate change, with disastrous human consequences. The fuel price shock of 2008 and the related food and commodity prices, reflect both structural weaknesses and unresolved risks. Currently, there is no international consensus on the problem of global food security or on possible solutions to feed a population of 9 billion by 2050. Freshwater scarcity is already a global problem and forecasts suggest a growing gap by 2030, between annual freshwater demand and renewable supply. Collectively, these crises impact the possibility of sustaining prosperity worldwide and are compounding persistent social problems, such as job losses, socioeconomic insecurity, disease and social instability. The policy-making for Green Economy will differ across countries (depending on local environment and economic conditions), but there's a common framework which gathers: (i) integration of natural resource base into the same dynamics and decisions that drive growth; (ii) development of ways to create economic payoffs reflecting the value of the natural resource base of the economy; and (iii) mutually reinforcing aspects of economic and environmental policy. Realising the value of the natural resource base for growth will require the payoffs change for specific economic activities, adopting measures to overcome obstacles to green growth. Furthermore, policy initiatives could be designed in terms of a set of criteria: cost-effectiveness; adoption and compliance incentives; and ability to cope with uncertainty and provide a clear and credible signal to investors. Other important criterion includes effectiveness in stimulating innovation and the diffusion of green technologies, and the extent to which instruments can be designed and implemented in a way that facilitates international co-ordination [1].

A global transition towards a green economy will require substantial redirection of investment to increase the current level of public and private sector flows to key priority areas, the bulk of which will need to be mobilised through financial markets. United Nations Environment Programme (UNEP) suggests that the level of additional investment needed is between 1-2,5% of global GDP per year from 2010-2050. Currently, green economy investment is well below 1% of global GDP [2].

According to OECD, shifting to a greener growth path requires special attention to infrastructures such as energy, transport, water and communications networks. There is considerable potential for infrastructure investment to contribute to economic growth and prosperity because it enables trade specialisation, competition, access to new resources, the diffusion of technology and new organisational practices [1].

For instance, ENTSO-E advocates, in [3], that the way forward during the next 20 years must support today's innovations by building tomorrow's electricity highway. In parallel, European energy policies have set clean energy plans and targets by 2020 and 2050 [4], [5] . The new energy paradigm brings a set of demanding challenges to the power system operators, as a result of the integration of variable renewable energy sources (e.g. wind and solar), as well as the rise of the smart grid concept, in which there is an empowerment of the consumer/citizen, leading to a new and major role of loads in the system operation (becoming controllable and elastic). In addition, the power system is foreseen to broaden its boundaries to new services, following public policies towards the holistic integration of Energy, Transport and Climate objectives. Carbon cap-and-trade mechanisms applied on the power system are already on track in the European Union (EU). What's more, the electric mobility path will introduce major challenges to the Distribution System Operators (DSOs) but also to the Transmission System Operators (TSOs). Besides the Electric Vehicles (EVs) effect on the daily load profile and wholesale prices, electric mobility may bring a set of ancillary services within the scope of the system operators, enclosed to the Vehicle-to-Grid (V2G) concept. Additionally, a growing interplay between TSOs and DSOs is reckoned crucial.

The smart grid paradigm is pushed forward owing to recent technology breakthroughs, applied on power systems, such as advanced metering, smart substations, electricity storage, cyber-security models, etc. Although the benefits led by the smart grids rollout, utilities may expect worth mentioning challenges on the system operation.

The large integration of renewable energy sources (RES) has been impacting the TSOs and DSOs' day-to-day operations, as listed next [6]:

- Power Flow inversion in secondary substations, High Voltage/Medium Voltage substations and even in 150/60 kV substations;
- Increase of congestions on distribution and transmission networks at daily off-peak periods;
- Balancing of generation surplus in valley hours;
- Security problems (frequency stability, ramps);
- Risks for lack of regulating capacity margins;
- Primary Reserve - increase of photovoltaic and wind generation implies an equivalent reduction of thermal generation available for primary reserve services;

- Tertiary Reserve: intermittent/fluctuating RES generation increases uncertainty in real time balancing of load and generation; tertiary reserve assigned to substitute secondary reserve, is not always enough.

In view of this Energy Revolution, ENTSO-E presents the next trends for the power systems [3]:

- *Distributed renewable energy sources*

  Large power plants with high base loads and slow ramping capabilities will gradually be supplanted by highly distributed renewable energy resources with variable generation. Energy sources will be expectedly cleaner, but they will also have to be stable and efficient. This will require a new paradigm for developing the grid (infrastructure and power technologies), as well as substantial balancing between control areas to ensure that supply meets demand.
- *Single Electricity Market for Europe*

  A Single Electricity Market for Europe will allow integrate balancing markets and establish a framework for advanced grid operating systems that enables storage, demand response and other distributed resources.
- *Power tariffs increase*

  The political and regulatory pressure for lower costs and higher operating efficiency will conflict with the evolution towards clean energy and smart grid implementation.
- *Smart Grids*

  As the existing infrastructure evolves towards the smart grid, there will be new opportunities for transmission and distribution systems, as well as for power generation. By exploiting innovative sensory monitoring and control technologies, smart grids will ease the assimilation of distributed energy sources and allow consumers to participate directly in energy management.

The referred new energy paradigm will then present various challenges for both the supply and demand side. Besides integrating large amounts of RES, the future power systems will have to ensure flexibility, stability and reliability. According to [7], the variability of RES can be offset by:

- “Peaking plants” (e.g. hydro units or gas turbines) which are able to follow load-variations rapidly, due to their technical features (e.g. load gradients, power ramps, start-up times). Appropriate price signals would attract investments in these “conventional” generation units, ensuring they provide the system with the flexible “back-up” capacity.

- Active Demand Side Management (DSM), in which suppliers could stimulate customers to shift their consumption from “peak” to “off-peak” hours, by rewarding them with economic incentives.
- The expansion of transmission and distribution networks can effectively mitigate grid congestions. This solution is however viable only where the problem of local opposition to the construction of large infrastructures is successfully overcome. Besides traditional grid reinforcement, the development of smart grids would allow the system to effectively cope with bidirectional flows of electricity, related to the phenomenon of decentralized generation and “prosumers”, and manage overload problems without the need to reinforce the grid.
- The development of cross-border transport capacity can strengthen the system’s flexibility, simply because it allows that system to import or export additional sources of flexibility, available in neighbouring countries. A country could benefit from peaking units available in foreign countries, when load is increasing, and export electricity when wind is blowing very strongly.
- Implementation of electricity storage, which is seen as an inevitable strategy to cope with larger variability and intermittency of supply. Electricity storage should be considered as one of the many means to provide various services to the system, such as capacity firming, capacity accommodation, voltage and frequency regulation, or back-up capacity.

Bearing in mind the alternatives for enhancing the power systems’ flexibility, it is crucial to build a comprehensive assessment of electricity storage impact and benefits.

The future role of electricity storage technologies will depend on: i) technical and cost developments; ii) evolution of alternative strategies for the same services. If Europe moves towards the Super Grids (electricity highways with massive solar energy transported from North Africa to Central Europe, huge amounts of offshore wind energy being produced in the North Sea and nuclear energy from Eastern Europe contributing to Western European electricity supply), bulk electricity storage is likely to be rather adequate. On the other hand, if Europe opts for system with increased penetration of small-scale distributed generation and successful demand side management, then smaller-scale storage systems and thermal storage (directly connected to end-users) would be critical and the amount of electricity to be transported across the power system would be reduced. Additionally, the rollout of EVs and their potential for controlled charging/discharging is still uncertain [8]. Anyway, the available technologies for electricity storage can be adopted in a complementary way, for instance implementing pumped hydro storage (bulk storage) together with EVs charging (dispersed storage).

In case of isolated power systems (such as islands), electricity storage option gains an even bolder relevance for enhancing the system's flexibility, since there is lack of interconnection capacity.

Besides the challenges presented to power systems, a holistic energy planning requires addressing the transport sector. So, concerning sustainable mobility drivers, one should firstly bear in mind that, within the EU, over 70% of the population lives in cities and this number is projected to continue growing to 80% by 2030, though the EU population is not expected to increase in the following decades [9]. As a result, cities are responsible for the bulk of the world's energy use and, consequently, for a significant share of the world's Greenhouse Gas (GHG) emissions. Within the EU, cities are responsible for about 70% of the overall primary energy consumption, and this share is expected to increase to 75% by 2030 [9]. Regarding transport, energy demand is strongly linked to the specific characteristics of a city (urban mobility). Urban density and CO_2 emissions tend to have a direct inverse correlation. That's to say, the lower the density of a city, the higher its emissions from the transport sector. Urban planning is thus a key factor in the demand for transport. Furthermore, the suitability of different mobility modalities, such as walking and cycling, depends on the morphology and dimensions of the city. Therefore, the management of energy demand, done at a local level, allows tailoring the actions based on the city's characteristics [10].

Besides the urban planning towards a more sustainable mobility, technological innovation can help the transition to a more efficient and low carbon transport system, by acting on three main factors: i) vehicle efficiency through new engines, materials and design; ii) cleaner energy use through new fuels and propulsion systems; iii) better use of networks and safer and more secure operation through information and communication systems. Emissions from road, rail and inland waterways could in fact be brought back to below 1990's levels in 2030, in combination with measures such as: pricing schemes, to tackle congestion and air pollution; infrastructure charging; intelligent city planning; and improving public transport. The gradual transition towards large-scale penetration of cleaner vehicles in all transport modes (including plug-in hybrids and electric vehicles) should be fostered through CO_2 standards and smart taxation systems. In view of the synergies with other EU sustainability objectives (such as the reduction of oil dependence, the competitiveness of Europe's automotive industry as well as health benefits), the EU compelled to accelerate the development and early deployment of electrification, and in general, of alternative fuels and propulsion methods, for the whole transport system [11].

Sustainable biofuels could be used as an alternative fuel, especially in aviation and heavy duty trucks, with strong growth in these sectors after 2030. In case electrification would not be deployed on a large-scale, biofuels and other alternative fuels would need to play a greater role to achieve the same level of emissions reduction in the transport sector. For biofuels this could lead, directly or

indirectly, to a decrease of the net GHG benefits and increased pressure on bio-diversity, water management and the environment in general. This reinforces the need to advance in 2nd and 3rd generation biofuels, and to proceed with the ongoing work on indirect land use change and sustainability [11].

What's more, "green vehicles", are likely to contribute significantly to the Europe 2020 priorities for developing an economy based on knowledge and innovation (smart growth), and promoting a more resource efficient, greener and more competitive economy (sustainable growth). According to the European Commission (EC), the flagship initiative "Resource-efficient Europe" seeks to promote new technologies to modernise and decarbonise the transport sector, thereby contributing to increase competitiveness. One aim of the flagship initiative is, thus, to promote "green vehicles" by encouraging research, setting common standards and developing the infrastructure needed to support the shift towards a resource efficient and low-carbon economy, which is efficient in the way it uses all resources. The EC advocates that two tracks need to be followed simultaneously: promoting clean and energy efficient vehicles based on conventional internal combustion vehicles (ICV); and facilitating the deployment of new technologies in ultra-low-carbon vehicles [12].
When it comes to the electric mobility, it must come together with an increased investment on RES for power generation, in order to bring environmental benefits.

In view of the aforementioned challenges and trends, models for energy planning ought to be upgraded, by utterly integrating:

- Renewable energy sources variability;
- Energy efficiency measures;
- Electric mobility architecture;
- Vehicle-to-grid strategy;
- Electricity storage systems;
- ICV-based sustainable mobility;
- Carbon emissions cap-and-trade mechanisms;
- Power systems' reliability indices;
- Uncertainty modelling.

Furthermore, emerges the relevance of addressing the sustainability challenge in isolated systems, such as islands. Islands contain a set of characteristics which obstacle their economic attractiveness, and jeopardize the accomplishment of sustainability goals. Isolated territories show lack of competitiveness, since they face a lot of extra costs. In addition, islands are generally characterised

by weak infrastructures of general economic interest, as transport, communication, energy and water [13]. Thus, isolated energy systems face the next challenges:

- Limited quantity of resources (human and natural);
- Remoteness (can't have good accessibility and cheap transport);
- Market failure (lack of economies of scale and few options for energy supply);
- Inconsistent regulation (solutions from the mainland are applied to a different reality, which require a different approach);
- Security of supply (islands have to take extra measures to ensure system stability and security of supply, which is even more challenging with the growing penetration of variable RES, such as wind and solar);
- Carbon emissions (islands' dependency on fossil fuel power generation will lead to a bold financial effort to comply with EU emissions trading scheme);
- Import dependency (typically islands have fossil fuel power generation, which results on a high energy dependency and vulnerability to prices volatility).

According to Eurelectric, in [14], the EU totals 286 islands, with 10 million people occupying an area of 100 000 km^2 and located in three major geographical areas: the Atlantic; the North; and the Mediterranean (accounting for 85% of the population). The EU islands belong to eleven member states, five of them accounting for over 75% of the islands.

Eurelectric also refers that islands' economic and social profile generally is less favourable than the corresponding to the country to which they belong. Although many islands have significant natural resources, most of them import considerable amounts of fossil fuels, mainly oil. Oil-based products are not only used in transport, but also in power generation. Additionally, islands located in remote places can't afford power interconnection investments. That's to say, high costs restrict the number of islands investing on interconnections, including just larger ones and those relatively close to mainland [14].

Yet islands are not only subject to threats. These isolated systems materialize a noticeable opportunity to become *Living Labs*, for new energy solutions, since they consist of a mirror of the European energy system. These *Living Labs* can integrate innovative projects such the ones designed for demand response, smart grids and electric mobility, with rapid findings and conclusions. Thus, isolated systems can perform a major role in testing the upcoming smart and sustainable energy systems.

1.2 Thesis Scope and Research Questions

The previous section allowed drawing the most challenging research drivers, for planning the future energy systems. In view of that, this thesis seeks to bring value to the scientific community, by developing a methodology for enhancing the energy sustainability of a given isolated system, through a multicriteria evaluation of renewable energy sources integration, plus electricity storage, sustainable mobility and the adoption of energy efficiency measures.

The renewable energy increase in the generation mix presents several challenges for isolated power systems. One relevant constraint refers to the variability of renewable energy sources (e.g. wind) during the day, which in case of having large amounts of renewable-based capacity and/or applying energy efficiency measures could lead to energy surplus and/or difficulties in managing the power system. Consequently, emerges the need of building accurate storage strategies, aiming to: use surplus renewable power; help the power system operation; and, therefore, reduce CO_2 emissions from the power system.
On the other hand, sustainable mobility strategies should be defined, by analysing the costs and benefits of efficient ICVs, biofuels and behavioural change, as well as EVs.

To sum up, an energy planning approach is worth developing, by tackling multicriteria and different technology alternatives. The referred methodology should, then, answer to the following research questions:

1. *How can a methodology be built to compare different alternatives for energy planning, through a set of criteria and attributes?*
2. *What is the correlation between additional capacity of renewable energy sources and energy efficiency measures, when it comes to the selected criteria?*
3. *How to compare electric mobility and ICV-based sustainable mobility, in terms of costs and benefits?*
4. *What is the influence of sustainable mobility strategies on the electricity storage contribution for the system?*
5. *What are the preferred alternatives for enhancing the energy sustainability of a given isolated power system?*

1.3 Thesis Outline

The current thesis starts to present, in chapter 2, a state of art on the current research topic, by providing a review on electricity storage and electric mobility developments, and identifying the most relevant advantages and disadvantages of each technology. A survey on energy planning models is also carried out, through the diagnosis of research gaps.

In chapter 3, an overview is performed on the major theoretical fundamentals for energy planning, including the environmental impact, economic and financial costs, and adequacy of the generation system. In this chapter a theoretical introduction to multicriteria decision aid is depicted. A review of approaches to model uncertainty is also provided, as well as decision paradigms and rules.

Afterwards, the proposed methodology for multicriteria energy planning is explained in chapter 4, by modelling the next criteria: environmental impact (carbon emissions from the transport sector and power system); economic and financial costs (carbon-based costs, power generation costs, costs of centralized storage, costs of electric mobility, and costs of energy efficiency measures); and adequacy of the generation system (loss of load expectation).

The proposed energy planning approach is then applied to a case study, in chapter 5. The chosen testing system is São Miguel Island, bearing in mind its power system characteristics and expected investments. This chapter, besides identifying energy planning alternatives and computing the selected attributes for the year 2030, presents a discussion of the obtained results, as well as a multi-attribute and multi-scenario analysis dealing with uncertainty.

Finally, the research conclusions are drawn in chapter 6, where the most important thesis contributions are identified, as well as future work perspectives.

Chapter 2

2 State of Art on the Research Topic

2.1 Introduction

In this chapter a state of art is provided, on electricity storage technologies and electric mobility. A detailed characterization is presented, when it comes to technical functionalities, applications, costs and benefits, as well as regulatory framework. This chapter also includes an overview on energy planning tools and models, through a characterization of the most applied approaches, and the identification of research drivers.

To sum up, this section seeks to draw a critical overview on strategies for electricity storage and electric mobility, as well as the gaps of current energy planning models.

2.2 Electricity Storage Technologies

Overview

Energy storage technologies aim to transform electricity, into other form of energy (mechanic energy, chemical energy, heat, etc.), which is stored and afterwards converted back to electricity. Nowadays, it is possible to find a set of available technologies for electricity storage, which can be classified by their: energy transformation process/physical principal; functionalities of the technology; and services or applications for the power system [15].

Concerning the energy transformation process, one can identify [7]:

- mechanical storage: pumped hydro storage; compressed air energy storage, adiabatic compressed air storage; and flywheels.
- electromagnetic storage: superconducting magnetic energy storage; super capacitors; and superconductors.
- electrochemical storage: conventional batteries (Li-ion, Lead-Acid); high-temperature batteries (NaS, ZEBRA); and Flow batteries (VRB, PSB, ZnBr).

When it comes to the functionalities method, the technologies can perform:

- Intertemporal shift of energy: capacity to transfer the energy over a considerable length of time (from some minutes to some hours or even some days or months).
- Fast response: capacity to rapidly inject or absorb the power, within some tens of milliseconds.

The energy shift allows the management of power generation/consumption equilibrium, supporting system flexibility and renewable integration. Therefore, for this purpose it is critical that storage technology offers several hours of autonomy, with a large power capacity (e.g. hundreds of MW) and reduced response time (e.g. 1-5 minutes). According to the following figures, one observes that hydro pumped storage is the technology that best satisfies these functionalities, followed by compressed air energy storage.

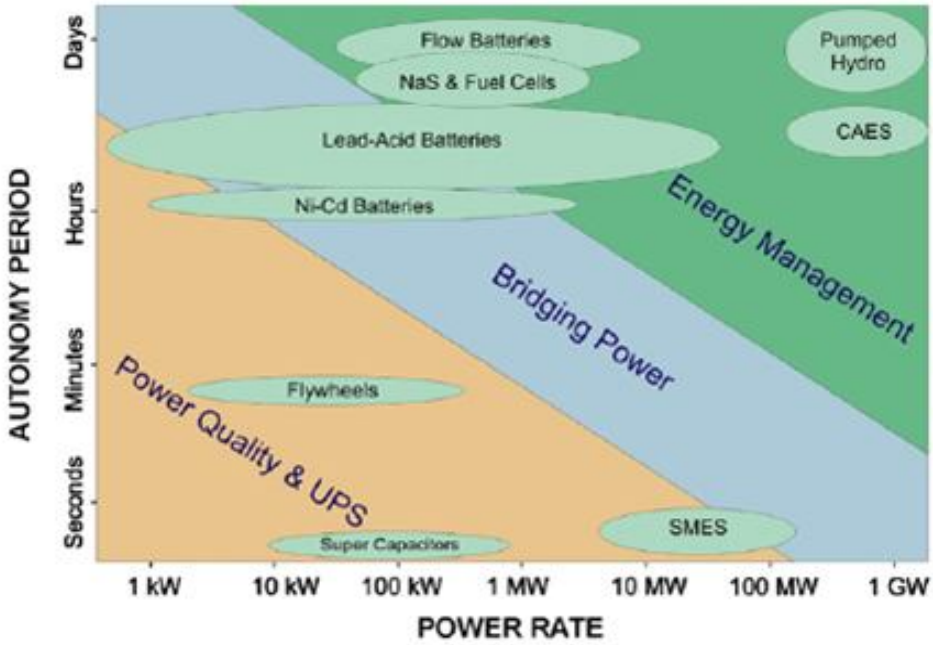


Fig. 1: Electricity storage technologies portfolio (1) [16]

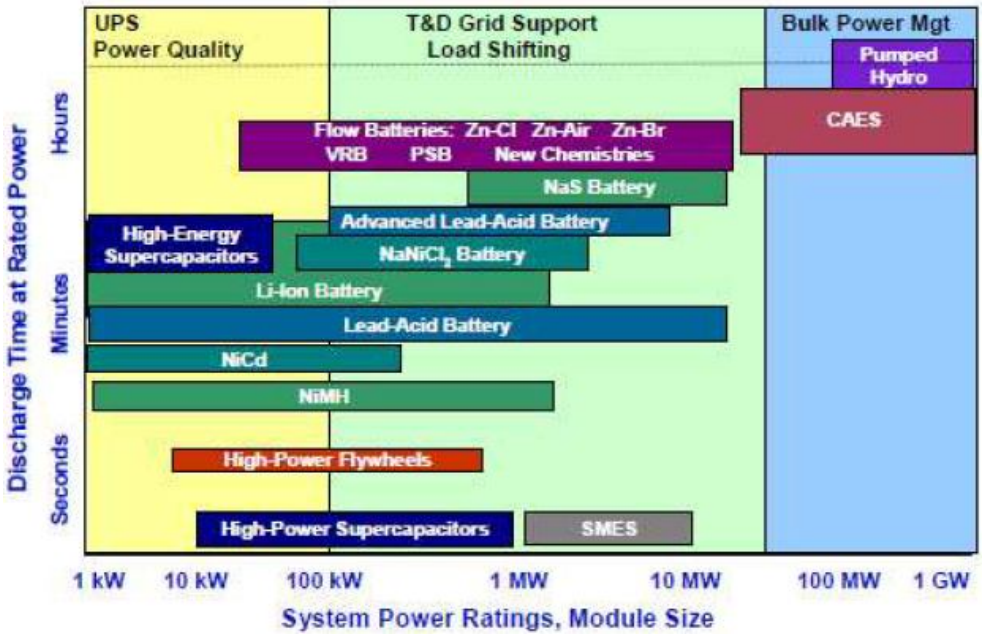


Fig. 2: Electricity storage technologies portfolio (2) [17]

Regarding the fast response functionality, the corresponding technologies are mostly related to applications for the power systems' reliability and to power quality issues. Some electricity storage technologies may perform both functionalities, whereas others are rather suitable for one of the functionalities [15].

The third method for the electricity storage classification, consist on the assessment of specific services that the technology can deliver to the power system (which depend on their functionalities), as presented next.

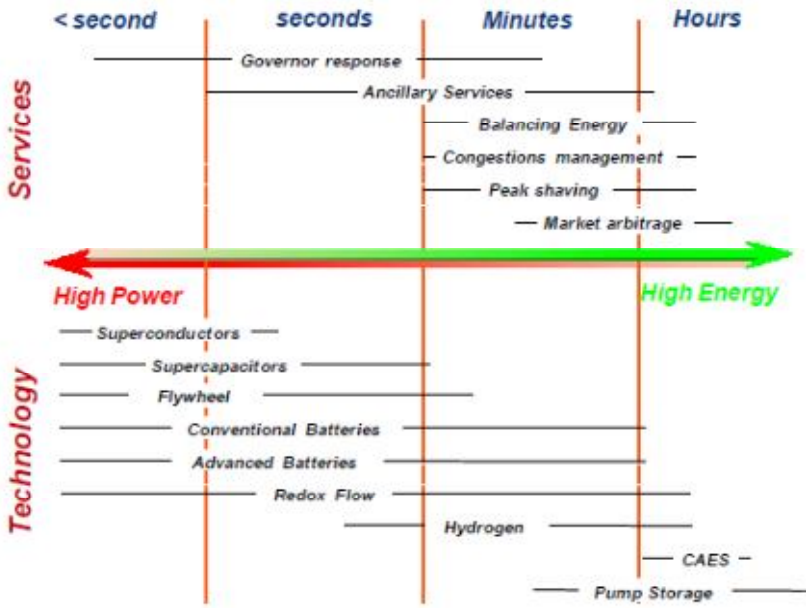


Fig. 3: Classification of electricity storage technologies using the services delivered method [15]

Additionally, the electricity storage technologies can be differentiated among each other, according to: costs of investment in terms of both capacity (MW) and energy (MWh); efficiency; lifetime; and environmental impact [7].

When it comes to the location, typically, electricity storage has been mostly based in centralized facilities (e.g. pumped hydro storage). Yet there is now a trend to commission small-scale, decentralized storage. Hence, electricity storage could be connected directly to transmission grids, distribution grids, renewable energy sources and consumers. Electric vehicles are also perceived as mobile storage units. Besides electricity storage, thermal storage facilities may be applied at consumer level or combined with large and remote concentrated solar power facilities. Consequently, storage facilities can be commissioned near power generation or closer to end-users, operated by centralized or decentralized ways, and benefiting the whole system or benefiting a single actor. In view of the previously mentioned, the future role of electricity storage will be

influenced by the degree, location and timing of the flexibility requirements related to the power systems' evolution [8].

Therefore, it isn't possible to identify the "best" storage technology, depending on the objective for electricity storage and project constraints (e.g. power grid, natural conditions of the site, etc.). A technical description is hereafter carried out, for each technology option.

Pumped Hydro Storage

Pumped hydro represents more than 99% of world's total storage capacity (i.e. 127 GW of global storage capacity). In Europe, there are over 43 GW of installed power for pumped hydro storage, which stands for 5% of total net installed generation capacity [16], [18], [19], [20].

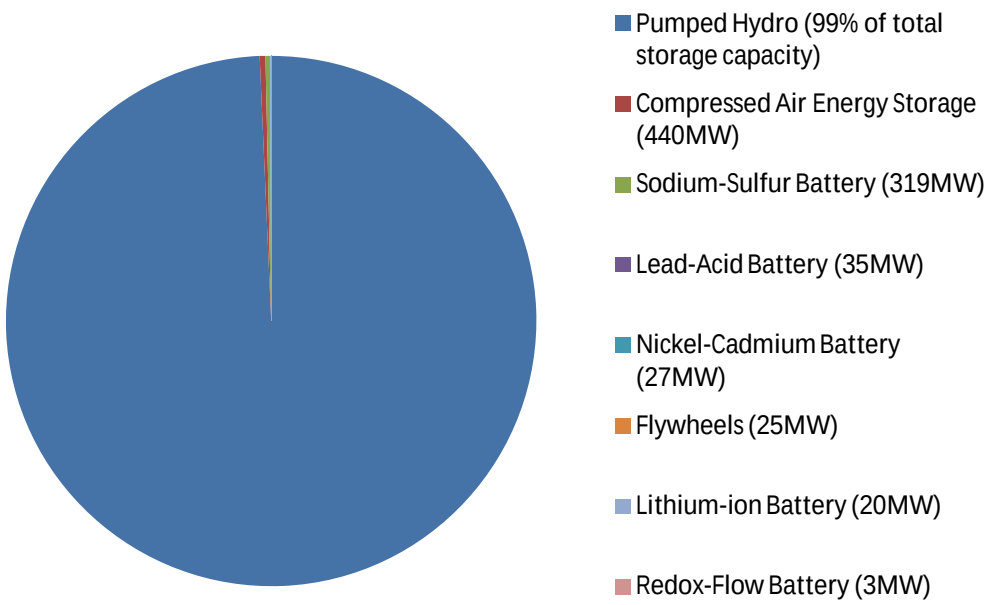


Fig. 4: Electricity storage worldwide, adapted from [21]

In the US, 38 pumped hydro storage facilities can store the equivalent to more than 2% of the country's power generation capacity, whereas in Japan this figure is about 10% [22]. According to IEA, in [23], since 1970 more than 100 GW of pumped turbines have been installed around the world.

In Europe, the majority of electricity storage facilities is concentrated in the Alpine regions of France, Switzerland and Austria, as well as in Italy, Germany and Spain [8]. In Portugal, there was an installed capacity of pumped hydro storage of 1 GW, in 2008 [24].

The starting point of pumped hydro storage projects coincided with the development of the high-head pump turbines, supplied for the Numappara Power Station (Japan), in 1973, with more than

500 meters of head. The world's highest pump turbine unit, with a pumping head of 779 meters and turbine capacity of 412 MW, was installed in 1999, in Kazunogawa Pumped Storage Power Station (Japan). There are ambitious plans for electricity storage, as the Eagle Mountain Pumped Storage Project in southern California. This project seeks to carve two reservoirs out of an abandoned iron surface mine, in order to store electricity from local wind and solar farms, having 1,3 GW of installed capacity (as much as a nuclear power plant) [22].

Rangoni, in [7], and EPRI, in [17], stated that pumped storage is the most mature and cost-efficient large-scale storage technology, currently available, as confirmed by the pumped hydro's share among the total storage capacity, commissioned around the world. Moreover, a recent review carried out in [22], supported by an expert panel (including specialists from US DOE, Ball State University, EPRI, University of Cambridge and MIT), rated the pumped hydro storage solution with higher scores for all the concerned criteria (technology scale up; cost-effectiveness; and operation efficiency), than for the other storage technologies.

The pumped hydro Centralized Storage Facility (CSF), in periods of discharging (usually during off-valley period), generates power just as a conventional hydropower plant and, in periods of charging (usually during valley hours), water is pumped from a lower reservoir to an upper one. The schematic of the infrastructure associated to the pumped hydro is described next.

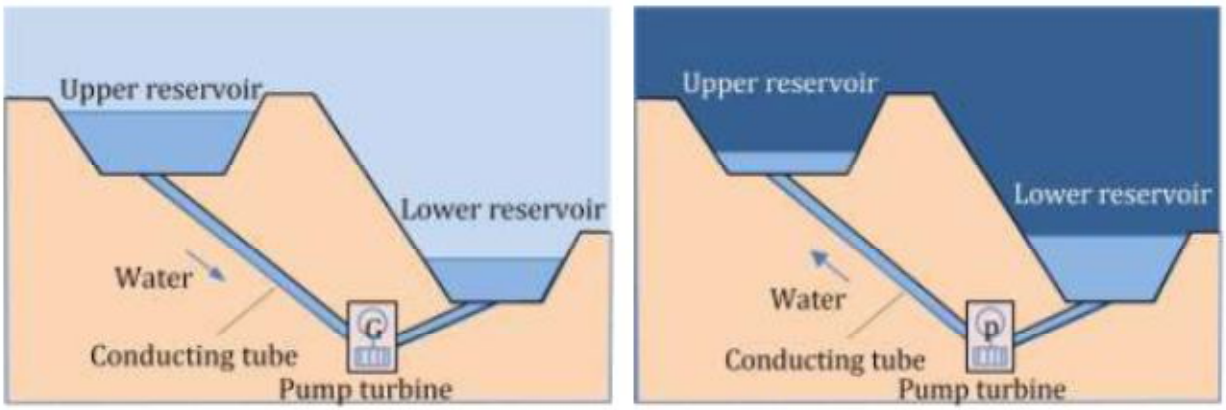


Fig. 5: Pumped hydro CSF operation [23]

Besides the load shift capability, pumped hydro storage is also used for combined operation with wind farms, in order to smooth the overall output and enable larger penetration of renewable energy in the network [25]. In the case of a combined wind power/pumped hydro storage, this architecture enables: a) to store energy produced in low consumption periods, to satisfy demand in peak periods; b) to store energy in the reservoirs during high wind speed periods to be used afterwards for filling

wind-power gaps [26]. According to Schoenung, in [27], advanced pumped storage hydro technologies enable frequent and rapid (less than 15 seconds) changes among the pumping, generating and spinning modes. The pumped hydro units have a wide range of installed capacity levels, from a few MW to some GW. Discharging time extend from some hours to some tens of hours [15].

Pumped hydro storage facilities can be either mixed pumped hydro or simple pumped hydro structures. The mixed pumped hydro storage plants use a large reservoir, having a higher effective storage capacity, based on a natural source of water. Thus, it can operate during high water seasons. On the other hand, during dry seasons the pumped hydro facility can provide support to meet the load. Generally, 200 to 400 MW class systems are chosen. Regarding the simple pumped hydro storage type, it has only an artificial reservoir, so charging it with water is critical [23].
A pumped hydro storage facility is similar to a typical hydropower plant, differing in the requirement for the lower lake and extra machinery in the powerhouse for pumping, which consists on the next possible configurations [25], [15]:

- Group of four units, where a pump is coupled to a motor and a turbine is coupled to a generator. This configuration is no longer applied, having as drawback the high volume required for the site.
- Group of three units, where a pump and turbine are both coupled to a single reversible motor/generator. The efficiencies of the pump and turbine can be optimized and multi-stage pumps can be used for very high heads.
- Group of two units, where a reversible pump/turbine is coupled to a reversible motor/generator. This configuration requires a smaller space compared to the other two architectures, having also a lower installation cost. On the other hand, this technical option leads to a lower efficiency.

There are still hybrid combinations of reversible and non-reversible turbines. For instance, the French Grand Maison pumped hydro storage facility has a turbine capacity of 1790 MW and pump capacity of 1160 MW, consisting on 8 reversible Francis turbines and 4 Pelton. This architecture could gain a momentum, taking into account that future pumped hydro storage facilities will certainly be based on old hydro power plants (owing to limited sites for new pumped hydro storage). In those cases, the new machinery to install will be scarce, having only the need to add pumps or auxiliary machines [15].
According to the IEA, in [23], in the reversible pump of a conventional pumped hydro plant, the capacity of the pump is smaller than the capacity of the water turbine. As a result, the water

pumping process takes longer than the generation process. Therefore, it is advisable to speed-up the pumping process, during periods of reduced-rate power availability. However, the addition of pumping capacity might damage the turbine runner (e.g. cracking). One successful example of pumped hydro storage upgrade is the Blenheim Gilboa project, in New York State, in which efficiency was significantly increased [23].

Concerning the start-up time of pumped hydro storage facilities, these technologies are suitable for following short-cycle power demand variation, with governor-free operation, since they take only about 60 seconds to turn out full output. Nonetheless, the conventional single-speed unit does not work to stabilize grid frequency, in the night time, taking into account that when it is operating in the pumping mode, input power can not be changed because it is determined exclusively by the pumping head. The pump turbine uses a turbo impeller, so the rotational speed and the pumping head determine the input of the pump turbine. As a result, when operating at a given pumping head, a single-speed pump turbine, driven by a synchronous motor, cannot vary the input. As opposition, an adjustable-speed pump turbine, driven by an adjustable speed motor, can vary the input. This capacity allows tuning the grid frequency, during valley periods, and enables the use of fluctuating renewable wind or solar energies, to pump water to the upper reservoir. Hence, an adjustable-speed unit can contribute to stabilizing the grid frequency, by rapidly changing input power. The main characteristic of the adjustable-speed units is to adjust the input power, when performing automatic frequency control, at the same time of charging the energy in the upper reservoir. Operational hours are fairly longer for adjustable-speed units than for single-speed units, and, in addition, pump starts are much more frequent for variable-speed units than for single-speed units.

Pumped hydro storage with variable-speed doubly fed asynchronous machines started to be competitive and two machines (370 MW each) will be connected to the transmission grid (400 kV), in Portugal. This technology allows that in the pumping (motor) mode, the absorbed power in each machine can vary between 70/80 and 100% of the nominal power, in reduced times, and so the power plant can “follow” the grid load and wind generation changes. This capability is similar to the spinning reserve, by enhancing the wind power integration, mostly in extreme off-peak load periods. Yet the connection process should be developed carefully, to ensure a stable and reliable interaction with the transmission grid. In view of that, REN identified a set of technical requirements for connecting these variable-speed doubly fed asynchronous machines [28].

In addition, some pumped hydro storage facilities - of both single-speed and variable-speed types - can operate in a capacitor mode, in order to tune the phase difference or the reactive power of the power grid. The capacitor mode operation is based on the water downward depression of the

runner/impeller, by compressed air, in order to reduce stirling power loss led by a spinning runner [23].

One should also analyse the seawater option, for pumped hydro storage. This technical option draws a set of advantages:

- It is easer to find an appropriate location for the pumped hydro storage facility, owing to the vast ocean that can be used as lower reservoir;
- This option can have an efficiency of up to 80%, due to the short waterway length, which reduces the hydraulic losses by 93% to 98%.

As drawback, the seawater solution leads to an overall cost increase of 15%, resulting from corrosion prevention measures [23].

Pumped hydro storage brings major benefits to the power system operation. Nevertheless, these facilities have also challenges to tackle, such as economical difficulties due to lack of appropriate locations that satisfy environmental, topographical and geological conditions. Thus, the IEA foresees that underground reservoir systems can be a solution to these difficulties [23].

It is known that for conventional pumped hydro plants, both the upper and the lower reservoirs are installed above ground. Alternatively, underground pumped hydro systems can be either based on fresh-water underground pumped hydro systems (that use artificial underground tunnels as the lower reservoir and a natural lake as the upper reservoir), or seawater underground pumped hydro systems (that use artificial underground tunnels as the lower reservoir and the ocean as an upper reservoir). A typical underground pumped hydro system is presented as follows.

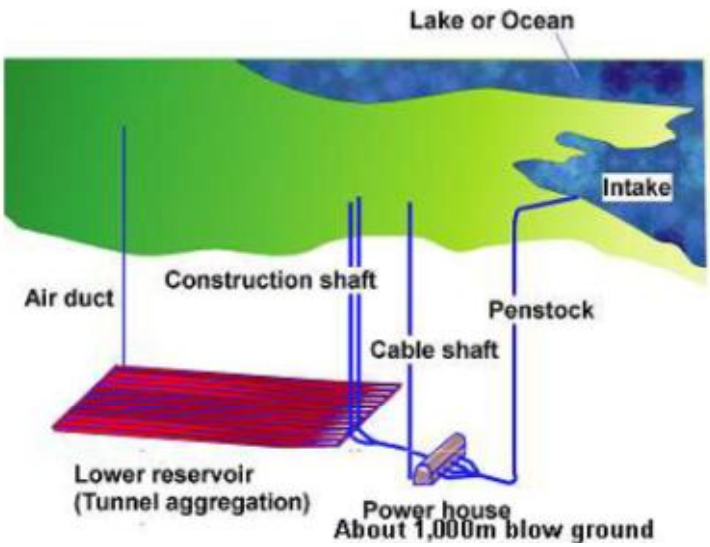


Fig. 6: Underground hydro pumped storage plant [23]

Underground pumped hydro plants have some extra characteristics, regarding the conventional solution [23]:

- Reduce the impact on the above-ground environment, such as the natural scenery;
- Preserve the ecological system of raptor species;
- Expand the range of plant location choice by relaxing the restrictions on topographical conditions;
- Reduce transmission costs by installing the pumped hydro plant nearer the site of electricity consumption.

Compared to conventional pumped hydro facilities, underground plants have been designed to be more practical solutions for the future.

Compressed Air Energy Storage

Compressed air energy storage (CAES) is a competitive technology for bulk electricity storage, next to pumped hydro storage. CAES stores energy during valley periods, by compressing air within an air reservoir (using a compressor powered by low cost electric energy system). During off-valley hours, the CAES releases the compressed air, which is heated with a small amount of fuel and fed into a combustion turbine, in order to generate electricity. This turbine is three times more efficient than a conventional gas turbine, since the combustion turbine doesn't have to use part of its output to drive an air compressor, because the air is pre-compressed [15], [16]. Bearing in mind that CAES uses a fuel to heat air, during the discharge generation cycle, it is not a pure electricity storage plant. The global energy efficiency of the CAES is 40-50% and has a start-up time of about 10 minutes [29]. CAES' output ranges from a few MW to some GW, and the discharging time can reach some tens of hours [15].

When it comes to the Advanced Adiabatic CAES, the heat released during the compression stage is stored before the compressed air enters into the air reservoir. Therefore, during the discharge phase, the compressed air and the heat are both released, avoiding the external fuel burning for the air heating, in order to drive the combustion turbine. As a consequence, the adiabatic CAES lead to higher energy efficiency (70%) [30].

Concerning the CAES worldwide installation, there is one unit in Huntorf (Germany), commissioned in 1978, and another in Alabama (US), commissioned in 1991. The Huntorf plant (operated by E.ON) has a compressor of 60 MW and a turbine of 290 MW, delivering full output for 2 hours. The Alabama's facility (run by PowerSouth Energy Cooperative) has a 50 MW of compressor capacity and 110 MW of turbine capacity, supplying a full output for 26 hours [15], [16], [22]. In addition, an adiabatic CAES facility is considered for development in Germany, within the ADELE project, in which RWE Power, General Electric, Züblin and DLR are working to

launch a demonstration plant in Stassfurt (360 MWh, 90 MW), located in a region with wind power [8].

Lithium Ion (Li-ion) Batteries

Lithium-ion batteries are dominating the small portable electronic markets, owing to major advantages such as a high open circuit voltage and efficiency near 100%. This type of batteries is becoming more popular as they get economy of scale [31]. Li-ion batteries do not suffer from memory effect and also have a low self-discharge rate. On the other hand, these batteries are very expensive due to their special packaging and internal overcharge protection circuits [32]. Hence, the cost of this type of batteries should be reduced, in order to become a suitable option for large scale power integration, for peak shaving or storage [16], [33]. In addition, these batteries require a Battery Management System to perform, for instance, the state of charge monitoring.

Sodium Sulfur (NaS) Battery

The Sodium Sulfur (NaS) batteries consist of an anode of sodium and a cathode of sulfur, which are separated by a solid electrolyte membrane made with beta-alumina. This membrane allows the migration of sodium ions from the anode to cathode, during the discharge phase and the reverse process during the charge phase. A sodium sulfur battery has a high energy density, high efficiency (85% DC/DC) and life-cycle of about 250 cycles (at full capacity) per year, for 15 years. During the charging and discharging process, the heat generated by the chemical reaction is enough to keep the operating temperature. Yet when the battery stays inactive, it needs to consume energy equivalent to 0.6-1% of its nominal capacity per hour, to maintain the high temperature. The investment cost of NaS batteries ranges from 1000 to 1500 €/kW [15]. Concerning this technology demonstration, there are projects in Berlin-Adlershof, Gran Canaria, and Reunion Island [8].

ZEBRA (Sodium-Nickel-Chloride) Battery

This technology is a high-temperature battery system, being able to support a wider temperature range than NaS batteries. As drawback, these batteries have a lower energy density. Although ZEBRA batteries are mainly used in automotive and mobile applications, they can also be applied for stationary applications to support renewable energy integration, for load-levelling [8].

Metal Air Batteries

Although metal-air batteries are compact and relatively inexpensive, they have a life of a few hundred cycles and an efficiency of about 50%. The electrical recharging of metal air batteries is difficult and inefficient, thus most them are not rechargeable [16], [32]

Lead-Acid Battery

These batteries are able to maintain a relatively high power-to-weight ratio (i.e. high overall performance as a power source), as well as a low cost. In view of that, lead-acid batteries are tuned for UPS applications and the automobile market. One of the known applications of lead acid batteries is at the American Electric Power, which installed 250-kW, 30-s Pure Wave UPS, using conventional lead-acid batteries [16]. Furthermore, the project DEMO-RESTORE, financed under FP6, intends to test the robustness of these batteries as a support to PV systems [8].

Nickel-Cadmium (Ni-Cd) Battery

Ni-Cd batteries are less developed, but have advantages over Lead-acid batteries, mainly owing to the toxicity of some used materials and challenges related to the conformity with EU regulations on batteries and waste (Directive 2006/66/EC) [8].

Flow battery

In the flow battery system, the electrolytes are stored separately in large storage tanks, outside the electrochemical reactor. The energy rating is determined by the size of the storage tanks and the amount of electrolytes. Therefore, it can be dimensioned independently from the power rating of the battery, making the system more flexible. Currently, three types of flow batteries have achieved the demonstration and commercialization stages: Vanadium Redox Batteries (VRB); Polysulphide Bromide Batteries (PSB); Zinc Bromine (ZnBr) batteries. The response time of flow batteries is very fast, enabling a shift from charging to discharging mode in about 1/1000 second. The DC/DC efficiency for these batteries is about 80%. The main drawbacks of this battery technology are the risk of electrolyte leakage and low energy density. Till now, VRB and ZnBr batteries are currently commercialized, whereas PSB are still in the demonstration stage [15].

Flywheels

Concerning the operation principle of flywheels, these store kinetic energy in a spinning mass and, during the charging phase, electricity is used to spin up the flywheel through a motor. At the discharging phase, electricity is generated by the same motor from the rotational energy. The energy rating of the flywheels is set up by the rotor's mass and speed. The power rating is determined by the motor-generator. The major feature of flywheels regards its high power density (400-1600 W/kg), which is meaningful for ensuring the transitory stability of power systems. Flywheels are useful for frequency and voltage control, levelling the fluctuating load and non-interruptible power supply. The DC/DC efficiency of flywheels can be higher than 90%, yet this is decreased with

lower discharge power. Since flywheels can be completely discharged in some minutes or hours, they require external power to maintain certain level of charge, in a standby mode. The investment cost of a flywheel system tuned for power application ranges 150-600 €/kW [15].

There are many demonstration projects of this technology, such as the Spanish project SA2VE (application in railway transport, energy management for buildings and power supply quality); the flywheel facility installed, in 2005, in the Flores Island of the Azores Archipelago (to allow higher integration of wind power in this island, providing peak lopping and spinning reserves); and in Graciosa Island (Azores), which addresses wind power integration and diesel fuel offset [8].

Super Capacitor

Although super capacitors are comparable to lead-acid batteries in energy density and cost, they present thousands of deep discharges and superior performance at low temperatures [34]. Super capacitors are also capable to perform very fast charges and discharges, going through a large number of cycles without degradation. These capabilities turn this technology suited to voltage regulation [35], [16]. In terms of demonstration projects, there is the STORE project (Canary Island) for ultra capacitors and the FP6 project HyHeels, which envisages super capacitors as a means to optimize hydrogen-based systems [8].

SMES – Superconducting Magnetic Energy Storage

The operation of SMES systems consists of storing energy in a magnetic field created by the flow of direct current in a superconducting coil. This system has an efficiency of about 95% from input back to output [35]. The most relevant advantage of SMES facilities refers to the short time delay during charge and discharge. Power is available almost instantaneously and very high power output can be supplied for a brief period of time. This feature is relevant, when comparing to other electricity storage options (e.g. pumped hydro storage or CAES) that have a larger time delay (seconds to several minutes), taking into account the energy conversion from the stored mechanical energy back into electricity. Additionally, the loss of power is lower than for other storage technologies, since electric currents encounter almost no resistance [16].

Taking into consideration the energy requirements for SMES refrigeration, as well as the high cost of superconducting wires, these systems are currently used for short duration electricity storage. In view of that, SMES is mostly enclosed to enhancing power quality. Small SMES units are commercially available and larger projects are underway. Power quality control units have typically 1 MW, installed at manufacturing plants requiring ultra-clean power, like microchip production facilities. When it comes to power grids applications, Northern Wisconsin is a known example of SMES installation, where a string of distributed SMES units was deployed to improve the

transmission system stability. The transmission line is subject to large and sudden load variations, owing to the operation of a paper mill, with uncontrolled fluctuations and voltage collapse. Utilities preferably charge their SMES facilities from the base load power at night, in order to meet the peak load demands during the day [36]. SMES systems are also used to supply grid stability in distribution grids, as referred in [16]. In Europe, there is a set of successful demonstration projects, namely in Germany, Finland and France, operating at 20 kW. Besides demonstration projects, research prototypes of SMES have also been designed in Italy, Germany, Finland and Spain [8].

Power-to-Gas Storage

These systems rely on an energy-consuming electrolysis process to split water into oxygen and hydrogen. Afterwards, a methane-rich gas (equivalent to natural gas) is produced using the H_2 obtained and CO_2, and feeding the natural gas network. In addition, the stored gas can be fed back to gas power stations [8]. This technology could be particularly useful for multi-utility companies (with electricity and natural gas businesses), such as EDP and REN (in Portugal), RWE and E.ON (in Germany), National Grid (in UK), Energinet (in Denmark), Svenska Krafnät (in Sweden), and others [37], [38], [39], [40].

The roundtrip efficiency of this solution is about 70% [41]. As advantages, this option allows higher power capacity than conventional pumped hydro storage systems, and enables long-run storage (by bridging shortages, due to RES variability, for up to 2 months) [8]. As drawbacks, currently, this system is still inefficient, being mostly suitable for power systems with lack of potential sites for pumped hydro storage. Fraunhofer IWES and Hydrogenics have been carrying out pilot projects, whereas E.ON has been developing an installation that can convert wind power into H_2 at Falkenhagen [8].

Hydrogen Storage

Hydrogen storage can be assessed as a type of power-to-gas storage, since an electrolyser unit converts power into H_2 and, at times of higher load demand, it is transformed back into electricity using fuel cells. H_2 can be stored on underground caverns, salt domes and depleted oil and gas fields. Hydrogen storage has both high energy rating and energy density, and low self-discharge rate. Thus, it is appropriate to be coupled with large wind farms, or support power grids in isolated systems. Yet this solution is still technically immature, highly cost-intensive and presents a reduced round-trip efficiency [8].

Thermal storage

There are three types of thermal storage: 1) sensible heat storage (exploiting the change in a material's temperature to store and release heat); 2) latent heat storage (storing and releasing heat through a change in a material's physical state, e.g. liquid to solid and vice versa); 3) and thermochemical heat storage (based on a reversible chemical reaction) [42]. The thermal power rating is mostly set up by the size of heat exchangers, pimps and other auxiliary components. The volume of the storage tank determines the energy content [8].

When it comes to storage duration, it can go from days to one year (sensible heat storage); hours to weeks (latent heat storage); and a few hours to a day (thermochemical heat storage) [42].

The next figure draws the power costs and maturity stages of the electricity storage technologies.

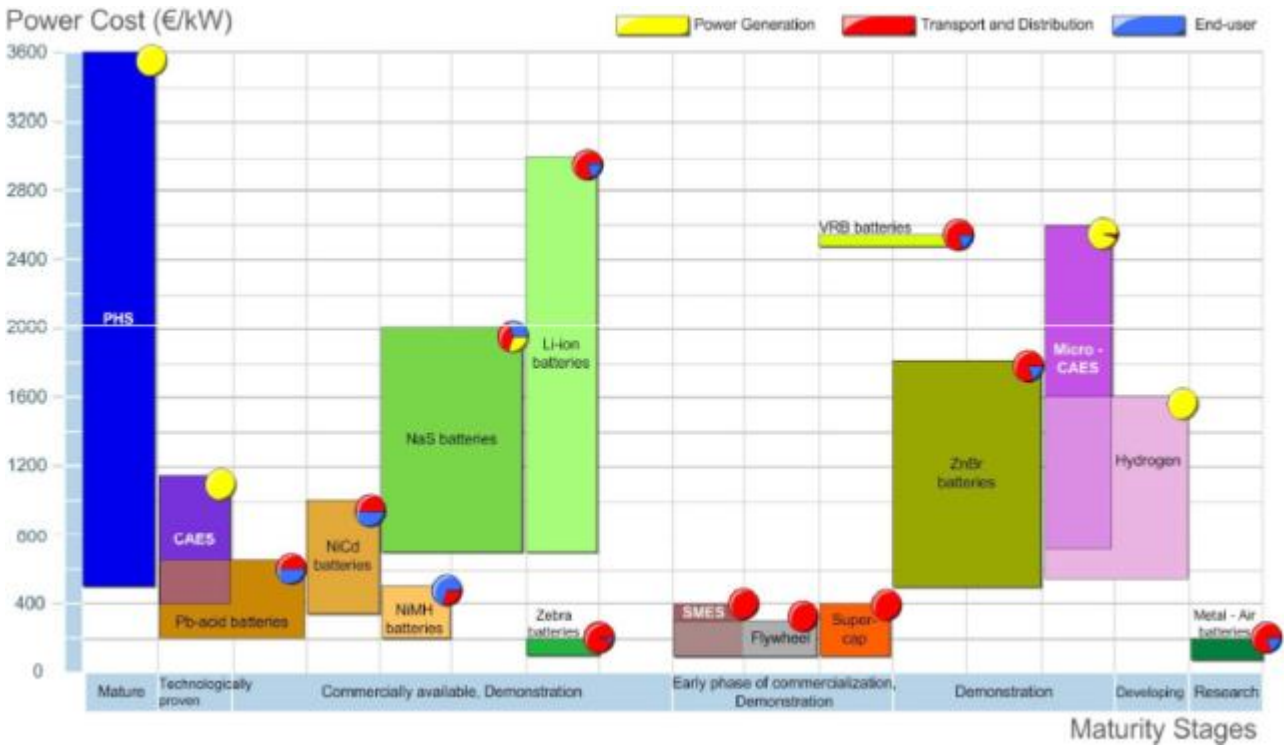


Fig. 7: Power costs and maturity of the energy storage technologies [43]

Greenhouse Gas Emissions Comparison

Taking into account that greenhouse gas emissions are generally proportional to energy use, battery storage systems have much higher emissions than pumped hydro storage or CAES, with similar size, including construction, operation and maintenance.

Pumped hydro storage has low energy demand relative to the volume of energy stored, despite the dam building process. Concerning the CAES, this facility requires a relatively low energy for construction operations, but its hybrid storage-generation nature demands significant energy during

operation. CAES leads to higher emissions than other technologies, during operation stages, owing to the natural gas process combustion.

But a holistic assessment on greenhouse gases requires a life-cycle analysis, including primary energy consumption. In fact, when an energy mix is based on fossil fuels, primary energy emissions dominate the emissions assessment of stored power [44].

The greenhouse gas emissions from the analyzed storage facilities are presented underneath, for different power systems mix.

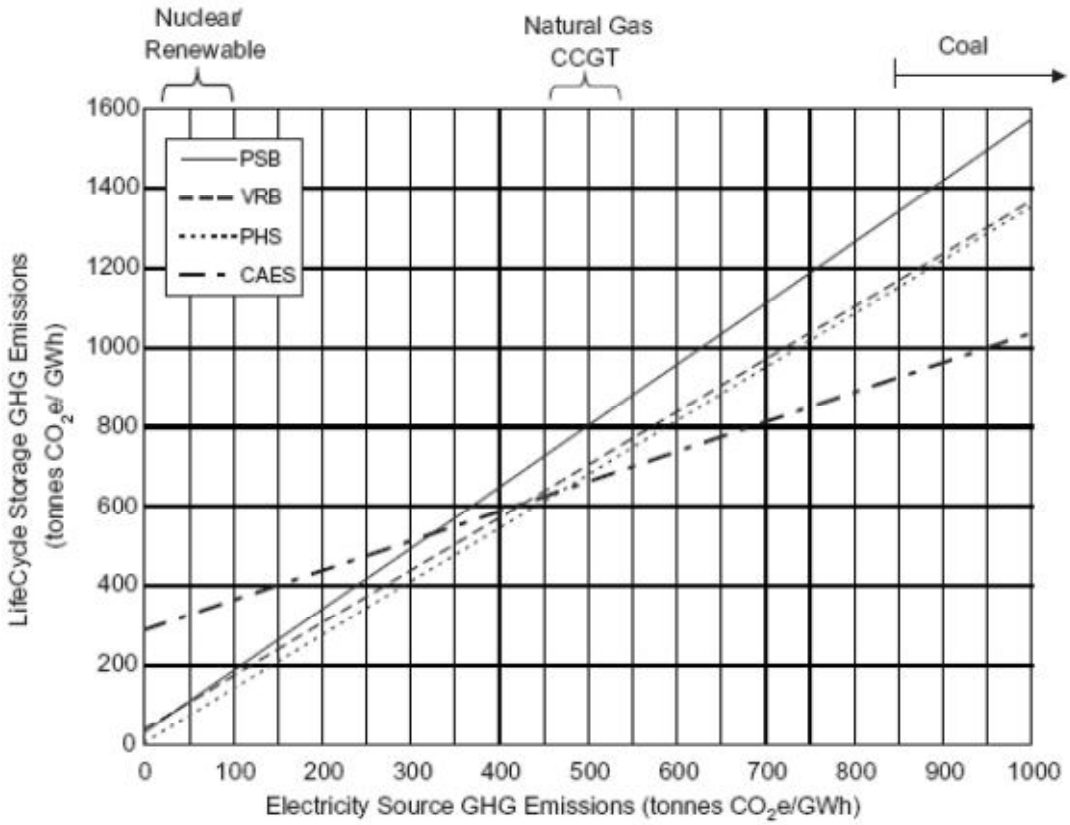


Fig. 8: Greenhouse gas emissions from energy storage technologies [44]

From the previous plot, some conclusions can be drawn [44]:

- CAES has higher greenhouse gas emissions than pumped hydro or battery storage, when coupled to a low-emission energy mix.
- CAES turns environmentally favourable when emissions from the power system increase.
- CAES becomes the preferred storage technology, in terms of greenhouse gas emissions, when the electricity comes from gas, oil or coal generation sources.

- Pumped hydro and battery storage have a similar performance in terms of greenhouse gas emissions, but pumped hydro has lower global emissions due to effect the construction related emissions.
- The PSB has a lower emissions impact than the VRB technology, when installed in a low-emission power system. But in a fossil-fuel-based energy mix, the lower efficiency of PSB results in higher emissions than the other storage technologies.

Energy Markets and Electricity Storage

Concerning the electricity storage participation in energy markets, there is a set of services that could be provided, such as [8]:

- Price arbitrage;
- Demand response;
- Extra high end-user power quality/autonomy;
- Balancing services;
- Primary and secondary frequency control;
- Voltage control;
- Blackstart;
- Congestion relief;
- Connection of generators and load.

Spot and balancing markets should be analyzed jointly, as proposed in [8], bearing in mind that the price signals of balancing markets could account for the price depression in the day-ahead spot market. That's to say, if it is less expensive to buy power near real-time, there is lack of economic incentive to buy it in the day-ahead, at a higher price. There is a set of reasons that could lead to a price depression in balancing markets, as described next [8].

- *ad-hoc peak load arrangements*: *ex-ante* capacity payment for peak load units, which enables them to bid into the energy market at a lower price; the Norwegian TSO (Statnett) implemented a reserves option market to secure enough resource bidding into the balancing market; the French TSO (RTE) remunerates a capacity payment for fast tertiary reserve to bid into the balancing mechanism.
- *price fixation method in balancing markets*: bids are selected according to the merit order of the bidding prices; the marginal price remuneration of the selected bids is not the global "rule" in balancing market; alternatively, balancing energy may be remunerated based on pay-as-bid (e.g. Austria, Italy) or at average prices (e.g. France, Germany or the UK).

- *lack of liquidity*: this is motivated by the small market scale, limited number of market participants and restrictive bidding requirements.

Ruester *et al.*, proposed the next market design, in view of electricity storage participation [8]:

- *ad-hoc peak load arrangements* should be considered when defining "energy-only" markets.
- regarding the *price fixation mechanisms* in day-ahead and balancing markets, remuneration in both markets should be harmonized and ensure an economically efficient dispatch.
- *liquidity of the balancing market* could be enhanced by modifying market rules. Generally, only the balance entities are allowed to participate in the balancing markets bidding. Hence, minimum bidding requirements and rules should be relaxed, which would give market access to small and decentralized players, such as storage facilities and other flexibility solutions. Besides setting a value to electricity storage services, this market change may have a positive impact on market liquidity.

Regulation of Electricity Storage

As opposition to the established in the gas sector, in the electricity sector storage has not been confirmed as a regulated market segment. In truth, till now, electricity storage has been assessed by regulators as a generating technology, ignoring its capabilities for enhancing the system's flexibility [7].

Anyway, electricity storage urges organizing the provision of services, in a way that:

a) technical benefits can be achieved within a regulatory framework that gives fair and stable opportunities to the different actors;
b) sustainability of the related businesses is assured;
c) consumers' costs are maintained at an adequate level [8].

The role of distributed storage (including EVs) and smart appliances is particularly demanding in regulatory terms, with the emergence of the new concept of aggregator and the Smart Grids, but a complete framework must be built to integrate all the alternative means of storage. According to Ruester *et al.*, the core of the business model for electricity storage is how the facility's functionalities are matched with services to be provided [8]. Hence, the business model of electricity storage depends of:

- finding the optimal match between functionalities and services to provide by the storage unit;
- market design and regulatory framework in order to adequately reward individual stakeholders, acknowledging their value in terms of electricity storage services.

Besides the energy shift purpose (for storing RES surplus) – which is addressed in this research – electricity storage facilities can provide the following innovative reserve services:

- Regulation Reserve (frequency control);
- Balancing Reserve ("new" tertiary reserve to handle, for instance, wind forecast errors);
- Congestion Management Reserve.

In view of these drivers, regulated actors might ask for controlling electricity storage devices given their mission to "keep the lights on". For instance, Svenska Kraftnät (Swedish TSO) owns and operates gas turbines (400 MW) for system balancing (i.e. handling disturbances). In addition, Directive 2009/28/EC states: "Member States shall take appropriate steps to develop transmission and distribution grid infrastructure, intelligent networks, storage facilities and the electricity system, in order to allow the secure operation of the electricity system as it accommodates the further development of electricity production from renewable energy sources" [45].
Accordingly, a recent change in Italian legislation (implementing Directive 2009/28/EC) allows the TSO (Terna) to build and manage "diffused" storage systems such as batteries, by calling on the TSO to identify in its network development plan, the reinforcements necessary to ensure that renewable generation is fully dispatched (avoiding curtailments), stating that these interventions may include storage systems. The Italian Ministry of Economic Development has approved Terna's 2011 national transmission development plan, including the implementation of the batteries for electricity storage for as much as 75 MW, out of which 35 MW under the Plan for the Development of the Grid and 40MW under the Plan for the Security of the Grid [46].

Yet part of the deregulated actors' revenue may come from the provision of ancillary services. Looking at the possible horizons of deciding the usage of storage (forward, day-ahead, intraday, balancing market and real-time balancing), one could see that the use of storage by TSOs comes at the last place. Ruester *et al.*, stated that residual capacities of storage, once put at the disposal of a TSO (after commercial trading), could effectively contribute to balancing. Hence, a regulatory decision to ensure that the residual capacities of any asset, including storage, would not be wasted if they could be used for ancillary services, and would be fairly remunerated, is required. The benefits of regulated ownership might be justified if electricity storage services are considered regulated services, being highly beneficial for system stability, but without introducing interference to competitive activities.

The Challenges of Isolated Power Systems

The electricity storage need is even more undeniable in the case of isolated power systems, such as islands, if renewable energy integration is foreseen to increase considerably. As a consequence, the scientific community has undertaken some important studies and research activities, which will be briefly recovered henceforth.

When it comes to isolated power systems, there is a set of potential technologies for energy management applications: battery energy storage; fuel cells; flow batteries; pumped hydro storage; CAES; and flywheels. Accordingly, Kaldellis *et al.* developed a methodology for electricity storage systems that can both utilize the excess/rejected energy produced from renewable energy power plants and improve the operation of existing thermal power units [47]. Furthermore, Kaldellis and Zafirakis analyzed, in [48], the cost effect of introducing selected storage technologies in a large variety of autonomous electrical grids so as to ensure higher levels of renewable energy sources penetration.

As previously presented, one of the most mature storage technologies is the pumped hydro storage. When it comes to the particular case of isolated power systems, it is possible to increase wind generation at a competitive cost if all options are examined using externalities. This evidence was ratified by Bueno and Carta, in [49], based on an optimum sized economic model of a wind/pumped hydro storage system developed for Gran Canaria island. Furthermore, according to a study developed by Kapsali *et al.*, in [50], for Lesbos Island, the proposed wind/hydro solution, besides allowing wind generation increase, might lead to an improvement of the energy supply stability and security of supply; reduction of imported oil dependency; minimization of environmental impacts; and regional development free of weighty investment costs. Nevertheless, the research developed by Katsaprakakis *et al*, in [51], for the islands of Crete and Rhodes – aiming to reduce the annual energy production cost and maximize the wind energy penetration – concluded that the pumped storage introduction in isolated power systems, with high thermoelectric production and wind energy rejection, is not always economically feasible. According to the referred study, the project feasibility depends on each specific power system. Namely, the pumped storage approach reveals to be particularly suitable for power systems with soaring specific costs from energy generation and high annual consumption of expensive fossil fuels.

Additionally, according to the study developed by Brown *et al.*, in [52], results showed that including pumped hydro storage can be an effective means of allowing larger penetration of intermittent renewable energy sources, improving both the dynamic security and the economic operation of the system. In this approach the shedding of pumping units is also considered as a way to keep the system stability when sudden wind power losses occur.

In respect to CAES, this technology does not really suit for small isolated systems, because the installed capacity of CAES ranges from a few MW to some GW. However, in big islands, and according to Kaldellis *et al.*, CAES is considered to be a technology capable to compete with pumped hydro storage systems [47].

Regarding the flywheel system, this solution is found with units in the range of some hundreds of kW. Moreover, its potential operational period is limited by a maximum of a few minutes. Clear benefits can be obtained from the presence of flywheel storage in small isolated power systems [47]. As a matter of fact, the introduction of flywheel storage into an isolated hybrid grid allows the increase of renewable energy penetration. This statement was inferred by Hamsic *et al.*, in [53], from a study developed for the island of Flores (Azores, Portugal), in which the addition of a flywheel storage system, in the wind/diesel/hydro power system, has improved the system stability and raised renewable energy penetration, by plunging diesel fuel usage. Flywheels are in this case used to compensate renewable generation intermittency, balancing in fast way the system when facing sudden wind power changes.

Concerning fuel cells' vocation, Ntziachristos *et al.*, carried out a study of coupling a wind-turbine with a fuel cell in order to enhance the wind power utilization, in the non-interconnected Greek archipelago grid [54]. The outcome of the referred study revealed that it is possible to replace conventional power units with a hybrid system, delivering energy at constant power.

When it comes to hydrogen storage in isolated power systems, Agbossou *et al.* stated that the surplus renewable generation can be used to produce and store hydrogen and, at times of insufficient renewable generation, electricity is regenerated from the stored hydrogen [55]. The combined operation of renewable generation (i.e. wind power) and hydrogen storage gives as well the possibility to use the hydrogen produced from electrolysis as fuel for vehicles, as affirmed by Holen and Korpas, in [56]. For instance, Korpas and Greiner developed a study which describes how H_2 storage can be applied in both isolated and grid-connected systems, and how the produced H_2 can be utilized for stationary energy supply and/or as a fuel for transportation [57]. In addition, as a result of a study based on a Norwegian island's power system, Korpas proposed to use H_2 as a fuel for a local ferry [58]. However, according to the assessment presented by Greinera *et al.*, for a wind–hydrogen energy system implemented in a Norwegian island, an isolated system was concluded to be a poor alternative, both in what concerns to H_2 cost and in an environmental point of view [59]. Besides, according to a study developed by Kavadias *et al.*, based on Island of Crete's

information, it was deduced that the optimum size of a hydrogen production facility largely depends on the proportion and time-scattering of the renewable energy being rejected [60].

Concerning flow batteries, above a certain quantity of electrolytes, these units may be applied for large scale energy storage and, therefore, compete with pumped hydro storage and CAES. This happens because flow batteries' capacity depends on the size of the electrolytic tanks, as affirmed in [47]. In particular, vanadium redox-flow batteries could be a reasonable alternative for load levelling and seasonal energy storage in small grids and stand-alone photovoltaic systems. Specifically, Joerissen *et al.* developed a cost analysis which shows that vanadium redox-flow batteries could compete with current high capacity lead-acid batteries used in stationary applications [61].

Regarding battery energy storage applications, there's almost no restrictions. However, for instance Li-ion systems may be used only for very small islands, with maximum power rate less than 500 kW, as presented in [47].

Taking into account the current advantages of the pumped hydro storage (in terms of costs, emissions and maturity), for energy management purposes, regarding the other possible technologies (i.e. CAES), this storage option was chosen to investigate in this thesis.

2.3 Electric Mobility

The transport sector accounts for over half of the world's consumption of oil and much of this is used by road vehicles. The broad adoption of vehicles powered wholly, or in part, by batteries would create a noteworthy contribution for the urban air quality enhancement. However, the environmental effectiveness of the EVs implementation depends mostly on each generation mix. EVs use an electric motor to move the vehicle and are recharged with electricity. The energy is stored in batteries or in other alternative storage systems on board the vehicle. The higher the renewable share in the mix, the larger the environmental benefits from EVs. As a result of the exposed, a generation mix that is likely to have renewable power surplus (e.g. power systems with high penetration of hydro power plants and large amounts of wind power), should pursue accurate strategies in order to use that renewable excess [62].

The European Commission envisages the EVs as a niche market in the near future, but sales are expected to expand when battery technologies improve. There are forecasts assuming EVs will have a market share in new car sales of 1 to 2% in 2020, rising to 11 to 30% in 2030. For plug-in hybrid

electric vehicles (PHEVs), a share of 2% is forecasted by 2020, and 5 to 20% by 2030 [63], [12]. BP estimates 4% of EVs among global vehicle fleet in 2030 and the consortium A.T. Kearney / INESC Porto projects 1,2% of EVs share, at most, among the Portuguese light vehicles fleet, in 2020 [64].

According to the European Commission, affordability is a major factor in introducing EVs to the mainstream consumer market. Consumer prices will have to fall significantly through technological improvements and economies of scale to expand market share. This technology has a bold potential to utterly address a set of global challenges, such as global warming, dependency from fossil fuels, local air pollution and storage of renewable energy in vehicle batteries through smart grids. The European Commission also states that pure EVs appear to be more promising for urban use, given the relatively limited range provided by batteries and the potentially better cost-benefit ratio of deploying recharging infrastructure first in cities. Lower pollutant and noise emissions also lead to meaningful social benefits in urban areas [12].

Taking into account the aforementioned policy-making-drivers, the UK Department for Transport investigated the scope for the transport sector to switch to vehicles powered through electricity from the grid, in the period until 2030 [65]. The report aimed to provide a better knowledge of the contribution that the introduction of EVs and PHEVs can make to the long-term reduction of the UK's CO_2 emissions. This study inferred that the EVs' role in the mid-run will be enclosed to urban environments (starting with city markets and van fleets). On the other hand, PHEVs will have greater penetration in the market in the medium term, owing to their increased flexibility.

A similar study was carried out in Denmark by Nielsen and Jørgensen, in [66], targeting to analyze energy, environmental and electricity market aspects of integrating electric vehicles in the future Danish energy system. Consequences of large-scale utilisation of electric vehicles are analyzed. Furthermore, the aim is to illustrate the potential synergistic interplay between the utilisation of electric vehicles and large-scale utilisation of fluctuating renewable energy sources, such as wind power. Economic aspects for electric vehicles interacting with a liberalised electricity market are analysed. The project was focused on battery electric vehicles and fuel cell vehicles based on hydrogen. According to this study, the EV compared to the conventional ICV is very attractive, from both an energy efficiency and CO_2 emission point of view. EVs entering the fleet in the period 2025 to 2030 have considerable lower carbon emissions than the ICVs. The combination of the Danish power supply system development towards reduced CO_2 emission/kWh and the technical development of the EV, lead in very low EV long-term specific CO_2 emissions.

For the US case, Cheah *et al.* examined the vehicle design and sales mix changes necessary to double the average fuel economy of new US cars and light-trucks by 2035 [67]. To achieve this

target, three technology options - that are available and can be implemented on a large scale - are assessed: channelling future vehicle technical efficiency improvements to reducing fuel consumption rather than improving vehicle performance; increasing the market share of diesel, turbocharged gasoline and hybrid electric gasoline propulsion systems; and reducing vehicle weight and size. Results from this study imply that continuing the current trend of ever increasing performance and size will have to be reversed if significantly lower vehicle fuel consumption is to be achieved.

In what pertains to PHEVs, Markel and Simpson presented a comparison of the costs (vehicle purchase costs and energy costs) and benefits (reduced petroleum consumption) of these vehicles relative to hybrid-electric and conventional vehicles. According to the author, the PHEV cost-benefit equation is quite sensitive to a range of factors, such as: battery costs, fuel costs, vehicle performance, and driving habits [68]. Taking into consideration the large variability and uncertainty in these factors, the author concluded that is difficult to predict the future potential for PHEVs to penetrate the market and reduce fleet petroleum consumption. The report also emphasized that it does seem likely that "it will be quite a challenge to justify the PHEV capital cost premium on the basis of reduced lifetime energy costs alone. Other incentives and business models may be required to create an attractive value proposition for PHEV motorists."

According to the EU Project MERGE [69], the increase of EVs penetration will lead to a considerable impact on power grids, which could be handled by: 1) reinforcing the grid infrastructure to cope with the increased load (expensive); or 2) controlling the grid loading through active demand side management, which will avoid the need to reinforce the grid and generation infrastructures. Together with the smart grids concept, emerges the V2G strategy. According to Kempton and Tomic, the basic concept of V2G is that EVs provide power to the grid while parked. Basically, there are three types of vehicles well-matched to the V2G concept: battery, fuel cell (vehicles running on gasoline, natural gas or hydrogen) and hybrid. All of these use an electric motor to provide all or part of the mechanical drive power [70].

The use of V2G requires the capability of 2-way energy flow between the EV and the Charging Post (CP), and the inclusion of both these flows within billing. This should be pursued together with the installation of 2-way communication electronic meters (usually named smart meters), at the CP level, and remote communication between the CP and the supplier/aggregator, who will act as billing authority. V2G also implies control strategies, in order to tune the battery charging/discharging with power system needs [69].

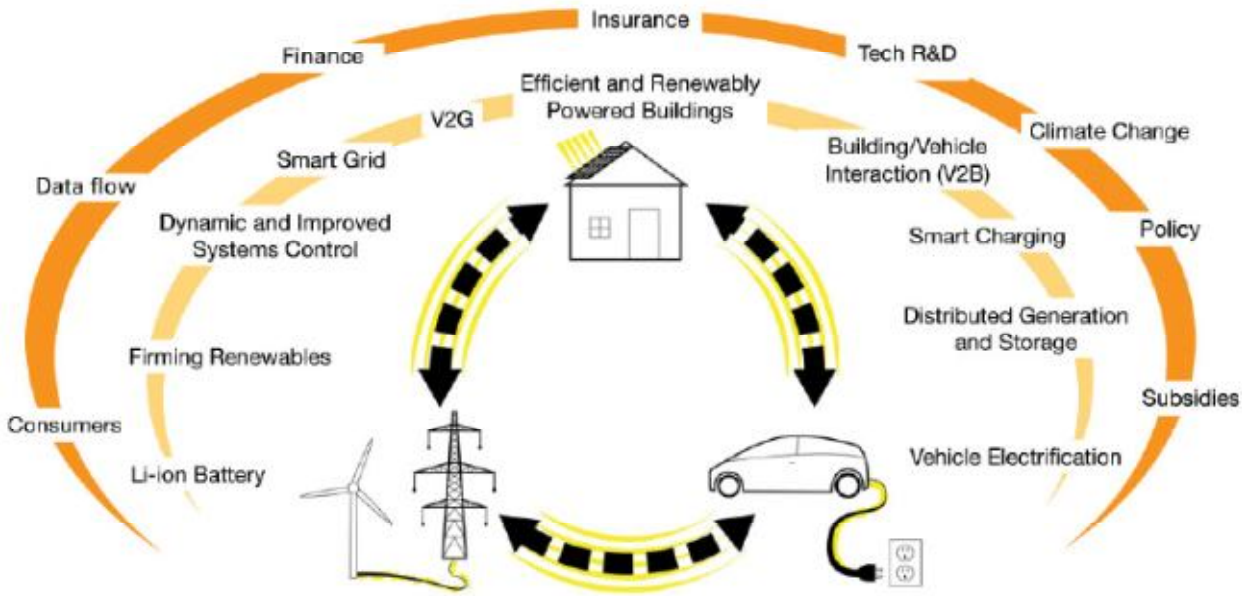


Fig. 9: V2G concept [71]

Concerning strategies and business models for the V2G implementation, Kempton and Tomic suggested that after the initial high-value, V2G markets saturate and production costs drop, V2G can provide storage for renewable energy generation [72]. The authors' calculations suggest that V2G could stabilize large-scale (one-half of US electricity) wind power with 3% of the fleet dedicated to regulation for wind, plus 8-38% of the fleet providing operating reserves or storage for wind. Additionaly, Kempton and Dhanju proposed V2G as a storage resource for large-scale wind power [73]. In that article, the authors advocated that EVs will simultaneously reduce petroleum needs of the light vehicle fleet and allow wind generation increase (by tapping energy surplus via V2G). Furthermore, Kempton highlighted, in [72], that one efficient way to use the renewable surplus relies on the replacement of traditional vehicles by EVs.

In what regards to power markets, Letendre and Kempton examined a range of EVs to provide four types of power: baseload, peak, spinning reserves, and regulation (up and down) [74]. According to the authors, V2G does not make sense for baseload power, since the per-kWh cost is too high and drive train designs assume low operating time (average 1 hour/day). On the other hand, the economic value of other forms of V2G appears high, more than enough to offset the initially higher costs of EVs. Accordingly, Kempton and Tomic stated, in [70], that V2G's greatest near-term promise is for quick-response, high-value electric services. These quick-response electric services are purchased to balance constant fluctuations in load and to adapt to unexpected equipment failures. Furthermore, the works presented in [75] conclude that, in the United States, EVs can be cost-effective as a source of peak power or as spinning reserves.

The following figure depicts the suitability of different vehicle types for electricity storage versus backup, and for differing electric markets.

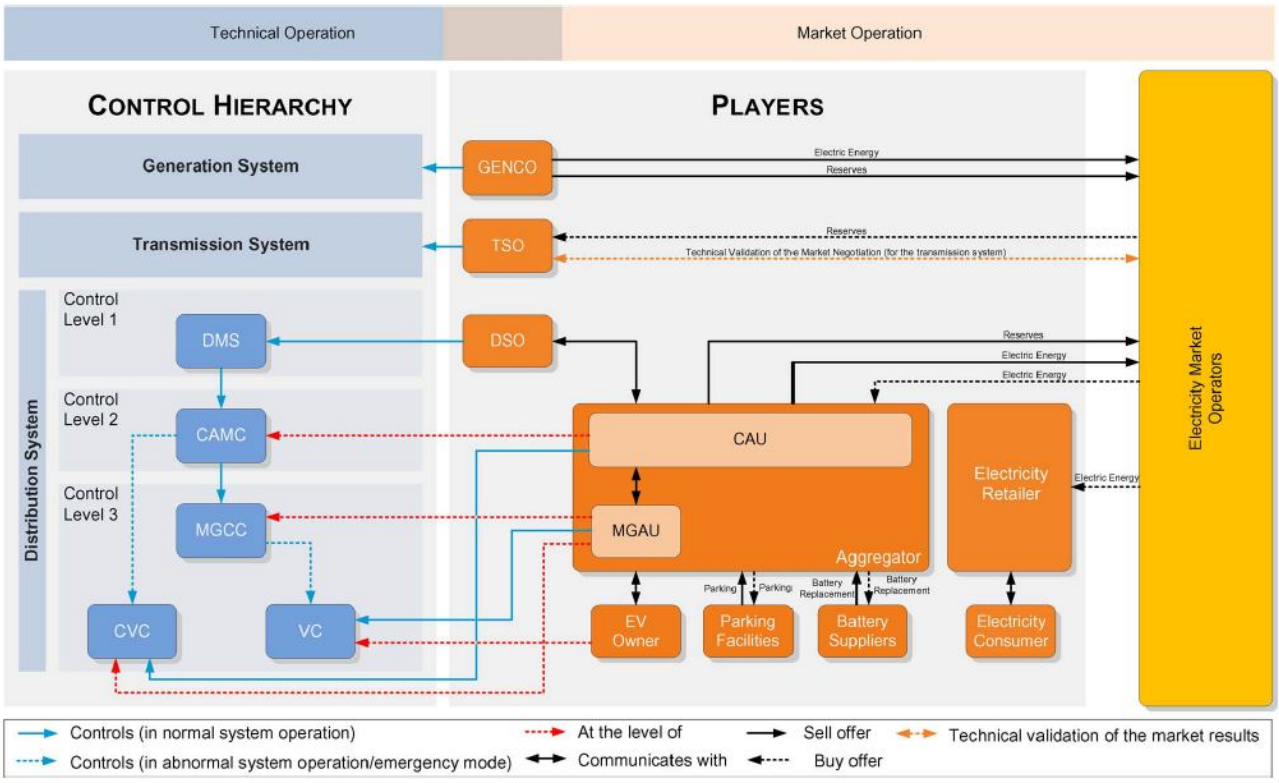
Vehicle type	Renewable Energy		Electricity Market		
	Backup	**Storage**	**Regulation**	**Spinning Reserve**	**Non-Spinning Reserve**
EV		++	++	++	
PHEV	++	+	+	++	++
Fuel Cell	++				++

Fig. 10: Suitability of different vehicle types for energy storage versus backup, and for differing electric markets, adapted from [73]

The UK Department for Transport affirmed, in [65], that V2G can be a useful concept in remote or vulnerable locations, when it could provide backup power at times of supply interruptions. According to the referred study, V2G could also offer benefits to the generator in demand smoothing at peak times, by reducing demand from the grid.

Regarding smart charging strategies, Peças Lopes *et al.* analyzed, in [76], the impacts led by the EVs rollout through two charging approaches (dumb charging and smart charging) on load/generation profiles. For the purpose of this analysis, a 2011's wet and windy day was considered, where large hydro and wind generation exists. The authors concluded that for the analyzed day with 11% EVs integration, the absence of a smart charging strategy leads to a considerable load increase at the end of the day and, therefore, the EVs do not absorb the energy surplus occurring at valley hours. The lack of smart charging strategies performs even worse for the scenario with 61% of EVs integration, as the generation mix is not capable to follow the demand soar. Concerning CO_2 emissions, the referred work showed that there are major environmental benefits on account of EVs integration, when accompanied with smart charging strategies.

In addition, Peças Lopes *et al.* provided, in [77], a conceptual framework to successfully integrate EVs into power systems, both in terms of the grid technical operation, as well as the electricity markets environment. All the players involved in both these processes, as well as their activities, are described in detail, as sketched out next.



Legend:

CAU - Central Aggregation Unit

MGAU - Microgrid Aggregation Unit

VC - Vehicle Controller

CVC - Cluster of Vehicles Controller

GENCO - Generation Company

MG - Microgrid

MMG - Multimicrogrid

MGCC - Microgrid Central Controller

CAMC - Central Autonomous Management Controller

DMS - Distribution Management System

AGC - Automatic Generation Control

Fig. 11: Technical management and market operation framework for EV integration into electric power systems [77]

In [77] , several simulations are also presented, in order to illustrate the potential impacts/benefits arising from the EVs grid integration, comprising steady-state and dynamic behaviour analysis.

According to recent works, the necessary infrastructure to handle the upcoming Electric Mobility (EM) was identified [78]. Basically, the EM system gathers:

- User;
- Electric Vehicle;
- Charging Post;

- DSO;
- And a new agent – the Supplier/Aggregator (SupAg).

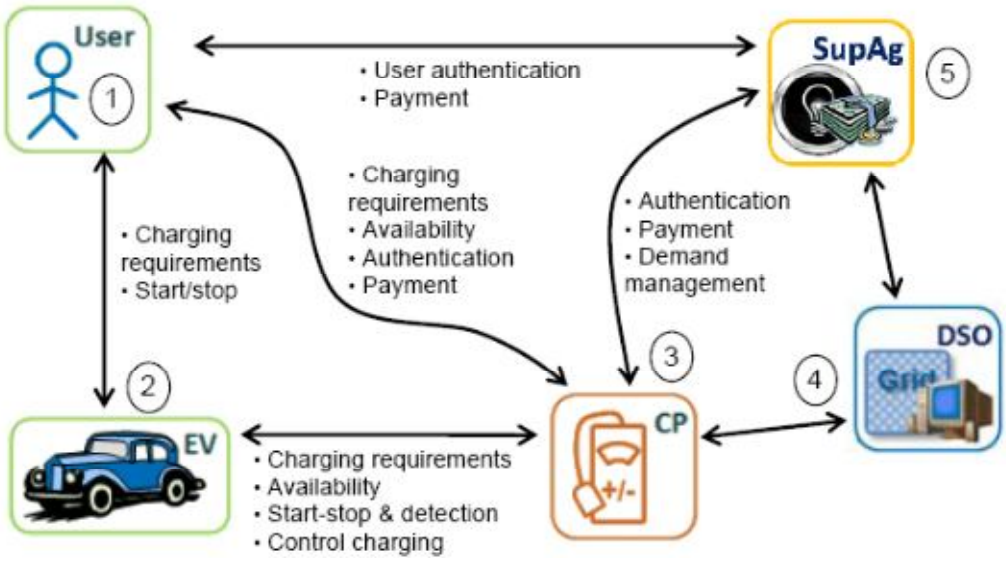


Fig. 12: The EM Infrastructure [78]

The SupAg is considered as the responsible entity for both selling electricity to the users (i.e. supplier) and aggregating their charging demand (i.e. aggregator). The supplier is the entity that purchases electricity from the power market and sells it to the users, while the aggregator is the entity which groups charging demand of a number of EV and can offer demand side management of this aggregated group of EV to the market. The work presented in [78] considers that the aggregator is expected to be owned by the suppliers, since it is rather economically justifiable.

Alternatively, the supplier and the aggregator can be different entities, as established for Portugal, where there is an EM Network Operations Manager (aggregator), providing services to the EM Retailers (suppliers), who buy electricity in the wholesale market, in order to sell it to the EVs' users. Besides these two entities, the Portuguese authorities have also defined a legal framework for the CP Operator, which shall be licensed players in charge with the CP's installation, operation and maintenance [79].

Concerning the EM process, Fig. 12 presents how the elements of the EM infrastructure should communicate with each other. The charging procedure may enclose four high level stages, as follows [78].

- Stage 1: allow connection;
- Stage 2: charging process;
- Stage 3: payment;
- Stage 4: disconnect.

As opposition to the internal combustion vehicles – in which the refuelling occurs almost exclusively at fuel stations – the EVs have a broader range of charging sites, within the electricity grid. The charging sites can be grouped into three categories:

- Public (e.g. on-street and large car parks);
- Private (e.g. individual and shared domestic garages, and workplaces);
- Commercial charging (e.g. recharging stations and commercial fleets).

When it comes to the charging option, it can be based on [65], [80]:

- standard charging (taking 6 to 8 hours to full storage);
- fast charging (taking 20 to 30 minutes to full storage);
- battery swap.

For the EM spread, a broad installation of charging posts is required in public and commercial places, besides the home charging infrastructure. An advanced infrastructure would be, therefore, required to handle the EM rollout [71].

A major issue for the EM massive implementation stands for the considerable strain of the EVs' charging on the power system. As previously mentioned, smart charging strategies are recommended to handle the potential EVs' strain on the power system. The development of smart charging strategies is, as a result, crucial to avoid generation capacity expansion and network reinforcement. The strategy to accommodate the electricity load, from EVs, should be materialized through innovative products, like smart meters and energy management software.

The next table presents a set of smart charging solutions provided by the market.

Table 1 - Smart charging technologies [71], [81], [82], [83], [84]

Company	Technology
Coulomb Technologies	Smart charging added to charging hardware. Partnership with GridPoint.
Ford/Microsoft	Microsoft Hohm to be used in all electric Ford Focus.
General Motors	OnStar System to be used on Chevy Volt.
Google	Vehicle dispatch algorithm.
GridPoint	Smart Charging 3.0, used in eTec program, in a partnership with Coulomb.
IBM	Linking smart charging with renewable energies, within the EDISON project with SIEMENS and Dong Energy.
Nissan	EV-IT system, in partnership with GE.
Pacific Northwest National Laboratory	Smart charger controller, licensed to Zap.
Juice	PlugStart, in partnership with GE.
GE	WattStation.
ITRON	OpenWay system, installed in American utilities (i.e. SDGE, SCE and DTE Energy).
SIEMENS	VersiCharge.
EFACEC	QC 45 – Quick Charger.

When it comes to the payment method, typically power utilities follow either pre-payment (e.g. United Kingdom and South Africa) or payment in arrears (requiring an account to be debited after charging), in which one consumer/customer stands for one meter. In the case of EM, the payment method becomes critical and rather complex, since the EVs can be charged in several sites, therefore, using different meters.

The next figure presents the possible payment options within the EM concept.

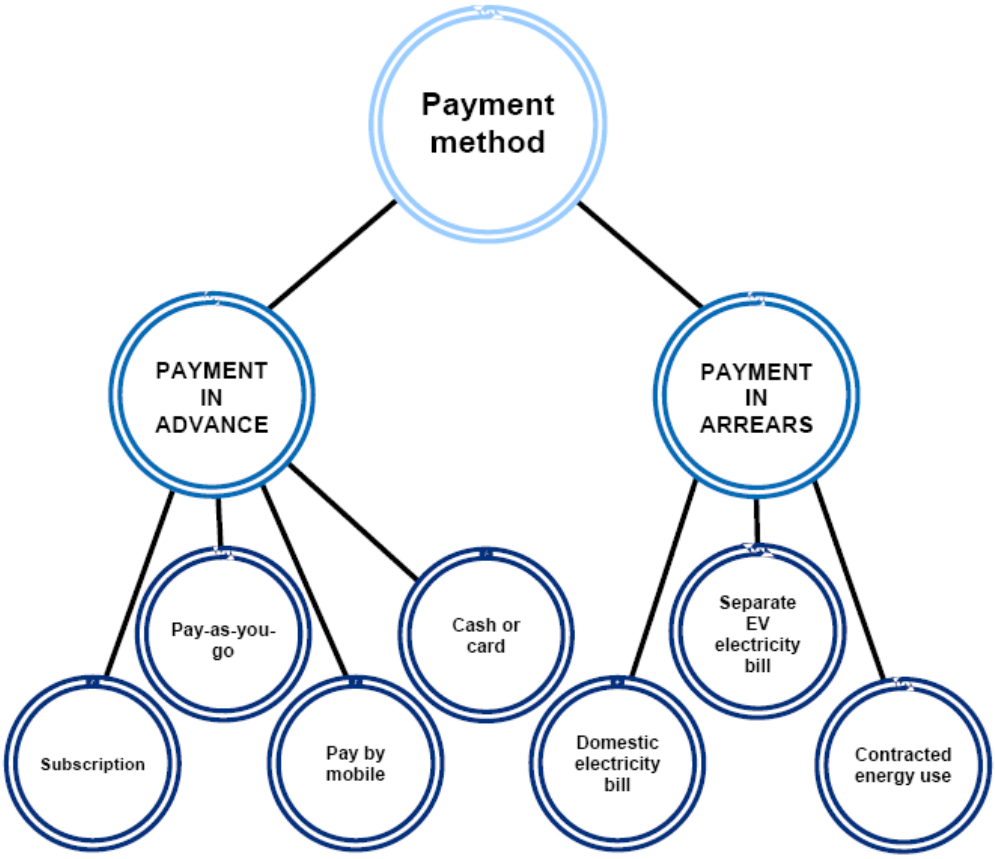


Fig. 13: Payment mode for EM [78]

Regarding the communication architecture, there is a broad range of available technologies for wired and wireless communication between the different elements of the infrastructure (authentication; communication from the EV to CP; and communication from the CP to DSO or SupAg), namely:

- RFID;
- CAN-bus;
- RS-485 (used for loop communication);
- Power Line Carrier (PLC), typically applied for smart metering;
- Ethernet;
- GPRS.

Within the European project MERGE, the work presented in [78] has identified the most suited technologies for each purpose, as presented next.

Table 2 – Communication technologies for the EM infrastructure

	Location		
	Private	**Public**	**Fast Charging**
Authentication	If necessary: 1. RFID 2. Touch screen	1. RFID 2. Touch screen	1. RFID 2. Touch screen
EV to CP	1. CAN-bus 2. RS-485 3. PLC	1. CAN-bus 2. RS-485 3. PLC	1. CAN-bus 2. RS-485 3. PLC
CP outwards	1. Domestic internet 2. PLC 3. GPRS	1. GPRS 2. PLC	1. GPRS 2. PLC

The strategy towards the implementation of the electric mobility infrastructure should consider the advantages and disadvantages of each technology, regarding the case under analysis. The next points provide a critical assessment on the available communication options.

- Touch screen: this option could be used either within the EV or in the CP. If the touch screen is located in the EV, the battery management system can use the input from the user and control the charging.
- RS-485: the RS-485 could be used for either communications from the EV to CP, or for CP to a central provider or node of a larger network. This communication option is often used in block smart metering (e.g. a building), where the meters are equipped with a RS485 interface, in order to establish a loop connection with the data communicator (linked to up to roughly 30 meters), which is equipped with a GSM/GPRS modem.
- Ethernet: this technology is rather tuned to communications from many CP to a wider network, than from EV to CP. Ethernet is also a common communication technology for smart metering within private installations (e.g. shopping centre).
- CAN-bus: this technology is widely used in recent vehicles, thus the use of a CAN-bus to connect the EV to the CP would be easy to apply.
- PLC: this option uses the power network for two-way data communication. PLC provides good advantages (the infrastructure costs and installation time is reduced) but the main purpose of the physical network is not data communication support. Today PLC communications have evolved and have been consolidated as the main communication required by the market for smart grids' Local Area Network. The most mature PLC version is the PLAN-SFSK, with proven robustness (e.g. Alliander and ErDF smart metering projects). In addition, the PRIME OFDM is a new PLC version (proposed by Iberdrola), which pledges higher transmission speed. High frequency PLC could be used for communication between the EV and CP. Low frequency PLC is rather appropriate to use by the DSO or supplier/aggregator for communication or control over long distances.

- Wi-Fi: this technology could be used for communication between the EV and CP, or between the CP and a central provider over a limited distance. As drawbacks, this option has some weaknesses regarding data privacy and difficulties in determining which EV is communicating with which CP.
- GPRS: this option is not suitable for the short distance communication between the EV and CP, but is adequate for long distance communication between the CP and DSO or supplier/aggregator. In fact there are today tens of thousands GPRS smart meters, installed all over the world.
- RFID: a contactless RFID smartcard could be used for simple and secure user authorisation, and as a cashless payment method.

2.4 Energy Planning Models and Tools

The research on energy planning tools has been addressed during the last few decades, for different motives (e.g. oil crises, energy geopolitics, environment threats, etc.). A literature review on energy planning studies, allows the identification of two model types in what pertains to the detail level in modelling the system: top-down models; and bottom-up models. The top-down models are macroeconomic tools, whereas bottom-up models are engineering models, which dive into a detailed characterization of the energy system [85].

Connelly *et al.* presented, in [86], a review on 37 energy planning models and suggested the next classification.

- Simulation tool: these tools simulate the operation of a given energy system to supply a given set of energy demands. Typically a simulation tool is operated in hourly time-steps over a one-year time-period.
- Scenario tool: this type of tool usually combines a series of years into a long-run scenario. Typically scenario tools function in time-steps of 1 year and combine such annual results into a scenario of typically 20-50 years.
- Equilibrium tool: these tools seek to explain the behaviour of supply, demand and prices in a whole economy or part of an economy (general or partial) with several or many markets. It is often assumed that agents are price takers and that equilibrium can be identified.
- Top-down tool: as stated before, these are macroeconomic tools using general macroeconomic data to determine growth in energy prices and demands. Typically top-down tools are also equilibrium tools.

- Bottom-up tool: these tools identify and analyse the specific energy technologies and thereby identifies investment options and alternatives.
- Operation optimization tool: these tools optimize the operation of a given energy system. Typically operation optimization tools are also simulation tools, optimizing the operation of a given system.
- Investment optimization tool: these tools optimize the investments in an energy system. Typically, optimization tools are also scenario tools, optimizing investments in new energy facilities and technologies.

When it comes to the geographical scope of the tools, as well the corresponding timeframe, the next table brings a more detailed characterization.

Table 3 – Scope and profile of energy planning tools

Tool	Scope	Timeframe	Time-step
Mesap	National/regional	No limit	1 minute to several years
TRNSYS16	Local	Multiple years	Seconds
HOMER	Local	1 year	Minutes
SimREN	National/regional	No limit	Minutes
EnergyPLAN	National/regional	1 year	Hourly
SIVAEL	National/regional	1 year	Hourly
STREAM	National/regional	1 year	Hourly
WILMAR Planning Tool	International	1 year	Hourly
RAMSES	International	30 years	Hourly
GTMax	National/regional	No limit	Hourly
H2RES	Island	No limit	Hourly
MARKAL/TIMES	National/regional	Max 50 years	Hourly, daily, monthly
PERSEUS	International	Max 50 years	Based on typical days
UniSyD3.0	National/regional	Max 50 years	Bi-weekly
RETScreen	User-defined	Max 50 years	Monthly
E4cast	National/regional	Max 30 years	Yearly
EMINENT	National/regional	1 year	None/yearly
IKARUS	National/regional	Max 50 years	Yearly
PRIMES	International/national	Max 50 years	Years
INFORSE	National/regional	More than 50 years	Yearly
ENPEP-BALANCE	National/regional	75 years	Yearly
LEAP	National/regional	20 to 50 years	Yearly
MESSAGE	Global	Max 120 years	5 or 10 years
MiniCAM	Global and regional	More than 50 years	15 years
AEOLIUS	National/regional	1 year	Minutes
HYDROGEMS	Project-oriented	1 year	Minutes
energyPRO	Project-oriented	Max 40 years	Minutes
BCHP Screening Tool	Project-oriented	1 year	Hourly
ORCED	National/regional	1 year	Hourly
EMCAS	National/regional	No limit	Hourly
ProdRisk	National/regional	Multiple years	Hourly
COMPOSE	Project-oriented	No limit	Hourly
EMPS	International	25 years	Weekly
WASP	National/regional	Max 50 years	12 load duration curves/year
Invert	National/regional	Max 50 years	Yearly
NEMS	National/regional	Max 50 years	Yearly
Valoragua	International/national	1 year	Weekly interval divided in 5 steps

After presenting a common classification of the energy models types and their scope, an overview is provided on some of the most applied tools, to the type of energy planning to address in this research.

⇒ **E4cast**: this is a partial-equilibrium tool employing an integrated analysis of power and gas

sectors. The model represents two sets of conditions, i.e. quantity and competitive price constraints. The competitive equilibrium is reached when all the constraints are fulfilled. E4cast is used to simulate future energy requirements and identify the way these can be achieved. The analysis is applied for an annual time-step, up to a maximum of 30 years. The tool accounts all the costs and the energy consumption is foreseen by fuel, industry and region, for an annual basis. This model provides an outlook for the Australian energy sector that is feasible and satisfies the economic competitive price conditions. In this tool, constraints on power and gas flows are considered in terms of existing and planned networks limits [87].

⇒ **EnergyPLAN**: this is a user-friendly tool programmed in Delphi Pascal. Input is defined by the user in terms of technologies and cost specifications. The main goal of the model is to support the design of national or regional energy planning strategies, based on technical and economic analyses of the consequences of implementing different investments. EnergyPLAN gathers the whole national or regional energy system, including heat, electricity, transport and industrial sectors. It is a deterministic input/output tool and optimizes the operation of a given system. General inputs are: demand; renewable energy sources; energy plants capacities; and costs. Outputs are: energy balances and resulting annual productions; fuel consumption; import/export of electricity; and total costs. This is an hour simulation model, optimizing the operation of a given system throughout one year. This tool is based on analytical programming as opposed to iterations, dynamic programming or advanced mathematical tools [88].

⇒ **MARKAL/TIMES**: this family of tools is tailored by the input data to represent the evolution of a specific energy system, over a period of 40 to 50 years, at the national, regional, state/province or community level. The TIMES and MARKAL models share the same basic modelling paradigm, i.e. both are technology explicit and dynamic partial equilibrium models of energy markets. The equilibrium is obtained by maximizing the total surplus of consumers and suppliers via Linear Programming. The two models also share the multi-regional feature [89]. All thermal, renewable, storage/conversion and transport technologies can be simulated by these tools [90]. Each annual load duration curve can be detailed at three levels: seasonal (or monthly); weekdays/weekends; and hourly [86]. MARKAL is implemented through an open architecture provided by the General Algebraic Modeling System (GAMS) [91]. This model gathers a set of energy or emission control technology types, represented by performance and cost characteristics. The input to the model consists of a menu with both existing and future technologies and the supply and demand sides are integrated. The optimization routine selects the technology option that

produces the least-cost solution subject to a set of constraints. MARKAL does not allow/require an a priori ranking of greenhouse gas abatement measures, as an input to the model. That's to say, the model selects the preferred technologies and then provides the ranking [89]. When it comes to TIMES, this tool fills some gaps of MARKAL, such as allowing the user to define period lengths in a more flexible way, as well as the planning horizon. In addition, in TIMES any commodity and process may have user-chosen time-slices, whereas in MARKAL only two commodities have rigidly defined time-slices (electricity and low temperature heat). TIMES has also a larger number of commodity-related variables and more accurate and realistic depiction of investment cost payments [92].

⇒ **Mesap**: this tool can be used as a market information system for energy trading; power plant information system for electricity generators; regulatory data management system for grid operators; environmental information system for environmental protection agencies; and tool for planning, simulation and balancing of energy systems. Mesap is a high performance database, enabling flexible data management [93]. Mesap consists of three parts: the calculation modules; the Mesap information system; and additional tools for specific modules or purposes [94]. The simulation is developed through a time-step ranging from 1 minute to several years and the total time-frame is unlimited.

⇒ **EMINENT**: this tool consists of a database and an assessment tool, providing a general framework for the evaluation of new energy technologies and solutions for national energy systems. EMINENT evaluates the performance and potential impact of recent technologies over a one-year time-period. The tool gathers two databases: a database of national energy infrastructures, containing information on the number of consumers per sector, type of demand, typical quality of the energy required, and the consumption and installed capacity per end-user; and a second database, that contains key information on new thermal generation, heat and renewable technologies. The tool is capable to compare the technologies, regarding financial, environmental and energy concerns [95], [86].

⇒ **MESSAGE**: this is a systems engineering optimization tool used for the energy systems planning in the medium to long-term, energy policy analysis and scenario development. The model provides a framework for representing an energy system with all its interdependencies from resource extraction, imports/exports, conversion, transport and distribution, to the supply of energy end-use services such as light, space conditioning, industrial production processes and transportation. Scenarios are developed by minimizing the total systems and the model configures the energy system evolution from the base year to the target year. The outcomes of the models include estimates of strategies for specific climate stabilization targets, by identifying the least-cost technologies portfolio. This tool

includes endogenous technology learning for various technologies using a Mixed Integer Programming approach. Message uses a 5 or 10 year time-step to simulate a maximum of 120 years [96].

⇒ **H_2RES**: this tool is designed for balancing hourly time series of water, electricity, heat and hydrogen demand, storage technologies and power supply (wind, solar, hydro, geothermal, biomass, fossil fuels or mainland grid). This model is tuned to energy planning of isolated regions (such as islands), with lack of interconnection. It can also assist in planning single wind, hydro or solar power producer, connected to a larger power system. The methodology adopted by this tool is divided in the next tiers: 1) mapping the needs (electricity, heat, cold, transport fuel, water, waste treatment, wastewater treatment, etc.); 2) mapping the resources (wind, sun, geothermal energy, ocean energy, hydro potential, water resources, but also imported resources such as natural gas, oil, water shipped, potential to dump waste and wastewater, etc.); 3) develop scenarios with technologies that can use available resources to cover the needs (conventional and pioneering technologies for power generation, water heating, waste and wastewater treatment); 4) modelling the scenarios [97].

⇒ **LEAP**: this tool can be used to track energy consumption, generation and resource extraction, in all sectors of the economy. It can be used to account both energy sector and non-energy sector's greenhouse gases emissions, as well as analyze emissions of local and regional air pollutants. LEAP's modelling capabilities operate at two levels: 1) calculations are done for energy, emissions and cost-benefit; 2) users enter spreadsheet-like expressions, enabling econometric and simulation approaches to be embedded within the model's accounting framework. New versions of LEAP also handle optimization modelling, allowing the construction of least cost models of capacity power system expansion and dispatch. LEAP is generally applied to study national energy systems, using an annual time-step and with a time horizon between 20 to 50 years. Yet some results are computed for a shorter timeframe, enabling, for instance, the observation of loads and generation profiles throughout the year. LEAP gives the opportunity to evaluate alternative scenarios, by comparing energy requirements, social costs and benefits, and environmental impacts [98].

⇒ **PRIMES**: this tool is differentiated from the others by the detailed combination of micro-economy with engineering, from a long-term perspective (up to 2050). It performs impact assessment of specific energy and environment policies, applied at Member State or EU level, including: price signals, such as taxation and subsidies; technology promoting policies; RES supporting policies; efficiency promoting policies; and environmental policies. PRIMES is then tuned to long-run energy system projections, for both the demand and supply sides. PRIMES' projections include: energy balances; structure of demand by

sector; structure of power system and other fuel supplies; technology roadmap; overall costs, costs per sector, overall system costs and investment; consumer prices and certificate prices; emissions. Nonetheless, PRIMES can neither perform short-term forecasts nor closed-loop energy-economy equilibrium analysis, unless linked with a macroeconomic model. In addition, PRIMES is unable to develop short-term engineering analysis of the power and gas systems operation [99], [100].

⇒ **Valoragua**: this model is a developed in FORTRAN and composed by several modules. It performs the management of a hydrothermal electric power system, at a national level or with cross-border interconnections. This tool establishes the optimal operation strategy for a given power system by the use of the "value of water" concept, in each power station, for each time interval (i.e. month/week) and for each hydrological condition. From a methodological perspective, the optimal management of electric power system is formulated as a non-linear optimization problem, where the hydro subsystem is completely desegregated. The objective is to minimize the total variable generation costs, subject to a set of constraints. Therefore, the model enables determining the operational characteristic in order to reach the minimum operation costs. The problem solution gathers the use stochastic dynamic programming, linear programming and non linear programming. The model supplies detailed information on technical, economic and environmental behaviour of each generation centre and the system. Valoragua is run for one year, while the month or the week is the time interval unit considered for the management purposes of the power system. Each time interval (month or week) is divided in time steps for the load characterization (typically five discrete steps). The main goal of Valoragua is to optimize the integrated management of a hydro-thermal power system, linking the water management and the power system operation, bearing in mind physical, technical, economic and operation characteristics of the system. This model also computes thermal-based power generation emissions and optimizes maintenance schedule of power plants. Valoragua is often used for analyzing: energy import/export contracts; maximize power generation revenues; long-term management of stored water in reservoir with regulating capability; better use of water in a multi-purpose scheme, considering its operation constraints [101].

2.5 Summary and Main Conclusions

This chapter allowed identifying the main characteristics of technology options for electricity storage and electric mobility, which is crucial for building energy planning criteria and alternatives. In addition, an overview was presented on the major energy planning tools. Accordingly, emerges

the need to identify the corresponding gaps and research drivers. The fact is that most of the top-down tools are fairly oriented to provide a global picture of the energy system, being fed by macroeconomic input data. When it comes to bottom-up engineering approaches, a set of tools (e.g. Aeolius, Balmorel, BCHP Screening Tool, Compose, EMCAS, EMPS, GTMax, WASP) is tuned to a specific technical field or energy vector. On the other hand, there is another group of tools (e.g. E4Cast, EMINENT, MARKAL/TIMES, LEAP, PRIMES, Mesap, H_2RES, EnergyPLAN, Message, Valoragua) that is tailored to present a global view on the system, when it comes to energy, economy and environment.

Taking into account these models' characteristics and the upcoming changes in the energy systems (mentioned in chapter 1), a set of further analyses and approaches should be developed, such as:

- Energy planning of small scale systems, such as islands;
- Multicriteria comparison of different alternatives for energy planning, for different scenarios;
- Modelling strategies for demand-side energy efficiency, in terms of energy/emissions savings impact and associated costs;
- Reliability of the power systems (e.g. adequacy of the generation capacity);
- Operation costs of the power system, from a zoom-in perspective (e.g. unit commitment and economic dispatch);
- Environmental and economic impact from the adoption of new mobility strategies, such as electric mobility, efficient ICVs, biofuels and behavioural change;
- Technical, environmental and economic impact from the implementation, in the power system, of new operation strategies, such as electricity storage and EVs V2G;
- Uncertainty modelling.

In view of these gaps, an energy planning methodology is worth developing, in order to evaluate long-term alternatives for planning isolated systems, through a multi-attribute and multi-scenario analysis.

Chapter 3

3 Theoretical Fundamentals for Energy Planning with Electricity Storage and Sustainable Mobility

3.1 Introduction

This chapter pursues an overview on theoretical fundamentals for energy planning, namely: environmental impact; economic and financial costs; and adequacy of the generation system. These topics are traditionally addressed in energy planning, though they are typically analyzed through different models, depending on the problem purpose. Alternatively, this work aims to deliver an integrated vision and approach regarding different criteria. Environmental concerns deserve a deeper attention in this thesis, than in typical works on power systems engineering, since this dissertation is made within a PhD Program in Sustainable Energy Systems.

This chapter also provides an overview on multicriteria decision aid, by making a review on the concepts and characterizing multi-objective and multi-attribute problems. In the end, a review on approaches to model uncertainty is also provided, as well as decision paradigms and rules.

To sum up, this chapter presents the theoretical concepts and framework to perform, subsequently, the mathematical formulation associated to the research.

3.2 Environmental Impact

3.2.1 Greenhouse Gases and Climate Change

Changes in the atmospheric abundance of greenhouse gases and aerosols, in solar radiation and in land surface properties modify the energy balance of the climate system. These changes are expressed in terms of radiative forcing, which is used to compare how a range of human and natural factors drive warming or cooling influences on global climate [102].

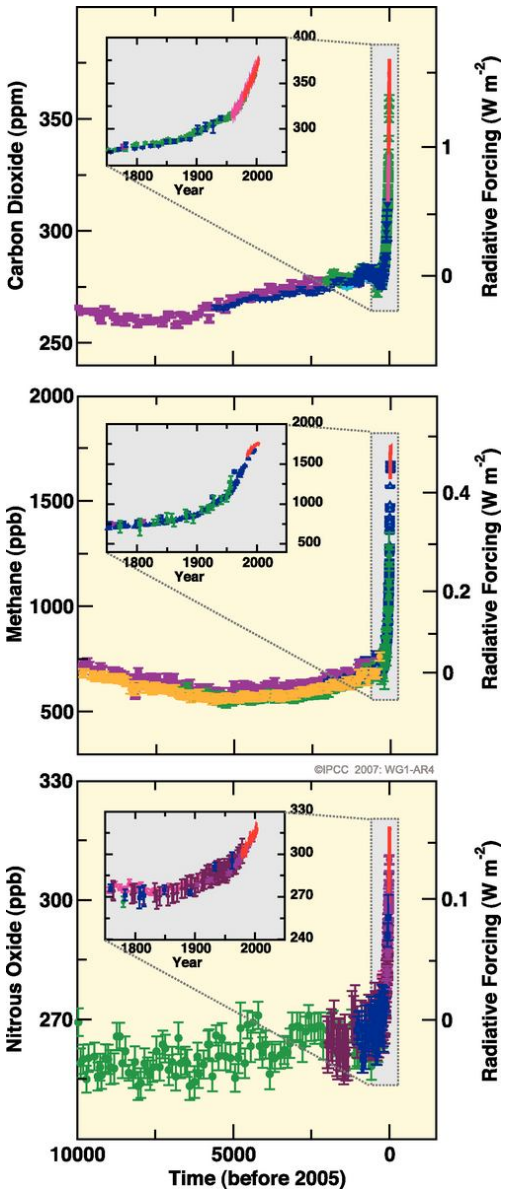


Fig. 14: Atmospheric concentrations of carbon dioxide, methane and nitrous oxide [102]

The stocks of greenhouse gases in the atmosphere are rising, as a result of human activity, being carbon dioxide the most important anthropogenic greenhouse gas [103]. Recent studies inform that the current level of greenhouse gases in the atmosphere is more than 390 parts per million (ppm) CO_2, compared with only 280 ppm before the Industrial Revolution [104]. These concentrations have already led to a globally averaged increase in the surface temperature of the planet of 1 degree Celsius [104]. As the Intergovernmental Panel on Climate Change (IPPC) stated in [102], the main cause for carbon dioxide increase since the pre-industrial period stands for fossil fuel use and land-use change (with a smaller impact). Stern also highlights the increasing risks of serious, irreversible impacts from climate change, linked with business-as-usual paths for emissions [103]. It is believed that the level of greenhouse gases in the atmosphere would double pre-industrial levels by 2050 (i.e.

550 ppm) and would keep rising thereafter, for a scenario without increases on the annual flow of emissions beyond today's rate. On the contrary, the annual flow of emissions is rather accelerating, owing to investments in high-carbon infrastructure and rising demand for energy and transport. Stern states that, at current trend, average global temperatures will rise by 2 to 3 °C within the next fifty years or so [103]. What's more, the OECD suggests that without more ambitious policies than the ones already announced (e.g. Copenhagen and Cancun conferences), the world will be on course for atmospheric concentrations of nearer to 685 ppm CO_2 by 2050 [104]. Fig. 15 points a set of emissions projections, which would lead to an increase on global average temperatures, at the end of the century, of 3 to 6 °C regarding pre-industrial levels.

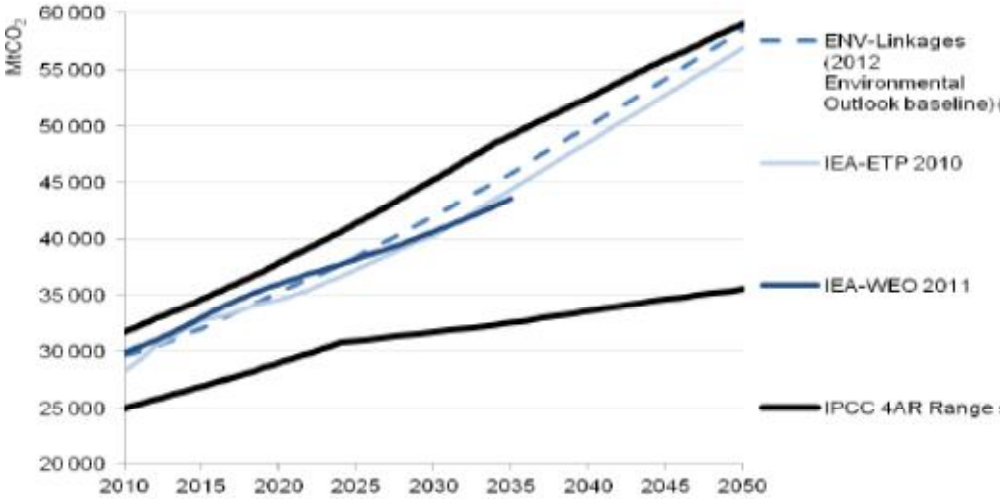


Fig. 15: Comparison of global emissions CO2 from fossil fuel combustion across selected studies [105]

Stern also affirms that stabilisation of greenhouse gas in the atmosphere is feasible and compatible with economic growth. The developed countries have noticed a decrease on the responsiveness of emissions to income growth, owing to changes in energy technologies and the structure of economies [103]. The fact is that is possible to decarbonise both developed and developing economies, while tackling economic growth in both. Stern refers that stabilisation requires a slump of annual emissions to the level that balances the Earth's natural capacity to remove greenhouse gases from the atmosphere [103]. Stabilising at or below 550 ppm CO_2 would demand the emissions' peak in the next 10-20 years, followed by a decrease at a rate of at least 1-3% per year. The set of pathways is presented in Fig. 16. Basically, by 2050 global emissions would need to be roughly 25% below current levels.

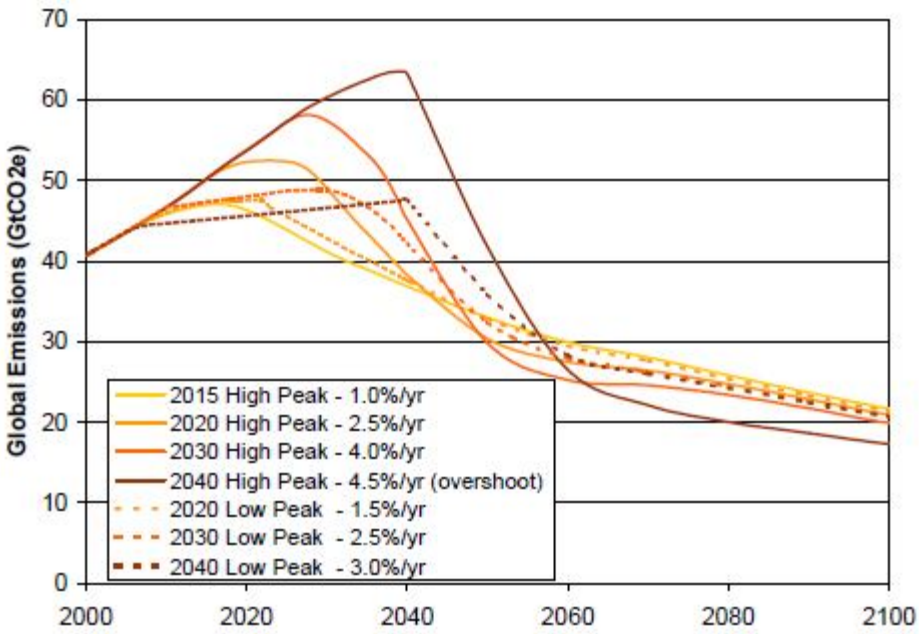


Fig. 16: Pathways for greenhouse gas stabilization [103]

Stern foresees that the annual costs for a stabilisation at 500-550 ppm of CO_2 concentration would be around 1% of GDP by 2050 [103]. The author reckons the greenhouse gas emissions can be cut in four ways:

- Reducing demand for emissions-intensive goods and services;
- Increased efficiency, which can save both money and emissions;
- Action on non-energy emissions, such as avoiding deforestation;
- Switching to lower-carbon technologies for power, heat and transport.

A key driver for low carbon economy results from the high price of delay, which would lead to acceptance of more climate change and higher mitigation costs. As OECD highlighted, the costs of delayed action may be so high that reaching the 2 °C goal may become unaffordable, unless additional mitigation measures are put in practice before 2020 [104]. Moreover, there are new opportunities for C*leanTech* industries and services, with a market worth likely to be at least $500 billion per year by 2050 [103].

3.2.2 Mitigation Mechanisms

In 1992, the United Nations Framework Convention on Climate Change (UNFCCC) was set up, in Rio de Janeiro. 153 countries signed the agreement, which has become the cornerstone of the international community's attempt to tackle one of the most serious threats to Planet Earth [106].

In 1997, the Kyoto Protocol was created to cut greenhouse gas emissions worldwide, without immediate demands on the developing countries but calling on each of the developed countries to reduce their emissions by specific amounts from 1990 levels, by 2012. The Kyoto Protocol has been ratified by all the Annex I's parties (industrialized countries), unless the US and Australia. However, during the UNFCCC conference occurred in Bali (December 2007), the Australian Government announced that the country would ratify the Kyoto Protocol.

To enhance the efficiency of the overall system of reducing emissions, an emissions trading mechanism has been introduced, with great potential for cost savings. For instance, the US cost of meeting its commitments could be reduced by 60% [106].

The Kyoto Protocol defined three "flexibility mechanisms" to lower the overall costs of achieving its emissions targets. With these mechanisms, Parties become able to access cost-effectively opportunities to reduce emissions or to remove carbon from the atmosphere, in other countries. If in one hand, the reduction emissions cost depends on each region, on the other hand, the effect for the atmosphere of limiting emissions is the same, regardless where the action is taken.

Under the Kyoto Protocol, the amount to which an Annex I Party (industrialized country) must reduce its emissions over the five-year commitment period is divided into units each equal to one tonne of carbon dioxide equivalent. These assigned amount units (AAUs), and other units defined by the Protocol, give the basis for the Kyoto mechanisms by providing for a Party to gain credit from action taken in other Parties that may be counted towards its own emissions target.

The three Kyoto mechanisms are:

1. The Clean Development Mechanism (CDM);
2. The Joint Implementation (JI);
3. Emissions Trading (ET).

The CDM and JI enable developed countries, that have binding emission reduction or limitation targets under the Kyoto Protocol, to invest in clean energy projects in third countries and credit the resulting emission savings towards their own emission targets. The CDM covers projects in developing nations. Reductions since 2000 are potentially eligible to receive credits called certified emission reductions (CERs). JI applies to projects in countries that have agreed to an emission target (industrialised countries and countries with economies in transition). JI projects yield credits known as emission reduction units (ERUs) from the beginning of the first Kyoto commitment period [107].

Bearing in mind the dynamics of climate change negotiations, the next table presents an overview on the major deliverables on climate change policies, over time.

Table 4 - Overview on major deliverables on climate change policies [108]

Year	Deliverable
1979	The first World Climate Conference takes place.
1988	The Intergovernmental Panel on Climate Change is set up.
1990	IPCC's first assessment report is released. IPCC and second World Climate Conference call for a global treaty on climate change. United Nations General Assembly negotiations on a framework convention begin.
1991	First meeting of the Intergovernmental Negotiating Committee takes place.
1992	The Intergovernmental Negotiating Committee adopts UNFCCC text. At the Earth Summit in Rio, the UNFCCC is opened for signature along with its sister Rio Conventions, UNCBD and UNCCD.
1994	UNFCCC enters into force.
1995	The first Conference of the Parties (COP 1) takes place in Berlin.
1996	The UNFCCC Secretariat is set up to support action under the Convention.
1997	Kyoto Protocol formally adopted in December at COP3.
2001	Release of IPCC's Third Assessment Report. Bonn Agreements adopted, based on the Buenos Aires Plan of Action of 1998. Marrakesh Accords adopted at COP7, detailing rules for implementation of Kyoto Protocol, setting up new funding and planning instruments for adaptation, and establishing a technology transfer framework.
2005	Entry into force of the Kyoto Protocol. The first Meeting of the Parties to the Kyoto Protocol (MOP 1) takes place in Montreal. In accordance with Kyoto Protocol requirements, Parties launched negotiations on the next phase of the Kyoto Protocol under the Ad Hoc Working Group on Further Commitments for Annex I Parties under the Kyoto Protocol (AWG-KP). What was to become the Nairobi Work Programme on Adaptation (it would receive its name in 2006, one year later) is accepted and agreed on.
2007	IPCC's Fourth Assessment Report released. Climate science entered into popular consciousness. At COP13, Parties agreed on the Bali Road Map, which charted the way towards a post-2012 outcome in two work streams: the AWG-KP, and another under the Convention, known as the Ad-Hoc Working Group on Long-Term Cooperative Action Under the Convention.
2009	Copenhagen Accord drafted at COP15 in Copenhagen. This was taken note of by the COP. Countries later submitted emissions reductions pledges or mitigation action pledges, all non-binding.
2010	Cancun Agreements drafted and largely accepted by the COP, at COP16.
2011	The Durban Platform for Enhanced Action drafted and accepted by the COP, at COP17.

Rather recently (2011), the 195 Parties to the UN climate conference in Durban agreed on a roadmap, proposed by the EU, for drawing up a legal framework by 2015 for climate action by all countries. The Durban conference also agreed that there will be a second commitment period of the Kyoto Protocol; made operational the new Green Climate Fund for developing countries; and approved a series of measures which build on the progress made at last year's Cancun conference [108].

From a regional perspective, the EU is a leader in the climate change combat. The Europe 2020 Strategy for smart, sustainable and inclusive growth includes five headline targets that set out where the EU should be in 2020. One of them relates to climate and energy. Member States have committed themselves to reducing GHG by 20%, increasing the share of renewables in the EU's

energy mix to 20%, and achieving the 20% energy efficiency target by 2020. According to the European Commission, the EU will certainly meet two of those targets, but will not fulfil with its energy efficiency goal [109].

The European Commission presented recently its "Analysis of options beyond 20% GHG emission reductions: Member State results" [110]. The Commission's communication explored the options, and related costs and benefits, for moving towards a 30% reduction. The Commission advocates that reaching the 20% GHG emissions reductions target and the 20% renewables target by 2020, has lower costs than originally foreseen. In fact, the costs for energy users in the year 2020 have fallen to an estimated €48 billion, or 0,3% of GDP, with further expansion of renewable energy accounting for a major part of this. The Commission considers that the 20% emissions reduction target is now less expensive than was assumed in 2008, which means that the 30% reduction scenario has turned out less expensive too. Getting 25% out of 30% reductions domestically, by 2020, is now estimated to cost around €70 billion, without taking into account the indirect economic benefits of accelerated technology innovations, increased energy security or reduced air pollution [110].

In a complementary way, the European Commission has recently proposed the Europe 2020 flagship initiative for a resource-efficient Europe and is now putting forward a series of long-term policies on transport, energy and climate change. The European Commission in [109] has set out key elements that should shape the EU's climate action, road to a competitive low carbon economy by 2050. The European Council has also reconfirmed (in February 2011) the EU objective of reducing GHG emissions by 80-95%, by 2050, compared to 1990.

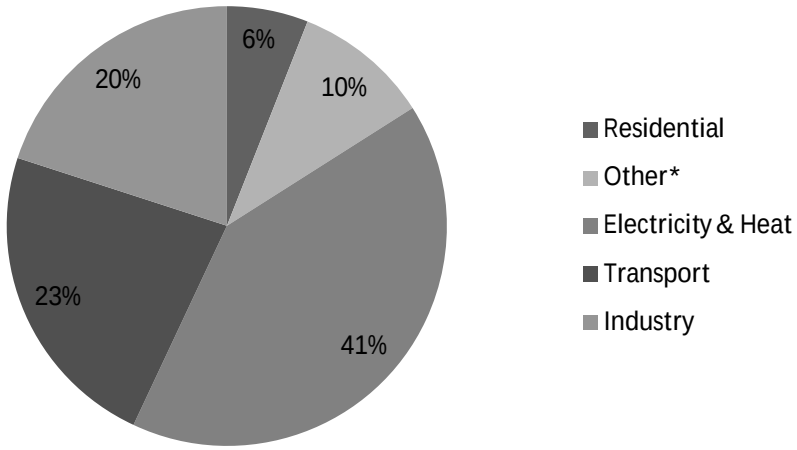
3.2.3 Sector Analysis

Emissions fall into four group of sectors: Electricity and Heat; Industry (with Oil and Gas, Steel and Iron, Cement, and Chemicals); consumer-related sectors (Buildings, Transport and Waste); and land-use related sectors (Forestry and Agriculture). The European Commission has drawn a sector analysis for a low carbon economy, according to the next table [109].

Table 5 - Sector GHG reductions

GHG reductions compared to 1990	2005	2030	2050
Total	-7%	-40 to -44%	-79 to -82%
Sectors			
Power (CO_2)	-7%	-54 to -68%	-93 to -99%
Industry (CO_2)	-20%	-34 to -40%	-83 to -87%
Transport (including aviation CO_2, excluding maritime)	+30%	+20 to -9%	-54 to -67%
Residential and services (CO_2)	-12%	-37 to -53%	-88 to -91%
Agriculture (non-CO_2)	-20%	-36 to -37%	-42 to -49%
Other non-CO_2 emissions	-30%	-72 to -73%	-70 to -78%

According to IEA, the electricity and heat generation, and transport produced nearly two-thirds of global CO_2 emissions in 2009, as shown in the next figure.



* Other includes commercial/public services, agriculture/forestry, fishing, energy industries other than electricity and heat generation, and other emissions not specified elsewhere.

Fig. 17: World CO_2 emissions by sector in 2009, adapted from [111]

As observed from the previous figure, generation of electricity and heat is the largest producer of CO_2 emissions, standing for 41% of the world's emissions in 2009, even though the greening process is undergoing. The IEA also remembers that by 2035 the electricity demand will be approximately three-quarters higher than current demand [111]. This is explained by the rise of population and income in developing countries, as well as by the growing electrification of household, commercial and industry consumptions. When it comes to the supply side, renewable energy sources are expected to grow over the next 25 years, from the current 19% (in 2008).

What's more, UNEP has presented a split of energy sources contributions among the energy supply, as depicted in the next figure.

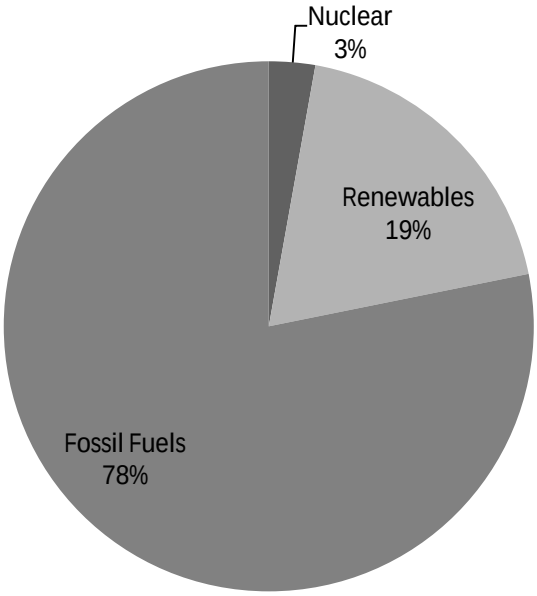


Fig. 18: Renewable energy share of global final energy consumption, in 2008, adapted from [112]

Within renewable energy sources, hydropower stands for 3,2%, traditional biomass 13%, biomass/solar/geothermal/hot water heating 1,4%, and wind/solar/biomass/geothermal power generation accounts 0,7%.

When it comes to the transport sector, according to the IEA this is the second-largest sector, accounting 23% of global CO_2 emissions in 2009, with a 1,7% decrease from 2008 [111]. The next figure presents a breakdown of the transport emissions, by type of use.

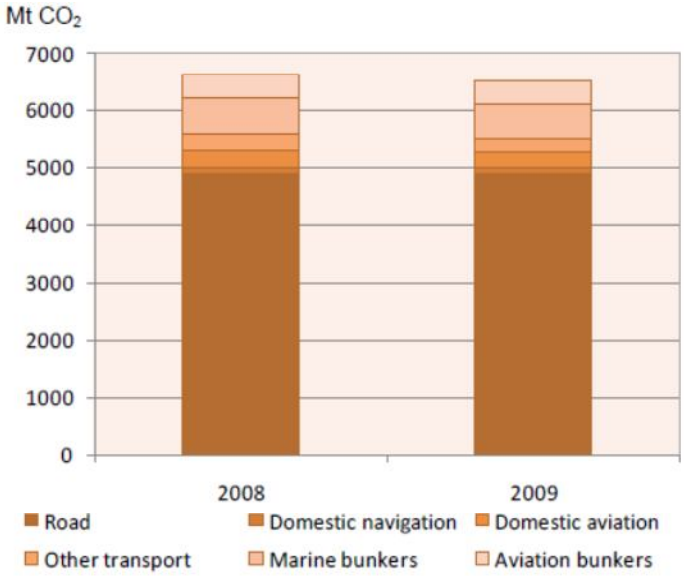


Fig. 19: CO_2 emissions from transport in 2008 and 2009 [111]

The UNEP has also made a projection for carbon emissions from the transport sector, as presented below.

Fig. 20: Total emissions and reductions under a green economy scenario (2050 G2), relative to Business-as-Usual scenarios (2050 BAU and 2050 BAU2) [112]

In addition, the IEA foresaw a global demand increase for transport by about 40%, by 2035 [111]. The quoted study advocates that to tackle transport emissions, policy makers should consider measures to require improved vehicle efficiency, as well as encourage a shift from individual to public transport, together with a shift to low-carbon fuels, including electric/plug-in hybrid vehicles,

hydrogen vehicles and greater use of biofuels. This study emphasizes the need of complementary policies (e.g. emissions pricing), which would both reduce the environmental impact of transport and help reducing oil prices, bearing in mind demand projections.

McKinsey & Company has identified major categories for abatement opportunities of GHG emissions, namely: energy efficiency; low carbon energy supply; terrestrial carbon (forestry and agriculture); and behavioural change [113].

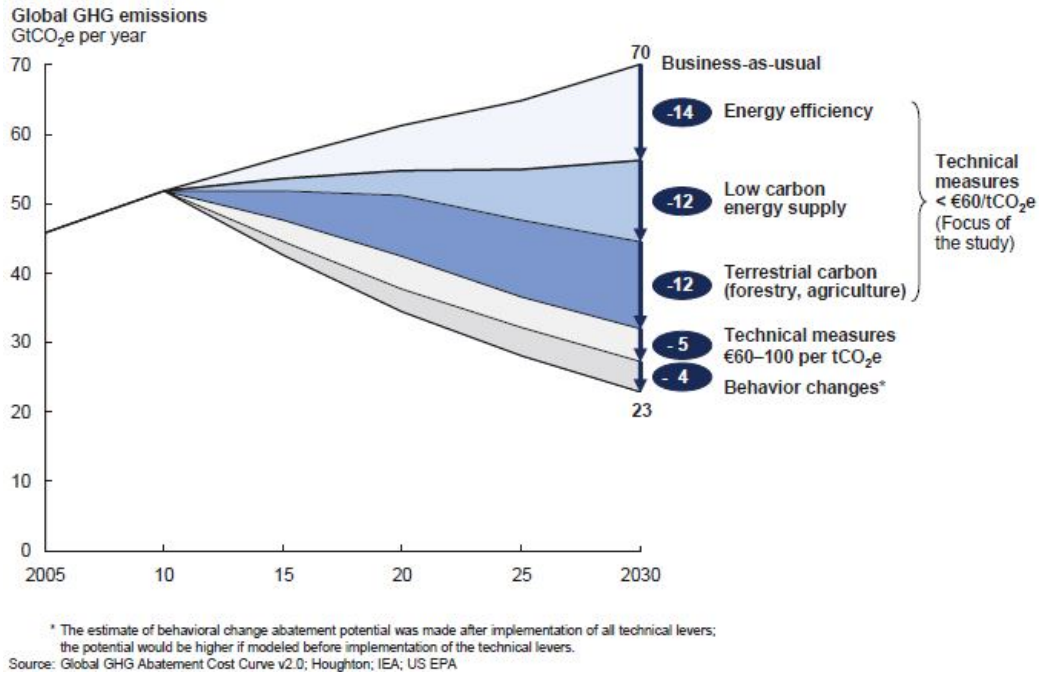


Fig. 21: Major categories of abatement opportunities [113]

Furthermore, UNEP presented a green economy study, identifying sector measures and opportunities for a decarbonised growth, as observed underneath.

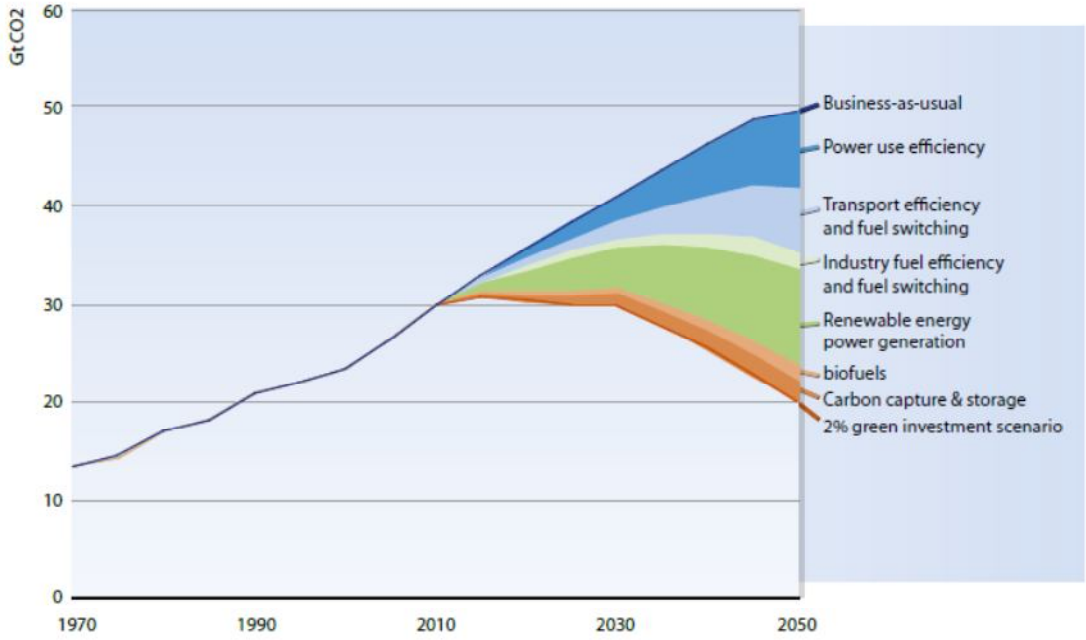


Fig. 22: Total emissions and reductions under a green economy scenario, relative to Business-as-Usual [112]

In view of the previous analyses of UNEP, IEA and McKinsey & Company, a set of pathways is worth studying, for the energy systems "greening", i.e.: renewable energy sources; energy efficiency; and sustainable mobility (e.g. EVs, efficient ICVs, biofuels and behavioural change).

3.3 Economic and Financial Costs

3.3.1 Carbon Economy

As previously mentioned, the Kyoto Protocol established three mechanisms to lower the overall costs of achieving the emissions targets. The three Kyoto mechanisms are:

1. The Clean Development Mechanism (CDM) defined in Article 12 provides for Annex I Parties to implement projects that reduce emissions in non-Annex I Parties, or absorb carbon through afforestation or reforestation activities, in return for certified emission reductions (CERs, tCERs and lCERs) and assists the host Parties in achieving sustainable development and contributing to the ultimate objective of the Convention. The CDM is supervised by the CDM Executive Board.
2. The Joint Implementation (JI) basic principles are defined in Article 6 of the Kyoto Protocol. Under JI, an Annex I Party (with a commitment inscribed in Annex B of the Kyoto Protocol) may implement an emission-reducing project or a project that enhances removals by sinks in the territory of another Annex I Party (with a commitment inscribed in Annex B of the Kyoto Protocol) and count the resulting emission reduction units (ERUs) towards meeting its own Kyoto target.

3. Emissions Trading (ET), as set out in Article 17, provides for Annex I Parties to acquire units from other Annex I Parties. These units may be in the form of AAUs, removal units, ERUs, CERs, tCERs and lCERs.

Carbon transactions are defined as purchase contracts whereby one party pays another party in return for GHG emissions reductions or for the right to release a given amount of GHG emissions, which the buyer can use to meet its compliance – or corporate citizenship – objectives concerning climate change mitigation. Payment is made using one or more of the following forms: cash, equity, debt, convertible debt or warrant, or in-kind contributions such as providing technologies to abate GHG emissions [85].

There is a range of active programs to manage GHG emissions that establishes a market by setting a target (absolute cap or intensity target) and that allow mandated participants to trade emissions allowances in order to meet compliance requirements at the lowest possible cost. Various Emission Trading Schemes exist inside and outside the scope of the Kyoto Protocol. These trading schemes are part of the commitment of States or companies to reduce their GHG emission. The EU Emissions Trading System (EU ETS) continues to be the most prominent of these markets in terms of overall volume and financial value transacted, with compliance, risk management and arbitrage being its major drivers and spill-over effects being felt in project-based and other allowance markets [114] .

The EU ETS has been established through binding legislation proposed by the European Commission and approved by the EU Member States and the European Parliament, being the first international trading system for CO_2 emissions in the world. From the start of 2007 the EU ETS applies not only to the 27 EU Member States, but also the other three members of the European Economic Area – Norway, Iceland and Liechtenstein [115].
The EU ETS is based on six fundamental principles.

- It is a “cap-and-trade” system;
- Its initial focus is on CO_2 from non-renewable power plants and big industrial emitters;
- Implementation is taking place in phases, with periodic reviews and opportunities for expansion to other gases and sectors;
- Allocation plans for emission allowances are decided periodically;
- It includes a strong compliance framework;

- The market is EU-wide but taps emission reduction opportunities in the rest of the world through the use of the CDM and JI, and provides links with compatible systems in third countries [107].

The EU ETS is a “cap and trade” system, that is to say it caps the overall level of emissions allowed but, within that limit, allows participants in the system to buy and sell allowances as they require. These allowances are the trading “currency” of the system. One allowance gives the holder the right to emit one tonne of CO_2. The cap on the total number of allowances is what actually creates scarcity in the market. At the end of each year, installations should surrender allowances equivalent to their emissions. Companies that keep their emissions below the level of their allowances can sell their excess allowances. Those facing difficulty in keeping their emissions in line with their allowances, have a choice between taking measures to reduce their own emissions - such as investing in rather efficient technology or using less carbon-intensive energy sources - or buying the extra allowances they need in the market, or a combination of the two. Such choices are likely to be determined by relative costs. In this way, emissions are reduced wherever it is most cost-effective to do so [115].

For phase I (2005-2007) and phase II (2008-2012) of EU ETS, Member States drew up national allocation plans (NAPs), which determined their total level of ETS emissions and how many emission allowances each installation in their country receives. The European Commission presented in 2008 a proposal for amending the Directive 2003/87/EC (that establishes the EU ETS), which was published on June 5th 2009. The new allocation methodology in phase III brings bold differences, regarding the previous ones. Firstly, in phase III there will only be a Community-wide harmonised allocation method, in which auctioning should be the basic principle for allocation, and from 2013 the total number of allowances should decrease annually in a linear manner [116]. The starting point of this line is the average total quantity of allowances (phase II cap) to be issued by Member States for the 2008-12 period, adjusted to reflect the broadened scope of the system from 2013. The linear factor by which the annual amount shall decrease is 1,74% in relation to the phase II cap [117]. The linear factor of 1,74% used to determine the phase III cap will continue to apply beyond the end of the trading period in 2020 and will determine the cap for the fourth trading period (2021 to 2028) and beyond. It may be reviewed by 2025 at the latest.

This amendment to the Directive of the EU ETS has also obliged power producers to acquire all of their emissions allowances at auctions from 2013 onwards, at the market price. Transitional free allocation to installations should be provided through harmonised Community-wide rules, in order

to minimise distortions of competition with the Community. None of such rules should give incentives to increase emissions, ensuring that an increasing proportion of these allowances is auctioned. Allocations must be fixed prior to the trading period so as to enable the market to function properly [117].

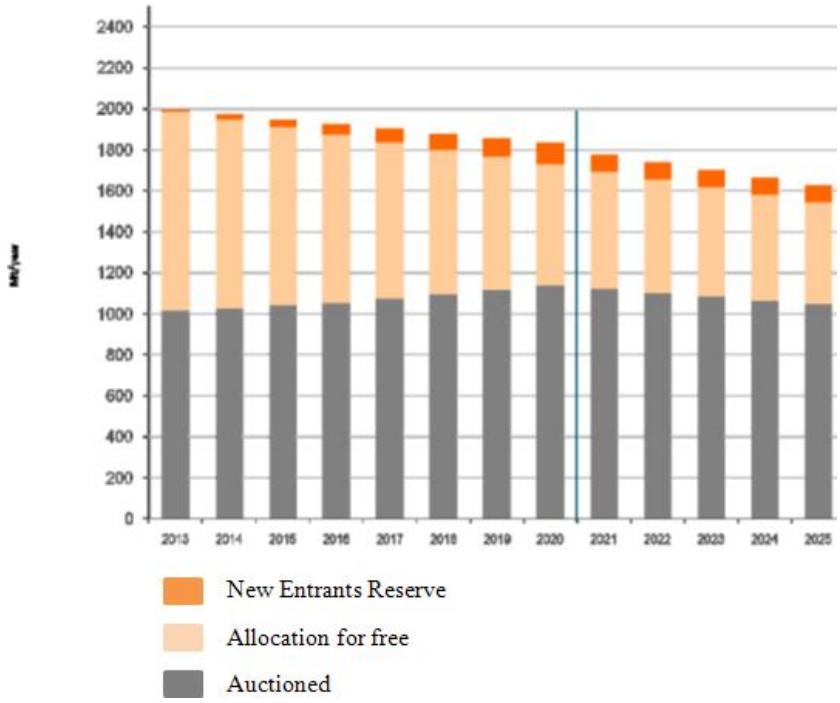


Fig. 23: Distribution of allowances for EU ETS phases III and IV [118]

This directive also provides a solidarity mechanism in order to help less affluent EU states with the transition to a low-carbon economy (the twelve "new" Member States and Greece and Portugal benefit from this solidarity mechanism). They will receive an increased amount of emissions permits to auction – i.e. 12% more than their actual share in overall EU GHG emissions – that will give them an opportunity of generating substantial revenues from selling allowances [119].
According to the European Commission/DG Climate Action, the allocation process starts with the Community-wide and fully harmonised Implementing Measures (CIMs) [116]. Based on the CIMs, the Competent Authorities calculate the preliminary annual allocation on a sub-installation level and each Member State submits to the EC the list of all incumbent installations – covered by the ETS Directive within its territory – and any free allocation to each installation. This list is called National Implementation Measures (NIMs).

According to the European Commission, the auction format will be a single-round, sealed bid, uniform price auction [120]. During a single bidding window of the auction, bidders can place any

number of bids, each specifying the number of allowances they would like to buy at a given price. Directly following the closure of the bidding window, the auction platform will determine and publish the clearing price, at which demand for allowances equals the number of allowances offered for sale in the concerned auction. Successful bidders will be the ones who have placed bids for allowances at or above the clearing price. All successful bidders will pay the same price, regardless the price they specified in their bids.

The Auctioning Regulation provides for allowances to be auctioned in the form of spot products, which means delivery within a maximum of five working days after the auction. Spot products have been chosen for their simplicity and because, unlike futures, they do not lock-in the trading of the auctioned allowances to the auction platform(s), which could have a potential negative impact on competition between trading places in the secondary market [121].

In order to limit the impact of auctions on the secondary market, the auctions will be relatively frequent. The common auction platform will hold auctions, at least weekly, for EUAs. According to Zapfel, the auctioning platform must be a Regulated Market, in the meaning of the Markets in Financial Instruments Directive (MiFID) and should be established as a common auction platform (24 Member States will make use of it, except Germany, Poland and United Kingdom) [122]. When it comes to auctions predictability, annual volumes will be determined in the Regulation and the auction calendar will be fixed about a year in advance.

One should emphasize that the auctions revenues go directly to Member States and 50% of revenues from auctioning should be used for climate related purposes. For instance, Portugal's share among the EU ETS is around 1,72%, which leads to €187 million per year of revenues, at 2011's prices.

Regarding market performance, large scale auctions mean a major change for the daily operations of the market. For comparison, the EU ETS auctioning encloses 1 billion allowances per year and in 2010 the secondary market volume was around 5,5 billion allowances. Therefore, auctioning will work if the clearing price mirrors the price in the secondary market [122].

The secondary markets operate carbon allowances derived from the primary market, such as EUA, CER and ERU, traded in major markets like ECX, BlueNext, EEX and GreenX. The secondary markets can trade allowances as spot, futures, organized and over-the-counter (OTC). Therefore, the generation companies should define adequate hedging strategies, such as a "single-shot" bid (acquiring the total amount of required allowances), sequential transactions according to needs (weekly or monthly) or a diversified strategy by combining auctions and futures (to purchase not only short-run allowances but also mid-run products) [123].

3.3.2 Power Generation Costs

Drivers for Costs

The life cycle cost of electricity generation is usually defined as the discounted lifetime cost of ownership of using a generation asset, converted into an equivalent unit cost of generation [124]. There are two main components of life cycle costs:

- Investment (or capital) costs of bringing the asset to a point of operation. These are usually called Capital Expenditures (CAPEX). The capital cost when excluding the financing terms, is usually called "overnight cost".
- Operation Costs, including the fixed costs (of keeping the plant available to generate) and the variable of costs of operation. These are usually called Operation Expenditures (OPEX).

Capital Costs

In power generation projects, the time value of money (discounting) and the discount rate are critical, since these are usually long-life capital intensive projects, with high operation costs [125]. According to NREL, basically, there are two categories of methodologies to calculate the capital costs of power generating assets, namely: discounted cash-flow analyses; and recovery factor analyses [126].

The discounted cash-flow (DCF) methodology provides the annual estimation of revenues, expenses, tax obligations or benefits, and repayments to all capital providers. These annual net cash flows are discounted to a single net present value (NPV) and internal rate of return (IRR).

The recovery factor methodology replaces the year-by-year free cash flow estimates of the discounted cash-flow analysis, by converting capital costs to an annual figure, which estimates tax benefits or obligations and repayments to all capital providers, over the project life. Therefore, the annual capital cost is calculated by multiplying the initial investment by the recovery factor. A number of alternative methodologies fall into the recovery factor analysis category, such as: capital recovery factor (CRF); fixed-charge rate (FCR); and Economic Carrying-Charge Rate (ECCR).

The CRF converts a present value into a stream of equal annual payments over a specified time, at a discount rate (interest). The CRF is a value between 0 and 1 designed to calculate the annual cost required to fully amortize an investment over a specified period [125], [126].

According to Kahn, the FCR is a fraction, between 0 and 1, which expresses the sum of annual requirements for return, taxes and depreciation (and, in some cases, other fixed overhead costs) [127]. Thus, the annual return requirements consolidate debt and equity returns, into a single figure (like a weighted average cost of capital). The FCR is multiplied by the project's total installed cost, in order to find the revenue requirement, attributable to the fixed costs [126].

When it comes to the ECCR methodology, it gathers all costs related to a new unit, including: depreciation of and return on the initial investment; property taxes; and fixed and maintenance costs during the unit's life [128]. As opposition to the FCR, the ECCR is used specifically to compute the cost of energy of a project, in the first year. According to Kahn and NREL, the ECCR methodology generates a stream of payments that increase at a constant rate, since the year-one value is escalated by an inflation rate, in order to approximate the cost of market entry over time [126], [127].

The next table summarizes the described methodologies for the capital cost calculation, including also other investment analysis tools (simple payback and profitability index method).

Table 6 – Summary of capital cost calculation methodologies [126]

Methodology	Description	Calculation
Discounted cash-flow	Discounts to present value the estimated annual cash flows to equity investors; provides either before-tax or after-tax results.	Initial equity investment plus net present value of free cash flow to equity over the project life; internal rate of return of investment and cash flows for a specified period.
Capital recovery factor	Amortizes an investment into a stream of equal annual payments; provides pretax results; also called "annuity method".	Sums weighted average cost of capital and depreciation annuity.
Fixed-charge rate	Calculates the portion of a project's year-one revenue requirement, attributable to fixed costs; provides after-tax results.	Sums annual weighted average cost of capital, tax, depreciation, and fixed overhead.
Economic carrying-charge rate	Amortizes all fixed costs to produce a stream of annual payments that increase at a constant rate; provides after-tax results.	Sums year-one weighted average cost of capital, tax, depreciation, and fixed overhead to derive year-one cost of energy.
Simple payback	Estimates the number of years necessary to recover an initial equity investment; provides before-tax results.	Initial equity investment/annualized cash flow to equity.
Profitability index method	Indicates the efficiency of invested capital; used to rank projects based on net present value per money invested.	Net present value /total installed cost.

The capital costs of power plants enclose the next set of components:

- The main plant and equipment package, often referred as engineering, procurement and construction (EPC) price.
- Infrastructure/connection costs, including power, fuel and cooling system (these could also be included in the EPC price).
- Development costs, including permitting, advisory services, land options/purchase.
- Interest and funding cost during construction.

As stated by Mott MacDonald, market conditions can have a key impact on capital costs of power plants, taking into consideration EPC prices for the main mature technologies [124]. The next figure shows the trend of EPC prices over time.

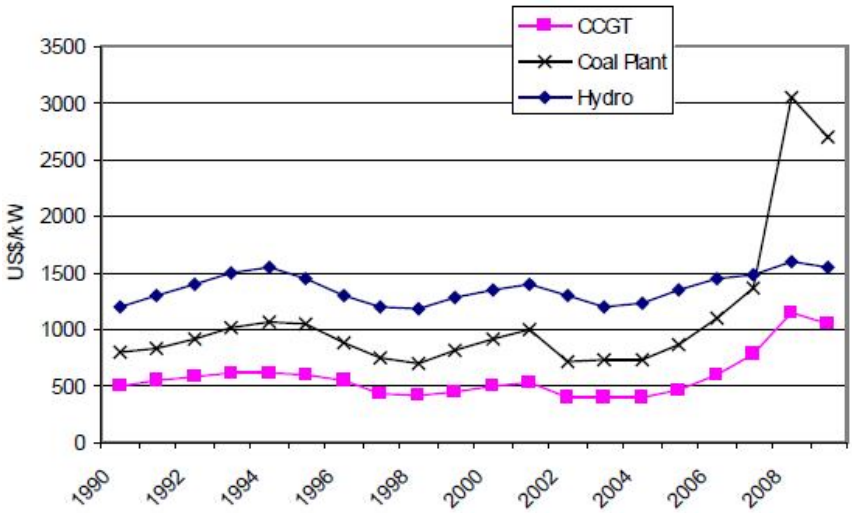


Fig. 24: EPC prices over time [124]

It is possible to compare the power generation technologies, according to their capital costs. Mott MacDonald presented, in [124], the next power technologies hierarchy in terms of capital costs: nuclear is more expensive than coal; coal is more expensive than oil fired plant; fired boiler-steam plant is more expensive that combined cycle gas turbine (CCGT); and CCGT costs some 50% more than an equivalent open cycle gas turbine. Regarding renewable energy sources, biomass combustion based plant may be seen as an expensive version of a coal plant. For wind power, offshore projects have higher capital costs, owing to more complex foundations, assembly and electrical cable connection to shore.

The capital costs differences among generation technologies are led by a combination of the complexity of the technology and its energy density. Energy technologies that generate more energy per square metre, usually need less material inputs than those with lower energy densities. Furthermore, technologies with complex designs and production processes, often have higher capital costs per installed power, than less sophisticated technologies. In addition, there are other characteristics that influence the capital cost, such as the fuel and residue handling requirements, and control and safety systems [124].

The main costs drivers for mature power technologies are market conditions and commodity prices. These technologies are usually called nth of a kind (NOAK), whereas the units still at a learning stage are called first of a kind (FOAK). Consequently, FOAK encloses additional risks than NOAK,

related to the implementation of new technologies, new construction techniques and supply chain management. Traditionally, these risks are carried by the original equipment manufacturer (OEM), the EPC contractor and the developer.

According to Mott MacDonald, the FOAK EPC comprises four elements [124]:

- the base cost of build (i.e. cost of equipment and construction);
- a FOAK premium, reflecting the OEM and contractor's expectations of additional costs of undertaking the first projects;
- the OEM and contractors' risk premium, which provides a contingency;
- the OEM's and contractor's profit.

When there's still little track record on a given new technology, the FOAK premium can be high. As opposition, for a NOAK project the EPC prices will have no FOAK premium and minimal, if any, OEM/Contractor's contingency. The next figures present the EPC prices for FOAK and NOAK plants, ordered in 2010.

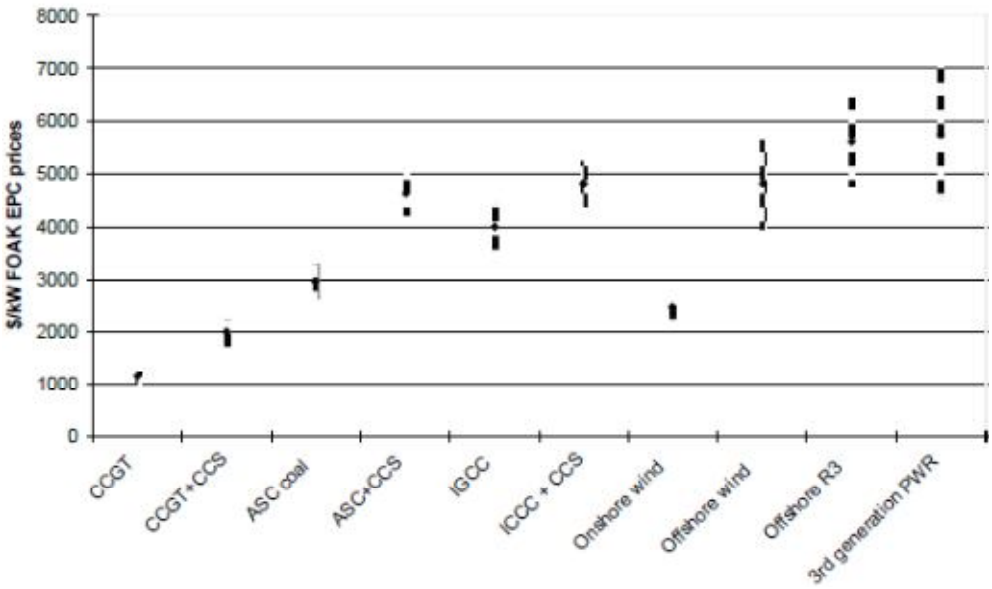


Fig. 25: EPC prices for FOAK plants, ordered in 2010 [124]

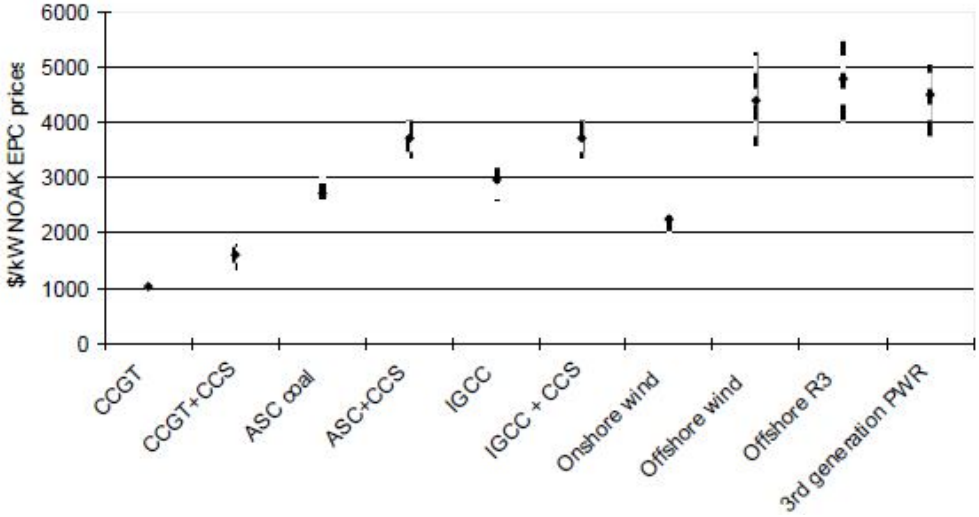


Fig. 26: EPC prices for NOAK plants, ordered in 2010 [124]

Operation Costs

Within the operation costs, there are some specific costs that include:

- Operating labour.
- Planned and unplanned maintenance (additional labour, spares and consumables).
- Through life (time dependent) capital maintenance.
- Property taxes (rates), insurance and network use of system charges.

Concerning the variable costs of operation, these include fuel, carbon, output related repair and maintenance and residue disposal and treatment. In this thesis, the carbon costs are treated separately (in section 4.3.3.2), allowing also a cost-based environmental assessment of emissions from power generation. Fuel costs are determined by the type of fuel, heat rate and fuel prices. Regarding repair and maintenance costs, these tend to be related to the plant type, fuel used and operating regime. Finally, residue disposal and treatment are mostly influenced by the fuel used and compliance requirement, regarding residues.

Power plants can be categorised either as being expensive machines for converting free or low cost energy into electricity (e.g. renewable energy sources), or low cost engines for converting expensive fuels into electricity (i.e. fossil fuels). For the expensive fuel converters, the major cost drivers are the efficiency of fuel conversion and the fuel price [124].

Concerning renewable energy sources, the life cycle cost of the projects is dominated by capital costs, rather than operation expenditures. However, the annual fixed and variable costs also impact a project's economics. According to NREL, the annual operations cost of a renewable energy unit includes: project management; insurance; property taxes; permit maintenance; site maintenance;

land lease or royalty payments; and others [126]. Since most renewable energy sources are still FOAK technologies, generally these are given incentives that take many forms: tax credits and accelerated depreciation deductions; production incentives; rebates; and grants (both taxable and non-taxable). Traditionally, renewable energy facilities receive specific feed-in-tariffs (FIT). It is possible to find out wide FIT mechanisms in Europe and North America, such as the generation-cost models adopted in Germany, the Netherlands, Ontario (Canada), Vermont (US), Florida (US) [126], and also Spain and Portugal.

Regarding non-renewable technologies, the life cycle cost of energy is dominated by fixed and variable costs. Within variable costs, fuel costs are linked to the fuel consumption (which depends on the plant efficiency and power output in each period of time) and to fuel price. Generally, the functions that model these costs are non-continuous and non-convex. Nonetheless, it is common to approximate those costs with polynomial functions.

Additionally, one should also consider the shut-down and start-up costs, which have an economic impact due to: fuel waste; extra maintenance; and additional feed water and energy for heating. According to Viana, the start-up and shut-down costs are also unpleasant from a social, technical and environmental perspective, since they are stressful to operators, reduce the effective life of the generating units (owing to heating and cooling cycle, pressurisation and decompression of boilers, etc.) and the GHG emissions increase during the transient period of start-up and shut-down [129]. Usually, shut-down costs are significantly lower than start-up costs.

Bearing in mind the referred fuel, start-up and shut-down costs, the unit commitment and economic dispatch (UCED) become a critical problem, when dealing with the identification of operation costs and their impact on energy planning. Before tackling the economic dispatch problem, the unit commitment problem should be solved, because it is necessary to know - in advance - which are the units that will be operating in the interval under analysis, in order to proceed to their output (electricity generation/interval) set up by the economic dispatch model. The unit commitment is a crucial sub-problem for scheduling generation units to be “on” or “off”, during each interval of the scheduling period. This problem has a set of constraints, such as: meet the demand; fulfill minimum value of spinning reserve; and fulfill minimum and maximum limits of the unit.

The UCED problem has been studied for long time, moving from simple calculations to rather sophisticated methods [130]. There is a set of available methods for UCED, which can be grouped as follows: extensive enumeration; priority list (merit order scheduling); dynamic programming and its variants; Lagrangian relaxation; branch-and-bound method; linear programming; expert systems/artificial neural networks; simulated annealing; and genetic algorithms [131].

In section 4.3.3.3 a more detailed description is provided on the developed algorithm for unit commitment and economic dispatch used in this research.

3.3.3 Costs of Centralized Electricity Storage

Cost structure of Pumped Hydro Storage

The overall cost of a project is a decisive factor, thus the selection of the appropriate storage technology will be affected by capital cost. The following figure depicts the storage technologies' cost per unit energy versus cost per unit power.

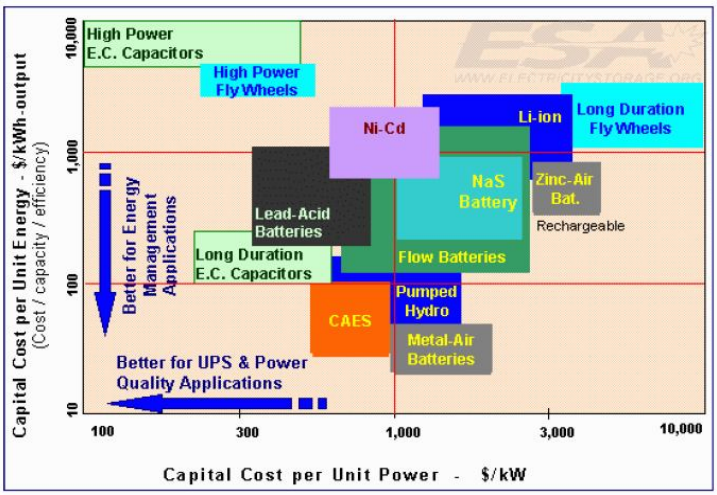


Fig. 27: Storage technologies' cost per unit energy vs. cost per unit power [132]

As mentioned in section 2.2, pumped hydro storage is the chosen technology to study the centralized storage in this work, taking into account its benefits (in terms of costs, emissions and maturity), for energy management in isolated systems. Pumped hydro storage is a mature technology with no experience curve efficiency expectations. According to the IEA, the typical capital cost breakdown for the pumped hydro storage facility is the following [23]:

- Dam: 30%
- Chanel: 21%
- Generator: 15%
- Civil Engineering: 9%
- Others: 25%

Pumped hydro storage facilities are long-run investments, with high initial capital costs and low operation and maintenance costs. A pioneering pumped hydro storage plant, with the new variable

speed pumps, was installed in Thuringia, Germany, in April 2004. The Goldisthal plant is the largest pumped storage plant in Germany, with a total installed capacity of 1 060 MW (with four pumps from Voith Siemens Hydro, of which two are variable speed pumps). This plant took six years to build and had a capital cost of €620 million, owned and operated by Vattenfall. More recently (October 2009), Alstom and Axpo AG signed a €178 million contract, to install four 250 MW variable speed pumps in eastern Switzerland, by 2015. In the same year, Alstom had also signed a €125 million deal to supply four 157 MW variable speed pumps, for the new pumped hydro storage facility Nant de Drance, in Switzerland [133].

Regarding operation costs, Rangoni stated that a pumped hydro storage facility gets enough market margin (to cover its fixed costs), if its electricity selling price is at least 1,4 times higher than the purchase price, owing to the electricity losses involved in pumping [7]. For example, the recent Goldisthal pumped storage facility buys electricity (for pumping), during off-peak hours, at 20 €/MWh, having a selling price, during peak periods, of 50 €/MWh, resulting in a 30 €/MWh gross margin. The equivalent annual capital costs (amortized during 30 years) plus the variable costs account for 17 €/MWh, which leads to 13 €/MWh of profits [133].
However, for a specific isolated system, accurate costs estimations are necessary, taking into account the storage installations details. In addition, the specific costs of the electro-mechanical solution must be properly identified for this purpose.

3.3.4 Costs of Electric Mobility

Cost structure

Taking into account the previously described EM infrastructure, for capital cost analysis, the existence of an infrastructure for smart metering would be advisable (in line with EC's guidelines for advanced metering), in order to allow two-way remote communication for control/management and billing purposes. Therefore, the additional infrastructure components, urged by EM, are [71], [134], [79]:

- EM Network Management tool (hosted at the DSO);
- EM Business and Operations Management tool (hosted at the aggregator);
- Smart Payment System (hosted at the aggregator);
- CP (installed by the certified CP Operator).

The next figure presents the three-layer architecture of a traditional power system with the required tools for the EM. Basically, one has the Control and Management Layer, the Power System Layer

and the Infrastructure Layer, gathering the Advanced Meter Infrastructure (AMI), the CP and the EV.

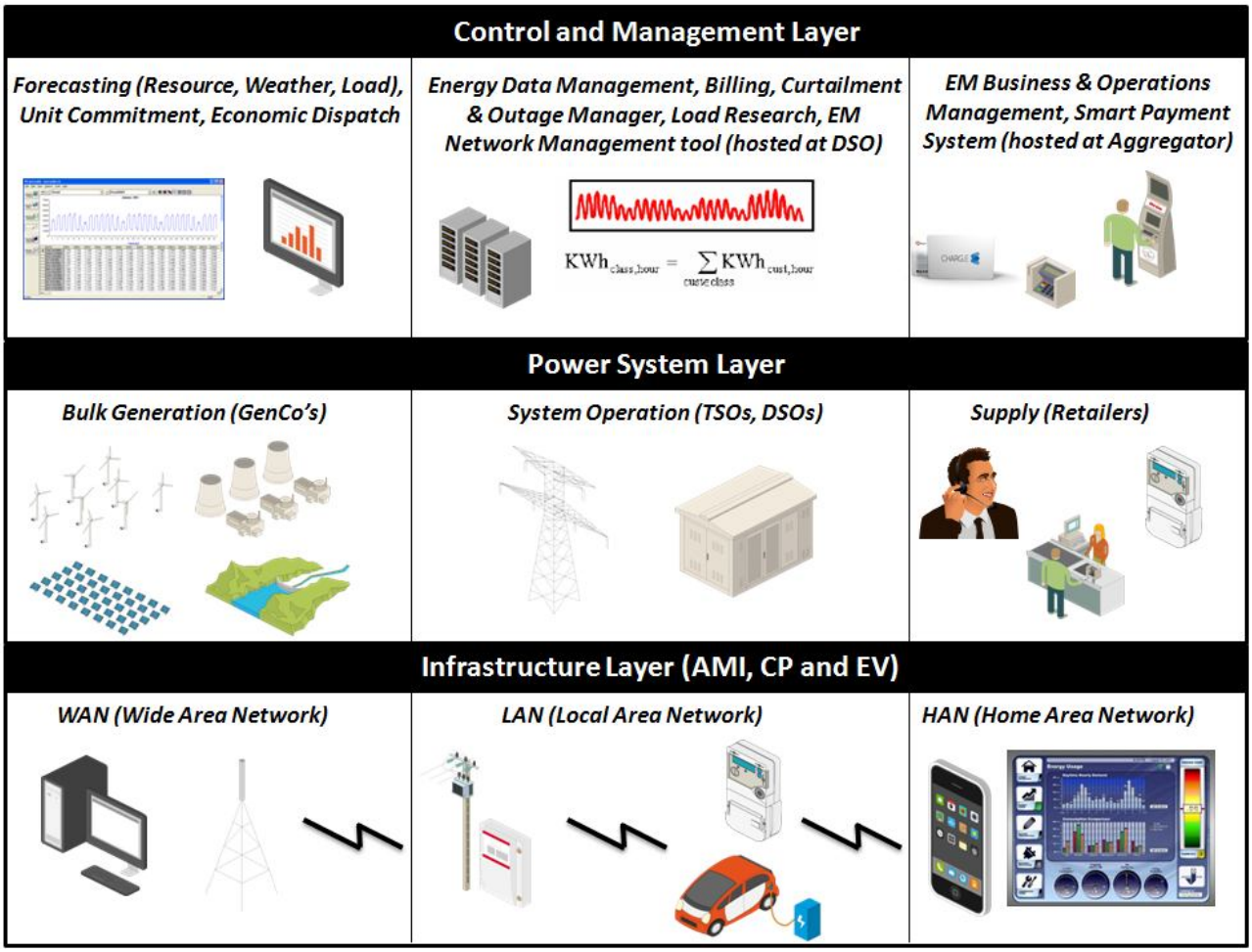


Fig. 28: Three-layer architecture of a power system with EM requirements

Concerning the CP, the EM system is likely to require one public CP for one EV [71]. For instance, the EM rollout may represent between $80 billion and $180 billion in the US, over the next two decades, with the cost of CP technologies ranging from $1 000 to $10 000 (costs in US and Europe).

When it comes to the operation costs of EM, the UK's Department for Transport stated that EVs and PHEVs, besides benefiting from the lower carbon content of their energy, also benefit from the lower cost of electricity compared to fossil fuels [65]. The referred report emphasized that the energy cost of charging an EV using off-peak electricity is roughly one seventh the cost of fuelling a corresponding ICV. Nonetheless, one should include the cost of battery depreciation among the EVs operation costs, in order to make fair comparisons. The following figure presents a comparison between the operation costs of an EV and ICV, over time.

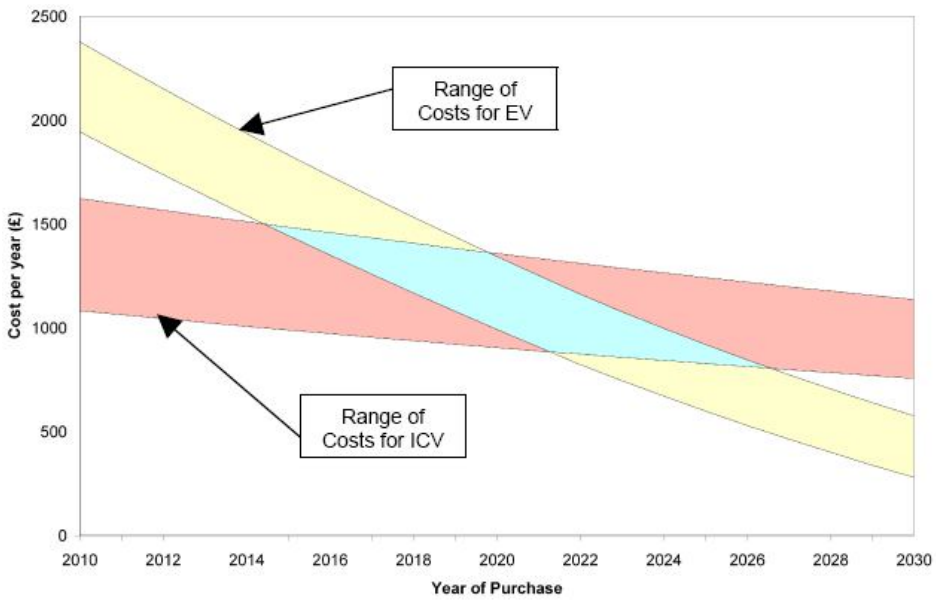


Fig. 29: Comparison between the running costs of an EV and ICV [65]

According to the quoted work, the EVs will be competitive with the ICVs between 2015 and 2026 (overlap area), depending on the relative price to consumers of batteries, electricity and fossil fuels.
Concerning the electricity purchase costs for EVs charging, there are already some dedicated tariff regimes. For example, the Californian utility Pacific Gas & Electricity Company (PG&E) offers a large difference between peak load and off-peak load rates for EVs charging. In summer, the off-peak rate is 5,6 c$/kWh, compared to 28,0 c$/kWh at peak times [135]. DTE Energy has also a special regime for EVs' users, with a 7,7 c$/kWh rate at off-peak periods and 18,2 c$/kWh at peak load period [136]. Another US utility, San Diego Gas & Electric (SDGE), presents a wider rate regime for EVs, having super off-peak (14,5 c$/kWh), off-peak (16,7 c$/kWh) and peak (25,8 c$/kWh) [137].

In order to foster the adoption of EVs, a set of public funding initiatives have been raised. This is justified because usually utilities are not allowed to add the cost of chargers to their rate base, thus, the EM investment would cut their profits. In those circumstances, the EM adoption would lead to costs pass-through to the end users, which would make EVs less attractive as an alternative to gasoline-powered vehicles.
The next table summarizes the current public stimulus for EM in several countries.

Table 7 – EM stimulus [65], [138]

EM funding	
US	- The Department of Energy awarded $3.4bn for the development of the smart grid. $8.1billion was allocated to the smart grid from the public and private sectors combined. - Business owners can receive a tax credit of up to half the cost of EV charging equipment installation through the federal Alternative Fuel Vehicle Refuelling Property Credit, which was expanded in 2009 to a maximum of $50 000. - EV charging equipment manufacturers can receive the tax credit if the refuelling property is acquired by a tax-exempt organization, governmental unit, or a foreign person or entity. - DTE Energy has launched a program, in which the first 2 500 customers who purchase a plug-in vehicle and enrol in the EV rate, will receive a separately-metered charging station.
Portugal	- Private customers buying one of the first five thousand electric cars, from 2010, will be entitled to an incentive of €5 000. - Incentives for buying an EV may be as high as €6 500 if the bought EV is to replace an end-of-life vehicle. - The purchase of an EV will entitle the buyer to Income Tax relief (for individuals) and Corporation Tax relief (for companies). - EVs are exempt from both ISV (Vehicle Tax) and IUC (Single Circulation Tax).
Norway	- EVs exempt from car registration tax. For a B class car the registration tax is around €7 500. - VAT (25%) does not apply to EVs. EVs are not subject to the annual car tax of €345. - EVs do not have to pay road tolls in Oslo. - EVs qualify for free parking which can provide annual savings of around €2 000 - €4 000. - EVs are permitted to use bus lanes.
Denmark	- EVs do not pay registration tax. EVs are exempt from annual car tax and qualify for free parking.
Sweden	- Low or zero carbon emission vehicles get a subsidy of 10 000 SEK (€2 500).
Netherlands	- EVs in the Netherlands are exempted from car registration tax.
Belgium	- Belgian vehicles which emit less than 105g CO_2/km will have a €4 100 reduction in registration tax.
Switzerland	- Individual cantons provide their own EV incentives.
Germany	- Germany is currently considering inner circle parking and congestion charge incentives for EVs similar to those in London.
France	- A French initiative named Eco-pastille, which began on January 1st 2008, sees that people who buy EVs receive €5 000 back. - Free parking spaces for EVs (equipped with charging apparatus) are also being reviewed. - The Government is committed to invest $1,5 billion in EV charging infrastructure.
Greece	- No road tax or car registration fees for EVs. - EVs are also free to drive in Athens when parts of it are restricted to other vehicles to reduce traffic congestion. - There is also free charging on the street of some cities.
Italy	- Certain cities in Italy have restricted driving within the city to EVs only. - Some cities also allow free parking and charging for EVs.
Spain	- For an EV bought in Spain €6 000 or 15% of the price of the vehicle will be returned to the customer.
Israel	- The Israeli government is providing tax incentives to help Project Better Place achieve its goals. - It taxes petrol cars at 72% while EVs are only taxed at 10%.
United Kingdom	- A $46 million fund was established for a network of EV charging stations including more than 11 000 stations to be installed in London by 2012.

3.3.5 Costs of Energy Efficiency Measures

Measures for the Power System

The European Commission has presented its Energy Efficiency Plan, to be adopted by the Member States [139]. This plan sets a range of energy efficiency measures, namely:

- Sustainable buildings: buildings with a "near zero-energy" performance level. In view of that, the Commission will present a legal instrument requiring that public authorities will refurbish at least 3% of their buildings each year.
- Energy Performance contracting: under this performance-based form of purchasing, monetary savings from lower utility bills and maintenance costs that result from energy efficiency measures are used to cover part or all of the measures' investment costs. Energy Service Companies (ESCOs) deliver energy efficiency improvements, accepting financial risk by covering – or helping to finance – upfront investment costs and refinancing this through the savings achieved.
- Tackling heat use in buildings: promote the use of district heating in the context of integrated urban planning.
- Training: energy efficient building solutions are often technically demanding. Therefore, it is necessary to deliver appropriate training for architects, engineers, auditors, craftsmen, technicians and installers, involved in refurbishment.

The Portuguese Action Plan for Energy Efficiency (following Directive 2006/32/EC) was raised in 2008 and aimed to reduce business-as-usual final energy consumption in 10%, by 2015. This plan designed 12 programs, tackling energy consumption by households, services, industry, public administration and transport [140]. The referred plan was reviewed in 2012 and the XIX Portuguese Government announced a new energy efficiency target, which consists of reducing the final energy consumption in 25% by 2020 [141]. To support Portugal's energy policies review (energy efficiency and renewable energy sources), a study was provided by the A.T. Kearney/INESC Porto consortium [64]. Moreover, the Portuguese Regulator for Energy Services (ERSE) launched a set of electricity efficiency measures, to put in place from 2011 to 2032, with 2 244 GWh of potential savings over the period [142]. This plan encloses some relevant measures, such as:

- Demand Response;
- Smart Metering;
- Energy Auditing;
- Efficient equipments;
- Load control and automated shedding.

Demand response is, indeed, a concrete measure for energy economy. According to US Department of Energy, demand response is defined as the "changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized" [143]. What's more, the Federal Energy Regulatory Commission (FERC) highlighted the relevance of demand response, as the ability of customers to respond to either a reliability trigger or a price trigger, from their utility operator, in order to decrease their power consumption [144]. As opposition to peak clipping (in which the actions are focused on a limited period of hours of the year), demand response actions are applied to any part of the load profile, not just to the period of peak usage. Demand response is, as a result, dependent on the installation of smart appliances that can rapidly respond (near real-time) to the utility's signals and, in addition, requires the adoption of smart meters with in-house displays or other options for home-area-network (e.g. energy consumption available in the internet, smart phone or TV).

A Staff Report for FERC discusses five different demand response programs including [145], [146]:

- Dynamic pricing with enabling technology;
- Direct load control;
- Interruptible/curtailable rates;
- Emergency demand response;
- Capacity market programs;
- Demand bidding/buyback programs;
- Ancillary services market programs.

Additionally, FERC proposes a National Action Plan on Demand Response, aiming to maximize the cost-effectiveness of the measures, by enabling price-responsiveness and facilitating market penetration of newly smart grid technologies and programs [144].

In what regards to smart grids deliverables, VaasaETT conducted a large pool of pilot projects on smart metering, concluding that informative billing can deliver 1 to 12% of energy savings [147]. Moreover, the IEA foresaw that feeding back energy end use information can lead to roughly 10% of average energy savings [148].

Measures for the Transport Sector

The European Commission, in its "Roadmap for building a competitive low-carbon Europe by 2050", emphasized that technological innovation can help the transition to a more efficient and sustainable transport system, by acting on three major factors: vehicle efficiency through new engines, materials and design; cleaner energy use through new fuels and propulsion systems; and better use of networks and safer and more secure operation through information and communication systems [109]. In addition, the European Commission has already launched initiatives to make transport greener and more sustainable, as follows [149]:

- Internalise the external costs of transport;
- Revise the heavy goods vehicles charging directive, to encourage differentiated charging systems;
- Tackle local and regional pollution;
- Limit emissions from new vehicles;
- Limit noise pollution;
- Congestion management.

In parallel, the "Action Plan on Urban Mobility" provides a framework for 20 EU-level actions [150]. In a rather detailed way, McKinsey & Company [151] and APDC [152] identified a set of opportunities to reduce energy consumption and carbon emissions from transport sector, such as:

- Efficient Internal Combustion Vehicles;
- Biofuels;
- Traffic improvement;
- Driving behaviour change;
- Reduce distance driven;
- Initiative "pay-as-you-emit";
- Intermodality;
- Car sharing/pooling;
- Virtualization (i.e. adoption of video-conferences and e-government)
- Freight logistics.

Investment on Energy Efficiency

In the EU-level, energy efficiency is part of the 2020 Strategy for smart, sustainable and inclusive growth, and of the transition to a resource efficient economy. The EU has set itself a target, for 2020, of saving 20% of its primary energy consumption compared to projections (or 20% GHG

emissions reductions, compared to 1990 levels). It will be pursued with other policy actions under the Flagship Initiative for a Resource Efficient Europe [139].

Despite launching the 20% efficiency target, the EC has recently provided a technical analysis on moving towards a 30% reduction of GHG emissions, by 2020 [153]. In terms of investment needed, stepping-up to 25% domestic GHG emissions reductions (compared to 1990 and -13% compared to 2005) would lead to an estimated cost of €70 billion. In the other hand, this 25% target would save an average of €20 billion in fuel costs, each year, over the period 2016-2020, compared to the reference scenario (20% GHG emissions reductions, compared to 1990 levels). Concerning the 30% reduction target, total costs are foreseen to encompass €82 billion (including the costs of the additional energy efficiency measures).

In the US, the Department of Energy issued, in October 2009, 100 awards totalling $3.4 billion to stimulate the development of smart grids, including projects for demand response adoption, based on pricing concepts such as dynamic pricing [144]. For instance, demand response actions represented, in 2009, a cost of $3,6 billion [154].

In Portugal, the Action Plan for Energy Efficiency estimates that to achieve the 10% efficiency target, by 2015, will be required an annual investment of €30 million, over the period. The reviewed version of that plan has still lack of consolidated information, since the Portuguese General Directorate for Energy and Geology (DGEG) is currently (at the moment of the thesis writing) analysing the contributions collected, within the public consultancy period. Additionally, the electricity efficiency program of ERSE accounted €37 million, for projects submitted in the 2011-2012 call. One should refer that the financing sources and models, for DGEG and ERSE initiatives, are different.

Regarding sustainable mobility, APDC delivered the program Smart Portugal 2020, estimating 34% of CO_2 emissions savings from the transport sector, by 2020 (comparing to the business-as-usual scenario) [152]. This sustainable mobility program would worth €1,2 billion. Sustainable mobility was also addressed by McKinsey & Company, which presented a study proposing 11 to 22% of carbon emissions savings by 2030, regarding 2006 level [113]. This abatement pathway would account, in 2030, €170 billion or €1 899 per vehicle.

3.4 Adequacy of the Generation System

3.4.1 Concepts of Adequacy and Security

Before diving into a detailed description of reliability indices, it is useful to define and differentiate the concepts of adequacy and security. Generally, the concept of adequacy is considered to be the existence of enough facilities (generation units and transmission and distribution networks) to meet

the demand, being therefore associated to static conditions [155]. Adequacy is, as a result, "used to describe a system state in which the actual entry to and departure from that state is ignored and is thus defined as a steady-state condition", as stated by Billinton and Allan, in [156].

On the other hand, security is concerned to the ability of the system to respond to disturbances arising within the system. These disturbances include conditions causing local and broad effects, as well as the loss of major generation and transmission lines [155]. Typically (but not exclusively), security is related to the dynamic process that occurs when the system transits between one state and another state [156]. In this final state, both equality and inequality constraints are verified.

According to Billinton and Allan, adequacy provides valuable input for decision making [156]. Adequacy and security are, however, correlated. That's to say, a system with large amount of reserve capacity has a higher flexibility to react to unforeseen disturbances. On the other hand, when facing a power shortage, a given system with limited planning reserves can still be operated in a secure way, whereas a system with a larger reserve can be operated insecurely [157].

Bearing in mind the scope of the present research, an adequacy assessment will be conducted for reliability studies.

3.4.2 Hierarchical levels of the system

The most common approach for analysing a power system, is through the identification of its main functional zones, namely: generation systems; transmission systems; and distribution systems.

Billinton presented the concept of hierarchical levels (HL), aiming to identify group functional zones of power systems [155]. The referred author set out three levels:

- HL1: consists of generation facilities and their ability to satisfy the demand;
- HL2: refers to the composite generation and transmission system, and its ability to deliver electricity to supply points;
- HL3: refers to the complete system, gathering distribution and its ability to satisfy the capacity and energy demands of consumers (these studies are rather complex, owing to the scale of the problem).

When it comes to the timeframe, the system operation challenges can be identified through the next layers:

i. Long-term system security of supply: operational reserve required to the system;
ii. Transmission grid development plan: future stability and security of the system, and integration areas;

iii. Intraday system and grid management: very high levels of renewable energy non-dispatchable;

iv. High generation intermittence.

3.4.3 Reliability of Generating Capacity

Theoretical Introduction

The problem of defining the necessary amount of generating capacity is divided in two areas of study: static capacity requirements; and operating capacity requirements. The static capacity area performs a long-run assessment of the system requirements, being considered as the installed capacity that must be planned and built in advance. The static reserve must provide to the system enough capacity to handle outages, scheduled maintenance and load growth. According to this approach, adequacy is measured of both planned and installed capacity in terms of a percentage reserve. Nevertheless, this criterion has an important objection, since it analyses the power systems on the basis of peak load, regardless the specific characteristics of load and generating plants.

The basic approach to evaluate the adequacy of a certain generation configuration consists in three parts: generation model; load model; and risk model. The generation and load models are combined (convolved) to form the appropriate risk model [156].

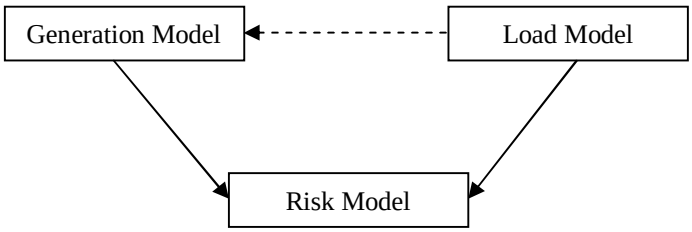


Fig. 30: Generating capacity reliability evaluation

When it comes to the operating capacity area, it is concerned with short-term assessment of the actual required capacity to satisfy the demand. Basically, the major difference between static and operating capacity evaluation stands for the period time under analysis [156].

The integration of renewable energy sources has led to several impacts on the power systems operation, namely on security of supply, such as the required mobilization at peak load periods (due to lack of RES), and the response to sudden generation drops (owing to rapid changes in the resource). This (and other) drivers increase the need for operating reserve. Although deterministic approaches have very attractive characteristics (e.g. simple implementation, easy understanding, assessment and judgment), the perception of many planning engineers that past experience, in

addition to some known critical situations, is enough to assess system risk conditions is not valid. What's more, past experience with renewable sources such as wind power is scarce. Yet the principles of some deterministic standards (e.g. ''N-1" criterion) are useful [158]. Methodologies based on probability concepts are useful to assess the power systems performance, having been applied to generation and transmission capacity planning, operating reserve assessment, distribution systems, etc. Conventional probabilistic indices (described subsequently) are already widely used, and Well-Being Analysis has been built combining the deterministic perception with probability concepts [158].

Chronological or sequential Monte Carlo simulation has been used for generating system well-being analysis. Matos *et al.* presented an application of chronological Monte Carlo simulation to evaluate the reserve requirements of generating systems, considering renewable energy sources. The referred work studied the behaviour of reliability indices (conventional and well-being), when a major portion of the energy sources is renewable (i.e. mainly hydro, wind and mini-hydro power sources) [158]. Sequential simulation identifies all chronological aspects, being capable to represent equipment aging process, time varying loads, and spatial and time correlations. According to the referred authors, chronological Monte Carlo simulation is very suitable owing to its flexibility, since it allows representing non-exponential residence times, meaningful when dealing with chronological processes. Additionally, chronological Monte Carlo simulation is an effective mean to adequately model and solve the difficulties to deal with renewable energy sources, their natural uncertainties (i.e. hydrologic inflow sequences, wind speed variations, etc.) and correlations.

Generating Unit Unavailability

In static capacity evaluation problems, the basic generating unit parameter to be used, is the probability of finding the unit on forced outage. This probability is known as Forced Outage Rate (FOR) and expressed as follows [156].

$$Unavailability = FOR = U = \frac{\lambda}{\lambda+\mu} = \frac{r}{m+r} = \frac{r}{T} = \frac{f}{\mu} = \frac{\sum[down\ time]}{\sum[down\ time]+\sum[up\ time]} \quad (3.\ 1)$$

$$Availability = A = \frac{\mu}{\lambda+\mu} = \frac{m}{m+r} = \frac{m}{T} = \frac{f}{\lambda} = \frac{\sum[up\ time]}{\sum[down\ time]+\sum[up\ time]} \quad (3.\ 2)$$

Where,

λ is the expected failure rate;

μ is the expected repair rate;

m is the mean time to failure, which is equal to $1/\lambda$;

r is the mean time to repair, which is equal to $1/\mu$;

$m + r$ is the mean time between failures, which is equal to T;

f is the cycle frequency;

T is the cycle time, which is equal to $1/f$.

The next figure presents the concepts of unavailability and availability for the two-state model.

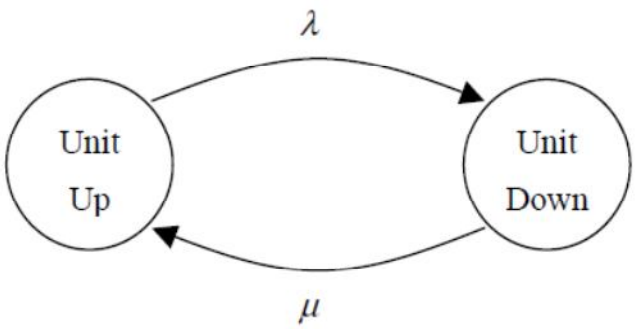


Fig. 31: Two-state model [156]

Capacity Outage Probability Table

The capacity outage probability table (COPT) is an array of capacity levels and the corresponding probabilities. The units can be combined applying probability concepts, and this methodology can be extended to build a useful recursive technique [159].

As alternative to the classical recursive technique, one can find other methodologies for the COPT computation. In cases where the system is very large, the discrete distribution of system capacity outages can be approximated by a continuous distribution [160], which approaches the normal distribution as the system size increases. However, the results achieved with this methodology are less accurate comparing to the obtained using the recursive technique [161]. In addition, Schenk and Rau proposed a Fourier transform method in order to improve the accuracy of the continuous model, though it is only compared with the recursive technique when the system is sufficiently large [162]. This approach is especially inaccurate for systems with hydro units with low FOR [163].

Another alternative approach consists of transforming the unit capacity tables into the frequency domain through fast Fourier transforms and to convolve using a point by point multiplication. An inverse fast Fourier transform can be used to generate the final COPT [164]. This method is considerably faster than the direct recursive technique and leads to more accurate results than the Fourier transform method [156].

Conventional Reliability Indices

The most common indices used for the assessment of generation adequacy are the Loss of Load Expectation (LOLE), the Loss of Energy Expectation (LOEE) and the Loss of Load Frequency (LOLF). The LOLE is the expected number of days (hours) in a specified period in which the daily peak load (hourly load) exceeds the available generating capacity. The LOEE is the expected unsupplied energy due to generating inadequacy and incorporates the severity of the deficiencies. The LOLF is the expected frequency of encountering a generation deficiency in a given period [165], [166].

According to the literature, most electric power utilities adopt the LOLE index in their generation system planning. Although the broad use of LOLE, this index can barely recognize the difference between a small capacity shortage and a large one (it is focused on the loss of load). Nonetheless, the LOLE responds to the adequacy criterion purpose in this research, which is to indicate the capacity adequacy of a given generation configuration. The adoption of other indices could present worth collecting data, but would lead to redundant information, according to the purpose of this thesis. For this reason, LOLE is the adopted index for generation planning with several scenarios/alternatives. This takes place, for example, in France, Netherlands and Belgium [156], [167].

LOLE

For LOLE calculation, the generation model is convolved with the load model in order to produce the risk index. There is a wide range of load models, but the simplest (and widely used) is the daily peak load, in which the individual daily peak loads are arranged in descending order, to form the daily peak load variation curve. Alternatively, the model is named load duration curve, when the individual hourly loads are used.

The loss of load index is then obtained by combining the COPT with load characteristics. It should be emphasized that a loss of load occurs when the capability of the generating capacity remaining in service is exceeded by the load level. For the case of LOLE index, the individual daily peak loads are combined with the COPT, to get the expected number of days in which the daily peak load will exceed the available capacity, in the specified period.

In case of scheduled outages (i.e. periodic inspection and maintenance), the COPT won't be constant throughout the period, therefore the modified capacity model is obtained by creating a new COPT for each capacity condition. The annual LOLE is divided into periods and is, as a result, calculated as the sum of individual LOLE, computed for each COPT (combined with the period load model).

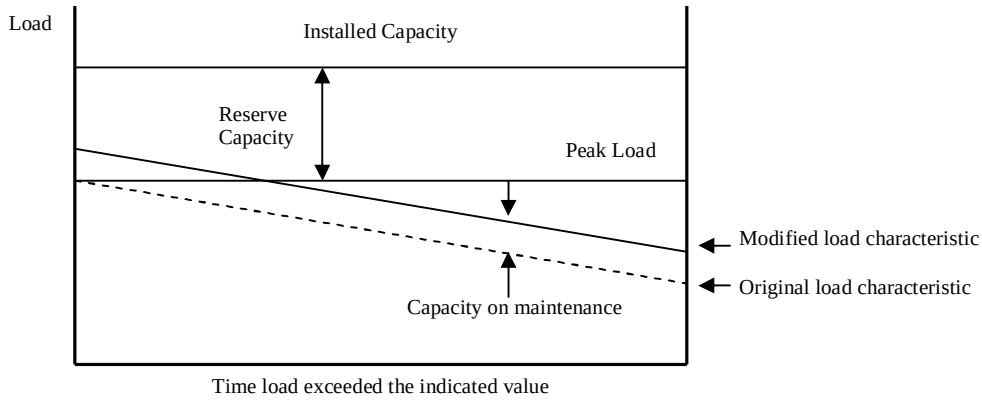


Fig. 32: Approximate method for including maintenance, adapted from [156]

According to Billinton and Allan, the most realistic approach to handle maintenance capacity, for LOLE calculation, is to combine the available units into a COPT applicable for the considered period [156]. Yet for maintenance considerations, the referred authors suggested that annual LOLE can be determined by three ways:

- Monthly (or period) basis considering maintenance;
- Annual basis neglecting maintenance;
- Worst period basis.

For the annual method neglecting the maintenance, a constant capacity level exists over the whole period. This assumption is justified because, typically, the year is divided into a peak load season and a light load season, and the maintenance is often planned for the latter period. Since the contribution of the light load season to the annual risk is usually low, the assumption of a constant capacity level is justified.

Well-being Indices

As stated previously, well-being analysis combines the deterministic perception with probability concepts, and provides additional characterization of the performance of the power system, by splitting the success states into healthy and marginal states, depending on whether or not a deterministic rule for reserve is satisfied. The specified value for secondary reserve or the largest available unit in the system, are typical thresholds used for this purpose. For instance, in the first case, the state is considered healthy if the margin between available generation and load is greater than the required secondary reserve [168].

Well-being analysis encompasses the next indices [169], [170], [171], [172]:

- EH - expected healthy hours, which is the expected number of hours in a period (e.g. year) the system will stay in healthy states;
- EM - expected marginal hours, which is the expected number of hours in a period (e.g. year) the system will stay in marginal states;
- FH and FM - expected frequency associated with healthy and marginal states, respectively;
- DH and DM - expected duration of system residing in healthy and marginal states, respectively. The deterministic criterion used to differentiate between healthy and marginal states may be the specified value for the secondary reserve, but the loss of the largest available unit in the system can also be used.

Chronological Monte Carlo simulation

According to Peças Lopes *et al.*, the algorithm associated with the chronological Monte Carlo simulation starts by defining – for each simulation of a specific year – the hourly load to be served by the system, and set up (through historical registers) the series of hourly wind availability and monthly hydro volumes that are used to estimate hydro power available capacity. Generation in special regime (biomass, biogas, solid waste, industrial waste, combined heat and power) is considered, as well as maintenance, which is assigned to the chronological periods where it is expected to occur. Over this chronological frame – that preserves the correlations between load, maintenance, wind and hydro – the times to failure and repair times of each individual generator are sampled, according to their statistical distributions and specific parameters (failure rate and mean repair time). This defines a number of success states, where the available power is sufficient to meet the load, and failure states that result from the unavailability of generation, due to the units' failures or lack of natural resources, in a way that load cannot be supplied. In each failure state power not supplied is computed and chronology is, again, used to identify the information about the failure event duration. By repeating the simulation for a significant number of years, statistics of these indicators are obtained, leading to the performance indices [168].

Operating Reserve Assessment

Grid operators have developed techniques for managing the variability and uncertainty of demand and conventional generation, in a system, by carrying operating reserves. The term "operating reserve" was defined in [173] as the "active power capacity that can be deployed to assist with generation and load balance and frequency control". Systems also require reactive power reserve for voltage support and a long-term reserve in order to ensure system adequacy (as described afterwards).

Reserves may be classified by [173]:

- the direction of their actions: an upward response (up-regulation) is required when there is less generation than load and can be secured from additional generating power or a decrease in participating loads; a downward response (down-regulation) is required when there is more generation than load and can be obtained from a drop in generating power or an increase in participating loads.
- the required response time: fast response in order to arrest a frequency drop; slower response for reserve that replaces other reserve categories (a matter of minutes or tens of minutes); for longer time scales, there can be also reserve provision for additional reserves, balancing or supplemental or reserve, to counter forecast errors.

A proposal for assessing the performance of the operating reserve was presented in [168] and [158], through the RESERVAS model. According to this model, at a certain period of time, minimum number of units will have to be dispatched to satisfy the forecasted load and the specified needs for primary and secondary reserve. In order to complete the operating reserve, units that could be available in less than one hour must be identified (tertiary reserve) [168].

In this model, the next power balance equation is set to assess the risk indices associated with the operating reserve.

$$R_{OPE} = R_S + R_T < \Delta L + \Delta P_W + \Delta G \tag{3. 3}$$

Where, R_{OPE} refers to the operating reserve at period t, R_S is the secondary reserve at period t, R_T is the tertiary reserve at period t; ΔL stands for the short term load deviation at period t, ΔP_W refers to the possible wind power capacity variation at period t, and ΔG represents the generating capacity variation due to forced outages at period t.

The previous equation describes the risk of changes in the load, wind power capacity and generating outages not being properly covered by the amount of spinning reserve, and also by those generators that can be synchronized within 1 hour. From this comparison, risk indices like the ones mentioned for generation adequacy analysis can be evaluated [158], [168].

3.5 Muticriteria Decision Aid

3.5.1 Overview

"Decision aiding is the activity of the person who, through the use of explicit but not necessarily completely formalized models, helps obtain elements of responses to the questions posed by a stakeholder of a decision process. These elements work towards clarifying the decision and usually recommending, or simply favouring, a behaviour that will increase the constituency between the evolution of the process and this stakeholder's objectives and value system." This definition was provided by Roy in [174]. A decision is related to the comparison of different points of view (some in favour and some against a given decision), which can be approximately defined as criteria. For many years this multicriteria nature of a decision was disregarded by the use of single-criterion methodologies. Nonetheless, for at least thirty years, a new look at decision problems has gained importance, by evaluating the pros and cons of several points of view. This methodology is generally named Multicriteria Decision Aid or Multicriteria Decision Analysis (MCDA). The basic principles of MCDA are very clear: a finite or infinite set of actions (alternatives, solutions, courses of action); at least two criteria; and at least one decision-maker [175], [176].

The process of planning engineering systems (electricity, gas, water, communications, etc.) encompasses the formulation of a decision. In view of that, the system should be modelled and projected in order to be subject to a decision by the decision maker. The problem can be either operation-based or strategy-based, depending on the hierarchical level of the decision. Typically, operation problems seek to optimize the exploitation of a given resource, for performing a pre-defined task. These problems have been previously evaluated by the decision makers, who have defined the tasks, resources and rules of the problem. Alternatively, in strategic planning the decision maker is actively involved and the problems are rather abstract, which requires the identification of objectives, criteria and alternatives. Therefore, identification of problem nature is fundamental for an adequate separation between operation optimization and decision aid [177].

Decision aid requires that a particular stakeholder is identified as decision maker, who plays a critical role in the process evolution and is under his/her behalf that the decision aid is applied. Nevertheless, the decision maker might be a spokesperson of third parties. The decision aid is usually developed by the analyst, who should be a specialist and is on charge to build the model [174]. According to Chankong and Haimes, in [178], the MCDA starts with the decision maker's perception of the need for change regarding the system about which he/she is committed. Afterwards, the decision situation will be diagnosed, by identifying the decision variables, alternatives and criteria. At the stage of the problem formulation, the vaguely stated criteria ought to be translated into an operational set of specific multiple criteria. Taking into consideration that the

alternatives must be compared, a set of attributes should be defined. These attributes – whose values can be obtained from the model or by subjective judgements – are used as benchmarks of the attainment degree of the criteria.

After the problem formulation step, a well-tuned model should be built-up. A model is understood as a collection of key variables and their relationships, which together can comprehensively tackle the problem under analysis. One of the functions of the model is to generate alternative courses of action. The assessment and evaluation steps are finished when each alternative is evaluated relative to others, concerning a decision rule (or set of rules) used to rank the alternatives [178].

The following figure summarizes the MCDA process.

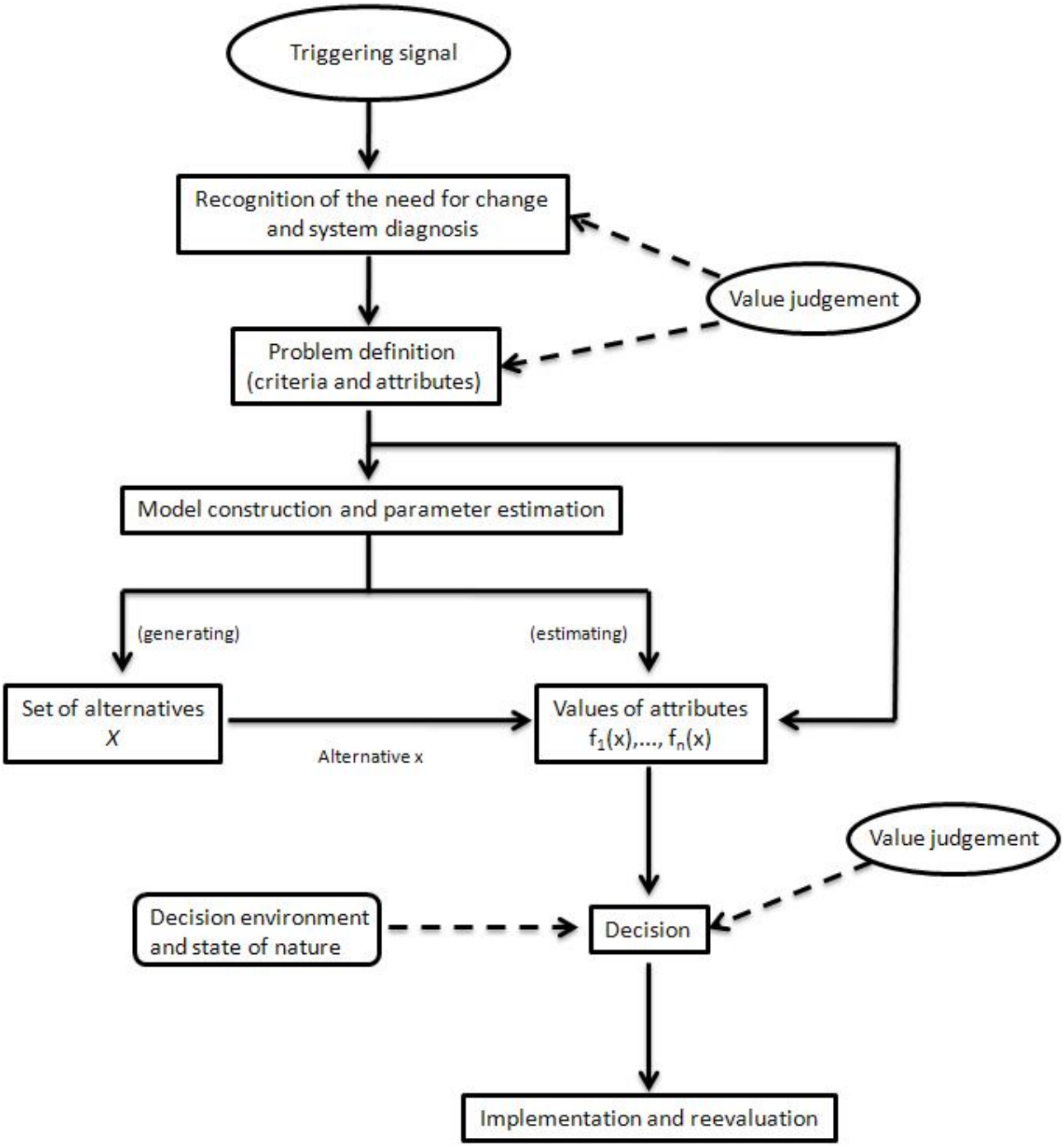


Fig. 33: Multicriteria decision process, adapted from [178]

Concerning the types of multicriteria problems, Roy defined the next groups [179]:

- Choice problems: when a simple choice must be made from a set of possible actions (or decision alternatives).

- Sorting problems: when actions must be sorted into classes or categories such as “definitely acceptable”, “possibly acceptable but needing more information”, and “definitely unacceptable”.
- Ranking problems: when actions must be ranked according to some sort of preference order, which might not necessarily be complete.
- Learning (descriptive) problems: when actions and their consequences must be described in a formalized manner so that decision makers can evaluate them. These are essentially learning problems, in which the decision maker aims to get a larger understanding of what may or may not be achievable.

Belton and Stewart have added two more types of multicriteria problems [180]:

- Design problems: these problems imply searching, identifying or creating new decision alternatives to meet the goals and aspirations identified through the MCDA process. Keeney endorsed this methodology in [181], through the concept of “value focused thinking”.
- Portfolio problems: when a subset of alternatives must be chosen from a large set of possibilities, taking into consideration both the characteristics of the individual alternatives and the manner in which they interact, as well as the positive or negative synergies between them.

3.5.2 MCDA Problems

Taxonomy

This thesis follows the taxonomy presented in [182], [183] and [177], when it comes to the classification multi-objective/multi-attribute.

These authors stated that decision aid problems can be classified into two categories:

- Multi-attribute problems (MA);
- Multi-objective problems (MO)

The MA problems are usually enclosed to a number of predetermined alternatives. The alternatives have associated with them an achievement level of the attributes, based on which the final decision is made. The final selection of the alternative is made with the help of inter and intra-attribute comparisons. One the other hand, MO problems aim to compute the “best” alternative, by considering the various interactions within the design constraints which best satisfy the decision maker, by way of attaining some acceptable levels of a set of quantifiable objectives [182].

The next figure sketches the MCDA classifications.

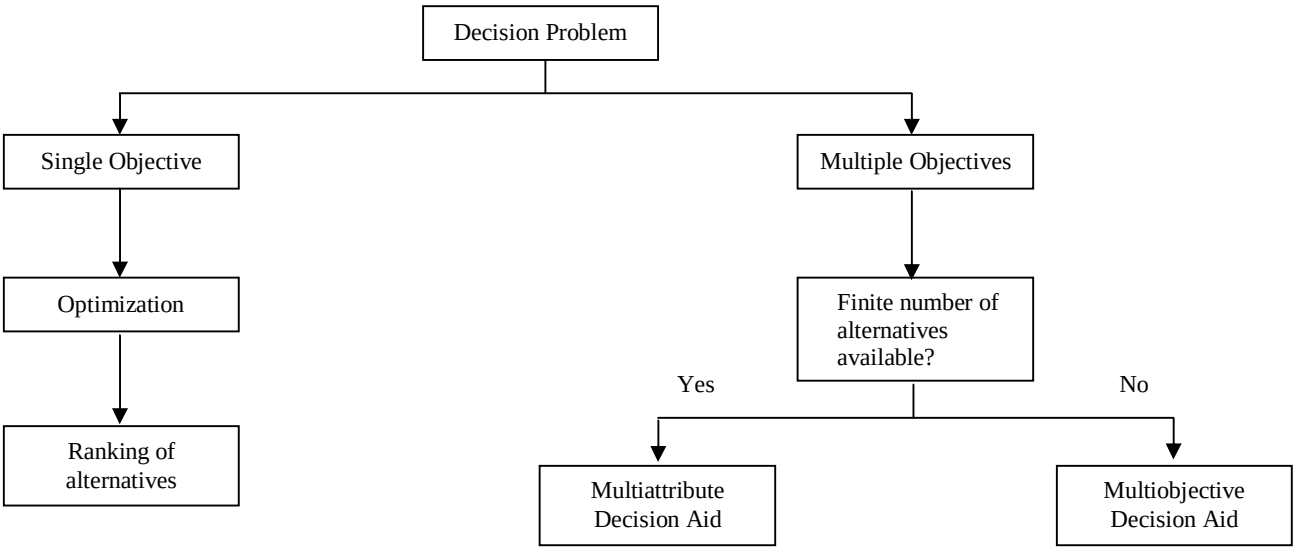


Fig. 34: Categories of MCDA problems

Prior to characterizing MCDA problems, key concepts should be clarified. According to Chagkong and Haimes "a noninferior solution is one which is not dominated by any other feasible solution". Yu provided, in [184], a generalized concept for nondominated (or noninferior) solutions, which is based on the domination structure. This structure is related to the decision maker's preference, which determines how one alternative dominates another one [178].

Thus, the next concepts can be presented, which will be useful in chapter 5 [178], [185], [176], [186]:

- Dominated (inferior) alternative: a solution is dominated if and only if there exists another one that is better in at least one criterion, without being worse in any of the remaining criteria.
- Efficient (nondominated, noninferior, Pareto optimal) alternative: a solution is efficient if and only if it is not dominated by any other feasible alternative.
- Ideal: (non feasible) solution that joins up the individual optima; defined only in the attributes' space.

Multiobjective Problems

The MO methods are characterized by: a set of quantifiable objectives; a set of well defines constraints; a process of obtaining some trade-off information, implicit or explicit, between the stated quantifiable objectives and also between stated or unstated non-quantifiable objectives. Hence, the MO decision aid is associated with design problems, as opposition of the selection problems tackled by MA [182].

A multiobjective problem can be formulated as following:

$$
\begin{aligned}
&\max F(x) \\
&\text{subject to:} \\
&\qquad G(x) = 0 \\
&\qquad H(x) \leq 0 \\
&\qquad x \geq 0
\end{aligned}
$$

where,

$F(x)$ vector of objective functions;

x vector of decision variables;

$G(x)$ set of equality constraints;

$H(x)$ set of inequality constraints.

Solving a MO problem consists of finding its set of efficient solutions. According to Chankong and Haimes, in [178], efficient solutions can be found by methods based on a weighting characterization or based on ε-constraint characterizations. When it comes to MO decision aid, depending on the types of preference information elicited and the ways they are used, methodologies could be grouped as follows: methodologies that use some form of global preference; methodologies that require preference elicitation by weights, priorities, goals and ideals; and methodologies that require eliciting preference through trade-offs [178].

Multiattribute Problems

In these problems, there is a finite set of predefined alternatives (discrete), namely $A = \{a_1, a_2, \ldots, a_m\}$, where A is the finite set m of alternatives. The alternatives are assessed by a set of criteria $C = \{c_1, c_2, \ldots, c_n\}$, which reflects the decision maker's concerns, and a set of attributes $X = \{x_{1,1}, \ldots, x_{m,n}\}$. The attributes levels serve as yardstick by which the attainment degree of the criteria can be assessed. The values of the attributes for a given alternative are obtained from the model or through subjective judgements [176], [178].

A MA problem can be presented by means of a payoff matrix, which is depicted underneath.

Alternatives \ Criteria	c_1	…	c_n
a_1	x_{11}		x_{1n}
…	…	…	…
a_m	x_{m1}	…	x_{mn}

Fig. 35: Payoff matrix of a MA problem

Regarding the resolution of MA problems, the next tiers should be followed [176], [177]:

1. Reduce the set of alternatives, *A*, to the efficient ones, by eliminating the dominated alternatives.
2. Evaluate and make further selections from the set of efficient alternatives.
   In large and complex decision problems, this selection is eased by modelling or quantifying the decision maker's values and preferences regarding the criteria.

There is a wide range of methodological concepts for solving MA problems. The methods applied in MA problems can be grouped into the next categories (according to the ways the decision maker is involved, the kind of information being given to and elicited from the decision maker, and the way in which information on preference is processed): direct assessment; sequential elimination; and spatial proximity.

The first category of methods is based on the multi-attribute utility theory and assumes that the decision maker is able to specify precise answers to a wide range of preference elicitation questions. There is a set of methods that follow this approach, such as the direct rating and mid-point methods for constructing value functions, the Analytical Hierarchy Process (AHP) method, Simple Multi-Attribute Rating Technique (SMART), and the Utility Theory Additive (UAT). Multi-attribute utility theory, proposed by Keeney and Raiffa in [187], assumes that the decision maker's preference "can be quantified, measured, and represented in the form of a real-valued function called multi-attribute value function or utility function" [178]. With this utility function the decision problem is solved through a routine evaluation and search procedure. Thus, having identified the attributes and alternatives, the next tiers should be followed, as recommended by Chankong and Haimes in [178]: 1) verify the existence of the multi-attribute value function; 2) select a suitable form of the function; 3) construct component functions to use in step 2; 4) determine scaling constants; 5) check consistency and make the final analysis.

When it comes to the second category, two famous approaches can be found in the literature for sequential elimination: Lexicographic method and outranking methods. In the Lexicographic method, the decision maker is asked to rank order the attributes in terms of their importance, and the most important one is used in the first screening step, in which alternatives with most preferred value for the referred attribute are kept, whereas the others are rejected. So a modified group of alternatives is built and the ones having the most preferred value for the second most important attribute are selected, and the others are discarded. This process continues until the modified group of alternatives has one alternative (the best one), or until all the attributes have been screened once [178]. Concerning the outranking methods, the underlying concept was introduced by Roy in [188]. For any alternatives *a'* and *a''* (which belong to the set of alternatives *A*), $a'S_a a''$ (i.e. *a'* outranks or is indifferent to *a''*) if and only if given the decision maker's preference ordering ≥, and given information on the values of attributes $X_1(a)$, $X_2(a)$, …, $X_n(a)$, there are reasons to believe that $a' \geq a''$, while there is no essential reason to disapprove that statement [178].

In what pertains to outranking methods, these are applicable to discrete choice problems and perform pair-wise comparisons of alternatives. One of the most applied outranking method is the ELECTRE, introduced by Roy in [188] and used to: make the final selection; classify alternatives in "reject" or "non-reject" classes; or classify alternatives in indifference classes and rank order the referred classes [178]. ELECTRE has already experienced several changes regarding the original method, such as ELECTRE II [189], ELECTRE III [190], ELECTRE IV [191], ELECTRE IS [192] and ELECTRE TRI [193]. Another widely used outranking method is the PROMETHEE [194], which is also based on pair-wise comparison of alternatives, as ELECTRE. There are still other outranking methods, such as ORESTE [195], TACTIC [196], EVAMIX [197], REGIME [198] and MAPPAC [199].

Finally, when it comes to the third category for solving MA problems, the indifference curve method is often applied to problems with up to three attributes. In this method, the alternatives that lie on the same indifference curve are indifferent to one another. There is a close relationship between this method and the multi-attribute value function, but the indifference curve approach is both less restrictive and prescriptive than the latter. According to Chankong and Haimes, "for any two points on the same indifferent curve, there is always a trade-off involving a certain amount of degradation of one attribute the decision maker is willing to tolerate in exchange for a certain amount of improvement of the other attribute while preferences for the two points remain the same" [178]. This statement seeks to define the "indifference trade-off" concept.

A trade-off is *de facto* a stimulus for spurring a strategic criterion (e.g. environmental preservation, power system reliability, etc.). That's to say, the trade-offs setting up materializes the decision

maker's willingness/unwillingness to pursue a certain strategy. Basically, trade-off analysis enables selecting solutions on the basis of indifference curves, which describe the decision maker's preferences structure. Thus, constant trade-offs lead to linear indifference curves [200].

Given two alternatives, a_1 and a_2, the corresponding levels of n attributes are $f(a_1) = (f_1(a_1), f_n(a_1))$ and $f(a_2) = (f_1(a_2), f_n(a_2))$. A trade-off between two attributes f_k and f_j is obtained as follows [178].

$$\alpha = \frac{f_k(a1) - f_k(a2)}{f_j(a1) - f_j(a2)} \tag{3. 4}$$

With this formulation, the decision maker can compare changes in two attributes at a time, which facilitates the preferences assignment.

But as Keeney highlighted in [201], value judgements are required to make value trade-offs, since they can't be calculated directly from other information. Anyway, information and auxiliary calculations can be useful to support making meaningful and better-informed value trade-offs. Hence, the decision maker is who judges about whether certain value judgements are appropriate. As a result, a good value trade-off accurately represents the decision maker's views.

But trade-offs have some limitations. For instance, constant trade-offs imply additive and linear value functions.

3.5.3 Uncertainty and Risk

The planning process – of different kinds of activities – frequently addresses situations of decision under uncertainty. Some authors define uncertainty as factors which have a major influence on a utility, but are beyond the utility's foreknowledge or control, such as fuel prices or regulatory changes. Risk is reckoned as the hazard to which a utility is exposed because of uncertainty, like the cost of electricity, capital requirements or environmental effects [202], [203]. In addition other authors state that "risk is associated with the lack of certainty of an outcome and how sensitive one is to that outcome and thus to the uncertainty" [204]. Furthermore, Chankong and Haimes characterize different types of decision problems, i.e. decision making under certainty, decision making under risk, decision making under uncertainty and decision making under conflict. These authors stated that decision making under certainty corresponds to the case where it is known with certainty that one and only one of r states of nature occurs. When it comes to decision making under risk, it is possible to estimate the probability of occurrence of each state of nature, either subjectively or objectively. In what pertains to decision making under uncertainty, it is a class of decision problems where it is not possible to estimate the probabilities of the states of nature. For

these problems, risk can't be quantified or analyzed explicitly, though the element of risk remains. Usually, in these cases, risk is coped through proper selection of decision rules. Finally, decision making under conflict corresponds to problems in an environment consisting of rational opponents with conflicting interest [178].

Alternatively to the previous approaches, Matos does not distinguish uncertainty and risk in [205]. According to this author, dealing with uncertainty, or risk, includes building models for uncertainty (what may happen) and decision (what to do). A review of approaches to model uncertainty is now provided [205].

- Scenarios

  Usually, it is possible to characterize each scenario by a linguistic label that shows the comprehensive nature of scenario definition. In the scenarios approach, uncertainty variables are globally estimated, correlations are considered and diverse structured futures are built. Although the basic idea about scenarios does not require a probability distribution, the concept of "most likely scenario" is sometimes invoked in a qualitative way (meaning generally that all the other possible scenarios will be discarded). An impact model is required to turn the scenarios approach meaningful, since they are possible occurrences of data and parameters. The impact could be described by a single attribute or multiple attributes.

- Intervals

  Another approach to deal with uncertainty corresponds to assuming that some or all of the data and parameters are described by intervals, instead of a single real number. Similarly to scenarios, intervals try to capture every possible future value of the relevant data.

- Probabilistic models

  When additional data is available – coming from statistics or symmetry considerations – probabilistic models become improvements to the two previous approaches. Setting up probabilities to scenarios is indeed a usual practice. Yet sometimes come up subjective probabilities, meaning a set of probability values estimated by an expert. A rather usual situation consists of holding probability distributions for the data, enabling, theoretically, the use of each alternative's probability distribution of the consequences.

- Fuzzy models

  When statistical information is not available or when the problem is subject to qualitative descriptions (corresponding to expert declarations about the data or the impact of the alternatives), fuzzy set theory comes up as another way of incorporating additional information in the uncertainty model. The general fuzzy number can be perceived as a set of nested intervals, with increasing degrees of membership (or possibility values). This means

that each value of the support interval has assigned a real number (the degree of membership) that measures its compatibility with the vague declaration associated with the fuzzy number. An impact model is also required in fuzzy models. Yet sometimes the fuzzy impact comes directly from an expert vague judgment.

Having drawn an overview on approaches to model uncertainty, now a set of decision paradigms and rules is presented.

- Expected Value Paradigm

  This paradigm is applied in probabilistic context, being described by the next decision rule: *Choose the alternative with the best expected value of the attribute*. "Best" refers to "minimum" or "maximum", depending on the decision problem. Despite being often used in isolated situations, the Expected Value Paradigm assumes implicitly that a number of similar decision situations will be repeated over the time. The referred decision rule is generally associated with the decision tree approach, which consists of decision nodes and outcome nodes, action branches and outcome branches. A decision tree always starts with an initial decision node and ends with outcome branches. The tree is gradually reduced by the use of the mentioned decision rule. The Expected Value Paradigm is, thus, an aggregation procedure, which substitutes a probability distribution of outcomes by its expected value. Therefore, the paradigm transforms the original problem into a deterministic single criterion problem [205].

- Utility Theory

  Implicit in any decision making process is the need to build the preference order, so that alternatives can be ranked and the final choice can be selected. Utility theory attempts to construct the preference order by directly eliciting the decision maker's preference. The decision rule for this theory is the following: *Choose the alternative with the greatest expected utility* [205]. Risk behaviour is linked to how the decision maker values a given attribute, in the face of uncertainty. If a decision maker judges the actual values of an attribute, in situations of uncertainty, in the same way as under certainty, such a decision maker is described as risk-neutral. Chankong defined in [178] that a decision maker is said to be:

  i. Risk neutral if and only if $u_i(x)$ is a linear function of x_i;
  ii. Risk averse if and only if $u_i(x)$ is a strictly concave function of x_i;
  iii. Risk prone if and only if $u_i(x)$ is a strictly convex function of x_i.

- E-V Analysis and Risk-based Value Functions

  Representation of alternatives in the E-V plan is common, thus corresponding prescriptive models with value functions have been developed. These approaches are alternative to utility theory models, since they use value functions on deterministic indices, while utility functions are applied directly to the probability distributions of the attributes.

- Robust Optimization

  A major approach in what pertains to uncertainty problems is based on the concept of robustness and related notions, like disappointment or regret. This approach applies the minimax paradigm: *Choose the alternative that, in the worst case, has the best value of the attribute*. This principle is expressed by the next equation, which minimizes costs under different scenarios (where Z is the set of alternatives and S is the set of scenarios).

$$min_{z \in Z}\{max_{s \in S}\ Cost(z, s)\} \tag{3. 5}$$

This approach is appropriate when there are no repeated decisions, where bad outcomes may be compensated by future good outcomes. The minimax principle is classified as an *absolute robust approach*, suited for goal satisfaction or competition situations where the uncertainty comes from competitors' decisions. The *minimax regret approach* is adequate to situations where the quality of the decisions is evaluated *ex post facto*. That's to say, no one cares with the possible scenarios that finally did not happen, and market situations where losses are automatically gains of competitors. Regret is expressed by the difference between the outcome of the decision (after the resolution of the uncertainty) and the best possible outcome in the same scenario, as described bellow.

$$min_{z \in Z} max_{s \in S} Regret(z, s) = min_{z \in Z} max_{s \in S}(Cost(z, s) - Cost^{*}(s)) \tag{3. 6}$$

Where,

$$Cost^{*}(s) = min_{z \in Z}\big(Cost(z, s)\big) \tag{3. 7}$$

$Cost^{*}(s)$ is the best possible outcome in scenario s.

- Bellman and Zadeh Fuzzy Decision

  This is a symmetrical approach, where satisfaction of constraints and goals is unified, so each alternative has a degree of membership to the Fuzzy Decision, equal to the minimum of the degrees of membership to the fuzzy sets Goal and Restriction.

3.6 Summary and Main Conclusions

This chapter presented an overview on theoretical fundamentals for energy planning, namely: environmental impact; economic and financial costs; and adequacy of the generation system. This survey is critical for building, adequately and utterly, a methodology for multicriteria energy planning.

Additionally, a theoretical overview was provided on multicriteria decision aid, as well as on uncertainty and risk. These concepts will be applied in the methodology and case study assignments.

To sum up, this chapter presented the theoretical concepts and framework to perform, subsequently, the mathematical formulation associated to the research.

Chapter 4

4 Methodology for Multicriteria Energy Planning

4.1 Introduction

This chapter describes the methodology developed for the multicriteria energy planning of isolated systems. The methodology hereafter described, is pursued through the following steps:

a) Problem identification and global description;
b) Defining the scope and objectives for the problem;
c) Problem formulation, including the identification of decision variables, alternatives, criteria and attributes;
d) Mathematical modelling.

The methodology, within this thesis, provides a mathematical formulation which aims to enhance the energy sustainability of a given isolated system, through a multicriteria evaluation of renewable energy sources integration, plus electricity storage, sustainable mobility and the adoption of energy efficiency measures.

This chapter is, then, the cornerstone for building an innovative approach for planning energy systems, which will be subsequently tested through a case study.

4.2 Problem Identification and Global Description

4.2.1 Scope and Objectives

In ancient rhetorics, the *circumstantiae* was an important component of argumentation, serving to define the specific attributes or circumstances of the case. Hermagoras of Temnos (Greek rhetorician of the 2nd century BC) is known for his system of invention and has defined the theory of the seven circumstances, by delimiting the hypothesis to seven attributes, which Pseudo-Augustine lists as: *quis, quid, quando, ubi, cur, quem ad modum, quibus adminiculis.* Or in English: who, what, when, where, why, in what way, by what means [206].

In this section, these questions are answered, in order to present a clear sight of the current thesis' scope.

Taking into account the research drivers presented in chapter 1 (*why*), the present work aims to enhance the sustainability of a given energy system, when it comes to environment, economic and generation adequacy criteria (*what*). This objective is pursued through the development of a multi-criteria energy planning methodology (*in what way*) addressing renewable energy integration, electricity storage, sustainable mobility and the adoption of energy efficiency measures (*by what*

means). Concerning the time horizon, the referred methodology is conceived to carry out a long-run energy planning, from a few years to decades (*when*).

When it comes to the work applicability, the current research is built for the case of isolated systems (e.g. an island), bearing in mind the challenges and constraints related to the energy planning in such cases (*where*). This thesis embodies, therefore, an energy planning approach, providing technical support to the decision maker, who is assumed to be a regional authority of the corresponding system (*who*).

4.2.2 Problem Formulation

Decision Situation

The energy planning process starts when the decision maker's reckons the need to design a strategic and long-run study for a given isolated system, taking into account different strains, such as environmental worries, costs or system's operation performance. The decision maker is assumed to be an authority of the system under analysis, with power and legitimacy to decide among a set of feasible options. The energy plan should be holistic, by gathering strategies applied in both the demand and supply sides of the power system, as well as in the transport sector.

In view of the previous overview, the decision situation of the energy planning problem should be characterized. Although there is no formal guideline for identifying an adequate decision situation, this can be typified by the next elements:

- A set of decision variables and alternatives;
- A set of criteria;
- A set of attributes.

The endeavour for defining a problem demands a comprehensive understanding of the meaning, structure and properties of the alternatives, criteria and attributes. Keeney and Raiffa presented a set of illustrative examples, which summarize the involved concepts and emphasized that there are no universal definitions of these terms [187].

Alternatives and Decision Variables

The alternatives are options, plans or strategies that represent possible solutions for the problem [207]. Roy presented the mutual exclusiveness of the concept of "alternative", stating that an alternative "corresponds to the particular case in which modelling is such that two distinct potential actions can in no way be conjointly put into operation" [208]. The author also referred that the set

of alternatives can be denoted by A, where a_i stands for a given alternative among a finite number of potential actions m.

$$A = \{a_1, a_2, \dots, a_m\} \tag{4. 1}$$

In the current research, the alternatives are defined by considering the investments and policies that are being studied by the decision maker, who is represented by the regional authorities of the analyzed energy system. Hence, the alternatives identification reproduces a set of potential hypotheses for a given energy system. As affirmed by Roy, an action is qualified as potential when is possible to be implemented, or deserves interest within the decision aid [208].

Accordingly, each alternative is a strategy, enclosing a set of decision variables, namely:

- Load variation (increase/decrease) associated to the adoption of energy efficiency measures.
- Installed capacity of renewable energy sources (RES): business-as-usual RES increase; mid-range RES increase; or high-range RES increase.
- Sustainable mobility options: efficient ICVs, biofuels and behavioural change; or strategies based in EVs introduction.
- Electricity storage strategies: storage through a Centralized Storage Facility and/or Electric Vehicles charging, including the Vehicle-to-Grid concept.

Criteria and Attributes

The alternatives evaluation is carried out by defining key criteria, which are based on general aspects (e.g. reliability, environmental impact, etc). The criteria selection is one of the first steps within the decision aid. According to Roy, in order to verify the suitability of the chosen criteria, one should confirm that [208]:

- What is apprehended by each criterion is sufficiently intelligible for each of the stakeholders;
- Each criterion is perceived to be a relevant instrument for comparing potential actions along the scale associated with it, without prejudging their relative importance, which could vary significantly among the stakeholders.

In addition, a coherent family of criteria must be [209]:

- Exhaustive: all important points of view must be included;
- Consistent: if two alternatives A and B are equivalent except in criterion k, and A_k is better than B_k, then A must be at least as good as B;
- Non-redundant: eliminating a criterion leads to the violation of one of the preceding axioms;
- Furthermore, there are other desirable properties, as follows [210]:

- Legibility: the number of criteria must be relatively low;
- Operationality: the family of criteria must be accepted by the stakeholders and decision-makers.

When it comes to the criteria assessment, an attribute is associated to each criterion, which serves as yardstick [178]. Hwang and Masud defined the attributes as characteristics, qualities or performance parameters of alternatives [182]. That is to say, an attribute is a measurable quantity whose value reflects the degree of achievement for a given criterion, to which the attribute is ascribed.
The association of an attribute to a criterion requires the fulfilment of the next properties [178]:

- Comprehensiveness: an attribute is comprehensive if its value is sufficiently indicative of the degree to which the criterion/objective is met.
- Measurability: an attribute is measurable if it is reasonably practical to assign a value in some scale to the attribute for a given alternative.

Besides the properties of an attribute, a set of attributes should follow some properties. Keeney and Raiffa stated that a set of attributes must be: complete, operational, decomposable, non-redundant and minimal [187].

Having in mind the thesis objective for enhancing the sustainability of a given isolated energy system – by planning renewable energy integration, plus electricity storage, sustainable mobility and energy efficiency measures – one has defined the concerned criteria and attributes. Each criterion, C_i, gathers a set of attributes, X_i, and sub-attributes, which are presented as follows:

- C_1: Environmental impact (minimize)
  $\Rightarrow X_1$: CO_2 emissions from transport sector
- C_2: Economic and Financial costs (minimize)
  $\Rightarrow X_2$: Overall alternative costs
    - Carbon-based costs
    - Power generation costs (renewable and non-renewable generation)
    - Costs of Centralized Storage Facility
    - Costs of Electric Mobility
    - Costs of Energy Efficiency Measures (power system and transport sector)
- C_3: Adequacy of the generation system in terms of reliability (maximize)
  $\Rightarrow X_3$: Loss of Load Expectation index (minimize)

This formulation was initially applied in the research. Nonetheless, the multicriteria assessment of the alternatives (namely comparing costs and emissions) becomes clearer and more comprehensive,

when carbon emissions from the power system are accounted through an environmental attribute, rather than by an economic attribute. Hence, if carbon costs are disregarded and the corresponding power system's emissions are accounted in the environment impact criterion, the previous criteria identification will be then redesigned, as follows:

- C_1: Environmental impact (minimize)

  $\Rightarrow X_1$: CO_2 emissions from transport sector and power system
- C_2: Economic and Financial costs (minimize)

  $\Rightarrow X_2$: Overall alternative costs
  - Power generation costs (renewable and non-renewable generation)
  - Costs of Centralized Storage Facility
  - Costs of Electric Mobility
  - Costs of Energy Efficiency Measures (power system and transport sector)
- C_3: Adequacy of the generation system in terms of reliability (maximize)

  $\Rightarrow X_3$: Loss of Load Expectation index (minimize)

Since carbon costs accountability is followed by energy planning divisions of generation companies and governmental institutions, in this research both formulations for carbon emissions assessment will be provided (i.e. carbon emissions as a cost and as environmental criterion).

4.3 Mathematical Modelling

4.3.1 Framework

Addressing each of the identified criteria and attributes requires building a specific mathematical formulation, which is described in this section. In what pertains to environmental impact, global carbon emissions shall be accounted, as a result of energy use (transport and power system).

In terms of the economic and financial costs, these include: carbon-based costs (if carbon emissions from the power system are accounted as a cost); power generation costs; costs of centralized storage facility; costs of electric mobility; and costs of energy efficiency measures (power system and transport sector).

When it comes to the adequacy of the generation system in terms of reliability, the loss of load expectation index shall be computed.

The calculation of these attributes is formulated in the decision maker's perspective, for a certain year in the future. The development of a formulation based on an annual assessment, enables the decision maker to get a deeper understanding of the system's evolution (and impacts) throughout the planning timeline.

4.3.2 Environmental Impact

Formulation

Carbon emissions from energy use are computed by multiplying quantities of fossil fuel combusted (measures in energy terms) by emission factors which are specific to fuels and countries [211]. The broad assessment on CO_2 emissions within an energy system demands data collection from both the power system and transport sector. The equation which gives the annual CO_2 emissions from both the power system and transport sector, *TE*, is the following (obtained from a typical daily pattern).

$$TE = \left(\sum_i^n (N_v \times sh_i \times m_d \times et_i) \times (1 - sh_{EV}) + \sum_h^H \sum_j^N G_{h,j} \times eg_j\right) \times D \qquad (4.2)$$

Where,

n is the number of fuel types for internal combustion vehicles;

i is the type of internal combustion fuel;

N_v is the total number of light vehicles;

sh_i is the share of light vehicles with fuel i;

m_d is the daily mileage of light vehicles (km);

et_i stands for the well-to-wheel emissions factor of light vehicles with fuel i (gCO_2/km);

sh_{EV} is the share of electric vehicles among the light vehicles of the system;

H refers to total hours of a day;

h corresponds to a certain hour;

N is the number of non-renewable electricity generators per fuel type;

j is the fuel type of non-renewable electricity generation;

$G_{h,j}$ is the hourly electricity generation of j type generation (kWh);

eg_j represents the emissions factor (including processing and extraction, transport of raw material, and electricity generation) owing to j type of electricity generation (gCO_2/kWh);

D is the number of days of the target year.

The inclusion of well-to-wheel emissions due to transport sector, and power system's emissions from extraction, transport of fuel and electricity generation, allows evaluating the global impact that islands have in world's emissions.

Although the comprehensiveness of the previous formulation, energy planning entities sometimes account carbon emissions from the power system as a cost, associated to the European Emissions

Trading System. If that option is followed, the attribute for environmental impact only considers the transport sector emissions. Hence, the carbon emissions attribute is calculated by the next equation.

$$TE = (\sum_i^n (N_v \times sh_i \times m_d \times et_i) \times (1 - sh_{EV})) \times D \quad (4.3)$$

This methodology was based on several reports on carbon emissions assessment, such as [212], [211], [213], [214].

One should emphasize that in systems with lack of fossil fuels for energy use (e.g. Portugal), a carbon dioxide analysis is in certain way an energy dependence analysis. Therefore, the lower the carbon emissions, the higher will be the energy independence. Accordingly, the level of carbon emissions of such energy system is also linked to the use of endogenous natural and human resources, which are associated to the energy dependence degree. As a result, the lower the carbon emissions and the energy dependence, the higher will be the use of endogenous resources. These relationships are highlighted by both the OECD and UNEP [215], [112].

4.3.3 Economic and Financial Costs

4.3.3.1 Global Formulation

The attribute for the overall alternative costs should gather the Operation Expenditures (OPEX) and the additional Capital Expenditures (CAPEX) from a set of sub-attributes:

- Carbon-based costs (TAC_{CO2});
- Power Generation costs (TAC_{PS});
- Costs of Centralized Storage Facility (TAC_{ss});
- Costs of Electric Mobility (TAC_{EV});
- Costs of Energy Efficiency Measures (TAC_{Eff}).

Thus, the total annual costs, *TAC*, are obtained from the next equation.

$$TAC = TAC_{C02} + TAC_{PS} + TAC_{ss} + TAC_{EV} + TAC_{Eff} \quad (4.4)$$

To simplify the costs accountability, all the referred costs are assumed to be handled by the local utility, yet the costs for energy efficiency measures and electric mobility may be indirectly financed by the regional authorities.

Currently, there is a wide range of programs for supporting clean technologies and low carbon economy, which award projects and products with considerable public subsidies, such as the 2009's

US Smart Grid Investment Program, that provided grants of up to 50% for electric utilities' investments on Smart Grids [216].

4.3.3.2 Carbon-based costs

Formulation

This formulation is only valid if carbon emissions from the power system are accounted as a cost, instead of an environmental attribute.

Taking into account the EU ETS overview presented in chapter 3, at the end of each trading period installations must surrender allowances equivalent to their emissions. Thus, if a GENCO (electricity Generation Company) keeps its emissions below the emissions cap, it can sell the excess allowances. But if the GENCO has emitted more CO_2 than its cap, it will have to buy further allowances in the market.

The carbon price should be combined with the difference between the annual CO_2 emissions from the power system and the corresponding cap, as described underneath.

$$TAC_{C02} = \theta \times CP_1 + (E_{PS} - \theta) \times CP_2 \tag{4. 5}$$

Where,

TAC_{CO2} stands for the annual carbon-based costs (€);

θ is the annual allocation of CO_2 allowances (cap), received from the auctioning (tonCO_2);

CP_1 is the average auctioning price of allowances in the EU ETS (€/tonCO_2);

CP_2 is the average EUAs price in the secondary market (i.e. spot, forwards, organized and OTC) for additional allowances (€/tonCO_2);

E_{PS} refers to the actual annual CO_2 emissions from the power system (tonCO_2).

The annual emissions from the power system, E_{PS}, are obtained as follows.

$$E_{PS} = \left(\sum_h^H \sum_j^N G_{h,j} \times eg_j\right) \times D \tag{4. 6}$$

Where, $G_{h,j}$, eg_j and D were introduced in section 4.3.2.

4.3.3.3 Power Generation Costs

Global Formulation

The annual costs related to power generation, ACC_{PS}, gather capital and operation costs, as follows.

$$TAC_{PS} = ACC_{PS} + OMC_{PS} = ACC_{PS} + NRC + RC \quad (4.7)$$

Where,

ACC_{PS}, refers to the equivalent annual capital cost for additional power generation units (€);

OMC_{PS}, refers to the annual operation and maintenance cost for power generation units (€);

NRC is the annual operation and maintenance cost for non-renewable energy sources (€);

RC is the annual operation and maintenance cost for renewable energy sources (€).

Capital Costs

As presented in section 3.3.2, to make financial decisions, calculations are typically made on a yearly basis and capital cost is annualized. One way to annualize a single capital cost is to multiply it by the capital recovery factor. The CRF converts a present value in a stream of equal annual payments, over a specific time and at a specific discount rate. That is to say, the equivalent annual capital cost is the amount of money to be paid at the end of each year, to amortize the present value for the capital cost, CC_{PS}, at a rate *d* and during *n* years.

Therefore, the equivalent annual capital cost, ACC_{PS}, is computed by combining the cost of capital with the depreciation annuity, as follows [125], [126].

$$ACC_{PS} = CC_{PS} \times CRF = CC_{PS} \times \frac{1}{\frac{1}{d} - \frac{1}{d \times (1+d)^n}} \quad (4.8)$$

The CRF is a value, between 0 and 1, representing the annual cost required to fully amortize an investment over a specified period.

In this thesis, one considers that capital costs for renewable energy sources are included in the corresponding feed-in-tariff, as a common cost-based incentive [126].

Unit Commitment, Economic Dispatch and Operation Costs of non-renewable energy sources

The operation costs of non-renewable energy sources are determined by the Unit Commitment and Economic Dispatch, for the corresponding generation diagram of the time under analysis. Before solving the economic dispatch problem, the unit commitment problem should be solved, in order to know, in advance, which are the units that will be switched on in the interval under analysis, to proceed to their output (electricity generation/interval) set up by the economic dispatch model. The unit commitment is a crucial sub-problem for scheduling generation units to be “on” or “off” during each interval of the scheduling period (from 1 day to 2 weeks, typically in hourly intervals), allowing the minimization of start-up and shut down costs. The economic dispatch gives, thereafter,

the units' power output in order to minimize fuel costs, subject to a set of constraints (meet the demand, fulfill minimum value of spinning reserve, and fulfill minimum and maximum limits of the unit) [131].

In this formulation, the Unit Commitment and Economic Dispatch problem is applied to a typical daily load profile of a certain isolated system. The UCED is divided into 24 sub-problems (one sub-problem per period) and for each period of time:

- the units are assigned to be "on" or "off";
- the power output of each unit that is "on" is calculated.

Taking into account the relevance of start-up and shut-down costs, the UCED is *de facto* a multi-period problem, being impossible to solve it in a separate way for each period.

The basic thermal UCED problem is modelled as a single objective problem that aims to minimize total operation costs. Fuel costs are linked to the fuel consumption of each unit, which depends on the power output in each period of time and type of unit (fuel oil, diesel, etc). The functions that represent the fuel costs are, generally, non-continuous and non-convex. Nevertheless, since non-convexity of such functions prevents the use of conventional optimisation techniques, polynomial interpolation is often applied and a linearization can be made to describe the fuel consumption at different power levels, for each unit type, as referred in the literature [217], [200], [218]. This approach was followed in this research, as subsequently presented in chapter 5.

When it comes to start-up costs and shut-down costs, these are incurred each time a power plant is turned "on" and "off", respectively. The start-up costs depend on the latest period the unit was operating and, for steam units, on whether the machine was kept hot, or not, while the "off" period. Nonetheless, this research assumes that the power system under study has no steam units (these are just commissioned in larger systems) and the start-up costs are constant, as also followed by [219]. Concerning shut-down costs, these can be represented as a constant, being lower than start-up costs, as referred in [129].

The classical UCED problem has, then, the following formulation and corresponds to the minimization of power generation operation costs in a 24h period [220], [221].

$$Minimize \sum_{i=1}^{h}\sum_{k=1}^{n}\left[u_{i,k} \times (F(P_{i,k}) + C_k^u \times (1 - u_{i-1,k})) + (1 - u_{i,k}) \times u_{i-1,k} \times C_k^d\right] \tag{4. 9}$$

Subject to:

$$\sum_{k=1}^{n} u_{i,k} \times P_{i,k} = P_i^L, \ \forall i \tag{4. 10}$$

$$\sum_{k=1}^{n} u_{i,k} \times P_k^{max} \geq P_i^L + SR_i, \forall i \tag{4. 11}$$

$$u_{i,k} \times P_k^{min} \leq P_{i,k} \leq u_{i,k} \times P_k^{max}, \forall i, k \tag{4. 12}$$

$$u_{i,k} = 1 \ for \ \sum_{i=i_{su}}^{i-1} u_{i,k} < MUT_k \ , \forall k \tag{4. 13}$$

$$u_{i,k} = 0 \ for \ \sum_{i=i_{du}}^{i-1} (1 - u_{i,k}) < MDT_k \ , \forall k \tag{4. 14}$$

Where,

$u_{i,k}$ is the status (1 – on; 0 – off) of unit k, at period i;

F refers to the fuel and fixed costs in period i, of unit k with $P_{i,k}$ of power output;

$P_{i,k}$ is the power output from unit k at period i;

h is the number of periods;

n is the number of units (non-renewable generators);

C_k^u refers to the costs of starting-up unit k;

C_k^d represents the costs of shutting-down unit k;

P_k^{max} is the maximum power output of the fossil-fired unit k;

P_k^{min} is the minimum power output of the fossil-fired unit k;

SR_i is the spinning reserve at period i;

MUT_k is the minimum up-time of unit k;

MDT_k is the minimum down-time of unit k;

i_{su} is the hour at which the unit k is started up;

i_{sd} is the hour at which the unit k is shut down.

The described formulation is, however, inadequate for power systems with renewable generation and electricity storage facilities, including EVs' V2G operation. For the UCED with renewable generation, such as wind, the renewable output is typically subtracted from demand, producing the "net load," which can then be used to compute the thermal generator requirements [222]. Therefore, the modified formulation for UCED is now presented, by integrating the power output from renewable energy sources, centralized storage and V2G (if exist), for a typical day of operation.

$$min\ NRC = \sum_{i=1}^{h}\left\{\sum_{k=1}^{n}\left[u_{i,k} \times (F(P_{i,k}) + C_k^u \times (1 - u_{i-1,k})) + (1 - u_{i,k}) \times u_{i-1,k} \times C_k^d\right]\right\} \times D$$

(4. 15)

Subject to:

$$\sum_{k=1}^{n} u_{i,k} \times P_{i,k} = P_i^L - P_i^R - P_i^S - P_i^V,\ \forall i \quad (4.\ 16)$$

$$\sum_{k=1}^{n} u_{i,k} \times P_k^{max} \geq SR_i + P_i^L - P_i^R - P_i^S - P_i^V, \forall i \quad (4.\ 17)$$

$$u_{i,k} \times P_k^{min} \leq P_{i,k} \leq u_{i,k} \times P_k^{max}, \forall i, k \quad (4.\ 18)$$

$$u_{i,k} = 1\ for\ \sum_{i=i_{su}}^{i-1} u_{i,k} < MUT_k\ , \forall k \quad (4.\ 19)$$

$$u_{i,k} = 0\ for\ \sum_{i=i_{du}}^{i-1} (1 - u_{i,k}) < MDT_k\ , \forall k \quad (4.\ 20)$$

Where,

NRC refers to the annual operation and maintenance cost for non-renewable energy units;

D is number of days of the target year;

P_i^R is the total renewable power output at period *i* (including wind, hydro, geothermal, biomass, etc.);

P_i^S is the power output from centralized storage (e.g. pumped hydro) at period *i* (which electricity comes from surplus renewable energy sources), according to a strategy for daily CSF generation profile, tuned to supply electricity at off-valley periods (assuming a constant power output);

P_i^V is the power output from EVs V2G at period *i*, according to a strategy for daily V2G profile with a constant power output (included in the UCED as input data, disregarding the uncertainty inherent to the drivers/users' behaviour);

P_i^L is the electricity load at period *i*, including the additional load from EVs' charging, disregarding the uncertainty inherent to the drivers/users' behaviour (the stored electricity by the centralized storage facility is not accounted in the load, since it is conceived as a service to the system, instead of a load to serve).

The previous objective functions are subject to five constraints, which are described as follows:

- System power balance demand: in each period, the committed units must satisfy the total load demand.

- Spinning reserve requirements: the spinning reserve is the unused capacity which can be activated on decision of the system operator, being provided by devices which are synchronized to the network and able to affect the active power [223]. A commonly used deterministic criterion sets the desired amount of spinning reserve so that the system can withstand the outage of any single generating unit without perform load shedding. This criterion is also known as N-1 criterion [220], [173]. Many system operators set the spinning reserve in order to be enough to handle the outage of the largest power unit in service [224], [225].
- Unit generation limits: thermal units are neither technically capable of producing below a given minimum production level, nor above a maximum.
- Unit minimum up and down times: if a unit is "on" it must be kept "on" for at least MUT periods of time. On the other hand, if a unit is "off", it must remain "off" for at least MDT periods of time.

Concerning the available methods for UCED, these have already been mentioned in section 3.3.2. Taking into account the characteristics and purpose of the present research, a merit order scheme, using a priority list, is developed. In fact, the merit order priority list for the UCED, presents a satisfactory compromise accuracy/computational effort [226]. This method ranks all the system units according to a merit function and, based on this ranking and for each time interval, the units are switched "on" or "off" until load and spinning reserve constraints are fulfilled [129]. This technique is applied in several power utilities from different countries, owing to its ease of application and understanding [131]. Moreover, this approach is often used in market environments, where suppliers are ordered according to their bid prices and selected, in that order, until load demand is satisfied [129]. The commitment priority may be determined by applying the Commitment Utilization Factor (CUF), the classical Average Full Load Cost (AFLC) index or both [131].

The priority criterion followed in this research is based on the AFLC, which is the cost per unit of power when the unit is at its full capacity, being expressed as follows, for unit *k* [227].

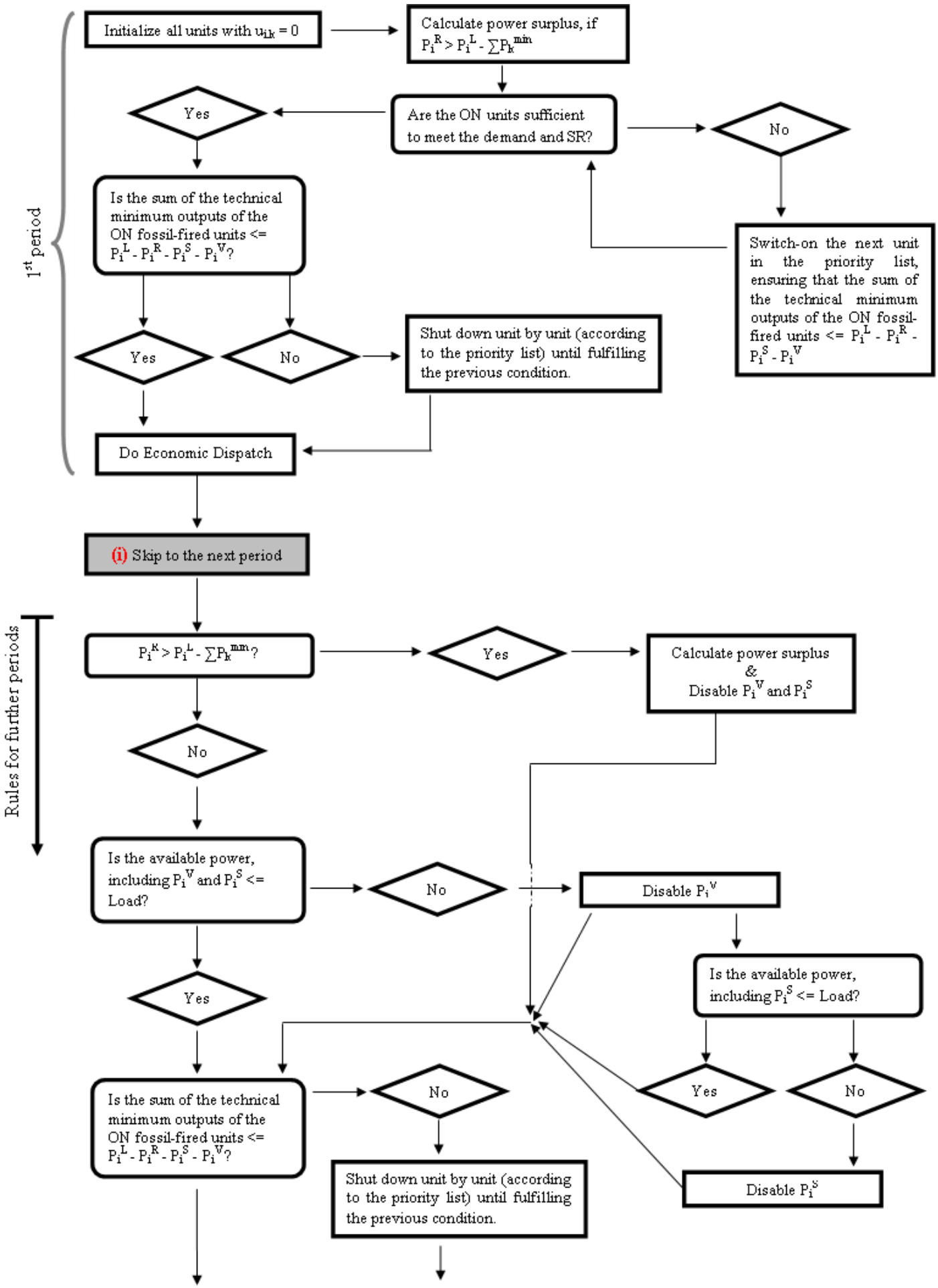
$$AFLC = \frac{working\ cost\ at\ maximum\ production\ level}{maximum\ production\ level} = \frac{F(P_k^{max})}{P_k^{max}} \tag{4. 21}$$

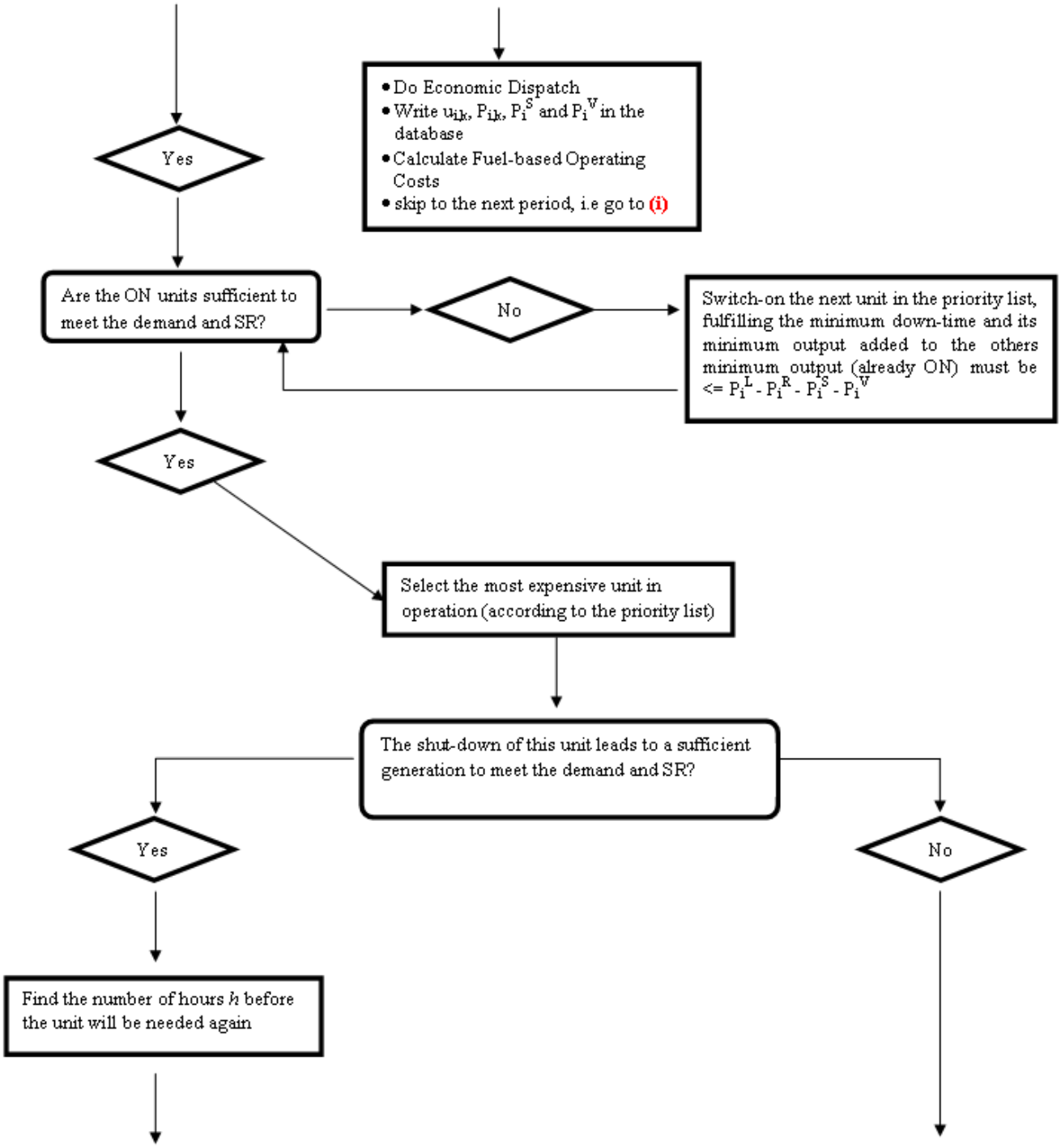
The algorithm to solve the UCED problem (through the merit order priority list method) was built in the course of the current research, using Matlab® environment. This algorithm is applied to a

typical daily load profile (in Atlantic and Mediterranean islands there is a weather steadiness throughout the year, with reduced seasonality effect on the load profile). At each period of time, the previously described constraints are verified and the power surplus is quantified. There is power surplus when RES generation plus thermal power (at technical minimums) exceeds the load (including the additional load for EVs charging, if exists). In such cases, the CSF stores the power surplus, to be afterwards (off-valley period) injected into the grid at a constant power output. Yet that energy shift is only possible, if the sum of the CSF power output at a certain period (according to a strategy for its generation profile) with RES and thermal power (at technical minimums) doesn't exceed the load. When it comes to V2G, it also has a constant power output (at off-valley period), according to a strategy for V2G profile, except if the sum of that power together with the CSF, RES and thermal power (at technical minimums), is higher than the load. That's to say, there is only V2G and CSF at a certain period, if there is no power surplus.

In the end of each period, the algorithm performs the economic dispatch and writes in a database the status ("on" or "off"), power output and operation costs of each thermal unit. The V2G and CSF power outputs are also exported back to the database. Yet this algorithm just computes the operation costs from thermal units (non-renewable). Other costs are calculated separately through specific mathematical formulation, such as costs from RES, EVs, centralized storage facility, carbon emissions and energy efficiency measures.

The logic of the referred algorithm is characterized by the next flowchart.


1st period
Initialize all units with $u_{ik} = 0$
Calculate power surplus, if $P_i^R > P_i^L - \sum P_k^{min}$
Are the ON units sufficient to meet the demand and SR?
Yes
No
Switch-on the next unit in the priority list, ensuring that the sum of the technical minimum outputs of the ON fossil-fired units <= $P_i^L - P_i^R - P_i^S - P_i^V$
Is the sum of the technical minimum outputs of the ON fossil-fired units <= $P_i^L - P_i^R - P_i^S - P_i^V$?
Yes
No
Shut down unit by unit (according to the priority list) until fulfilling the previous condition.
Do Economic Dispatch
(i) Skip to the next period
Rules for further periods
$P_i^R > P_i^L - \sum P_k^{min}$?
Yes
Calculate power surplus & Disable P_i^V and P_i^S
No
Is the available power, including P_i^V and P_i^S <= Load?
No
Disable P_i^V
Is the available power, including P_i^S <= Load?
Yes
Yes
No
Is the sum of the technical minimum outputs of the ON fossil-fired units <= $P_i^L - P_i^R - P_i^S - P_i^V$?
No
Shut down unit by unit (according to the priority list) until fulfilling the previous condition.
Disable P_i^S


Do Economic Dispatch
Write u_{ik}, P_{ik}, P_i^S and P_i^V in the database
Calculate Fuel-based Operating Costs
skip to the next period, i.e go to (i)
Yes
Are the ON units sufficient to meet the demand and SR?
No
Switch-on the next unit in the priority list, fulfilling the minimum down-time and its minimum output added to the others minimum output (already ON) must be <= P_i^L - P_i^R - P_i^S - P_i^V
Yes
Select the most expensive unit in operation (according to the priority list)
The shut-down of this unit leads to a sufficient generation to meet the demand and SR?
Yes
No
Find the number of hours h before the unit will be needed again

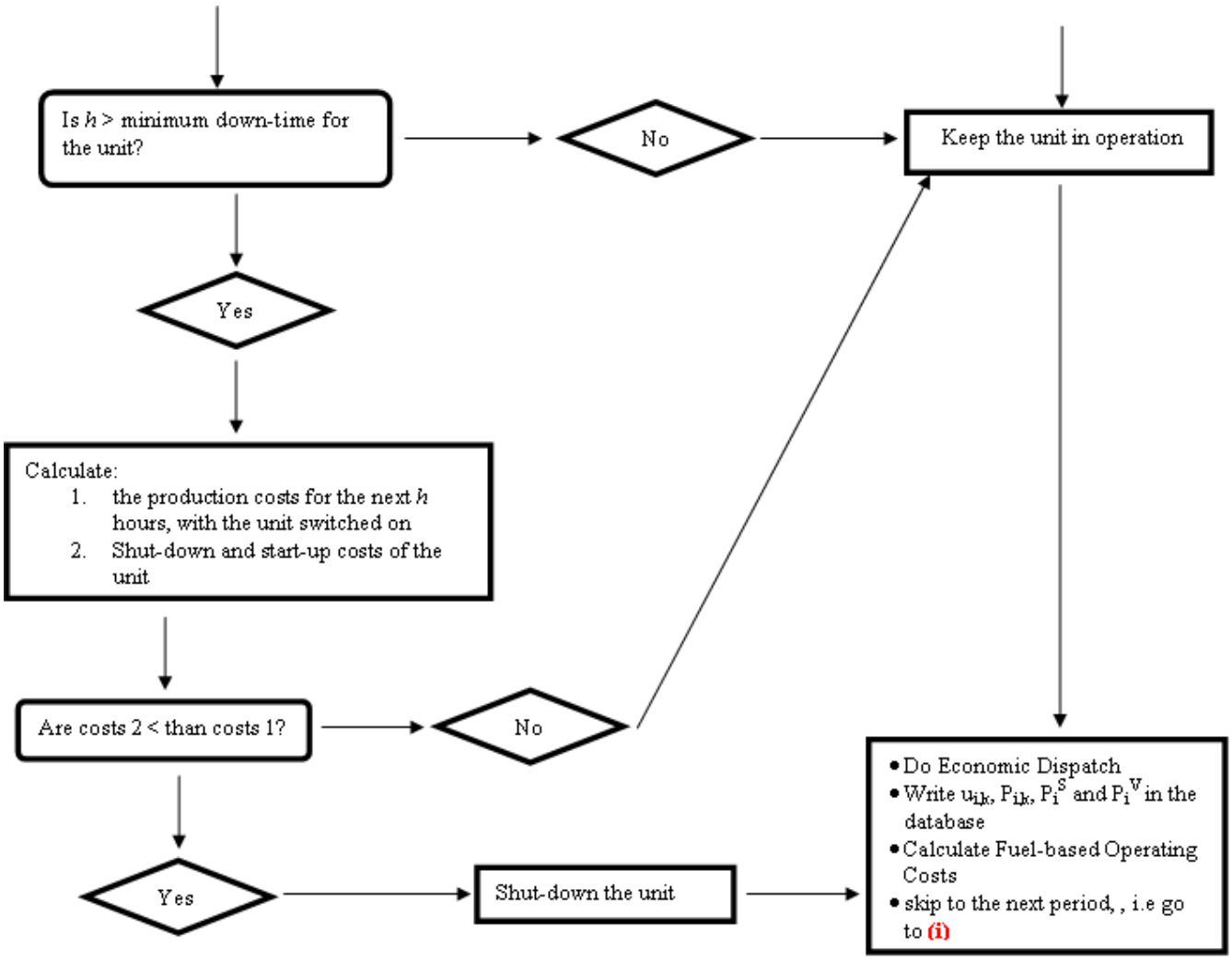


Fig. 36: Flowchart of the priority-list-based UCED algorithm

Operation Costs of renewable energy sources

Besides the non-renewable energy units, it is also worth evaluating the costs of the renewable energy sources. However, unlike fossil-fuel power generation, the costs of RES are typically accounted through a specific feed-in tariff, which includes both capital and operation costs. This feed-in tariff represents, therefore, the purchase cost per unit of energy produced [228], [229]. The below suggested formulation, assumes that there is absence of long-run (decades) forecasts on hourly power generation from RES, which requires an extrapolation based in past values (typical day). Hence, the power generation from RES, in the target year, is calculated by the use of past registers of data, as well as the difference of renewable-based installed capacity.

The annual renewable generation costs, *RC*, are then obtained from the next equation.

$$RC = \left(\sum_{i=1}^{h}\left(\sum_{k=1}^{n} RG_{i,k}^{I} \times \left(\frac{RP_k^I + RP_k^{II}}{RP_k^I}\right) \times C_k^R\right)\right) \times D \qquad (4.22)$$

Where,

$RG_{i,k}^{I}$ is the renewable generation of energy type *k*, at period *i*, in the base year (MWh);

RP_k^{I} is the already installed power of renewable generation of energy type *k*, in the base year (MW);

RP_k^{II} is the new installed power of the renewable generation of energy type *k*, in the target year (MW);

C_k^{R} is the feed-in-tariff for renewable generation, energy type *k*, that includes capital and operation costs (€/MWh);

D is number of days of the target year.

According to the described, the generation costs from RES are utterly computed by the previous equation, since capital costs are included in the feed-in tariff.

The previously described formulation for power generation costs was applied into the São Miguel Island, in the year 2008. The characteristics of the referred power system are presented in Annex I.

With the use of cost and technical-based data provided by the local utility, the UCED algorithm was applied to a typical 2008's day.

The obtained outcome was then compared with actual generation profiles occurred in São Miguel's power system during 2008. The referred comparative analysis confirmed that the obtained generation profiles (and corresponding operation costs), from the proposed merit order algorithm, reproduce the typical operation strategy.

Taking into account that the developed algorithm seeks to draw a typical operation day, if one extrapolates the obtained results to the 2008's 366 days, the annual operation costs from fuel oil units are €25,5 million, while renewable generation totaled €16,4 million. From data supplied by the local utility, the real 2008's fuel oil-based operation costs were €25,7 million, while the renewable ones were €15,9 million. Thus, these figures confirm the suitability of the proposed formulation, for calculating power generation costs, bearing in mind the scope of the current thesis. Anyway, the quality of this estimation could be improved by including more typical days of the referred year.

4.3.3.4 Costs of Centralized Storage Facility

Global Formulation

In sections 2.2 and 3.3.3 the pumped hydro storage was identified as technology for CSF and a review was presented on its capital and operation costs. The total equivalent annual costs, TAC_{ss}, for a CSF are described as follows [48], [229].

$$TAC_{ss} = ACC_{ss} + OMC_{ss} = ACC_{ss} + EC_{ss} + FC_{ss} \tag{4. 23}$$

Where,

ACC_{ss} stands for annualized capital cost (€);

OMC_{ss} refers to operation and maintenance cost (€);

EC_{ss} is the annual energy cost (€);

FC_{ss} is the annual fixed maintenance cost (€).

The details of the previous equation are hereafter explained, based on the premise that the local utility is the CSF investor and operator, and following similar approaches presented in [48] and [23].

Equivalent Annual Capital Cost, ACC_{ss}

Firstly, it is necessary to find out a parameter to describe the contribution of the storage system to the overall energy demand, ε. This parameter is presented underneath.

$$\varepsilon = F_{tot}/E_{tot}^{i} \tag{4. 24}$$

Where,

E^{i}_{tot} is the annual electricity demand of the target year (MWh);

F_{tot} is the annual electricity generated by the CSF, resulting from a strategy for daily generation profile, and calculated as follows (MWh).

$$F_{tot} = \left(\sum_{i=1}^{h} P_i^S\right) \times D = F_{stor} \times \eta_{SS} \tag{4. 25}$$

Where,

P_i^S is the CSF power output, at period *i*, according to a strategy for daily CSF generation profile, tuned to supply electricity at off-valley periods and with a constant power output (MW);

D is the number of days of the target year;
h stands for the hours of a day;
F_{stor} is the annual electricity stored by the CSF, due to RES surplus (MWh);
η_{ss} is the energy transformation (round-trip) efficiency of the CSF (%).

The previous equality assumes the technical feasibility of performing energy shift of the whole stored electricity (led by RES surplus). However, when a part or all the stored electricity is not allowed to be injected into the grid (owing to the power system operation rules), the referred equality is not applicable.

The UCED is run without defining the energy storage capacity (the CSF stores energy surplus, which is injected into the grid according to a generation strategy and with a constant power output), but for making an economic evaluation of CSF its main characteristics should be defined, i.e. the energy storage capacity, E_{ss}, and nominal power, N_{ss}.

$$E_{ss} = d_o \cdot \left(\frac{F_{tot}}{8760}\right) \cdot \frac{1}{\eta_{ss}} \cdot \frac{1}{DOD_L} \tag{4. 26}$$

Where,
d_o stands for the typical hours of energy autonomy in a day;
DOD_L is the maximum depth of discharge (%).

While the CSF nominal power is given by,

$$N_{ss} = \frac{P_p^S}{\eta_p} \tag{4. 27}$$

Where,
P_p^S is the CSF power output, at the peak power period p (MW);
η_p is the power generation efficiency of the CSF (%).

The installed power of the centralized storage facility can also be defined by projecting the load and generation profiles, in order to identify the daily energy surplus. Accordingly, the CSF installed capacity is defined to store the maximum amount of energy surplus.

Now it is possible to find the capital cost, CC_{ss}, of the storage system, as presented bellow.

$$CC_{ss} = (C_c . E_{ss} + C_p . N_{ss}) \times (1 + C_{co}) \quad (4.28)$$

Where,

C_c is the specific energy cost (€/MWh);

C_p is the specific power cost (€/MW);

C_{co} is the additional cost for corrosion prevention measures, in case of a seawater storage facility (% of capital cost increase), whereas in case of a freshwater system this parameter is zero.

C_c and C_p can be collected from benchmarking of international pumped hydro storage projects, as provided in [23].

Finally, one can compute the equivalent annual capital cost, which concept was presented in section 3.3.2 and deepened in section 4.3.3.3. Hence, the equivalent annual capital cost, ACC_{ss}, is found out by applying the next equation.

$$ACC_{ss} = CC_{ss} \times CRF = CC_{ss} \times \frac{1}{\frac{1}{d} - \frac{1}{d \times (1+d)^n}} \quad (4.29)$$

Where,

d is the discount rate (%);

n is the investment period (years).

Annual Operation and Maintenance Cost, OMC_{ss}

a) <u>Energy cost, EC_{ss}</u>

In conventional power exchange, the market operator ensures the matching between the highest buying orders, with lowest selling orders for each time step. The market operator maximizes the value of demand-side orders minus the cost of supply-side orders, subject to the demand-supply balance, and originating the market clearing price. With the addition of storage to the power exchange, the storage facilities are modulated as net action performers to the demand-supply balance [15]. According to the formulation proposed in [15], a discharging action leads to a positive profit to the storage owner, while a charging action represents a cost, thus a negative profit.

Unlike the market-based dynamics, typical in deregulated power systems, for isolated systems one assumes the electricity selling and purchase prices aren't established through the pool, rather via contracted prices.

The energy cost, EC_{ss}, is then drawn by the next equation, assuming storage/pumping operation during valley hours and power generation at off-valley periods.

$$EC_{ss} = F_{stor}.C_e^{SS} - F_{tot}.P_e^{SS} \tag{4. 30}$$

Where,

F_{stor} is the annual electricity stored by the CSF, due to RES surplus, as presented previously (MWh);

C_e^{SS} is the local electricity purchase cost for the valley-hour rate (€/MWh);

F_{tot} is the annual electricity generated by the CSF as presented previously (MWh);

P_e^{SS} is the local electricity selling price for the off-valley-hour rate (€/MWh);

When the energy cost is negative, the CSF investor and operator is getting positive gross margin from the energy storage/pumping process.

a) Annual Fixed Maintenance Cost, FC_{ss}

The FC_{ss}, is found by multiplying the CSF's capital cost, CC_{ss}, by a parameter, m, which stands for the fraction of the initial capital invested.

$$FC_{ss} = CC_{ss}.m \tag{4. 31}$$

The parameter m is a standard, being available from a benchmarking of pumped hydro projects.

4.3.3.5 Costs of Electric Mobility

Global Formulation

The total annual costs of the electric mobility, TAC_{EV}, gather the following strands: annual operation and maintenance cost, OM_{EV}; and annualized capital cost, ACC_{EV}.

$$TAC_{EV} = OMC_{EV} + ACC_{EV} \tag{4. 32}$$

The next formulation is based on the assumption that the local utility is the investor and operator of the EM.

When it comes to the capital costs, these are assumed to be supported by the EM investor and operator (i.e. local utility). The profits concerned with the EM investment and operation depend on the margin driven by the electricity trading for providing the EVs charging service.

Annual Operation and Maintenance Cost, OMC_{EV}

As previously described, the EVs may contribute for the power system operation, by consuming a certain share of the energy surplus (EVs charging) and injecting just a part of the stored energy into the grid, through the V2G concept.

As formulated for the centralized storage facility, the operation costs of EM assume that for isolated power systems the electricity selling and purchase prices aren't established through the market, rather via contracted prices. Additionally, the supplier and aggregator are supposed to be the same entity (i.e. SupAg), as suggested in [78]. The SupAg, in islands, can be considered to be the local DSO, which will provide all the EM and electricity operations.

Then, the EM operation cost is described by the next equation, assuming that the EVs charge during valley hours and, for the alternatives with V2G, the EVs inject electricity into the grid during off-valley hours.

$$OMC_{EV} = (C_{e1}^{EV} - P_{e1}^{EV}) \times E_{ch} + (C_{e2}^{EV} - P_{e2}^{EV}) \times E_{disp} \tag{4. 33}$$

While,

$$E_{ch} = \left(\sum_{i=1}^{h} EV_i^{ch}\right) \times D = (EV_{EC} \times m_d \times N_{EV} + EV_{ES} \times r^d \times N_{EV}) \times D \tag{4. 34}$$

$$E_{disp} = \left(\sum_{i=1}^{h} P_i^{V}\right) \times D = EV_{ES} \times r^d \times \eta_{conv} \times N_{EV} \times D \tag{4. 35}$$

Where,

C_{e1}^{EV} is the local electricity purchase cost for the valley-hour rate (€/MWh);

P_{e1}^{EV} is the local electricity selling price for the valley-hour rate (€/MWh);

E_{ch} is the annual electricity consumed for EVs charging, which results from a strategy for daily charging profile, tuned to maximize the RES integration (expectedly at valley periods) and taking into account energy demand for daily mobility and, if it is the case, the additional energy required to perform V2G at off-valley periods (MWh);

C_{e2}^{EV} is the cost of electricity generation through EV Vehicle-to-Grid (€/MWh);
P_{e2}^{EV} is the local electricity selling price at off-valley hours (€/MWh);
E_{disp} is the annual electricity dispatched from the EVs, according to a strategy for daily V2G profile, tuned to provide energy at off-valley periods (MWh);
EV_i^{ch} is the EVs power demand, at period *i*, according to a strategy for daily charging profile (MW);
h stands for the hours of a day;
D refers to number of days of the target year;
EV_{EC} is the energy consumed per EV for mobility purposes (MWh/km);
m_d is the daily mileage of each EV (km);
N_{EV} is the number of EVs in the system;
EV_{ES} is the total energy storage of the EV battery (MWh);
r^d is the rate of the EVs' daily available energy for V2G, according to a strategy for daily V2G profile (%);
P_i^V is the EVs power for V2G, at period *i*, according to a strategy for daily V2G profile with a constant power output (MW);
η_{conv} is the efficiency of the EV conversion of the stored energy back to electricity (%)

The equality presented in equation (4. 35) assumes the technical feasibility of performing energy shift of the whole stored electricity, for V2G purposes. However, when a part or all the stored electricity is not allowed to be injected into the grid (owing to the power system operation rules), the referred equality is not applicable.

When it comes to the cost of electricity generation through EV Vehicle-to-Grid, C_{e2}^{EV}, one proposes the next formulation, adapted from [230], [70] and [124].

$$C_{e2}^{EV} = \frac{ACC_{EV}}{E_{disp}} + C_d \tag{4. 36}$$

Where,
ACC_{EV} is the annualized capital cost for electric mobility, described subsequently (€);
C_d is the extra degradation cost owing to V2G functionalities (€/MWh).

The C_d is found by the next equation.

$$C_d = \frac{C_{bat}}{L_{ET}} \tag{4. 37}$$

The battery lifetime throughput energy for the cycling regime, L_{ET} (MWh), is obtained as follows.

$$L_{ET} = L_c \times EV_{ES} \times DoD \tag{4. 38}$$

Where,

C_{bat} is the battery capital cost, including replacement labour (€);

L_c stands for the lifetime in cycles;

DoD is the depth-of-discharge for the corresponding L_c (%).

Equivalent Annual Capital Cost, ACC_{EV}

Concerning the formulation for the equivalent annual capital cost (theory presented in section 3.3.2 and deepened in section 4.3.3.3), the capital recovery factor is multiplied to the capital cost of EM, as follows.

$$ACC_{EV} = CC_{EV} \times CRF = CC_{EV} \times \frac{1}{\frac{1}{d} - \frac{1}{d \times (1+d)^n}} \tag{4. 39}$$

Where,

ACC_{EV} is the equivalent annual capital cost (€);

CC_{EV} is capital cost (€);

d is the discount rate (%);

n is the investment period (years).

The EM capital cost should consider the investment on the EM infrastructure, presented in section 3.3.4.

4.3.3.6 Costs of Energy Efficiency Measures

Global Formulation

The annual costs for energy efficiency measures, TAC_{Eff}, gather power system and transport sector costs, as follows.

$$TAC_{Eff} = TAC_{EffPS} + TAC_{EffICVs} \tag{4. 40}$$

Where,

TAC_{EffPS}, refers to the annual costs for measures applied on the demand-side of the power system (€);

$TAC_{EffICVs}$, refers to the annual costs for measures applied on the transport sector (€);

Measures for the Power System

As stated previously, some alternatives follow an energy efficiency pathway, as a result of thriving dedicated programs for demand response, demand side management, load control and sustainable buildings. The search out of the concerned energy efficiency costs is carried out right through the next tiers.

The annual electricity consumption in the target year *i*, E_{tot}^{i}, and the annual electricity demand variation, E_{EffPS}^{i}, are given by the following equations.

$$E_{tot}^{i} = E_{tot}^{i-1} \times (1 + E_{\Delta}) \tag{4. 41}$$

$$E_{EffPS}^{i} = E_{tot}^{i-1} - E_{tot}^{i} \tag{4. 42}$$

Where,

E_{Δ} is the percentage of annual load variation from year *i-1* to year *i*;

E_{tot}^{i-1} is the annual electricity demand in year *i-1* (GWh).

The energy efficiency depends, consequently, on the E_{Δ} and occurs only when this variable is negative. Hence, the total annual costs of energy efficiency applied to the power system, TAC_{EffPS}, are calculated as follows.

$$TAC_{EffPS} = E_{EffPS}^{i} \times C_{EffPS} \tag{4. 43}$$

C_{EffPS} is the energy efficiency cost applied to the power system (expressed in €/GWh), which increases linearly over time, being calculated through the next equation.

$$C_{EffPS} = a.x + b \tag{4. 44}$$

a and *b* describe the linear equation for the energy efficiency cost and *x* is the time variable. This equation is obtained from costs and savings data of ongoing energy efficiency and demand response programs [231], reflecting the marginal cost increase for energy efficiency with the course of time.

As referred previously, to simplify the costs accountability, in this work, these costs are assumed to be handled by the local utility, but can be considered as indirectly financed by the regional authorities.

Measures for the Transport Sector

When it comes to the transport sector, as described in section 3.3.5, there is a set of energy efficiency measures, gathering technology improvements (i.e. efficient internal combustion vehicles and biofuels), as well as behavioural changes (i.e. driving behaviour, distance driven, intermodality and car sharing). The annual ICVs' emissions for the energy efficiency alternatives, in the target year *i*, E_{ICVs}^{i} (tonCO_2), are calculated by the next equation [151].

$$E_{ICVs}^{i} = E_{ICVs}^{i-1} \times (1 - EE - TF - DB - DD - BF) \tag{4. 45}$$

Where,

E_{ICVs}^{i-1} stands for annual ICVs' emissions in year *i-1* (tonCO_2);

EE is the annual abatement potential owing for efficient ICVs (%);

TF is the annual abatement potential by improving the traffic flow (%);

DB is the annual abatement potential owing to improved driving behavior (%);

DD is the annual abatement potential by reducing the distance driven (%);

BF is the annual abatement potential by blending low carbon biofuel (%).

Now, the total annual costs of energy efficiency measures applied to the ICVs, $TAC_{EffICVs}$, are determined as follows.

$$TAC_{EffICVs} = C_{ET} \times (E_{ICVs}{}^{i-1} - E_{ICVs}^{i}) / Con \tag{4. 46}$$

As built for the power system, the cost of abatement measures, C_{ET} (expressed in €/GWh), increases linearly over time, being calculated through the next equation.

$$C_{ET} = a.x + b \tag{4. 47}$$

In which *a* and *b* describe the linear equation for the abatement cost and *x* is the time variable.

The conversion factor from tonCO_2 to GWh of energy consumption from the ICVs is represented by *Con*. Alternatively, the C_{ET} can be expressed in €/ton, leading to the next equation.

$$TAC_{EffICVs} = C_{ET} \times ({E_{ICVs}}^{i-1} - E_{ICVs}^{i}) \quad (4.48)$$

Again, these costs are assumed to be handled by the local utility, but can be considered as indirectly financed by the regional authorities.

4.3.4 Adequacy of the Generation System

Adopted Methodology

Although the clear benefits of analyses such as well-being indices and chronological Monte Carlo simulation, this work adopts the conventional reliability indices for generation adequacy assessment (namely, LOLE), owing to the scope and objectives of the current research.

Recursive algorithm for the COPT

The capacity model can be built by the use of a widely known recursive algorithm, described in [159]. According to Billinton and Allan, in [156], the cumulative probability of a given capacity outage state of *X* MW, after a unit is added, with capacity *C* MW and forced outage rate equal to *U*, is obtained by the following equation.

$$P(X) = (1 - U)P'(X) + (U)P'(X - C) \quad (4.49)$$

Where *P'(X)* and *P(X)* are the cumulative probabilities of the capacity outage state of *X* MW, before and after the unit is added, respectively. The previous equation is initialized by making *P'(X)* = 1 for $X \leq 0$ *P'(X)* = 0 otherwise. This formulation is exemplified in [156].

The referred recursive algorithm was developed using Matlab® and tested through several exercises, in order to be applied in this research.

Loss of Load Expectation

Although the existence of rather accurate methodologies to assess a wide range of situations that could occur during the operation of a power system, the LOLE shall be used in this work, due to the research goals and simplicity of the concerned index. The LOLE is obtained by combining the individual daily peak loads with the capacity outage probability table, to get the expected number of days in the specified period in which the daily peak load will exceed the available capacity. The mathematical formulation of the LOLE is given as follows.

$$LOLE = \sum_{i=1}^{n} P_i(C_i - L_i) \quad days/period \tag{4. 50}$$

Where,

n is the number of days;

C_i is the available capacity on day i;

L_i is the forecast peak load on day i;

$P_i(C_i\text{-}L_i)$ is the probability of loss of load on day i (obtained directly through the COPT).

Alternatively, the LOLE can be computed by the next equation.

$$LOLE = \sum_{k=1}^{n} p_k . t_k \quad time\ units \tag{4. 51}$$

Or

$$LOLE = \sum_{k=1}^{n} (t_k - t_{k-1})\, P_k \quad time\ units \tag{4. 52}$$

Where,

n is the number of capacity outage states;

p_k is the probability of the kth capacity outage state with magnitude O_k;

P_k is the cumulative outage probability of the kth capacity outage state with magnitude O_k;

t_k is the number of time units in the study interval that an outage magnitude, O_k, would result in a loss of load.

The next figure presents an example of a daily peak load variation curve for a period of 365 days. A given outage will contribute to the system LOLE by an amount equal to the product of the probability of the particular outage and the number of time units in the study interval that a loss of load would occur, if such a capacity outage is verified. Any capacity outage less than the reserve won't contribute to the system LOLE. On the other hand, outages higher than the reserve results in varying numbers of time units during which loss of load could occur.

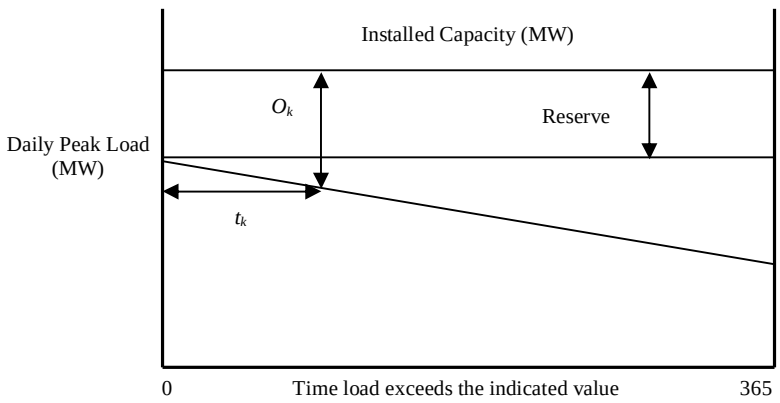


Fig. 37: Relationship between load, capacity and reserve

The period of study of the LOLE can be a week, a month or a year, being the annual approach the simplest application, with LOLE expressed in days per year (indicating the average number of days which a loss of load will be verified) [156].

LOLE with Renewable Energy Sources

Wind and hydro power cannot be adequately modelled by their capacity and FOR, since one has to count with the resource availability besides wind and hydro generators availability [232], [233]. According to [233], wind generators have typically very high electrical and mechanical availability, exceeding 95% in many instances. However, the "effective" forced outage rate for wind generators may be much higher, when recognizing the variability of wind. When it comes to reliability studies, for conventional generators, rated capacity, forced outage rates and specific maintenance schedules are the primary requirements. For an intermittent resource such as wind, at least one year of hourly power output is required.

The present research proposes to analyze wind and hydro power historical performance, in order to assess the impact on the reliability, once it provides "the most accurate fidelity for a backward-looking evaluation and is relatively simple to accomplish in most modelling frameworks", as highlighted in [234]. Through that approach, a vector is built gathering 365 daily wind power values at peak load periods, WP_i, taking into account that, essentially, only loads above 90% of the peak provide significant contributions to the system risk [235].

$$WP = [WP_1 \quad \cdots \quad WP_{365}] \tag{4. 53}$$

Hence, the wind power outage at peak load period of day i is given by the next equation.

$$O_i^{WP} = C^{WP} - WP_i \tag{4. 54}$$

Where,
O_i^{WP} is the wind power outage at peak load period of day i;
C^{WP} is the installed capacity of wind generation.

As performed for wind power, vectors for hydro power, HP_i, and daily peak load values, PL_i are also built.

$$HP = [HP_1 \quad \cdots \quad HP_{365}] \tag{4. 55}$$

$$PL = [PL_1 \quad \cdots \quad PL_{365}] \tag{4. 56}$$

Hydro power availability is treated, in this study, as wind power in terms of resource availability. Wind and hydro power values at daily peak load periods could result from just one annual series of data or, if possible, could be built from a study of several years.

According to methodologies proposed in [233], [232] and [236], a possible approach to include variable renewable energy sources into the methodology for LOLE calculation, is through the subtraction of the daily peak loads by the corresponding wind power and hydro power at peak load periods. That's to say, the available renewable power is treated as a negative load, leading to a modified vector of daily peak load values, MPL_i. This methodology is illustrated through the next equation.

$$MPL = PL - WP - HP \tag{4. 57}$$

Since in this research pumped hydro storage is planned for absorbing the energy surplus (which otherwise would be lost), the energy consumed for pumping isn't added to the system's load for generation adequacy assessment. Therefore, the load model for LOLE calculation doesn't take into account the additional load due to pumped hydro storage, since this strategy is understood as "service to the system" rather than "load to serve". Regarding the generation model, pumped hydro storage is treated as a conventional hydro power plant, at off-valley hours.
Concerning the electric mobility impact on the power system, the EVs' charging is disregarded, since it will occur during valley hours, having, as a result, no effect in the daily peak load curve. The V2G contribution is also neglected for the capacity adequacy assessment.

4.4 Summary and Main Conclusions

The current chapter encompassed the development of assignments for building a multicriteria energy planning methodology, aiming to enhance the sustainability of a given isolated system.

This section proposed a mathematical formulation for a set of criteria and attributes, namely:

- environmental impact (CO_2 emissions from transport sector and power systems);
- economic and financial costs (carbon-based costs; power generation costs; costs of centralized storage facility; costs of electric mobility; and costs of energy efficiency measures on the power system and transport sector);
- adequacy of the generation system (loss of load expectation index).

With this energy planning methodology, an isolated power system can be now addressed as case study.

Chapter 5

5 The São Miguel Island Case Study

5.1 Introduction

The methodology developed in this research is applied to São Miguel Island (Azores, Portugal), bearing in mind its power system characteristics and the local government's commitment to reach, by 2018, 40% of primary energy consumption from renewable energy sources. The required investments in renewable energy sources may include the reinforcement of Ribeira Grande geothermal facility, a new geothermal power plant or the reinforcement of Pico Vermelho geothermal facility, and a wind farm (already commissioned in the course of this work). Besides these power plants, other facilities could be commissioned such as further hydro power, biomass generation and centralized electricity storage, namely pumped hydro.

Taking into account the typical load and generation profiles of the concerned power system, the referred investments in renewable energy sources may lead to energy surplus. Hence, electricity storage options should be studied in order to enhance the sustainability of São Miguel Island. Concerning the demand-side, the impact of energy efficiency measures will also be assessed for this case study.

In what pertains to the transport sector, the local government vowed to promote the penetration of electric mobility. In addition to the study of electric vehicles' introduction in São Miguel Island, in this chapter other sustainable mobility options will be evaluated, namely efficient internal combustion vehicles, biofuels and behavioural change.

When it comes to the chapter organization, firstly the case study will be described in terms of its power system and transport sector. Afterwards, the alternatives for energy planning will be presented, as well as the input data for the attributes calculation. Finally, this chapter will draw the results obtained from the proposed methodology and a multi-attribute and multi-scenario analysis will be also carried out.

5.2 Overview on the Power System and Transport Sector

5.2.1 Power System

In what concerns past values of the demand, São Miguel's peak load has increased during the last few years and was registered in September, for 2000, 2001, 2004 and 2005, and December, for 2002, 2003, 2006 and 2007 [237]. In Annex I are depicted the annual and monthly peak loads for the last decade. The annual load has grown more than 3%/year for the last years. According to

forecasts provided in 2008, by São Miguel's local utility (EDA), the future demand is expected to keep rising, since there is a set of projected investments which will be responsible for additional electricity consumption [237]. Owing to the referred plans, the demand is expected to follow the following trend, with an average annual load increase of 3%.

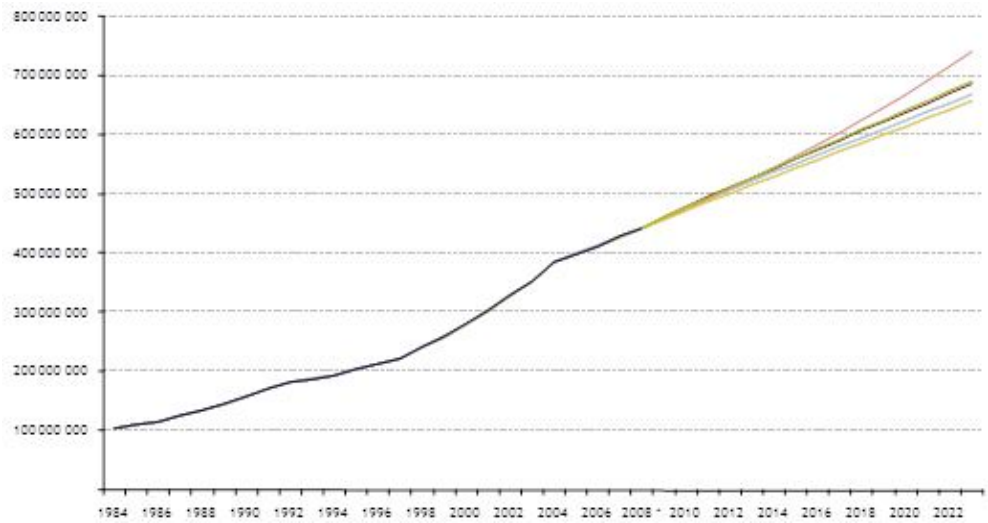


Fig. 38: São Miguel's generation forecast (kWh) [237]

Although the demand trend predicted by the local utility, the impact of energy efficiency measures on the system's load should be studied, as a result of the strategic energy plan vowed by the Regional Government in [238].

Regarding the supply side, in 2008 the generation system of São Miguel Island had roughly 130 MW of installed capacity with the following breakdown: one thermal power plant (Caldeirão) with 8 fuel oil units; two geothermal power plants (Ribeira Grande and Pico Vermelho); and seven small hydro power plants [237]. Detailed specification of these generation units are shown in Annex I and typical load/generation profiles are presented next.

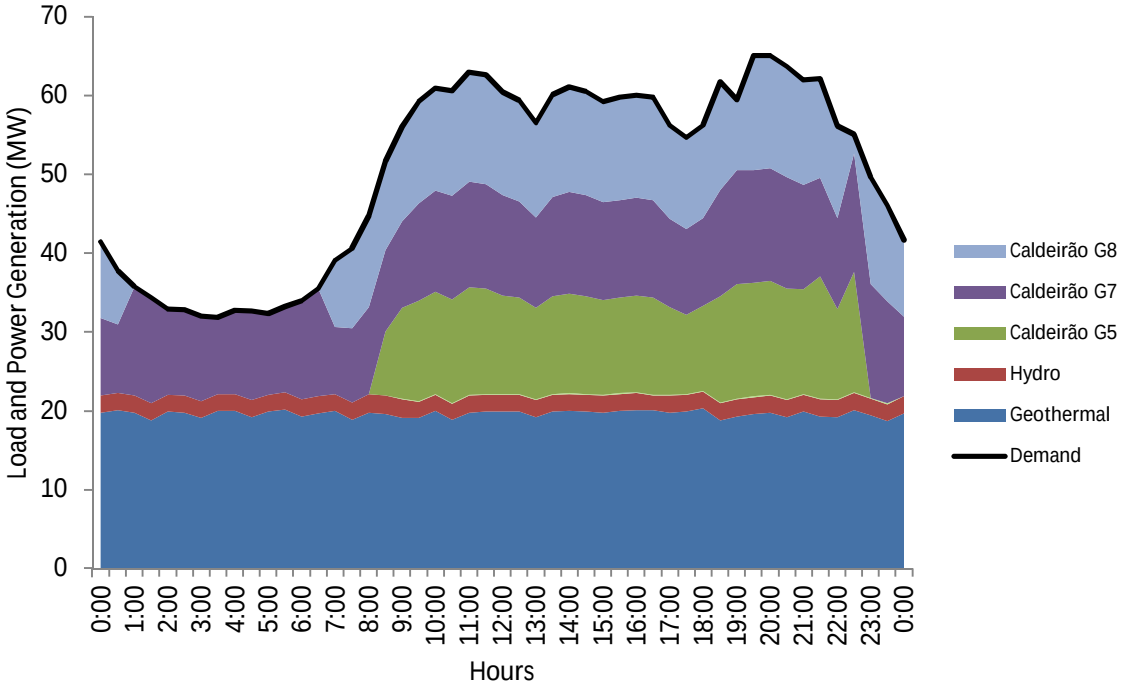


Fig. 39: Typical daily load and generation profiles, in 2008 (EDA)

Fuel oil and geothermal power generate together more than 90% of the demand, whereas the hydro facilities stand for approximately 5% of the load. Additionally, since there is a weather steadiness throughout the year, load and generation profiles appear similar for both winter and summer days. The previous load and generation profiles refer to the power system operation in 2008. More recently a 9 MW wind farm entered into operation (Graminhais).

In São Miguel Island, there is neither market for energy nor for reserve services. Through an analysis of the power system operation strategy, at least one 16,82 MW fuel oil unit is supposed to be in operation throughout the day, for frequency control purposes. In fact, hydro and geothermal units – and even electricity storage facilities and EV (through controllable charging and V2G) – could theoretically provide frequency control, but this research considers only regulation from fuel oil units.

When it comes to future investments on generation units, the local government pledged to reach, by 2018, 40% of primary energy consumption from renewable energy sources, and 50% of the global energy consumption from electricity [238]. As far as renewable energy is concerned, São Miguel's power system may receive the following investments [239]:

- 3 MW reinforcement of Ribeira Grande geothermal facility.
- Either build up a new geothermal facility (with 8-12 MW) or reinforce an already built power plant (Pico Vermelho) with further 10 MW. With the referred power upgrade, Pico

Vermelho would gather 20 MW of installed power and an annual average generation increase of 83 GWh. Concerning the new facility, EDA foresees an average generation of 67 to 100 GWh, per annum.

- In what regards to wind generation, in 2008, the Graminhais wind farm was studied, which would provide 9 MW of installed power and an expected annual average generation of 22,5 GWh. In fact, this wind farm has already been commissioned at the final stage of the current research.

5.2.2 Transport Sector

The fuel percentage of light vehicles in Azores, in 2003, was 56% of gasoline and 44% of diesel, and the total number of light vehicles was 91 850. It's worth mentioning that the diesel vehicles share is higher in the newest vehicles, than the verified for the gasoline ones, owing to the recent developments of diesel engines. Similarly, diesel vehicles share is higher in the oldest vehicles, than the verified for the gasoline ones, due to their higher lifetime. In what regards to future figures, TiS.PT states that by 2015 Azores will have 568 light vehicles/1000 inhabitants, which corresponds to a 42% increase over the 2003's figure (401 light vehicles/1000 inhabitants) [240].

Concerning the mileage from light vehicles, in Azores, this has been increasing during the last decades and that trend is likely to persist for the next few years. Taking into account the projected upgrades on São Miguel's roads and highways, light vehicles mileage is expected to grow above the GDP growth rate, by 2015. The mobility of passengers light vehicles is foreseen to be about 1 062 million vehicles-km by 2015, which corresponds to a 48,5% increase over 2003's value [240].
Accordingly, the Regional Government of Azores pledged, in 2008, to slump diesel and gasoline fuel consumption by 10%, in ten years. In view of that, clean technology-based vehicles, such as plug-in hybrid and electric vehicles, are planned to be supported. In addition, the Regional Government also vowed to promote the introduction, in the state-owned fleet, of hybrid mini-buses, plug-in hybrid and electric vehicles (in city journeys), and the destruction of end-of-life vehicles [238].

5.2.3 Electricity Storage Potential

São Miguel Island has a bold potential for electricity storage from renewable energy sources. In view of that, two sites have been selected for evaluating the suitability of pumped hydro storage, namely a seawater solution, in Feteiras district, or a freshwater solution, using Furnas' lake.

The freshwater solution envisages the construction of the upper reservoir with a 200m drop, in regards to the lower reservoir (the lake), as presented underneath [241].

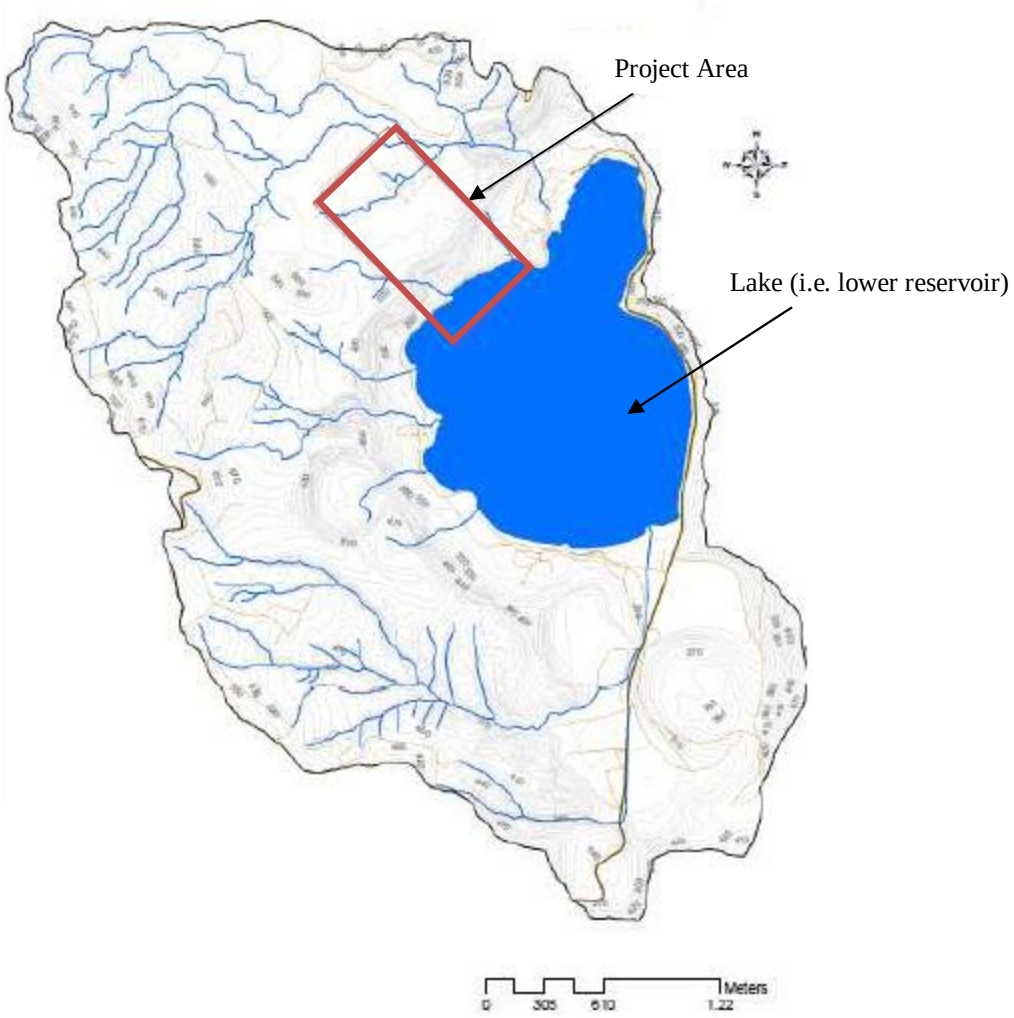


Fig. 40: Pumped hydro storage using Furnas' lake [241]

When it comes to the seawater solution, although São Miguel has 227,3km of shore width, there is lack of available sites for pumped hydro storage. Yet the Southwest of the island (Feteiras district) has adequate conditions for the project, with a head of over 250m [241].

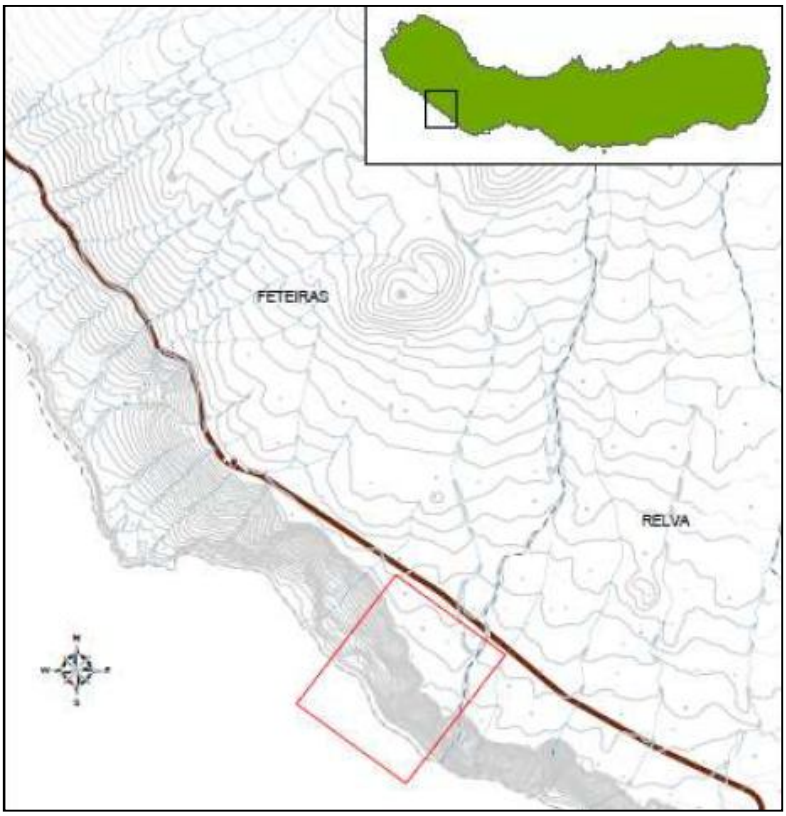


Fig. 41: Pumped hydro storage using the seawater solution [241]

5.3 Multicriteria Decision Aid for Planning São Miguel Island's Energy System

5.3.1 Introduction to the Problem

In this section, the proposed methodology for energy planning is applied in São Miguel Island, aiming to enhance the sustainability of that isolated system, through a multicriteria evaluation of renewable energy sources integration, plus electricity storage, sustainable mobility and the adoption of energy efficiency measures.

This methodology starts with the identification of potential hypotheses for energy planning, by considering the investments and policies announced by the regional authorities, and by building integrated strategies for both the power system and transport sector.

These alternatives for energy planning are then compared by the calculation of a set of attributes, namely: global carbon emissions as a result of energy use (transport and power system); economic and financial costs, which include carbon-based costs (if carbon emissions from the power system are accounted as a cost), power generation costs, costs of centralized storage facility, costs of electric mobility, and costs of energy efficiency measures (power system and transport sector); and when it comes to the adequacy of the generation system in terms of reliability, the loss of load expectation index is computed.

The calculation of these attributes is formulated in the decision maker's perspective and is based on an annual assessment, for two scenarios of prices. The chosen year for analysis was 2030, in order to evaluate the energy planning options through a long-term perspective, which is common in studies developed by entities such as the European Commission.

In the final stage of this study, a multi-attribute and multi-scenario analysis is performed, including auxiliary calculations for trade-offs and regret.

5.3.2 Alternatives Characterization

Overview

As stated in chapter 4, alternatives are defined by considering the investments and policies that are being studied by the decision maker, who is represented by the regional authorities of the analysed energy system. Hence, the alternatives identification reproduces a range of potential hypotheses for a given energy system, gathering a set of decision variables, i.e.: load variation associated to the adoption of energy efficiency measures; installed capacity of renewable energy sources; sustainable mobility options; and electricity storage strategies.

These alternatives for energy planning are built with the objective of enhancing the sustainability of São Miguel Island, in terms of environmental impact, economic and financial costs, and adequacy of the generation system.

Energy Efficiency Measures on the Load

Some alternatives follow an energy efficiency pathway, as a result of thriving dedicated programs for demand response, demand side management, load control and sustainable buildings. So, in what regards to electric energy demand variation, there are two pathways: annual demand increase (as foreseen by the utility); or annual demand decrease (by implementing energy efficiency measures).

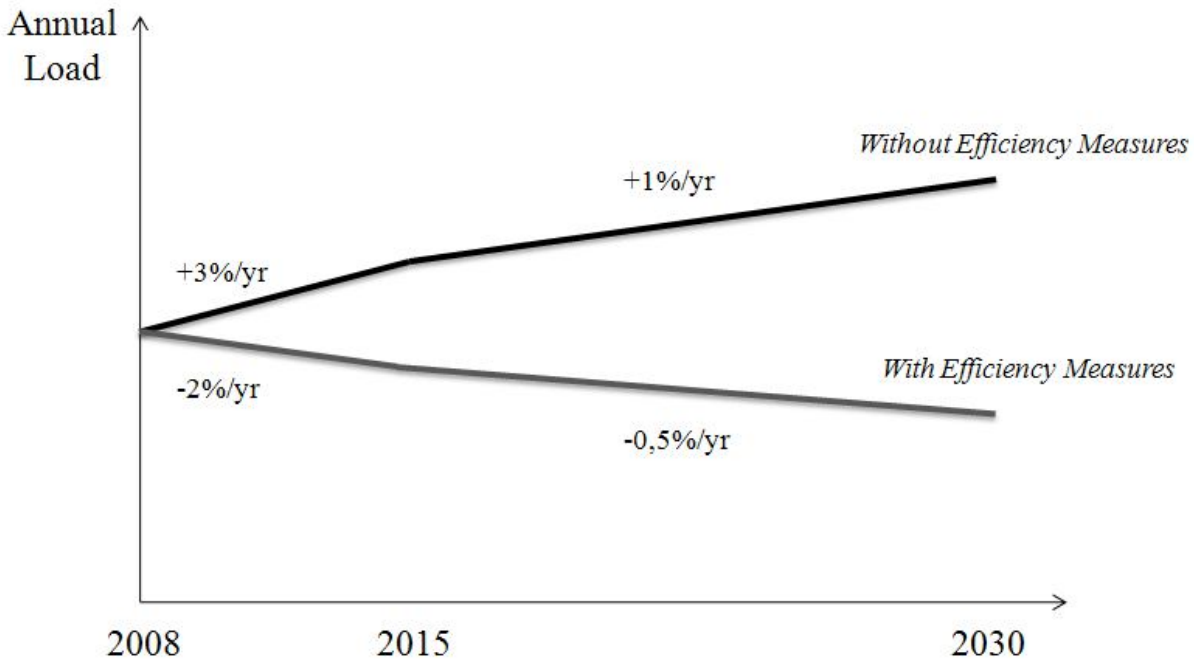


Fig. 42: Load variation pathways for the case study

For the alternatives without energy efficiency measures, the annual load increase pace is assumed to drop after 2015 (from +3%/year to +1%/year), bearing in mind the business-as-usual improvements on the appliances' efficiency as well as on the consumers' awareness.

When it comes to the alternatives with energy efficiency measures, the load decrease range is assumed to slow down after 2015 (from -2%/year to -0,5%/year). That's to say, the efficiency potential will drop a few years after these alternatives' implementation. The building process for the energy efficiency path followed the trends presented in section 3.3.5.

Pathways for Renewable Energy Sources

When it comes to the energy mix, one has defined three hypotheses for the capacity of RES: business-as-usual (just scheduled RES capacity); mid-range RES increase; or high-range RES increase. The next figure shows these pathways for RES capacity, including the following energy sources (adjusted with the studies made by the regional authorities): geothermal; hydro; wind; and biomass.

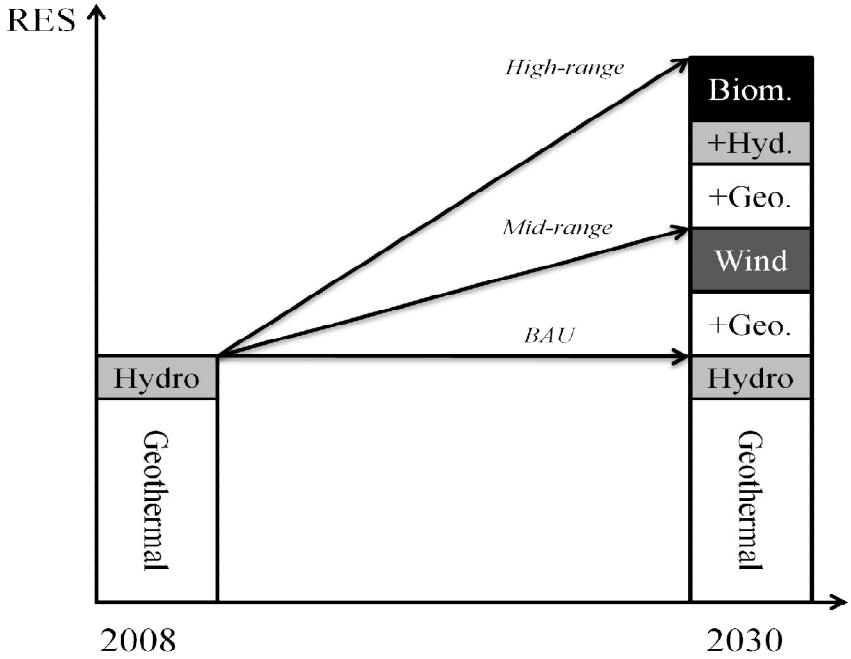


Fig. 43: Pathways for RES for the case study

The next table sketches out the installed capacity for each pathway.

Table 8 – Pathways for RES

Pathways for RES	Installed Capacity (MW)			
	Wind	**Hydro**	**Geothermal**	**Biomass**
High-range	9	9	47	10
Mid-range	9	5	37	0
BAU	0[1]	5	24	0

Transport Sector

For the transport sector, three options were identified towards sustainable mobility, namely:

- Strategy based on efficient ICVs, biofuels and behavioural change;
- Strategy based on the introduction of 5 000 EVs (which correspond to 7,5% of São Miguel's light vehicles fleet);
- Strategy based on the introduction of 10 000 EVs (which correspond to 15% of São Miguel's light vehicles fleet).

In this study, the transport sector is subject to a certain sustainable mobility strategy (one of the previous three), for all the alternatives.

[1] This hypothesis existed in 2008, but recently a 9 MW wind farm was commissioned. Nevertheless, this hypothesis was kept for the development of this research.

Concerning the EVs figures, these were built in order to internalize the trends of some recent forecasts for electric mobility rollout, as presented in section 2.3.

Electricity Storage

Finally, regarding electricity storage strategies, the next alternatives were defined: centralized storage facility (i.e. pumped hydro storage) and/or EVs charging, including the V2G concept. Besides the mobility goal (which should be preserved), the EVs may also contribute for the power system operation, by consuming a certain share of the energy surplus (EVs charging) and injecting just a part of the stored energy into the grid, through V2G.

The installed power of the centralized storage facility was identified, after projecting the load and generation profiles by 2030, in order to identify the daily energy surplus. The CSF installed capacity is set up to store the maximum amount of power surplus (i.e. 20 MW). The electricity storage facility's characteristics are presented in the next section.

Having presented the decision variables for the current problem, a set of potential alternatives for energy planning in São Miguel Island should now be built, including all the hypotheses for combining the decision variables, excluding the ones which result from the next conditions:

- The strategies for electric mobility are not independent from the strategy based on efficient ICVs, biofuels and behavioural change. That's to say, when the latter is adopted, this study assumes that there will not be introduced EVs and, as a consequence, V2G is obviously disregarded. But the centralized storage facility can be commissioned together with efficient ICVs, biofuels and behavioural change.
- The transport sector is subject to a certain sustainable mobility strategy (efficient ICVs, biofuels and behavioural change; 5 000 EVs; or 10 000 EVs), for all the alternatives. That's to say, this study disregards the absence of a sustainable mobility strategy.
- When there is an introduction of 10 000 EVs, the centralized storage facility is not installed. On the other hand, the strategy based on 5 000 EVs is always implemented together with the centralized storage facility. In both cases (10 000 and 5 000 EVs), V2G can be either performed or not.

These conditions were made after studying the energy system of São Miguel Island, and the interactions between the different individual options. The potential alternatives for energy planning are sketched out through the next figure.

Table 9 – Alternatives for energy planning of São Miguel Island

Energy Efficiency Measures on the Load	Renewable Energy Increase	Efficient ICVs, biofuels and behavioural change	Electric Mobility (Number of EVs)	Centralized Storage (Installed Capacity of Pumped Hydro Storage)	Vehicle-to-Grid	Alternative Number
No	High-range	Yes	No (0 EVs)	Yes (20 MW)	No	1
				No (0 MW)		2
		No	Yes (10 000 EVs)	No (0 MW)	Yes	3
					No	4
			Yes (5 000 EVs)	Yes (20 MW)	Yes	5
					No	6
	Mid-range	Yes	No (0 EVs)	Yes (20 MW)	No	7
				No (0 MW)		8
		No	Yes (10 000 EVs)	No (0 MW)	Yes	9
					No	10
			Yes (5 000 EVs)	Yes (20 MW)	Yes	11
					No	12
	BAU	Yes	No (0 EVs)	Yes (20 MW)	No	13
				No (0 MW)		14
		No	Yes (10 000 EVs)	No (0 MW)	Yes	15
					No	16
			Yes (5 000 EVs)	Yes (20 MW)	Yes	17
					No	18
Yes	High-range	Yes	No (0 EVs)	Yes (20 MW)	No	19
				No (0 MW)		20
		No	Yes (10 000 EVs)	No (0 MW)	Yes	21
					No	22
			Yes (5 000 EVs)	Yes (20 MW)	Yes	23
					No	24
	Mid-range	Yes	No (0 EVs)	Yes (20 MW)	No	25
				No (0 MW)		26
		No	Yes (10 000 EVs)	No (0 MW)	Yes	27
					No	28
			Yes (5 000 EVs)	Yes (20 MW)	Yes	29
					No	30
	BAU	Yes	No (0 EVs)	Yes (20 MW)	No	31
				No (0 MW)		32
		No	Yes (10 000 EVs)	No (0 MW)	Yes	33
					No	34
			Yes (5 000 EVs)	Yes (20 MW)	Yes	35
					No	36

5.3.3 Attributes Calculation

5.3.3.1 CO_2 emissions

The carbon emissions from the transport sector (light ICVs) and power system are computed through the methodology presented in section 4.3.2 and by integrating the next input parameters.

Table 10 – Parameters for the carbon emissions attribute

Parameter	Value	Source
Number of light vehicles	66 336	[240], [242]
Share of diesel light vehicles	50 %	Assumption based on [240]
Share of gasoline light vehicles	50 %	Assumption based on [240]
Daily mileage of light vehicles	35 km	[243]
Well-to-wheel emissions factor of diesel light vehicles	156 gCO_2/km	[65]
Well-to-wheel emissions factor of gasoline light vehicles	172 gCO_2/km	[65]
Emissions factor (including processing and extraction, transport of raw material, and electricity generation) owing to fuel oil electricity generation	0,8 $tonCO_2$/MWh	[212], [244]

When it comes to the share of fuel types in the transport sector, one assumed 50% of diesel and 50% of gasoline light vehicles, which corresponds to an increase of diesel ICVs' current percentage, according to the expected light vehicles' trend [240].

Concerning the environmental impact of biomass power plants, the corresponding carbon emissions are assumed neglectable in this study. The works done by [245] and [246] highlight that biomass power plants can have emission factors ($tonCO_2$/MWh) near zero.

5.3.3.2 Total annual costs

Scenarios for Prices

During the last years one has noticed a bold turbulence on the energy markets. In 2008, the oil prices fluctuated swiftly between 150 $ and 50 $, within just six months [113]. When it comes to the carbon price in the EU ETS, during its first trading period the European Union Allowances (EUA) dropped sharply from 30 €/$tonCO_2$ to near 0 €/$tonCO_2$ in less than half year [115].

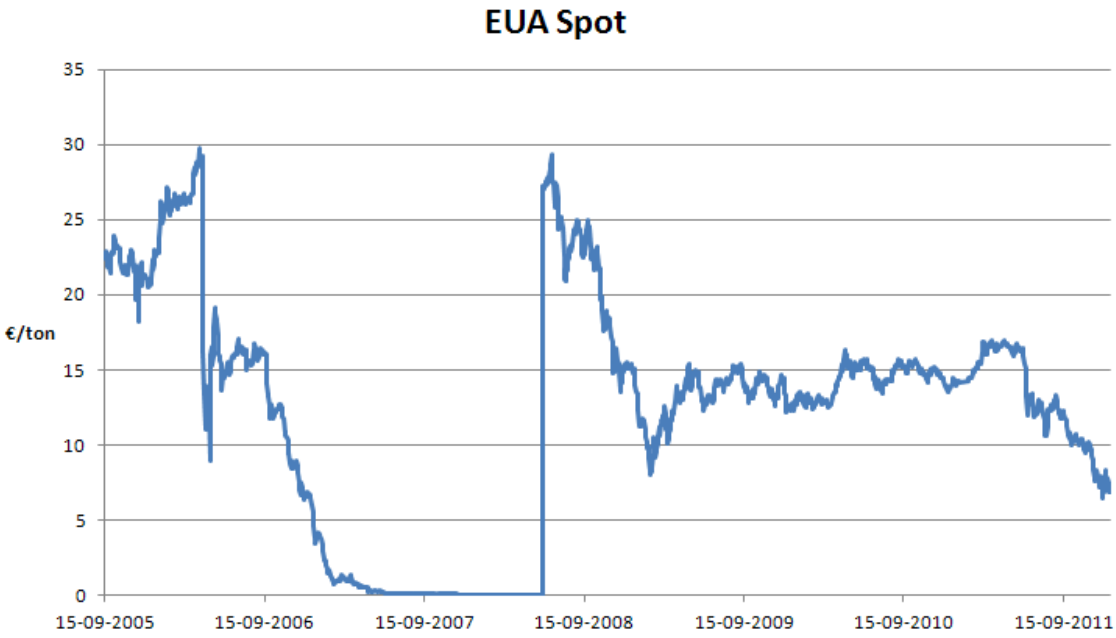


Fig. 44: ETS outlook, data from [247]

Therefore, it is worth analysing the forecasts carried out by some studies, regarding oil and carbon prices for the 2015-2030 perspective.

Table 11 - Oil prices forecast [113], [248], [249], [153], [250]

Source	Year	Value	Unit	EUR
Barclays Capital	2020	185	$(2011)/bbl	132
European Commission	2020	88	$(2007)/bbl	65
PIRA	2020	110	$(2008)/bbl	75
IHS	2020	81	$(2008)/bbl	55
US Energy Information Administration	2020	108	$(2008)/bbl	73
International Energy Agency	2020	100	$(2008)/bbl	68
WM	2020	101	$(2008)/bbl	69
European Climate Foundation	2050	115	$(2009)/bbl	83
McKinsey&Company (high scenario)	2030	120	$(2008)/bbl	82
McKinsey&Company (low scenario)	2030	60	$(2008)/bbl	41
Daiwa Institute of Research	2015-2020	100	$(2008)/bbl	68

Table 12 - Carbon prices forecast [113], [248], [249], [153], [250], [251], [103]

Study	Year	Value	Unit
European Commission - ETS (high pledge scenario)	2020	30	€/ton
European Commission - ETS (low pledge scenario)	2020	16	€/ton
European Climate Foundation (high scenario)	2050	40	€/ton
European Climate Foundation (low scenario)	2050	0	€/ton
European Climate Foundation (average scenario for the next 40 years)	2010-2050	20-30	€/ton
Eurelectric	2030	39	€/ton
International Energy Agency	2050	20	€/ton
Stern Review	2020	30	€/ton
JP Morgan	post-2012	30	€/ton
Deutsche Bank	2020	40	€/ton
New Carbon Finance	2020	24	€/ton
European Climate Exchange	2020	18	€/ton
IHS	2018	22	€/ton
Daiwa Institute of Research	2015	18	€/ton
Daiwa Institute of Research	2020	24	€/ton
Point Carbon	2020	16	€/ton

When it comes to the electricity prices forecasts, the Portuguese Government (Ministry for Economy and Employment) and EDP – Energias de Portugal estimated 3,4% to 4,5% of annual nominal increase, for the next years [252], [253]. In addition, Eurelectric foresaw a real annual increase of electricity prices ranging from 2,6% to 2,8%, as average trend for the current decade [251].

Taking into account the uncertainty regarding the oil, carbon and electricity prices forecasts, two scenarios are defined for this case study, i.e. “high prices” scenario and “low prices” scenario.

- “High prices” scenario (prices in 2030):
  - Oil: 80 €/bbl;
  - Carbon: 30 €/tonCO_2
  - Electricity: annual increase of 3,4% (nominal).
- “Low prices” scenario (prices in 2030):
  - Oil: 40 €/bbl;
  - Carbon: 16 €/tonCO_2;
  - Electricity: no annual increase (i.e. 2010 rates).

Carbon-based costs

The carbon-based costs are computed through the methodology presented in section 4.3.3.2. For the present case study, the National Allocation Plan for the second EU ETS period (2008-2012), capped the CO_2 emissions from Caldeirão (fuel oil) power plant at 245 432 ton CO_2/year [254]. The Caldeirão's emissions cap in 2030 is, then, computed by annually decreasing the emissions cap established for ETS II, by a linear factor of 1,74%.

Table 13 – Parameters for the calculation of carbon-based costs

Parameter	Value	Source
Emissions factor (including processing and extraction, transport of raw material, and electricity generation) owing to fuel oil electricity generation	0,8 tonCO_2/MWh	[212], [244]
Average auctioning price of allowances in the EU ETS	"High prices" scenario: 30,0 €/tonCO_2 "Low prices" scenario: 16,0 €/tonCO_2	[113], [248], [249], [153], [118]
Average EUAs price in the secondary market (i.e. spot, forwards, organized and OTC) for additional allowances	"High prices" scenario: 24,0 €/tonCO_2 "Low prices" scenario: 12,8 €/tonCO_2	

Power Generation Costs

The power generation costs are computed through the methodology presented in section 4.3.3.3. It should be emphasized that for the analysed case study, the weather pattern throughout the year was assumed steady, bearing in mind local conditions. Moreover, a typical wind power profile was collected from past registers of wind farms in the Azores Archipelago (i.e. Terceira Island). São Miguel's typical load, hydro and geothermal profiles were also identified and are provided in Annex I.

Taking into account the identified alternatives for energy planning, none of them included reinforcement of non-renewable energy sources, which leads to absence of capital costs from these generation types. Concerning fuel oil generation, typically this technology has a lifetime of 25-40 years [229]. Therefore, some fuel oil units will be decommissioned by 2030, which, for this study, were assumed to be two units (one of 7,7 MW and the other of 16,8 MW). The corresponding costs for decommissioning are disregarded in this research.

Concerning renewable energy sources, a feed-in tariff is assigned to each type of power generation, by including both capital and operation costs, as described in section 4.3.3.3. Since for some alternatives, a part or even all the energy surplus won't be absorbed (depending on the electricity storage strategy), that unused amount of available renewable energy sources won't generate operation costs. One assumed that in those circumstances, geothermal power plants should adjust their power output, enabling the integration of wind and hydro, through a ramp down procedure.

Although currently there are geothermal units capable to provide frequency control, in this research this regulation is not considered. Frequency control is assumed to be provided only by fuel oil units, without receiving any type of service remuneration.
The next table presents the required input parameters for cost calculation.

Table 14 – Parameters for the calculation of power generation costs

Parameter	Value	Source
Costs of fuel consumption (fuel oil units)	"High prices" scenario: 0,66 €/kg "Low prices" scenario: 0,33 €/kg	[255]
Maintenance cost (fuel oil units)	5 €/MWh	[256]
Start-up costs (fuel oil units)	100 €	Assumption based on [256]
Shut-down (fuel oil units)	50 €	Assumption based on [256]
Wind generation cost (electric energy)	74 €/MWh	Based on the Portuguese feed-in tariff [257]
Hydro generation cost (electric energy)	75 €/MWh	Based on the Portuguese feed-in tariff [257]
Geothermal generation cost (electric energy)	84 €/MWh	Based on the local utility's costs [258]
Biomass generation cost (electric energy)	107 €/MWh	Based on the Portuguese feed-in tariff [257]

When it comes to fuel costs, the specific fuel consumption at different points of operation is known [256]. With this data a polynomial interpolation was made, followed by a linearization to describe the fuel consumption at different power levels, for each unit type. The linear equation that describes the fuel consumption of each unit, at a certain power output, is combined with the corresponding cost of fuel.

Concerning spinning reserve, one has assumed that this should be enough to handle the outage of the largest power unit in service, as followed by some system operators [224], [225]. Since the algorithm for unit commitment and economic dispatch assumes that at least one 16,8 MW unit must be operating all over the day (biggest fuel oil unit type) – for frequency control – the spinning reserve is computed with 16,8 MW, corresponding to the installed power of the largest power unit in service.

Costs of Centralized Storage Facility

As described previously, in São Miguel, pumped hydro storage can be performed by either the seawater solution (in Feteiras district) or through the use of a lake as lower reservoir (Furnas' lake). According to a recent environmental impact assessment, although the fresh-water storage is less expensive and technologically easier for local circumstances, it leads to significantly more ecological and geological externalities than the seawater solution. The referred study, hence, advocated for the adoption of the seawater project, emphasizing as well that environmental and technical constraints can be overcome by the use of measures applied in Okinawa pilot-project (Japan) [241].

Therefore, this case study assumes the adoption of the seawater storage technology, resulting from the environmental impact assessment. Anyway, sensitivity analysis could be conducted for this power system, in case of admitting the installation of a fresh-water system, by using the methodology described in this research. In that case, the input data would be different, mostly when it comes to the facility's capital costs.

The CSF costs are computed through the methodology presented in section 4.3.3.4 and by integrating the next input parameters.

Table 15 – Parameters for the calculation of costs of centralized storage facility

Parameter	Value	Source
Maximum depth of discharge	95 %	[47]
Energy transformation (round-trip) efficiency of the storage system	80 %	[23]
Specific energy cost	10 €/kWh	[47]
Specific power cost	500 €/kW	[259], [23], [260], [261], [47]
Additional capital cost owing to the corrosion prevention measures for seawater technology	15 %	[23]
Local electricity selling price for the off-valley-hour rate	"High prices" scenario: 0,255 €/kWh "Low prices" scenario: 0,122 €/kWh	To formulate this price, one assumes that the demand for CSF's generation will be evenly split between residential and commerce and industry customers, based on the report presented by [262]. The prices trend is supported by [263], [264], [253]
Local electricity purchase cost for the valley-hour rate	"High prices" scenario: 0,104 €/kWh "Low prices" scenario: 0,050 €/kWh	
Fraction of the initial capital invested, for the fixed maintenance cost	0,25 %	[47]
Discount rate	8 %	[265], [153]
Investment period	25 years	

The CSF pumps water (stores) whenever there is energy surplus (expectedly during valley hours) and generates electricity throughout off-valley hours, assuming a constant power output through this period and fulfilling the operating rules established by the algorithm for fuel oil plants' unit commitment and economic dispatch.

Costs of Electric Mobility

The EM costs are computed through the methodology presented in section 4.3.3.5 and by integrating the next input parameters.

Table 16 – Parameters for the calculation of costs of electric mobility

Parameter	Value	Source
Local electricity selling price for the valley-hour rate	"High prices" scenario: 0,155 €/kWh "Low prices" scenario: 0,074 €/kWh	The prices trend is supported by [263], [264], [253]
Local electricity purchase cost for the valley-hour rate	"High prices" scenario: 0,104 €/kWh "Low prices" scenario: 0,050 €/kWh	
Local electricity selling price for the off-valley-hour rate	"High prices" scenario: 0,288 €/kWh "Low prices" scenario: 0,138 €/kWh	
Efficiency of the EV conversion of energy storage back to electricity	93%	[70]
Battery capital cost, including replacement labour	8 000 €	[266], [267]
Lifetime in cycles (for the corresponding depth-of discharge)	2 000	
Total energy storage of the battery	27,4 kWh	[70]
Depth-of-discharge	80%	
Capital Cost (Network Management tool + Business and Operations Management tool + Smart Payment System + CPs)	Software: €1 million CP: 750€/unit	Software licences for 50 000 CPs, with capital costs based on: Energy Data Management SW – San Diego Gas and Electric [268]; Smart Card Prepayment System – UK's market [269]; Meter Data Management SW – EU pilot-projects [270]. 1 CP/ EV and cost based on [71]
Discount rate	8%	[265], [153]
Investment period	25 years	

The EM in São Miguel assumes also an energy consumption/EV of 0,2 kWh/km [267], [271], and 9% of losses in the power grids [239]. For a daily mileage of 35 km, each EV will lead to an energy

demand of 7,7 kWh for mobility. This research assumes that just ¼ of the battery's energy is available for V2G (i.e. 7,5 kWh for a 27,4 kWh battery).

The next figure shows the assumed charging profile for one EV (without the additional energy for V2G), in order to maximize the renewable generation surplus.

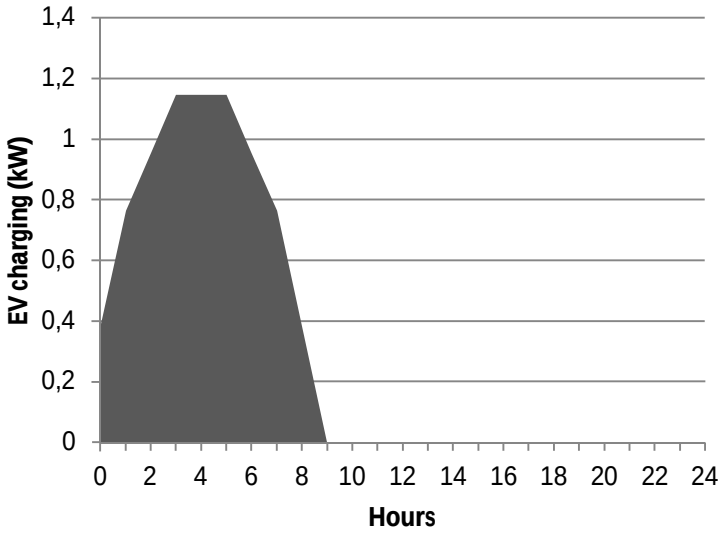


Fig. 45: Preferred load profile for charging one EV

The previous figure illustrates the preferred charging profile of EVs, usually called "smart charging". Although some EVs could opt for another charging profile, the current study assumes that the smart charging strategy is adopted by EVs.

The charging profile of an EV that performs V2G should add to the previous load profile the corresponding energy for that purpose, as bellow presented.

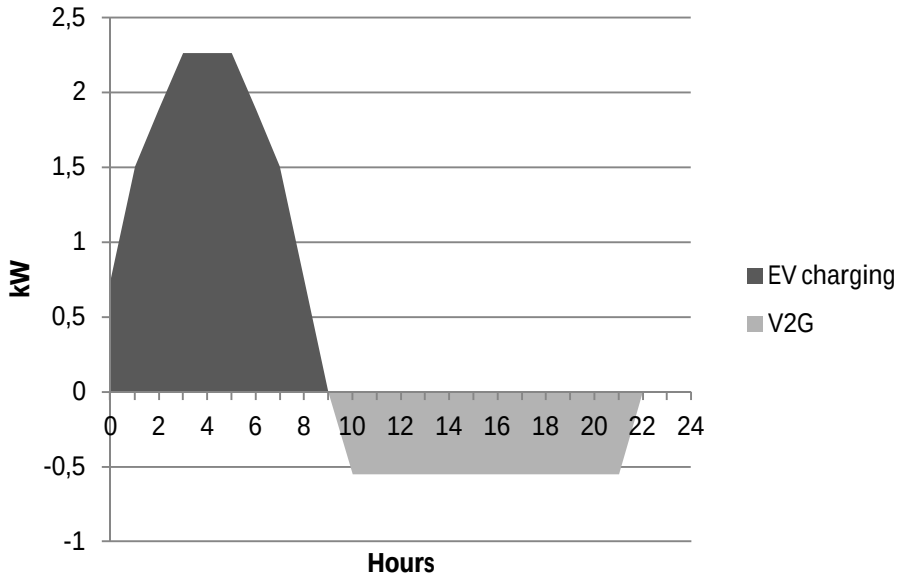


Fig. 46: Load profile for charging one EV including the V2G impact

The V2G contribution for the power system considers network and battery conversion losses, totalling 22% (grid-battery-grid) [70], [239].

When it comes to the capital costs, these are assumed to be supported by the EM investor and operator (i.e. local utility). The profits concerned with the EM investment and operation depend on the margin driven by the electricity trading for providing the EVs charging service.

Costs of Energy Efficiency Measures

The costs of energy efficiency measures are computed through the methodology presented in section 4.3.3.6 and by integrating the next input parameters.

Table 17 – Parameters for the calculation of costs of energy efficiency measures

Parameter	Value	Source
Parameters of the linear equation for the energy efficiency costs	*a*: 6,6 *b*: 98,3 These values are expressed in thousand €/GWh	[140], [231]
Annual abatement potential owing to efficient ICVs	0,46%	[151]
Annual abatement potential by improving the traffic flow	0,02%	
Annual abatement potential owing to improved driving behaviour	0,02%	
Annual abatement potential by reducing the distance driven	0,02%	
Annual abatement potential by blending low carbon biofuel	0,09%	
Conversion factor for the ICVs energy consumption	0,25 kgCO2/kWh	[272]

Regarding energy efficiency applied on the transport sector, in order to compare the competing strategies for sustainable mobility and to assess their results over the base year, the number of light vehicles is assumed constant from the base year to the target year. Additionally, for the electric mobility strategy a daily mileage of 35 km is assumed for the light vehicles, both for the base year and target year [273]. On the contrary, the alternatives with energy efficiency measures will improve that figure, through behavioural changes.

These assumptions are made in order to compare the EM and ICV-based sustainable mobility contributions, with a common transport profile.

5.3.3.3 LOLE

The LOLE calculation follows the methodology described in section 4.3.4 and considers the next reliability input parameters (assuming the decommissioning of two fuel oil units that are still currently operating, as presented in section 5.3.3.2), for the forced outage rates (FOR)

Table 18 – Parameters for the LOLE calculation [274]

Power Plant	FOR
Caldeirão G1 (fuel oil)	0,00277
Caldeirão G2 (fuel oil)	0,00277
Caldeirão G3 (fuel oil)	0,00355
Caldeirão G4 (fuel oil)	0,00400
Caldeirão G5 (fuel oil)	0,00400
Caldeirão G6 (fuel oil)	0,00400
Geothermal Pico Vermelho	0,00300
Geothermal Ribeira Grande	0,00300
Biomass	0,00300

For LOLE computing, the modified peak load variation curve is built by collecting São Miguel's daily load, hydro and wind power profiles, taking into account the assumptions presented in section 5.3.3.2 (Power Generation Costs).

5.3.4 Results in 2030

5.3.4.1 Methodological Framework

The previously described attributes are now computed for the year 2030, in order to evaluate the energy planning options through a long-term perspective. The attributes calculation is done for two scenarios of prices, as mentioned in section 5.3.3.2, i.e.: "high prices" scenario; and "low prices" scenario.

The results to present in this chapter follow the two methodologies proposed in section 4.2.2. That is to say, firstly carbon emissions from the power system are accounted as a cost, in the scope of the EU Emissions Trading Scheme. Subsequently, carbon costs are disregarded and the corresponding power system's emissions are accounted in the environment impact criterion. This last methodology will be adopted throughout the results analysis, since the multicriteria assessment of the alternatives (namely comparing costs and emissions) becomes clearer and more comprehensive, when carbon

emissions from the power system are accounted through an environmental attribute, rather than by an economic attribute

5.3.4.2 "High Prices" Scenario

The prices variation between the two scenarios (high and low prices), is rooted on different trends for oil, carbon and electricity prices by 2030. The next table presents the results of the proposed methodology in 2030, for the "high prices" scenario, considering the power system's emissions as costs.

Table 19 - Total annual carbon emissions, costs and LOLE for “high prices” scenario in 2030, including power system’s carbon emissions as costs

	Annual CO_2 emissions (kton)	Total Annual Costs (million Euros) - 2030						LOLE (days/year)
Alternative	Transport Sector (ICVs)	Carbon -based costs	Energy Efficiency measures	Power Generation	CSF[1]	EM[2]	TOTAL	
1	**121,76**	4,46	0,76	57,38	-2,57	0	**60,03**	**0,004**
2	**121,76**	5,04	0,76	58,05	0	0	**63,85**	**0,065**
3	**118,03**	4,93	0	60,16	0	-3,74	**61,35**	**0,065**
4	**118,03**	5,09	0	60,08	0	-0,61	**64,56**	**0,065**
5	**128,50**	4,67	0	58,58	-0,03	-1,77	**61,45**	**0,004**
6	**128,50**	4,68	0	59,06	-1,25	-0,26	**62,24**	**0,004**
7	**121,76**	7,52	0,76	61,29	1,13	0	**70,69**	**0,130**
8	**121,76**	7,52	0,76	61,29	0	0	**69,57**	**0,846**
9	**118,03**	8,13	0	64,44	0	-3,74	**68,83**	**0,846**
10	**118,03**	8,07	0	62,93	0	-0,61	**70,39**	**0,846**
11	**128,50**	7,83	0	60,86	1,13	-1,77	**68,04**	**0,130**
12	**128,50**	7,79	0	62,42	1,13	-0,26	**71,09**	**0,130**
13	**121,76**	10,02	0,76	69,52	1,13	0	**81,42**	**1,057**
14	**121,76**	10,02	0,76	69,52	0	0	**80,30**	**9,308**
15	**118,03**	10,63	0	72,21	0	-3,74	**79,10**	**9,308**
16	**118,03**	10,57	0	72,91	0	-0,61	**82,87**	**9,308**
17	**128,50**	10,32	0	70,66	1,13	-1,77	**80,34**	**1,057**
18	**128,50**	10,29	0	71,64	1,13	-0,26	**82,80**	**1,057**
19	**121,76**	2,15	1,22	41,07	38,08	0	**82,52**	**4E-08**
20	**121,76**	2,15	1,22	30,16	0	0	**33,54**	**1E-06**
21	**118,03**	2,15	0,46	32,50	0	-0,61	**34,51**	**1E-06**
22	**118,03**	2,15	0,46	32,50	0	-0,61	**34,51**	**1E-06**
23	**128,50**	2,15	0,46	42,24	14,63	-0,26	**59,22**	**4E-08**
24	**128,50**	2,15	0,46	42,24	14,63	-0,26	**59,22**	**4E-08**
25	**121,76**	2,53	1,22	33,08	1,09	0	**37,92**	**2E-06**
26	**121,76**	2,95	1,22	28,38	0	0	**32,55**	**2E-05**
27	**118,03**	2,66	0,46	31,85	0	-3,53	**31,43**	**2E-05**
28	**118,03**	2,95	0,46	30,71	0	-0,61	**33,52**	**2E-05**
29	**128,50**	2,40	0,46	30,95	-0,90	-1,56	**31,35**	**2E-06**
30	**128,50**	2,48	0,46	31,51	-1,02	-0,26	**33,17**	**2E-06**
31	**121,76**	4,42	1,22	32,84	0,88	0	**39,37**	**7E-06**
32	**121,76**	4,46	1,22	33,25	0	0	**38,93**	**2E-04**
33	**118,03**	5,02	0,46	31,57	0	-3,74	**33,31**	**2E-04**
34	**118,03**	4,96	0,46	32,94	0	-0,61	**37,75**	**2E-04**
35	**128,50**	4,72	0,46	30,74	1,13	-1,77	**35,27**	**7E-06**
36	**128,50**	4,69	0,46	32,62	1,13	-0,26	**38,64**	**7E-06**

[1] Centralized Storage Facility
[2] Electric Mobility

The previous results are drawn for an annual basis, for the year 2030, as explained in section 5.3.1. Accordingly, the next graphs are built in order to show the relationship between the total annual costs and the other attributes.

Firstly, the next graph presents the alternatives results for the attributes referred to Total Annual Costs (in million Euros) and Annual CO_2 Emissions from ICVs (in kton). One should highlight that carbon emissions from the power system are accounted within total annual costs, in the scope of the EU Emissions Trading Scheme.

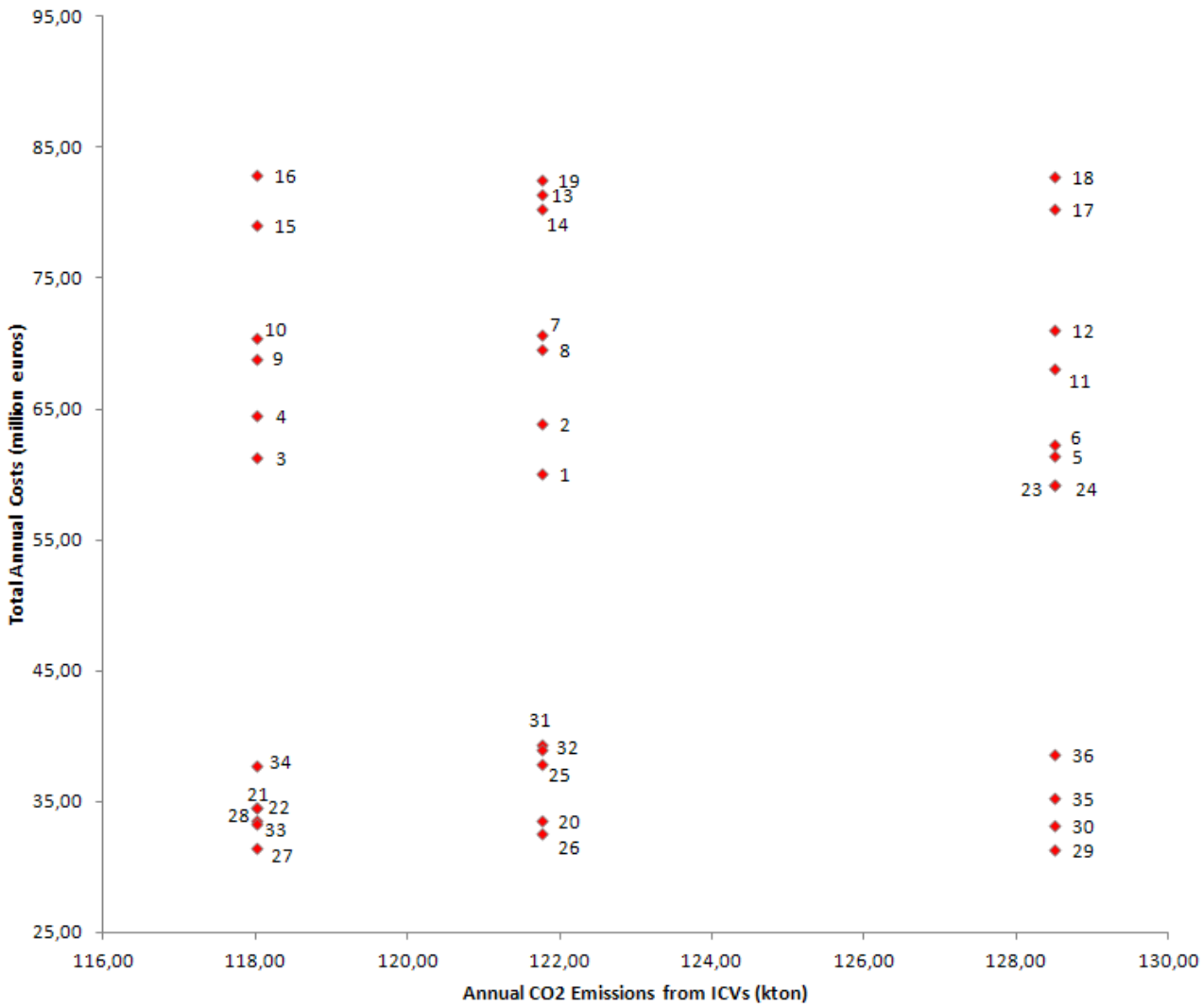


Fig. 47: Total annual costs and carbon emissions of the alternatives in 2030, for the "high prices" scenario, including power system's carbon emissions as costs (1)

The previous graph shows, basically, six groups of alternatives, in terms of electric mobility and energy efficiency measures on the load, as presented below.

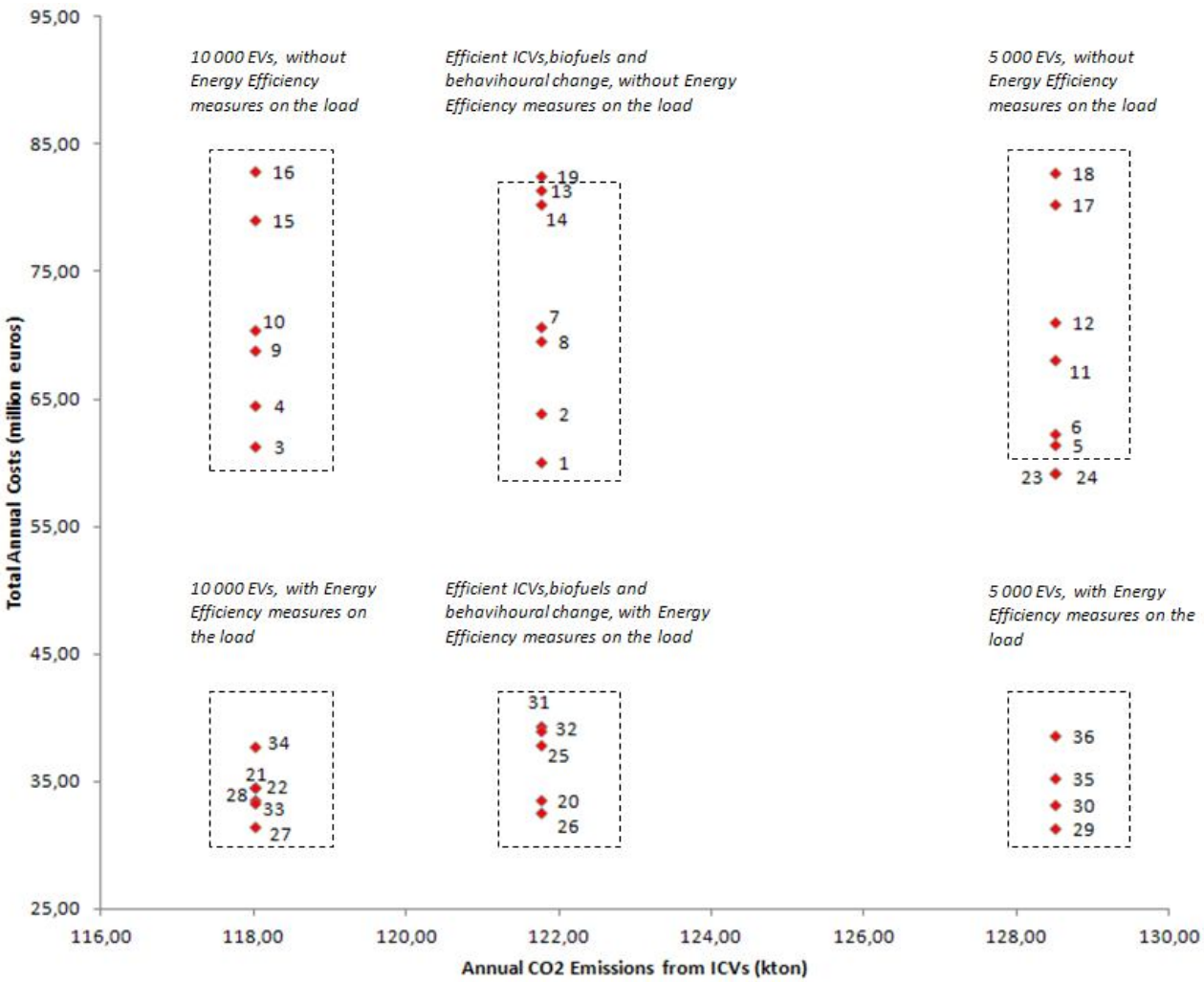


Fig. 48: Total annual costs and carbon emissions of the alternatives in 2030, for the "high prices" scenario, including power system's carbon emissions as costs (2)

Although the relevance of the previous plots, in fact it's hard to identify the relationship between total costs and corresponding global emissions (power system plus ICVs), since the CO_2 emitted by power generation units is accounted as a carbon cost according to the EU ETS (cap-and-trade). That carbon accountability is indeed followed by the energy planning divisions of GENCOs and governmental institutions, but leads to lack of environmental understanding, in view of a multicriteria assessment.

In view of this worry, the obtained results are now presented by disregarding carbon costs (within total annual costs) and adding the power system's CO_2 emissions to the ICVs emissions, as described by equation (4. 2).

Table 20 – Total annual carbon emissions, costs and LOLE for "high prices scenario" in 2030, including power system's carbon emissions in the environmental attribute

	Annual CO_2 emissions (kton)	Total Annual Costs (million Euros) - 2030					LOLE (days/year)
Alternative	Power System plus Transport Sector (ICVs)	Energy Efficiency measures	Power Generation	CSF[1]	EM[2]	TOTAL	
1	**262,98**	0,76	57,38	-2,57	0	**55,57**	**0,004**
2	**287,11**	0,76	58,05	0	0	**58,81**	**0,065**
3	**278,69**	0	60,16	0	-3,74	**56,42**	**0,065**
4	**285,21**	0	60,08	0	-0,61	**59,47**	**0,065**
5	**278,30**	0	58,58	-0,03	-1,77	**56,78**	**0,004**
6	**278,96**	0	59,06	-1,25	-0,26	**57,56**	**0,004**
7	**390,35**	0,76	61,29	1,13	0	**63,17**	**0,130**
8	**390,35**	0,76	61,29	0	0	**62,05**	**0,846**
9	**412,09**	0	64,44	0	-3,74	**60,70**	**0,846**
10	**409,41**	0	62,93	0	-0,61	**62,32**	**0,846**
11	**409,83**	0	60,86	1,13	-1,77	**60,21**	**0,130**
12	**408,49**	0	62,42	1,13	-0,26	**63,29**	**0,130**
13	**494,44**	0,76	69,52	1,13	0	**71,40**	**1,057**
14	**494,44**	0,76	69,52	0	0	**70,28**	**9,308**
15	**516,18**	0	72,21	0	-3,74	**68,47**	**9,308**
16	**513,51**	0	72,91	0	-0,61	**72,30**	**9,308**
17	**513,92**	0	70,66	1,13	-1,77	**70,01**	**1,057**
18	**512,58**	0	71,64	1,13	-0,26	**72,51**	**1,057**
19	**166,58**	1,22	41,07	38,08	0	**80,37**	**4E-08**
20	**166,58**	1,22	30,16	0	0	**31,39**	**1E-06**
21	**162,85**	0,46	32,50	0	-0,61	**32,36**	**1E-06**
22	**162,85**	0,46	32,50	0	-0,61	**32,36**	**1E-06**
23	**173,32**	0,46	42,24	14,63	-0,26	**57,07**	**4E-08**
24	**173,32**	0,46	42,24	14,63	-0,26	**57,07**	**4E-08**
25	**182,37**	1,22	33,08	1,09	0	**35,39**	**2E-06**
26	**200,14**	1,22	28,38	0	0	**29,60**	**2E-05**
27	**183,98**	0,46	31,85	0	-3,53	**28,78**	**2E-05**
28	**196,41**	0,46	30,71	0	-0,61	**30,57**	**2E-05**
29	**183,74**	0,46	30,95	-0,90	-1,56	**28,96**	**2E-06**
30	**186,98**	0,46	31,51	-1,02	-0,26	**30,69**	**2E-06**
31	**261,26**	1,22	32,84	0,88	0	**34,95**	**7E-06**
32	**262,86**	1,22	33,25	0	0	**34,47**	**2E-04**
33	**282,61**	0,46	31,57	0	-3,74	**28,29**	**2E-04**
34	**279,93**	0,46	32,94	0	-0,61	**32,79**	**2E-04**
35	**280,35**	0,46	30,74	1,13	-1,77	**30,56**	**7E-06**
36	**279,01**	0,46	32,62	1,13	-0,26	**33,96**	**7E-06**

[1] Centralized Storage Facility
[2] Electric Mobility

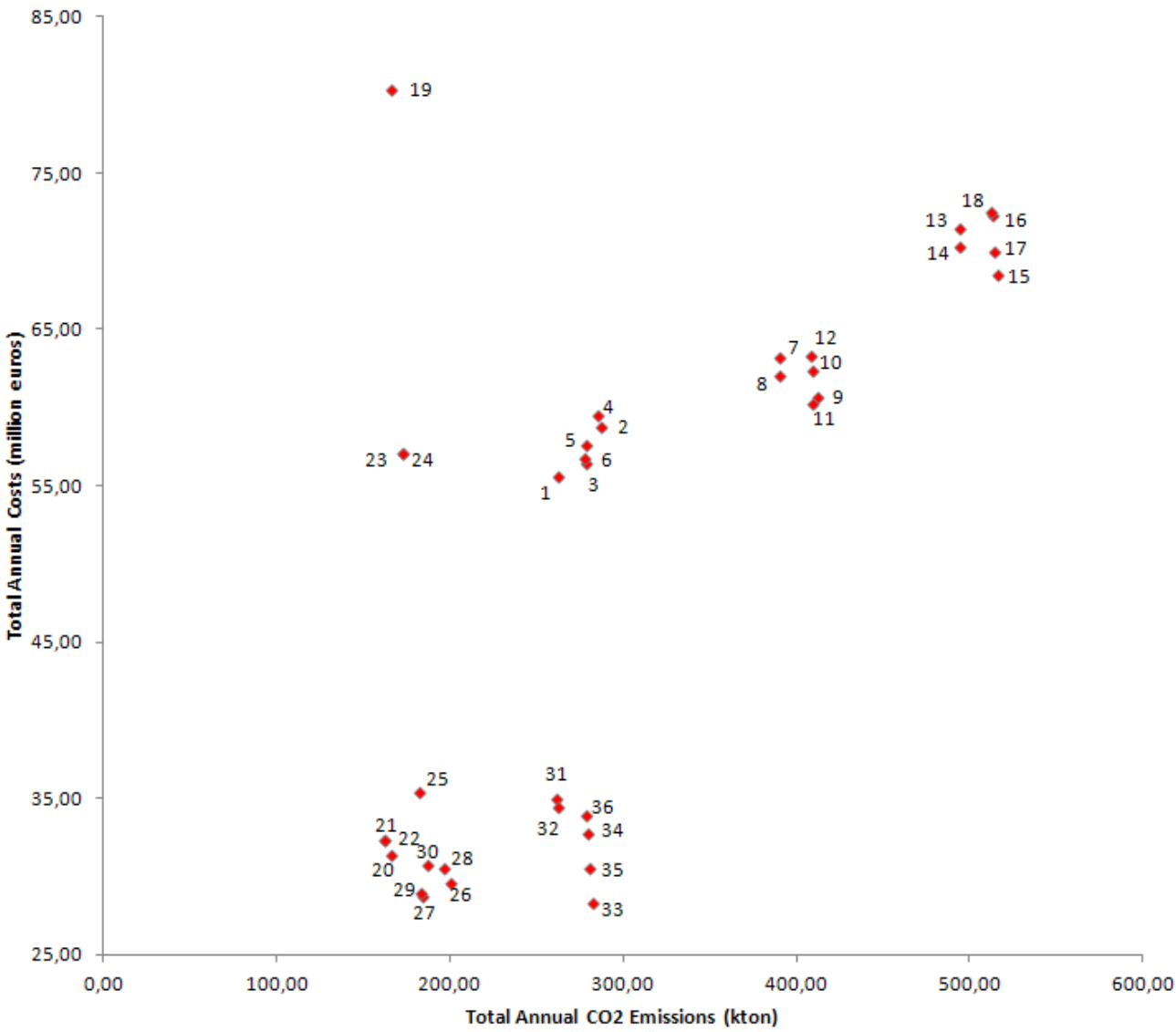


Fig. 49: Total annual costs and carbon emissions of the alternatives in 2030, for the "high prices" scenario, including power system's carbon emissions in the environmental attribute

According to the obtained results, alternatives with higher share of RES lead to lower carbon emissions. When it comes to the effect of energy efficiency measures on the load, the next graph illustrates that with the exception of alternatives 19, 23 and 24 (which are affected by the economic impact of CSF operation when there is energy surplus throughout all the day), all the other alternatives implementing energy efficiency measures on the load, have lower total annual costs.

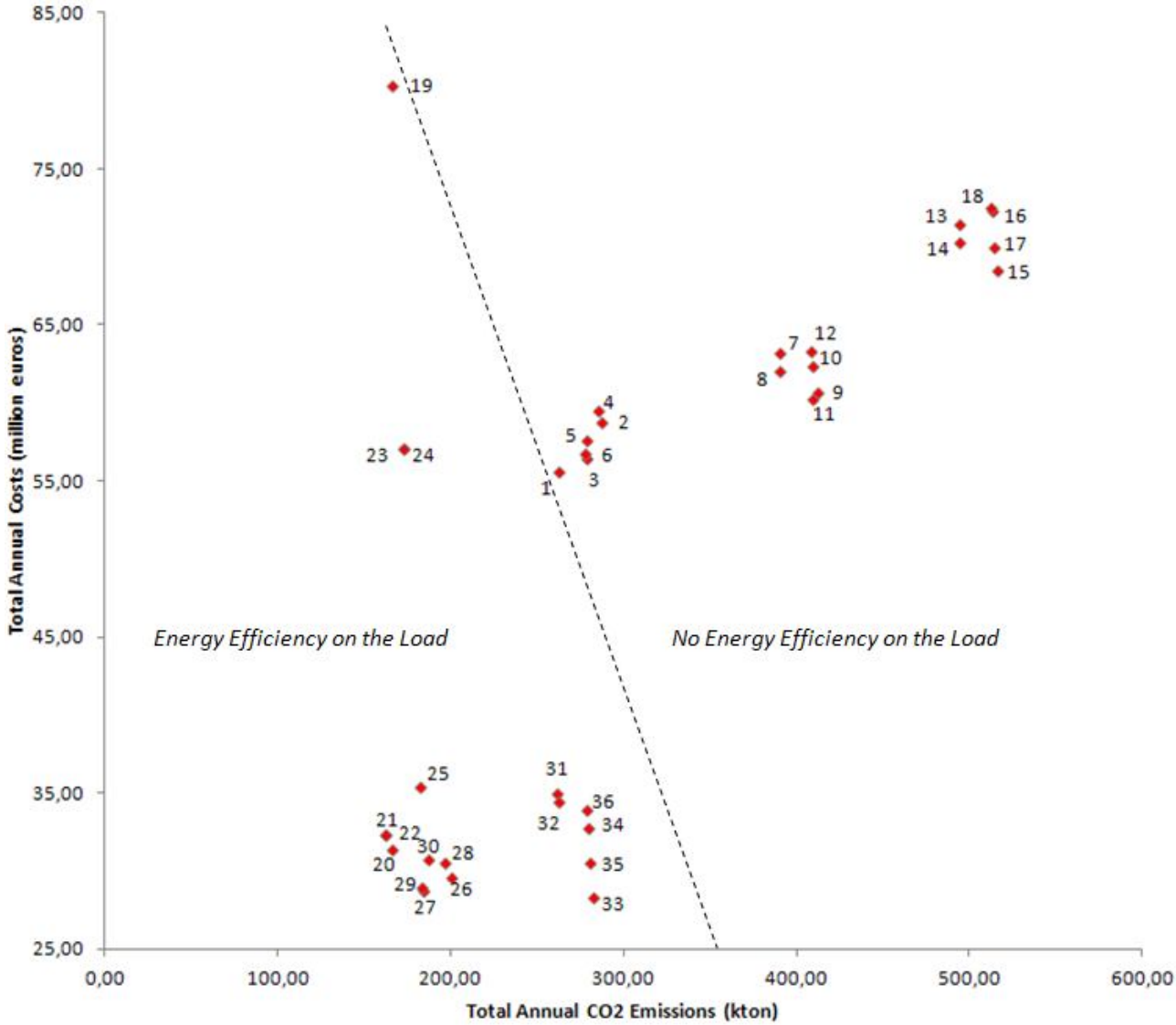


Fig. 50: Effect of energy efficiency measures on the load, on total annual costs and carbon emissions of the alternatives in 2030, for the “high prices” scenario

If the analysis is only focused on the power generation costs, all alternatives facing energy efficiency measures on the load present lower costs than the alternatives without energy efficiency measures. To explain this conclusion, an observation of the power generation options is worth performing, for both load increase and decrease pathways.

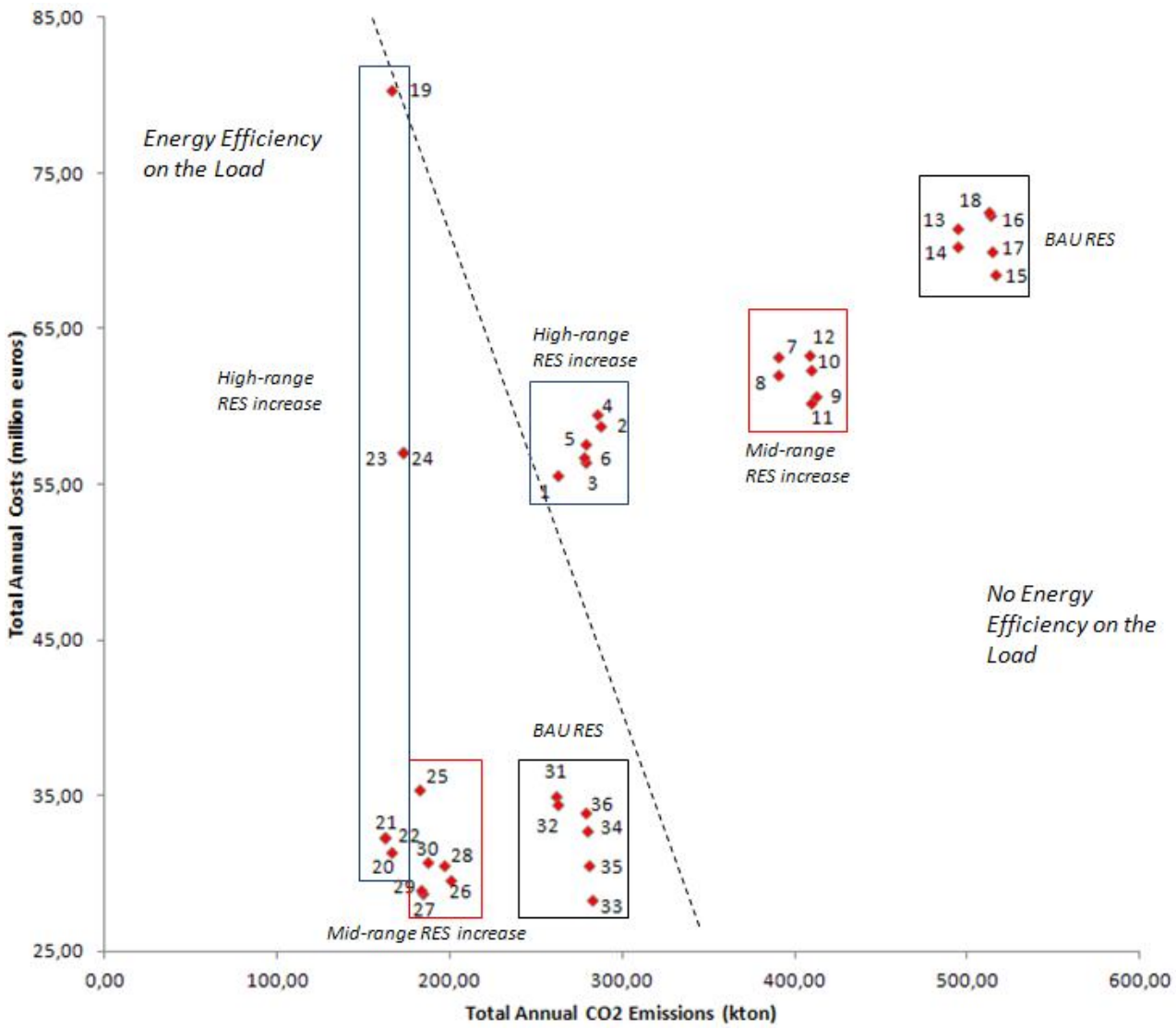


Fig. 51: Effect of energy efficiency measures on the load and RES pathways, on total annual costs and carbon emissions of the alternatives in 2030, for the "high prices" scenario

The previous plot ratifies the environmental benefits of RES increase and load decrease, and shows that, in terms of carbon emissions, alternatives with high-range RES increase and without energy efficiency on the load are similar to the ones with BAU RES together with energy efficiency measures on the power system.

When it comes to the cost-effectiveness of energy efficiency on the power system, an economic analysis should be carried out, by comparing: (i) annual cost per unit of electric energy generated, without investing on efficiency measures; (ii) annual cost per unit of electric energy generated, with energy efficiency measures; and (iii) annual cost per unit of electric energy generated, with energy efficiency measures, plus the annual cost for applying these measures.

This assessment will only consider comparable alternatives in terms of power generation, that's to say alternatives with neither electricity storage nor electric mobility.

Table 21 – Annual cost per unit of electric energy generated, without investing on efficiency measures, for "high prices" scenario in 2030

Annual Demand in 2030		654,37 GWh
Annual cost for electric energy generation (RES and non-RES)	High-range RES increase	58,05 million €
	Mid-range RES increase	61,29 million €
	BAU	69,52 million €
Annual cost per unit of electric energy generated	High-range RES increase	88,71 €/MWh
	Mid-range RES increase	93,66 €/MWh
	BAU	106,23 €/MWh

Table 22 – Annual cost per unit of electric energy generated, with energy efficiency measures, for "high prices" scenario in 2030

Annual Demand in 2030		369,04 GWh
Annual cost for electric energy generation (RES and non-RES)	High-range RES increase	30,16 million €
	Mid-range RES increase	28,38 million €
	BAU	33,25 million €
Annual cost per unit of electric energy generated	High-range RES increase	81,74 €/MWh
	Mid-range RES increase	76,89 €/MWh
	BAU	90,10 €/MWh

Table 23 – Annual cost per unit of electric energy generated, with energy efficiency measures, plus the annual cost for applying these measures, for "high prices" scenario in 2030

Annual Demand in 2030		369,04 GWh
Annual cost for electric energy generation (RES and non-RES)	High-range RES increase	30,63 million €
	Mid-range RES increase	28,84 million €
	BAU	33,71 million €
Annual cost per unit of electric energy generated (including the annual cost for energy efficiency)	High-range RES increase	82,99 €/MWh
	Mid-range RES increase	78,14 €/MWh
	BAU	91,35 €/MWh

The previous tables allow observing that alternatives implementing energy efficiency measures result on lower annual cost per unit of electric energy generated, comparing to analogous alternatives that don't invest on load reduction. That is also true even adding the annual costs for energy efficiency on power system, to the power generation costs. The annual costs of energy efficiency increase linearly over time and, in 2030, stand for 461 thousand Euros of investment.

The next figure represents graphically the concerned alternatives, in terms of total annual costs (more than just power generation costs) and total carbon emissions.

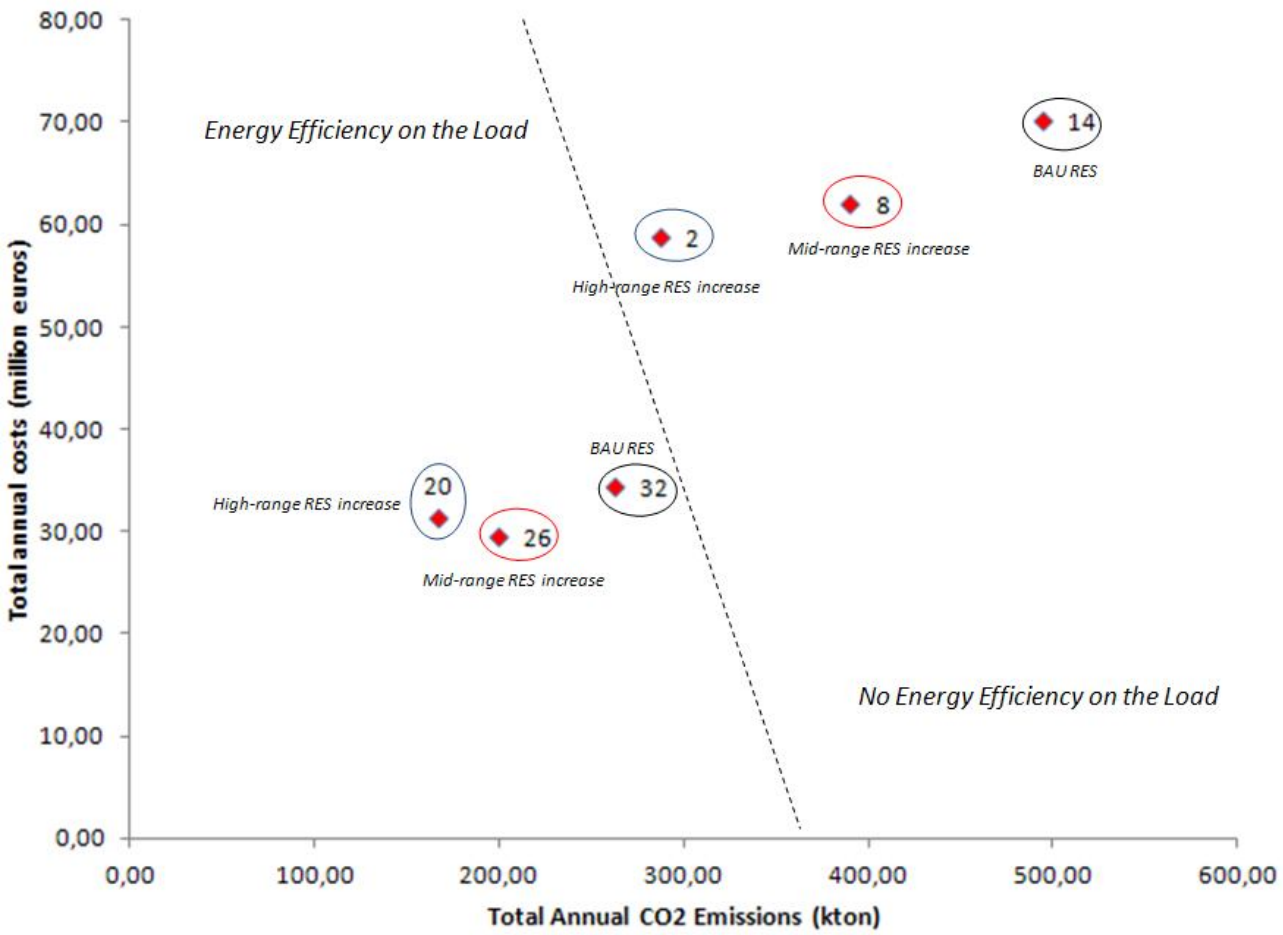


Fig. 52: Effect of RES pathways on total annual costs and carbon emissions of the alternatives in 2030, for the "high prices" scenario

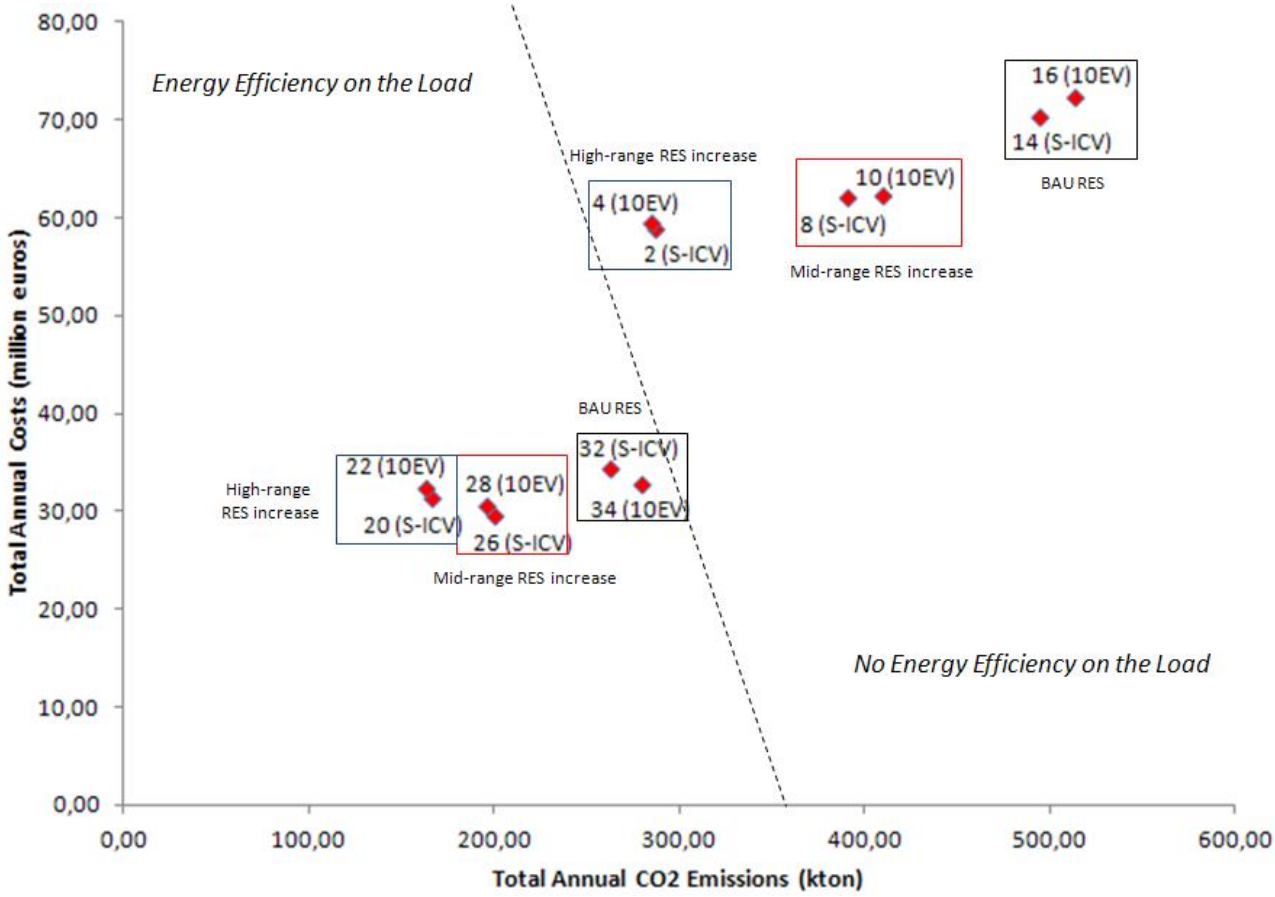
According to the above plot and tables, alternatives with energy efficiency measures on the load besides leading to a lower cost per unit of electric energy generated, also result on global lower costs than alternatives without energy efficiency.

Concerning total annual costs, renewable energy sources become more cost-competitive than fuel-oil thermal generation. That's to say, high-range and mid-range RES increase are economically more beneficial than BAU option, for both load strategies. If energy efficiency measures on the load are not applied, high-range RES increase leads to lower total annual costs than mid-range RES increase. In case of applying energy efficiency measures on the load, mid-range RES increase is less expensive than high-range RES increase, because in the latter biomass generation is commissioned, and geothermal and hydro power units are reinforced. The cost-effectiveness of this RES increase depends on the load level. When load is higher, the effect of expensive RES, such as biomass (feed-in tariff of 107 €/MWh), is smoothened. On the other hand, when load is decreased, the weight of biomass among global power generation cost increases (28% of the total power generation cost), comparing to the case in which there are no energy efficiency measures on the

load (20% of the total power generation cost). That's to say, it is worth reducing the load through energy efficiency measures, instead of commissioning expensive RES to compensate the load increase. These conclusions are ratified by Table 21, Table 22 and Table 23.

In terms of carbon emissions, alternatives applying energy efficiency measures on the load lead to lower amounts of CO_2.

To compare the mobility options in terms of costs and carbon emissions, the alternatives should be compared for the same planning specifications. Therefore, firstly mobility alternatives will be presented, without neither CSF nor V2G. The next graph presents the alternatives for sustainable mobility, including the RES and load characteristics.



Legend:

S-ICV: Efficient ICVs, Biofuels and Behavioural Change

10EV: 10 000 EVs pathway without V2G

Fig. 53: Assessment of mobility options in terms of costs and carbon emissions, in 2030, for the "high prices" scenario

The previous plot allows concluding that alternative 22 has the lowest total carbon emissions, whereas alternative 26 leads to the lowest costs. The referred graph also enables observing six

groups of alternatives, influenced by the RES strategy. The comparison of mobility options should then be done within each group of alternatives.

Within the group of alternatives that don't apply energy efficiency measures on the load, if BAU RES is followed, alternative 14 (Efficient ICVs, Biofuels and Behavioural Change) has both lower costs and carbon emissions than the other option (alternative 16). This is justified since the additional energy demand for EVs charging (alternative 16) is fulfilled by thermal units, which results on both higher power generation costs (more 3,4 million Euros) and emissions (more 22,8 kton CO_2), but lower ICVs emissions (less 3,7 kton CO_2).

When it comes to the alternatives adopting mid-range RES increase, alternative 8 (Efficient ICVs, Biofuels and Behavioural Change) leads to both lower costs and carbon emissions than the other option (alternative 10), due to the same reasons presented for the BAU RES option. Again this happens because the additional energy demand for EVs charging (alternative 10) is filled up by thermal units, which leads to both higher power generation costs (more 1,6 million Euros) and emissions (more 22,8 kton CO_2), but lower ICVs emissions (less 3,7 kton CO_2). These results allow inferring that there is a similar relationship between the mobility options, for both BAU and mid-range RES increase.

Alternatively, if high-range RES increase is followed, alternative 4 (10 000 EVs pathway), has lower carbon emissions than the other strategy (alternative 2). Now the extra energy demand for EVs charging is provided by RES, which lowers the total amount of emissions (less 1,9 kton CO_2), but still leads to higher power generation costs than alternative 2 (more 2,0 million Euros).

Concerning alternatives adopting energy efficiency measures, if BAU RES option is pursued, alternative 32 (Efficient ICVs, Biofuels and Behavioural Change) despite having lower emissions, leads to higher costs than alternative 34 (10 000 EVs pathway). In fact, alternative 32 leads to less 20,8 kton CO_2 from the power system than alternative 34, since the EVs are "fuelled" by additional thermal power generation. On the other hand, alternative 34 results on a fall of carbon emissions from the ICVs, comparing to alternative 32 (less 3,7 kton CO_2), but globally still has higher emissions than the latter (more 17,1 kton CO_2). In terms of power generation costs, theoretically, alternative 32 should also be more competitive. However, the analysis of the load/generation profile allows noticing that although alternative 34 has a higher demand of energy (more annual 27,8 GWh), the power generation costs are lower than the registered in alternative 32 (less annual 310 thousand Euros). Taking into account the operation rules of the system, alternative 34 enables a better cost performance of fuel oil units, than alternative 32, as sketched out next.

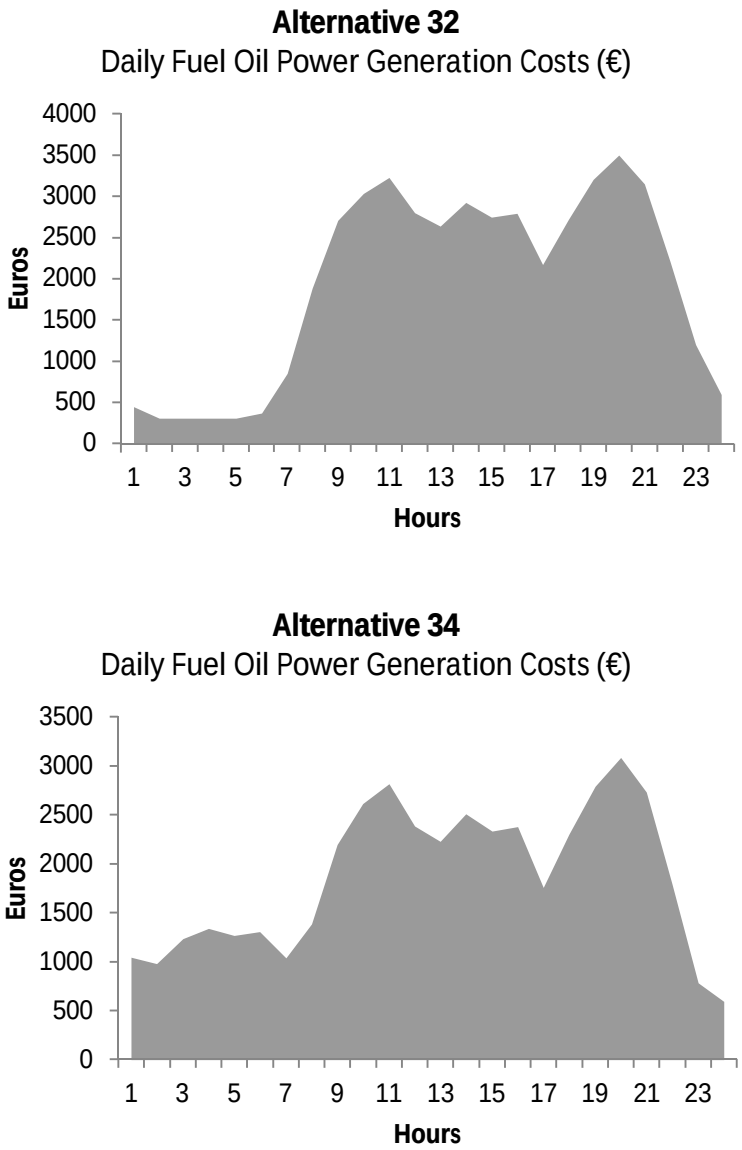


Fig. 54: Thermal-based power generation costs of alternatives 32 and 34, for the "high prices" scenario

Concerning the options with mid-range RES increase, alternative 28 (10 000 EVs pathway) leads to lower carbon emissions and higher costs than alternative 26 (Efficient ICVs, Biofuels and Behavioural Change). As a matter of fact, in alternative 28, the additional energy demand for EVs charging is provided by RES, therefore there are no extra carbon emissions from the power system owing to electric mobility. Furthermore, alternative 28 also benefits from the decrease of carbon emissions from the ICVs (less 3,7 kton CO_2 than alternative 26). Regarding the costs, the additional power generation for EVs "fuelling", in alternative 28, leads to more 2,3 million Euros of cost (accounted to RES), than for alternative 26.

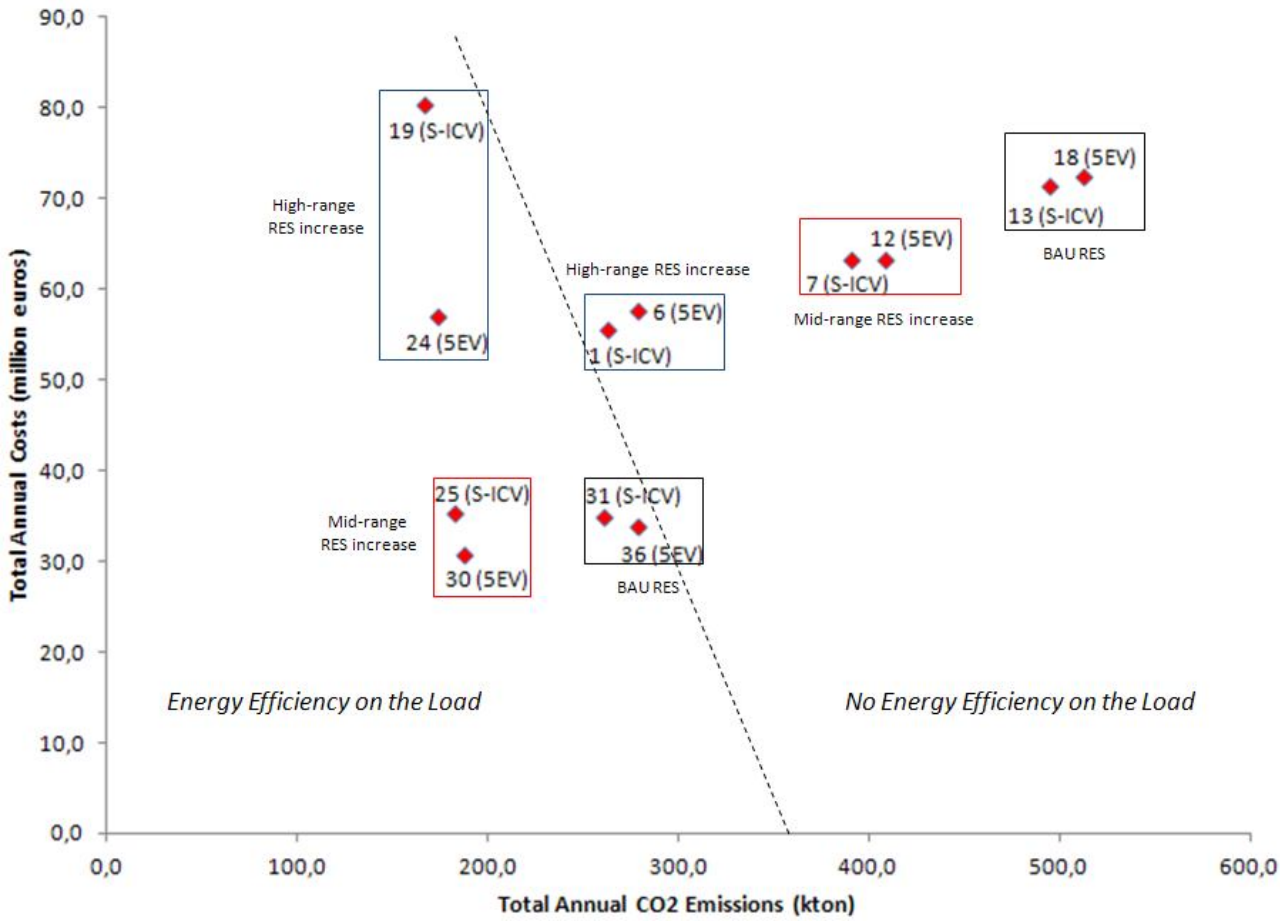
Finally, concerning the high-range RES increase, alternative 22 (10 000 EVs pathway) leads to lower carbon emissions and higher costs than alternative 20 (Efficient ICVs, Biofuels and

Behavioural Change). The relationship between these two alternatives is indeed similar to the registered in the case of mid-range RES increase, both on power generation costs and emissions.

From the previous analysis, some conclusions can be drawn:

- Electric mobility becomes environmentally more beneficial with the increase of RES;
- Electric mobility needs lower amounts of RES to be environmentally competitive, in the case of investing on energy efficiency measures on the load;
- Only when there is a load decrease and BAU RES, electric mobility appears economically competitive (thanks to the operation of power units with lower cost for electric energy generation).

At this time mobility alternatives will be presented, together with CSF, yet disregarding V2G strategy. The next graph presents the alternatives for sustainable mobility plus CSF, including the RES and load characteristics.



Legend:

S-ICV: Efficient ICVs, Biofuels and Behavioural Change, plus CSF

5EV: 5 000 EVs pathway (without V2G), plus CSF

Fig. 55: Assessment of mobility options together with CSF, in terms of costs and carbon emissions, in 2030, for the "high prices" scenario

The previous plot allows concluding that alternative 19 has the lowest total carbon emissions, whereas alternative 30 leads to the lowest costs. The referred graph also enables observing six groups of alternatives, influenced by the RES strategy. The comparison of mobility options should then be done within each group of alternatives.

Within the group of alternatives that don't apply energy efficiency measures on the load, if BAU RES option is followed, alternative 13 (Efficient ICVs, Biofuels and Behavioural Change, plus CSF) has both lower costs and carbon emissions than the other option (alternative 18). This is justified since the additional energy demand for EVs charging (alternative 18) is fulfilled by thermal units (there is no energy surplus), which results on both higher power generation costs (more 2,1 million Euros) and emissions (more 11,4 kton CO_2), and higher ICVs emissions (more 6,7 kton CO_2).

When it comes to the alternatives adopting mid-range RES increase, alternative 7 (Efficient ICVs, Biofuels and Behavioural Change, plus CSF) leads to both lower costs and carbon emissions than the other option (alternative 12), due to the same reasons presented for the BAU RES option. Again this happens because the additional energy demand for EVs charging (alternative 12) is filled up by thermal units (there is no energy surplus), which leads to both higher power generation costs (more 1,1 million Euros) and emissions (more 11,4 kton CO_2), and higher ICVs emissions (more 6,7 kton CO_2). These results allow inferring that there is a similar relationship between the options for mobility together with centralized storage, for both BAU and mid-range RES increase.

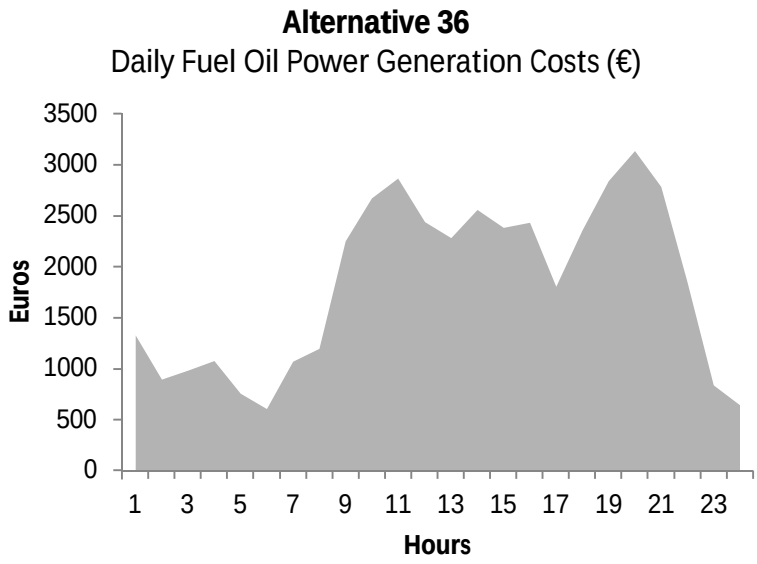
In line with these findings, if high-range RES increase is followed, alternative 1 (Efficient ICVs, Biofuels and Behavioural Change, plus CSF), has both lower costs and carbon emissions than the other option (alternative 6).

Alternative 6 leads to additional energy demand for EVs charging, which stands for more 13,9 GWh/year totally supplied by RES. This alternative has also 23,6 GWh/year of energy surplus stored by the CSF (through an equivalent load increase). When it comes to alternative 1, it observes an energy surplus of 36,9 GWh/year (based on RES), stored by the centralized storage facility (through an equivalent load increase). Therefore, both alternatives have the same RES power generation costs. In addition, alternative 1 has lower thermal-based power generation costs (less 1,7 million Euros) and carbon emissions (less 9,2 kton CO_2), owing to a larger energy shift from the CSF (more 10,6 GWh of CSF power generation). In case of energy surplus, the larger the EVs charging, the lower will be the stored energy by the CSF. In terms of emissions from the ICVs, alternative 6 results on more 6,7 kton CO_2, in 2030.

To sum up, if energy efficiency is not applied on the load, the alternatives personified by Efficient ICVs, Biofuels and Behavioural Change, plus CSF, are preferred both in terms of costs and emissions.

Hereinafter an analysis is performed on the alternatives implementing energy efficiency measures on the load.

If BAU RES option is followed, alternative 31 (Efficient ICVs, Biofuels and Behavioural Change, plus CSF) has lower global carbon emissions (less 17,7 kton CO_2) but slightly higher total annual costs (more 1,0 million Euros) than alternative 36. Alternative 36 leads to additional energy demand for EVs charging, which stands for more 13,9 GWh/year. Part of this extra load is supplied by RES (2,4 GWh/year). In alternative 31, where there are no EVs, that energy (surplus) is stored by the CSF, which is afterwards converted into electricity (with transformation losses). Therefore, both alternatives have equal RES power generation costs. Concerning thermal-based power generation costs, alternative 36 although has a higher electric load, results on faintly better cost performance (less 0,2 million Euros per year), due to the power system operation rules, as sketched out below.



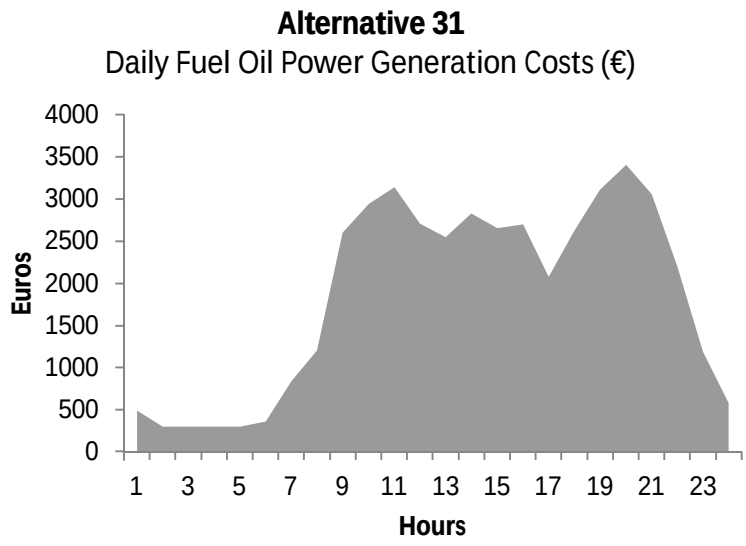


Fig. 56: Thermal-based power generation costs of alternatives 31 and 36, for the "high prices" scenario

Nonetheless, alternative 36 leads to higher carbon emissions from both the power system (more 11,0 kton CO_2, due to the effect of EVs charging) and ICVs (more 6,7 kton CO_2), than alternative 31.

Concerning the options with mid-range RES increase, alternative 30 (5 000 EVs plus CSF) leads to higher carbon emissions and lower costs than alternative 25 (Efficient ICVs, Biofuels and Behavioural Change, plus CSF). Alternative 30 leads to additional energy demand for EVs charging, which stands for more 13,9 GWh/year totally supplied by RES. This alternative has also 39,0 GWh/year of energy surplus stored by the CSF (through an equivalent load increase). When it comes to alternative 25, it observes an energy surplus of 53,0 GWh/year (based on RES), stored by

the centralized storage facility (through an equivalent load increase). Therefore, both alternatives have the same RES power generation costs.

Alternative 30 allows a higher energy shift through CSF (more 2,6 GWh/year) and better cost performance of thermal-based power generation (less 1,6 million Euros of power generation costs per year), due to the power system operation rules. These drivers justify a higher cost-competitiveness of alternative 30, over alternative 25. What's more, since the CSF generation is higher in alternative 30, the carbon emissions from the power system are lower in this option, than in alternative 25. Bearing in mind that the additional energy demand for EVs charging (in alternative 30) is provided by RES, there are no extra carbon emissions from the power system owing to electric mobility. However, alternative 25 has lower carbon emissions from the ICVs (less 6,7 kton CO_2) than alternative 30.

Finally, regarding the options with high-range RES increase, alternative 24 (5 000 EVs plus CSF) leads to higher carbon emissions and lower costs than alternative 19 (Efficient ICVs, Biofuels and Behavioural Change, plus CSF). Alternative 24 leads to additional energy demand for EVs charging, which stands for more 13,9 GWh/year totally supplied by RES. This alternative has also 129,8 GWh/year of energy surplus stored by the CSF (through an equivalent load increase), but there is yet 31,2 GWh/year of energy surplus not stored owing to lack of capacity of the CSF. When it comes to alternative 19, it stores 129,8 GWh/year of energy surplus (based on RES) by the CSF (through an equivalent load increase), but there is still 45,1 GWh/year of energy surplus not stored, bearing in mind lack of CSF capacity.

In terms of power generation costs, alternative 24 has higher RES based costs than alternative 19 (more 1,2 million Euros/year) for EVs charging. Both alternatives observe energy surplus during all day, which turns thermal generation operating at minimum levels. Hence, alternatives 19 and 24 share the same fuel oil power generation costs. One should also emphasize the harmful effect of an all-day energy surplus, which leads to ineffective CSF operation. That's to say, since CSF can't inject electricity back into the grid (after storing the energy surplus), it is unable to perform energy trading. This results on very high positive operation costs (negative gross margin) from the CSF for both alternative 19 and 24, totalling excessive annual costs comparing to the analogous alternatives. In view of these findings, the present match between high-range RES increase and energy efficiency on the load turns CSF an inappropriate option, owing to lack of opportunity for performing its energy shift mission.

When it comes to the environment perspective, the alternatives under analysis have the same carbon emissions from the power system. Bearing in mind that the additional energy demand for EVs charging (in alternative 24) is provided by RES, there are no extra carbon emissions from the power

system owing to electric mobility. However, alternative 19 has lower carbon emissions from the ICVs (less 6,7 kton CO_2) than alternative 24.

From the previous analysis the next insights can be drawn:

- If energy efficiency measures are applied on the load, the option with Efficient ICVs, Biofuels and Behavioural Change, plus CSF, originates lower carbon emissions, but higher total costs than the alternative with 5 000 EVs plus CSF;
- If energy efficiency measures are not applied on the load, the option with Efficient ICVs, Biofuels and Behavioural Change, plus CSF, originates both lower carbon emissions and total costs than the alternative with 5 000 EVs plus CSF.

As far as V2G is concerned, the next plot depicts the alternatives with electric mobility in terms of the V2G strategy ("Yes" for alternatives applying V2G; "No" for alternatives not applying V2G).

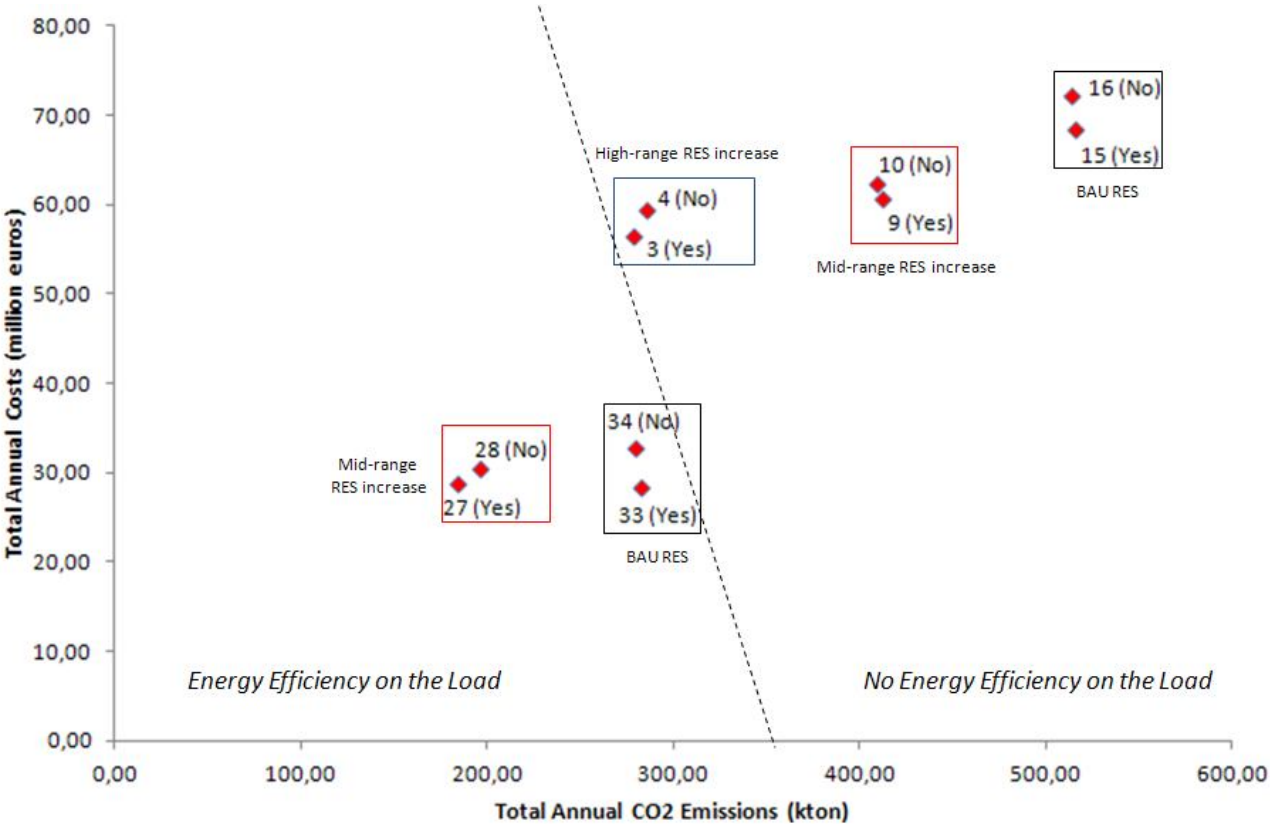


Fig. 57: Total annual costs and carbon emissions of alternatives with 10 000 EVs in 2030, for the "high prices" scenario

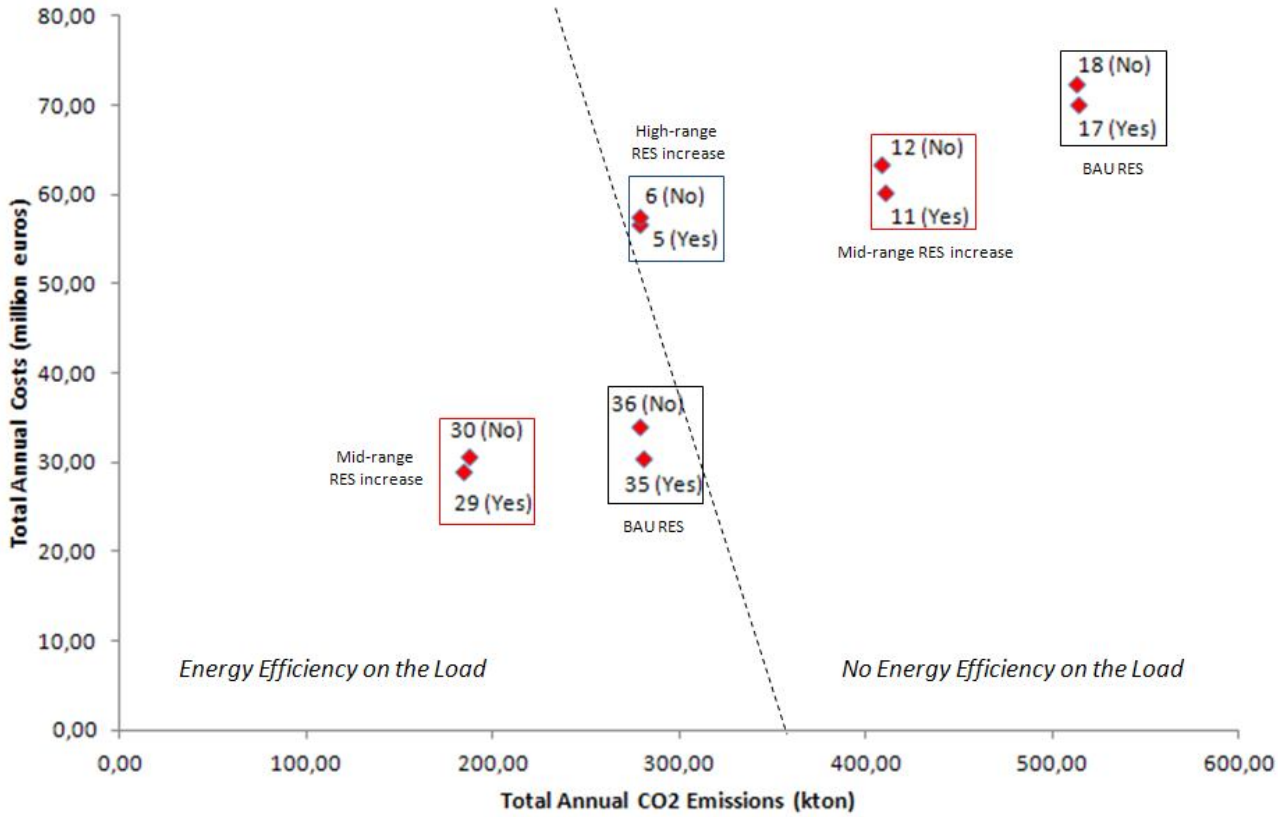


Fig. 58: Total annual costs and carbon emissions of alternatives with 5 000 EVs in 2030, for the "high prices" scenario

These graphs don't include the alternatives 21 and 22 (Fig. 57), as well as 23 and 24 (Fig. 58), because in the corresponding circumstances (high-range RES increase and energy efficiency on the load), there is lack of opportunity for V2G. That's to say, 21 is equal to 22 (no V2G) and 23 is equal to 24 (no V2G).

Therefore, excluding alternatives 21 and 23 (which actually don't perform V2G) all the alternatives with V2G have lower total costs, than the ones without V2G. Although V2G requires a higher demand for EVs charging (during valley hours) – and, as a result, larger power generation costs in that period – the rise of power generation costs is offset, during off-valley hours, with a reduction of thermal-based generation through the V2G strategy.

The economic advantage of alternatives with V2G, for this prices scenario, results from positive gross margin (negative costs) benefited by the electric mobility investor and operator (local utility), which is driven by the current prices scenario's parameters for electricity rates, combined with the amount of energy charged to and dispatched by EVs.

When it comes to the environment analysis, one should highlight that V2G strategy has no influence on the CO_2 emissions from ICVs, since the V2G energy requirements are fulfilled by an electricity consumption increase from the EVs, without changing the mobility pattern. Therefore, the environment impact of V2G depends on the energy mix, as well as the global balance between CO_2 emitted due to EVs charging and CO_2 avoided owing to the electricity dispatched by EVs, through V2G.

Regarding the previous graphs (alternatives with 10 000 EVs and 5 000 EVs), when there is no energy efficiency on the load, V2G allows lowering global carbon emissions only if high-range RES increase is followed. Alternatively, for alternatives applying energy efficiency measures, V2G leads to lower CO_2 emissions in the case of mid-range RES increase.

Finally, when it comes to the reliability influence on energy planning, the next figure presents the alternatives results for the attributes referred to Total Annual Costs (in million Euros) and Loss of Load Expectation (days/year).

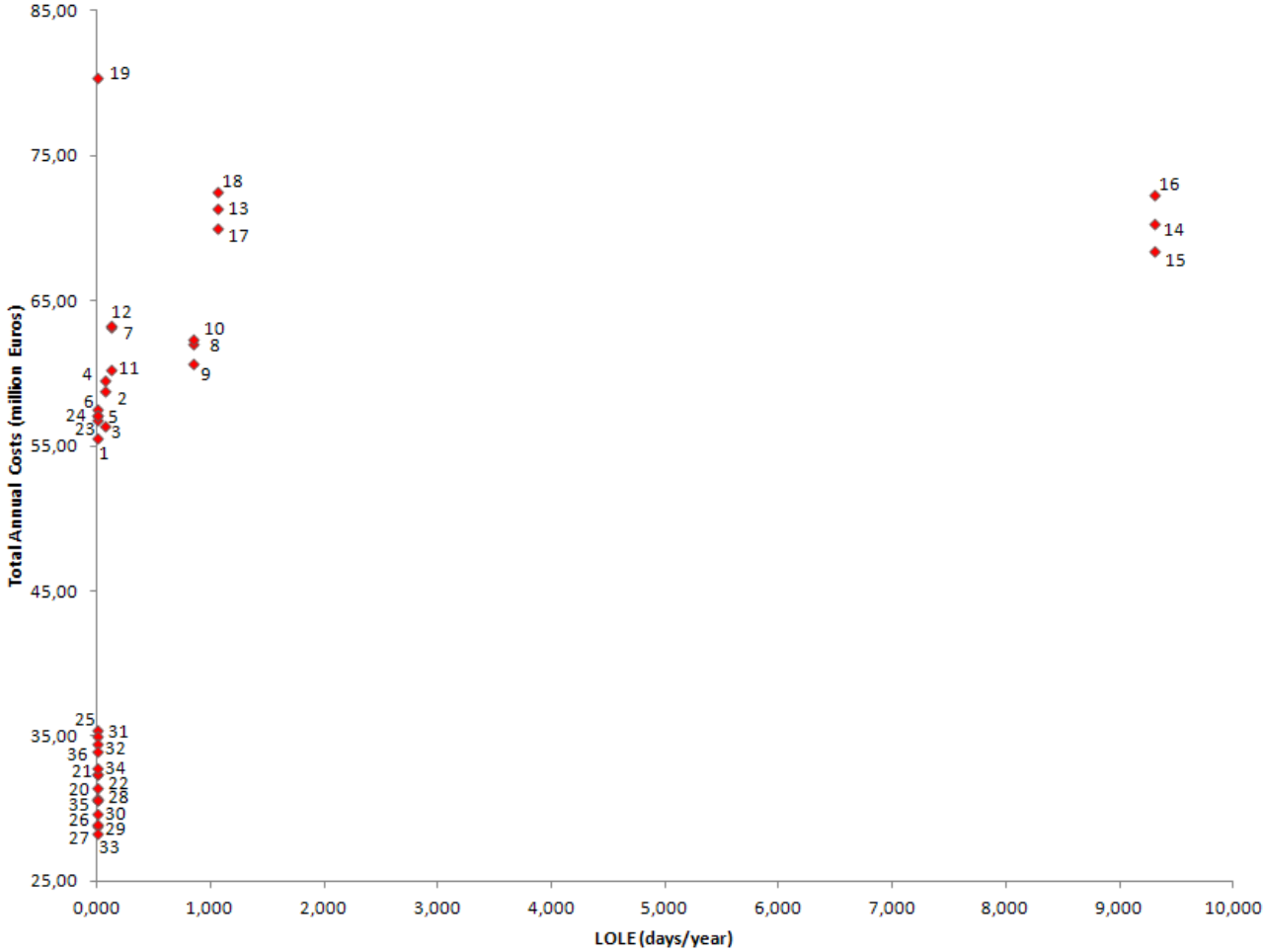


Fig. 59: Total annual costs and LOLE of the alternatives in 2030, for the “high prices” scenario

Taking into account that alternatives 14, 15 and 16 draw unacceptable LOLE, the next figure disregards the referred alternatives.

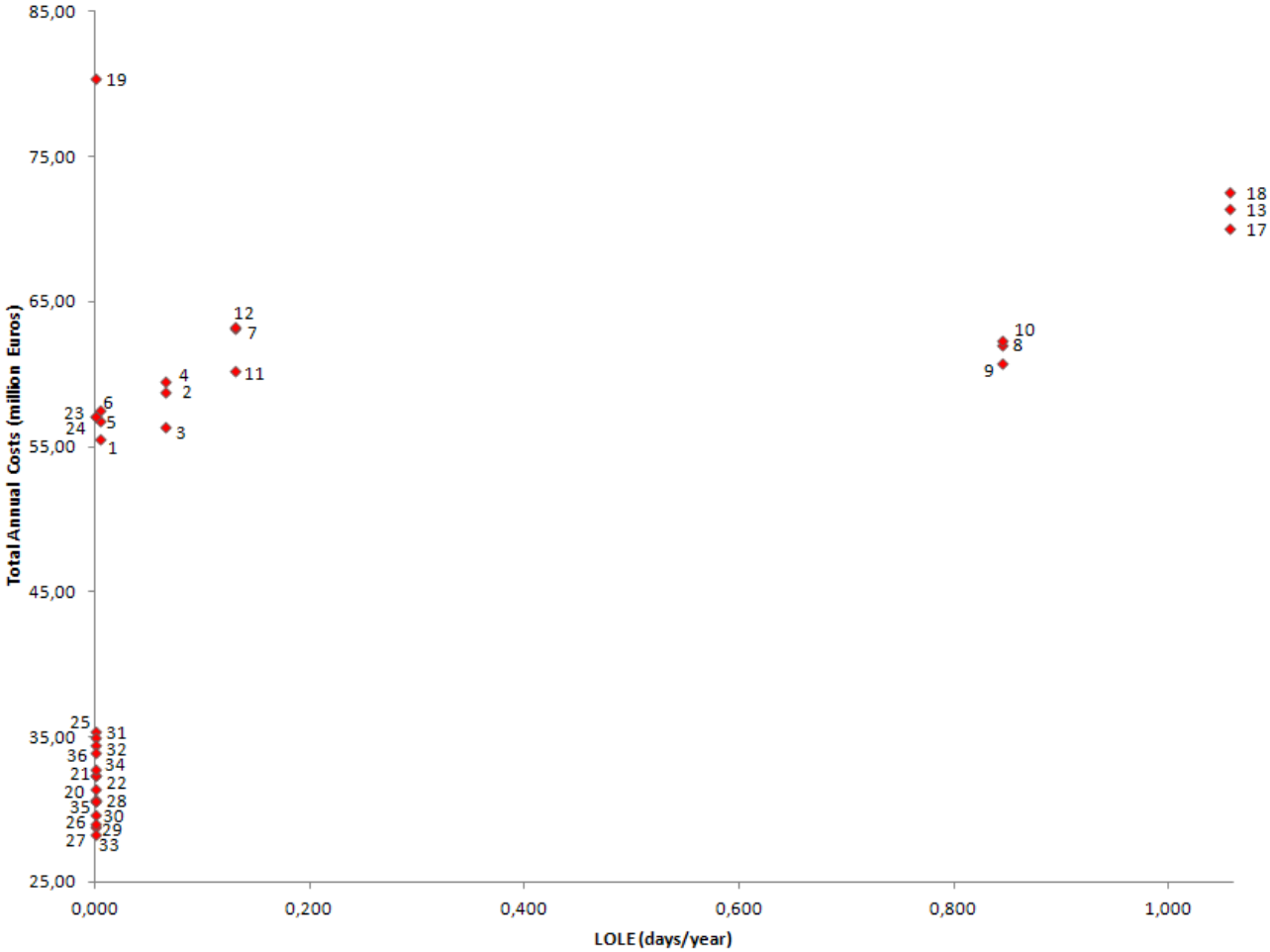


Fig. 60: Total annual costs and LOLE of a reduced set of alternatives in 2030, for the “high prices” scenario

From the previous graphs one observes a set of alternatives having a LOLE very close to zero. In view of getting a rather detailed analysis on the Cost/LOLE relationship, the next figure presents the influence of energy efficiency measures on the load and RES strategies.

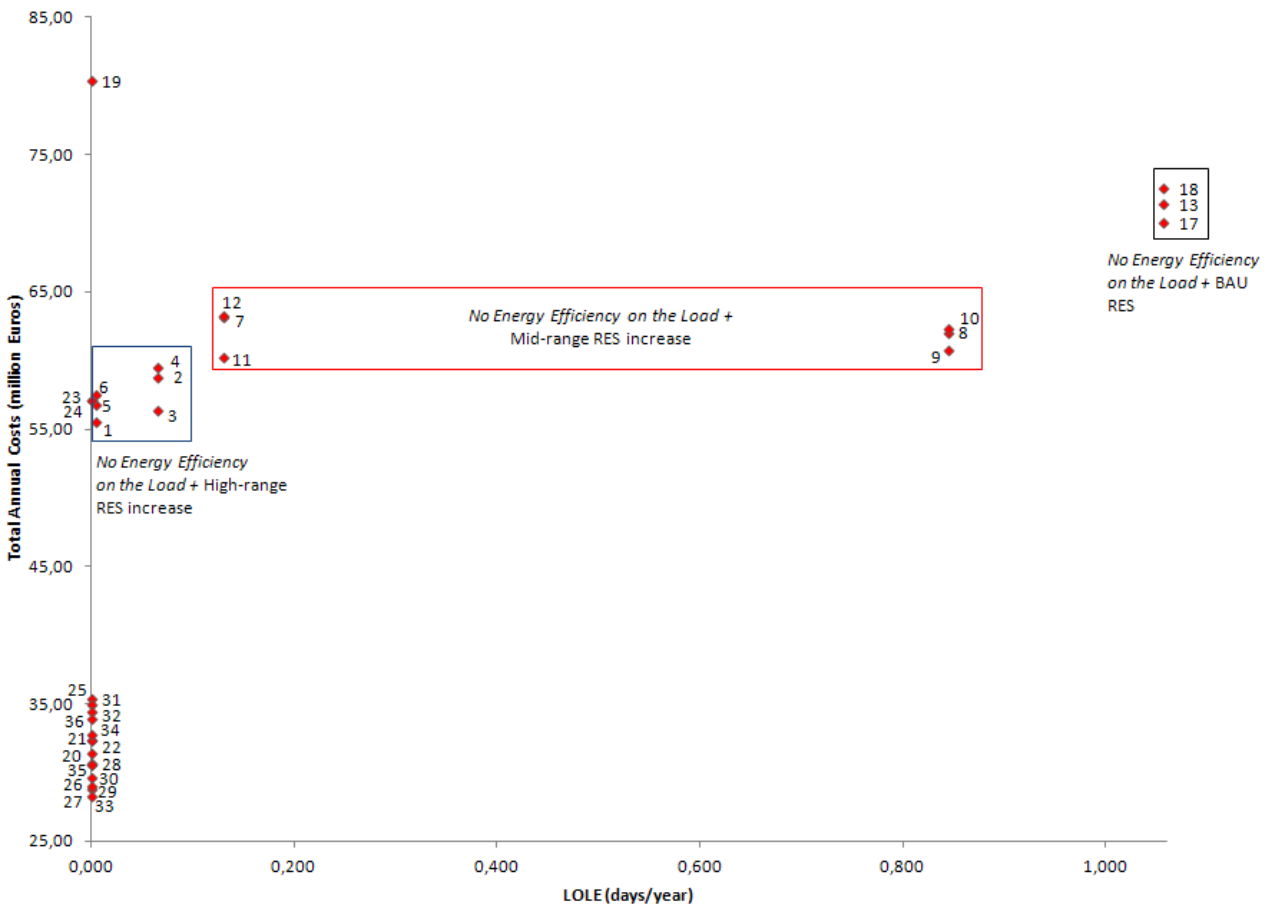


Fig. 61: Effect of energy efficiency measures on the load and RES pathways on total annual costs and LOLE, of a reduced set of alternatives in 2030, for the "high prices" scenario

The previous graph allows inferring that all the alternatives facing energy efficiency measures on the load present lower LOLE than the alternatives without energy efficiency measures. In addition, LOLE is lower in alternatives with higher capacity of renewable energy sources. At this moment, one should remember that the fuel oil power capacity is the same for all the RES pathways. That's to say, high-range RES increase doesn't lead to a thermal power decommissioning, comparing to the mid-range RES increase and BAU RES option.

Regarding the effect of electricity storage on the generation system adequacy, the presence of CSF decreases considerably the LOLE. Accordingly, all the alternatives with hydro pumped storage present better adequacy levels than the others. The CSF has the effect of a hydro power unit, concerning adequacy assessment. Concerning the electric mobility impact on the power system adequacy, the EVs' charging is disregarded, since it occurs during valley hours, having, as a result, no effect in the daily peak load curve. In addition, V2G contribution is also neglected for LOLE assessment.

The CSF effect on the generation system adequacy can be observed by comparing alternatives, with the same energy mix, but with and without CSF. The text table just presents alternatives without energy efficiency on the load, to get a clearer impact of both RES levels and CSF.

Table 24 – CSF and RES effect on LOLE, for alternatives without energy efficiency on the load, for the "high prices scenario" in 2030

RES pathway	**Electricity Storage strategy**	**LOLE (days/year)**
High-range RES increase	With CSF (alternatives 1, 5 and 6)	0,004
	Without CSF (alternatives 2, 3 and 4)	0,065
Mid-range RES increase	With CSF (alternatives 7, 11 and 12)	0,130
	Without CSF (alternatives 8, 9 and 10)	0,846
BAU	With CSF (alternatives 13, 17 and 18)	1,057
	Without CSF (alternatives 14, 15 and 16)	9,308

5.3.4.3 "Low Prices" Scenario

The next table presents the results of the proposed methodology in 2030, for the "low prices" scenario, considering the power system's emissions as costs.

Table 25 - Total annual carbon emissions, costs and LOLE for “low prices” scenario in 2030, including power system’s carbon emissions as costs

	Annual CO_2 emissions (kton)	Total Annual Costs (million Euros) - 2030						LOLE (days/year)
Alternative	Transport Sector (ICVs)	Carbon -based costs	Energy Efficiency measures	Power Generation	CSF[1]	EM[2]	TOTAL	
1	**121,76**	2,38	0,76	50,25	-0,64	0	**52,75**	**0,004**
2	**121,76**	2,69	0,76	49,14	0	0	**52,59**	**0,065**
3	**118,03**	2,63	0	51,77	0	1,32	**55,73**	**0,065**
4	**118,03**	2,71	0	51,24	0	0,13	**54,08**	**0,065**
5	**128,50**	2,49	0	50,93	0,57	0,76	**54,76**	**0,004**
6	**128,50**	2,50	0	51,15	-0,01	0,11	**53,75**	**0,004**
7	**121,76**	4,01	0,76	45,02	1,13	0	**50,92**	**0,130**
8	**121,76**	4,01	0,76	45,02	0	0	**49,80**	**0,846**
9	**118,03**	4,34	0	46,62	0	1,32	**52,28**	**0,846**
10	**118,03**	4,30	0	45,86	0	0,13	**50,29**	**0,846**
11	**128,50**	4,17	0	44,79	1,13	0,76	**50,85**	**0,130**
12	**128,50**	4,16	0	45,60	1,13	0,11	**51,00**	**0,130**
13	**121,76**	5,34	0,76	44,20	1,13	0	**51,43**	**1,057**
14	**121,76**	5,34	0,76	44,20	0	0	**50,30**	**9,308**
15	**118,03**	5,60	0	45,58	0	1,32	**52,51**	**9,308**
16	**118,03**	5,57	0	45,94	0	0,13	**51,64**	**9,308**
17	**128,50**	5,44	0	44,79	1,13	0,76	**52,12**	**1,057**
18	**128,50**	5,43	0	45,30	1,13	0,11	**51,97**	**1,057**
19	**121,76**	1,15	1,22	39,86	18,85	0	**61,07**	**4E-08**
20	**121,76**	1,15	1,22	28,95	0	0	**31,32**	**1E-06**
21	**118,03**	1,15	0,46	31,29	0	0,13	**33,03**	**1E-06**
22	**118,03**	1,15	0,46	31,29	0	0,13	**33,03**	**1E-06**
23	**128,50**	1,15	0,46	41,03	7,61	0,11	**50,36**	**4E-08**
24	**128,50**	1,15	0,46	41,03	7,61	0,11	**50,36**	**4E-08**
25	**121,76**	1,35	1,22	30,19	1,11	0	**33,87**	**2E-06**
26	**121,76**	1,58	1,22	25,77	0	0	**28,57**	**2E-05**
27	**118,03**	1,42	0,46	29,61	0	1,24	**32,72**	**2E-05**
28	**118,03**	1,58	0,46	28,11	0	0,13	**30,28**	**2E-05**
29	**128,50**	1,28	0,46	29,22	0,16	0,67	**31,79**	**2E-06**
30	**128,50**	1,32	0,46	29,56	0,10	0,11	**31,56**	**2E-06**
31	**121,76**	2,36	1,22	25,17	1,01	0	**29,76**	**7E-06**
32	**121,76**	2,38	1,22	25,27	0	0	**28,87**	**2E-04**
33	**118,03**	2,68	0,46	24,56	0	1,32	**29,02**	**2E-04**
34	**118,03**	2,64	0,46	25,26	0	0,13	**28,49**	**2E-04**
35	**128,50**	2,52	0,46	24,13	1,13	0,76	**28,99**	**7E-06**
36	**128,50**	2,50	0,46	25,15	1,13	0,11	**29,35**	**7E-06**

[1] Centralized Storage Facility
[2] Electric Mobility

The previous results are drawn for an annual basis, for the year 2030, as explained in section 5.3.1. Accordingly, the next graphs are built in order to show the relationship between the total annual costs and the other attributes.

Firstly, the next graph presents the alternatives results for the attributes referred to Total Annual Costs (in million Euros) and Annual CO_2 Emissions from ICVs (in kton). One should highlight that carbon emissions from the power system are accounted within the total annual costs, in the scope of the EU Emissions Trading Scheme.

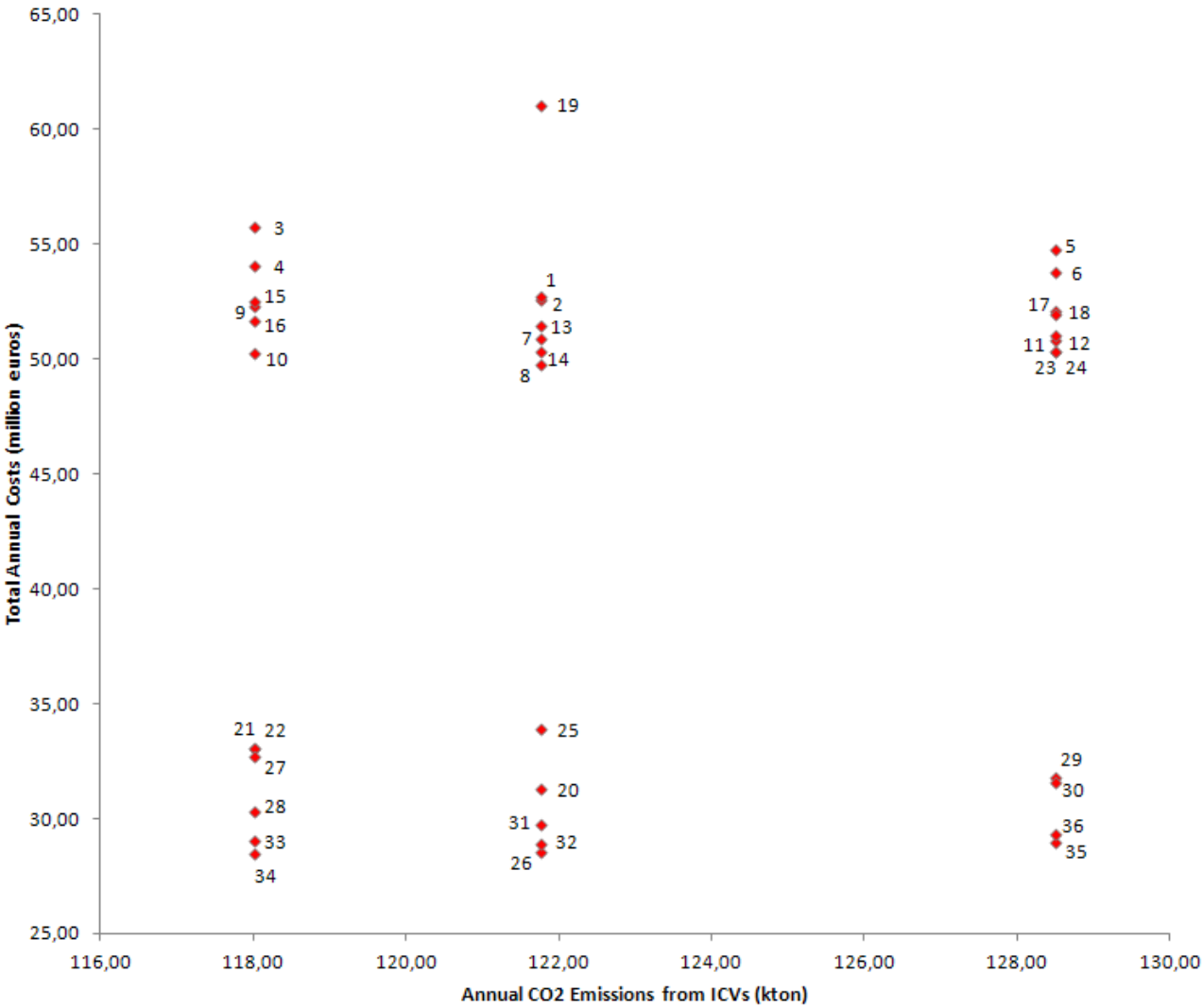


Fig. 62: Total annual costs and carbon emissions of the alternatives in 2030, for the "low prices" scenario, including power system's carbon emissions as costs (1)

The previous graph shows, basically, six groups of alternatives, in terms of electric mobility and energy efficiency measures on the load, as presented below.

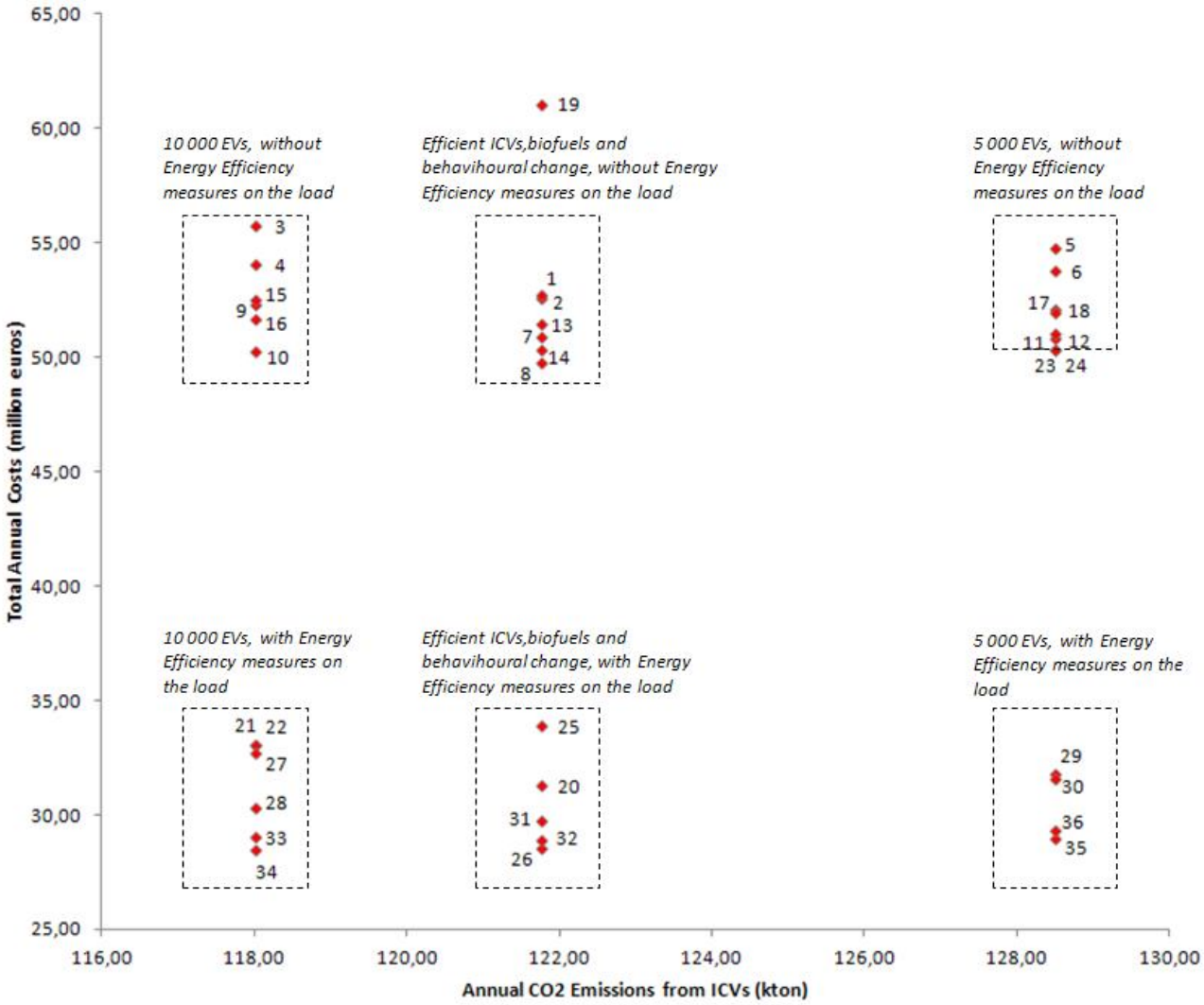


Fig. 63: Total annual costs and carbon emissions of the alternatives in 2030, for the "low prices" scenario, including power system's carbon emissions as costs (2)

As inferred for the "high prices" scenario, it's hard to identify the relationship between total costs and corresponding global emissions (power system plus ICVs), since the CO_2 emitted by power generation units is accounted as a carbon cost according to the EU ETS (cap-and-trade). In view of this worry, the obtained results are now presented by disregarding carbon costs (within total annual costs) and adding the power system's CO_2 emissions to the ICVs emissions, as described by equation (4. 2).

Table 26 – Total annual carbon emissions, costs and LOLE for “low prices” scenario in 2030, including power system’s carbon emissions in the environmental attribute

	Annual CO_2 emissions (kton)	Total Annual Costs (million Euros) - 2030					LOLE (days/year)
Alternative	Power System plus Transport Sector (ICVs)	Energy Efficiency measures	Power Generation	CSF[1]	EM[2]	TOTAL	
1	**262,98**	0,76	50,25	-0,64	0	**50,37**	**0,004**
2	**287,11**	0,76	49,14	0	0	**49,90**	**0,065**
3	**278,69**	0	51,77	0	1,32	**53,10**	**0,065**
4	**285,21**	0	51,24	0	0,13	**51,37**	**0,065**
5	**278,30**	0	50,93	0,57	0,76	**52,27**	**0,004**
6	**278,96**	0	51,15	-0,01	0,11	**51,25**	**0,004**
7	**390,35**	0,76	45,02	1,13	0	**46,91**	**0,130**
8	**390,35**	0,76	45,02	0	0	**45,79**	**0,846**
9	**412,09**	0	46,62	0	1,32	**47,94**	**0,846**
10	**409,41**	0	45,86	0	0,13	**45,99**	**0,846**
11	**409,83**	0	44,79	1,13	0,76	**46,68**	**0,130**
12	**408,49**	0	45,60	1,13	0,11	**46,84**	**0,130**
13	**494,44**	0,76	44,20	1,13	0	**46,09**	**1,057**
14	**494,44**	0,76	44,20	0	0	**44,96**	**9,308**
15	**516,18**	0	45,58	0	1,32	**46,90**	**9,308**
16	**513,51**	0	45,94	0	0,13	**46,07**	**9,308**
17	**513,92**	0	44,79	1,13	0,76	**46,67**	**1,057**
18	**512,58**	0	45,30	1,13	0,11	**46,54**	**1,057**
19	**166,58**	1,22	39,86	18,85	0	**59,92**	**4E-08**
20	**166,58**	1,22	28,95	0	0	**30,17**	**1E-06**
21	**162,85**	0,46	31,29	0	0,13	**31,88**	**1E-06**
22	**162,85**	0,46	31,29	0	0,13	**31,88**	**1E-06**
23	**173,32**	0,46	41,03	7,61	0,11	**49,21**	**4E-08**
24	**173,32**	0,46	41,03	7,61	0,11	**49,21**	**4E-08**
25	**182,37**	1,22	30,19	1,11	0	**32,52**	**2E-06**
26	**200,14**	1,22	25,77	0	0	**27,00**	**2E-05**
27	**183,98**	0,46	29,61	0	1,24	**31,30**	**2E-05**
28	**196,41**	0,46	28,11	0	0,13	**28,71**	**2E-05**
29	**183,74**	0,46	29,22	0,16	0,67	**30,51**	**2E-06**
30	**186,98**	0,46	29,56	0,10	0,11	**30,24**	**2E-06**
31	**261,26**	1,22	25,17	1,01	0	**27,40**	**7E-06**
32	**262,86**	1,22	25,27	0	0	**26,49**	**2E-04**
33	**282,61**	0,46	24,56	0	1,32	**26,34**	**2E-04**
34	**279,93**	0,46	25,26	0	0,13	**25,85**	**2E-04**
35	**280,35**	0,46	24,13	1,13	0,76	**26,47**	**7E-06**
36	**279,01**	0,46	25,15	1,13	0,11	**26,85**	**7E-06**

[1] Centralized Storage Facility
[2] Electric Mobility

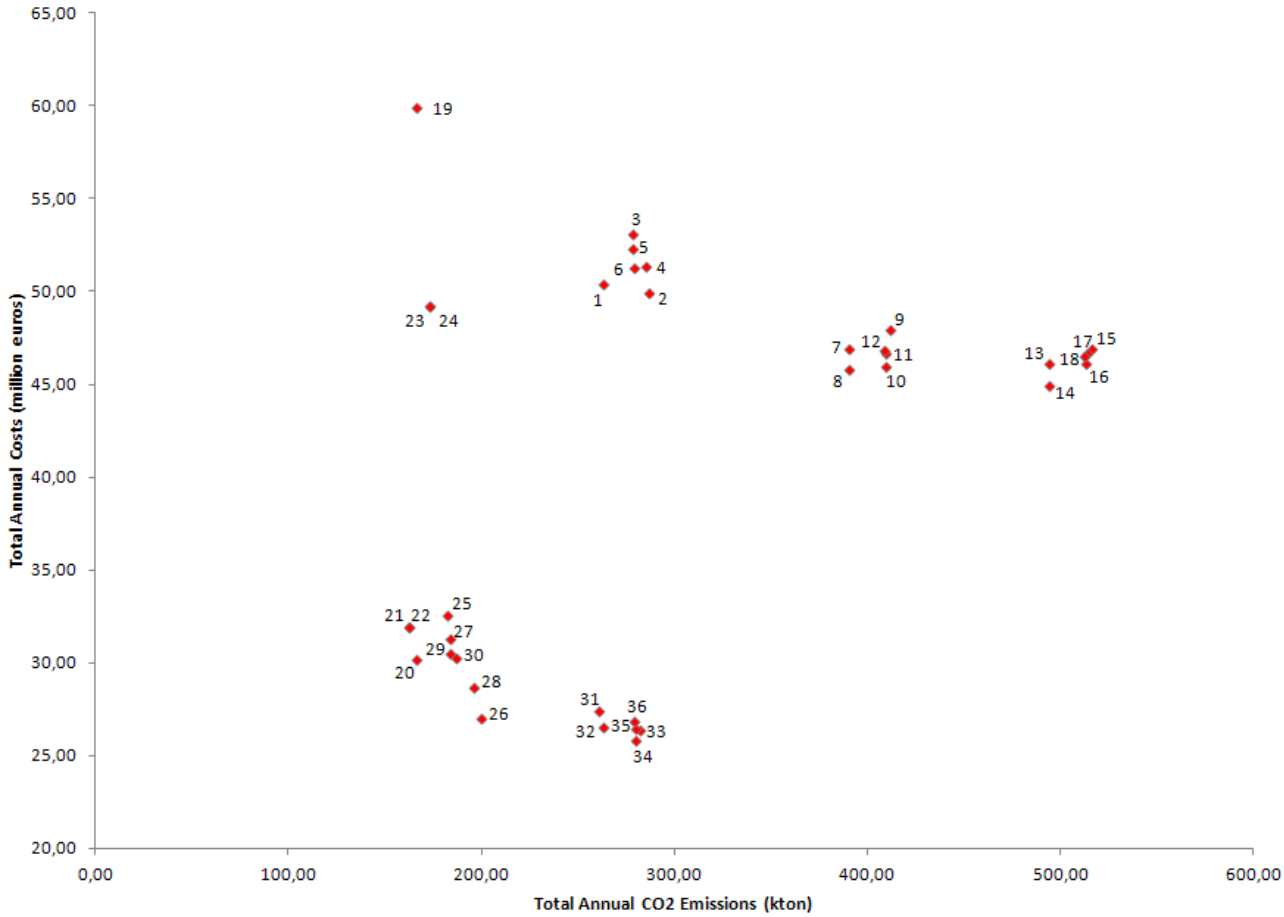


Fig. 64: Total annual costs and carbon emissions of the alternatives in 2030, for the "low prices" scenario, including power system's carbon emissions in the environmental attribute

According to the obtained results, alternatives with higher share of RES lead to lower carbon emissions. When it comes to the effect of energy efficiency measures on the load, the next graph illustrates that with the exception of alternatives 19, 23 and 24 (which are affected by the economic impact of CSF operation when there is energy surplus throughout all the day), all the other alternatives implementing energy efficiency measures on the load, have lower total annual costs.

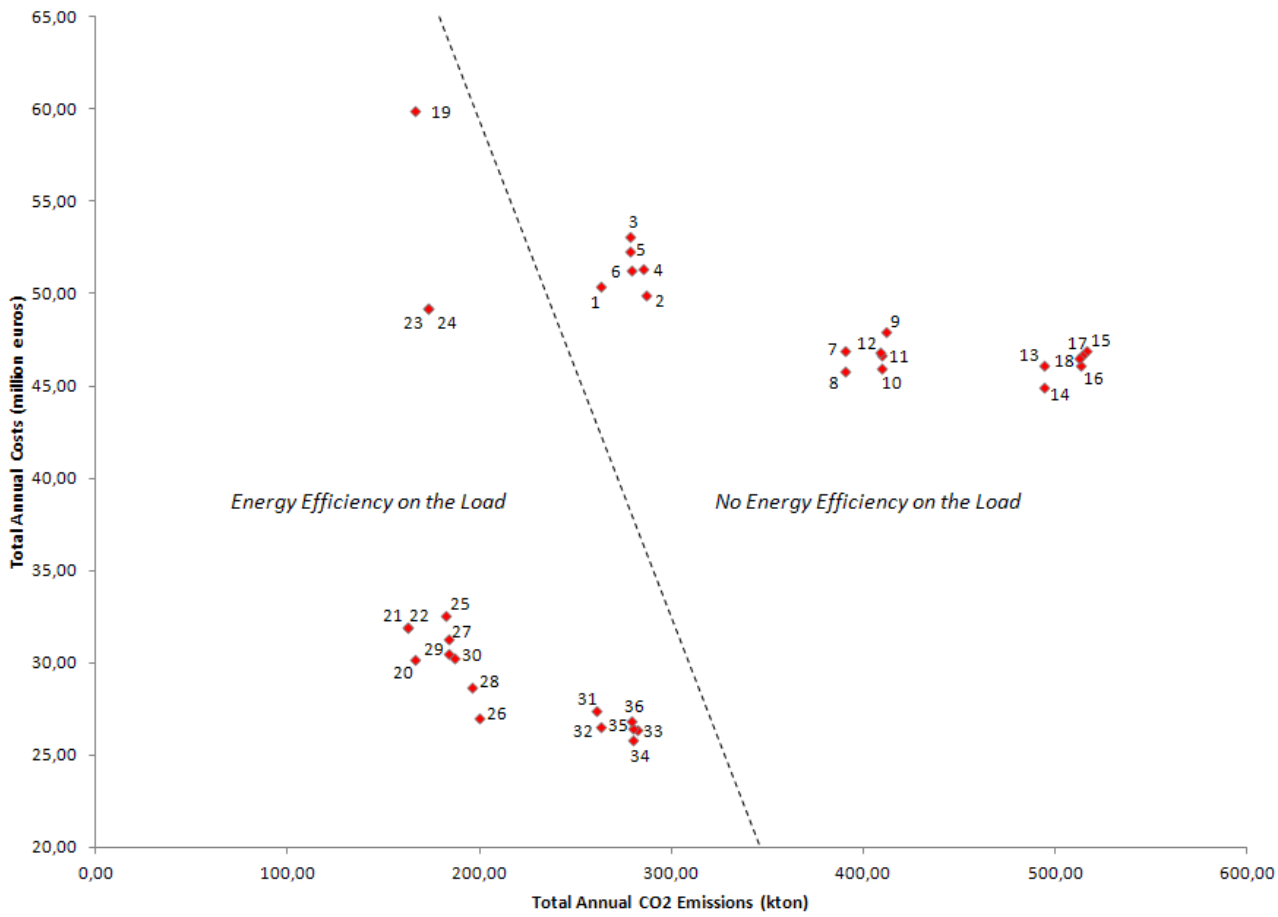


Fig. 65: Effect of energy efficiency measures on the load, on total annual costs and carbon emissions of the alternatives in 2030, for the “low prices” scenario

If the analysis is only focused on the power generation costs, all alternatives facing energy efficiency measures on the load present lower costs than the alternatives without energy efficiency measures. To explain this conclusion, an observation of the power generation options is worth performing, for both load increase and decrease pathways.

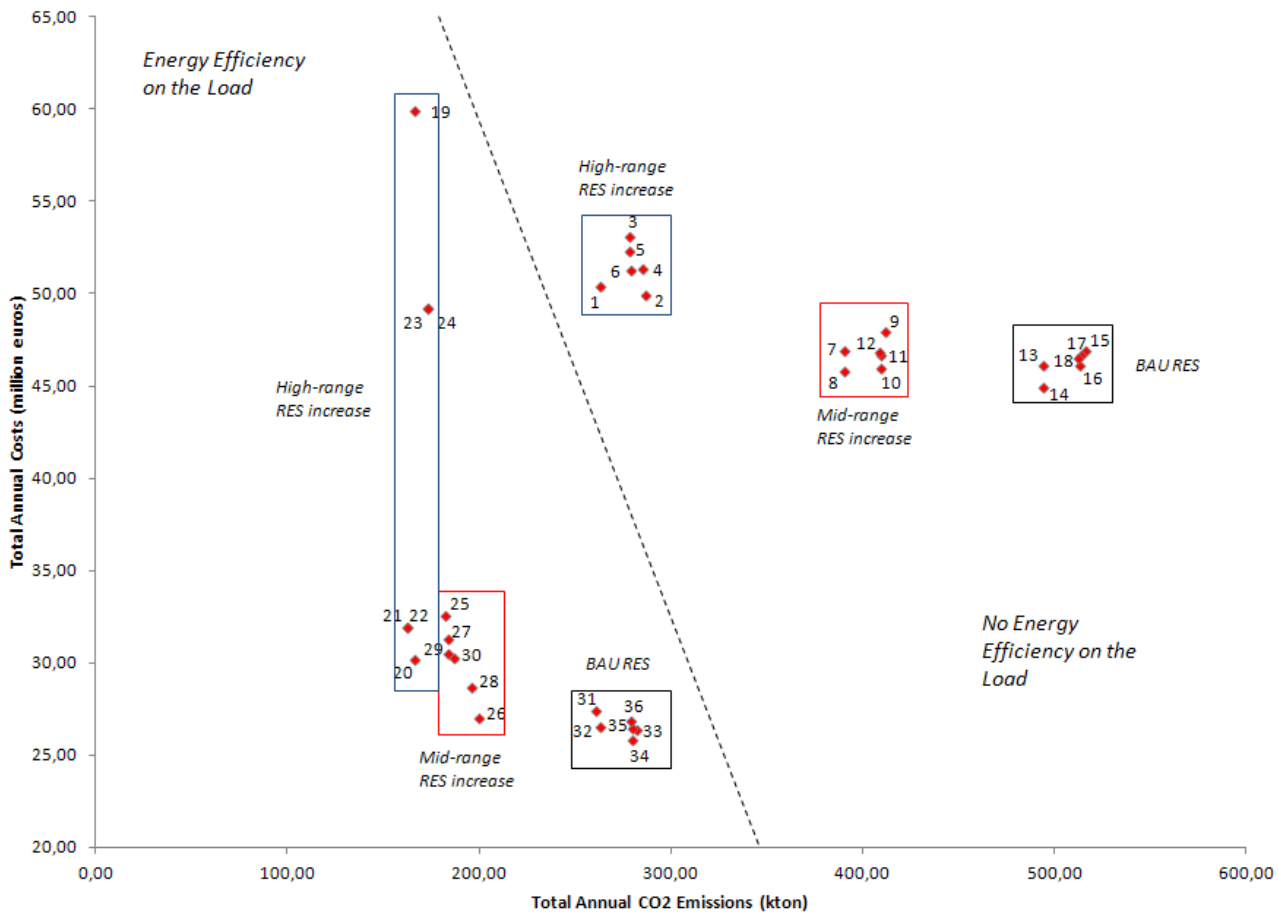


Fig. 66: Effect of energy efficiency measures on the load and RES pathways, on total annual costs and carbon emissions of the alternatives in 2030, for the "low prices" scenario

The previous plot ratifies the environmental benefits of RES increase and load decrease, and shows that, in terms of carbon emissions, alternatives with high-range RES increase and without energy efficiency on the load are similar to the ones with BAU RES together with energy efficiency measures on the power system. This finding was already stated in the analysis for the "high prices" scenario.

When it comes to the cost-effectiveness of energy efficiency on the power system, an economic analysis should be carried out (as described for the "high prices" scenario), by comparing: (i) annual cost per unit of electric energy generated, without investing on efficiency measures; (ii) annual cost per unit of electric energy generated, with energy efficiency measures; and (iii) annual cost per unit of electric energy generated, with energy efficiency measures, plus the annual cost for applying these measures.

This assessment will only consider comparable alternatives in terms of power generation, that's to say alternatives with neither electricity storage nor electric mobility.

Table 27 – Annual cost per unit of electric energy generated, without investing on efficiency measures, for “low prices” scenario in 2030

Annual Demand in 2030		654,37 GWh
Annual cost for electric energy generation (RES and non-RES)	High-range RES increase	49,14 million €
	Mid-range RES increase	45,02 million €
	BAU	44,20 million €
Annual cost per unit of electric energy generated	High-range RES increase	75,10 €/MWh
	Mid-range RES increase	68,81 €/MWh
	BAU	67,54 €/MWh

Table 28 – Annual cost per unit of electric energy generated, with energy efficiency measures, for “low prices” scenario in 2030

Annual Demand in 2030		369,04 GWh
Annual cost for electric energy generation (RES and non-RES)	High-range RES increase	28,95 million €
	Mid-range RES increase	25,77 million €
	BAU	25,27 million €
Annual cost per unit of electric energy generated	High-range RES increase	78,45 €/MWh
	Mid-range RES increase	69,84 €/MWh
	BAU	68,47 €/MWh

Table 29 – Annual cost per unit of electric energy generated, with energy efficiency measures, plus the annual cost for applying these measures, for “low prices” scenario in 2030

Annual Demand in 2030		369,04 GWh
Annual cost for electric energy generation (RES and non-RES)	High-range RES increase	29,41 million €
	Mid-range RES increase	26,24 million €
	BAU	25,73 million €
Annual cost per unit of electric energy generated (including the annual cost for energy efficiency)	High-range RES increase	79,70 €/MWh
	Mid-range RES increase	71,09 €/MWh
	BAU	69,72 €/MWh

The previous tables allow observing that alternatives implementing energy efficiency measures result on higher annual cost per unit of electric energy generated, comparing to analogous alternatives that don’t invest on load reduction. This relation becomes even bolder when adding the annual costs for energy efficiency on power system, to the power generation costs. The annual costs of energy efficiency increase linearly over time and, in 2030, stand for 461 thousand Euros of investment. This finding is contradictory to what was obtained for the “high prices” scenario, in

which the alternatives applying energy efficiency measures were more beneficial than the others, regarding the cost per unit of electric energy generation.

The next figure represents graphically the concerned alternatives, in terms of total annual costs (more than just power generation costs) and total carbon emissions.

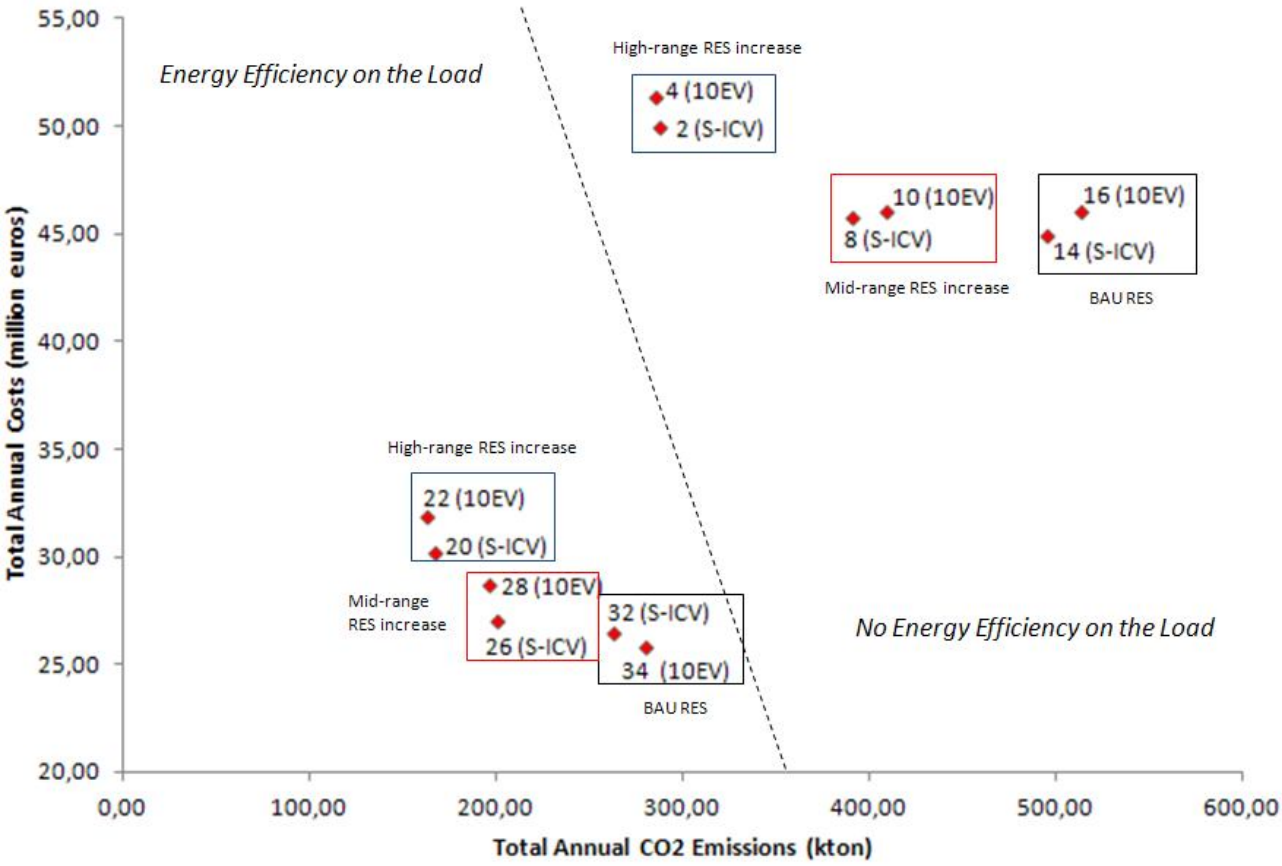
Fig. 67: Effect of RES pathways, on total annual costs and carbon emissions of the alternatives in 2030, for the "low prices" scenario

According to the above plot, although alternatives with energy efficiency measures on the load lead to a higher cost per unit of electric energy generated, these result on global lower costs than alternatives without energy efficiency.

Concerning total annual costs, fuel-oil thermal generation becomes more cost-competitive than renewable energy sources. That's to say, BAU RES option is economically more beneficial than high-range and mid-range RES options, for both load strategies. According to the previous plot and Table 27, Table 28 and Table 29, BAU RES plus energy efficiency on the load is the preferred match, when it comes to total annual costs.

In terms of carbon emissions, alternatives applying energy efficiency measures on the load lead to lower amounts of CO_2. In addition, the higher the RES share in the mix, the lower the carbon emissions.

To compare the mobility options in terms of costs and carbon emissions, the alternatives should be compared for the same planning specifications. Therefore, firstly mobility alternatives will be presented, without neither CSF nor V2G. The next graph presents the alternatives for sustainable mobility, including the RES and load characteristics.



Legend:

S-ICV: Efficient ICVs, Biofuels and Behavioural Change

10EV: 10 000 EVs pathway without V2G

Fig. 68: Assessment of mobility options in terms of costs and carbon emissions, in 2030, for the "low prices" scenario

The previous plot allows concluding that alternative 22 has the lowest total carbon emissions, whereas alternative 34 leads to the lowest costs. The referred graph also enables observing six groups of alternatives, influenced by the RES strategy. The comparison of mobility options should then be done within each group of alternatives.

Within the group of alternatives that don't apply energy efficiency measures on the load, if BAU RES option is followed, alternative 14 (Efficient ICVs, Biofuels and Behavioural Change) has both lower costs and carbon emissions than the other option (alternative 16). This is justified since the additional energy demand for EVs charging (alternative 16) is fulfilled by thermal units, which

results on both higher power generation costs (more 1,8 million Euros) and emissions (more 22,8 kton CO_2), but lower ICVs emissions (less 3,7 kton CO_2).

When it comes to the alternatives adopting mid-range RES increase, alternative 8 (Efficient ICVs, Biofuels and Behavioural Change) leads to both lower costs and carbon emissions than the other option (alternative 10), due to the same reasons presented for the BAU RES option. Again this happens because the additional energy demand for EVs charging (alternative 10) is filled up by thermal units, which leads to both higher power generation costs (more 0,8 million Euros) and emissions (more 22,8 kton CO_2), but lower ICVs emissions (less 3,7 kton CO_2). These results allow inferring that there is a similar relationship between the mobility options, for both BAU and mid-range RES increase.

Alternatively, if high-range RES increase is followed, alternative 4 (10 000 EVs pathway), has lower carbon emissions than the other strategy (alternative 2). Now the extra energy demand for EVs charging is provided by RES, which lowers the total amount of emissions (less 1,9 kton CO_2), but still leads to higher power generation costs than alternative 2 (more 2,1 million Euros).

Concerning alternatives adopting energy efficiency measures, if BAU RES option is pursued, alternative 32 (Efficient ICVs, Biofuels and Behavioural Change) despite having lower emissions, leads to higher costs than alternative 34 (10 000 EVs pathway). In fact, alternative 32 leads to less 20,8 kton CO_2 from the power system than alternative 34, since the EVs are “fuelled” mostly by additional thermal power generation. On the other hand, alternative 34 results on a fall of carbon emissions from the ICVs, comparing to alternative 32 (less 3,7 kton CO_2), but globally still has higher emissions than the latter (more 17,1 kton CO_2). In terms of power generation costs, theoretically, alternative 32 should also be more competitive. However, the analysis of the load/generation profile allows noticing that although alternative 34 has a higher demand of energy (more annual 27,8 GWh), the power generation costs are lower than the registered in alternative 32 (less annual 10,5 thousand Euros). Taking into account the operation rules of the system, alternative 34 enables a better cost performance of fuel oil units, than alternative 32, as sketched out next.

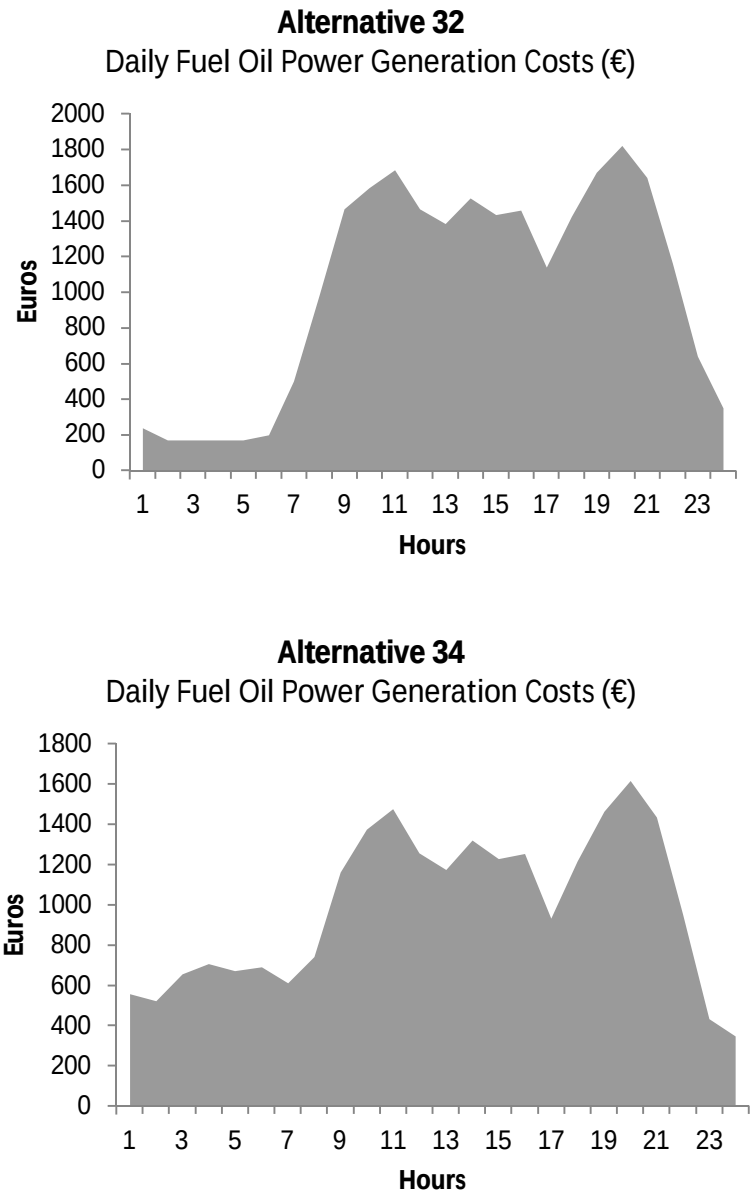


Fig. 69: Thermal-based power generation costs of alternatives 32 and 36, for the "low prices" scenario

Concerning the options with mid-range RES increase, alternative 28 (10 000 EVs pathway) leads to lower carbon emissions and higher costs than alternative 26 (Efficient ICVs, Biofuels and Behavioural Change). As a matter of fact, in alternative 28, the additional energy demand for EVs charging is provided by RES, therefore there are no extra carbon emissions from the power system owing to electric mobility. Furthermore, alternative 28 also benefits from the decrease of carbon emissions from the ICVs (less 3,7 kton CO_2 than alternative 26). Regarding the costs, the additional power generation for EVs "fuelling", in alternative 28, leads to more 2,3 million Euros of cost (accounted to RES), than for alternative 26.

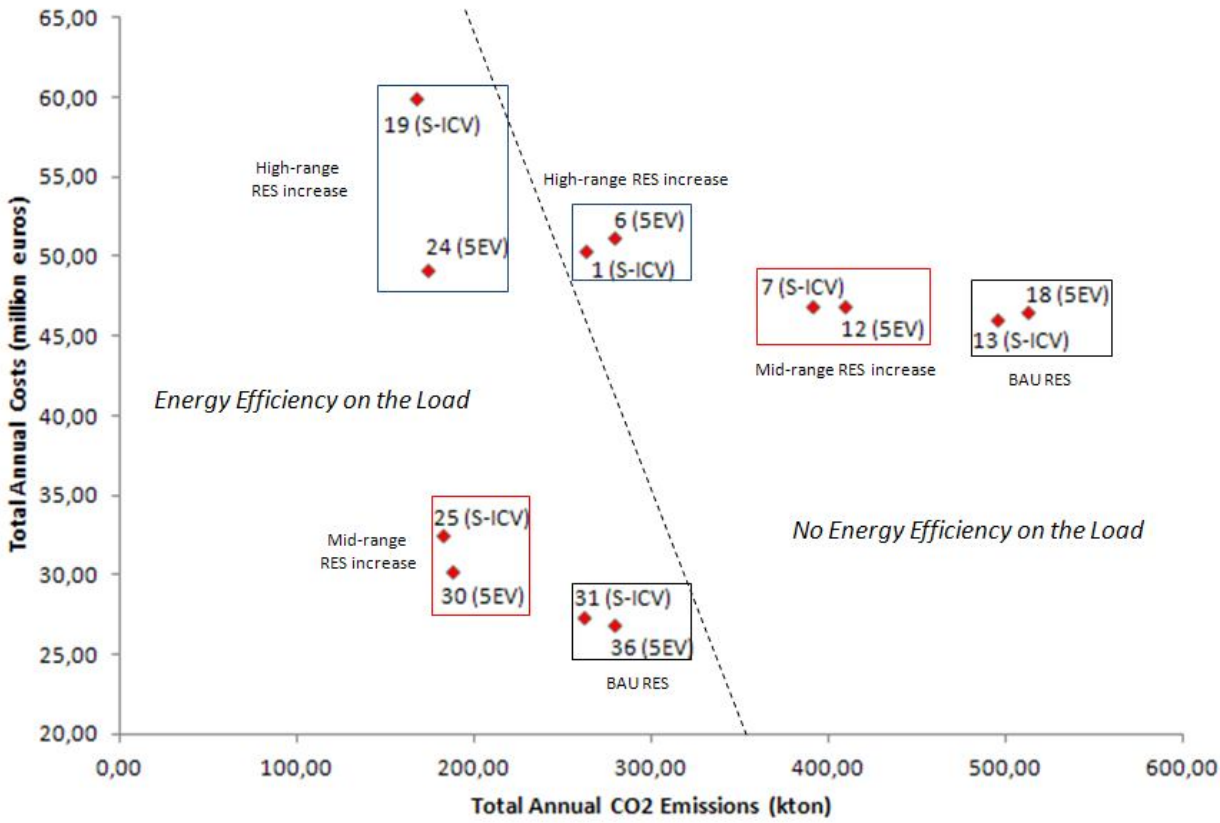
Finally, regarding the high-range RES increase, alternative 22 (10 000 EVs pathway) leads to lower carbon emissions and higher costs than alternative 20 (Efficient ICVs, Biofuels and Behavioural

Change). The relationship between these two alternatives is indeed similar to the registered in the case of mid-range RES increase, both on power generation costs and emissions.

From the previous analysis, some conclusions can be drawn, similar to what was presented for the "high prices" scenario:

- Electric mobility becomes environmentally more beneficial with the increase of RES;
- Electric mobility needs lower amounts of RES to be environmentally competitive, in the case of investing on energy efficiency measures on the load;
- Only when there is a load decrease and BAU RES, electric mobility appears economically competitive (thanks to the operation of power units with lower cost for electric energy generation).

At this time mobility alternatives will be presented, together with CSF, yet disregarding V2G strategy. The next graph presents the alternatives for sustainable mobility plus CSF, including the RES and load characteristics.



Legend:

S-ICV: Efficient ICVs, Biofuels and Behavioural Change, plus CSF

5EV: 5 000 EVs pathway (without V2G), plus CSF

Fig. 70: Assessment of mobility options together with CSF, in terms of costs and carbon emissions, in 2030, for the "low prices" scenario

The previous plot allows concluding that alternative 19 has the lowest total carbon emissions, whereas alternative 36 leads to the lowest costs. The referred graph also enables observing six groups of alternatives, influenced by the RES strategy. The comparison of mobility options should then be done within each group of alternatives.

Within the group of alternatives that don't apply energy efficiency measures on the load, if BAU RES option is followed, alternative 13 (Efficient ICVs, Biofuels and Behavioural Change, plus CSF) has both lower costs and carbon emissions than the other option (alternative 18). This is justified since the additional energy demand for EVs charging (alternative 18) is fulfilled by thermal units (there is no energy surplus), which results on both higher power generation costs (more 1,1 million Euros) and emissions (more 11,4 kton CO_2), and higher ICVs emissions (more 6,7 kton CO_2).

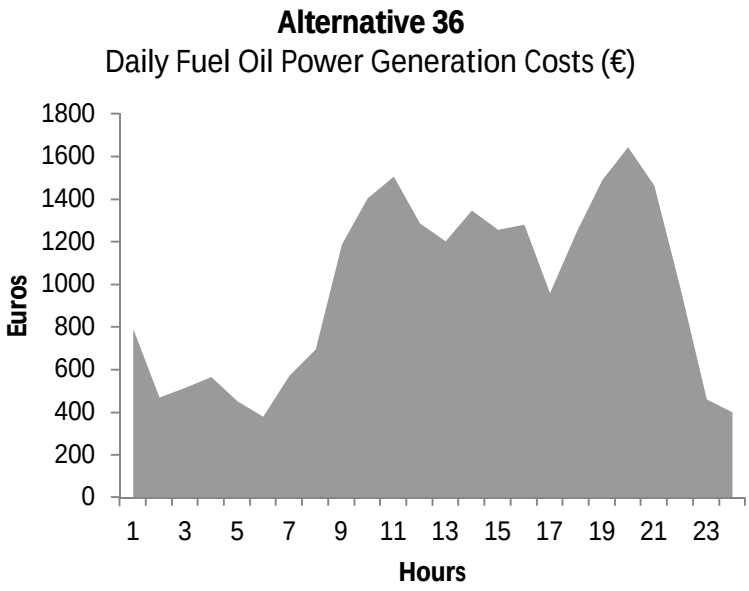
When it comes to the alternatives adopting mid-range RES increase, alternative 7 (Efficient ICVs, Biofuels and Behavioural Change, plus CSF) leads to lower carbon emissions than the other option (alternative 12), but the latter results on slightly lower total costs than the former. Although alternative 12 has higher power generation costs (more 575 thousand Euros due to the additional energy demand for EVs charging, filled up by thermal units), it leads to lower total costs than alternative 7 owing to the effect of investment costs on Efficient ICVs, Biofuels and Behavioural Change (more 761 thousand Euros) of the latter option. Regarding the environmental attribute, alternative 12 results on both higher carbon emissions from the power system (more 11,4 kton CO_2) and from ICVs (more 6,7 kton CO_2).

In addition, if high-range RES increase is followed, alternative 1 (Efficient ICVs, Biofuels and Behavioural Change, plus CSF), has both lower costs and carbon emissions than the other option (alternative 6). Alternative 6 leads to additional energy demand for EVs charging, which stands for more 13,9 GWh/year totally supplied by RES. This alternative has also 23,6 GWh/year of energy surplus stored by the CSF (through an equivalent load increase). When it comes to alternative 1, it observes an energy surplus of 36,9 GWh/year (based on RES), stored by the centralized storage facility (through an equivalent load increase). Therefore, both alternatives have the same RES power generation costs. In addition, alternative 1 has lower thermal-based power generation costs (less 0,9 million Euros) and carbon emissions (less 9,2 kton CO_2), owing to a larger energy shift from the CSF (more 10,6 GWh of CSF power generation). In case of energy surplus, the larger the EVs charging, the lower will be the stored energy by the CSF. In terms of emissions from the ICVs, alternative 6 results on more 6,7 kton CO_2, in 2030.

To sum up, if energy efficiency is not applied on the load, the alternatives personified by Efficient ICVs, Biofuels and Behavioural Change, plus CSF, are preferred both in terms of costs and emissions, except when mid-range RES increase is chosen, for which the 5 000 EVs pathway together with CSF contributes for lower costs than the former option.

Hereinafter an analysis is performed on the alternatives implementing energy efficiency measures on the load. If BAU RES option is followed, alternative 31 (Efficient ICVs, Biofuels and Behavioural Change, plus CSF) has lower global carbon emissions (less 17,7 kton CO_2) but higher total annual costs (more 554 thousand Euros) than alternative 36.

Alternative 36 leads to additional energy demand for EVs charging, which stands for more 13,9 GWh/year. Part of this extra load is supplied by RES (2,4 GWh/year). In alternative 31, where there are no EVs, that energy (surplus) is stored by the CSF, which is afterwards converted into electricity (with transformation losses). Therefore, both alternatives have equal RES power generation costs. Concerning thermal-based power generation costs, alternative 36 although has a higher electric load, results on better cost performance (less 23 thousand Euros per year), due to the power system operation rules, as sketched out below.



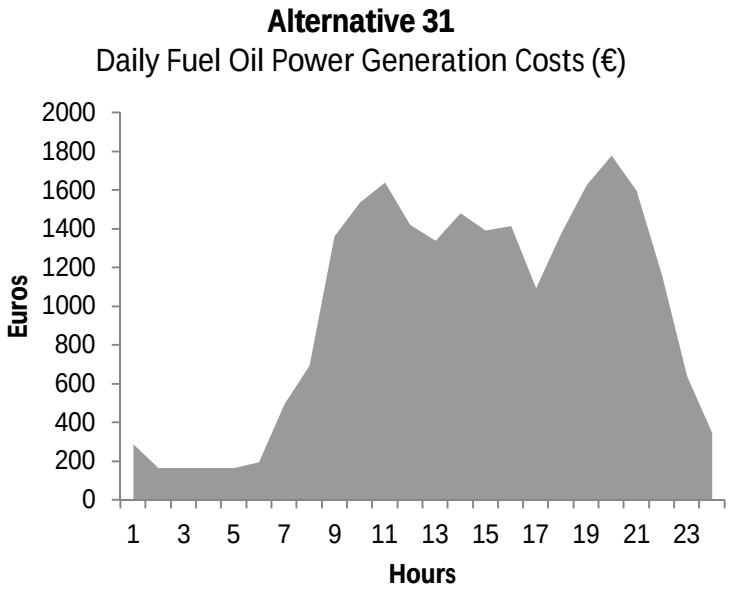


Fig. 71: Thermal-based power generation costs of alternatives 31 and 36, for the “low prices” scenario

Nonetheless, alternative 36 leads to higher carbon emissions from both the power system (more 11,0 kton CO_2, due to the effect of EVs charging) and ICVs (more 6,7 kton CO_2), than alternative 31.

Concerning the options with mid-range RES increase, alternative 30 (5 000 EVs plus CSF) leads to higher carbon emissions and lower costs than alternative 25 (Efficient ICVs, Biofuels and Behavioural Change, plus CSF). Alternative 30 leads to additional energy demand for EVs charging, which stands for more 13,9 GWh/year totally supplied by RES. This alternative has also 39,0 GWh/year of energy surplus stored by the CSF (through an equivalent load increase). When it

comes to alternative 25, it observes an energy surplus of 53,0 GWh/year (based on RES), stored by the centralized storage facility (through an equivalent load increase). Therefore, both alternatives have the same RES power generation costs.

Alternative 30 allows a higher energy shift through CSF (more 2,6 GWh/year) and better cost performance of thermal-based power generation (less 626 thousand Euros of power generation costs per year), due to the power system operation rules. These drivers justify a higher cost-competitiveness of alternative 30, over alternative 25. What's more, since the CSF generation is higher in alternative 30, the carbon emissions from the power system are lower in this option, than in alternative 25. Bearing in mind that the additional energy demand for EVs charging (in alternative 30) is provided by RES, there are no extra carbon emissions from the power system owing to electric mobility. However, alternative 25 has lower carbon emissions from the ICVs (less 6,7 kton CO_2) than alternative 30.

Finally, regarding the options with high-range RES increase, alternative 24 (5 000 EVs plus CSF) leads to higher carbon emissions and lower costs than alternative 19 (Efficient ICVs, Biofuels and Behavioural Change, plus CSF). Alternative 24 has an additional energy demand for EVs charging, totalling 13,9 GWh/year fully supplied by RES. This alternative has also 129,8 GWh/year of energy surplus stored by the CSF (through an equivalent load increase), but there is yet 31,2 GWh/year of energy surplus not stored owing to lack of capacity of the CSF. When it comes to alternative 19, it stores 129,8 GWh/year of energy surplus (based on RES) by the CSF (through an equivalent load increase), but there is still 45,1 GWh/year of energy surplus not stored, bearing in mind lack of CSF capacity.

In terms of power generation costs, alternative 24 has higher RES based costs than alternative 19 (more 1,2 million Euros/year) for EVs charging. Both alternatives observe energy surplus during all day, which turns thermal generation operating at minimum levels. Hence, alternatives 19 and 24 share the same fuel oil power generation costs. One should also emphasize the harmful effect of an all-day energy surplus, which leads to ineffective CSF operation. That's to say, since CSF can't inject electricity back into the grid (after storing the energy surplus), it is unable to perform energy trading. This results on very high positive operation costs (negative gross margin) from the CSF for both alternative 19 and 24, totalling excessive annual costs comparing to the analogous alternatives. In view of these findings, the present match between high-range RES increase and energy efficiency on the load turns CSF an inappropriate option, owing to lack of opportunity for performing its energy shift mission.

When it comes to the environment perspective, the alternatives under analysis have the same carbon emissions from the power system. Bearing in mind that the additional energy demand for EVs

charging (in alternative 24) is provided by RES, there are no extra carbon emissions from the power system owing to electric mobility. However, alternative 19 has lower carbon emissions from the ICVs (less 6,7 kton CO_2) than alternative 24.

From the previous analysis the next insights can be drawn:

- If energy efficiency measures are applied on the load, the option with Efficient ICVs, Biofuels and Behavioural Change, plus CSF, originates lower carbon emissions, but higher total costs than the alternative with 5 000 EVs plus CSF;
- If energy efficiency measures are not applied on the load, the alternatives personified by Efficient ICVs, Biofuels and Behavioural Change, plus CSF, are preferred both in terms of costs and emissions, except when mid-range RES increase is chosen, for which the 5 000 EVs pathway together with CSF contributes for lower costs than the former option.

As far as V2G is concerned, the next plot depicts the alternatives with electric mobility in terms of the V2G strategy ("Yes" for alternatives applying V2G; "No" for alternatives not applying V2G).

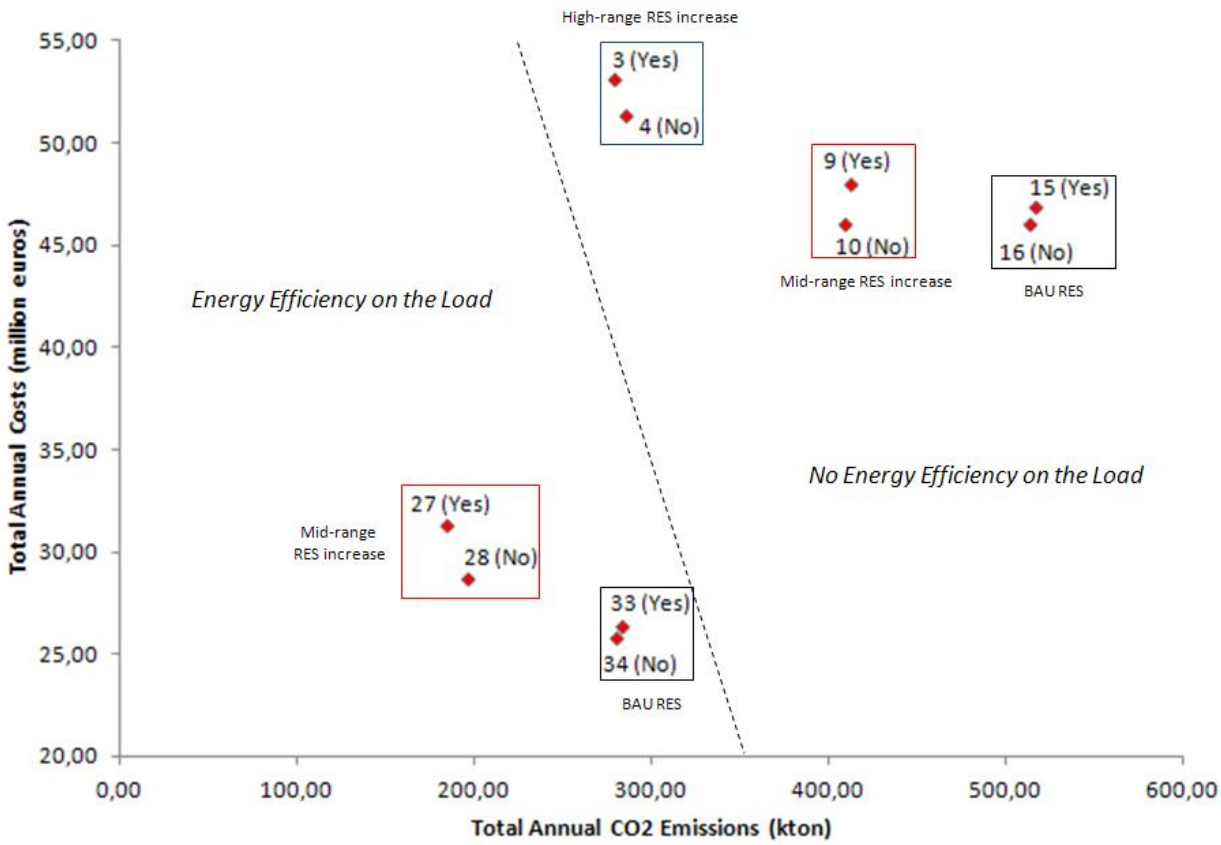


Fig. 72: Total annual costs and carbon emissions of alternatives with 10 000 EVs in 2030, for the "low prices" scenario

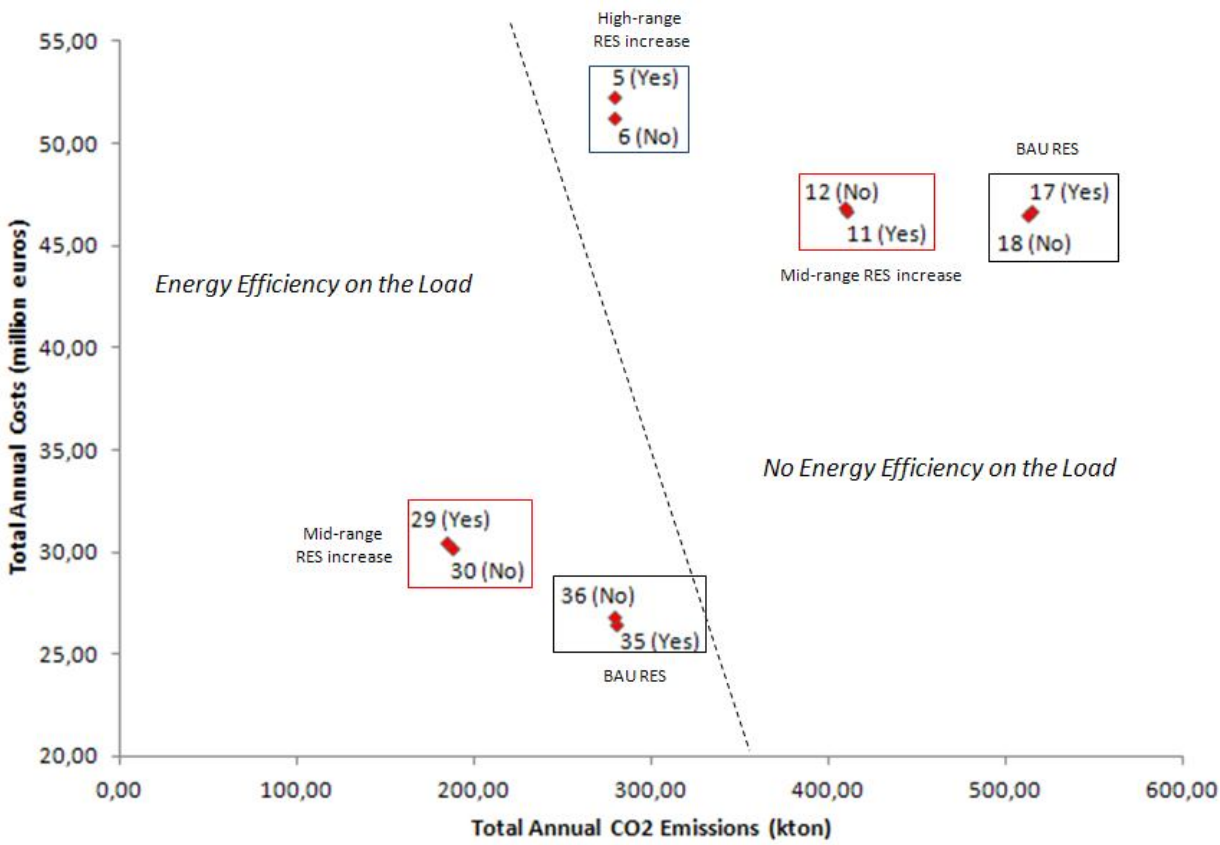


Fig. 73: Total annual costs and carbon emissions of alternatives with 5 000 EVs in 2030, for the "low prices" scenario

These graphs don't include the alternatives 21 and 22 (Fig. 72), as well as 23 and 24 (Fig. 73), because in the corresponding circumstances (high-range RES increase and energy efficiency on the load), there is lack of opportunity for V2G. That's to say, 21 is equal to 22 (no V2G) and 23 is equal to 24 (no V2G).

Concerning the alternatives with 10 000 EVs, all them with V2G have higher total costs. As opposition to what happens for the "high prices" scenario (where V2G is beneficial in terms of costs), the energy trading performed by the electric mobility investor and operator (local utility) results on negative gross margin (positive costs), as a consequence of lower electricity rates for the current scenario. That's to say, the local utility is unable to completely pass through (to electricity consumers) the purchase cost of electricity generated through V2G. In addition, if in one hand V2G reduces power generation costs during off-valley hours, in the other hand this strategy increases the load at valley periods.

In fact, alternatives 27 (efficiency measures on the load; mid-range RES increase; without CSF; with 10 000 EVs; and V2G) and 29 (efficiency measures on the load; mid-range RES increase; with CSF; with 5 000 EVs; and V2G) have higher total annual costs in the "low prices" scenario, than in the "high prices" scenario. This happens mostly due to the effect of electric mobility costs.

When it comes to alternatives with 5 000 EVs, V2G is only beneficial in terms of total costs for the next combinations:

- Energy efficiency on the load, together with BAU RES;
- No energy efficiency on the load, together with mid-range RES increase.

In these cases V2G is a cost-competitive solution, because the drop of power generation costs during off-valley hours is enough to offset the positive costs of electric mobility.
The difference between 10 000 and 5 000 EVs, in terms of V2G impact, derive from the magnitude of the negative margin related to the energy trading, associated to the electric mobility. The larger the number of EVs performing V2G in this prices scenario, the higher the negative margin (positive costs) of the electric mobility investor and operator. These electric mobility costs are a combination of current prices scenario's parameters for electricity rates, and the amount of energy charged to and dispatched by EVs.

When it comes to the environment analysis, one should highlight that V2G strategy has no influence on the CO_2 emissions from ICVs, since the V2G energy requirements are fulfilled by an electricity consumption increase from the EVs, without changing the mobility pattern. Therefore, the environment impact of V2G depends on the energy mix, as well as the global balance between CO_2 emitted due to EVs charging and CO_2 avoided owing to the electricity dispatched by EVs, through V2G. For alternatives when there is no energy efficiency on the load, V2G allows lower global carbon emissions only if high-range RES increase is followed. Alternatively, for alternatives applying energy efficiency measures, V2G leads to lower CO_2 emissions in the case of mid-range RES increase.

Finally, when it comes to the reliability influence on energy planning, the next figure presents the alternatives results for the attributes referred to Total Annual Costs (in million Euros) and Loss of Load Expectation (days/year).

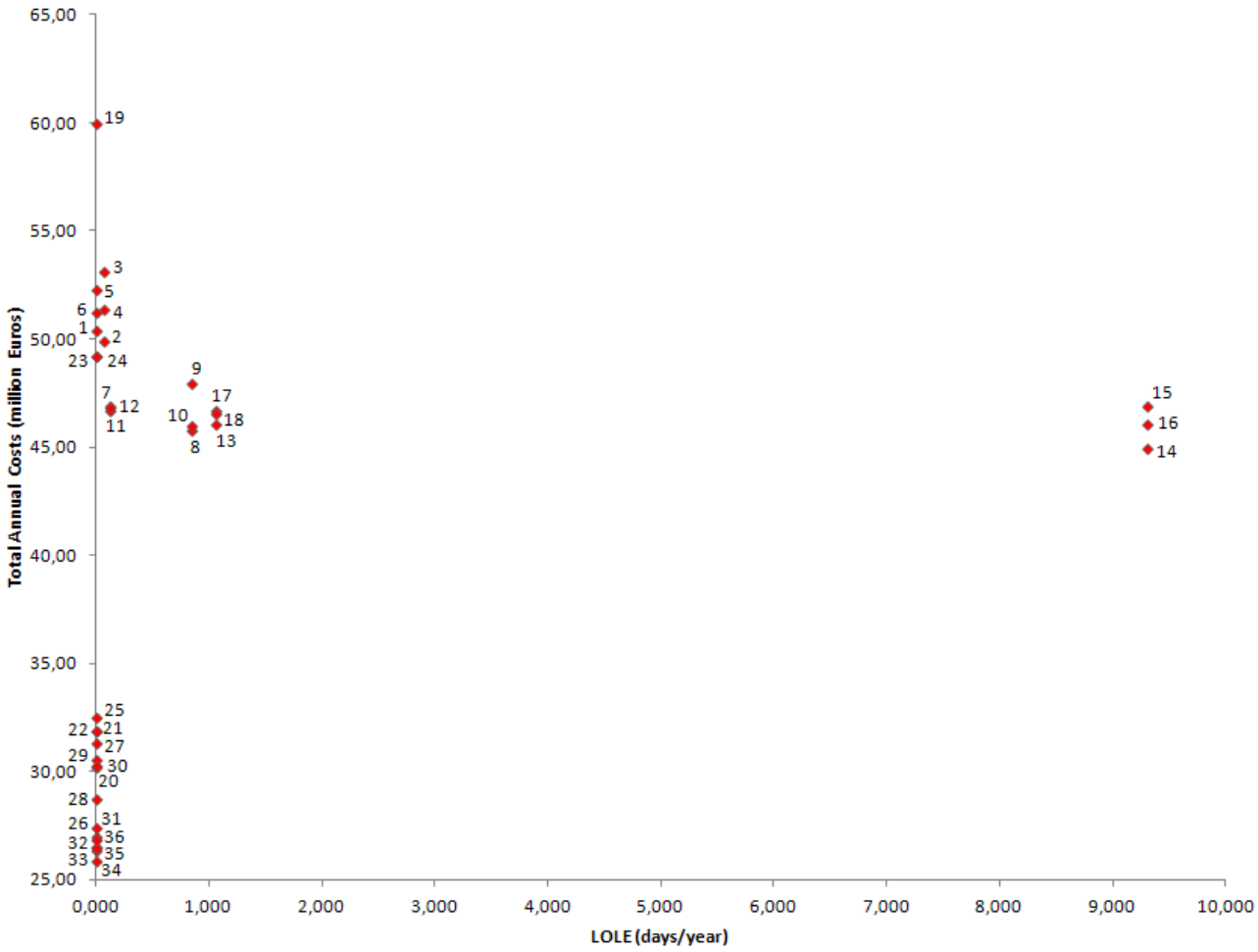


Fig. 74: Total annual costs and LOLE of the alternatives in 2030, for the “low prices” scenario

Taking into account that alternatives 14, 15 and 16 draw unacceptable LOLE, the next figure disregards the referred alternatives.

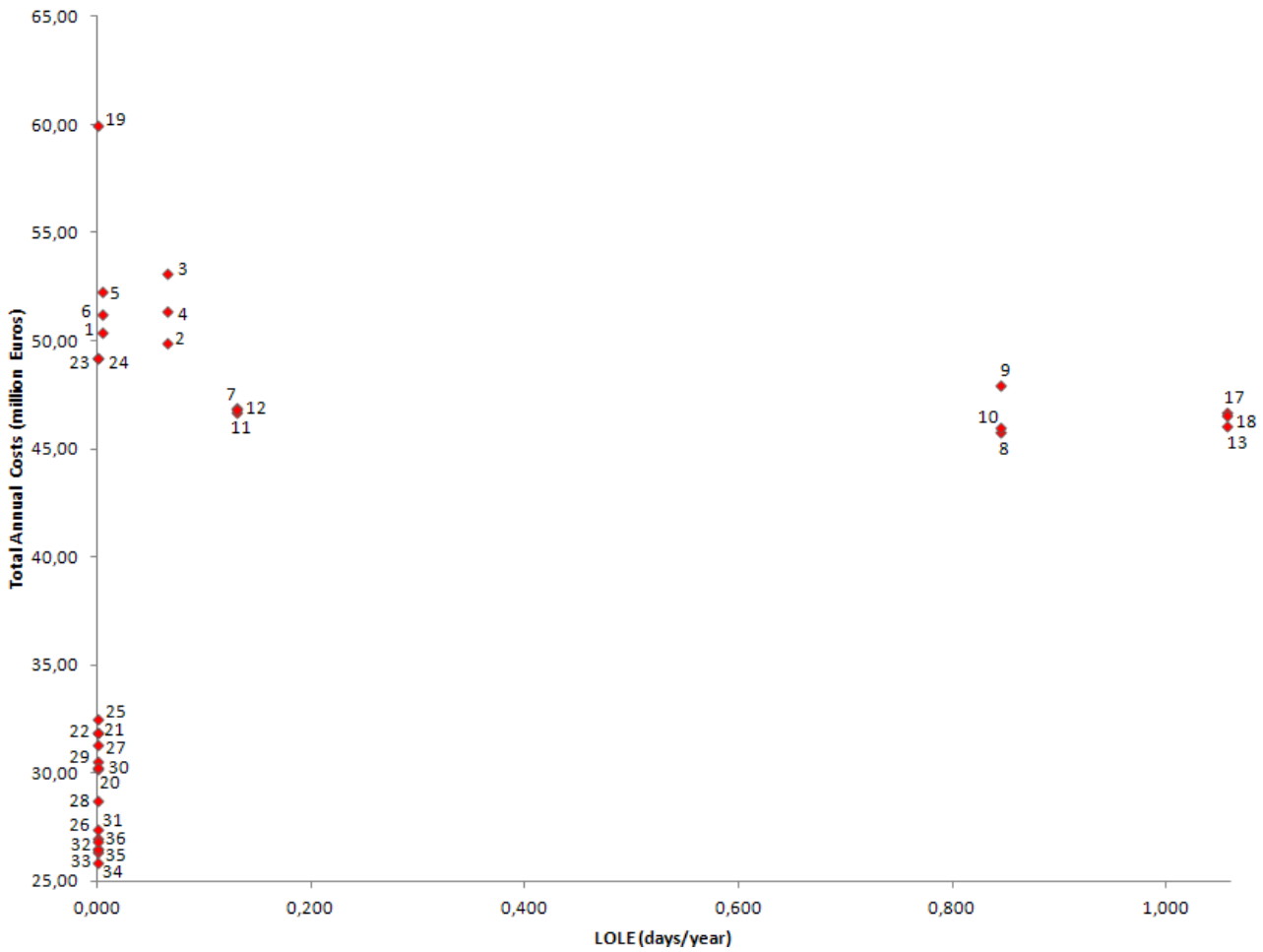


Fig. 75: Total annual costs and LOLE of a reduced set of alternatives in 2030, for the “low prices” scenario

From the previous graphs one observes a set of alternatives having a LOLE very close to zero. In view of getting a rather detailed analysis on the Cost/LOLE relationship, the next figure presents the influence of energy efficiency measures on the load and RES strategies.

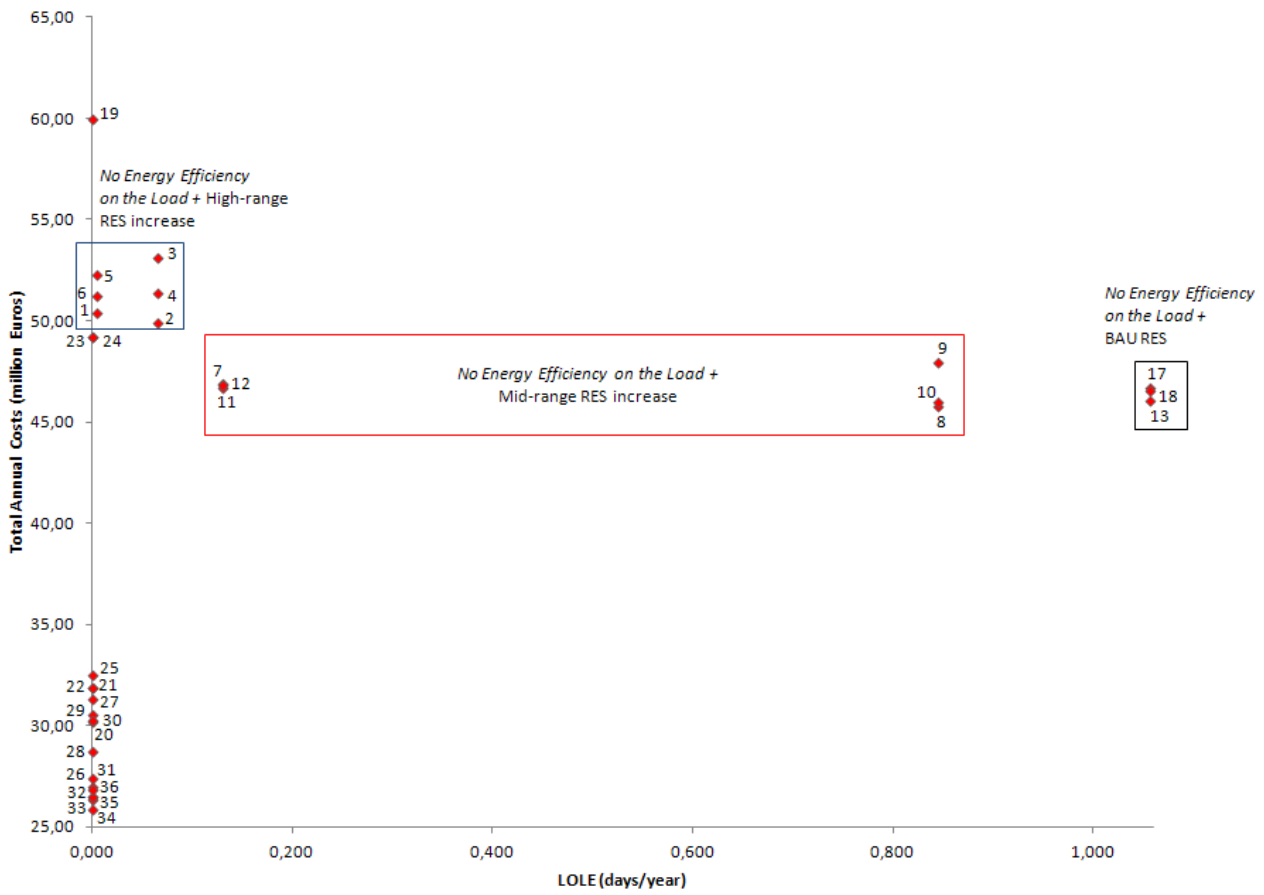


Fig. 76: Effect of energy efficiency measures on the load and RES pathways on total annual costs and LOLE, of a reduced set of alternatives in 2030, for the "low prices" scenario

The previous graph allows inferring that all the alternatives facing energy efficiency measures on the load present lower LOLE than the alternatives without energy efficiency measures. In addition, LOLE is lower in alternatives with higher capacity of renewable energy sources. At this moment, one should remember that the fuel oil power capacity is the same for all the RES pathways. That's to say, high-range RES increase doesn't lead to a thermal power decommissioning, comparing to the mid-range RES increase and BAU RES.

Regarding the effect of electricity storage on the generation system adequacy, the presence of CSF decreases considerably the LOLE. Accordingly, all the alternatives with hydro pumped storage present better adequacy levels than the others. The CSF has the effect of a hydro power unit, concerning adequacy assessment. Concerning the electric mobility impact on the power system adequacy, the EVs' charging is disregarded, since it occurs during valley hours, having, as a result, no effect in the daily peak load curve. In addition, V2G contribution is also neglected for LOLE assessment.

The CSF effect on the generation system adequacy can be observed by comparing alternatives, with the same energy mix, but with and without CSF. The text table just presents alternatives without energy efficiency on the load, to get a clearer impact of both RES levels and CSF.

Table 30 – CSF and RES effect on LOLE, for alternatives without energy efficiency on the load, for the "low prices" scenario in 2030

RES pathway	**Electricity Storage strategy**	**LOLE (days/year)**
High-range RES increase	With CSF (alternatives 1, 5 and 6)	0,004
	Without CSF (alternatives 2, 3 and 4)	0,065
Mid-range RES increase	With CSF (alternatives 7, 11 and 12)	0,130
	Without CSF (alternatives 8, 9 and 10)	0,846
BAU	With CSF (alternatives 13, 17 and 18)	1,057
	Without CSF (alternatives 14, 15 and 16)	9,308

5.3.5 Multi-attribute and Multi-scenario Analysis

Having analysed the results from both high and low prices scenarios, now decision issues shall be addressed. The problem under study is multi-attribute (three attributes) and multi-scenario (two scenarios). The three attributes calculated in this case study are: annual carbon emissions costs from power system and transport sector; total annual costs; and loss of load expectation. Through the results analysis provided in the previous section, the LOLE was found reasonable for most of the alternatives (for both scenarios), except for a reduced set of alternatives.

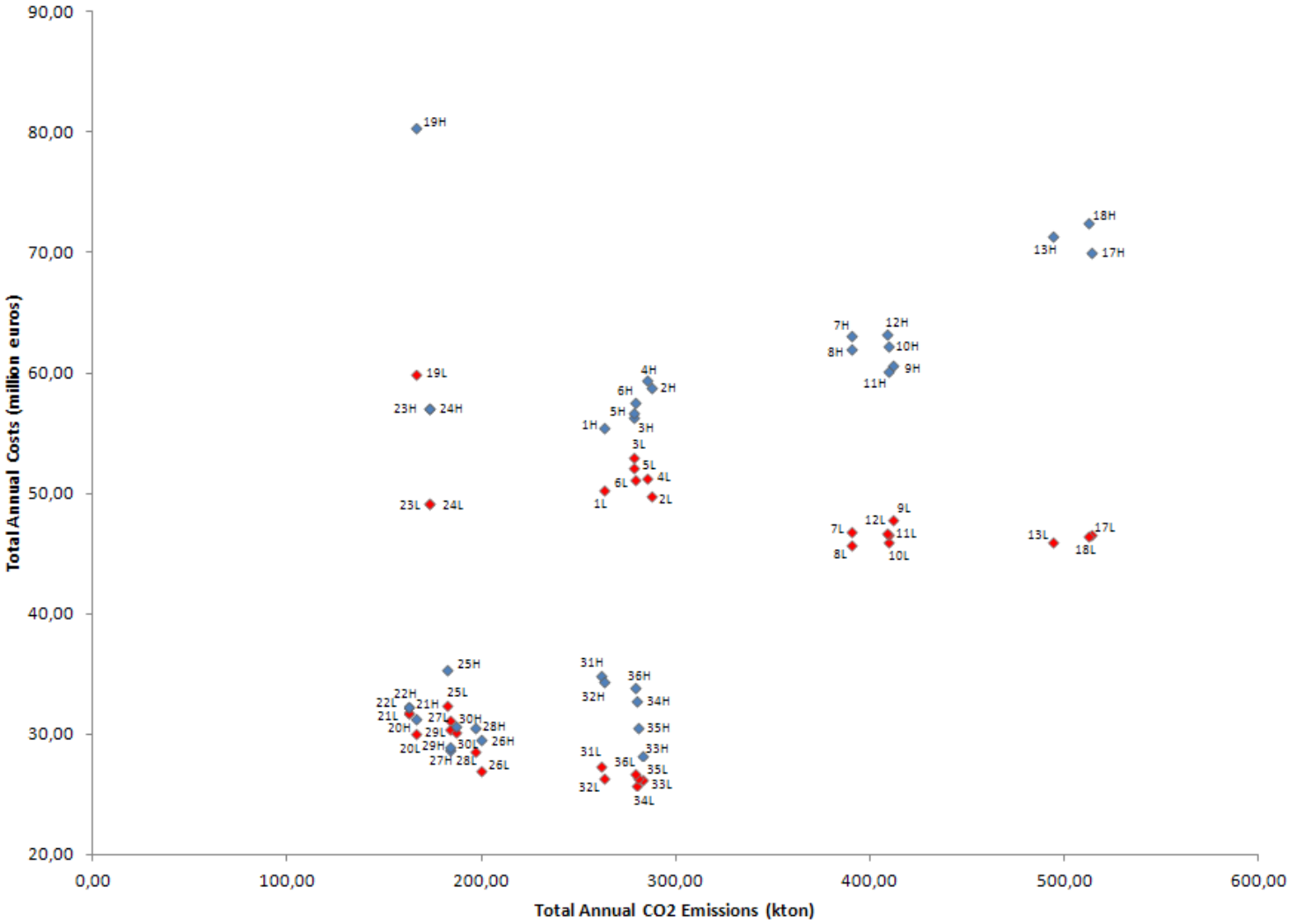
As a consequence, the next approach is followed for the multi-attribute and multi-scenario analysis:

1. Find a reduced set of alternatives, using LOLE as constraint;
2. Exclude dominated alternatives;
3. For each scenario, provide auxiliary calculations regarding the trade-offs and compute the alternatives' equivalent costs;
4. Apply a meaningful risk index.

Thus, an analysis is proposed for two attributes (carbon emissions and costs), taking into account the obtained values for LOLE. But in the circumstance of having different values for LOLE, this study would be done for the three attributes (carbon emissions, costs and LOLE).

Step 1

In this step, LOLE is perceived as a constraint. As observed previously, except alternatives 14, 15 and 16, all the other alternatives generate reasonable LOLE (< 1,06 days/year) for both scenarios. Therefore, these alternatives will be disregarded in the next steps of this study. The reduced set of alternatives is presented next.



Legend:

"H" refers to an alternative for the "high prices" scenario (blue pointer)

"L" refers to an alternative for the "low prices" scenario (red pointer)

Fig. 77: Total annual costs and carbon emissions of alternatives in 2030, for the "high prices" and "low prices" scenarios, after applying the LOLE constraint

Step 2

As stated in section 3.5, for each scenario, a solution is dominated if and only if there is another one that is better in at least one criterion, without being worse in any of the remaining criteria. In case of more than one scenario, a solution is dominated if the previous condition is verified for all the scenarios.

Therefore, the dominated alternatives for the current case are the following: 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 17, 18, 19, 23, 24, 25 and 31. Some examples of dominated alternatives can be given. For instance, alternative 8 (no energy efficiency measures on the load; mid-range RES increase; efficient ICVs, biofuels and behavioural change; no CSF) is dominated by alternative 26 (energy efficiency measures on the load; mid-range RES increase; efficient ICVs, biofuels and behavioural change; no CSF). In this comparison, the adoption energy efficiency is a differentiating factor.

As a result of this procedure, the next group of non-dominated alternatives was found: 20, 21, 22, 26, 27, 28, 29, 30, 32, 33, 34, 35 and 36. Yet alternative 21 won't be included in the decision study, since it is represented by 22 (owing to lack of V2G opportunity, as previously explained).

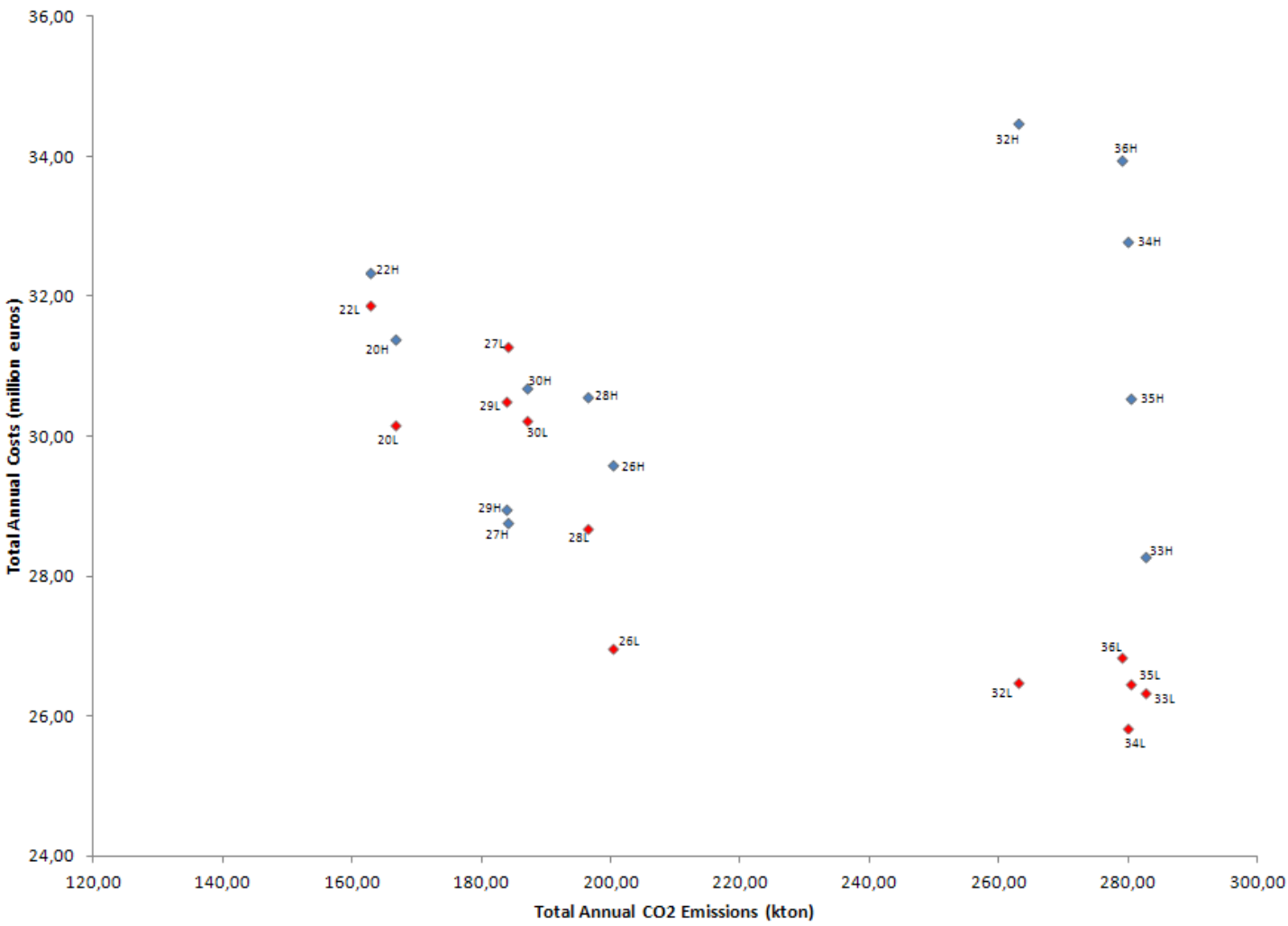


Fig. 78: Total annual costs and carbon emissions of non-dominated alternatives in 2030, for the "high prices" and "low prices" scenarios

The previous graphs allow presenting the next findings.

- All the non-dominated alternatives implement energy efficiency measures on the load.
- Centralized storage facility, as the only storage approach (without EVs charging), leads to dominated alternatives. If for the alternatives with an increasing load this electricity storage option is beneficial in terms of costs, when energy efficiency measures are applied it becomes more expensive.
- Centralized storage facility results only on non-dominated alternatives, when associated with EVs charging.

Step 3

As Keeney highlighted in [201], value judgements are required to make value trade-offs, since they can't be calculated directly from other information. However, due to the impossibility of having the decision maker's value judgements, a sensitivity study on the trade-offs is developed (continuing in *Step 4*). These auxiliary calculations can be useful to support making meaningful and better-informed value trade-offs.

This analysis considers the next range of trade-offs, in order to provide different perceptions regarding carbons emissions and costs: 0 €/tonCO_2; 10 €/tonCO_2; 20 €/tonCO_2; 30 €/tonCO_2; 40 €/tonCO_2; 50 €/tonCO_2; and 60 €/tonCO_2.

The next equation describes how to compute each Equivalent Cost of alternatives in "high prices" scenario, Z_H, and alternatives in "low prices" scenario, Z_L.

$$Z_H = Y_H + \alpha . X_H \tag{5. 1}$$

$$Z_L = Y_L + \alpha . X_L \tag{5. 2}$$

Where,

Y_H refers to total annual costs of a given alternative, in the "high prices" scenario;

X_H refers to total annual carbon emissions of a given alternative, in the "high prices" scenario;

α refers to the trade-off costs/carbon emissions;

Y_L refers to total annual costs of a given alternative, in the "low prices" scenario;

X_L refers to total annual carbon emissions of a given alternative, in the "low prices" scenario.

The use of the previous trade-offs allows computing the Equivalent Costs Z_H and Z_L, as follows.

Table 31 – Equivalent Costs of alternatives, in 2030, with 0 €/tonCO_2 as trade-off

Alternative	X_H (kton)	Y_H (million €)	Z_H (million €)	X_L (kton)	Y_L (million €)	Z_L (million €)
20	166,58	31,39	**31,39**	166,58	30,17	**30,17**
22	162,85	32,36	**32,36**	162,85	31,88	**31,88**
26	200,14	29,60	**29,60**	200,14	27,00	**27,00**
27	183,98	28,78	**28,78**	183,98	31,30	**31,30**
28	196,41	30,57	**30,57**	196,41	28,71	**28,71**
29	183,74	28,96	**28,96**	183,74	30,51	**30,51**
30	186,98	30,69	**30,69**	186,98	30,24	**30,24**
32	262,86	34,47	**34,47**	262,86	26,49	**26,49**
33	282,61	28,29	**28,29**	282,61	26,34	**26,34**
34	279,93	32,79	**32,79**	279,93	25,85	**25,85**
35	280,35	30,56	**30,56**	280,35	26,47	**26,47**
36	279,01	33,96	**33,96**	279,01	26,85	**26,85**

Table 32 – Equivalent Costs of alternatives, in 2030, with 10 €/tonCO_2 as trade-off

Alternative	X_H (kton)	Y_H (million €)	Z_H (million €)	X_L (kton)	Y_L (million €)	Z_L (million €)
20	166,58	31,39	**33,05**	166,58	30,17	**31,84**
22	162,85	32,36	**33,99**	162,85	31,88	**33,51**
26	200,14	29,60	**31,60**	200,14	27,00	**29,00**
27	183,98	28,78	**30,62**	183,98	31,30	**33,14**
28	196,41	30,57	**32,53**	196,41	28,71	**30,67**
29	183,74	28,96	**30,79**	183,74	30,51	**32,35**
30	186,98	30,69	**32,56**	186,98	30,24	**32,11**
32	262,86	34,47	**37,10**	262,86	26,49	**29,12**
33	282,61	28,29	**31,11**	282,61	26,34	**29,17**
34	279,93	32,79	**35,59**	279,93	25,85	**28,65**
35	280,35	30,56	**33,36**	280,35	26,47	**29,28**
36	279,01	33,96	**36,75**	279,01	26,85	**29,64**

Table 33 – Equivalent Costs of alternatives, in 2030, with 20 €/tonCO_2 as trade-off

Alternative	X_H (kton)	Y_H (million €)	Z_H (million €)	X_L (kton)	Y_L (million €)	Z_L (million €)
20	166,58	31,39	**34,72**	166,58	30,17	**33,50**
22	162,85	32,36	**35,61**	162,85	31,88	**35,14**
26	200,14	29,60	**33,60**	200,14	27,00	**31,00**
27	183,98	28,78	**32,46**	183,98	31,30	**34,98**
28	196,41	30,57	**34,49**	196,41	28,71	**32,63**
29	183,74	28,96	**32,63**	183,74	30,51	**34,18**
30	186,98	30,69	**34,43**	186,98	30,24	**33,98**
32	262,86	34,47	**39,73**	262,86	26,49	**31,75**
33	282,61	28,29	**33,94**	282,61	26,34	**32,00**
34	279,93	32,79	**38,39**	279,93	25,85	**31,45**
35	280,35	30,56	**36,16**	280,35	26,47	**32,08**
36	279,01	33,96	**39,54**	279,01	26,85	**32,43**

Table 34 – Equivalent Costs of alternatives, in 2030, with 30 €/tonCO_2 as trade-off

Alternative	X_H (kton)	Y_H (million €)	Z_H (million €)	X_L (kton)	Y_L (million €)	Z_L (million €)
20	166,58	31,39	**36,38**	166,58	30,17	**35,17**
22	162,85	32,36	**37,24**	162,85	31,88	**36,77**
26	200,14	29,60	**35,60**	200,14	27,00	**33,00**
27	183,98	28,78	**34,30**	183,98	31,30	**36,82**
28	196,41	30,57	**36,46**	196,41	28,71	**34,60**
29	183,74	28,96	**34,47**	183,74	30,51	**36,02**
30	186,98	30,69	**36,30**	186,98	30,24	**35,85**
32	262,86	34,47	**42,36**	262,86	26,49	**34,38**
33	282,61	28,29	**36,77**	282,61	26,34	**34,82**
34	279,93	32,79	**41,19**	279,93	25,85	**34,25**
35	280,35	30,56	**38,97**	280,35	26,47	**34,88**
36	279,01	33,96	**42,33**	279,01	26,85	**35,22**

Table 35 – Equivalent Costs of alternatives, in 2030, with 40 €/tonCO_2 as trade-off

Alternative	X_H (kton)	Y_H (million €)	Z_H (million €)	X_L (kton)	Y_L (million €)	Z_L (million €)
20	166,58	31,39	**38,05**	166,58	30,17	**36,83**
22	162,85	32,36	**38,87**	162,85	31,88	**38,39**
26	200,14	29,60	**37,60**	200,14	27,00	**35,00**
27	183,98	28,78	**36,14**	183,98	31,30	**38,66**
28	196,41	30,57	**38,42**	196,41	28,71	**36,56**
29	183,74	28,96	**36,30**	183,74	30,51	**37,86**
30	186,98	30,69	**38,17**	186,98	30,24	**37,71**
32	262,86	34,47	**44,99**	262,86	26,49	**37,00**
33	282,61	28,29	**39,59**	282,61	26,34	**37,65**
34	279,93	32,79	**43,99**	279,93	25,85	**37,05**
35	280,35	30,56	**41,77**	280,35	26,47	**37,69**
36	279,01	33,96	**45,12**	279,01	26,85	**38,01**

Table 36 – Equivalent Costs of alternatives, in 2030, with 50 €/tonCO_2 as trade-off

Alternative	X_H (kton)	Y_H (million €)	Z_H (million €)	X_L (kton)	Y_L (million €)	Z_L (million €)
20	166,58	31,39	**39,72**	166,58	30,17	**38,50**
22	162,85	32,36	**40,50**	162,85	31,88	**40,02**
26	200,14	29,60	**39,60**	200,14	27,00	**37,00**
27	183,98	28,78	**37,98**	183,98	31,30	**40,50**
28	196,41	30,57	**40,39**	196,41	28,71	**38,53**
29	183,74	28,96	**38,14**	183,74	30,51	**39,70**
30	186,98	30,69	**40,04**	186,98	30,24	**39,58**
32	262,86	34,47	**47,62**	262,86	26,49	**39,63**
33	282,61	28,29	**42,42**	282,61	26,34	**40,47**
34	279,93	32,79	**46,79**	279,93	25,85	**39,85**
35	280,35	30,56	**44,57**	280,35	26,47	**40,49**
36	279,01	33,96	**47,91**	279,01	26,85	**40,80**

Table 37 – Equivalent Costs of alternatives, in 2030, with 60 €/tonCO_2 as trade-off

Alternative	X_H (kton)	Y_H (million €)	Z_H (million €)	X_L (kton)	Y_L (million €)	Z_L (million €)
20	166,58	31,39	**41,38**	166,58	30,17	**40,17**
22	162,85	32,36	**42,13**	162,85	31,88	**41,65**
26	200,14	29,60	**41,61**	200,14	27,00	**39,00**
27	183,98	28,78	**39,82**	183,98	31,30	**42,34**
28	196,41	30,57	**42,35**	196,41	28,71	**40,49**
29	183,74	28,96	**39,98**	183,74	30,51	**41,53**
30	186,98	30,69	**41,91**	186,98	30,24	**41,45**
32	262,86	34,47	**50,24**	262,86	26,49	**42,26**
33	282,61	28,29	**45,24**	282,61	26,34	**43,30**
34	279,93	32,79	**49,59**	279,93	25,85	**42,65**
35	280,35	30,56	**47,38**	280,35	26,47	**43,30**
36	279,01	33,96	**50,70**	279,01	26,85	**43,59**

Step 4

In section 3.5.3, an overview was made on approaches to model uncertainty. Taking into account the type of formulation adopted in this study (i.e. scenarios are not characterized by probabilities) and the fact that "high prices" scenario leads, typically, to higher equivalent costs than the "low prices" scenario, the minimax regret approach is adopted.

According to the minimax regret approach, initially, the best alternative (lowest costs) in each scenario is identified. Then, regret is computed for each scenario, by subtracting the best alternative's value from the alternatives' Equivalent Costs, of the corresponding scenario.

The next tables show the results from the minimax regret approach, for each trade-off.

Table 38 – Minimax regret ranking of alternatives, in 2030, with 0 €/CO_2ton as trade-off

Alternative	Z_H (million €)	Z_L (million €)	*Regret in "high prices" scenario* (million €)	*Regret in "low prices" scenario* (million €)	*Minimax Regret Ranking*
20	31,39	30,17	3,10	**4,32**	5
22	32,36	31,88	4,07	**6,03**	11
26	29,60	27,00	**1,31**	1,15	2
27	28,78	31,30	0,49	**5,45**	9
28	30,57	28,71	2,28	**2,86**	4
29	28,96	30,51	0,67	**4,66**	8
30	30,69	30,24	2,40	**4,39**	6
32	34,47	26,49	**6,19**	0,64	12
33	28,29	26,34	0,00	**0,49**	1
34	32,79	25,85	**4,51**	0,00	7
35	30,56	26,47	**2,27**	0,62	3
36	33,96	26,85	**5,67**	1,00	10
Best in scenario	**28,29**	**25,85**			

Table 39 – Minimax regret ranking of alternatives, in 2030, with 10 €/CO_2ton as trade-off

Alternative	Z_H (million €)	Z_L (million €)	*Regret in "high prices" scenario* (million €)	*Regret in "low prices" scenario* (million €)	*Minimax Regret Ranking*
20	33,05	31,84	2,43	**3,19**	5
22	33,99	33,51	3,37	**4,86**	9
26	31,60	29,00	**0,98**	0,35	2
27	30,62	33,14	0,00	**4,49**	8
28	32,53	30,67	1,91	**2,02**	3
29	30,79	32,35	0,17	**3,70**	7
30	32,56	32,11	1,94	**3,46**	6
32	37,10	29,12	**6,48**	0,47	12
33	31,11	29,17	0,50	**0,52**	1
34	35,59	28,65	**4,97**	0,00	10
35	33,36	29,28	**2,74**	0,63	4
36	36,75	29,64	**6,13**	0,99	11
Best in scenario	**30,62**	**28,65**			

Table 40 – Minimax regret ranking of alternatives, in 2030, with 20 €/CO_2ton as trade-off

Alternative	Z_H (million €)	Z_L (million €)	*Regret in "high prices" scenario* (million €)	*Regret in "low prices" scenario* (million €)	*Minimax Regret Ranking*
20	34,72	33,50	2,26	**2,50**	4
22	35,61	35,14	3,16	**4,14**	9
26	33,60	31,00	**1,14**	0,00	1
27	32,46	34,98	0,00	**3,99**	8
28	34,49	32,63	**2,04**	1,63	3
29	32,63	34,18	0,17	**3,18**	6
30	34,43	33,98	1,97	**2,98**	5
32	39,73	31,75	**7,27**	0,75	12
33	33,94	32,00	**1,48**	1,00	2
34	38,39	31,45	**5,93**	0,45	10
35	36,16	32,08	**3,71**	1,08	7
36	39,54	32,43	**7,08**	1,43	11
Best in scenario	**32,46**	**31,00**			

Table 41 – Minimax regret ranking of alternatives, in 2030, with 30 €/CO_2ton as trade-off

Alternative	Z_H (million €)	Z_L (million €)	*Regret in "high prices" scenario* (million €)	*Regret in "low prices" scenario* (million €)	*Minimax Regret Ranking*
20	36,38	35,17	2,09	**2,17**	3
22	37,24	36,77	2,94	**3,77**	7
26	35,60	33,00	**1,30**	0,00	1
27	34,30	36,82	0,00	**3,82**	8
28	36,46	34,60	**2,16**	1,60	2
29	34,47	36,02	0,17	**3,02**	6
30	36,30	35,85	2,00	**2,84**	5
32	42,36	34,38	**8,06**	1,38	12
33	36,77	34,82	**2,47**	1,82	4
34	41,19	34,25	**6,89**	1,25	10
35	38,97	34,88	**4,67**	1,88	9
36	42,33	35,22	**8,03**	2,22	11
Best in scenario	**34,30**	**33,00**			

Table 42 – Minimax regret ranking of alternatives, in 2030, with 40 €/CO_2ton as trade-off

Alternative	Z_H (million €)	Z_L (million €)	*Regret in "high prices" scenario* (million €)	*Regret in "low prices" scenario* (million €)	*Minimax Regret Ranking*
20	38,05	36,83	**1,91**	1,83	2
22	38,87	38,39	2,73	**3,39**	6
26	37,60	35,00	**1,47**	0,00	1
27	36,14	38,66	0,00	**3,66**	8
28	38,42	36,56	**2,29**	1,56	3
29	36,30	37,86	0,17	**2,86**	5
30	38,17	37,71	2,03	**2,71**	4
32	44,99	37,00	**8,85**	2,00	11
33	39,59	37,65	**3,45**	2,65	7
34	43,99	37,05	**7,85**	2,05	10
35	41,77	37,69	**5,63**	2,69	9
36	45,12	38,01	**8,98**	3,01	12
Best in scenario	**36,14**	**35,00**			

Table 43 – Minimax regret ranking of alternatives, in 2030, with 50 €/CO_2ton as trade-off

Alternative	Z_H (million €)	Z_L (million €)	*Regret in "high prices" scenario* (million €)	*Regret in "low prices" scenario* (million €)	*Minimax Regret Ranking*
20	39,72	38,50	**1,74**	1,50	2
22	40,50	40,02	2,52	**3,02**	6
26	39,60	37,00	**1,63**	0,00	1
27	37,98	40,50	0,00	**3,50**	7
28	40,39	38,53	**2,41**	1,52	3
29	38,14	39,70	0,16	**2,69**	5
30	40,04	39,58	2,06	**2,58**	4
32	47,62	39,63	**9,64**	2,63	11
33	42,42	40,47	**4,44**	3,47	8
34	46,79	39,85	**8,81**	2,84	10
35	44,57	40,49	**6,60**	3,49	9
36	47,91	40,80	**9,93**	3,80	12
Best in scenario	**37,98**	**37,00**			

Table 44 – Minimax regret ranking of alternatives, in 2030, with 60 €/CO_2ton as trade-off

Alternative	Z_H (million €)	Z_L (million €)	*Regret in "high prices" scenario* (million €)	*Regret in "low prices" scenario* (million €)	*Minimax Regret Ranking*
20	41,38	40,17	**1,56**	1,16	1
22	42,13	41,65	2,31	**2,65**	6
26	41,61	39,00	**1,79**	0,00	2
27	39,82	42,34	0,00	**3,34**	7
28	42,35	40,49	**2,53**	1,49	5
29	39,98	41,53	0,16	**2,53**	4
30	41,91	41,45	2,09	**2,45**	3
32	50,24	42,26	**10,43**	3,26	11
33	45,24	43,30	**5,43**	4,30	8
34	49,59	42,65	**9,77**	3,64	10
35	47,38	43,30	**7,56**	4,29	9
36	50,70	43,59	**10,88**	4,59	12
Best in scenario	**39,82**	**39,00**			

As illustrated by the previous tables:

- Alternative 33 (energy efficiency measures on the load; BAU RES; 10 000 EVs; no CSF; V2G) is the preferred one when the trade-offs are 0 €/tonCO_2 and 10 €/tonCO_2;
- Alternative 26 (energy efficiency measures on the load; mid-range RES increase; efficient ICVs, biofuels and behavioural changes; no CSF) is the preferred one when the trade-offs are 20 €/tonCO_2, 30 €/tonCO_2, 40 €/tonCO_2 and 50 €/tonCO_2;
- Alternative 20 (energy efficiency measures on the load; high-range RES increase; efficient ICVs, biofuels and behavioural changes; no CSF) is the preferred one when the trade-off is 60 €/tonCO_2.

Taking into account the obtained alternatives ranking, for each analyzed trade-off, the next graph is built, in order to perform a sensitivity study of the trade-offs effect on the maximum regret.

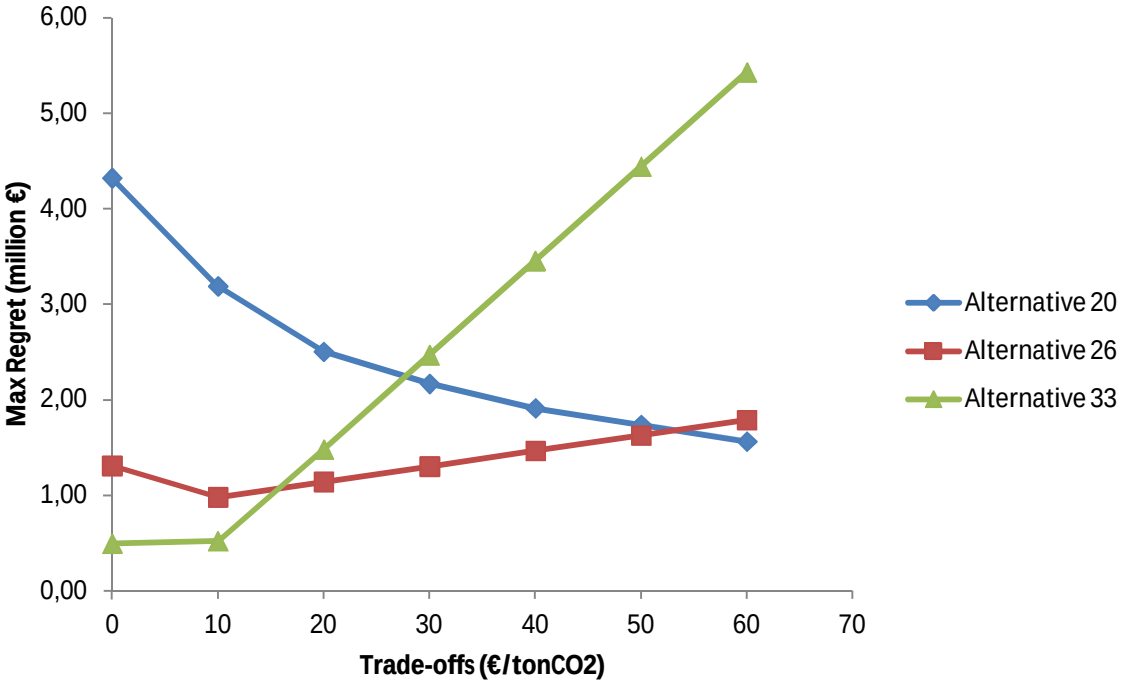


Fig. 79: Sensitivity study of trade-offs effect on the maximum regret

According to the previous graph, the next relations between alternatives can be presented:

- Alternative 33 leads to lower maximum regret than alternative 26, if $\alpha < 16$ €/tonCO_2;
- Alternative 33 leads to lower maximum regret than alternative 20, if $\alpha < 28$ €/tonCO_2;
- Alternative 26 leads to lower maximum regret than alternatives 20 and 33, if $16 < \alpha < 53$ €/tonCO_2;
- Alternative 20 leads to lower maximum regret than alternatives 26 and 33, if $\alpha > 53$ €/tonCO_2.

As expected, the preferred alternative depends considerably on the trade-off.

5.4 Summary and Main Conclusions

In this chapter, the methodology proposed by the current research for energy planning was applied in São Miguel Island, aiming to enhance the sustainability of that isolated system, through a multicriteria evaluation of renewable energy sources integration, plus electricity storage, sustainable mobility and the adoption of energy efficiency measures.

The energy planning methodology developed for the chosen case study brought the next findings.

"High prices" scenario

- According to the study carried out for São Miguel Island, for the "high prices" scenario, the environmental benefits of RES increase and load decrease were ratified. This assessment enabled concluding that alternatives implementing energy efficiency measures result on both lower total annual costs and cost per unit of electric energy generated, comparing to analogous alternatives that don't invest on load reduction. In fact, for this scenario, alternatives with energy efficiency lead to both lower costs and emissions, regardless the RES capacity.
- Concerning total annual costs, renewable energy sources become more cost-competitive than fuel-oil thermal generation. That's to say, high-range and mid-range RES increase are economically more beneficial than BAU option, for both load strategies. If energy efficiency measures on the load are not applied, high-range RES increase leads to lower total annual costs than mid-range RES increase. In case of applying energy efficiency measures on the load, mid-range RES increase is less expensive than high-range RES increase, because in the latter biomass generation is commissioned, and geothermal and hydro power units are reinforced. The cost-effectiveness of this RES increase depends on the load level. As described in this chapter, when load is higher, the effect of expensive RES, such as biomass, is smoothened. On the other hand, when load is decreased, the weight of biomass among global power generation cost increases (28% of the total power generation cost), comparing to the case in which there are no energy efficiency measures on the load (20% of the total power generation cost). That's to say, it is worth reducing the load through energy efficiency measures, instead of commissioning expensive RES to compensate the load increase.
- In the "high prices" scenario, alternatives performing V2G have lower total costs, than the ones without V2G.

"Low prices" scenario

- Although alternatives with energy efficiency measures on the load lead to a higher cost per unit of electric energy generated, these result on total lower annual costs than alternatives without energy efficiency. For this scenario, alternatives with energy efficiency also lead to both lower total annual costs and emissions, regardless the RES capacity.
- Concerning total annual costs, fuel-oil thermal generation becomes more cost-competitive than renewable energy sources. That's to say, BAU RES option is economically more beneficial than high-range and mid-range RES options, for both load strategies. According to the analysis provided in this chapter, BAU RES plus energy efficiency on the load is the

preferred match, when it comes to total annual costs. In terms of carbon emissions, the higher the RES share in the mix, the lower the carbon emissions.

- In the "low prices" scenario, V2G is only beneficial in terms of total costs for alternatives with 5 000 EVs, and among these, when there is energy efficiency on the load, together with BAU RES, and when there is no energy efficiency on the load, together with mid-range RES increase.

Besides the previous conclusions, others can be drawn, regardless the prices scenario:

- Electric mobility needs lower amounts of RES to be environmentally competitive, in the case of investing on energy efficiency measures on the load;
- Only when there is a load decrease and BAU RES, electric mobility appears economically competitive (thanks to the operation of power units with lower cost for electric energy generation).
- If energy efficiency measures are applied on the load, the storage option without EVs charging (i.e. Efficient ICVs, Biofuels and Behavioural Change, plus CSF) originates lower carbon emissions, but higher total costs than the alternative with 5 000 EVs plus CSF;
- If energy efficiency measures are not applied on the load, the storage option without EVs charging (i.e. Efficient ICVs, Biofuels and Behavioural Change, plus CSF) originates both lower carbon emissions and total costs than the alternative with 5 000 EVs plus CSF.

In this chapter, a multi-attribute and multi-scenario analysis was developed, which provided meaningful findings, as presented next:

- All the non-dominated alternatives implement energy efficiency measures on the load.
- Centralized storage facility, as only storage approach (without EVs charging), leads to dominated alternatives. If for the alternatives with an increasing load this electricity storage option is beneficial in terms of costs, when energy efficiency measures are applied it becomes more expensive.
- Centralized storage facility only results on non-dominated alternatives, when associated with EVs charging.
- In what pertains to the environmental criteria, if energy efficiency measures are not implemented on the load, V2G allows lowering global carbon emissions only if high-range RES increase is followed. Alternatively, for alternatives applying energy efficiency measures, V2G leads to lower CO_2 emissions in the case of mid-range RES increase.

From the sensitivity study concerning the trade-offs effect on the maximum regret, for low trade-offs (less valorisation of emissions) alternative 33 (energy efficiency measures on the load; BAU

RES; 10 000 EVs; no CSF; V2G) is the best. But for intermediate values (up to 53 €/tonCO_2), alternative 26 (energy efficiency measures on the load; mid-range RES increase; efficient ICVs, biofuels and behavioural changes; no CSF) is the best. Additionally, if there is a clear commitment for the reduction of carbon emissions (trade-off higher than 53 €/tonCO_2), then alternative 20 (energy efficiency measures on the load; high-range RES increase; efficient ICVs, biofuels and behavioural changes; no CSF) is the preferred.

Chapter 6

6 Conclusions

6.1 Answers to Research Questions

In chapter 1, a set of research drivers were identified, including the development of comprehensive energy planning for isolated systems, addressing utterly: renewable energy sources variability; energy efficiency measures; electric mobility architecture; vehicle-to-grid strategy; electricity storage systems; sustainable mobility based on internal combustion vehicles (ICVs); carbon emissions cap-and-trade mechanisms; power systems' reliability indices; and uncertainty modelling.
In view of the diagnosed research motivation, this thesis aimed bridging knowledge gaps and bringing scientific value, by developing a methodology for enhancing the energy sustainability of a given isolated system, through a multicriteria evaluation approach, considering renewable energy sources integration, plus electricity storage, sustainable mobility and the adoption of energy efficiency measures.
The assessment of this work's achievements is pursued by answering to the research questions raised in chapter 1.

1. *How can a methodology be built to compare different alternatives for energy planning, through a set of criteria and attributes?*

In chapter 4, a methodology was described for multicriteria energy planning, encompassing the following steps: problem identification and global description; defining the scope and objectives for the problem; problem formulation, including the identification of decision variables, alternatives, criteria and attributes; and mathematical modelling.
That methodology has also established a framework for the proposed research, by answering to the next questions: who, what, when, where, why, in what way, by what means. This outline allowed clarifying the purpose of the work and preparing the arrangement for the approach, described in the same chapter.
Prior to identifying the decision situation, an overview was made, in chapter 3, on theoretical fundamentals for energy planning. That overview allowed characterizing the decision situation, in chapter 4, by setting up a set of decision variables and alternatives; a set of criteria; and a set of attributes.
The decision variables consist of: load variation (increase/decrease) associated to the adoption of energy efficiency measures; installed capacity of renewable energy sources (business-as-usual, mid-range and high-range renewable energy sources increase); sustainable mobility options (i.e. efficient

ICVs, biofuels and behavioural change; or strategies based in electric vehicles introduction); and electricity storage strategies (centralized storage facility and/or electric vehicles charging, including the vehicle-to-grid concept). When it comes to the criteria, this work has required a specific mathematical formulation for the evaluation of attributes associated to each of the next criteria: environmental impact; economic and financial costs; and adequacy of the generation system.

Regarding the alternatives identification, in chapter 5, the potential hypotheses were set up, for planning a given energy system (which in this thesis is São Miguel island). These alternatives were built by considering the investments and policies studied by the decision maker, who was assumed to be the regional authorities of the analysed energy system. The chosen year for analysis was 2030, to evaluate the energy planning options through a long-term perspective

In order to handle the uncertainty of energy planning, two scenarios were built regarding the costs evolution. The formulated attributes were then computed, enabling a comparison between the alternatives under analysis.

2. *What is the correlation between additional capacity of renewable energy sources and energy efficiency measures, when it comes to the selected criteria?*

From the study carried out for São Miguel Island, for the "high prices" scenario, the next set of observations can be drawn.

- Environmental benefits of renewable energy sources (RES) increase and load decrease were ratified (also true for the "low prices" scenario).
- Alternatives implementing energy efficiency measures result on both lower total annual costs and cost per unit of electric energy generated, comparing to analogous alternatives that don't invest in load reduction. In fact, for this scenario, alternatives with energy efficiency lead to both lower costs and emissions, regardless the RES capacity.
- Concerning total annual costs, renewable energy sources become more cost-competitive than fuel-oil thermal generation. That's to say, high-range and mid-range RES increase are economically more beneficial than the business-as-usual (BAU) option, for both load strategies.
- It is worth reducing the load through energy efficiency measures, instead of commissioning expensive RES to compensate the load increase.

When it comes to the "low prices" scenario, the next set of remarks is presented.

- Although alternatives with energy efficiency measures on the load lead to a higher cost per unit of electric energy generated, these result on total lower annual costs than alternatives without energy efficiency. For this scenario, alternatives with energy efficiency also lead to both lower total annual costs and emissions, regardless the RES capacity.

- Concerning total annual costs, fuel-oil thermal generation becomes more cost-competitive than renewable energy sources. That's to say, BAU RES option is economically more beneficial than high-range and mid-range RES options, for both load strategies.
- According to the analysis provided in chapter 5, BAU RES plus energy efficiency on the load is the preferred match, when it comes to total annual costs. In terms of carbon emissions, the higher the RES share in the mix, the lower the carbon emissions.

In terms of the adequacy of the generation system, a decreasing load and increasing RES capacity (without decommissioning, in advance, thermal units) leads to lower loss of load expectation (LOLE).

3. *How to compare electric mobility and ICV-based sustainable mobility, in terms of costs and benefits?*

As presented in chapter 5, three strategies were designed for sustainable mobility by 2030, i.e.: efficient ICVs, biofuels and behavioural change; introduction of 5 000 electric vehicles (7,5% of São Miguel's light vehicles fleet); and introduction of 10 000 electric vehicles (15% of São Miguel's light vehicles fleet).

From the analysis developed in that chapter, some conclusions can be drawn, regardless the prices scenario:

- Electric mobility becomes environmentally more beneficial with the increase of RES;
- Electric mobility needs lower amounts of RES to be environmentally competitive, in the case of investing on energy efficiency measures on the load;
- Only when there is a load decrease and BAU RES, electric mobility appears economically competitive (thanks to the operation of power units with lower cost for electric energy generation).

4. *What is the influence of sustainable mobility strategies on the electricity storage contribution for the system?*

In chapter 5, the next pathways were defined for electricity storage: centralized storage facility (i.e. pumped hydro storage) and/or electric vehicles (EVs) charging, including the vehicle-to-grid (V2G) concept. From the analysis developed in that chapter, some conclusions can be drawn, regardless the prices scenario:

- If energy efficiency measures are applied on the load, the storage option without EVs charging (i.e. efficient ICVs, biofuels and behavioural change, plus centralized storage facility) originates lower carbon emissions, but higher total costs than the alternative with 5 000 EVs plus centralized storage facility (CSF);

- If energy efficiency measures are not applied on the load, the storage option without EVs charging (i.e. Efficient ICVs, Biofuels and Behavioural Change, plus CSF) originates both lower carbon emissions and total costs than the alternative with 5 000 EVs plus CSF.

5. *What are the preferred alternatives for enhancing the energy sustainability of a given isolated power system?*

The proposed energy planning methodology, when applied to São Miguel Island, draws the next conclusions, besides the ones already depicted by answering to the previous research questions:

- All the non-dominated alternatives implement energy efficiency measures on the load;
- Centralized storage facility, as the only storage approach (without EVs charging), leads to dominated alternatives. If for the alternatives with an increasing load this electricity storage option is beneficial in terms of costs, when energy efficiency measures are applied it becomes more expensive.
- Centralized storage facility results only on non-dominated alternatives, when associated with EVs charging;
- In the "high prices" scenario, alternatives performing V2G have lower total costs, than the ones without V2G.
- In the "low prices" scenario, V2G is only beneficial in terms of total costs for alternatives with 5 000 EVs, and among these, when there is energy efficiency on the load, together with BAU RES, and when there is no energy efficiency on the load, together with mid-range RES increase.
- In what pertains to the environmental criteria, if energy efficiency measures are not implemented on the load, V2G allows lowering global carbon emissions only if high-range RES increase is followed. Alternatively, for alternatives applying energy efficiency measures, V2G leads to lower CO_2 emissions in the case of mid-range RES increase.

Furthermore, in chapter 5, a multi-attribute and multi-scenario analysis was presented by performing a sensitivity study on the effect of the trade-offs on maximum regret. According to this study, for low trade-offs (less valorisation of emissions) alternative 33 (energy efficiency measures on the load; BAU RES; 10 000 EVs; no CSF; V2G) is the best. But for intermediate values (up to 53 €/tonCO_2), alternative 26 (energy efficiency measures on the load; mid-range RES increase; efficient ICVs, biofuels and behavioural changes; no CSF) is the best. Additionally, if there is a clear commitment for the reduction of carbon emissions (trade-off higher than 53 €/tonCO_2), then alternative 20 (energy efficiency measures on the load; high-range RES increase; efficient ICVs, biofuels and behavioural changes; no CSF) is the preferred.

6.2 Main Contributions

To sum up, this work presents the next major contributions.

- A new methodology for multicriteria energy planning was developed, for isolated systems, by filling some critical knowledge gaps. This methodology consists in a process of systematic building of energy planning alternatives, for an isolated system, from a set of basis options, namely the integration of renewable energy sources, strategies for sustainable mobility (ICV-based or electric mobility), electricity storage options (centralized storage facility and/or electric vehicles charging), and adoption of energy efficiency measures.
- The proposed approach includes the consideration of uncertainty in the prices, by defining two scenarios and implementing the regret concept, through a multicriteria and multi-scenario perspective.
- For evaluating the alternatives, a detailed modelling of meaningful criteria is provided, i.e.: environmental impact; economic and financial costs; and adequacy of the generation system. Thus, one significant contribution of this thesis is related with the mathematical formulation for computing the selected attributes (associated to the criteria), especially the equations describing the economic and financial costs of centralized storage facility and electric mobility.
- The proposed energy planning methodology benefited from the development of an algorithm for unit commitment and economic dispatch, including renewable energy sources, centralized electricity storage, and EVs charging and V2G. This algorithm adopts the logic of the merit order priority list method, and maintains the simplicity and accountability of that approach. The algorithm for unit commitment and economic dispatch allows an hourly analysis of the power system, though the long-run time horizon of the energy planning focus.
- The developed approach was applied into a real case study and, consequently, meaningful findings could be assessed and followed by the corresponding regional authorities. The analysis carried out for São Miguel Island delivered a set of expected findings (environmental benefits of RES and energy efficiency), but also innovative understanding, such as: the economic benefits of EVs V2G for energy shift; cost competitiveness of RES, for the “high prices” scenario; economic benefits of energy efficiency measures on the load; and contribution of efficient ICVs, biofuels and behavioural change, for lowering carbon emissions.

To conclude, the methodology built within this thesis is believed to upgrade current approaches and, as a result, bring concrete contributions and applicable value to the energy planning process of isolated systems, either through a utility-oriented perspective, or government-oriented viewpoint.

6.3 Suggestions for Future Work

In terms of future works following the current research topic, a set of further studies would be worth performing, as described next:

- Apply a similar multicriteria approach for interconnected power systems, by comparing electricity storage with interconnection capacity reinforcement, and with demand response;
- Upgrade the described formulation to study power systems with market rules;
- Study the ability of electricity storage facilities and EVs for providing services to the system (e.g. reserve services);
- Add transmission and distribution networks to the energy planning methodology, in order to study the location of dispersed storage, for congestion management and dealing with power flow inversion;
- Build a regulatory study to address the services provided by electricity storage, EVs and demand response players, through a fair remuneration and new market design;
- Enhance the reliability studies, by addressing operating reserve assessment;
- Study the uncertainty inherent to the EVs charging and V2G;
- Develop a formulation to integrate the stakeholders' preferences, regarding each of the energy planning alternatives;
- Perform a sensitivity analysis regarding the installation of a fresh-water pumped hydro storage facility (i.e. Furnas' lake, São Miguel Island), by using the methodology described in this research.

Chapter 7

7 References

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Annexes

Annexes

Annex I

Data of the power system of São Miguel Island

In this annex the main characteristics of São Miguel's power system are presented.

Table 45 - Evolution of the annual peak load in S. Miguel (kW), adapted from [275]

São Miguel	2003	2004	2005	2006	2007	2008*	2009*	2010*	2011*	2012*
Generation (MWh)	353 828	386 700	400 109	413 137	428 923	442 992	458 393	474 023	488 246	502 468
evolution %	7,0	9,3	3,5	3,3	3,8	3,3	3,5	3,4	3,0	2,9
Peak Load (kW)	62 180	64 800	69 600	70 250	72 150	74 315	76 326	78 536	80 489	82 628
evolution %	9,3	4,2	7,4	0,9	2,7	3,0	2,7	2,9	2,5	2,7

*Estimation

Table 46 - Evolution of the monthly peak load in S. Miguel (kW) [275]

Month	2001	2002	2003	2004	2005	2006	2007	2008
Jan	46600	50080	54300	59090	62900	65500	68450	69750
Feb	44700	48940	54640	57750	59400	63200	65850	66200
Mar	47300	50010	51700	57050	61400	63200	63250	63150
Apr	43850	49960	53080	57580	60650	60600	63450	64700
May	47200	50270	53180	58300	61800	63190	64100	65130
Jun	48500	51980	55180	63350	63600	62950	66550	69350
Jul	51850	54870	59270	62800	63800	66740	69300	71480
Aug	52050	54820	60470	63400	64940	67600	70000	72200
Sep	**54450**	56070	60500	**64800**	**69600**	69080	69600	73850 *
Oct	50560	51900	58170	61550	63650	66600	68750	70813 *
Nov	49560	55690	58870	60300	61500	66150	68200	70246 *
Dec	52600	**56870**	**62180**	63900	66400	**70250**	**72150**	**74315 ***

* Estimation

Table 47 – Generation Units in S. Miguel (kW) [275]

Unit	Installed Power (MW)
Caldeirão (fuel oil power)	**98,06**
Unit I	7,70
Unit II	7,70
Unit III	7,70
Unit IV	7,70
Unit V	16,82
Unit VI	16,82
Unit VII	16,82
Unit VIII	16,82
Salto do Cabrito (hydro power)	**0,71**
Tambores (hydro power)	**0,11**
Canário (hydro power)	**0,40**
Foz Rib. Quente (hydro power)	**0,82**
Rib. Praia (hydro power)	**0,80**
Nova (hydro power)	**0,61**
Túneis (hydro power)	**1,61**
Pico Vermelho (geothermal power)	**13,00**
Ribeira Grande (geothermal power)	**14,80**
TOTAL	**130,93**

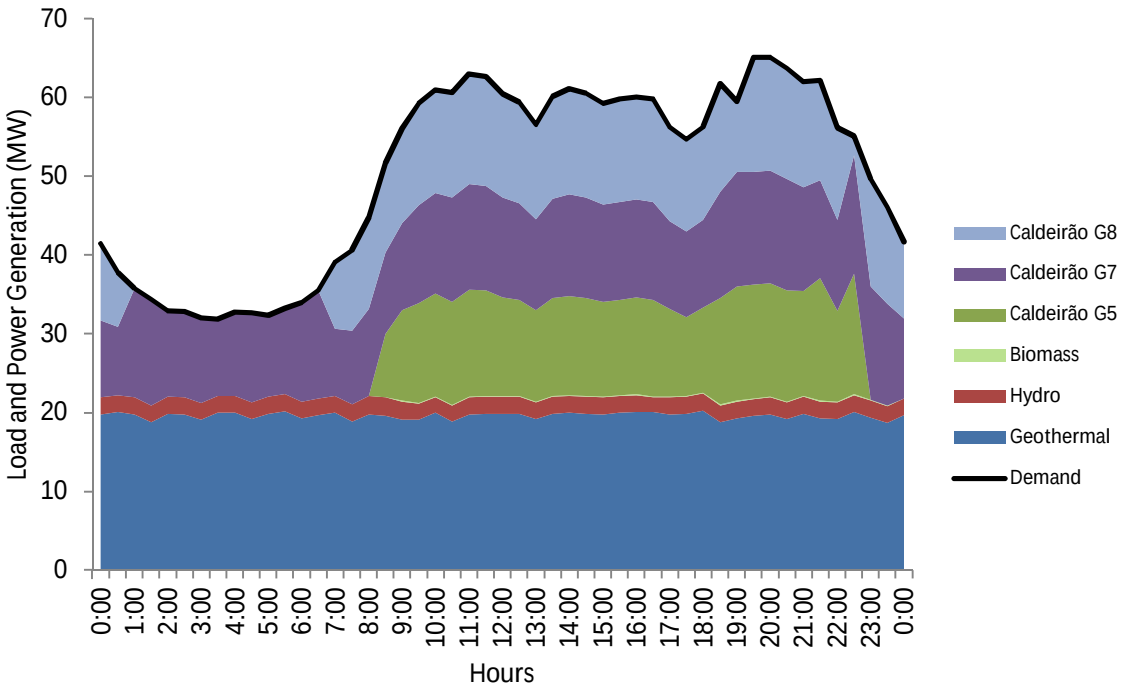

Fig. 80: Typical daily load and generation profiles, in 2008 (EDA)