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Potential of Smart Renewable Hubs with Gridsol technology in Europe

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July 2019

Abstract

With the signing of the Paris Agreement in 2015, the EU Member States pledged to actively contribute to climate mitigation through a concrete, prompt action. As a consequence, the 2018 European Climate Strategy identified a series of trajectories the EU economy might follow to accomplish relevant CO_2 reduction targets; these aim at limiting the global warming to 2 or - more ambitiously - 1.5 degrees in 2050 with respect to pre-industrial levels. In this context, carbon prices may thus be subject to a steep growth and the rising demand for new fuels (e.g. hydrogen) is likely to increase the gross electricity need. This study investigates how this setting can contribute to a deployment of Concentrating Solar Power (CSP) and of a new concept like Gridsol, which integrates the central tower CSP technology with a gas engine equipped with a heat recovery system; when fed with biogas, the hub dispatches 100 % clean power to the grid. Their role in the power system, their functioning and integration into larger Smart Renewable Hubs along with wind and solar energy are studied for five Southern European countries: France, Greece, Italy, Portugal and Spain.
The research builds on the open-source, bottom-up, fundamental market model Balmorel, whose structure is utilised to characterise the units functioning. The optimisation, which grounds on linear programming techniques, is carried out with aggregate time series data: the aggregation scheme is refined so as to render the solar resource appopriately. Scenarios are eventually designed to investigate the potential of CSP and Gridsol in a nearly decarbonised Europe.

The findings highlight that medium-range CO_2 prices ($<$ 100 [EUR/t]) are enough to reduce the emission level by 94% with respect to 1990. In Europe, the designed scenarios reach this price in the medium term; at that point in time, CSP is not projected to be cost-competitive with respect to other renewable technologies (solar PV, wind energy). However, the rising need for new fuels, the declining costs for biogas methanisation and a consistent drop in the CSP overnight expenditures are the identified key-drivers for a long-term spreading of CSP and Gridsol in Southern Europe. These factors are the object of a sensitivity analysis that provides a broad outlook on the attractiveness of CSP in Europe until 2050, both as a single-source technology and integrated into Gridsol or larger Smart Renewable Hubs. The outcomes mark: the importance of large thermal storage, whose volume can exceed 20 hours; the role of CSP as a base-load supplier, with capacity factors up to 68 % ; the strong competition with the semi-dispatchable group solar PV + batteries and the significance of national and cross-national dynamics on the local profitability of renewables.

Sommario

Con la sottoscrizione degli Accordi di Parigi nel 2015, gli Stati Membri dell'Unione Europea si sono impegnati a intraprendere azioni tempestive ed incisive per contenere il surriscaldamento globale. La Strategia Climatica pubblicata dalla Commissione Europea nel 2018 ha individuato e tracciato una serie di percorsi volti alla creazione di un'economia comunitaria sostenibile nel lungo termine; tra gli obiettivi figura la riduzione delle emissioni di anidride carbonica in misura tale da limitare l'aumento della temperatura terrestre a 2 o, più ambiziosamente, 1.5 gradi rispetto ai livelli pre-industriali. Entro questa cornice, i prezzi della CO_2 subiranno un probabile, marcato rialzo e la crescente richiesta di combustibili alternativi quali l'idrogeno contribuiranno ad aumentare la richiesta di elettricità. Questo lavoro approfondisce il legame tra decarbonizzazione e diffusione del solare termico a concentrazione (CSP) con tecnologia a torre centrale, eventualmente integrato in un sistema ibrido come Gridsol; quest'ultimo prevede l'affiancamento di un ciclo a gas con recupero di calore al CSP: se alimentato a biogas, il sistema dispaccia energia 100 % rinnovabile. Il loro ruolo nella rete, il funzionamento e l'inclusione in più grandi Smart Renewable Hubs contenenti eolico e solare sono studiati per cinque nazioni del Sud Europa: Francia, Grecia, Italia, Portogallo e Spagna.
La ricerca si avvale del modello open-source Balmorel, la cui struttura viene sfruttata per caratterizzare il funzionamento dei sistemi in oggetto. L'ottimizzazione, che si fonda su tecniche di programmazione lineare, ricorre all'aggregazione temporale delle serie storiche in ingresso, un passaggio dovuto per determinare la taglia delle unità in modelli per sistemi energetici su vasta scala. Particolare attenzione è prestata alla rappresentazione dell'energia solare. Infine, opportuni scenari sono costruiti con lo scopo di definire il potenziale di CSP, Gridsol e Smart Renewable Hubs in un'Europa che punta a zero emissioni nel 2050.

I risultati evidenziano che moderati prezzi della CO_2 (< 100 [EUR/t]) sono sufficienti per una riduzione del livello di emissioni pari al 94% rispetto al 1990. Nell'ipotesi di un'azione incisiva contro i cambiamenti climatici, gli scenari ideati per questa tesi rivelano che tale livello di prezzo è raggiunto nel medio periodo in Europa; le proiezioni di costo per il CSP mostrano che la tecnologia potrebbe non essere competitiva con le altre rinnovabili entro pochi anni. Tuttavia, l'aumento della richiesta di combustibili alternativi, la riduzione dei costi di metanizzazione del biogas e un notevole calo del capitale necessario per gli investimenti dimostrano di essere i fattori decisivi per la diffusione nel lungo periodo del solare a concentrazione. L'analisi di sensitività fondata su quesi aspetti restituisce un panorama multiforme ma dettagliato sulle prospettive del CSP come singolo impianto, intregrato in Gridsol o in più ampi Smart Renewable Hubs. I risultati indicano: l'importanza di sistemi di accumulo aventi grossi volumi di stoccaggio, anche oltre le 20 ore; il ruolo del CSP nella produzione di base, con fattori di capacità fino al 68 %; la competizione con il gruppo fotovoltaico + accumulo elettrochimico e la rilevanza delle dinamiche intra- ed extra-nazionali nel sistema interconnesso europeo per il loro impatto sulle rinnovabili.

Acknowledgements

We often do not reflect much on how many inputs and influences our everyday lives have; sometimes we just take them for granted. I am grateful to whoever made a part of myself in these past 24 years. This work marks the end not only of a university programme, but of a long educational cycle that started some years ago in the Venetian countryside. A big thank to everybody that I will not mention here but contributed to my education.

A first due thank you to my supervisors, who accepted to follow me on this journey: in Denmark, Kenneth and Mattia, with whom I shared amazing moments in Bilbao; in Italy, prof. Andrea Lazzaretto.

I continue this section by reminding myself I was lucky to experience these two years at the Technical University of Denmark. The people I got to meet have contributed to an incredible personal growth in a little time span. As this work is the finish line of a long run, I must mark I would have never started without the support of my family. Reluctant to imagine me far from home, my mum and dad have always tacitly sustained my choices and provided me with valuable and heartfelt advice. A big thank you also to my brother Davide. This Master's started in Padova, where my ex-flatmates and longtime friends Filippo, Fabio, Paolo, Alberto and Christian have brought forth some of the most beautiful memories I carry with me. It was hard to leave you back then.

Nevertheless, I was lucky enough to meet exceptional friends that have lightened these two though but meaningful and rewarding years in Copenhagen: the Italian, Spanish, Greek and German fellows above all. A special thank you goes to Charlie, Eduard, Giulia, Helge, Marco, Tommaso, Virginia; I would also like to mention the Danish people that welcomed and made the effort to integrate me in their circle. It was extremely appreciated.

I send a heartfelt thank you to Pier Ludovica, who creatively cheered and encouraged me in some decisive steps.

Last but not least, a big thank you to all the Ea crew that was always available for questions, help and guidance in these months: Anders, János, Lars B, Lars P, Katja, Nina. They were also always available for having fun. Still, an infinite gratitude goes to Alberto, who patiently followed me throughout this last academic journey and listened to my ideas, doubts and philosophical ramblings. You are a great person and a precious friend.

Dedication

To Giovanna, Walter, Davide, Rosa and Emma

Doesn't your learning reveal that the only reason why I please you and mean so much to you is because I am kind of a looking-glass for you, because there is something in me that answers you and understands you? Really, we ought all to be such looking-glasses to each other and answer and correspond to each other.

Hermann Hesse, Steppenwolf

Nomenclature

WTA Willingness To Accept

LCOE Levelised Cost of Energy (Electricity) [EUR/MWh]

MV Market Value [EUR/MWh]

WACC Weighted Average Cost of Capital

CSP Concentrated Solar Power

PV Photovoltaics

DNI Direct Normal Irradiation [W/m^2]

GHI Global Horizontal Irradiation [W/m^2]

TES Thermal Energy Storage

BESS Battery Energy Storage System

EES Electric Energy Storage

GT Gas Turbine

ST Steam Turbine

SRH Smart Renewable Hub

HPP Hybrid Power Plant

RU Renewable Unit

Bb Balbase (Balmorel simulation mode)

LP Linear Programming

MILP Mixed Integer Linear Programming

FLH Full Load Hours [h]

CAPEX Capital expenditures [EUR/MW] or [EUR/MWh]

OPEX Operational expenditures [EUR/MW] or [EUR/MWh]

ESM Energy System Model

ETS Emission Trading System

MSR Market Stability Reserve

IRENA International Renewable Energy Agency

CHP Combined Heat and Power

CF Capacity Factor [%]

VRE Variable Renewable Energy

RES Renewable Energy Sources

p Electricity price [EUR/MWh]

E Generation [MWh] or alike

C Curtailment level [MWh] or alike

GHG Greenhouse Gas

CO_2 Carbon dioxide

CCS Carbon Capture and Storage

H_2 Hydrogen

If not specified elsewhere, EUR refers to EUR2015.

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Chapter 1

Introduction

1.1 Motivation

A 2018 report from the International Renewable Energy Agency (IRENA) outlines the potential of renewables within the European Union (EU); the findings outreach the revised European target for 2030 (34 % of renewables in the energy mix instead of 32.5 %) and mark the existence of a rich soil for a further cost-effective development of solar and wind technologies [1]. These constitute a paramount measure to accelerate the decarbonisation of the energy sector. However, the substitution of conventional, fossil generators with non-programmable units carries along a set of problems that call for a radical transformation of the existing technical and economic structures. On one side, the transmission and distribution grids require new investments to guarantee security of supply and affordable energy for consumers; on the other side, traditional electricity markets are affected by an increasing share of generation from renewable technologies, which rapidly change the market dynamics and ask for a continuous redesign of the economic, regulatory and political framework.

Smart Renewable Hubs (SRHs), possibly integrating the Gridsol concept, can solve some of the aforementioned structural issues: local generation and consumption of energy reduce grid losses and the cost of transmitting power from and to remote locations; equipping stochastic generators with back-up units and storage technologies *in loco* can help the spread of renewable

energy; the uncertainty associated with volatile resources - which translates into a revenue loss for the assets' owner - is mitigated in hours of scarcity.
Concentrating Solar Power (CSP) can be integrated into SRHs. CSP can supply also base load power, when equipped with thermal storage [2]; IRENA foresees a total 4-5 [GW] of installed capacity in the EU 28 by 2030. The real figure strongly depends on: CSP cost trajectories; attractiveness of alternative cost-competitive technologies; the unit's reliability and its ability to effectively target one or more market segments; technological advancement and the design of components based on innovative concepts; public subsidies. In Europe, the solar resource makes CSP an attractive solution for the countries in the Mediterranean area; as of 2017, Spain had 2.3 [GW] of installed CSP capacity and that accounted for 47 % of the worldwide operating units of the same kind [3]. Despite holding this record, Spain has not built new CSP units since 2013; the situation is at a standstill due to a stop to national subsidies, in the form of feed-in tariffs until 2013. As of now, no effort is explicitly directed towards CSP deployment, as the last and future renewable auctions will be technology-neutral [4]. The tight rules adopted to drastically reduce carbon emissions might foster the spreading of CSP, whose evolution can lead to hybrid concepts such as Gridsol or SRHs. The latter might represent a decisive turn for also for the consistent installation of units in other European countries where the solar resource is sufficient.

With the supply sector progressively giving up on subsidies, renewable technologies owe their spreading to other market mechanisms; in the European Union (EU), a contribution to their deployment is supposed to come from the Emission Trading System (ETS). In general, CO_2 prices are expected to increase as a result of a refined design of the EU ETS and of the associated Market Stability Reserve (MSR) [5]. The projected growth in the cost of carbon allowances would favour the phase-out of traditional power plants and therefore a further diffusion of renewable energy, with CSP being a plausible alternative. On the other hand, investments in fossil-free units are hampered by uncertain revenues for the assets owner, who is increasingly exposed to market dynamics and sees hurdle rates rise; moreover, the market value of renewable energy technologies is a decreasing function of their penetration [6]. The future power sector is asked to adapt to this shift in the generation fleet and at the same time to respond to a growth in demand: e-fuels and hydrogen may hold a pivotal role in the future. This context, characterised by high uncertainty yet ambitious climate goals, can be the ground for CSP to spread in Southern Europe.

1.2 Learning objectives

The development of relatively accurate large-scale models (technology- and geography-wise) has called for simplifications in the simulation set-up; one of the burning issues is related to the aggregation of time series data in order to keep the computational time within reasonable limits. Literature on the topic is lacking in the framework of large-scale Energy System Models (ESMs); in addition, the quality of the aggregate time series is usually tested in the time series domain and not directly on the results. The first part of the thesis focuses on this topic, enriches the literature on time aggregation, outlines a method and identifies key quantities for validating the chosen technique in the domain of the objective function. The focus is on the rendering of solar energy. Time aggregation is of uttermost importance in large-scale energy models, as it is (at the time being) a necessary step for the identification of the optimal generation fleet of the future. The topic is treated in relation to the open-source model Balmorel, which is the main tool adopted for the analyses. Gridsol and Smart Renewable Hubs are modelled according to its functioning and their impact is tested on the entire European system.
From a technical point of view, Gridsol is a hybrid power plant and its strength lies not only in expected high full load hours (FLH), but also in very contained emissions. The features that make this hybrid power plant different from other cost-competitive alternatives are discussed and the strong points of SRHs integrating the Gridsol technology are highlighted; the framework within which this study moves forward adheres to the latest Climate Strategy published by the European Commission [7]. In this manner, Gridsol is evaluated also for its contribution to the European long-term climate and energy targets (until 2050). More explicitly, environmental externalities (CO_2 emissions) are included in the analysis in order to assess the profitability of Gridsol from a socio-economic perspective.

1.2.1 Research questions

Owing to the mentioned methodologies and objectives, this Master's thesis aims at providing answers to the following core research questions:

- how important can Concentrating Solar Power and Gridsol be in the future European power sector?
- what is the influence of high carbon prices and of a soaring demand for new fuels on the spreading of CSP in Europe?
- are CSP and Gridsol an attractive solution to be integrated into larger Smart Renewable Hubs? If so, how do technologies behave therein and what characterises their operations?

1.3 Outline of this work

This section gives an overview of the thesis content, which is visualised in Figure 2.1. The scenario analysis, which constitutes the core of the thesis, is only the ultimate result of a laborious process; this involves the creation of a simulation set-up that return the desired outcomes with a certain accuracy and within a reasonable time frame. The results leading to the chosen aggregation scheme are presented separately at the end of the related Chapter, as they are part of a different discussion. The core outcomes regard CSP and its integration into hybrid concepts in Europe, which is extensively discussed in the Results Chapters.

The next Chapters expand on the following:

- an introduction to the concepts relevant for the understanding of the thesis. In the first place, these include energy markets fundamentals, how they are related to Energy Systems Models and what are the challenges in the field; a particular focus is reserved to Balmorel. Second, they involve the state-of-the-art of CSP technologies, their diffusion and how they relate to hybrid power plants (or Smart Renewable Hubs, Chapter 2);

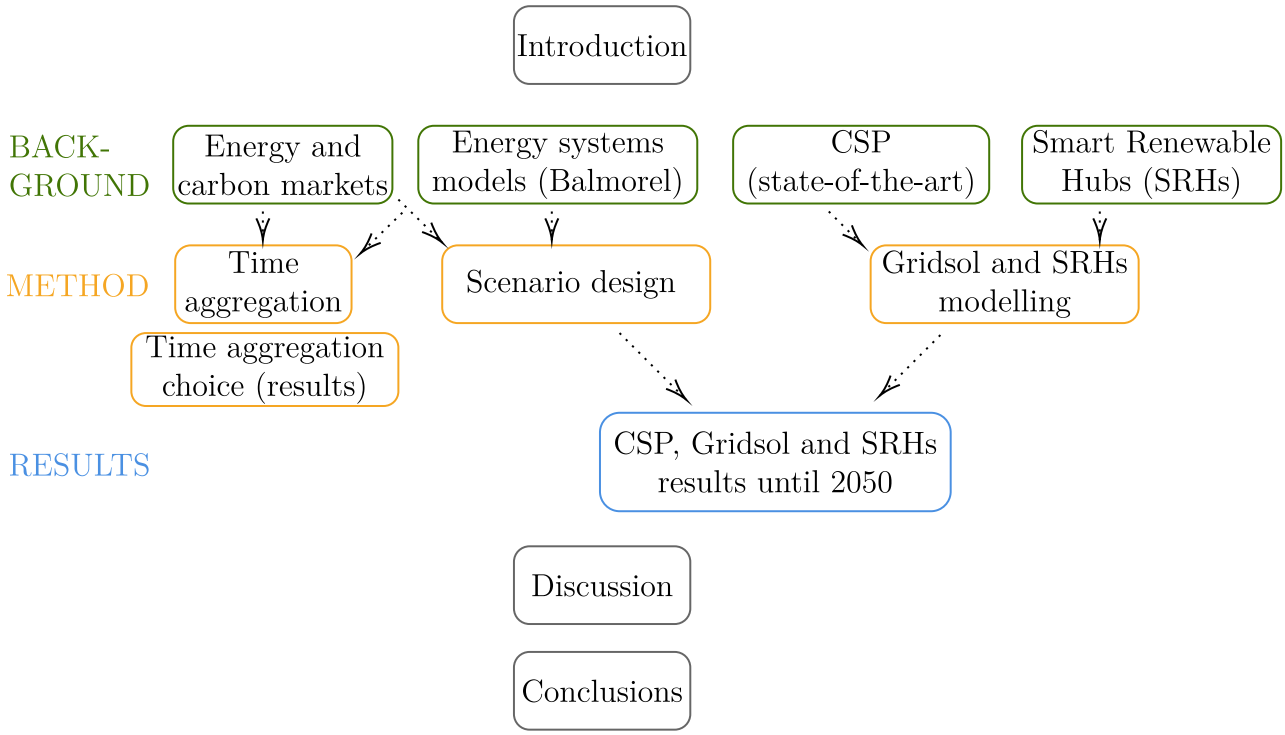


Figure 1.1: Thesis overview.

- the importance of proper time aggregation schemes in the context of large-scale Energy Systems Models; the focus is on runs that require time aggregation for optimising the investments. These topics are extensively discussed in Chapter 3, where particular attention is payed to the rendering of solar energy;
- the technical and financial characteristics of the Gridsol technology and of Smart Renewable Hubs, along with their implementation in Balmorel (Chapter 4);
- the scenario design and the model compliance with the latest European energy and environmental pathways towards 2050 (Chapter 5);
- an overview of the long-term potential of CSP and Gridsol in Southern Europe (Chapter 6), where the results are analysed from a technical, economic and environmental viewpoint;
- the description of the structure of Smart Renewable Hubs until 2050 (Chapter 7);
- the seasonal and hourly functioning of a typical CSP plant, of the Gridsol hub and of a representative Smart Renewable Hub (Chapter 8);

- the discussion around the results (Chapter 9);
- the conclusion (Chapter 10).

In summary, this thesis gives an original contribution to:

- the discussion on time aggregation for investment runs, with a specific focus on Balmorel. An assessment of the techniques is performed in the results domain;
- the modelling of hybrid power plants in Balmorel
- the identification of the future value of CSP, in particular its role in a power sector forced to abide by the rules of a cap-and-trade quota system;
- the identification of the technical importance of SRHs, taking into account the European outlook on energy and climate.
- the obstacles hindering a big deployment of CSP, including a study under the key parameters that work around the barriers.

Chapter 2

Background Theory

This Chapter serves as a general introduction to the most important concepts used throughout the thesis. The content can be visualised in Figure 2.1: a first chunk introduces to the basics of energy markets and their integration within energy system models and Balmorel in specific; the second part reviews the state-of-the-art for CSP technologies, their worldwide diffusion and their possible application into hybrid power plants, in particular Smart Renewable Hubs integrating the Gridsol technology. Each of the topics mentioned here will be further developed and reused in the core of the work.

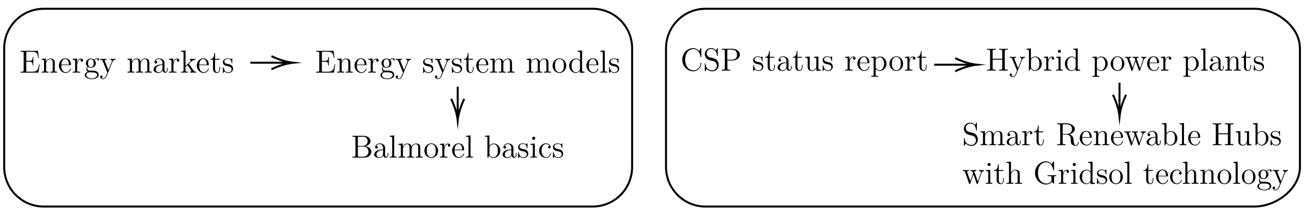


Figure 2.1: Chapter outline.

2.1 Foundations of energy markets

The Balmorel model (described in the following) is grounded in traditional day-ahead markets for energy trading, whose functioning is introduced in this Section. Here the basics relevant for understanding and analysing the results are presented. These markets are cleared according to the classic theory of supply and demand, as shown in Figure 2.2. Generators are scheduled if their Willingness To Accept (WTA) is lower or equal than the market clearing price; even if the WTA does not necessarily coincide with the short-run marginal cost of generation (because of strategic behaviour), the latter can serve as a reference to sort producers according to the so-called merit order (Figure 2.4). The *short-run marginal cost of generation* represents the increase in cost due to a marginal increase in energy production. The scheduled unit with the highest short-run marginal cost of generation sets the wholesale market price. Conversely, the *long-run average cost of generation* includes all kind of costs needed to supply one unit of energy and therefore coincides with the Levelised Cost Of Energy (LCOE). The first can vary with time, depending for example on fluctuations in the variable costs (e.g. fuel costs); the second is the result of a pre-assessment and reflects average generation costs over the entire economic lifetime of the plant.

It comes straight away that plants such as solar fields and wind farms, enter the market easily because of their low (or null) short-run marginal costs of generation. This causes some relevant consequences, e.g. a dynamic need of back-up technologies and their changing scheduling to maintain supply and demand in equilibrium, or the variability of electricity price profiles during the day. These and other facts are discussed in the following.

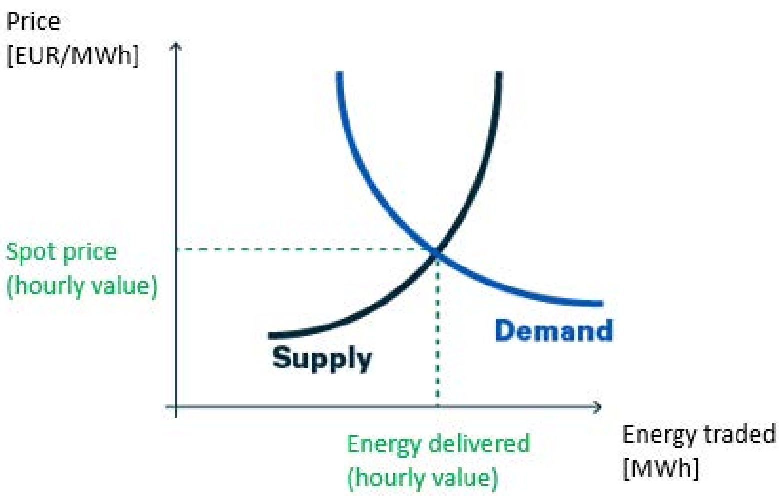


Figure 2.2: Demand and supply are matched on an hourly basis to obtain the spot price and the energy delivered. Adapted from [8].

Most energy system models (see Section 2.3), including Balmorel, integrate only the day-ahead market in the optimisation process. Despite being managed by different bodies in Europe (e.g. NordPool in the Nordics, EPEXSPOT in the UK and continental Europe), this type of market is subject to the same principles across the continent. Day-ahead markets are cleared one day in advance with respect to the day of delivery: around noon time of day *d-1* producers bid and, if included in the so-called *merit order* (Figure 2.4), pledge to deliver a certain amount of energy on a hourly basis for the upcoming day. This mechanism binds generators to dispatch a certain volume 12 to 36 hours in advance; aside of unplanned outages and other unforeseen breakdowns that could occur also to conventional units, it is with large share of renewable energy that intra-day and balancing markets rise in importance. This is due to the fluctuating nature of Variable Renewable Energy (VRE) and the related challenges in accurate forecasting.

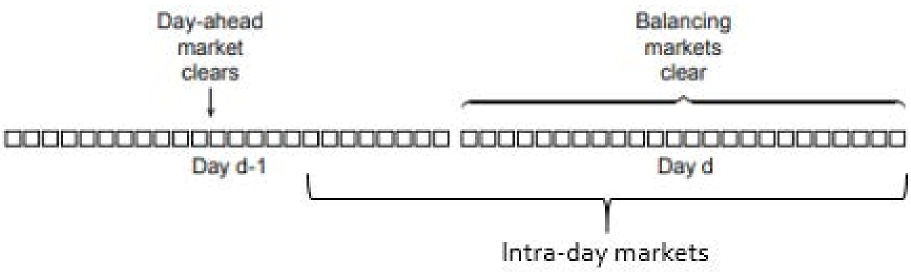


Figure 2.3: Different types of markets for energy trading. Adapted from [9].

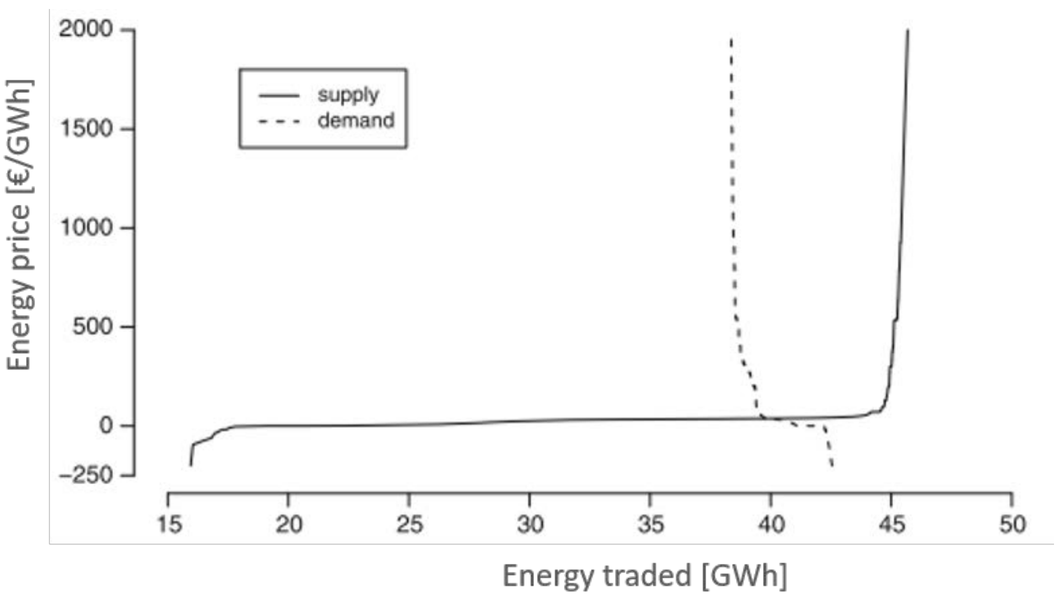


Figure 2.4: Merit order curve in the Scandinavian Elspot market for October 15th, 2012 (7-8 a.m.). Adapted from [9].

Intra-day markets, though working according to the merit order effect, are designed differently across Europe and real-time markets are difficult to represent; in addition, their inclusion in ESMs would bring a minor value to the accuracy of results and at the expenses of a higher computational time: despite an increase in generation from Renewable Energy Sources (RES), the monetary volumes of intra-day and real time markets are expected to remain a few percents of the day-ahead figures also in the forthcoming years [10]. A study on the effects on this type of markets is not part of this thesis.

2.1.1 Assessing the value of renewables in electricity markets

Non-dispatchable technologies, such as solar PV and wind power, are subject to the market mechanisms in the absence of support schemes. In other words, the revenues for such generators (without storage) are conditional on the volume generated in a specific hour and on the spot price in the same time span. The use of the Market Value MV [EUR/MWh] (or *capture price*, as it is often referred to), defined as follows

$$\mathrm{MV(t)} = \frac{\mathrm{electricity\ \ sales(t)}}{\mathrm{electricity\ \ generation(t)+curtailment(t)}} \quad \text{for t} = 1, 2, ..., 8760$$

has become increasingly relevant to assess the attractiveness of renewable technologies [6]. In fact:

- projections that illustrate a fast upcoming decrease in storage costs would pave the way to their large-scale utilisation. This would allow non-dispatchable units to accumulate energy in moments of low demand (and prices) to release it during peak hours. Units virtually shift production to when the load surges;

- it gives a proper framework to evaluate the competitiveness of renewables in case of no subsidies, which are being cut out more and more as their share in the generation fleet gets consistent.

The electricity curtailment (above formula) can be defined as the production falloff in periods when a unit has a favourable short-run marginal cost of generation [11]. Unplanned outages are of course excluded by this definition. Alternatively, curtailment is the energy a renewable unit is not able to dispatch because of technical limitations (e.g. grid stress, congestions, oversupply of electricity). Storage units are the means to reduce curtailment and, more in general, what Hirth labels as ’profile costs’, i.e. the costs of being a non-dispatchable technology. This element constrains the market potential of VRE sources and is intimately related to their market share. For instance, a system penetrated by a large amount of solar PV without storage would experience a drop in electricity prices during the central hours of the day, as a result of excess generation (Figure 2.5). The outcome is limited profit margins for such units. Storage facilities, be they connected to CSP (thermal) or wind and PV (electric), help reverting this situation by virtually shifting the production. The relationship between market penetration and the price seen by VRE generators has been recently studied [6], and correlations can be found in the literature (Figure 2.6). The market value is here normalised with the average spot price (this is also called *value factor*). It can be seen that models sketching the evolution of energy systems show how the profitability of VRE sources is highly sensitive to their market share, which is a reason why support mechanisms are designed.

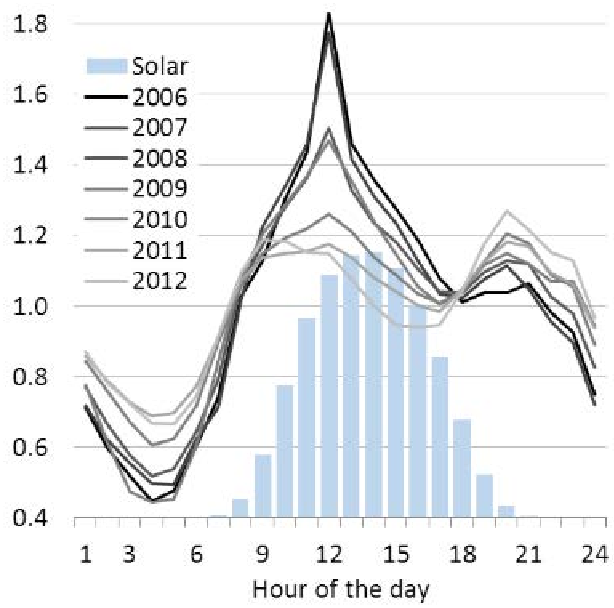


Figure 2.5: Evolution of the wholesale market price in Germany with increasing solar PV penetration. The lines show the evolution in the relative market price (y-axis), the bars the normalised solar PV generation on a summer day. Source: [12].

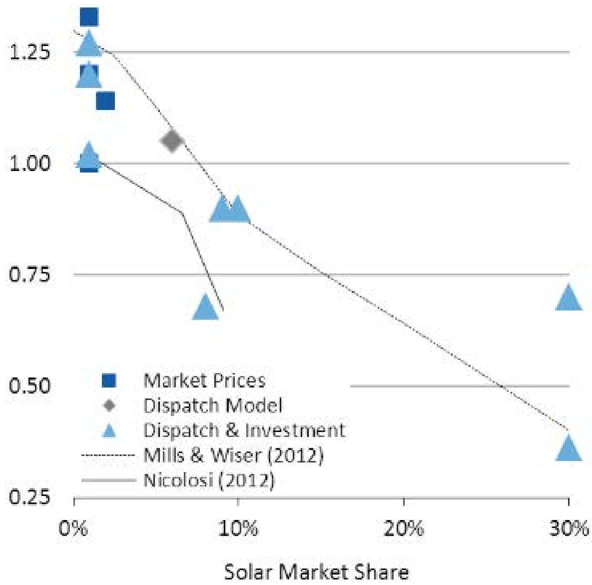


Figure 2.6: Correlation between PV market share and normalised market value (y-axis). Source: [12].

These models, including the one adopted for this thesis, consider only the day-ahead market functioning. It is to be borne in mind that also balancing needs contribute to the gap between spot and capture price. For all the reasons previously mentioned (but with this last limitation), the market value is chosen as a key indicator for assessing the results of this thesis. Little can be found in the literature on CSP capture prices, especially for the future, when the technology can be relevant for power supply under specific conditions.
A comparison with the LCOE [EUR/MWh] permits to assess the competitiveness of this and other renewable technologies in the long-term. The LCOE is defined as

$$LCOE = \frac{I_0 + \sum_{y=1}^{n} \frac{OPEX_y}{(1+r)^y}}{\sum_{y=1}^{n} \frac{E_y}{(1+r)^y}} \tag{2.1}$$

and represents the average cost of producing one unit of energy during the economic lifetime n of the asset. I_0 are the total overnight costs, E_y and $OPEX_y$ are the energy generated and the overall operational costs in year y, r the socio-economic discount rate. The market value can therefore be seen as the threshold (maximum) LCOE for the investment to be profitable. Whenever

$$\text{MV} \geq \text{LCOE}$$

the average potential revenues obtained by selling energy on the market are greater than the average costs of producing that unit; this equation marks a line for the profitability of energy technologies. In other words and considering trends as the one in Figure 2.6, the future impact of renewable energy can be read by looking at the interaction between LCOE (and therefore capital costs, considering their weight) and MV.

2.2 The European Emission Trading System (EU ETS)

The increasing need to account for externalities (especially CO_2 emissions) in the energy markets design has lead to the birth of complementary tools, both in Europe and worldwide. The European Emission Trading System (EU ETS) was introduced in 2003 with the 2003/87/EC directive [13], with the purpose of putting into a place a set of market instruments and structures that help the EU fulfil its environmental targets. Owing to the 2008 financial crisis, to the loose rules for the industrial sector (international credits), to the advancements in other sectors (energy efficiency measures for instance) and the interaction effect with other policies (subsidies), the EU ETS has largely failed to provide the desired price signals to sustain and accelerate decarbonisation [14]. The emission trading scheme has then undergone a series of reforms in the years 2014-2015, which established the Market Stability Reserve (MSR) and tightened the cap for GHG emissions by increasing the yearly linear reduction factor to 2.2 % (previously 1.74 %).

In 2017, the EU ETS covered 40 % of the total greenhouse gas emissions in Europe [15]. The power sector has consistently cut its emissions since the establishment of the scheme and it still leads the emissions reduction effort, marking an estimated 21 % cut between 2012 and 2018 [16]. This figure is almost as high as the 22 % drop in total emissions the EU has achieved in nearly three decades, from 1990 to 2017 [17]. Still, it is far from the adventurous 80-100 % cut pledged by signing the Paris Agreement (to be achieved in 2050).

Given these ambitious goals, the EU ETS should provide the opportune price signals for actors to invest in sustainable energy. However, the external above-mentioned factors have weakened the role of the scheme; the clearing prices have fluctuated consistently in the past years (Figure 2.7) and investments in renewable energy have been supported by other initiatives. The recent reforms are assumed to reinforce the EU ETS role in achieving the preset climate targets; in the power and heat sector they can be attained through 100 % renewable energy penetration or, possibly, the use of Carbon Capture and Storage (CCS). At present, CCS technologies have not seen cost reductions that boost their competitiveness [18], so a large uptake is unlikely to happen.

Figure 2.7: Historical CO_2 prices in the EU ETS. Data is from 09-06-2009 to 09-06-2019. Horizontal axis: years; vertical axis: price [EUR/t]. Source: [19].

The EU ETS is central in this thesis as it contributes to the definition of the scenarios where Gridsol and Smart Renewable Hubs are assessed. More details can be found in Chapter 5.

2.3 Energy system modelling

The importance of large-scale energy system modelling for policy design is documented already in the 1970s, when computational power reached a high-enough level to process simulation and optimisation tasks [20]. The purpose and characteristics of such models have evolved with time, mainly to address coeval transformations and challenges linked to energy supply and climate protection. It is especially from the 1990s and the signing of the Kyoto Protocol in 1997 that Energy System Models (ESMs) have focused on the integration of renewable energy in the generation mix; concurrently, greenhouse gas (GHG) reduction became a priority in the political agenda and the choice of energy conversion technologies has since then been influenced by parameters other than the pure economic convenience (externalities excluded). Renewable energy has been subsidised to favour its market penetration (already in 1991 in Germany and in the UK, in Italy in 1992 [21]) and conventional generation discouraged by the establishment of market instruments such as the above-mentioned EU ETS (Directive 2003/87/EC [13]).

From an energy point of view, the European Union is a very interlinked entity, in both a technical and political sense. First, the member States are connected by transmission lines, which enable the power generated in one country to flow to a neighbouring one. Second, the EU shares tools to achieve pre-determined, common targets, such as the above-mentioned ETS. Both economic and technical aspects are accounted for in ESMs, with some inevitable simplifications. Rendering the detailed reality in a model is an unrealistic and unachievable target; therefore, less complex relationships are needed to describe it. In any energy model, a past or present system is simplified so as to provide a solid but lean characterisation of existing structures; next, assumptions are introduced to design or obtain future trajectories. Based on the type of analytical approach, i.e. top-down or bottom-up, the focus is either on macroeconomic relations that determine the functioning of economic institutions or on the technologies that define the optimal mix of future systems respectively [20]. Top-down models are especially suited when different sectors are under consideration [22]. When only the energy sector is analysed, bottom-up models have proved to be more convenient and informative; as this approach focuses on a narrow part of the economy, they are also called 'fundamental' (or, alternatively, 'partial equilibrium') models. They employ disaggregate data and a framework so that the optimisation tool decides for the most efficient or least costly solution. Convergence in large-scale models is usually attained by employing Linear Programming (LP) techniques; they constitute the state-of-the-art for problems of such sizes, as new, more advanced methods would require a computational effort beyond reach. Optimising the operation of energy plants is a relatively light task for linear programming algorithms; nonetheless, in ESMs the functioning of the system is simplified by neglecting operational constraints. These would require the use of integer variables (Mixed Integer Linear Programming, MILP), so as to solve a classic unit commitment problem. The typical goal of an optimisation process is to find the *structures* s (i.e. the size of the energy system) and the relative *operations* o so that they minimise the total system costs. These can be decomposed into capital (CAPEX) and operational expenditures (OPEX):

$$\min_{s,o} z = \min_{s,o}(a \cdot \mathrm{CAPEX}(s) + \mathrm{OPEX}(s,o))$$

where z represents the problem's objective function and a the factor the annualises capital expenditures.

This is the rationale that guides a large-scale ESM like Balmorel towards the optimal solution; notwithstanding, the model's architecture is particularly complex and each problem calls for a *ad hoc* design of structural parameters and of the framework within which the real system operates. In other words, the analyst faces a series of difficulties in representing the reality to be optimised; in [23], four major challenges related to energy system models are listed: they are linked to the representation of time and space, to the system growing complexity, to the transparency and the uncertainty of the results, to behavioural and social aspects. Apart from the latter, which is difficult to assess and seldom accounted for, all the other problems are treated in this work as far as the Gridsol project is concerned. The details can be found in the next Chapters.

Time and space are paramount parameters in ESMs. An hourly resolution is needed to render both the behaviour of units such as storage facilities and to emulate the functioning of energy markets. When active, electric and thermal storage units load and release energy in a continuous manner, so that a relatively dense (however discrete) resolution is mandatory to capture their functioning. Day-ahead energy markets, as explained in the previous Section, are cleared in advance for every hour of the next day. A standard year is composed of 8760 hours; such a large amount of hours makes investment runs difficult or even impossible to carry out in full-time resolution mode, so that a well thought-out time aggregation is crucial to obtain reliable results. Aggregation occurs also space-wise. Geography sets up the environments where physical exchanges happen (they define the system boundaries for energy flows), it recreates zones upon which markets are cleared or where constraints given for instance by local or national policies are implemented.

The system complexity is reduced by neglecting the detailed technical modelling of power and heat grids and the extensive functioning of systems for energy production. These features fall outside the main aim of large-scale ESMs, which is essentially to support decision-making and policy design. A simplified, yet effective rendering of aggregate transmission capacitites between regions is sufficient for analysing key market and grid issues, such as bottlenecks and congestion prices. Still, different tools can be (and are in practice) integrated to provide a holistic view on the desired topics; they can e.g. include models for fault analyses or the operational details of the electric grid.

The future development of costs, prices, demand trends etc. are the outcome of assumptions or analysis that are subject to uncertainty, and so are the results of the simulations. This uncertainty is often tested with scenarios on different choices of the exogenous variables. An exogenous variable (or parameter) is chosen and given as an input by the modeller. Typical examples are renewables profiles and technological costs. Not every ESM has the same types of externally defined variables. The relevant ones are presented in the next Section as far as Balmorel is concerned.

In ESMs, the societal perspective is considered. This translates into a choice of parameters that reflect risks, interests, costs and benefits for the community as a whole. Common welfare is assessed, for instance, by accounting for environmental consequences and undertakings are characterised by a lower risk than what would result from the private's perspective. Concretely, this requires the inclusion of costs related to GHG emission and a reduced interest rate (or Weighted Average Cost of Capital, WACC) for the investments. More quantitative details can be found in the next Chapters.

In the following, a brief description of Balmorel is provided; its strength and weaknesses are briefly discussed and the features directly connected to this project are highlighted.

2.3.1 Balmorel as an optimisation tool

The Balmorel model saw the light at the turn of the century to represent the "electricity and CHP [Combined Heat and Power] sectors around the Baltic Sea" [24]. It has spread ever since, and it is currently used by research centers, universities and private companies operating mainly (but not exclusively) in the Nordic region. Balmorel is an open-source, bottom-up, fundamental model which optimises the investments and the operations of large-scale energy systems; it is coded in GAMS (Generalised Algebraic Modelling System) and converges to the optimal solution by means of linear programming techniques, but allowing also for the incorporation of integer variables. The latter are introduced when the problem size allows for it and when operational details are of uttermost relevance for the analysis.

Aside of the input data mentioned in the previous Section, Balmorel requires a set of quantities to be defined exogenously: these are demand prognoses, fuel prices, the existing and committed generation fleet, existing and committed transmission capacity, policy constraints and the technology catalogue from which the model chooses the future generation units. These need to be set for the years considered in the simulations.

Balmorel can be run in four different 'Balbase' (Bb) options that make it suitable for a variety of scopes (Table 2.1); the Bb4 option is here not described, as it is currently not in use at Ea Energy Analyses. The Bb1 mode allows for the optimisation of a user-defined system without factoring new investments in; on the contrary, Bb2 includes possible investments in both transmission and generation capacity. These two options work with a myopic approach when several years are simulated, in that they start from the newly found solution for Year 1 to optimise further [24]. Within the year, the model assumes perfect foresight. This is valid for all cases but Bb3, where the results from a previous investment run (Bb2) are generally used as input values for a series of weekly myopic optimisations. The input values (new investments, storage status through the year etc.) provide an architecture for performing analyses with a high temporal resolution [25]. This thesis makes extensive use of the Bb2 and Bb3 options;

in the following, they will also be referred to as ’investment run’ and ’full-time resolution run’ respectively.

Table 2.1: Main features of the three considered simulation methods.

	Bb1	Bb2	Bb3	Bb4
Optimisation period	One year	One year	One season	One or more years
Optimisation of investments	No	Yes	No	Yes
Seasonal optimisation of storage	Yes	Yes	No	Yes

2.3.2 Geography and time in Balmorel

Geography offers a sufficiently wide array of spatial entities where to define parameters and constraints. These can be related to physical quantities (in this case the entity acts as a control volume) or they can set up the space where economic structures work and policies wield control over environmental and energy targets. There exist three different spatial layers in Balmorel: they are Country, Region and Area in decreasing order of breadth [25]. Policies, targets and fuel prices are defined at Country level, energy markets are cleared at the Region level; transmission lines connect therefore Regions, to assess possible congestions and bottlenecks. In the simplified Balmorel representation, there can be only one line linking two distinct Regions. The electricity balance also occurs here, and the model can be employed to evaluate the suitability of new investments in transmission infrastructures. Instead, the heat balance is carried out at the Area level, where also the profiles for renewable resources are defined. Depending on the scope of the analysis and on the type of quantity, Areas can e.g. represent large district heating grids or tiny strips of land characterised by high wind speeds. It holds that:

$$\text{Country} \subseteq \text{Regions} \subseteq \text{Areas}$$

The degree of spatial resolution is conditional on the type of analysis that is conducted; in the simplest case, a Country contains a single Region, which comprises a single Area.

Time is also structured into three different layers: Year, Season and Term in descending order of granularity [25]. Seasons and Terms are rather strict subdivisions of the above respective layer,

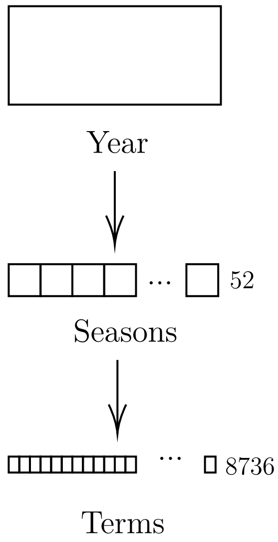


Figure 2.8: Subdivisions of a Balmorel Year.

in that they split respectively Years and Seasons into periods of fixed and discrete length. The most common approach is to match Terms and hours, that consequently result in the smallest time segment available. Seasons coincide with weeks: every Season contains 168 hours. Given that the number of weeks in a year is not an integer value, the Balmorel Year is composed of 52 Seasons (weeks) and therefore 8736 Terms (hours); this results in a slightly shorter Year than the standard one (Figure 2.8).

When dealing with systems wide in geography, a challenge is related to time zones. Balmorel uses the Central European Time (CET) as the reference time. Countries which do not belong to this time zone have their profiles shifted backwards (Portugal, Great Britain) or forward (Greece). These differences sum up to geographical, natural discrepancies in the input profiles. Further considerations can be found in the next Chapter.

2.4 Concentrated Solar Power

Concentrated Solar Power (CSP) coupled with thermal storage is expected to deliver around 6 % of the world's demand for power in 2030 and twice that amount in 2050 [26]. The success of this carbon free technology relies on the capability of assuring firm production and dispatchable generation contrary to other types of VRES. Nonetheless, the CSP global installed capacity totalled to only 4.9 [GW] at the end of 2017, against the much more consistent 402 [GW] and 539 [GW] of PV and wind power respectively [3]. Several projects are however in the pipeline, with China alone announcing 5 [GW] of new plants by 2020 [27].

Contrary to PV, CSP technologies exploit the Direct Normal Irradiation (DNI) instead of the Global Horizontal Irradiation (GHI). Figure 2.9 is a map showing the abundance of DNI as a function of geography. In countries where the resource is high enough (typically greater than 2000 [kWh/m^2/year], but some studies consider 1800 [kWh/m^2/year] as a threshold [26]) CSP plants are already operational or under construction (Chile, the US, South Africa, Morocco, Australia, China to name a few [3]). As clear from the map, in Europe the DNI is scarcer, but sufficient all around the Mediterranean region to turn CSP into a viable option. Its success is not only related to abundance of irradiation, but also to land availability, subsidies and competitiveness of generators that target the same market segments. After a fast development in Spain due to subsidy allocation (beginning of the 2010s, Figure 2.10), only small, desultory investments have followed. When the above-mentioned, critical conditions for its deployment are unmet, CSP suffers from the cheap and consolidated alternatives it can substitute in the market, i.e. mainly peakers (gas cycles) and photovoltaics. A turning point can be marked by the inclusion of big storage units, but at present the majority of CSP plants in Europe, which were built in the past decade, is not equipped with thermal storage [26]. The average capacity factor stood at around 27 % for CSP in Spain in 2015 [4], but large storage facilities can significantly boost this figure. Aside of Spain, small CSP installations are present in Italy and Germany (6 and 2 [MW] respectively [28]). Nonetheless, 20 and 115 [MW] are in the pipeline in France and Italy respectively [29].

CSP plants have been operational for decades and they exist in a number of different alternatives as regards the solar field [32]: parabolic through, power tower, linear Fresnel and parabolic dish. The first is the most common option among the existing installed capacity, but the second is the most promising technology for a large scale deployment. The reason can be found in high efficiencies and capacity factors, as reported in Table 2.2. The other two concentrating systems have not reached the required solidity to progress in their commercialisation. The Gridsol project considers exclusively the power tower technology; in the following, only its peculiar

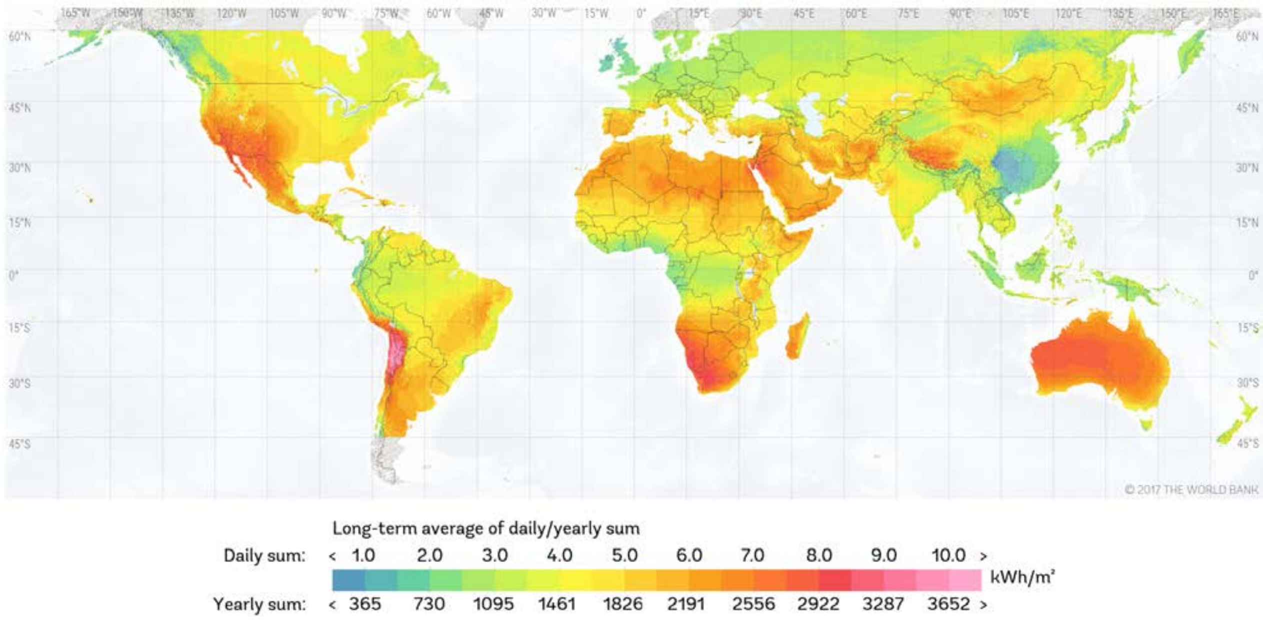


Figure 2.9: World map for the Direct Normal Irradiation (DNI). Source: [30].

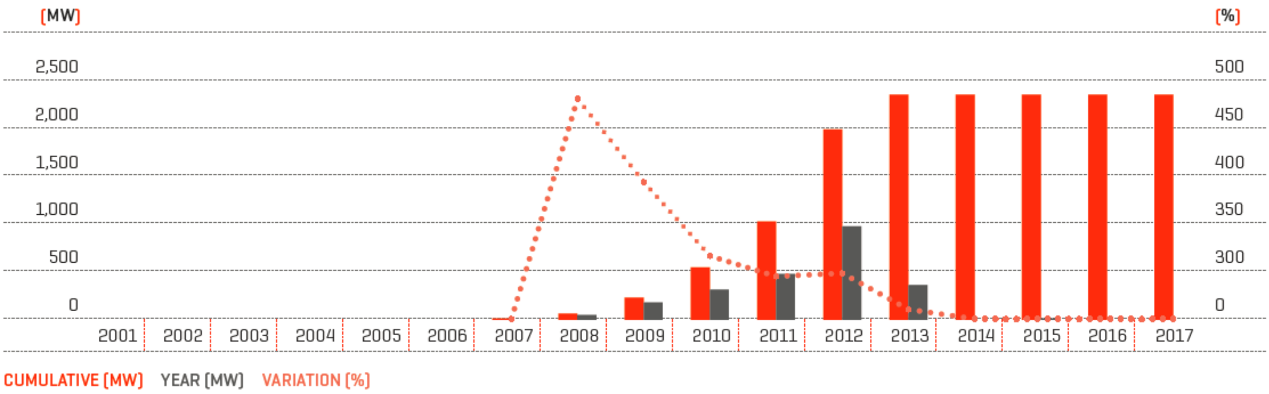


Figure 2.10: Evolution of CSP capacity in Spain until 2017. Source [31].

characteristics are mentioned.

All solar fields comprise an optical system that concentrates the DNI into a receiver; in the case under consideration, the first is constituted by heliostats, the latter by one or more towers. The irradiation heats up a medium that exchanges heat with a hot storage; through an additional heat exchanger, the temperature of a power cycle working fluid (typically steam in a Rankine cycle) is raised before the expansion in the turbine. A more detailed description is provided in Chapter 4. As previously mentioned, thermal storage is a key for CSP to pursue ambitious targets; notwithstanding the high initial costs, especially for large tanks, the LCOE of such systems lessens if compared to units without storage. The following points summarise the

Table 2.2: Performance of different CSP technologies. Source: [32].

	Average efficiency [%]	Capacity factor [%]
Parabolic trough	14-18	24
Power tower	14-25	25-70
Linear Fresnel	14-18	24
Parabolic dish	18-25	25

major barriers this technology has to overcome in the near future to enhance its attractiveness [29]:

- high overnight costs. These can be reduced by learning effects and economy of scale;
- poor overall exploitation of the solar resource. As shown is Table 2.2, the system's complexity (absorbers, receiver, heat exchangers, storage and power block) drives down its thermodynamic efficiency. Improvements can be attained by adopting novel, more efficient optical systems, different types of storage (e.g. working with latent heat) or advanced power blocks. Supercritical cycles are an option in this case, but their higher costs (if compared to a traditional sub-critical cycle) need to be counterbalanced by a decrease in the LCOE;
- weak supply chain and industrial competitiveness. The vertical integration of firms involved in the supply chain is seen as a key to lean the business operations of an industry that has yet to develop.

CSP can find applications in several other context, such as desalination units or to boost existing fossil-fuel-fired plants. These contributions, even when directly connected to power production, are not accounted for in the model, as their contribution is difficult to assess and at any rate marginal in the European energy sector.

2.5 Smart Renewable Hubs

This section summarises and improves on some of the concepts outlined in the previous Sections by considering their application to Smart Renewable Hubs (SRHs or, more in general, Hybrid

Power Plants HPPs), which are at the core of this work. HPPs have gathered a big interest in the last years due to their technical resilience. They are largely scalable and flexible, as they result from the combination of technologies with different attributes. Commonly, renewables are integrated with traditional internal combustion engines or gas turbines, which are activated when natural resources are scarce. In Figure 2.11 a general scheme of HPP is presented. CSP is part of it, along with other Renewable Units (RU). All generators have the possibility to store the energy produced to dispatch it when convenient. The storage (be it thermal, TES, or electric, EES) increases the power plant flexibility. The scheme shows a possible configuration of HPP and is not representative of all design possibilities, as for example pumped hydro is not considered.

HPPs contribute to increasing the renewable share in the energy sector, with the presence of back-up units boosting also the plant full load hours (FLH) and guaranteeing firm generation. For this reason, they are also a viable solution for off-grid applications. In any case, the control strategy is a decisive tool to increase competitiveness, as it minimises the sub-optimal operation of the system.

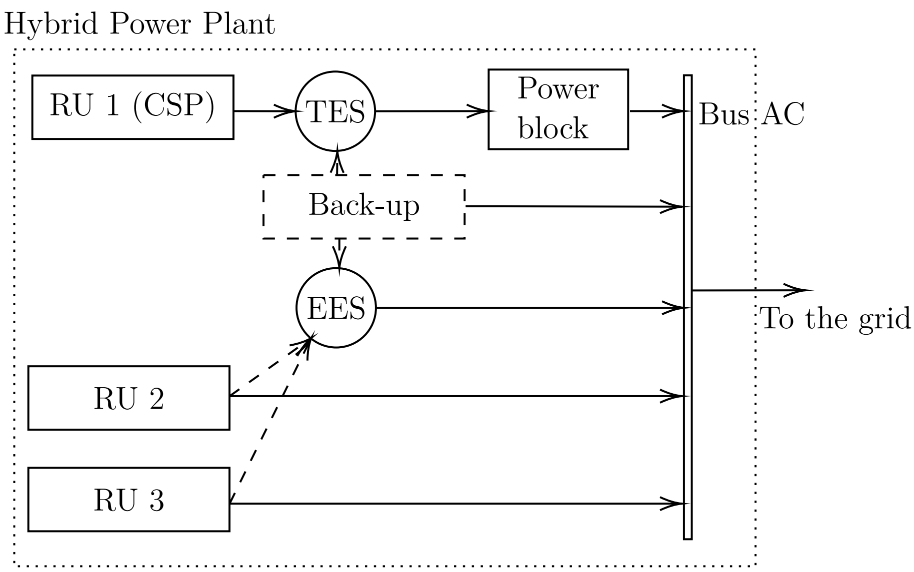


Figure 2.11: Schematic representation of a hybrid power plant with CSP. RU: Renewable Unit; TES: Thermal Energy Storage; EES: Electric Energy Storage. Power electronics are not represented for simplicity.

Power plants entirely relying on renewable energy sources, as conventional solar PV fields and wind farms, have challenged the grid and the markets because of their inherent traits; these have led to a deep transformation of the economic structures and the architectures underlying energy supply. Technologies that rely solely on renewable energy bring about:

- uncertainty in the short-term generation. Wind and solar power plants are referred to as non-dispatchable units, in that their generation is largely unpredictable to the desired degree of accuracy: renewable sources are stochastic, whereas fossil fuel power stations can all be scheduled to satisfy load requirements. The largely unpredictable availability of irradiation and wind makes back-up units a necessity to guarantee security of supply. Moreover, from the investor's perspective, uncertain generation means uncertain (sub-optimal) revenues in the energy markets;

- extra system costs for accelerating their deployment. Most renewable technologies still require a support scheme to increase their market share. In the early stage, they represent non-mature technologies. An improvement in their learning rate is precisely one of the desired outcomes of subsidy design;

- null short-term marginal costs of generation, which lower the clearing price of day-ahead markets. Renewable power plants enter the so-called merit order curve at the low-end, forcing conventional, more expensive generators aside. This way they are guaranteed to dispatch, but they shift the merit order down; the encounter between demand and supply happens at a relatively low market price, thereby reducing revenues for all producers. Low prices penalise conventional generators for their high operational costs (especially fuel supply) but also renewable technologies, characterised by high capital investments.

As touched upon before, the dispatchability of wind farms and solar fields can largely improve by integrating electric storage; however and at present, their specific costs are not competitive enough (even against other storage concepts, e.g. pumped hydro) to supply power with continuity for a large amount of hours [33]. These considerations strengthen the attractiveness of HPPs, especially from the investor's perspective.

SRHs integrating CSP are a viable solution wherever the solar resource is sufficient. Since thermal storage makes CSP an alternative for intermediate load operation [1] and depending on the DNI availability even base-load operation [26], CSP is one of the few 100 % renewable back-up options to be combined with other green solutions. Gridsol, which is defined here as a combination of a CSP block integrating thermal storage and a gas turbine with heat recovery, is the particular hub under study in the three-year lasting project of the same name, funded by the European Union. Gridsol can be integrated in larger Smart Renewable Hubs, which in turn can comprise other renewable units.

Other hybrid solutions have been tested worldwide. PV-CSP plants have started to operate in countries such as Chile and South Africa and they can provide capacity factors over 80 %, close to the ones of conventional units [34]. In Europe, the existing CSP fleet does not come along with other integrated technologies. Few examples of hybrid power plants can be found at the moment, one being the El Hierro site in the Canary Islands [35]; the technological mix includes a wind firm, pumped hydro storage and diesel generators as back-up systems. The rise and normalisation of new markets, e.g. grounded on capacity mechanisms, can help this solution to spread all over the continent [36]. This thesis investigates the role of CSP in Europe and the profitability of hybrid systems possibly containing CSP in continental locations.

[1] An 'intermediate load' technology has features of both peakers and base-load generators.

Chapter 3

Time aggregation

This Chapter introduces to the problem of time aggregation in ESMs. A good aggregation of input time series is paramount in the context of this thesis, as the decarbonisation pathways under consideration lead to very large share of renewables in the supply sector. In fact, electricity production from renewable energy is subject to the availability of natural resources; in a modelling context, this requires time series to represent their temporal trend over the simulated horizon.
Considering that this research builds on the model in use at Ea Energy Analyses, the focus is on the rendering of solar energy, for which new, smoother profiles are adopted. Wind and hydro-power are modelled in a separate manner, which is not described here; they also certainly feel the effect of the aggregation scheme, but the presentation of the results focuses on solar PV; some results that include wind energy are presented in the Appendix A.2. This is for brevity since time aggregation is not at the centre of this work. Ultimately, this Chapter is part of the methodology of the thesis. The findings related to the aggregation research are presented at the end of this Chapter, as they are a preliminary activity to increase the core results reliability.

3.1 The problem

As previously discussed, hourly simulations are necessary to describe physical flows (e.g. in storage systems); this granularity is also aligned with the functioning of energy markets, which are cleared hour-by-hour in Europe.

Running large-scale models with a great number of equations and constraints is computationally heavy even when simple linear programming algorithms are applied; the phenomenon is accentuated when solving sizing problems, which demand more computational power than operational problems. The issue researchers and analysts have to face is to carry out simulations in a reasonable amount of time; this concern is consequently boosting an increasing interest in time aggregation techniques that slim the computational effort. In certain cases, time aggregation is a *preferred* option as it leads to satisfying results in a short period. In other (including this one), time aggregation is *necessary* as current memory limitations block the optimisation process. A copious amount of literature has been published on the topic; it aims at improving the aggregation techniques, but also at tailoring them to the specific model and problem. When performing analyses with large-scale models:

- the time available for the simulations may vary greatly depending on the case and on the final objective;
- the quality of the time aggregation technique is difficult to assess, in that a certain choice may render the case-specific, sought-after variables satisfactorily, but it may be sub-optimal if other parameters are considered instead. On top of that, time series data often refers to a reference year or is the result of projections/preliminary processing. This constitutes a source of uncertainty and therefore the method may be evaluated at a loss of generality.

Considering the reasons why time aggregation is performed, the validity of a technique is not often tested directly on the results; instead, the accuracy of the aggregate data is measured on the original time series (see for example [37]). In other contexts, where the size and complexity of the system are relatively small, it is actually possible to perform a simulation in full-time resolution mode; in this case, the quality of the aggregate data can be directly checked (time aggregation as a *preferred* option for sizing problems). On the contrary, a European model like the one under consideration *cannot* be run in full-time resolution mode and other types of verification need to be identified. The next section reviews previous studies and approaches in time aggregation techniques and discusses their application with respect to this work.

3.2 The methodology

Several research outputs have dealt with the problem of temporal resolution. For each of the systems under consideration, the goal is to reduce the computational time without compromising the quality of the results. The choice of the technique and its validation are the two fundamental steps in assessing its robustness.

3.2.1 The techniques

A common approach is that of making use of a small set of significant days that represents an entire year. This way, the optimisation tool aggregates the input data into few representative time slices and calculates the unknowns therein. Typical days can be:

- chosen directly from the original time series;
- derived 'artificially' with the aid of clustering techniques.

Another typical approach to the problem is averaging data over a set of hourly values. Average values lose track of important parameters in time series data, namely peak periods. The consequences may be that investments do not reflect the actual demand for power in a certain time slot and that the size of the components be sub-optimal. On the other hand, the set of significant days chosen with the above-mentioned approach may be not exhaustive; nonetheless the size of the set would be certainly limited, as each day holds 24 time steps on its own.

No technique can be proved to be better than another in general, and the quality of the aggregate data always depends on the input time series and on the type of the system under consideration; small systems may have in the clustered days a good input for sizing problems. As a first qualitative assessment found the typical days approach weak when representing different geographical areas, this thesis opts for averaging values over a well-defined, carefully-chosen time period. The geographical width brings about issues such as the one related to solar and demand peak hours; these occur at different hours of the day in Europe (Portugal and Greece belong to time zones separated by a two-hour gap). Figure 3.1 is an example of how solar profiles vary across the continent.

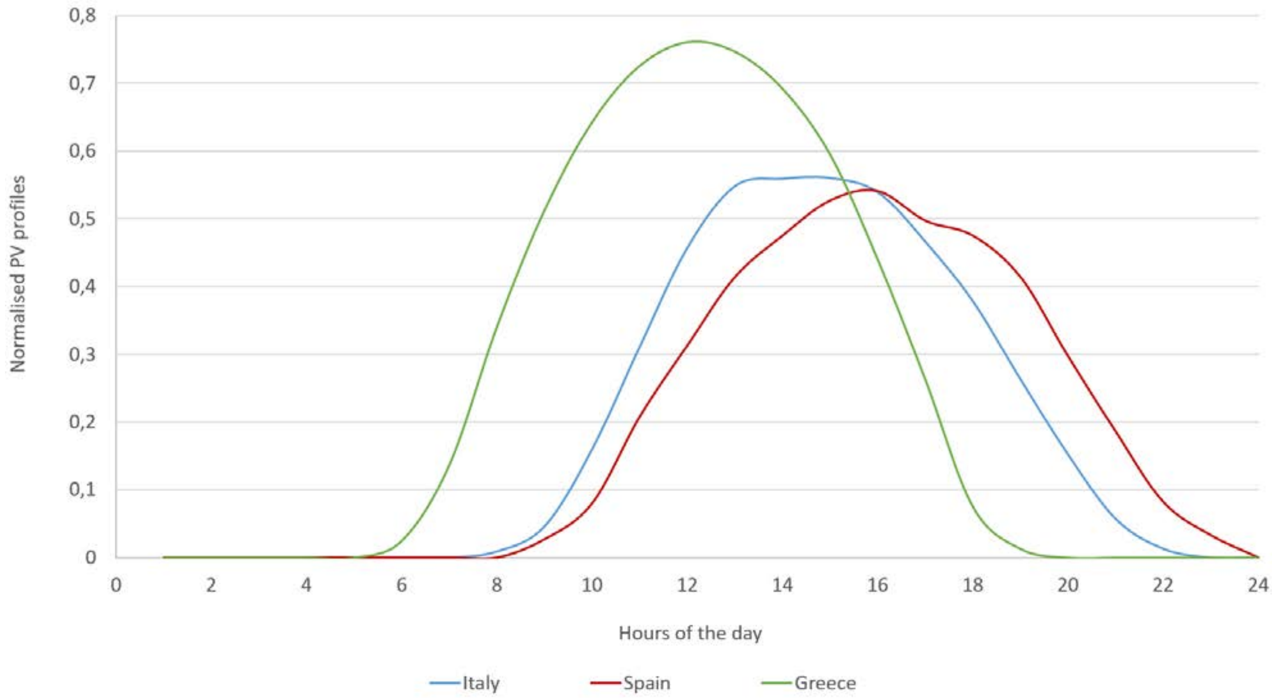


Figure 3.1: Solar profiles for a summer day across different countries.

3.2.2 Time aggregation in Balmorel

Time aggregation is used in the Bb2 mode (Section 2.3.1) to perform investment runs. The possibilities reviewed in this thesis concern two types of averaging techniques:

- classic averaging over a series of time segments;
- profile stretching for capturing peaks.

In the first case, the input time series are averaged over the defined number of simulated time steps and Seasons. The second approach - as the name suggests - stretches the profiles so that they capture peaks and troughs within each simulated period. The rationale behind this last technique is to keep track of the values driving the investments. In fact, ordinary averaging twists the input time series to the point that hours of high demand and potential full production from renewable units are missed. The shaved demand peaks can cause the undersizing of energy systems, which may be unable to meet the load; the distorted renewable profiles can oversize the conversion units instead (suffice it to think about prolonged, fictitious peaks, Figure 3.2). The stretched profile is subsequently adjusted for the mean to be preserved over the considered time period. Figure 3.2 exemplifies how the stretching process acts on time series data. Contrary to ordinary averaging, the weekly peak is maintained in the aggregate profile, and the remaining time steps under simulation are adjusted so as to recover the original mean. The peaks are assigned to the time steps where the average value is the highest (red line). In this example weekends follow a different aggregation scheme than working days (i.e., weekends and working days are aggregated into different time steps), so that only the values in the central hours of Saturday and Sunday are stretched to the weekly peak.

In the following, *time steps* indicate the set of aggregate weekly hours under simulation.

3.2.3 The validation

It was already mentioned that, due to the model size, the quality of the aggregate data cannot be tested directly employing the full-time resolution mode. The approach adopted in this thesis partially follows the one described in [38]. After the optimal investments are identified with the aggregate data (the *structures* s^{**}), they can be employed to find the associated optimal functioning o^{**}. The vectors s and o describe the state of the system under every possible condition; instead, s^{*} and o^{*} designate the respective optimal solutions, as achieved by a full-time resolution run. The aggregate problem yields a pair of optimal solutions (s^{**}, o^{**}) that differs from the desired (s^{*}, o^{*}). The rationale behind this validation method lies in the assumption that the optimal structures s^{*} do not vary when using the aggregate or the original

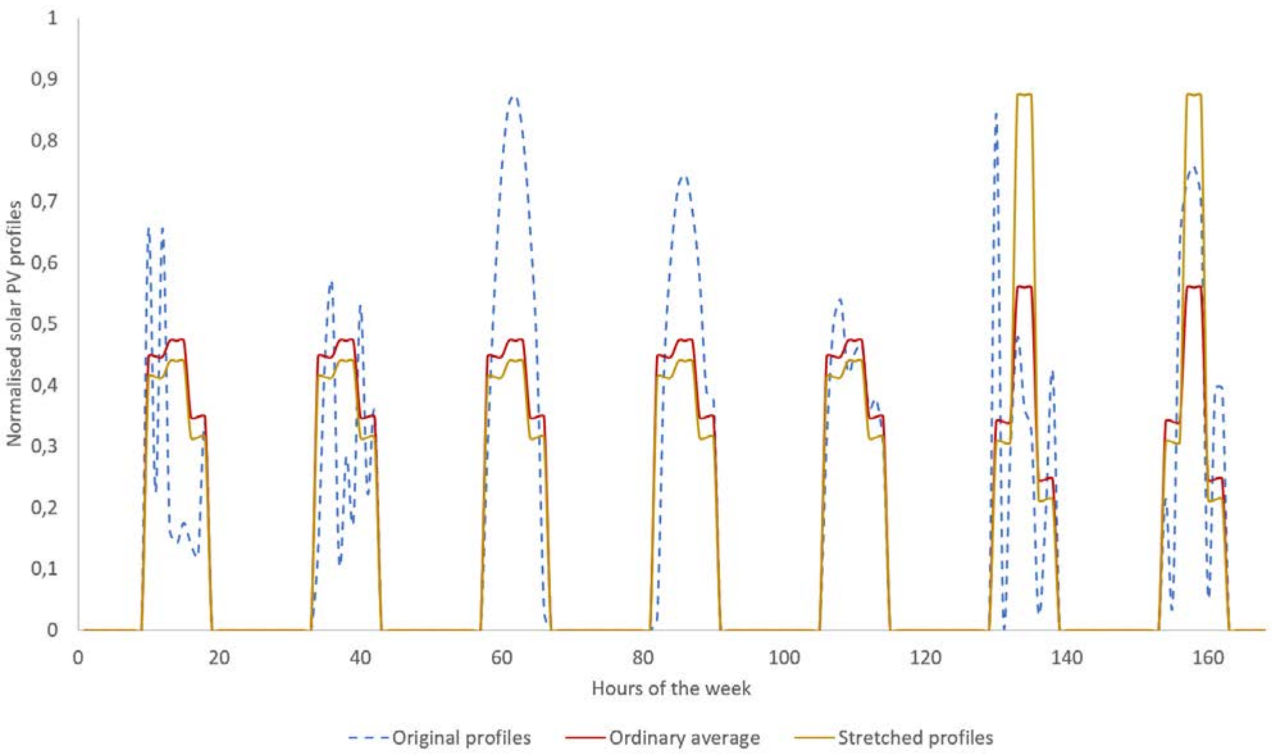


Figure 3.2: Example of a weekly solar PV profile and the corresponding ordinary and stretched averages.

time series (i.e. s^* and s^{**} almost coincide). This is not valid in general since averaging causes a loss of information, especially in relation to peaks and lows. However, the more the aggregation is accurate in the time series domain, the more this assumption is expected to hold true.

Under the above-mentioned assumption, the structures s^{**} serve as the input of an operation optimisation problem aimed at finding o^*, now with full time resolution. The research of the optimal functioning of energy systems, even of big size, under the market rules and through full-time resolution simulations is a relatively light task for current machines. The quality of the aggregated data can thus be measured in the domain of the objective function (or of the results, Figure 3.3).

In [38], the total system costs are the criterion for selecting the optimal aggregation technique. This thesis provides a further characterisation of this method, by looking at other specific results. In the case of large systems, as the one under consideration, the cost comparison is hardly a meaningful quality indicator; moreover, it doesn't directly capture the ultimate goal of aggregation. The model input time series are constituted by renewable resources (wind, energy)

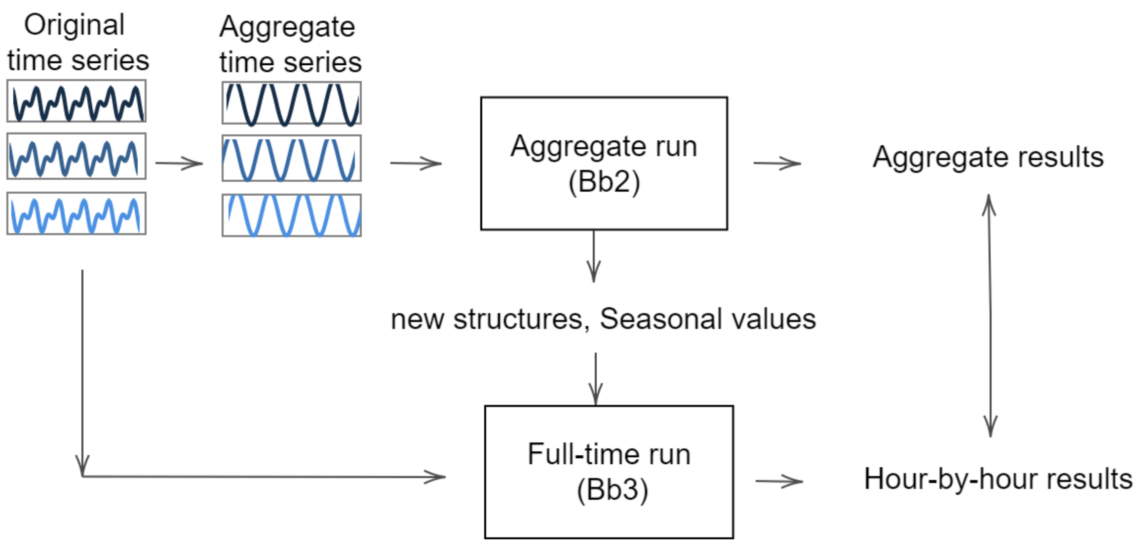


Figure 3.3: Aggregation process and method for testing the results. Reference is made to the Balmorel simulation options.

and demand profiles (Section 2.3.1). It is therefore more natural to validate the aggregate data on quantities q that directly relate to it, in particular:

- the generation mix, particularly from renewable energy;
- the electricity curtailment;
- the market value (or capture price) of renewable technologies.

The generation mix gives an overview of the impact of time aggregation on the entire system. In fact, the choice of a specific technique is also meant to maintain a significant level of detail for the technologies that are not dependent on the input time series (fossil fuel power plants, hydropower, biomass and storage). On top of that, the plants that require hourly input profiles (solar PV, wind farms) are assessed with dedicated quantities, such as electricity curtailment and market value. The first reveals possible conceptual weaknesses in the choice of the aggregation technique. Was there a big difference between the aggregated and the full-time run, then this would be an index of improper investments [1]. The second incorporates the wholesale market price in its definition, and is therefore a benchmark to assess the attractiveness

[1]Curtailment can occur for several reasons and be involuntary or the result of a voluntary agreement. In the context of large-scale energy system models, curtailment is mainly the outcome of mismatches between production and demand and, to a lesser extent, insufficient transmission infrastructures.

and profitability of the single technology. For each quantity q, the difference between full-time resolution and aggregate run is computed and, if needed, rearranged to obtain an indicator k:

$$k = k(q(s^{**}, o^{*}) - q(s^{**}, o^{**})) = k(q(Bb3) - q(Bb2)) \tag{3.1}$$

where the right member refers to the Balmorel model structure. The k values are employed in the assessment of the aggregation technique.

3.3 The original weekly time aggregation scheme

The starting point for this time aggregation research is the weekly aggregation scheme in use at Ea Energianalyse (Figure 3.4). T001, ..., T008 stand for the time steps under simulation; the Table is filled with logic values, in that only hours with 'ones' are included in the time step. The Figure shows that T001 averages the input time series from Monday to Friday and from 6 to 8 a.m., whereas T002 also aggregates all working days, but from 10 a.m. to noon and from 3 to 6 p.m. . The rest of the table sticks to the same logic.

The main characteristics of this scheme are: a differentiation between working days and week-ends; a common time step dedicated to night hours; a focus on the central hours of the day (T003, T007) and on the demand peak in working days (T004).

3.4 A preliminary assessment of the input data

It was already mentioned that the main objective of this research is to render solar production properly. Irradiance is characterised by daily patterns, which are an essential condition to conceive a temporal scheme valid for the entire year. The electricity demand is characterised by daily patterns as well; time aggregation affects also its time series, this being a rather delicate matter, since demand defines the investment levels. For the foregoing reasons, the

	T001	T002	T003	T004	T005	T006	T007	T008
Monday	1	1	1	1	1			
Tuesday	1	1	1	1	1			
Wednesday	1	1	1	1	1			
Thursday	1	1	1	1	1			
Friday	1	1	1	1	1			
Saturday					1	1	1	1
Sunday					1	1	1	1

	T001	T002	T003	T004	T005	T006	T007	T008
1st hour					1			
2nd hour					1			
3rd hour					1			
4th hour					1			
5th hour					1			
6th hour	1					1		
7th hour	1					1		
8th hour	1					1		
9th hour						1		
10th hour		1				1		
11th hour		1				1		
12th hour		1				1		
13th hour			1				1	
14th hour			1				1	
15th hour		1				1		
16th hour		1				1		
17th hour		1				1		
18th hour		1				1		
19th hour				1				1
20th hour				1				1
21st hour				1				1
22nd hour								1
23rd hour					1			
24th hour					1			

Figure 3.4: Initial aggregation scheme.

research integrates both solar PV (GHI) and demand profiles at the same time. A residual demand rd [MWh] is thus defined as follows

$$rd(t) = d(t) - sp(t), \quad \text{for t} = 1, 2, ..., 8736 \tag{3.2}$$

where d and sp are the demand and solar PV production in hour t respectively. For the analysis to be relevant, a reference run (with the previous aggregation scheme) is used to identify the countries that hold the largest share of PV production in 2030; this is also chosen to be the reference year for assessing the results [2]. The residual demand and solar PV production for France, Germany, Greece, Italy and Spain are considered as they together make up for more than 70 % of the expected solar generation in Europe in 2030. Most countries in this list are also Gridsol countries, where PV and CSP compete with each other. Indeed, summing the data

[2] 2030 is one of the possible choices. As the aim of this study is to well represent solar profiles, 2030 is preferred to the present as the solar penetration is higher. At the same time, the uncertainty related to the assumptions for future exogenous inputs makes 2030 a more solid choice than another year further in time.

for five countries comes also at a loss of information. For example, it is to be expected that in some time segments the hourly *rd* is relatively high for the five countries together, but low for a single nation. This would be the case when all states but one have poor solar profiles.

The method that guides this research is based on heuristics; the aggregation technique is refined iteratively, after assessing the results obtained from each simulation. It operates on two levels: finding an optimal amount of weeks to aggregate into a single Season and designing a scheme for the time steps under simulation. The residual demand *rd* is thus updated at every new iteration, soon after the new results are available.

Analysis at the Season level

By analysing the input time series, it is possible to identify patterns and similarities that suggest where to direct the heuristics. The correlation coefficient ρ is employed to find likeness among weeks (Seasons S):

$$\rho = \frac{\mathrm{cov}(S_i, S_j)}{\sigma_{Si}\sigma_{Sj}} \ , \quad i \neq j \tag{3.3}$$

where cov represents the covariance and σ the standard deviation between two weeks aggregated together S_i and S_j. i and j represent a couple of weeks or partial weeks combined into a unique Season. The number of weeks aggregated into one Season can be non-integer; in that case they are only partially accounted for (they are given a weight). A MATLAB script is implemented for this and the other purposes in the Seasonal analysis. All possibilities between 10 and 26 aggregate Seasons are investigated, that meaning that 10 to 26 Seasons are considered to represent a year. As an example, in the case of 10 Seasons each one contains data from the first six weeks, five full and the sixth partial (the maximum number of Seasons in a year is 52, Section 2.3.2); the procedure goes on until the yearly amount of Seasons is reached.
Figure 3.5 shows the similarity between weekly *rd* data. A correlation matrix is built and re-arranged so that in case of no aggregation the correlation coefficients are centred in '0'. This is the situation where each week constitutes a simulated Season and therefore the weekly aggregate profiles are perfectly correlated with each other (the values in that column are 'ones').

The plot assesses how big the correlation is between each week and the weeks immediately before (labelled with a '-') and after ('+'). The average ρ is obtained by taking the mean of all correlation coefficients resulting from matching one week with the 1,2,...,25 preceding weeks and the 1,2,...,26 subsequent weeks. For how the matrix is constructed, the blue line is symmetric, aside from holding one value more at the bottom right. As expected, it suggests that the larger the number of weeks aggregated together, the lower the correlation coefficient among them. The blue line well displays this descending trend; on average, two consecutive weekly *rd* profiles are highly correlated ($\rho = 0.856$), whereas the coefficient drops down to 0.57 at the graph's extremes. A richer picture is obtained by splitting the yearly weeks into two chunks, summer and winter. By averaging over weeks 14 to 38 (central months of the year), the resulting correlation is sensibly higher than in the previous case (orange line). As a consequence, winter weeks (the remaining) are poorly correlated with each other (yellow line). The plot suggests that winter weeks exhibit a weaker similarity, i.e. higher variability in demand patterns and/or production from solar PV. In particular, by aggregating 9 weeks during summertime the average correlation is still higher than when considering two random but consecutive winter weeks.

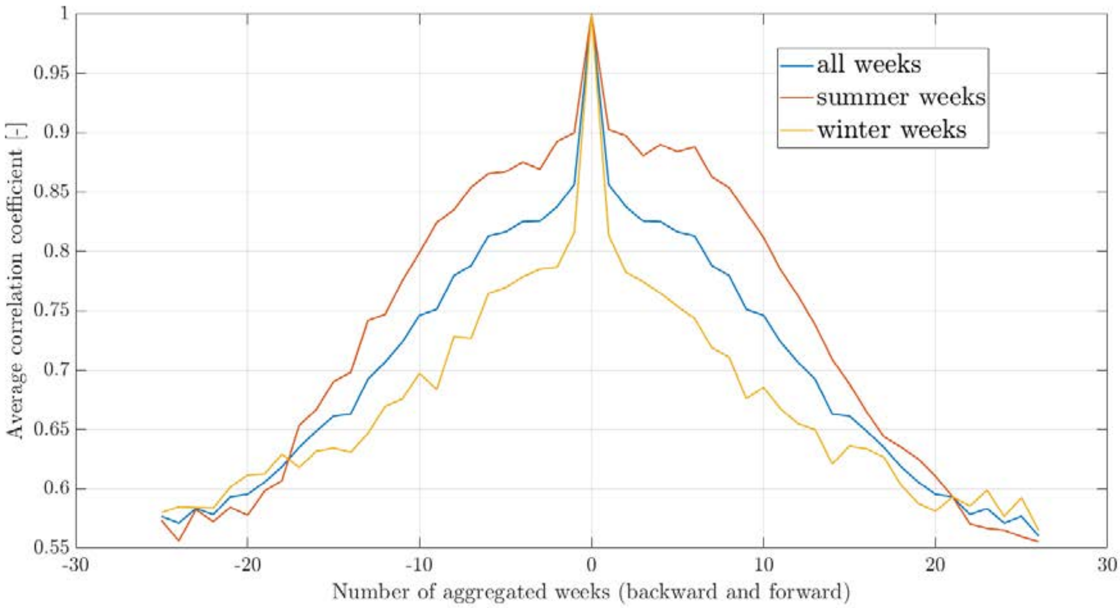


Figure 3.5: In the plot all weeks are 'centred' in zero and the average ρ obtaining by aggregating 1,2,..26 weeks backward and forward is displayed.

Table 3.1 shows how correlated the profiles are for different numbers of Seasons under simulation. The correlation coefficient is here computed not among all weeks, but for weeks aggregated into one specific Season. As an example, a simulation with 13 Seasons is equivalent to aggregating four entire weeks. The Table displays a moderate difference when changing from a coarser to a more refined aggregation. When 10 Seasons are simulated (i.e. when one Season is chosen to represent six weeks, five full and one partial, see 5.2 value) the average correlation coefficient $\bar{\rho}$ is less than 1 % lower than in the case of 26 Seasons. The correlation coefficients $\bar{\rho}$ do not change significantly if different aggregation schemes are adopted, i.e. if rds resulting from simulations with different aggregation schemes are considered: rd changes only slightly across the investigated options. $\bar{\rho}$ is a measure of how related the time series are; it therefore is a means to evaluate aggregation in the time series domain.

Table 3.1: Average correlation coefficients among weeks aggregated under one Seasons.

Seasons under simulation	Weeks into one Season	$\bar{\rho}$	Seasons under simulation	Weeks into one Season	$\bar{\rho}$
10	5.20	0.8638	19	2.74	0.8557
11	4.72	0.8410	20	2.60	0.8640
12	4.33	0.8503	21	2.48	0.8610
13	4.00	0.8289	22	2.36	0.8610
14	3.71	0.8559	23	2.26	0.8652
15	3.47	0.8550	24	2.17	0.8712
16	3.25	0.8514	25	2.08	0.8719
17	3.05	0.8630	26	2.00	0.8708
18	2.89	0.8581			

Analysis at the time step level

The research at the time step level aims at refining the scheme previously reported in Figure 3.4. First, a closer look at the weekends is taken. To create Figure 3.6, the vectors rd_{Sat} (Saturday) and rd_{Sun} (Sunday) are standardised. Given their standard deviations σ_{rd} and their means $\bar{rd}$, for each hour t it holds that

$$rd_{stand,t} = \frac{\bar{rd} - rd(t)}{\sigma_{rd}} \tag{3.4}$$

The standardised values are plotted on the x- and y-axes of Figure 3.6 (Saturday and Sunday respectively). Under the assumption that PV generation does not change systematically from Saturday to Sunday (i.e. weather conditions are the same on average), any difference in the residual demand *rd(t)* is only ascribable to different demand patterns. The graph shows that 80 % of the points lie below the bisector, that meaning that Saturdays have a higher demand when compared to Sundays. Most of the time, and especially in summertime, demand profiles for Saturdays exhibit an intermediate trend between that of a working day and Sundays; an example of summer week is shown in Figure A1 in the Appendix. This information is relevant as solar PV production is stronger during summertime, and therefore bigger differences in *rd* between Saturdays and Sundays disclose more pronounced deviations in demand patterns.

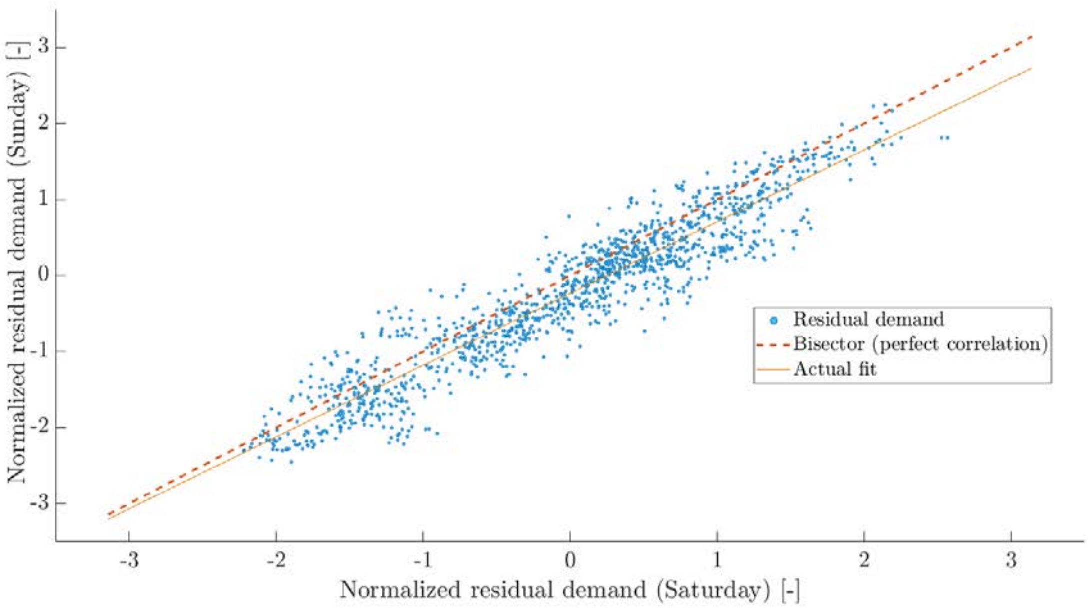


Figure 3.6: Normalised residual demand for Saturdays and Sundays.

Second, a qualitative assessment is made on the aggregation of several working days. The scheme that serves as a starting point for the analysis aggregates all five working days together. It is argued that such averaging may cause a loss of information, because too much data is incorporated into a unique array of values. Table 3.2 shows in a matrix form the correlation coefficients among each possible couple of days; the matrix is clearly symmetric. The $\bar{\rho}$ values are high for most combinations. A possible division of working days is highlighted in the Table: Monday + Tuesday and Wednesday + Thursday + Friday; this choice returns high $\bar{\rho}$. The matrix corroborates the behaviour displayed in Figure 3.6; Sunday displays lower correlation coefficients than Saturdays, whilst these latter lie among weekdays and Sundays.

Table 3.2: Average yearly correlation coefficients for the seven days of the week.

	Monday	Tuesday	Wednesday	Thursday	Friday	Saturday	Sunday
Monday	1	0.9514	0.9316	0.8961	0.9027	0.8955	0.8729
Tuesday	0.9514	1	0.9555	0.9208	0.9243	0.9069	0.8730
Wednesday	0.9316	0.9555	1	0.9502	0.9430	0.8984	0.8633
Thursday	0.8961	0.9208	0.9502	1	0.9581	0.8869	0.8659
Friday	0.9027	0.9243	0.9430	0.9581	1	0.9113	0.8720
Saturday	0.8955	0.9069	0.8984	0.8869	0.9113	1	0.9441
Sunday	0.8729	0.8730	0.8633	0.8659	0.8720	0.9441	1

The preliminary assessment on the input data and on the basis of the residual demand *rd* suggests that more accurate results in the objective function domain may follow on from:

- using dedicated time steps for the central hours of the day, so as to take into account that peaks occur at different hours (Figure 3.1);
- a high number of simulated Seasons;
- using dedicated time steps for Saturdays and Sundays;
- splitting the working days into two chunks.

In addition, the distinction between ordinary averaging and stretched averaging enlarges the array of possibilities; computational time is also taken into account for the decision. These findings guide the heuristics and lead to the final choice.

3.5 The findings

The assessment of the aggregation technique is carried out in the objective function domain by comparing generation level, power curtailment and market value between an investment (Bb2) and the corresponding full-time resolution (Bb3) run. These are the *k* indicators defined in Section 3.2.3. Overall, 20 different possibilities are tested; for brevity, only the most meaningful cases and outcomes are here presented.

The first results suggest that a contemporary refinement of the seasonal and the time step aggregation is undesirable from a computational point of view. All of the ameliorative actions mentioned at the end of the previous Section come at the expenses of higher computational times. The time required for carrying out a simulation rises consistently with any of the above-mentioned; as a guideline, a limit of 1 hour/simulated year is set for the final choice. This automatically excludes the possibility of refining the resolution extensively both Seasons-wise and time-steps-wise at the same time.

In general, the following is observed:

- countries benefit differently from one choice or another. In most situations, a technique shows to improve the solar representation in a certain area, but has no or little impact on other geographies;
- the stretched average normally performs better than the ordinary average;
- using dedicated time steps for the central hours of the day weakly improves the indicators and at the expenses of a marked increase in computational time;
- increasing the number of time steps under simulation has a stronger impact on computational time than refining the seasonal representation. Ceteris paribus, doubling the amount of time steps is found to extend the simulations by 10 to 20 % more than when doubling the number of Seasons.

The generation and curtailment levels between a Bb2 and a Bb3 run are easily comparable; their difference is an explanatory indicator. As for market values, their relative difference Δmv is computed first (i.e. their difference is divided by the Bb2 market value); average yearly figures are considered. A further calculation takes into account the weight of each Region, that is how high the generation level is locally ('Δmv corrected'). The relative difference is thus corrected by a factor f_R defined as follows

$$f_R = \frac{\frac{\mathrm{E_R}}{\mathrm{E_{ref}}}}{\left(\frac{\mathrm{E_R}}{\mathrm{E_{ref}}}\right)_{mean}} \tag{3.5}$$

where R represent the Region under consideration and *ref* the Region with the highest generation level E in 2030. The reference is Spain in all the tested configurations. In this manner Regions where solar PV penetration is stronger have a higher weight; finally the values are summarised by their average (see scheme below).

$$\underset{\text{(regional relative difference)}}{\frac{(MV_{Bb3} - MV_{Bb2})}{(MV_{Bb2})}} \xrightarrow{\mathrm{f}_R} \text{corrected relative difference} \longrightarrow \begin{array}{c}\text{average}\\ \text{over Regions}\end{array}$$

Table 3.3 shows the results with respect to the three selected indicators. The cases chosen for this comparison follow the guidelines listed at the end of the previous section; each case (but the original) includes the stretched averaging technique. TC divides the working days into Two Chunks: Monday+Tuesday and Wednesday+Thursday+Friday; DTS has Dedicated Time Steps for the central hours of the day; WS (Weekend Split) divides Saturdays and Sundays; DTS + WS combines the previous two; 24S and 26S have 24 and 26 Seasons under simulation respectively, while keeping the time step resolution relatively lean (11 time steps). It is interested to notice that the computational time grows rapidly with an increase in the number of time steps per Season, while it is more contained with more Seasons under simulation. In all cases where the time steps resolution is refined, the computational time overreaches one hour per simulated year. The difference in electricity generation ΔE coincides with the difference in curtailment ΔC, save for the sign; this is a consequence of no changes in demand and system's structures. This also means that a (small) percentage of the Bb2 generation ends up being curtailed in the related full-time resolution run (Bb3). Table 3.3 clearly shows that a refinement at the Season level yields a smaller difference in market value Δmv (absolute values). In light of the previous considerations, the final choice falls on the 26S setup, highlighted in Table 3.3. It yields the lowest Δmv, a reasonable computational time and small discrepancies in the curtailment level. The corresponding the scheme is presented in Figure 3.8.

A linear trend between ΔC and Δmv can be spotted (Figure 3.7), the R-squared being over 84 %. At the European level, the difference in curtailment influences the accuracy in the market value. Curtailment is always higher in the full-time resolution runs; this leads to lower prices in

Table 3.3: Comparison between relevant aggregation schemes. TC: Two Chunks; DTS: Dedicated Time Steps; WS: Weekend Split S: Seasons.

Case	Simulated Seasons (S) and Time Steps (TS)	Computational time [min/sim year]	ΔE (= - ΔC) [GWh]	Δmv corrected [%]
Original	12 S - 8 TS	$\sim$ 20	- 6270	16.42
TC	12 S - 16 TS	$\sim$ 80	- 8275	18.69
DTS	12 S - 15 TS	$\sim$ 80	- 5650	17.20
WS	12 S - 15 TS	$\sim$ 70	- 5322	16.77
DTS + WS	12 S - 16 TS	$\sim$ 85	- 4825	13.47
24S	24 S - 11 TS	$\sim$ 50	- 3073	12.43
26S	26 S - 11 TS	$\sim$ 50	- 3290	12.36

hours of production and in turn to more modest revenues (sales) and thus bigger discrepancies in market values.

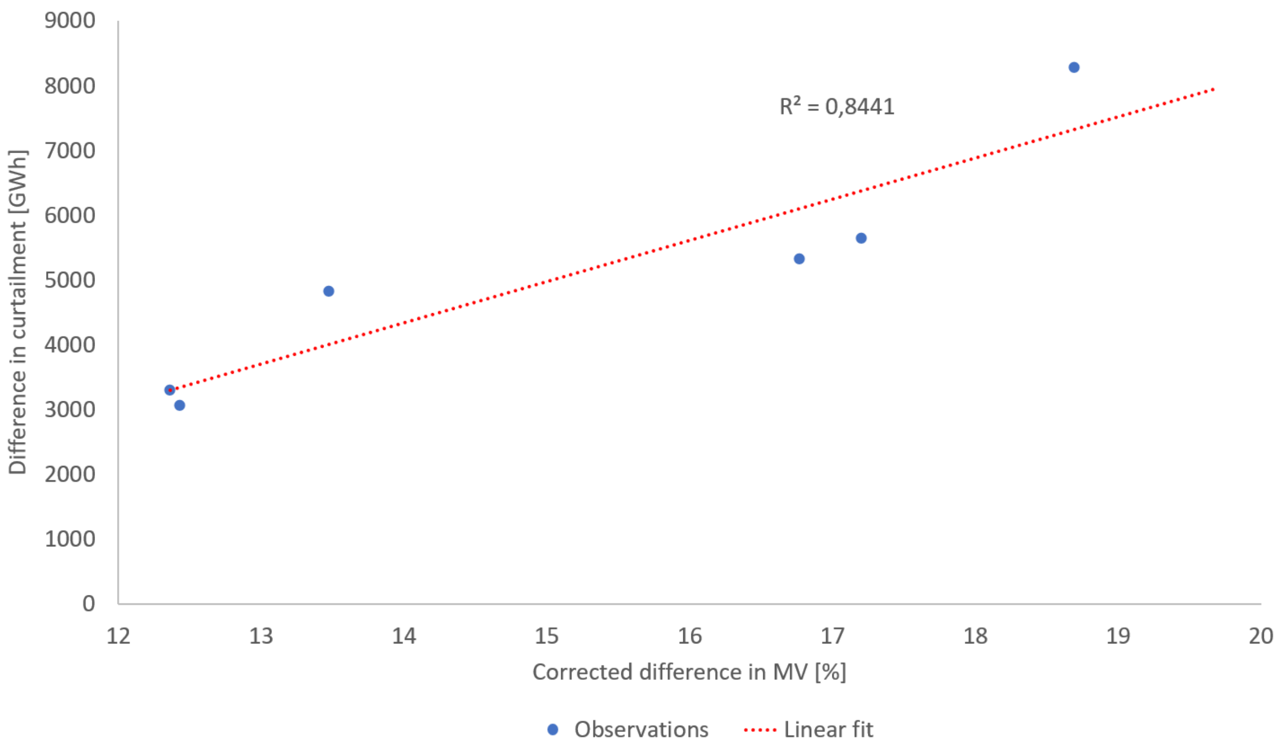


Figure 3.7: Relation between corrected Δmv and ΔC. The R-squared is also displayed in the figure.

Different generation levels hint at an appreciable reshaping of the merit-order curves from a Bb2 to a Bb3 run. Table 3.4, which carries figures from the chosen scheme, shows that consistent changes occur especially for hydropower and waste-to-heat plants. These are due to the transferring of fuel and storage values from the aggregate to the full-time resolution

Figure 3.8: New aggregation scheme. The number of time steps is increased by three so as to represent in detail central hours and late evening production.

run. Since the overall generation level is almost left untouched (- 0.15 %), the gap detected especially for hydropower is balanced by all the other units, with a consequent re-organisation of the merit-order curves.

Regardless of the tested scheme, the following considerations can be made:

- time aggregation does not influence neither the overall generation level, nor the PV production. The results for any of the tested configurations show a maximum deviation of 1.4 % (absolute) in solar PV generation between an investment and the corresponding hourly run;
- the energy curtailment C, while in a few cases relatively different, accounts for 3 % of the countrywide solar PV generation at the most. This suggests that the merit-order shifts have a more pronounced role than curtailment in the MV discrepancies between a Bb2 and the related Bb3 run.

For market values, as already shown, the gaps are wider. Electricity sales and more precisely

Table 3.4: Electricity generation by fuel in 2030; comparison between aggregate (Bb2) and full-time resolution (Bb3) run (entire Europe).

	Generation Bb2 [TWh]	Generation Bb3 [TWh]	Difference [%]
Biogas	31.7	30.6	- 3.47
Biomass	147.9	137.6	- 6.96
Coal	373.7	368.0	- 1.53
Hydro	555.0	591.4	+ 6.56
Natural gas	281.1	271.3	- 3.49
Nuclear	627.0	624.2	- 0.45
Solar PV	498.6	495.3	- 0.66
Waste	37.4	33.4	- 10.70
Wind	1005.1	1000.9	- 0.42
Other	7.3	6.8	- 6.85
Total	3564.8	3559.5	- 0.15

electricity prices (p [EUR/MWh]) are at the core of the detected mismatches. The relative difference in market value mv is explicitly:

$$\Delta mv = \frac{\left(\frac{\sum_t \frac{p_t \cdot E_t}{E_t + C_t}}{T}\right)_{Bb3} - \left(\frac{\sum_t \frac{p_t \cdot E_t}{E_t + C_t}}{T}\right)_{Bb2}}{\left(\frac{\sum_t \frac{p_t \cdot E_t}{E_t + C_t}}{T}\right)_{Bb2}} \simeq \frac{\overline{p}_{Bb3} - \overline{p}_{Bb2}}{\overline{p}_{Bb2}} \tag{3.6}$$

with T being the yearly amount of hours t where solar PV is operational. $\overline{p}$ stands for the average over the hours t. The fact that the overall curtailment level is negligible when compared to the generation is relaxed here by assuming that hours of high curtailment are a very small sub-group of the total yearly hours (it implies C_t is negligible); otherwise Equation 3.6 does not hold true. If the average price seen by solar PV generators is identical in the aggregate and full-time resolution runs, Δmv is zero for solar PV. Italy and Spain both display a Δmv between -15 and - 20 %, that is to say electricity prices are roughly and on average 15 to 20 % lower in a full-time resolution run than in the related aggregate run. Figure 3.9 shows the PV price duration curves for Italy and reinforces this statement. The average spot price in the Bb3 run is 17.90 % lower than in the corresponding Bb2 run (Table 3.5). The higher mean in the Bb2 run is due to some hours of prices spikes and a longer flat segment. Both are a consequence of time aggregation: a time step represents several hours in several weeks; when results are disaggregated, they cover a higher amount of hours than in reality. The effect is smaller at high temporal resolutions.

Considering that the projected solar PV share for 2030 is around 35 % in Italy, Table 3.5 suggests that other technologies (biomass plants, natural gas plants) see higher relative market prices in the full-time resolution run: the overall Bb3-Bb2 relative price difference stands at only - 1.78 % in Italy. The price difference is again a consequence of aggregation; skewed, aggregate input profiles lead to locally flat generation levels in a Bb2 run, whereas the original profiles produce a more dynamic, variant output; this causes shifts in the merit-order and, therefore, diverse hour-by-hour short-run marginal costs of generation between an aggregate and a full-time resolution simulation.

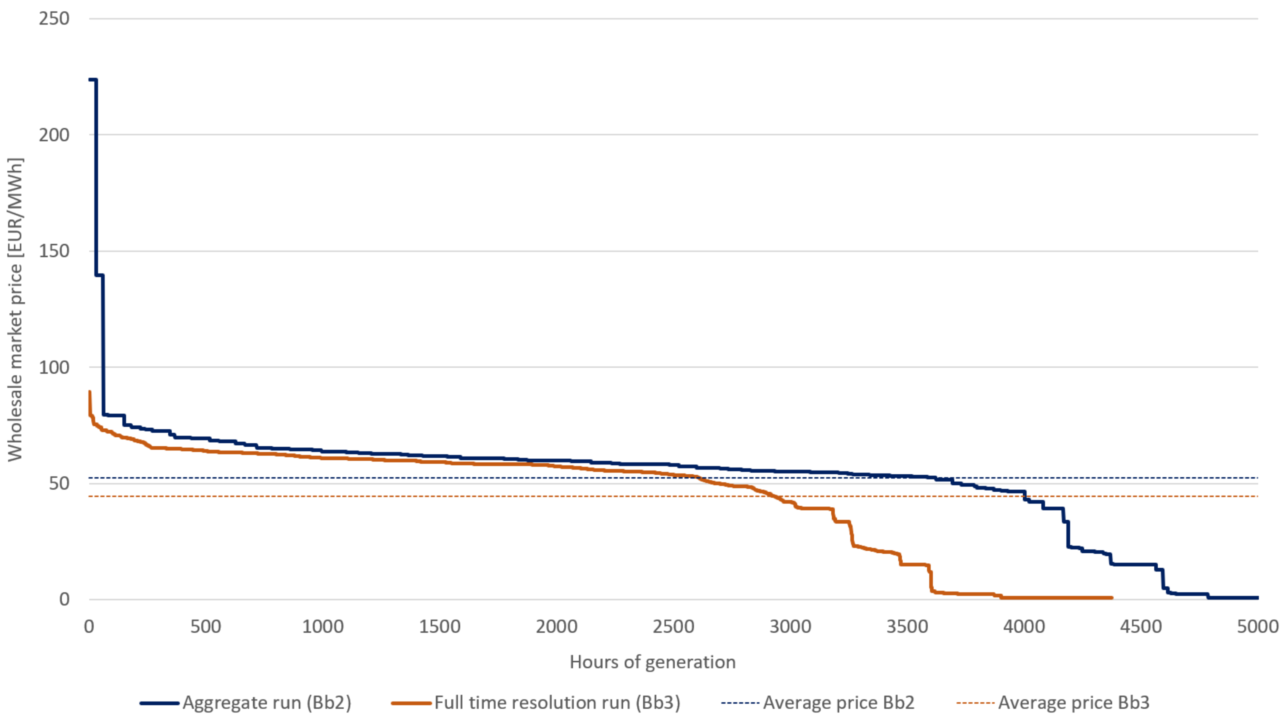


Figure 3.9: Price seen by solar PV generators in hours of production. Comparison between Bb2 and Bb3 runs.

In light of the previous findings, the market value appears to be a meaningful and telling indicator to detect problems in coupling aggregate and hourly runs. These mismatches can only marginally be addressed by a thought-out choice of the aggregation technique: they are a consequence of aggregating data rather than of the choice of a particular aggregation scheme. In the Appendix a more-detailed comparison with the previous aggregation scheme can be found; in general, the following is observed:

Table 3.5: Electricity prices seen by all technologies and solar PV alone in 2030 in Italy (average yearly values). Solar PV accounts for more than one third of the projected generation and the detected relative price difference settles at - 17.90 %. However, the overall national relative difference is a more modest - 1.78 %, which hints at the fact that other units see higher prices in the Bb3 run (reactors).

Unit	Bb2 [EUR/MWh]	Bb3 [EUR/MWh]	Difference [%]
Electricity price - all technologies Italy	62.30	61.21	- 1.78
Electricity price - only solar PV Italy	52.36	44.41	- 17.90

- high curtailment can be a sign of overinvestments, provided that the right curtailment level is unknown;
- the choice of the aggregation scheme is highly dependent on the input data (time series, profiles);
- there exists a correlation between quality of the aggregate data (as measured in the time series domain) and quality of the indicators (as measured in the results domain).

3.6 Conclusions

This Chapter has dealt with time aggregation in large-scale ESMs and in Balmorel in particular, with a focus on solar rendering. By taking advantage of the model's structure, a framework for assessing the results in the domain of the objective function is outlined and meaningful quantities are identified as key quality indicators (generation level, curtailment, market value). A preliminary quantitative and qualitative evaluation of the input time series and profiles is performed in order to guide the heuristic research. While keeping the computational time contained, a set of schemes are investigated and a finer resolution at the Season level, coupled with profile stretching, is shown to bring the most satisfying results.

This research defines also the limitations of simulations using aggregate data in large-scale energy system models. The averaging process leaves out some accuracy in the generation and curtailment levels. The differences reshape the merit-order curves in the full-time resolution run; for solar PV, electricity prices are seen to undergo a readjustment downwards. However and even if at the expenses of a higher computational time (2.5 times higher than in with the previous architecture), the research improved the overall representation of renewable sources and especially their market behaviour.

The relatively wide geography results in the biggest challenge. This is because different weather conditions (i.e. resource availability) can be expected at the same time across the countries; moreover, temporal lags even among similarly-shaped profiles occur. Time and discrepancies at week level occasionally begets approximate, locally unrepresentative aggregate data.

In view of the preliminary analysis, a further effort could be directed to implement a multiple time grid structure [39] such that the summer resolution be coarser may lead to fulfilling results, while reducing the computational effort. Other techniques, which have not been applied yet to Balmorel and in the case of large-scale systems, were not tested for this work, but might return a satisfying representation of economic and technical parameters. Nevertheless, the refinement of the aggregation scheme allows for a more accurate characterisation of the core results of this thesis, which include aggregate and hourly analyses of the European power sector until 2050. The specific technical, economic and environmental assumptions underlying this assessment are presented in the next Chapters.

Chapter 4

Modelling

This and the next Chapter define the methodology underlying the assessment of the profitability of Gridsol and Smart Renewable Hubs (SRHs). This Chapter discusses the practical implementation of the two hubs in Balmorel, whereas the next one (Chapter 5) outlines the framework within which the hybrid power plant attractiveness and functioning are tested.

4.1 The Gridsol hub: the concept and its Balmorel implementation

It was already mentioned (Section 2.5) that Gridsol (or the Gridsol hub) is a hybrid technology consisting of a gas turbine and a CSP block inclusive of thermal storage; the latter is loaded by both the CSP field and by the waste heat recovered from the gas engine. The scheme representing the Balmorel layout is reported in Figure 4.1. The hub consists of three Areas linked two-by-two by a thermal pipe of infinite capacity: this subdivision allows for tracking the thermal flows entering or exiting the units; in addition, thermal losses occurring in the hub's internal connections can be attributed to the pipe itself. Due to the lack of precise figures from the partners, an arbitrary value of 0.5 % was chosen in this regard. The division into three Areas forecloses also short circuits of thermal power from the CSP and gas turbine Area directly to the steam turbine; this result is achieved by adding an additional constraint on the heat released from the thermal storage, which is set to be always greater than or equal to the heat flowing through the bottom pipe of Figure 4.1:

$$Q_{t,\mathrm{TES-ST}} \leq Q_{unload_t,\mathrm{TES}} \tag{4.1}$$

where Q [MWh] designates the thermal energy at any hour t, TES the Thermal Energy Storage and ST the Steam Turbine. The technical features corresponding to the technologies represented in Figure 4.1 are reported in Table 4.1.

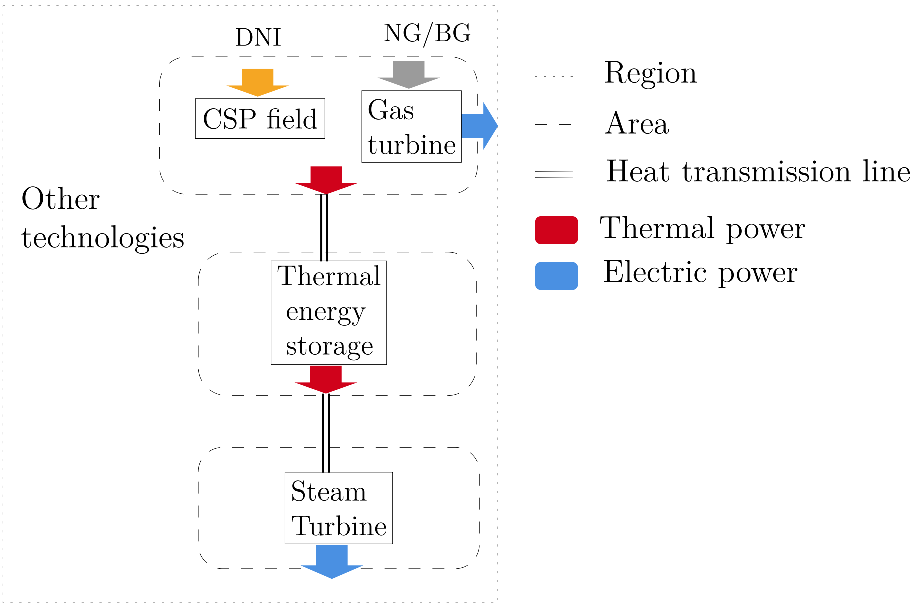


Figure 4.1: Schematic representation of the Gridsol hub. The Region where other technologies are located can either be the Main national Region or a Smart Renewable Hub Region (Section 4.2). DNI: Direct Normal Irradiation; NG: Natural Gas; BG: BioGas.

The DNI profiles along with the Full Load Hours (FLH) define the thermal production of the CSP field during the year; this kind of data is location-dependent and is given by the consortium partners. The unit's output is constituted by hourly values of thermal power (Table 4.1). The gas turbine can be fed by either natural gas or biogas. In reality the two fuels are interchangeable, provided that each is available at a local level; this technical constraint is however not a subject matter in this context. The turbine is equipped with a system to recover the waste heat from the flue gases; the technology's output is both electric and thermal power

Table 4.1: Technical features of the Gridsol hub (base values). TES: Thermal Energy Storage; FLH: Full Load Hours; NG: natural gas; BG: biogas.

Unit	Technology type	Input(s)	Output(s)	Efficiency [−]	Other technical features
CSP field	DNI to heat	Irradiance FLH	Thermal	-	
Gas turbine	Back-pressure	Fuel (NG or BG)	Electric Thermal	0.348 (electric)	$C_b = 1.04$
TES	Heat to heat	Thermal	Thermal	0.99 (round-trip)	
Steam turbine	Heat to power	Thermal	Electric	0.408	

(Table 4.1), the first contributing to the Regional electricity demand, the second to the Area's heat balance. The gas turbine is represented as a back-pressure technology in Balmorel, i.e. with a fixed power-to-ratio (C_b) output. The data obtained from the other consortium partners shows that for every unit of electricity, 0.96 units of thermal energy are obtained from the heat recovery system. The C_b ratio defined as

$$C_b = W_{out}/Q_{out} \tag{4.2}$$

is therefore set to 1.04. W_{out} and Q_{out} designate the power and heat in output respectively [MW]. The first law efficiency for the gas engine is

$$\eta_t = \frac{W_{out} + Q_{out}}{Q_{in}} = \eta_{el,GT} \cdot \frac{1 + C_b}{C_b} \tag{4.3}$$

where η_t and $\eta_{el,\mathrm{GT}}$ are the total efficiency and the electric efficiency respectively. $\eta_{el,\mathrm{GT}}$ is among the data provided by the partners, η_t is an input to the Balmorel model. The gas engine is likely to be subject to intermittent start-ups and shut-downs, considering the peak-load supply function of such technologies in power systems. The 34.8 % chosen for the efficiency of the gas turbine is in fact on the low-side of state-of-the-art, large-scale Brayton cycles [40]; it partially accounts for the intermittent usage of the engine and it is in line with thermodynamic simulations performed by other partners in the consortium. The same partners estimate the overall combined cycle efficiency to be 49 % for the gas turbine coupled with the thermal energy storage. This is a disadvantage with respect to ordinary combined cycles, which currently reach higher efficiencies. The 55 % figure reported by the Danish Energy Agency denotes an annual mean, as reported in their 2019 update of the technology catalogue [44]. However, in the Gridsol hub the bottoming cycle is shared between the CSP block and the gas engine and this constitutes an advantage, since the overnight expenditures are reduced.

The thermal power produced by both the CSP field and the gas turbine is transferred from the top Area in Figure 4.1 to the Thermal Energy Storage (TES) through an ideal transmission pipe. The storage works with a molten-salt mixture as the heat medium and it is modelled with a round-trip efficiency, without accounting for hourly losses (Table 4.1); the impact of such a modelling refinement would be minimal, yet increasing the computational effort. It is worthy to underline that the real configuration of the storage includes two tanks (hot and cold) and therefore more complex dynamics, which are neglected. Important parameters for the assessment of the TES performance are:

- the solar multiple [-], i.e. the ratio between the nominal heat output from the CSP field [MWt] and the steam turbine nominal heat input [MWt];
- the capacity in hours [h], i.e. the ratio between the storage volume and the steam turbine nominal heat input.

The first parameter is also a measure of how long the steam turbine is able to run if the CSP field produces at nominal power for one hour (in that case the solar multiple is measured in hours). The second indicates for how long the plant is able to run at nominal power without any radiation (i.e. with only the heat withheld by the storage). In the Gridsol hub, both the gas turbine and the CSP field generate thermal power that is sent to the storage and, subsequently, to the steam turbine. The definition of solar multiple can thus be ambiguous in this context. For this reason, the concept of *complementarity* is introduced. In principle, there may be hours when only the CSP field (or the gas turbine) is generating and conversely periods where both produce. There exists:

- no complementarity if both units are active at the same time;

- full complementarity if only one of the two is operative in the same time step.

Both are displayed in the calculations, as they can inform on different aspects. Additional details are discussed in the Results (Chapter 6).

The steam turbine (a full Rankine cycle) is a heat-to-power technology with fixed efficiency, as provided for by the consortium's partners (Table 4.1). The partial load behaviour of the single components and detailed technical aspects are neglected.

The Gridsol hub, which is composed of Areas, is always part of a Balmorel Region[1]. The model can invest in the hub:

- in the Main national Region (also 'Main Region' in the following), where the country-wise electricity demand is set;
- in the Smart Renewable Hub Region, connected to the former. This is the subject matter of the next Section.

Gridsol is therefore the object of two analyses: a first one that reveals the attractiveness of the concept in general, its interaction with the rest of the generation fleet and with the European interconnected system (Gridsol in the Main Region, Figure 4.2 left); a second one where its functioning in hybrid power plants is investigated (Gridsol in the Smart Renewable Hub Region).

The actual sites where the Gridsol concept is tested are: Marseille (France), Poloponnese (Greece), Puglia (Italy), Extremadura (Spain), Faro (Portugal). The DNI profiles (Section 4.3) are representative of these locations and are provided by the consortium partners. The countries where Gridsol can be installed are referred to as 'Gridsol countries' in the following.

[1]The electricity balance occurs at the Region level, Section 2.3.1. Each Country where Gridsol can be installed withholds only two Regions: the Main national Region and the smaller Smart Renewable Hub Region.

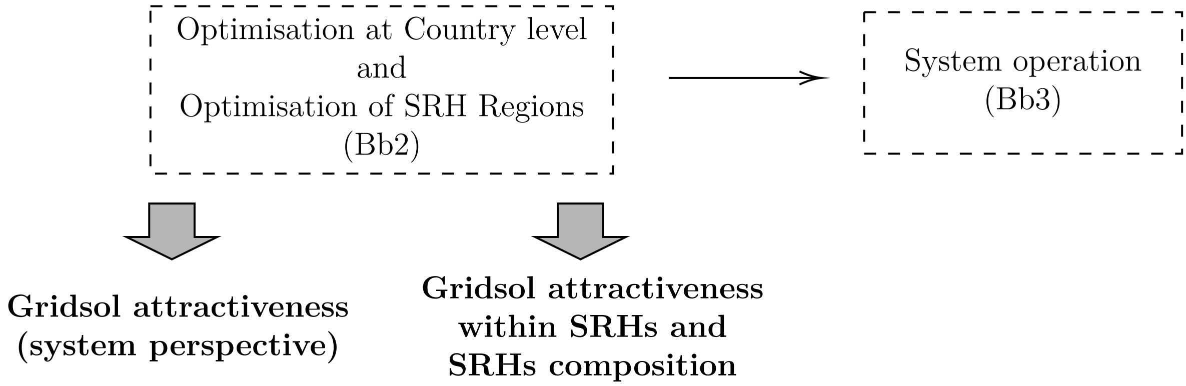


Figure 4.2: The optimisation-simulation process builds on two steps.

4.2 Smart Renewable Hubs with Gridsol: the concept and its Balmorel implementation

Smart Renewable Hubs (SRHs) can include renewable and non-renewable technologies that assure firm and stable power production; the attractiveness of the concept is driven by the (expected) high Full Load Hours (FLH) and the intelligent management of the units therein. A control system called 'DOME' (Dynamic Output Manager of Energy) coordinates the operation of the units and minimises the economic losses due to real-time balancing needs. In the optimisation process, Balmorel can freely choose the size of the components in both Gridsol and Smart Renewable Hubs, which comprise a CSP field, thermal storage, steam turbines, gas engines (these four form the above-described Gridsol), wind turbines, PV arrays and electric storage. The hub total installed capacity is unconstrained, but no more than 200 [MW] can be transferred to the Main Region: this is set by the interconnector linking the two, which has a 200 [MW] nominal capacity (Figure 4.3). Identifying the size of the components in a Smart Renewable Hub of given nominal output is not the purpose of this work; moreover, the model is linear and the capacities obtained with the optimisation can be re-sized so that the sum total up to the desired nominal hub value (Figure 4.4): therefore, the 200 [MW] capacity is an arbitrary and non-bounding figure. The Smart Renewable Hub Region is instead designed to have an overview of the composition of hybrid power plants in the thirty years to come; in addition, the interaction with other selected generation technologies can be easily studied.

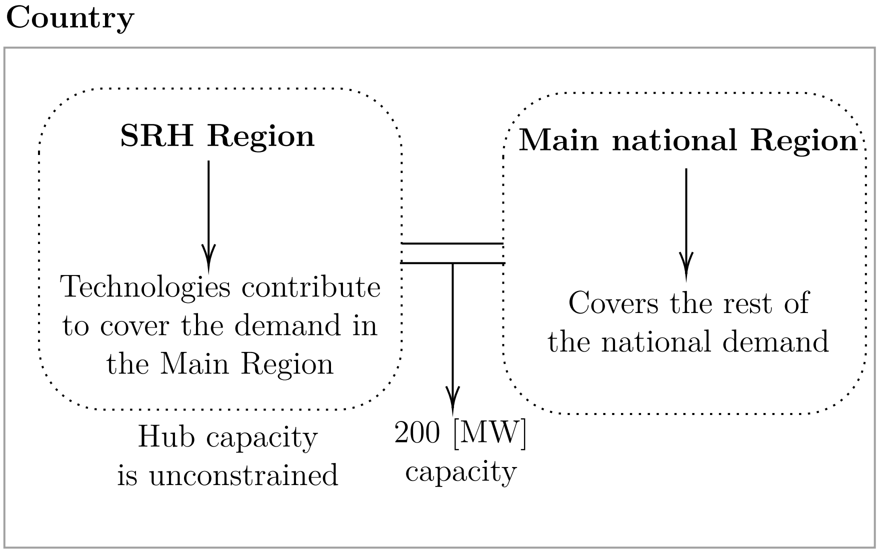


Figure 4.3: Smart Renewable Hubs contributes by supplying up to 200 [MW] to the Main national Region, where the electricity demand is set.

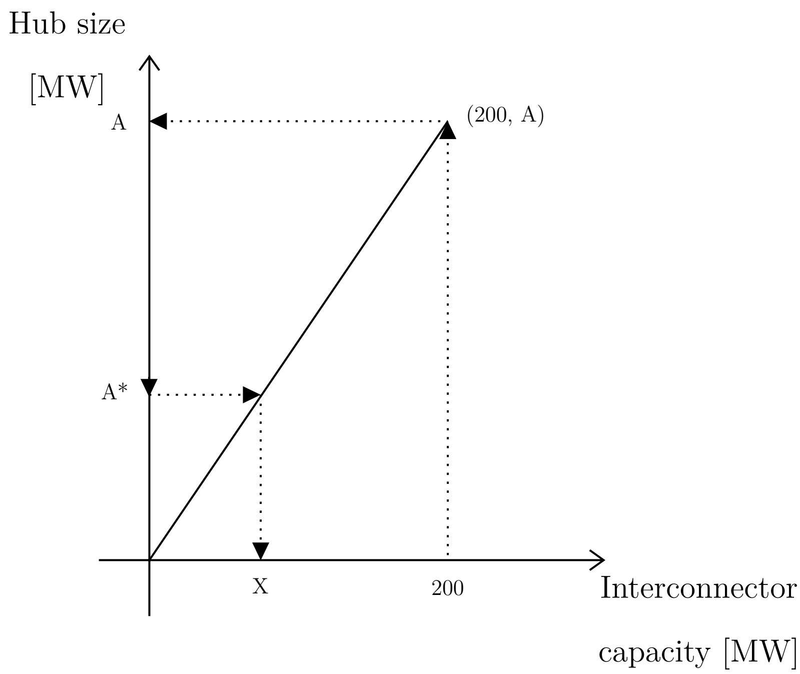


Figure 4.4: The relationship between interconnector capacity and hub size is linear. The desired hub size A^* corresponds to an interconnector capacity X that varies with year and location (the characteristic slope s varies).

The array of technologies the model can choose from is listed in Table 4.2, which omits the Gridsol data already presented in Table 4.1. The wind turbine power curve P_w is shaped as a logistic curve of formula

$$P_w = \frac{\gamma}{1 + \exp(-g \cdot K_w(u - M - \epsilon))} \tag{4.4}$$

with the exponential accounting for deviations from the theoretical output; this is due to geographical (speed, site) as well as technical (curve slope, offset) parameters. This kind of data, along with the Global Horizontal Irradiation (GHI) profiles for solar PV, is taken from Ea Energy Analyses database and denotes national means. Lastly, the electric storage is a utility-scale lithium battery that has a round-trip efficiency of 91 % [45], with a fixed ratio between volume and loading/unloading capacity (0.5/3 respectively): this is to say, to load and to unload one unit of energy 0.5 [MW] and 3 [MW] of capacity are available respectively.

Table 4.2: Smart Renewable Hubs technologies not included in the Gridsol hub.

	Technology type	Input(s)	Output(s)	Efficiency [-]
PV modules	GHI to power	Irradiance	Electric	-
Wind turbines	Wind speed to power	Wind speed u Max. output γ Inflexion wind speed M Max. slope g Smoothening factor K_w Offset ϵ	Electric	-
Electric storage	Power to power	Electric	Electric	0.91 (round-trip)

The Smart Renewable Hub Region is set to have an infinitesimal electricity demand, so that the entire power production flows to the Main Region through the interconnector; there it contributes to meet the national electricity demand. The technologies available for the investments in the hub are also present in the Main Region with the same technical features; however, the economic parameters are different. The model is incentivised to invest in the Smart Renewable Hub Region since a cost discount is attributed to all the possible investment technologies therein. In hybrid power plants, cost savings can originate from the shared power electronics and the presence of a single transformer station. These are among the so-called connection expenditures, i.e. the cost of integrating the units into the transmission or distribution grid. These costs include:

- grid connection costs, i.e. all the cables and stations necessary to link the generators to the local bus (component one);

- reinforcement costs, since the transmission or distribution grid may need a local upgrade (component two);
- any additional investment required to mitigate the uncertainty related to the production from renewable energy units (component three). The integrated intelligent system DOME is however asked to solve this issue locally.

The determination of connection costs is not uniform across Europe. When the first two components are included the approach is that of a *deep cost allocation*; conversely, when only the connection costs are taken into account the method is that of a *shallow cost allocation*. In 2010, the grid connection costs could range from 2.5 to more than 6 % of total disbursal for a wind project, depending on the state [41]; in [42] the average cost for connecting a wind turbine to grid was identified to be even over 8 % of the total investment cost; a more recent report from Agora Energiwende stresses the diversification of grid-related costs for new renewable projects, ascribable to different regulatory authorities [43]. An average connection cost of 50 000 [EUR/MW] is estimated for all units: it is thus assumed that the costs of connecting the entire hub to the grid are identical to the costs of connecting one single component. For a hub with four units connected to the bus, this translates into cost savings of 150 000 [EUR/MW], which are equally subdivided among the five generators: steam turbine, gas turbine, wind turbine, solar PV and electric storage[2]
Other than a refinement in the connection costs, modelling the hub as an independent Region allows to easily determine the plant's capacity factor by analysing the yearly flow through the interconnector E_y. The capacity factor CF is:

$$CF = \frac{E_y}{P_n \cdot 8736} = \frac{E_y}{P_{int} \cdot s \cdot 8736} \tag{4.5}$$

where P_n is the nominal hub size, P_{int} is the interconnector capacity (= 200 [MW]) and s is the slope of the linear characteristic in Figure 4.4.

[2]Although the components connected to the bus can be five in principle, the exact number of units the model decides to invest into is not known a priori. Four is an expected outcome. The implication of this choice is discussed in the Results, Chapter 7.

With one unique aggregate Bb2 simulation, Balmorel thus optimises the European system with the regular electricity demand and determines the optimal hub configuration; subsequently, the operational details of the entire system are obtained with a Bb3 run. This last is the ground for hourly analyses. As the purpose of this work is also to analyse how the composition of hypothetical SRHs evolves with the years, previous investments in the SRH Region are deleted when multiple years are optimised in series.

4.3 Input data: profiles and resources

The input data is essentially formed by natural resources data, fuel availability, technical and economic details. Technical parameters have already been discussed in the previous Sections, the focus of the following two being instead energy sources and financial data.

The solar resource (be it DNI or GHI) is a key input to the model. Every time series defining its availability is linked to the corresponding plant's FLH (Figure 4.5). For a discrete function such as the yearly DNI and for every technology exploiting it:

$$\frac{\sum_0^{8736} \mathrm{DNI(t)}}{\max_t \mathrm{DNI(t)} \cdot 8736} = \mathrm{FLH} \tag{4.6}$$

A similar reasoning holds true for solar PV technologies. In practice, both the DNI and the plant's FLH are assigned, since the second allow for swiftly correcting (raising) the conversion efficiency with time (see Section 4.5). Table 4.3 contains the FLH of the solar technologies in the five Gridsol countries; the values are the same inside and outside SRHs. As for CSP, the profile shape is given by the consortium partners, whereas it is taken from Ea Energy analyses database in the case of solar PV. The data shows a relative abundance of resource in Portugal and Spain, but the ratio between CSP and PV FLH is not the same across the five countries; moreover the CSP full load hours are always greater than PV's. This suggests than the two technologies may supply power at different times of the day or, in other words, that they are not perfectly interchangeable.

Each Country is given one unique input profile for natural resources; these are either national averages or they match the characteristics of a specific site: in principle the method can also be extended to more Regions per Country to allow for the detailed investigation of specific, potential hub locations. Finally, the availability of natural gas and biogas is not constrained in the model and their total use depends only on the cost assumptions for the future.

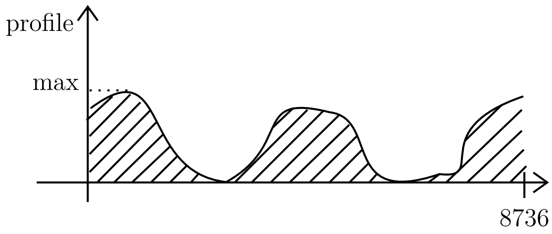


Figure 4.5: The profile shape is important, the absolute values are not. When the input profile is not in the [0,1] range, values are scaled with the global maximum. The area below the yearly profile curve is always proportional to the technology's FLH.

Table 4.3: Full Load Hours of solar technologies within Smart Renewable Hubs.

	France	Greece	Italy	Portugal	Spain
CSP field - FLH [h]	1847	1733	1620	2351	2143
PV arrays - FLH [h]	1076	1410	1190	1448	1550

4.4 Input data: financial details

The model uses the financial data to define the technological mix that minimises the total system costs. The figures (Table 4.4) are partly provided by the consortium partners (this is the case for the Gridsol hub); they are retrieved from the Danish Energy Agency's technology catalogue for the other units [44]. The same technologies are found in the Main Region with the same costs, except for the components connected to the bus, which are adjusted according to the assumptions of Section 4.2. Data is reported in EUR15, but the model requires the equivalent 1990 values as inputs; thus they are corrected by a factor 1.66, which accounts for historic inflation values.

A type of cost-related uncertainty concerns the size of the power plants, especially for CSP fields. This is to say that for certain units the specific investment cost in [EUR/MW] is a function of the unit size; the latter is however unknown beforehand, so costs are either averaged or correspond to those of a 'medium size' component.

The (economic) lifetime eL is an input for annualising costs; contrary to the technical lifetime reported in Table 4.4, it expresses the time period when it is economically convenient to use an asset. Table 4.4 clearly displays that solar PV has relatively low costs and a longer technical lifetime than the other technologies; this enhances its attractiveness. The economic lifetime eL is instead required to annualise expenditures. The annuity factor a defined as

$$a = -\frac{r}{1-(1+r)^{-eL}} \tag{4.7}$$

adopts a uniform socio-economic discount rate r over the considered geography, equal to 5 %; considering that the economic lifetime is also uniform across countries and assets (20 years), costs are annualised with a factor 0.0802.

Table 4.4: Financial data for the Smart Renewable Hubs in object (2020). CAPEX are in [MEUR15/MW] and fixed OPEX (f-OPEX) in [kEUR15/MW] except for storage, where specific costs refer to the unit's volume [MWh]. Variable OPEX (v-OPEX) in [EUR/MWh].

	Overnight cost CAPEX [MEUR15/MW]	Fixed O&M costs f-OPEX [kEUR15/MW]	Variable O&M costs v-OPEX [EUR15/MWh]	Technical lifetime tL [years]
CSP field	0.369	16.189	-	25
Gas turbine	0.562	13.270	4.501	25
Thermal energy storage (TES)	0.020	0.301	-	25
Steam turbine	1.363	29.961	-	25
Wind turbine	1.392	16.724	2.058	27
Solar PV	0.568	7.475	0.793	35
Electric storage	0.375	1.629	2.015	20

4.5 The future Smart Renewable Hub

The input data reported in the previous Sections outline the hub characteristics at the present time. Further assumptions are made for the cost and technological development for the years to come. There are two ways to consider technological development: the full load hours temporal progression and the energy conversion efficiency. Full load hours can change over the years to represent advancements for plants that rely on input time series (i.e. for those that have already a unitary efficiency in the model); instead, it is possible to operate directly on the efficiency (<1) of units such as storage technologies, reactors, other energy conversion equipment. Ea Energy Analyses assumes a solar PV efficiency increase as in Table 4.5. It is decided to extend the same assumption to CSP fields, so as to reflect improvements in optics, field design, losses reduction. Improvements are foreseen also for wind turbines; values are not reported for brevity, but they are taken once again from the company's database.

The other technologies within SRHs are also subject to an efficiency increase (Table 4.6). This is not the case of every single technology, as some are considered to be fully mature and hardly able to overreach the current performance: sub-critical steam Rankine cycles and latent heat thermal energy storages are among these. It is though possible that similar, more advanced substitute concepts replace the ones in the Table, e.g. super-critical cycles, but they are not considered in this work. The Gridsol gas turbine is supposed to benefit from an efficiency increase of 1 % every 5-10-year period, whereas BESS projections are taken from the Danish Energy Agency [44].

The consortium partners provide estimates for the future costs of the Gridsol hub components (Table 4.7); the chart lacks most variable O&M costs, since they were not provided; it is assumed that they are integrated into the fixed component. This data holds for all scenarios, except for the 'CSP+' and 'CSP breakthrough' (see Section 5.3). Table 4.8 complete the cost picture with the other SRH technologies. All the units appearing in Table 4.7 and 4.8 are also available for investments in the Main Region at the same cost, except for the hub units whose grid connection expenditures are discounted (Section 4.2).

Table 4.5: Full load hours (efficiency) increase for solar technologies. The increment refers to a solar unit (PV or CSP) installed between 2010 and 2019.

	PV / CSP				
	2020-2024	2025-2029	2030-2039	2040-2049	2050
Full load hours increase	6 %	7 %	9 %	11 %	13 %

Table 4.6: Efficiency of Smart Renewable Hubs units until 2050.

	2025-29	2030-39	2040-49	2050
TES	99 %	99 %	99 %	99 %
Steam turbine	40.8 %	40.8 %	40.8 %	40.8 %
Gas turbine	35.8 %	36.8 %	37.8 %	38.8 %
BESS	91 %	92 %	92 %	92 %

Table 4.7: Future costs for Gridsol technologies within SRHs. CAPEX are in [MEUR15/MW] and fixed OPEX (f-OPEX) in [kEUR15/MW] except for storage, where specific costs refer to the unit's volume [MWh]. Variable OPEX (v-OPEX) in [EUR/MWh]. Values between 2020 and 2024 are equal to the ones reported in the previous Section (present costs).

		2025-29	2030-39	2040-49	2050
CSP field	CAPEX	0.334	0.300	0.281	0.261
	f-OPEX	14.680	13.172	11.627	10.081
	v-OPEX	-	-	-	-
TES	CAPEX	0.017	0.014	0.013	0.011
	f-OPEX	0.259	0.217	0.194	0.172
	v-OPEX	-	-	-	-
Steam turbine	CAPEX	1.249	1.136	1.072	1.008
	f-OPEX	28.258	26.555	26.597	24.638
	v-OPEX	-	-	-	-
Gas turbine	CAPEX	0.518	0.474	0.445	0.416
	f-OPEX	12.889	12.507	12.202	11.897
	v-OPEX	4.501	4.501	4.501	4.501

Table 4.8: Future costs for non-Gridsol technologies in SRHs. Units and description as in Table 4.7.

		2025-29	2030-39	2040-49	2050
Solar PV	CAPEX	0.515	0.462	0.407	0.358
	f-OPEX	6.751	6.027	5.475	5.022
	v-OPEX	0.707	0.622	0.554	0.499
BESS	CAPEX	0.375	0.244	0.135	0.075
	f-OPEX	1.629	1.629	1.629	1.629
	v-OPEX	2.015	1.814	1.711	1.611
Wind turbine	CAPEX	1.358	1.379	1.302	1.228
	f-OPEX	16.180	16.436	15.203	14.490
	v-OPEX	2.013	2.075	1.964	1.870

Chapter 5

Scenario design

5.1 Scenarios for the integration of CSP and Gridsol into the European power system

The attractiveness of CSP and Gridsol highly depends on the framework within which the hybrid power plant operates. Gridsol and Smart Renewable Hubs provide 100 % renewable energy when biogas is available to feed the hub's gas engines. In a context where reducing carbon emissions is atop of the political agenda (yet with relevant uncertainties regarding the trajectories), an assessment that covers all the projected European pathways towards 2050 is of uttermost importance for a concept such as Gridsol. In ESMs, scenarios are actually meant to explore different possibilities related to the future development of the energy system. In 2016, the European Commission published a first outlook analysing the continental progress towards decarbonisation until 2050 ('Reference scenario' [46]). However, the ambitious climate targets undersigned in the Paris Agreement suggested that the current supply and end-use sectors, including the market instruments regulating them (the EU ETS above all, see Section 2.2), would lag behind the preset objectives. For this reason, the Commission released a new Climate Strategy in 2018, where eight alternative pathways are envisioned so as to reach the well-known '2.0 degrees' or '1.5 degrees' targets [7]. Each of them is based on the development of one or more concepts that would lead to the achievement of the climate goals. They are visually described with their acronyms in Figure 5.1, which highlights also the additional investments required on top of what was forecast in the 2016 Reference. Given the amount of diverse possibilities, the supplementary outlay can vary within a rather wide interval. A description of the single pathways is not provided here for brevity, but can be found in [17]. This thesis synthesises all the eight alternatives into two categories, which are named '2.0 degrees' and '1.5 degrees'. For both categories, the exogenous model inputs are elaborated so as to describe *most* pathways, i.e. to align the core assumptions of this thesis with the EU hypotheses. Each exogenous input building up the scenarios is described in this Chapter, with the underlying assumptions and criteria that lead to a specific choice.

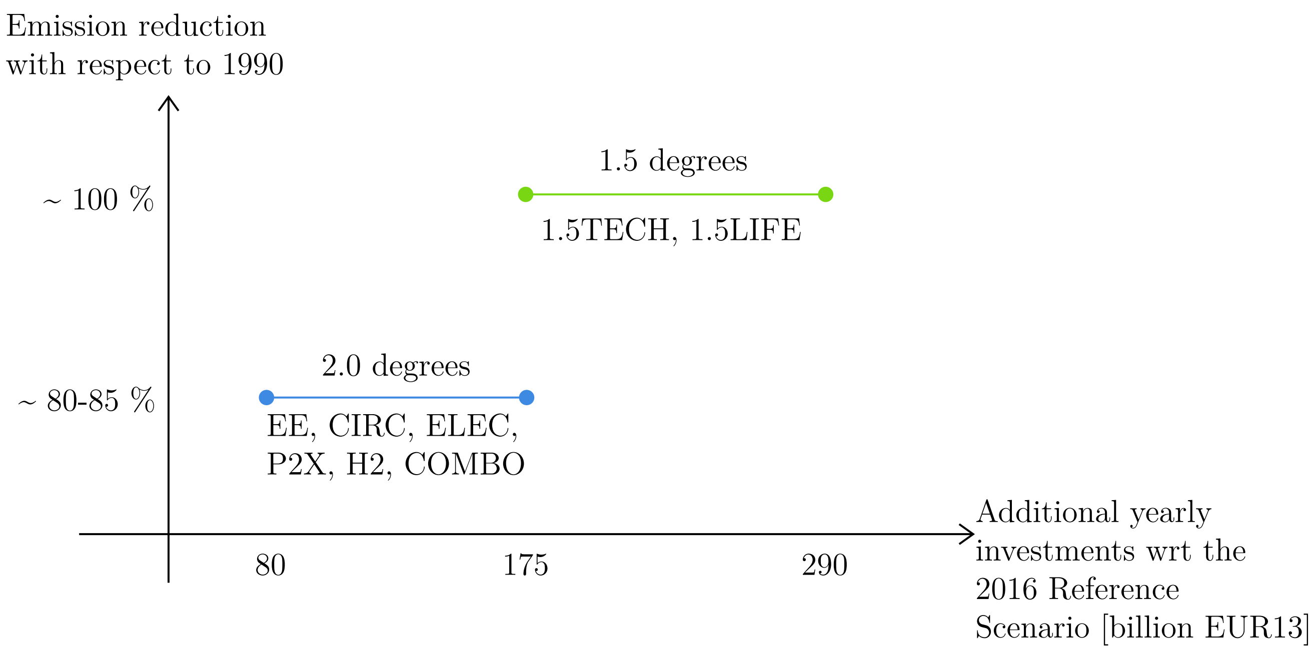


Figure 5.1: The eight climate-ambitious scenarios envisioned in the 2018 Climate Strategy. The emission reduction concerns here all the economy; figures for the power sector can differ from the aggregate value. The COMBO scenario is here included under the 2.0 degrees pathways, but can be seen as a bridge between the two main categories. Adapted from: [7].

The 2.0 and 1.5 degrees pathways describe one dimension of the sensitivity analysis in object, but they constitute also the basic setup for another type of research that involves different exogenous inputs. A first investigation aims at testing Gridsol as a hybrid concept, i.e. to which extent the configuration of the hub responds to diverse fuel prices. The focus is thus on the gas turbine. For this purpose the 2.0 and 1.5 degrees scenarios are expanded downwards in

Figure 5.2, where a different price trajectory is envisioned for biogas: the latter's production costs are supposed to never exceed 130 [DKK/GJ] (= 17.45 [EUR/GJ]) over the considered horizon. The 1.5 degrees pathway is also expanded upwards in Figure 5.2, where assumptions on CSP are relaxed. They relate to the cost of CSP components, whose capital-intensive characteristics are one of the major obstacles to its deployment. CSP cost projections are reduced by 25 % ('CSP+') and 40 % ('CSP breakthrough') with respect to the future trend provided by the partners; the cost reduction concerns all CSP components.

Figure 5.2 thus shows that the analysis develops on two levels. The decarbonisation pathways are fully examined on a horizontal line that extends from the conservative evolution of the power sector (the Baseline) to the implications that the most ambitious 1.5 degrees climate goal has on the electricity supply. The vertical dimension builds on the results found in the horizontal framework: first, the biogas price assumptions are challenged to assess their implications on the Gridsol hub in the 2.0 and 1.5 degrees scenarios ('2.0 degrees biogas' and '1.5 degrees biogas'); second, CSP costs are lowered to analyse the effects of its increasing share on the generation fleet. This specifications allow to focus on the strengths and weaknesses of CSP and Gridsol. The influence of these modifications on the broader concept of Smart Renewable Hub are the object of a further discussion.

The simulations cover the years between 2020 and 2050; the intermediate reference years trace the cost changes of the system components (Section 4.5) and are therefore 2025, 2030 and 2040. This allows the model to 'gradually' optimise the power sector for the years to come, i.e. to a more accurate choice of the technologies. In fact, big time gaps between simulated years tend to distort the investments, and in decarbonisation pathways this turns into an oversizing of renewable capacity.

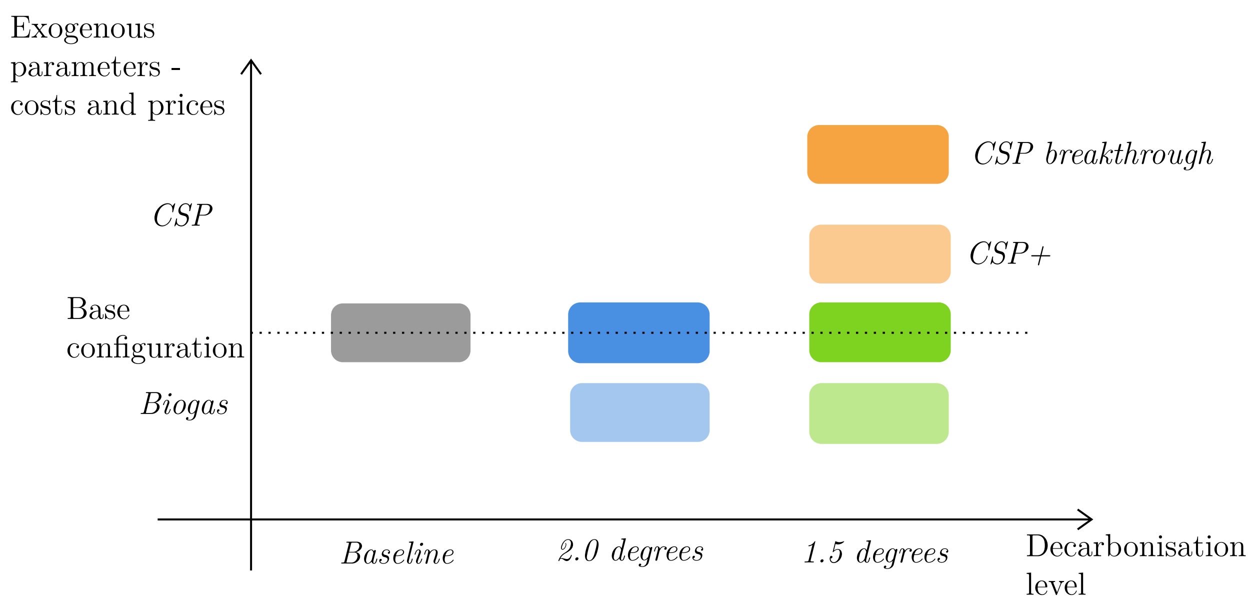


Figure 5.2: Scenarios under study.

5.2 Devising scenarios: the European context

5.2.1 A continent towards decarbonisation: the coal phase-out

A first, central action towards the achievement of climate targets is the the progressive close-down of conventional power plants. The diverse mix of energy generation technologies in the EU countries results in individual programmes for the replacements of coal-fired units. Figure 5.3 shows that a number of countries are already coal-free at present (Switzerland, Belgium, Luxembourg, the Baltic region) with Norway having only a small Combined Heat and Power (CHP) unit in operation, which is likely to be replaced in the near future; it is then represented in the same manner as the other coal-free countries. The rest of Europe splits into Western and Eastern (including Balkan) countries; the latter have not even discussed any coal phase-out, except in a few cases (Slovakia, Hungary). Hungary in particular is considering a possible shut-down of lignite power plants first, and a complete coal phase-out by the end of 2031 [47].

Overall, roughly 40 [GW] of installed coal capacity is going to be replaced in the countries that have announced the coal phase-out. Some states have already gone beyond coal as the ageing fleet required extensive renovation and maintenance; some others were induced to pursue the

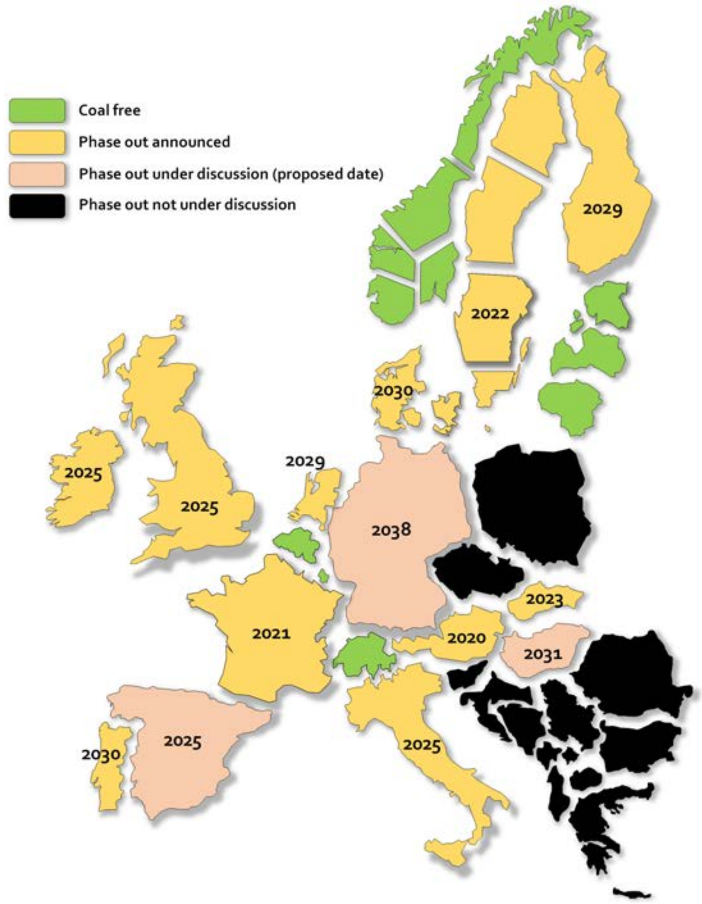


Figure 5.3: Countries that committed to the coal phase-out with relative shut-down year. Last update in June 2019.

renewable energy deployment because of the progressively tighter rules regulating the European market for carbon trading (Section 2.2, whose future evolution and purposes are discussed in the next Section.

5.2.2 The future market for carbon emission trading

In this section the implementation of a cap-and-trade system such as the EU ETS described in Section 2.2 is discussed. The scheme should provide adequate price signals to market participants so that they are brought to invest in renewable energy. From a modelling point of view, reduction in CO_2 emissions can be achieved by imposing a declining cap as in the real market functioning or by adjusting future CO_2 prices (in input) in a way that investments are directed towards carbon neutrality. In this work the second approach is chosen, as it reduces the computational effort; its validity is demonstrated in Section 6.1. Predictions on the long-term trend of CO_2 prices are a big source of uncertainty. Technically, the quota price should increase as the number of allowances is progressively reduced; the historical trend (Figure 2.7) conversely hints at many other factors having an influence on the price development. Some were already mentioned at the beginning of this Section. The financial crisis, the loose rules for some of the involved sectors, the investment in energy efficiency have - among others - yielded fluctuating prices, from minima of as low as 3 [EUR/t] recorded in 2013 to the recent spikes of over 27 [EUR/t], which mark a greater-than 80 % jump when compared to ten years ago.

Several reforms have characterised the scheme's functioning, the last one representing Phase 4 of the system and running until 2030. Its functioning is based on the joint effort of the cap-and-trade market and its complementary mechanisms. This is why predictions of future price trends up to 2030 do not span over a large range, but they often converge to a price of around 30 [EUR/t] in that year and in all conservative scenarios. Such a cost appears to be on the low side considering the recent developments, nonetheless this work sticks to this forecast. The price of 34.9 [EUR18/t] is chosen as the 2030 CO_2 price in the Baseline scenario; the projection coincides to what the European Commission foresees in their Reference scenario published in 2016 [46]. Several other studies have been published in recent years on the topic, some predicting a gradual increase in price, others a more fluctuating profile between 2020 and 2030 [48] [49] [50]. A linearly increasing trend is assumed in this analysis, beginning with a 2020 annual average price of 20.9 [EUR18/t]. This starting point constitutes an assumption common to all scenarios and entails a stabilisation of the current prices.

The other decarbonisation pathways envisioned by the EU do not mention any intermediate price between the present and 2050; however, it is mentioned that in any of the 'well-below two degrees' scenarios the emission reduction would lead to a CO_2 price of 250 [EUR15/t], and that figure would rise to 350 [EUR15/t] in a fully decarbonised Europe ('1.5 degrees', [17]). In this work, the price increase from 2020 to 2050 is split into two, so that a piece-wise linear function is constructed: a first, relatively weak rise until 2040 and a subsequent, steeper growth from 2040 on. It is assumed that the scarcity of allowances will cause the price to soar as the system draws closer to the carbon-free mark. Table 5.1 summarises the annual increase in price for the three CO_2 pathways and Figure 5.4 provides a graphical representation.

Table 5.1: Annual CO_2 price increase for each of the three decarbonisation pathways. Figures are in [EUR18/t]; when necessary, they are corrected for inflation with a 4.5 % factor in the period 2015-2018.

	Annual increase 2020-40	Annual increase 2040-50	2020 price	2030 price	2040 price	2050 price
Baseline	1.77	3.76	20.9	34.9	52.2	91.5
2.0 degrees	4.18	7.86	20.9	62.7	129.0	261.4
1.5 degrees	8.36	10.34	20.9	104.6	191.7	366

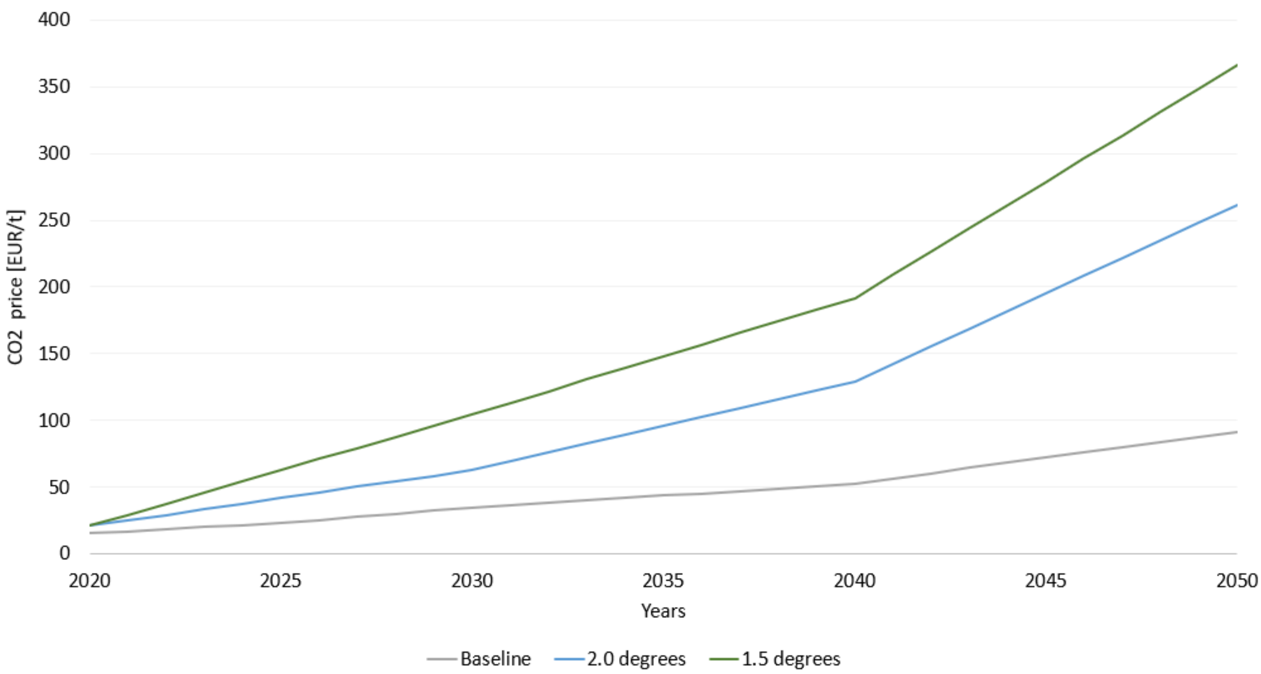


Figure 5.4: CO_2 quota prices [EUR18/t] for the three different decarbonisation pathways.

5.2.3 The natural gas and biogas prices

The CO_2 price level influences the choice of the technologies in the optimisation process. Its variations are particularly important for substitute fuels feeding the same units. A combined cycle or the Gridsol gas turbine in object would use either natural gas or biogas depending on the reciprocal price trends. In this work natural gas and biogas are considered perfect substitutes, in that:

- no constraint is put on biogas availability. From a technical point of view, the fuel is also already blended with natural gas in pipelines;

- the price of biogas equals at any point in time that of natural gas:

$$p_{biogas} = p_{naturalgas} + p_{CO_2} \cdot \delta_{ng} \quad [\text{EUR/GJ}] \tag{5.1}$$

where δ_{ng} [t_{CO2}/GJ] is the emission factor for natural gas (= 56.8 [kg_{CO2}/GJ]). Both fuel and carbon prices are uniform across the entire considered geography.

The technologies directly competing with each other, such as the Gridsol gas turbine and combined cycles, are therefore fed with a unique fuel, which will be referred to as 'Gridsol gas' in the following. Figure 5.5 shows the price trend for the Gridsol gas until 2050 in the three decarbonisation scenarios. The natural gas price projections are taken from the company's database. This assumption simplifies the set of events relating the two fuels; for instance, it is likely that sometime before the end of the investigated horizon biogas becomes cheaper than natural gas, especially in scenarios with high CO_2 prices. This process is also influenced by the potential reduction of methanisation costs, which in turn depend on the electricity price. For these reasons, an exception to Equation 5.1 is made to conduct an analysis on the impact of the biogas price, limited to the 2.0 and 1.5 degrees pathways. In a 2017 report by Ea Energy Analyses [51], biogas cost projections for 2020, 2030 and 2050 are shown to be only slightly different from one production technique to another. It is thus chosen to adopt a single declining linear trend between 2020 and 2050, with a 2020 price of 130 [kr/GJ] (= 17.45 [EUR/GJ]) and a 2050 price of 120 [kr/GJ] (= 16.11 [EUR/GJ]), regardless of the production process. The choice of the fuel price for a specific year falls on the natural gas + CO_2 price when this is lower than the biogas price, on the biogas price elsewhere. The goal of this sensitivity analysis is to understand the possible impacts (if any) of different fuel costs on the configuration of the Gridsol hub, i.e. with different operational expenditures for the back-up engine. In other words, it is a test on the strength of Gridsol as a hybrid power plant concept. In general, considering the uncertainty related to fuel prices in the long-term, the approach synthesised by Equation 5.1 is kept as a reference for all the other cases: the two fuels are completely interchangeable in the rest of the scenarios.

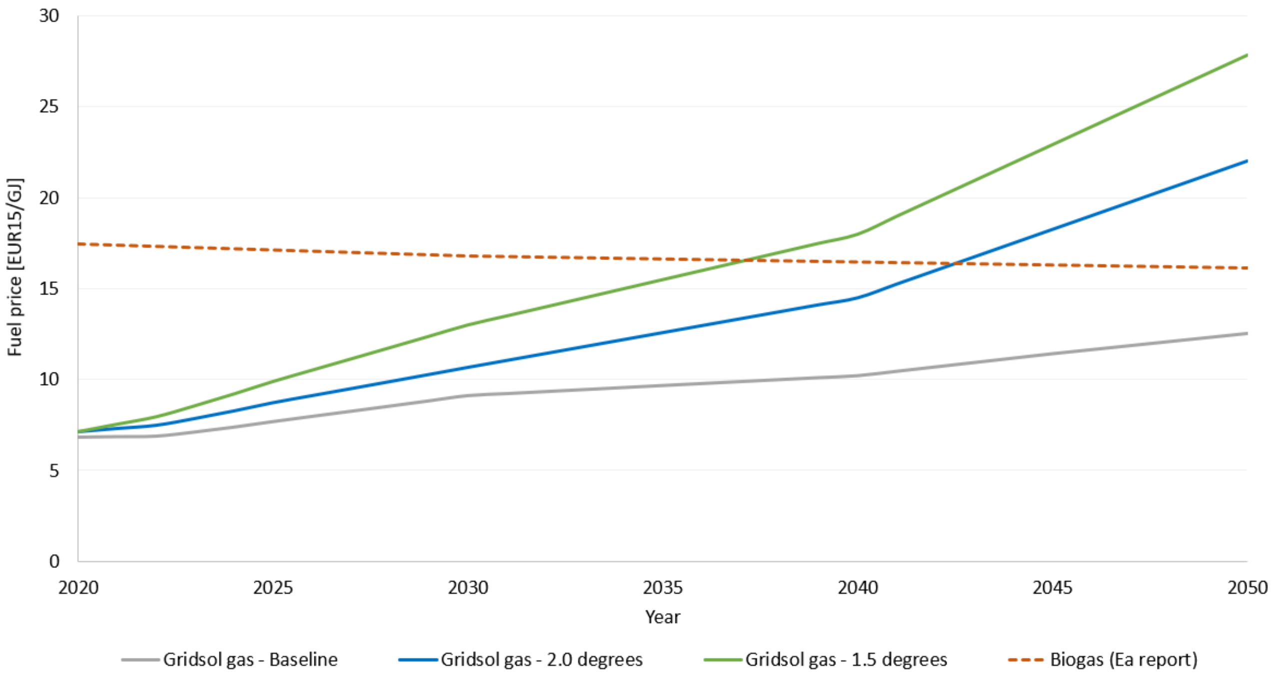


Figure 5.5: Future trend for the Gridsol gas price in the three decarbonisation pathways.

5.2.4 The Ten Year Network Development Plan

Fuel prices are among the exogenous inputs required by the model. Existing and commissioned transmission capacities are another; they are paramount as they can cause shifts in the power flows within the continent, on the basis of available capacity, transmission losses and costs. In Balmorel, interconnectors link two Regions together and a capacity increase is seen as a way to levelise the hourly spot prices in market pools first and in the entire continent in the second place. The Ten Year Network Development Plan (TYNDP) summarises the state-of-the-art of projects strengthening the European power grid. The most recent edition, published in 2018, brings together all the transmission projects in construction, in permitting or under consideration for the next 20 years in Europe [52]. The Balmorel model is updated with all the future projects 'in construction' and 'in permitting', which are underway and set to be operational before 2030. In addition, existing cross-national transmission capacities are updated according to the Net Transfer Capacity (NTC) 2020 published by ENTSO-e [53].

5.2.5 Final electricity demand projections

The European Commission delineates the future final electricity demand in the eight scenarios mentioned in Section 5.1 (Figure 5.6). With the exception of ELEC, the chart shows that the final electricity demand is decoupled from the decarbonisation level (and therefore independent on the specific scenario). All growths (but ELEC's) lie between 30 (1.5 LIFE) and 50 (COMBO) %, with respect to 2015. Table 5.2 is a personal elaboration showing also the projected growth when compared to 2030. The company's data based on previous elaborations hold a demand increase of 25 % with respect to 2030, which appears to be aligned with most EU projections, ELEC framework excluded. It is therefore chosen to keep a 25 % growth in demand across all the scenarios under analysis. More substantial deviations can be detected in generation projections, which are analysed in the following.

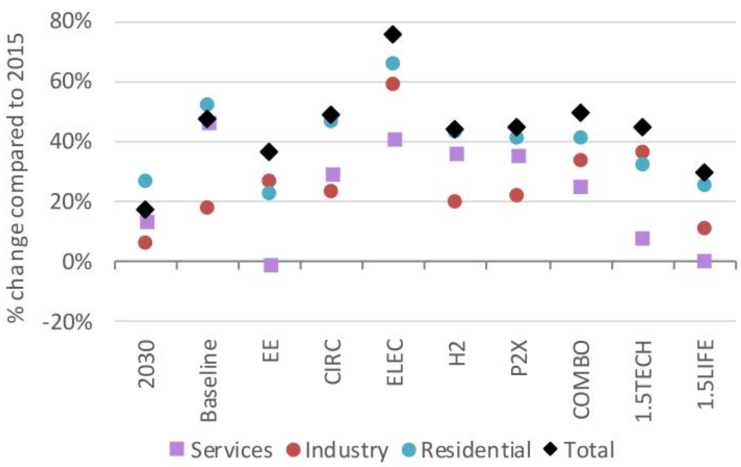


Figure 5.6: Increase in electricity demand in 2050 with respect to 2015 across all EU scenarios. The 2030 value is valid for all frameworks. Source: [17].

Table 5.2: Growth in electricity demand across the EU scenarios. Data is from 2050, see also Figure 5.7. Elaboration from [17].

	Baseline	EE	CIRC	ELEC	H2	P2X	COMBO	1.5TECH	1.5LIFE
Growth in electricity demand wrt 2015 [%]	48	36	49	75	44	45	50	45	30
Growth in electricity demand wrt 2030 [%]	26	16	27	50	23	24	28	24	11

5.2.6 Generation projections: electricity for clean fuels

In highly decarbonised scenarios, there also exists a strong decoupling between final electricity demand and generation trends. The final energy demand for electricity is not expected to increase significantly from the 2.0 to the 1.5 degrees scenario, as stressed in the previous Section; in some cases predictions even foresee a slight, relative downturn when compared to the Baseline. The outlook is rather different when looking at generation patterns. Figure 5.7 clearly shows that only in the Baseline and in the Energy Efficiency (EE) European scenarios the increase in generation lies below the increase in final consumption; the growth in gross electricity demand is very notable elsewhere. The gap between growth in generation and consumption is wider in the set-ups where synthetic fuels and hydrogen play a relevant role in the future energy supply.

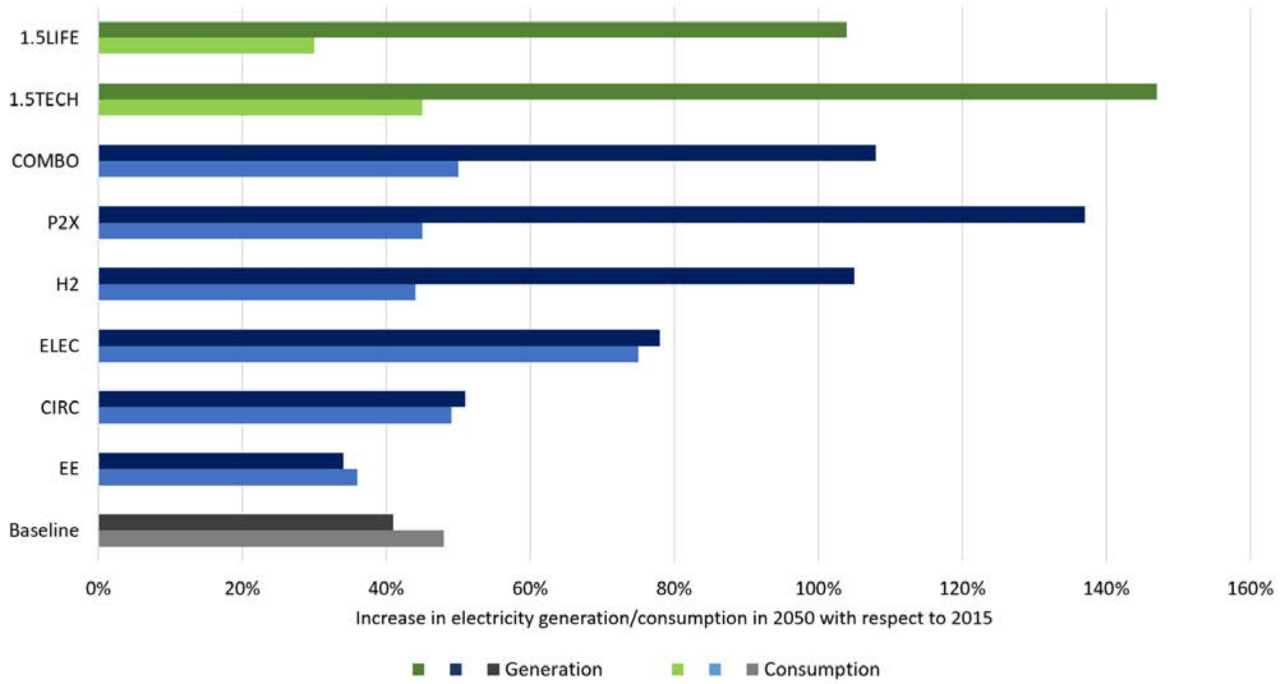


Figure 5.7: The nine EC projections for power production and consumption differ largely from one scenario to another. Elaboration from [17].

This analysis neglects the impact of e-fuels, but takes into account the future energy demand for hydrogen (H_2); the level differs from one scenario to the other, but depends on the decarbonisation target. Figure 5.8, which reports the expected consumption in 2050 for the entire Europe, highlights how the final demand for H_2 is strongly conditional on the specific assumptions underlying each scenario. Considering the high variance within the 2.0 degrees framework, the hydrogen demand is arbitrarily set to 20 [Mtoe] for this pathway; this matches most but extremes (H2) scenarios. In contrast, the Baseline incorporates a projection of 4 [Mtoe], which rises to 80 [Mtoe] in the 1.5 degrees set-up. No data is explicitly available for 2030, but the projected installed capacity for hydrogen production (Figure B1 in the Appendix) suggests that a very small demand is forecast for that year. This is common to all scenarios, as a differentiation occurs after 2030. For this reason, it is chosen to increase the H_2 demand linearly starting from 2030, which is set to be the first year with a non-null value.

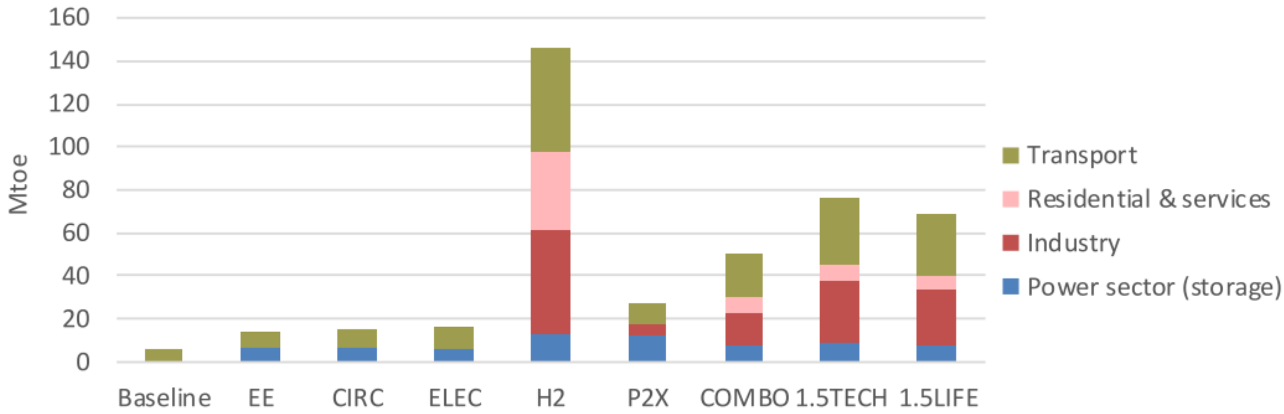


Figure 5.8: Hydrogen consumption by sector and across the 9 scenarios as forecast by the European Climate Strategy. Year: 2050. Source: [17].

In Balmorel, the hydrogen demand is split into the various countries based on their final electricity consumption; a flat shape defines the hour-by-hour profile. The conversion technology consists of electrolysers (SOEC) employing electricity as the only input and thermal power as the only output. Thermal power is utilised instead of proper hydrogen as a heat demand can be defined at the Area level, thereby allowing for a simple but effective modelling. The heat required for the endothermic cell reaction (around 15 % of the cell energy requirement [54]) is neglected. The technical features can be found in Table 5.2.6, which also reports the storage characteristics (H_2 storage); this is added to provide flexibility in the supply of hydrogen. The current scant large-scale utilisation of H_2 storage technologies (which come in a series of options) makes it hard to predict future trends and developments. Therefore, the only possibility envisioned in this work is the high-pressure cavern type [33]. The precise modelling of the hydrogen production process is out of the scope of the thesis; this addition serves the purpose of accounting for the mismatch existing between the growth in generation level and final electricity demand.

Table 5.3: Characterisation of technologies for hydrogen production and storage.

	Technology	Input	Output	Efficiency (round-trip) [-]	CAPEX [MEUR15/MWh]	OPEX [kEUR15/MWh]
SOEC 2030-39	Power to heat	Electric	Thermal	0.79	0.600	16.0
SOEC 2040	Power to heat	Electric	Thermal	0.79	0.500	13
H_2 storage	Heat to heat	Thermal	Thermal	0.88	0.008	0.154

5.3 Future costs of CSP power plants

At the beginning of this Chapter the 'CSP+' and 'CSP breakthrough' scenarios were defined as a way to represent one of the brightest conditions for a CSP deployment in Europe (Figure 5.2); a key hindrance to surmount is the relatively elevated overnight expenditures. The investment costs of renewable technologies are often related to the so-called learning rate: this is defined as the cost reduction [%] achieved with a doubling of the installed capacity. In [55] learning rates of up to 21 % are suggested for parabolic trough plants, but no clear pattern is identified for the central tower concept. In [56] a learning rate of 12 % is proposed, but again without differentiating between solar field concepts. Nonetheless, the overall CSP costs are foreseen to decrease by roughly 40 % between 2020 and 2050. Unlike PV, CSP is relatively immature and two other facts make it hard to elaborate learning curves. First, the relatively scarce amount of installed capacity (solar-field-wise) is non-uniform, in that diverse concepts have found application in the past decades (Section 2.4); second, the uptake of CSP technologies has been influenced by distinct support phases in a scattered geography [55]. The processing of learning curves and their use to predict future cost trends for CSP has therefore been trivial; this uncertainty is reflected in the scarce available literature and, where present, in the wide cost ranges. An example can be found in [57], where three scenarios for CSP installation in the Atacama desert cover a large spectrum of costs (Figure 5.9). Their analysis is conducted until 2037; future expenditures are expressed with a reduction factor that compares them to the present, i.e. at the beginning of the evaluation period (2018). The Gridsol partner's costs adhere to the high cost projection; however, it is to be borne in mind that these values depend also on other external developments that are geography-related, such as labour costs and quality of the solar resource. For example, higher FLH lead to higher production/installed capacity ratios; in other words, the costs per unit output are lower if the field size is smaller.

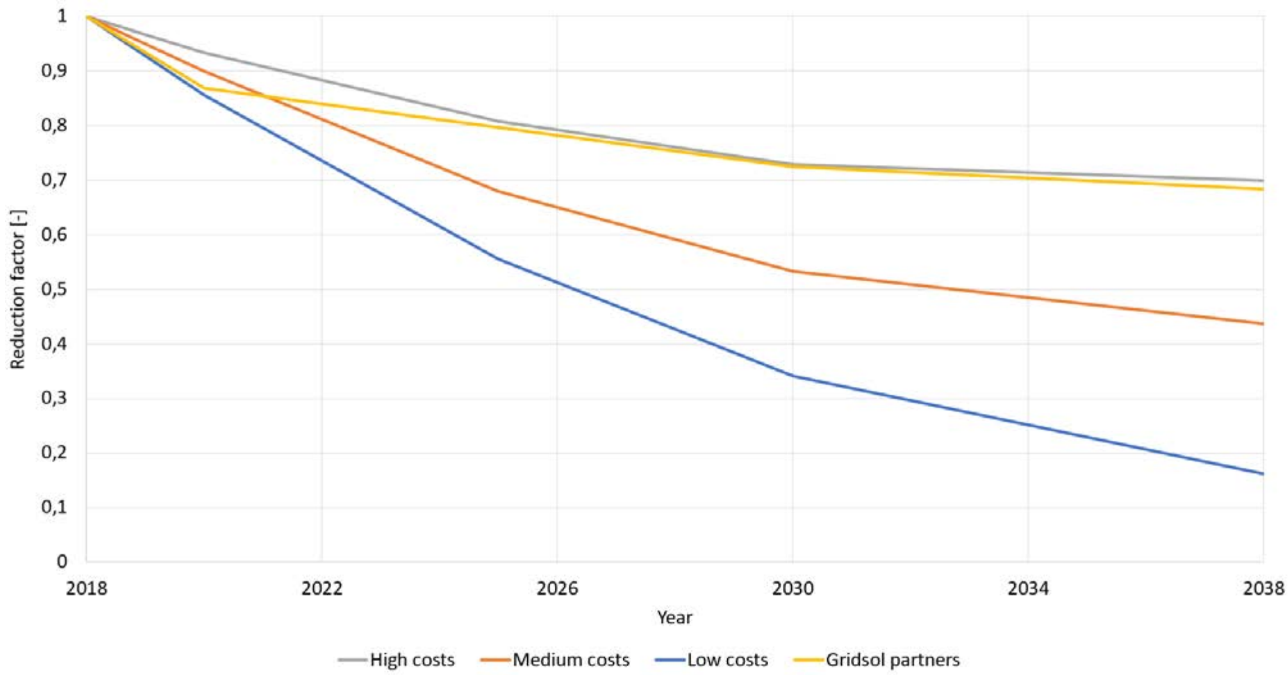


Figure 5.9: Cost projection for CSP power plants under three scenarios: high, medium and low costs. Adapted from [57].

The reported trends comprise only aggregate expenditures, in that they do not differentiate among components within the CSP block. In [58], future cost trends are reported separately for each element; the elaborated data is presented in Figure 5.10, which carries only overnight expenditures (they are the largest share, regardless of the operational time of the plant). It is clear that the components can benefit from different cost reductions. The power block is a mature technology and it is therefore expected to see more contained cuts than the other components. It is also evident that the partners' projections lie on the optimistic side; in any case, their data is assumed reliable as provided by companies leader in CSP development and installation. It is also to be born in mind that the industry is under fast development, this leading to continuously revised cost projections for CSP components; these may vary significantly from year to year.

It was previously underlined that the purpose of the 'CSP+' and 'CSP breakthorugh' scenarios is to envision an ideal (meaning very optimistic) cost framework to mark the upper boundaries of the CSP deployment in Europe, from a socio-economic perspective and conditional on the sole

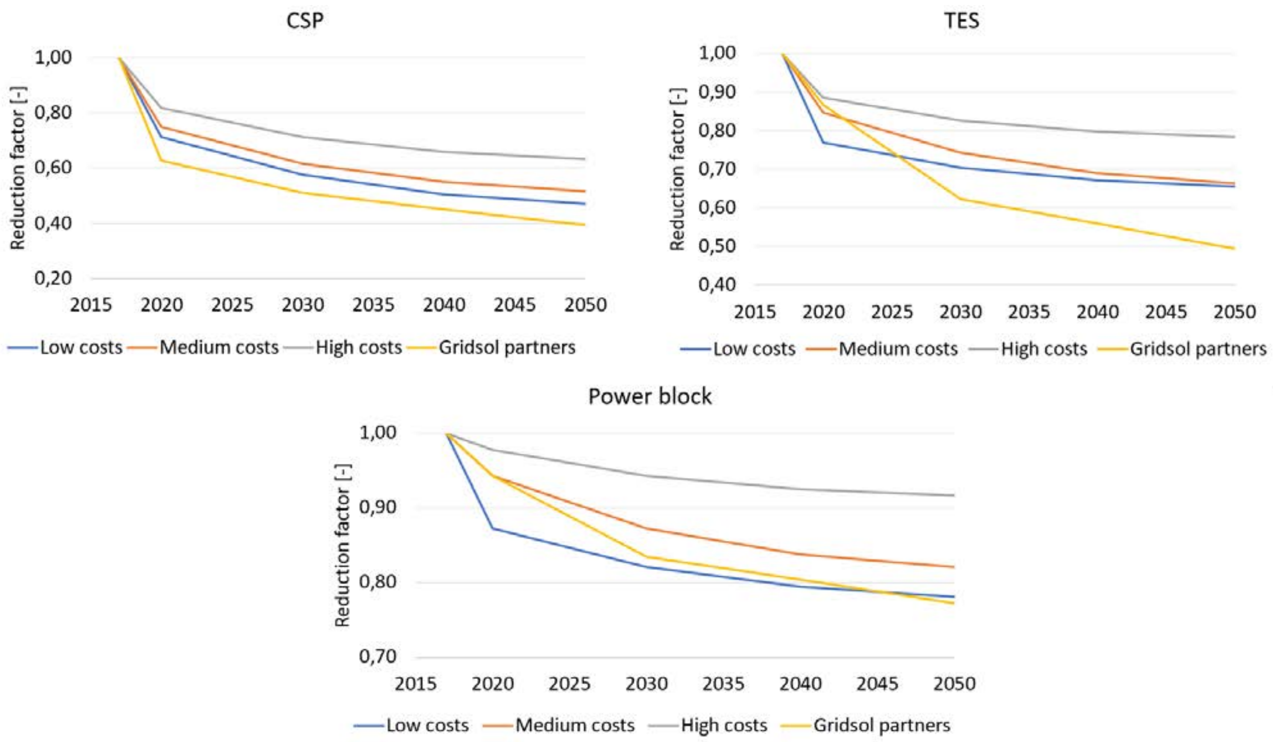


Figure 5.10: Investment cost projection for CSP components under three scenarios: high, medium and low costs. Adapted from [58].

market rules. For this purpose and considering how the partners projections relate to the other references presented in this Section, an additional 25 % (CSP+) or 40 % (CSP breakthrough) cost decrement is evenly assigned to the CSP field, the storage facility and the power block.

5.4 A note on calibration

The company's model is continuously tested on new updates, compared with relevant published statistics and adjusted for the results to be aligned with the actual functioning of the power and heat sectors; it is therefore assumed that the European model is calibrated. Only one adjustment is made to the exogenously defined capacities in Europe, which is an update of the existing CSP generation fleet in Spain. The 2304 [MW] of CSP capacity (see Section 2.4) are assigned 2000 FLH over the entire considered horizon and a common DNI profile that matches the one given by the consortium's partners for the Extremadura site.

Chapter 6

Results. Overview of the European system

The presentation of the results is split into three chunks. This Chapter focus on the CSP and Gridsol attractiveness in relation to the system where they are installed: capacity, generation and economic figures are presented so as to characterise the context and they are further elaborated to describe under which conditions CSP and Gridsol can have a role in the future European power sector. Chapter 7 summarises the findings connected to Smart Renewable Hubs, whereas Chapter 8 provides insights into the operational details of CSP, Gridsol and Smart Renewable Hubs.

This Chapter begins with two Sections that build on the understanding of the core results: in Section 6.1, the interaction between CO_2 prices and emissions is analysed to provide the grounds for a critical assessment of strengths and weaknesses behind the Gridsol concept; in Section 6.2, the context is explored through an analysis of the Baseline, which represents the conservative development of the power sector. The description of the evolution of the power system under the EU Climate Strategy conditions are outlined in Section 6.3. From there on, the focus is on the technical features of the CSP and Gridsol power plants: their contribution to the decarbonisation pathways, the sensitivity analyses on the biogas price (Section 6.4) and on the CSP capital expenditures (Section 6.5) are presented. Finally, a closer look at the economics is taken (Section 6.6).

6.1 Results from the EU ETS modelling. A qualitative assessment of the consequences

In Section 5.2.2, the future EU ETS was characterised by price trends rather than progressively tighter emission caps. In Figure 6.1 the emission reduction is visualised and the related Table 6.1 quantifies it with respect to 2015 and 1990 (the historical data is retrieved from the European Environmental Agency [59]). The 20.9 [EUR/t] price set in Section 5.2.2 brings the system beneath the 1000 [Mt] emission threshold in 2020 (995 [Mt] precisely), down 25 % from 2015 and down 47 % from 1990, when the level settled at 1331 and 1869 [Mt] respectively [59]. The power sector moves towards decarbonisation more or less rapidly, with the 1.5 degrees pathway reaching a 98.4 % reduction in 2050 (31 [Mt] left excluding Carbon Capture and Storage (CCS), in which the model cannot invest) against the milder, but still consistent 94.2 % cut that characterises the Baseline (with respect to 1990). In Section 5.2.2 the CO_2 price was shown to rise moderately until 2040, before spiking in the last decade under study; Figure 6.1 conversely displays that the emission cut is more prominent at relatively low carbon prices. This occurs only partly because of the coal phase-out, which is common to all the three pathways: the effect of rapidly soaring carbon prices is evident on the 2.0 and 1.5 degrees trajectories, which impose an emission cut of 775 and 869 [Mt] respectively in the course of a decade (+ 185 and + 280 CO_2 [Mt] avoided with respect to the Baseline). There is a range of CO_2 prices, roughly bound on the upper part by the 100 [EUR/t] mark, where the emission cut appears to be more consistent. The 100 [EUR/t] level is reached around 2030 in the 1.5 degrees trajectory, in 2035 by the 2.0 degrees and never by the Baseline (Section 5.2.2), that has a more linear graph and gradual emission cut. The blue line (2.0 degrees) tends to the green one (1.5 degrees) in the years 2040-50; even with a consistent gap in carbon prices, the effect on the total level of emissions is negligible above a certain threshold, which is found to be 100 [EUR/t] approximately. This is also why all pathways reach a high degree of decarbonisation ($\geq$ 90 %) at the end of the considered horizon. It can be stated that in highly-decarbonised visions there is a larger need for replacement of fossil-fuel units in the short-term: this is a key period for the deployment of renewable technologies. The space is seemingly more limited as the system approaches 2050, but in a context where the need for electricity may increase (hydrogen, synthetic fuels) CSP can have a role in expanding the generation fleet with a clean technology and in a flexible manner. At the same time, for a concept like Gridsol the high CO_2 prices are discouraging if the gas turbine is fed with natural gas; the biogas price should be low enough to replace it, provided that the estimated gas turbine efficiency of 49 % (if heat recovery is considered, Section 4.1) compete with a standard combined cycle. In short, to achieve *notable* level of deployments in highly-decarbonised scenarios CSP and Gridsol need to be driven by attractive economic and financial conditions and:

- in the short-term (2020-30), where the largest portion of emissions is abated, CSP would contribute to the replacement of the existing fossil-fuel fleet. In this period the technology would *contribute to the emission cut*;

- in the medium/long-term (2030-50), CSP can still count on the clean energy argument, but its role would be that of *keeping the emission level down*, in a setting where the gross electricity demand may rise and undergo a change in its profile because of hydrogen and synthetic fuels.

Table 6.1: CO_2 emission reduction in 2050 in the three decarbonisation pathways with respect to 2015 and 1990.

Pathway	CO_2 reduction [%] with respect to 2015	CO_2 reduction [%] with respect to 1990
Baseline	91.9	94.2
2.0 degrees	97.1	97.9
1.5 degrees	97.7	98.4

At present, the power sector still holds the biggest relative share of CO_2 emissions in Europe, but Figure 6.1 shows that the tendency is that of a very rapid decline, regardless of the specific scenario. The total GHG emissions are set to fall by 80-85 and nearly 100 % in the 2.0 degrees and 1.5 degrees trajectories respectively, but these numbers are valid *for all sectors* [17].

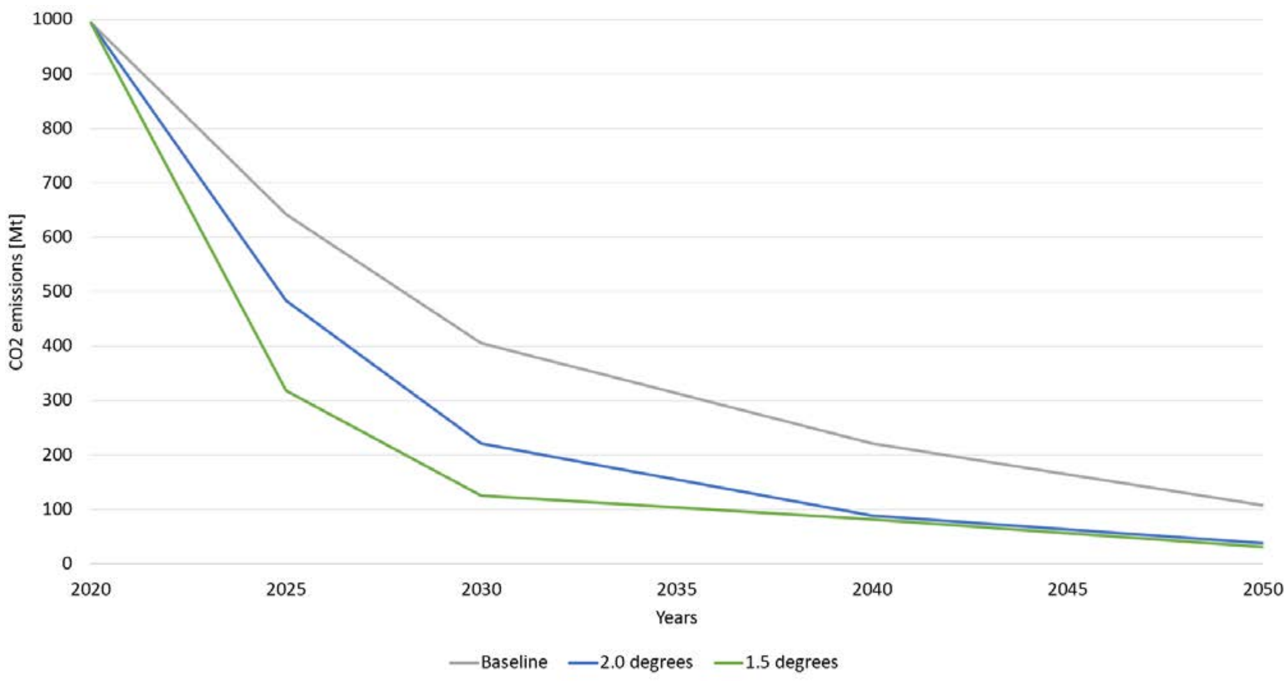


Figure 6.1: CO_2 emissions in the three decarbonisation pathways.

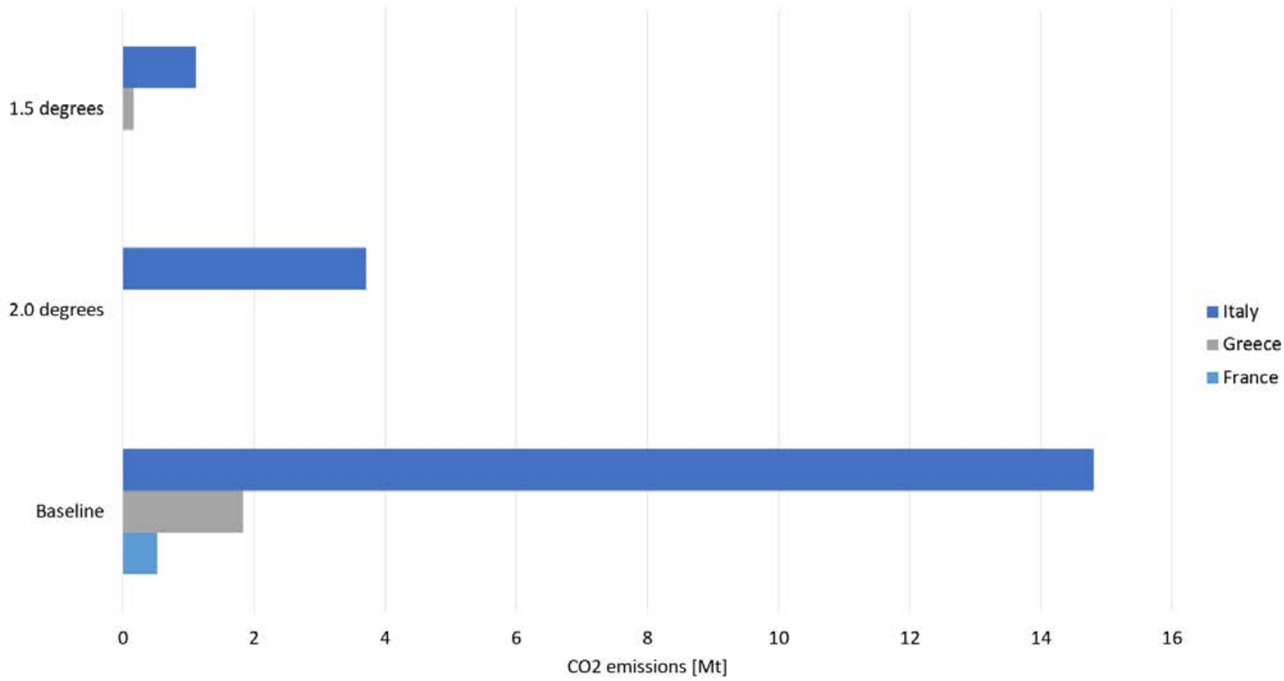


Figure 6.2: CO_2 emissions in the power sector for the five Gridsol countries (2050). Spain and Portugal are fully decarbonised.

The power sector shows to be incentivised to pursue high levels of decarbonisation already with medium CO_2 prices. In particular, a zoom to the five Gridsol countries (Figure 6.2) illustrates

that Spain and Portugal achieve full decarbonisation under the Baseline conditions. France counts on only clean conversion technologies in both the 2.0 and 1.5 degrees pathways, while Italy is seen to reduce its emissions to 3.71 and 1.11 [Mt] respectively in the two setups. It is interesting to notice that a very small share of natural gas generation persists in Greece in 2050 in the 1.5 degrees pathway: this is due to the rise in gross electricity demand needed in the electrolysis of water. The reappearance of combined cycles in Greece suggests that a larger, different need for electricity may favour an ongoing utilisation of combined cycles also in the long-term, at least locally. Gridsol can constitute also an alternative to combined cycles. This topic is further treated in Section 6.4.
In the context outlined here, CSP and Gridsol can consistently move ahead in the European landscape only with strong economic and technical advancements and possibly because of higher gross electricity needs.

6.2 The Baseline: an overview on the power sector

Section 6.1 and the snapshot provided by Figure 6.3 portray a European power sector that progressively tends to full decarbonisation even with moderate carbon prices; the investments in clean technologies are mainly driven by the rapidly declining costs of renewables and especially of electric storage. In the Baseline, the total electricity generation rises up to 5000 [TWh] in 2050 in the entire Europe, thereby marking a + 49 % increase with respect to 2020. This is more than what projected by the European Commission, but this analysis accounts for non-EU states too (Norway, Switzerland, Albania, Kosovo, Bosnia, Montenegro, Serbia), whose aggregate generation jumps from 300 to 440 [TWh] between 2020 and 2050. Figure 6.3 well displays some milestones changing the power sector in the years to come. The progressive coal phase-out, particularly visible in the decade 2020-30, involves key countries permanently shifting to cleaner sources (France, Great Britain, Italy, the Netherlands, Spain, Sweden): solid fuels are down to 7.7 % in 2030, while they supplied roughly one quarter of the entire gross demand in 2020. This goes to the benefit of also natural gas in the very short-term (it covers 12 % of the entire demand in 2025), but it is fossil-free generation that gradually takes over conventional units. The projected wind share in 2050 outreaches 50 %; if added to that of solar PV and hydro, an impressive 85 % is attained. Hydropower undergoes a smooth decline in relative terms over the considered time horizon, its share settling at 11 % in 2050 (16 % in 2020); however, its absolute generation actually sees a mild increase (+ 14 [TWh] in 2050 with respect to 2020). On the contrary, the presence of nuclear power plants weakens in both terms, as the old reactors are expected to be shut down in favour of other technologies (8 % in 2050 against the 22 % in 2020, - 330 [TWh] over the investigated horizon).

The solar share ($\sim$ 20 % in 2050) is almost entirely covered by PV units, the only CSP plants being the already operational Spanish installations (0.14 % in 2020 and 0.09 % of the total generation in 2050). Neither the Gridsol hub nor CSP find room in this scenario, despite the high share of renewables as the system approaches 2050. Generation from natural gas drops by roughly 50 % between 2020 and 2050, contributing to slightly more than 3 % of the gross demand at the end of the considered time horizon.

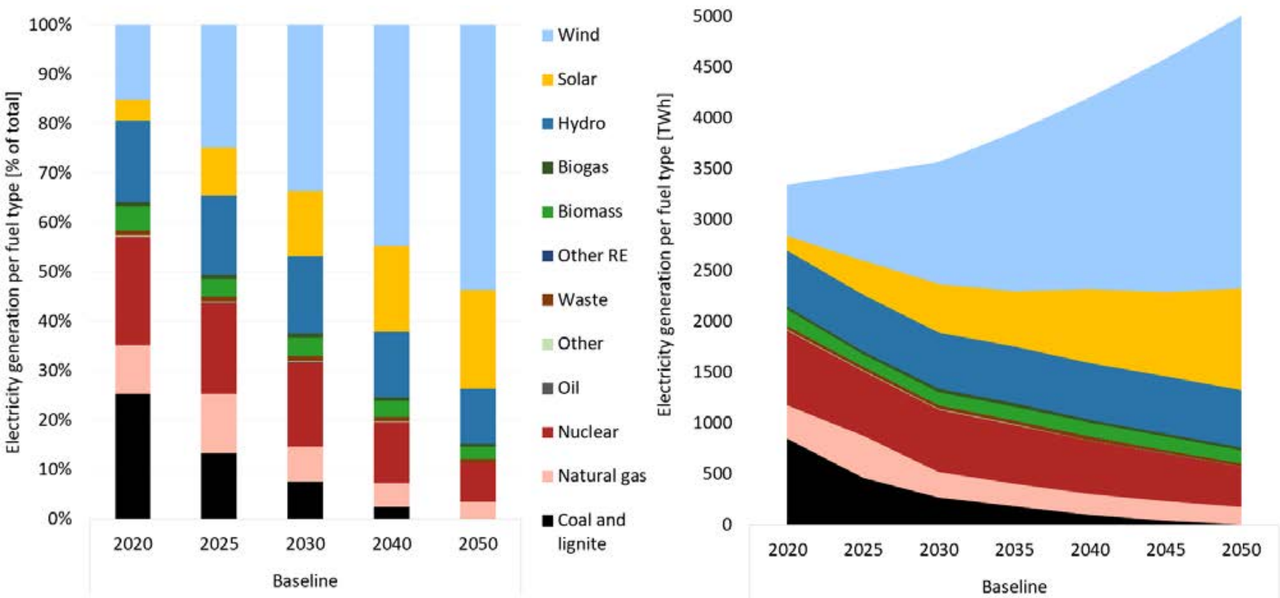


Figure 6.3: Generation per fuel type over the entire geography (each year for the Baseline scenario). Left graph: shares; right graph: absolute values.

The replacement of natural gas units would not therefore lead to a strong penetration of CSP and the disaggregate data of Figure 6.4 (national level) corroborates this statement. In the Gridsol countries (2050) natural gas lasts only in France, Greece and Italy, with generation shares of 0.1, 5.1 and 9.2 % respectively. The model foresees that a small share of oil generation still persists in Italy (0.03 %). Nuclear power is projected to supply nearly 20 % of the French gross electricity requirements (8.4 % in Spain). In a context with relatively low carbon prices and a modest increase in gross electricity demand, CSP does not find a fertile ground to spread.

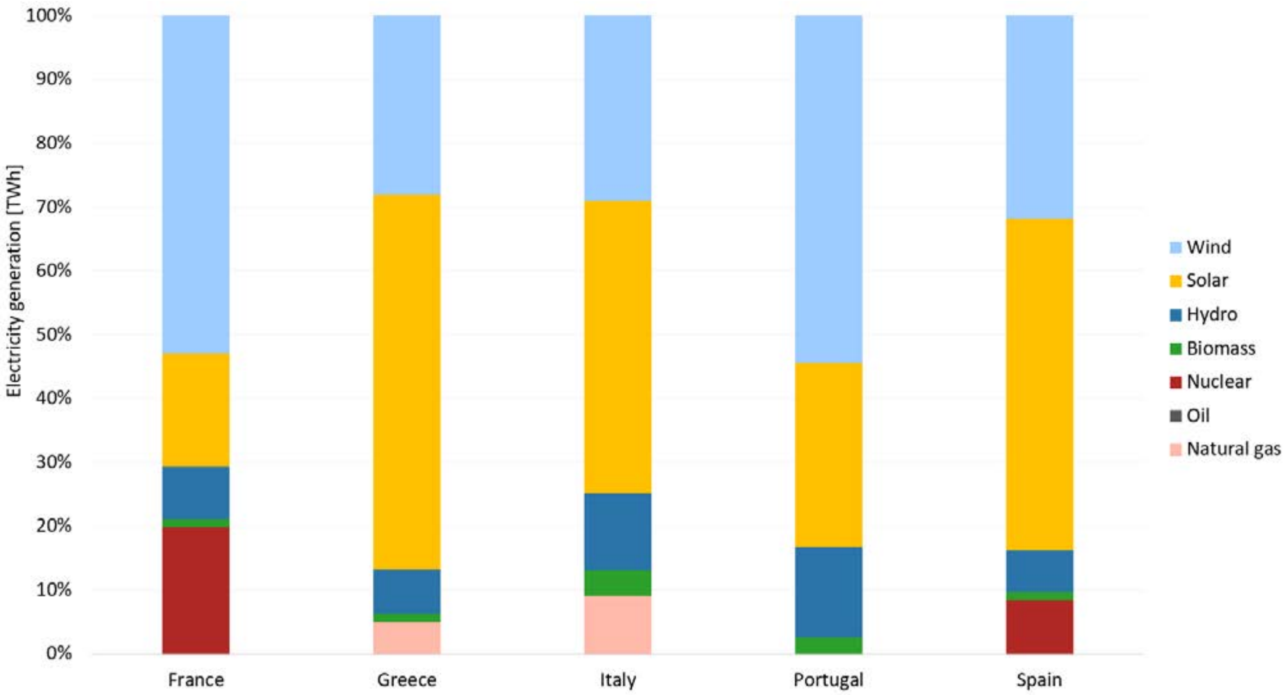


Figure 6.4: Generation per fuel type (shares) in the five Gridsol countries (Baseline, year 2050).

The installed power capacity characterises the future European system to a further level. Wind, solar and hydro still hold around three quarters of all operating units, but the solar and wind capacities are almost equal ($\sim$ 38 %): this is due to the fluctuating nature of the solar resource, whose availability appears to be a lot more uncertain than that of wind. It is relevant to notice that the natural gas capacity accounts for 7.5 % of the entire fleet, more than twice the corresponding generation share: this grounds on the function these units fulfil in the system, that is security of supply in hours with insufficient natural resources and peak load covering in periods of high demand (and prices). This aspect can in principle be fertile for the spreading of Gridsol in Europe: an intermediate-load technology that bridges the need of fossil-free generation (solar PV, wind) and back-up purposes (gas engines).

The deployment of renewable energy sources is also favoured by the steep downward trend in the price of electric storage, which has hindered further PV and wind installations up to the present moment. The almost null storage volume available in 2020 grows up to nearly 350

[GWh] in 2050, with a steep take-off after 2030 (Figure 6.6). This follows on a more pronounced cost decline.

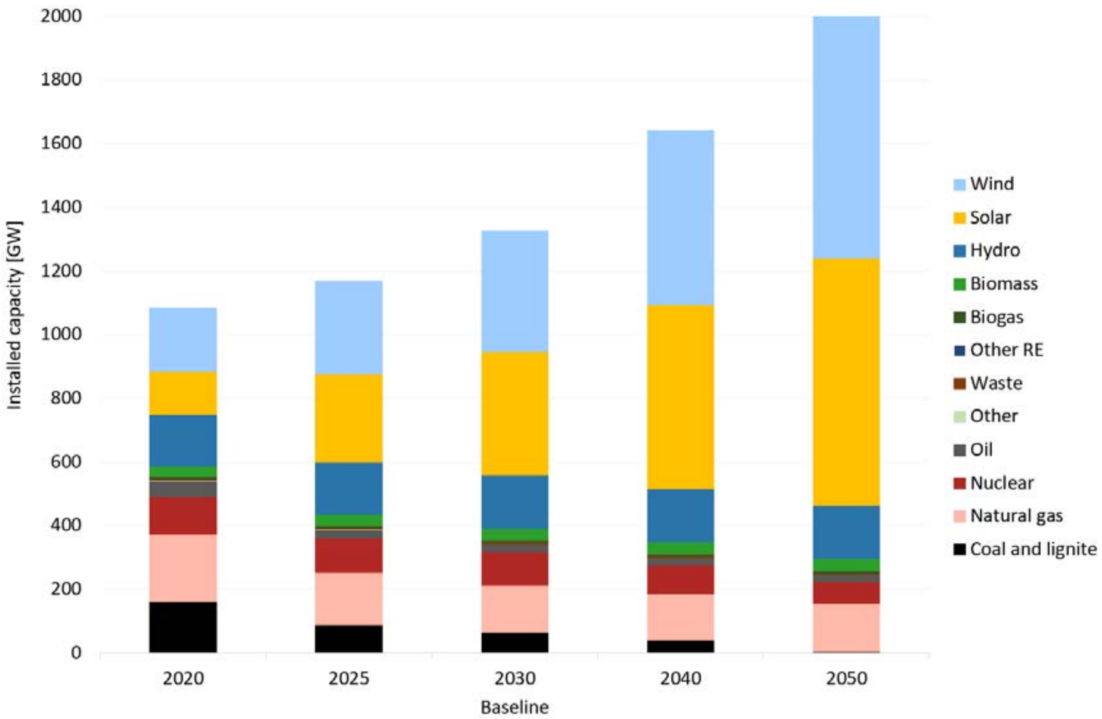


Figure 6.5: Installed power capacity [GW] per fuel type over the entire geography.

The Baseline defines the available room for CSP and Gridsol to develop. Considering their characteristics, the competitors are found in both the renewable sources (ready-to-dispatch, with low or null operational costs but also flexible when coupled with cheap storage facilities) and in the intermediate/base-load suppliers. The margin to substitute natural gas is rather small; on the whole, the Baseline shows that a gradual yet substantial cut in the emission level (Table 6.1) is not beneficial for CSP. The other renewable sources make up for the vast majority of the future EU generation fleet, but on this side the competition is fierce because of available, inexpensive electric storage, especially from 2040 on. This last fact constitutes the turning point for a stronger solar PV spreading. The next Section expands on the impact of CO_2 prices and increased gross electricity need on Gridsol and its attractiveness.

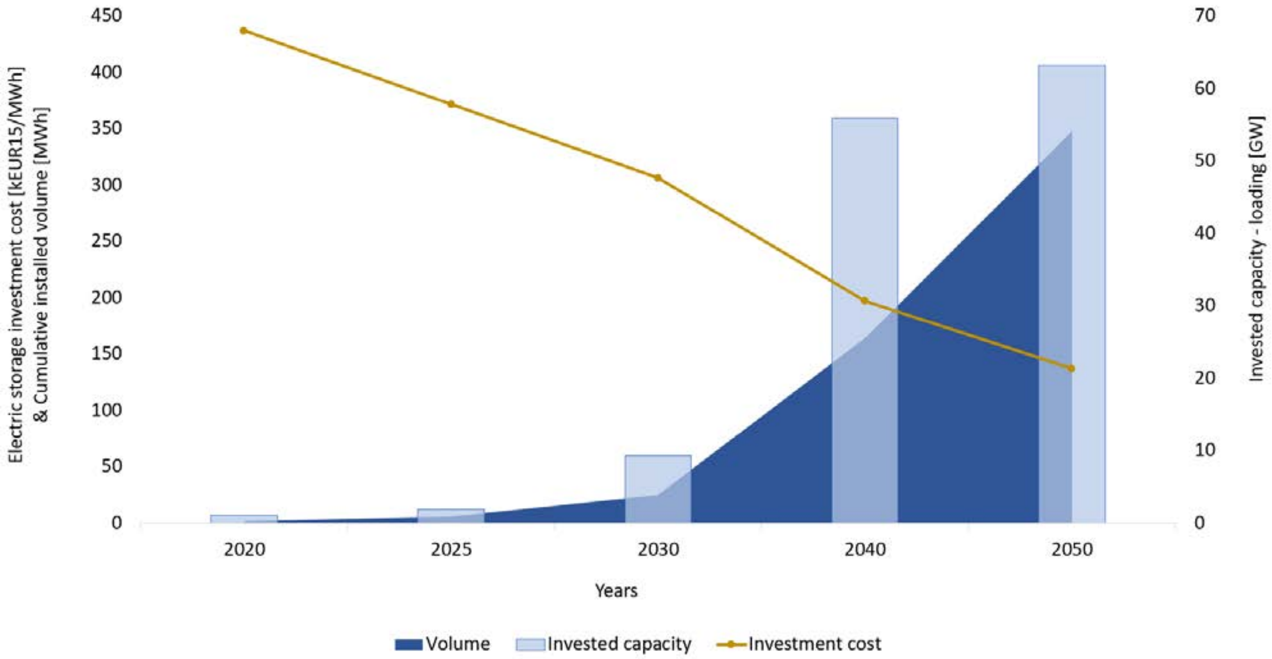


Figure 6.6: Projections of the electric storage spreading in Europe until 2050 (Baseline scenario).

6.3 Shaping a decarbonised power sector for a growing electricity use

6.3.1 Overview. Differences with the Baseline

The Baseline, 2.0 and 1.5 degrees pathways do not differ only by the different CO_2 prices, but also because of the hydrogen demand (Section 5.2.6). The latter requires additional power for the electrolysers, which bring the aggregate gross electricity demand up to 5576 and 6877 [TWh] in the 2.0 and 1.5 degrees pathways respectively (Figure 6.7): this marks a + 67 and + 106 % jump from the 2020 level. The gap among scenarios mildly begins with different CO_2 trajectories until 2030 (it can be stated that a higher cost of carbon allowances already contributes to a moderate increase in generation), but it broadens once the H_2 need enlarges.

As a consequence, the power fleet undergoes an expansion. In Figure 6.8 the changes in total installed capacity are shown at the European level: the left chart highlights the difference in installed power capacity per fuel (natural resource) type with respect to the Baseline; on the right, the chart shows the increase in storage loading capacity. Medium carbon prices are

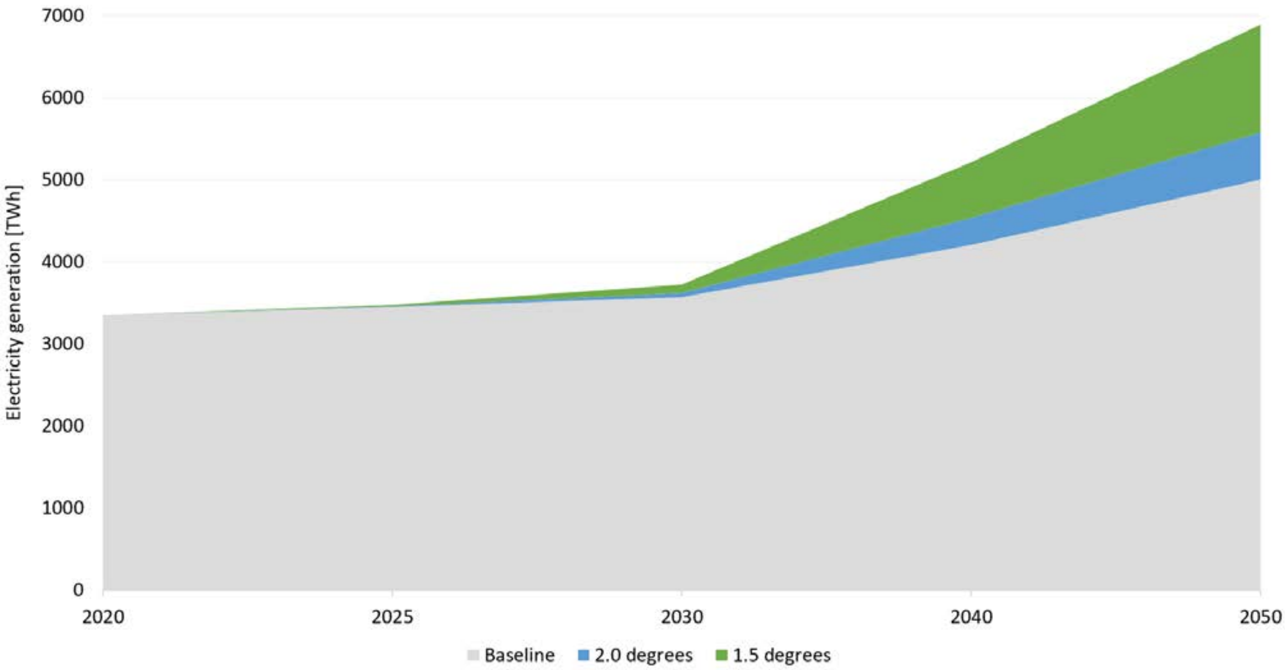


Figure 6.7: Generation levels over the entire considered geography for the three decarbonisation pathways.

enough to dismiss most of the coal capacity already in 2030, even through an anticipation of part of the coal decommissioning commitments (- 31 and - 52 [GW] in the 2.0 and 1.5 degrees pathways respectively). Natural gas is a cleaner fuel: in 2030 9 and 15 additional [GW] are installed in the 2.0 and 1.5 degrees pathways respectively; a small amount of the coal capacity set aside in the short-term is also substituted by natural gas units. At very high carbon prices (2040-50) most natural gas power plants would be replaced though: - 47 and - 75 [GW] in the 2.0 and 1.5 degrees scenarios respectively. Unsurprisingly, renewable energy benefits the most from high carbon prices, with solar PV towering above wind. In no year or case, the gap between the solar and the wind columns is inferior to 100 [GW]. A large part of this increase is certainly due to the larger need for H_2 in the two nearly-decarbonised scenarios. If compared to the Baseline, the hydrogen demand in 2050 is 16 and 76 [Mtoe] higher in the 2.0 and 1.5 degrees setups respectively; yet, the capacity increase is 416 [GW] in the 2.0 degrees scenario, while it stops at only 1080 [GW] in the 1.5 pathway. The non-linear relationship can be motivated by: a larger usage of hydrogen storage, which turns out to be cheaper than building new power capacity; on average, higher full load hours of the technologies installed in the 1.5 degrees scenario; a greater recourse to electric storage (right side of Figure 6.8 and Table 6.2). The installed loading capacity of the latter grows by 186 and 386 [GW] in the 2.0 and 1.5 degrees scenarios respectively (2050). Apart from the low investment cost, the success of solar PV is ascribable to the steeply descending cost trend of batteries (BESS).

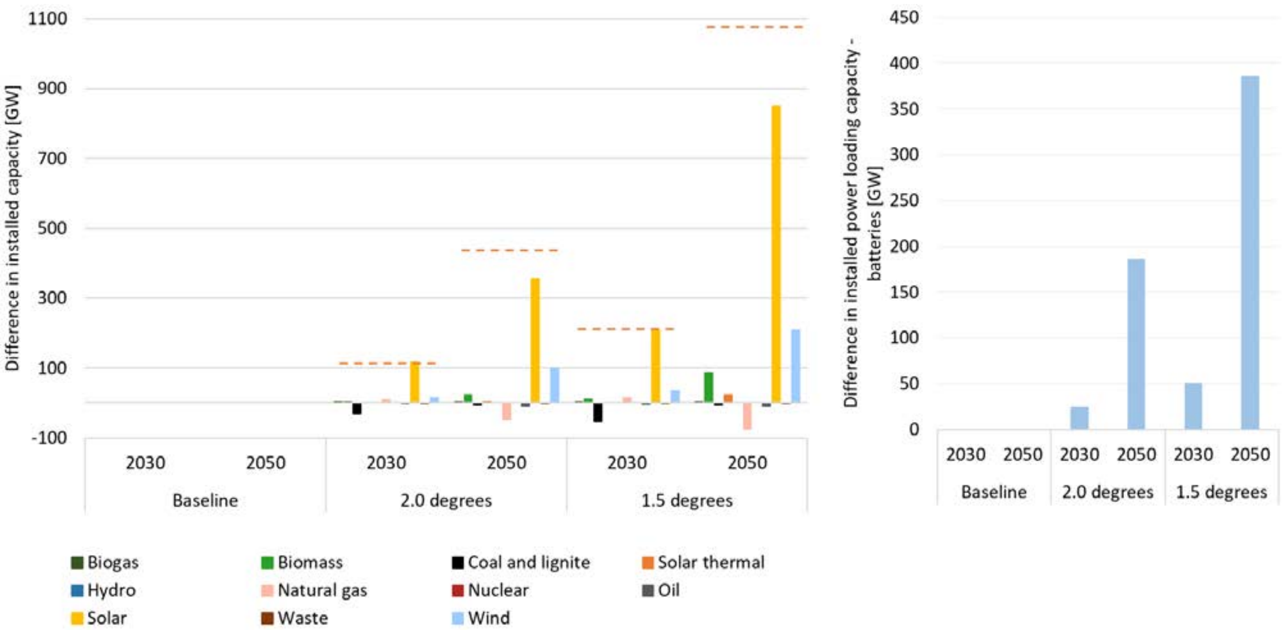


Figure 6.8: Comparison between installed power capacity in the Baseline and in the two decarbonisation pathways. Data is for 2030 and 2050 and for the entire Europe. Left: generators. The dashed lines refer to the net capacity increase; right: electric storage.

It is interesting to notice that this aggregate data hides non-uniform transformations at national level. Table 6.2 carries the detailed increase in PV and BESS installations for the five Gridsol countries in 2050. In those, new PV units constitute 43 and 46 % of the total new solar capacity for the 2.0 and 1.5 setups respectively; conversely, the share of new BESS in Southern Europe on the total new electric storage capacity varies from the 28 % of the 2.0 degrees setup to the 38 % of the 1.5 degrees scenario (suffice it to match Table 6.2 and Figure 6.8). In Greece, Spain and Portugal new PV plants are built along with new storage, while for France and especially Italy the correlation is weaker. This is partially due to lower PV full load hours in these two countries, but particularly to the different function PV fulfils. Where the technology FLH are the highest (that is in Spain and Greece, Table 4.3) the joined action of photovoltaics and batteries supplies power also in hours of no irradiation, whereas where the solar resource is poorer (Italy, France) this tendency is less evident and power is mainly produced and dispatched to meet the load immediately. Portugal has also very high full load hours, but the country takes advantage of the neighbouring Spain where the resource is better: power is able to flow from one country to another thanks to cross-national transmission lines. The interconnection capacity totals up to 4200 [MW] already in 2020 for flows from Spain to Portugal [53]. This strong bond causes no or little effect on new solar PV installations in Portugal.

Table 6.2: Increase in installed power capacity (power loading capacity for BESS) in the five Gridsol countries in 2050. Units: [GW].

	2.0 degrees		1.5 degrees	
	Solar PV	BESS	Solar PV	BESS
France	+ 65	+ 14	+ 142	+ 27
Greece	+ 16	+ 12	+ 35	+ 23
Italy	+ 51	+ 2	+ 102	+ 7
Portugal	0	0	+ 11	+ 8
Spain	+ 19	+ 24	+ 99	+ 83
Total	**+ 151**	**+ 52**	**+ 389**	**+ 148**

Table 6.3: Biomass and CSP capacity for the two decarbonisation pathways in 2050.

Pathway	Biomass [GW]	Solar thermal (CSP) [GW]
2.0 degrees	22	3
1.5 degrees	86	23

While in Greece and in the Iberian peninsula solar PV and batteries turn into semi-dispatchable groups, Balmorel deems other units to be more cost-effective for base and intermediate load supply in Italy and France. Figure 6.8 displayed also minor installations of biomass and solar thermal capacity: the exact values for 2050 are reported in Table 6.3. A large part of the new biomass plants and all the solar thermal units are situated in Southern Europe. In fact, the revision of the exogenous inputs (CO_2 price and H_2 demand) brings notable changes in the generation mix of the five Gridsol countries; in Figure 6.9 a comparison with the Baseline is drawn for 2050 (see also Figure 6.4). The rise in gross electricity demand coupled with high carbon prices requires new investments; this mix of exogenous inputs proves to be attractive for CSP in France and Italy, which are the only countries with new solar thermal power plants. The chart shows at the same time how the natural gas capacity is substituted and which technologies contribute to produce the extra electricity needed to feed the electrolysers. It is interesting to notice that also nuclear energy is affected by the presence of a larger amount of renewables. While its installed capacity remains stable (Figure 6.8), its generation is partly cut in favour of solar PV, biomass and CSP.

The very low cost of solar panels - joined with that of batteries - makes PV take over also other renewable sources, wind for instance. In Greece and Spain the generation from wind is reduced in both the 2.0 and 1.5 degrees scenarios, while in Portugal and especially in France its contribution to the new demand level is positive. This last country has in fact less favourable solar resources than the rest of Southern Europe.

The H_2 demand profile is flat and common to all pathways, only the generation level changes; hence, it can be stated that an increase in the gross electricity demand (which has a certain degree of *flexibility* since hydrogen can be stored) favours solar PV, biomass power plants and CSP in France and Italy, while it penalises wind energy. A reduced wind penetration can be noticed also in Portugal and Spain, where only photovoltaics take advantage of the context. This can be easily inferred from a comparison between the 2.0 and 1.5 columns in Figure 6.9.

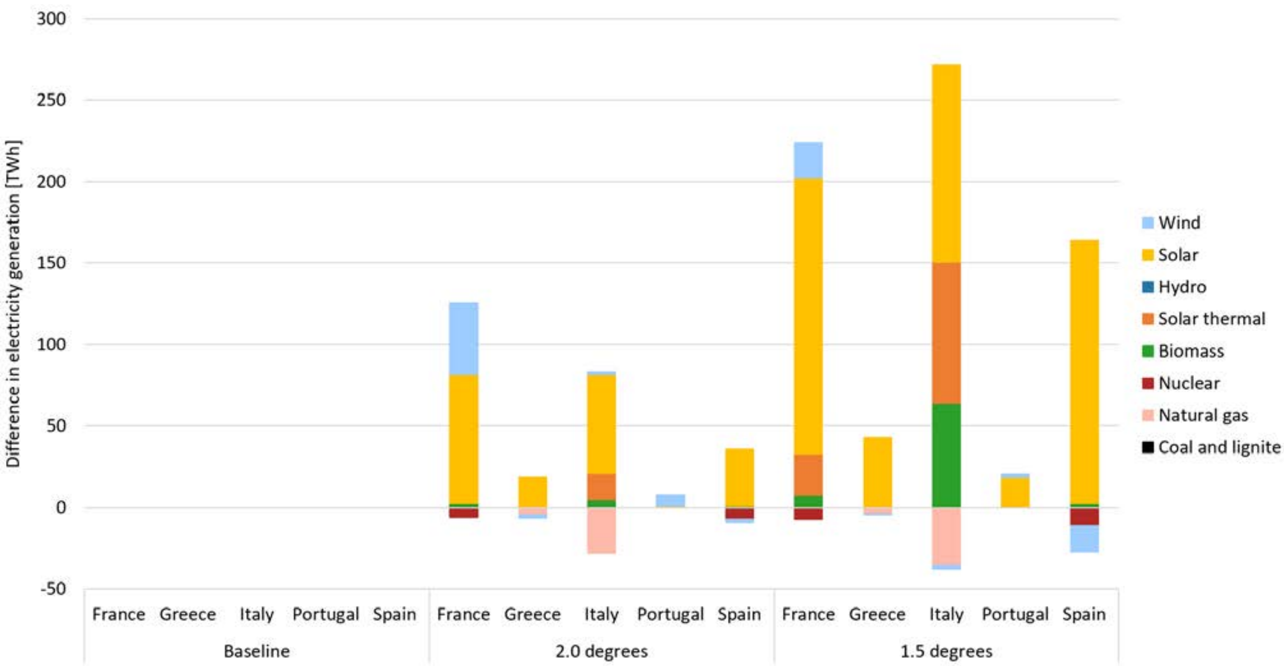


Figure 6.9: Difference in electricity generation per fuel type with respect to the Baseline for the five Gridsol countries. Year: 2050.

While France leads the Southern European countries in terms of extra generation in the 2.0 degrees pathway, the situation is overturned in the 1.5 setup. Italy enhances the extra national production (with respect to the Baseline) to a level higher than that of France, and to a great extent this goes to the benefit of biomass and CSP. By analysing the flows out of the two countries (Table 6.4), it can be seen that Italy diminishes its dependency on imports in a context with high CO_2 prices and a growing demand, while France exports more in the 2.0 degrees setup than in the 1.5 pathway. This can once again be inferred from Figure 6.9: the H_2 request is four times bigger in the 1.5 degrees pathway, yet the net increase in generation is visibly lower for France. These findings suggest that:

- regardless of the cause, boosting the gross electricity demand goes to the advantage of solar PV in any Gridsol country and in Europe in general;
- wind energy is penalised where the solar resource is high;
- in two countries, France and Italy, CSP finds a fertile ground. This is more notable in Italy as a larger gross demand incentives the national production and reduces imports. In other words, the installation of new power plants within the national borders is more attractive than expanding the transmission grid linking Italy and the neighbouring countries. Incidentally, France and Italy have the lowest full load hours for solar PV among the five Gridsol country (Table 4.3).

Table 6.4: Net flow out of Italy and France in the three pathways (2050).

	Baseline		2.0 degrees		1.5 degrees	
	France	Italy	France	Italy	France	Italy
Net flow out [TWh]	86.7	-80.5	137.4	- 76.5	89.1	- 52.8

6.3.2 Electricity prices

Besides incentivising renewable energy installations, steep growths in the carbon price create zones within the continent where the electricity price moves away from the EU average, which is reported in Figure 6.10 for the Baseline, the 2.0 and 1.5 degrees pathways. Decarbonisation requires additional investments that make the total system costs rise. A price boost occurs until 2025 no matter the assumptions behind the trajectory, while there is a tendency towards an either slight or pronounced decline from 2025 onward. This is due to notable cost reductions for generation and storage technologies and their growing share in the power sector (suffice it to remember the amount of storage installed in the Baseline in 2040 and 2050, Figure 6.6, but a similar trend characterises also the 2.0 and 1.5 pathways). The continuous pressure of high carbon prices on fossil-fuel power plants prevents the electricity price from decreasing, as the few remaining conventional units enter the market with high short-run marginal costs of generation. Moreover, a relatively big hydrogen demand in a decarbonised context promotes the use of clean but capital intensive technologies where the solar resource is not good enough. Examples have already been found in CSP and biomass power plants. The cost of building an almost entirely decarbonised system is evident in the persisting gap between pathways; in 2050, the Baseline brings the total European emissions down to 108 [Mt], only 76 [Mt] above the 1.5 degrees pathway, yet the average EU price is 13 [EUR/MWh] higher. The gap between the 2.0 and 1.5 degrees scenarios is even more impressive: the two are separated by just 6 [Mt] of CO_2 emissions at the end of the investigated horizon, but there exist a gap of 5 [EUR/MWh] in the average spot price between them. The cost of eliminating the last units of CO_2 is significant.

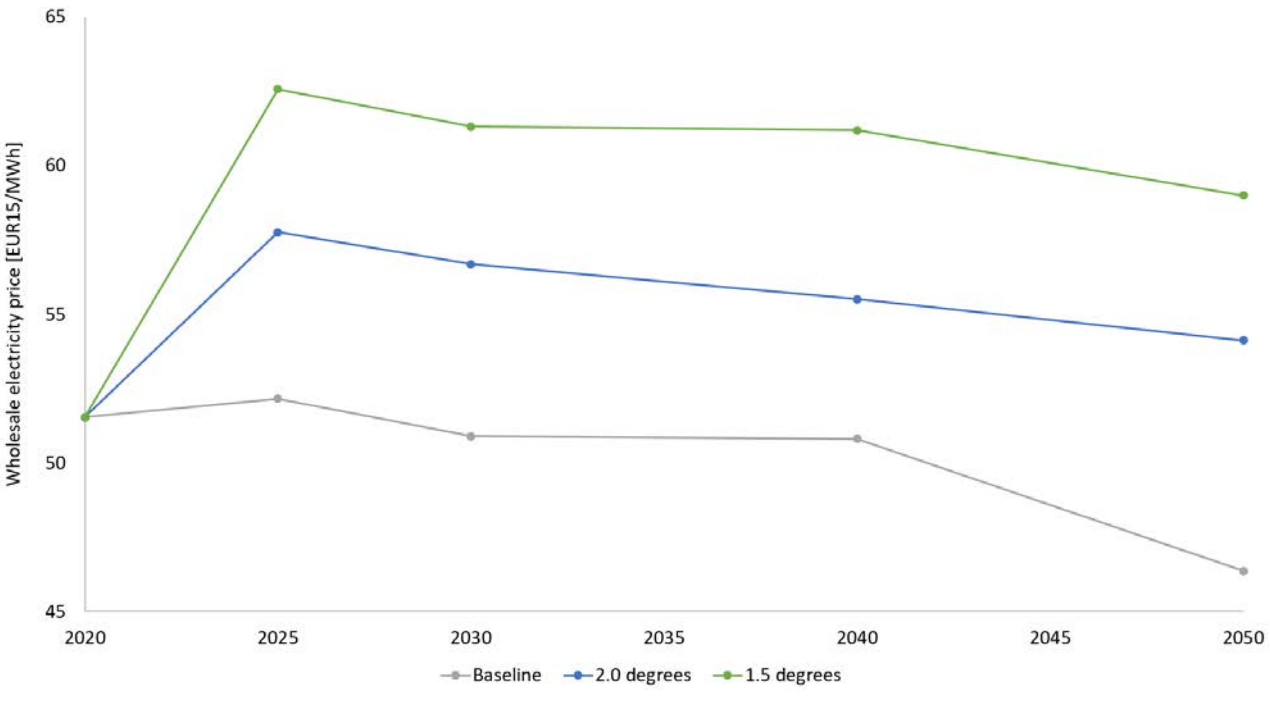


Figure 6.10: Average spot prices in Europe across the Baseline, the 2.0 and 1.5 degrees pathways.

The aggregate picture gives yet again a partial view on the dynamics within Europe. Figures 6.11 and 6.12 zoom on the Gridsol countries and relate the spot price throughout the investigated horizon to the EU average. The analysis distinguish between Iberian countries + Greece and Italy + France. Spain, Portugal and Greece are in fact characterised by sensibly lower spot prices than the EU average in the long-term. The gap is as big as 19 [EUR/MWh] in the 1.5 setup for Spain, whose average 2050 spot price does not exceed 40 [EUR/MWh] even in a high CO_2 price setting. The large amount of installed solar capacity coupled with the absence of fossil-fuel units make Greece and the Iberian peninsula two zones with relatively low market prices and reduced exchanges with the rest of the European system. Table 6.5 shows that the volume of energy flowing out of Spain towards France decreases in highly-decarbonised scenarios, but remains roughly 50 [TWh] bigger than the volume flowing from France to Spain; overall, the exports from Spain are approximately four to five times bigger than the energy the country imports. The solar resource in Spain is stronger than in France (Table 4.3) and the model deems the construction of new interconnectors between the two countries to be the least expensive solution for the system. Balmorel identifies in 12 [GW] the optimal capacity expansion over the French-Spanish border in the Baseline scenario and in 6 [GW] the reinforcements in the 2.0 and 1.5 degrees setups. This is more than twice the 5 [GW] of capacity that should be available in the very next years according to ENTSO-e, which has already planned a further 3 [GW] increment (both ways) before 2035. The upgrade would bring the total interconnection capacity to 8 [GW] in less than 15 years [53]. Portugal would benefit from the higher solar resource in Spain and from the already existing 4200 [MW] of interconnection capacity, which are enough to transfer the power reported in Table 6.5 under any scenario. Greece has one common feature to Spain and Portugal, that is relatively high full load hours for solar PV. These are enough for the combination of photovoltaics and batteries to constitute a semi-dispatchable group, which drives the average national price down.

Table 6.5: Exports from and to the Iberian countries in 2050 across all scenarios.

	PT → ES	ES → PT	ES → FR	FR → ES
Volume of exported energy - Baseline [TWh]	4.1	12.1	82.5	19.6
Volume of exported energy - 2.0 degrees [TWh]	3.2	13.4	63.5	13.6
Volume of exported energy - 1.5 degrees [TWh]	5.2	18.1	60.0	11.1

Costly peak-load technologies are progressively pushed out of the Iberian system, while the

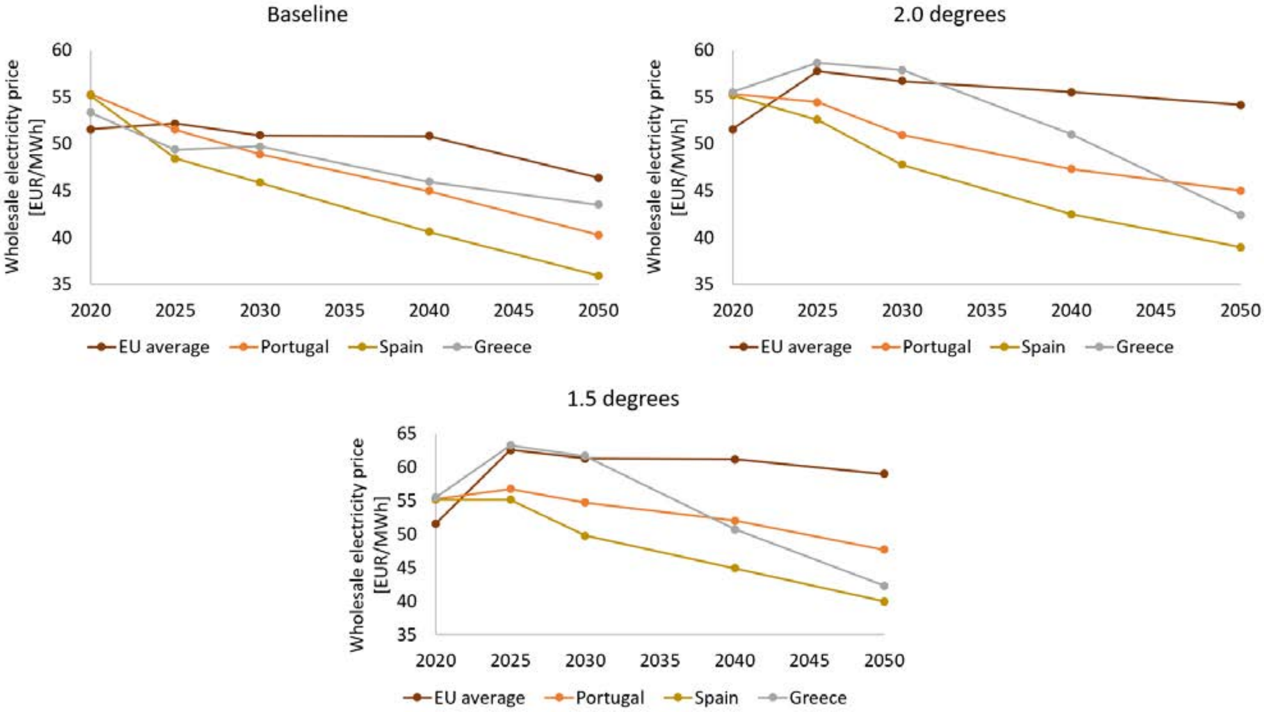


Figure 6.11: Average spot prices in Spain, Portugal and Greece across the Baseline, the 2.0 and 1.5 degrees pathways. Comparison with the EU average.

mix of wind and solar installations sustains the peninsular demand with the aid of batteries: these results stress the strength of solar PV in Spain. The picture appears different for France and Italy (Figure 6.12). The EU average spot price is generally lower than in any of these countries. Italy is firmly above the EU curve, with a peak in 2030 regardless of the pathway: in the 1.5 degrees scenario the gap is 8 [EUR/MWh], but it narrows as the system gets to 2050 (6 [EUR/MWh] at most, 1.5 degrees setup). The Italian system is highly influenced by the natural gas share, biomass and the imports; these aspects have actually characterised the peninsula already in the recent past [63]. The average 2050 price at which combined cycles sell energy in Italy (Market Value) is 206 [EUR/MWh] in the 1.5 degrees trajectory, 116 [EUR/MWh] for biomass. The first accounts for 0.5 % of the total generation, while the second for 12.3 %. France mainly benefits from cheaper nuclear energy in the short-term (a trough is reached in 2030 in all pathways: it is the only year where France has market prices comparable to the EU average in every scenario), but the average generation costs always exceed those of Italy in 2050. In this case, it is mainly hydropower and nuclear that rise the average spot price. The latter runs too little to cover relatively high operational expenses, selling energy at over 90

[EUR/MWh] and accounting for 15 % of the total generation. This data is for the 1.5 degrees scenario. The detailed generation mix is omitted here for brevity, but can be found in the Appendix C (Figure C1).

It is worthy to underline that a low average market price drives down also the average market value of a generator; hence, an overview on the spot prices allows to grasp how large a margin a new technology has for covering its LCOE in a specific year.

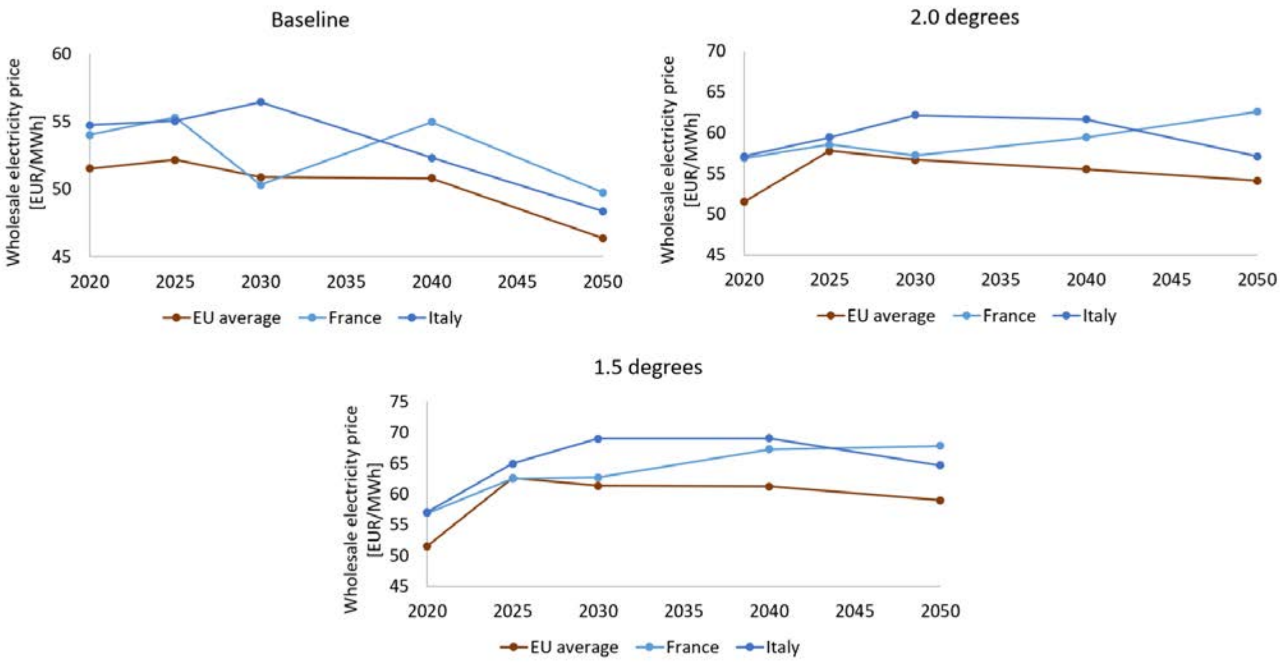


Figure 6.12: Average spot prices in France and Italy across the Baseline, the 2.0 and 1.5 degrees pathways. Comparison with the EU average.

Figure 6.8 laid bare a low penetration of CSP, which increases its capacity from the 0 [GW] of the Baseline to the 3 and 23 [GW] of the 2.0 and 1.5 degrees scenarios respectively. Its contribution in such decarbonisation pathways is modest: the next Section expands on this topic and analyses the configurations that make CSP a profitable technology in France and Italy. The results presented up until this point have illustrated the weak influence of high carbon prices jointly with a demand increase on a possible CSP deployment in Europe. The reasons can be summarised in the following:

- the largest part of the emission reduction occurs at medium-range carbon prices, roughly below 100 [EUR/t]. Given the designed trajectories, more than 80 % of the 2020 power sector emissions ($\sim$ 1000 [Mt]) are cut before 2030 (Figure 6.1), when CSP costs are not competitive with other base-load and peak technologies. CSP can rather expand the generation fleet in the long-term in case of higher electricity needs and hence new clean capacity;

- solar PV units and batteries are likely to experience a substantial cost decrease in the next 30 years. The two coupled together drive the system towards decarbonisation in the Gridsol countries (Spain and Portugal are carbon-free by 2050 in both the 2.0 and 1.5 degrees scenarios, Figure 6.2) and guarantee flexibility to the system. Demand in hours of no production is covered by the power first accumulated and then released by the electric storage. This semi-dispatchable group proves to be the least costly solution to decarbonise the power sector in countries with high solar PV full load hours (Greece, Portugal and Spain have more than 1400 FLH at present, an amount that rises by 13 % in 2050 for the assumptions summarised in Table 4.5);

- as a result from the preceding point, CSP turns out to be more attractive in areas with lower FLH (France, Italy), where they supply base-load power along with biomass and nuclear. These have higher LCOEs and short-run marginal costs of generations, so that a capital intensive technology like CSP finds room in the national mix. In the long-term, the average spot price is too low to pay the CSP investment back in Greece, Portugal and Spain.

6.3.3 CSP and Gridsol: the impact of a higher gross demand and high CO_2 prices

This Section analyses the configurations and technical features of the CSP installations in the 2.0 and 1.5 degrees pathways. In the presentation of the results, the components are referred to as 'CSP field', 'thermal storage', 'gas turbine' etc. even in the case of high installed capacities (> 1 [GW]). In these cases the capacity is supposed to be spread over different power plants; the Balmorel model is linear and sizes are scalable.

The Gridsol hub composed of a CSP block and a gas turbine does not find room in the two scenarios: high CO_2 prices (and therefore high natural gas/biogas prices, Section 5.2.3) do not constitute a fertile ground for gas engines to operate, as the fuel cost is prohibitive. This comes at no surprise, since Figure 6.2 has underlined that the cost of emissions is too high for investments in fossil-fuel power plants to be profitable. This is valid under the assumptions of Equation 5.1.

As already mentioned, Italy and France are the only countries with CSP investments; therein, the technology appears only in 2050 in both the 2.0 scenario (Italy), but already in 2040 in the 1.5 degrees setup. In this last pathway, CSP becomes profitable also in France to a lesser degree (2050). The installed power capacity is visually summarised in Figure 6.13, whilst Table 6.6 reports the the exact values and further elaborations.

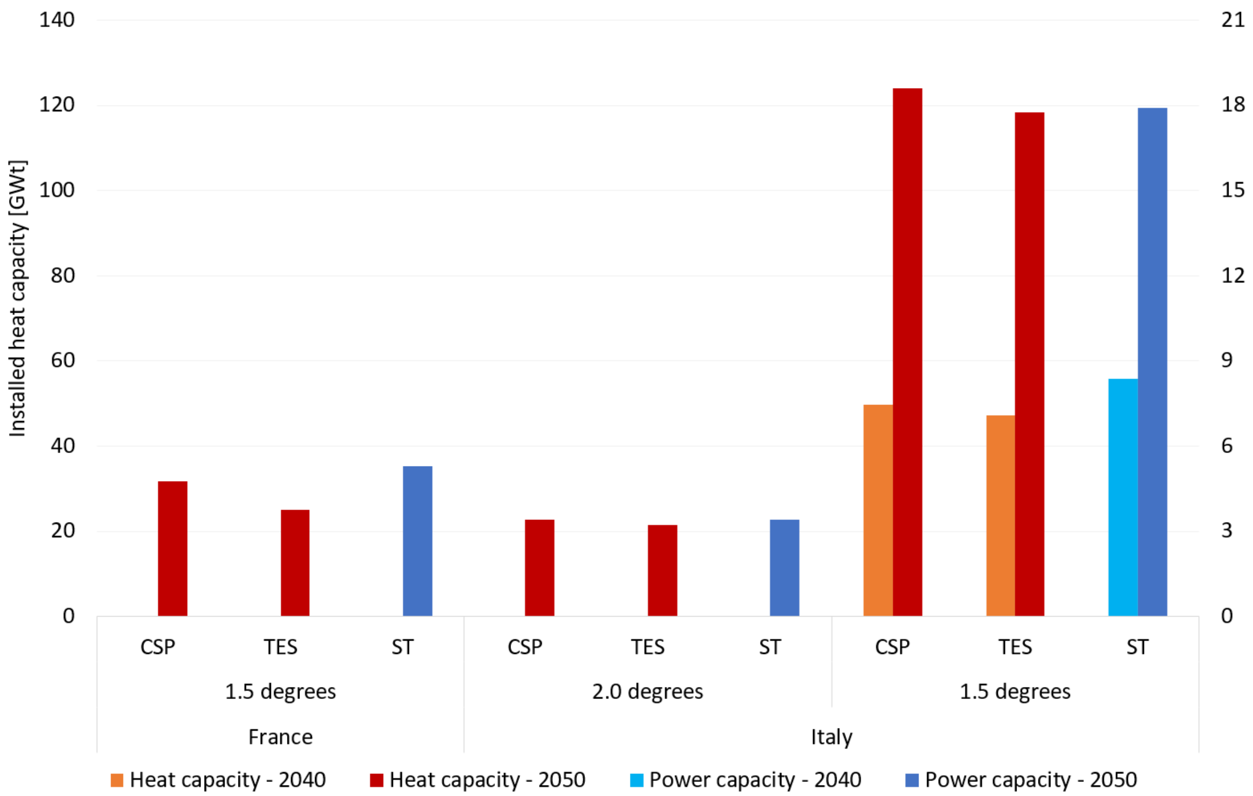


Figure 6.13: Installed CSP capacity in the 2.0 and 1.5 degrees pathways.

The installed power capacity totals up to 3.4 and 23.2 [GWe] in the 2.0 and 1.5 degrees scenarios respectively. The installations are strictly dependent on the high CO_2 prices and on the demand increase due to hydrogen. In Figure 6.12 it was shown that the rapid growth in carbon prices occurring in the decade 2020-30 causes both the average EU and the Italian electricity price to soar in 2030; a stabilisation or small decline follows on until 2040 for the two curves. The projected cost reduction in the decade 2030-40 coupled with the above-mentioned steady electricity price and the increasing hydrogen need make CSP attractive already in 2040 in Italy (1.5 degrees setup), while in France the average market price is still too low in the same year. In 2040-50, the average price surges in France (up to 68 [EUR/MWh]) and CSP appears also there. In the 2.0 degrees pathway the 2050 French price of 63 [EUR/MWh] is not enough for CSP to appear. Clearly, the average spot price is not the only indicator to keep into consideration, as the CSP profitability depends also on the plant characteristics. In particular, the LCOE is strongly conditional on operational details, especially on the full load hours (FLH). These decrease the LCOE as they boost the production (Equation 2.1). Table 6.6 shows that in no case the CSP steam turbine produces for less than 4000 equivalent hours at full capacity, i.e. that the profitability of CSP is linked to its role as an intermediate/base-load supplier. The electricity FLH rise up until 5518 in Italy in 2050 (1.5 degrees setup).

Table 6.6: Technical features of CSP installations in France and Italy.

	2.0 degrees	1.5 degrees		
	2050	2040	2050	
	Italy	Italy	France	Italy
Installed heat capacity (CSP field, cumulative) - [GWt]	22.7	49.8	31.8	124.1
Storage volume (cumulative) - [h]	20.5	17.4	15.5	21.5
Installed power capacity (cumulative) - [GWe]	3.4	8.4	5.3	17.9
Solar multiple (cumulative) [-]	2.70	2.42	2.45	2.82
Electricity FLH (cumulative) [h]	4698	4124	4762	5518

CSP can turn into a base-load technology when coupled with large-sized thermal energy storage (TES). Its volume exceeds 15 hours in any case, reaching 21.5 [h] in Italy in 2050 (1.5 degrees setup). This means that in the long-term CSP may take advantage of the low overnight cost of sensible heat storage to build a facility that can maintain the nominal power output for almost a day in absence of irradiation. These results are aligned with other findings insisting on the value of large thermal energy storage, over 10 [h] at present and projected to further increase in the future [34] [57] [58] [60] [61]. Large TES grounding on sensible heat are intuitively a key for CSP to spread: they currently are and will likely be cheaper than electric storage in the forthcoming years [62]. In Europe and especially where irradiation is not as good as in other locations, large storage volumes grow in importance; base-load service is the key for CSP to deploy, given the fierce competition with photovoltaics. The rather high solar multiples reaffirm this statement, and suggest that CSP fields should be largely oversized with respect to the nominal turbine output. This aspect becomes more evident in 2050 in Italy, where the nominal thermal output of the CSP field is 2.7 to 2.82 times the nominal thermal input of the turbine, depending on the scenario.

6.4 A different price trajectory for biogas

The outcomes from the '1.5 degrees biogas' scenario are discussed in the following. Aside from the biogas price - which is the object of this sensitivity analysis - the setup is shared with the 1.5 degrees pathway, and so are the main results previously described. The focus here is on CSP and Gridsol.

The alternative biogas trajectory presented in Section 5.2.3 imposed a cap on the biogas price, obtained from the projected costs of methanisation (upgrading) for the years to come. With this setup, in no case can the 'Gridsol gas' costs exceed 17.45 [EUR/GJ] (2020 value). An overview on the effects of this new condition are presented in Figure 6.14, which shows the cumulative installed capacity in 2050 for each country. The revised biogas price trajectories lead to the installation of a considerable amount of gas capacity, that in every situation exceeds that of the steam turbine. The picture varies from country to country; hence the specific national generation mix constitutes the basis to understand these results. The French and Italian power sectors are rather diverse (see Figure 6.3). Italy relies on natural gas in absence of high prices and, as for every other country, its future development is conditioned by the existing installations. The Italian natural gas capacity should gradually decrease in the long-term, starting from a value over 40 [GW] in 2020 [64] (the Balmorel model identifies it in 45.7 [GW]); in case of relatively low natural gas prices (2.0 degrees pathway), a part of the combined cycle fleet (10 [GW]) is still available in 2050, as the alternatives to these peakers are more expensive. In the 1.5 degrees pathway, such competitive advantage disappears: the existing combined cycles are all shut-down and new gas capacity in the form of the Gridsol gas turbine is built. A similar reasoning to that of Italy cannot be conducted for France (no gas capacity is present), but in this country the gap between steam and gas capacity is the widest; here the Gridsol gas turbine substitutes part of the biomass capacity but especially solar PV. Finally, the Greek generation fleet is found to be only moderately affected by Gridsol; its cumulative installed capacity does not exceed 1.7 [GW].

A comparison with Figure 6.13 is natural. It can be seen that the CSP contribution to the Italian Gridsol hub is contracted, but the hub total power capacity settles at a level slightly higher than in the hypothesis of higher biogas prices. There is another difference between the 2.0 degrees case analysed in the previous Section and the new setup: the available combined cycle capacity is roughly 2 [GW] higher in the previous analysis and the same 2 [GW] are covered by the new Gridsol gas turbine. These results show the great influence of the fuel price on the Gridsol hub configuration and mark how the concept can outperform standard combined cycles, whose 2050 60 % electrical efficiency [44] is not competitive with the Gridsol gas turbine, even if fed with biogas. The Gridsol capacity figures can be seen in Table 6.7.

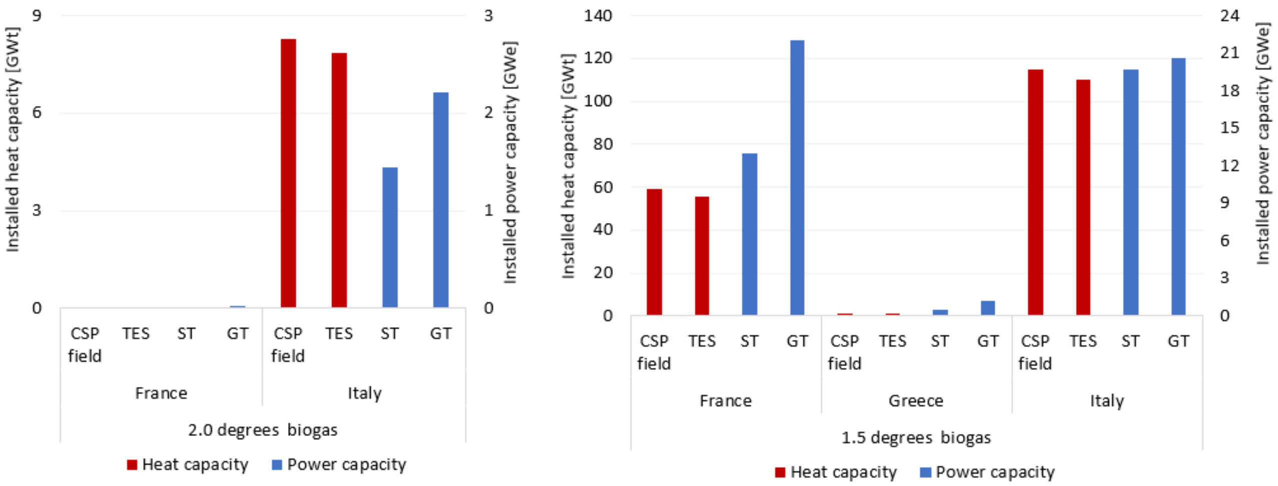


Figure 6.14: Installed CSP/Gridsol hub capacity in the 2.0 and 1.5 degrees pathway (cumulative, 2050).

Table 6.7 summarises also the other characteristic parameters of the hubs. The storage volume is reduced with respect to the previous case (Table 6.6): when the model invests in the gas turbine, this covers moments of peak or of lack of natural resources previously supplied by CSP only; in Italy, the CSP field capacity undergoes even a slight contraction.

The solar multiple definition for such a hub can be ambiguous, as discussed in Section 4.1. In fact, the gas turbine has 0.96 [GWt] of installed thermal capacity for each [GWe]. The difference between the solar multiple calculated under the full and no complementarity principles is an indicator of the gas turbine weight on the steam turbine capacity: this is contained in the case of Italy, but pronounced for Greece and France. In other terms, in these last two countries CSP benefits from the gas units: the last push the former. Suffice it to consider that the CSP field capacity does not vary in Italy with a different biogas price, but it does in the other two countries. In the case of Greece, this is decisive for the Gridsol hub to appear in the generation mix.

Table 6.7: Technical features of CSP and Gridsol installations in a context of low biogas prices. Year: 2050.

	2.0 degrees		1.5 degrees		
	Italy	France	Italy	France	Greece
Installed thermal capacity (CSP field, cumulative) - [GWt]	8.3	0.05	114.7	58.9	1.2
Storage volume (cumulative) - [h]	17.8	10.0	18.3	14.1	7.1
Installed power capacity (ST, cumulative) - [GWe]	1.4	0.02	19.7	13.0	0.5
Installed power capacity (GT, cumulative) - [GWe]	2.2	0.03	20.6	22.0	1.2
Solar multiple (cumulative) full complementarity	2.34	1.31	2.37	1.86	0.92
Solar multiple (cumulative) no complementarity	2.95	2.13	2.78	2.52	1.82

The biogas price has proven to have a notable effect on the profitability of the Gridsol hub, decisive for its appearance in Greece and driving also the CSP field investments in France. In addition:

- the Gridsol hub fed with a clean and relatively low-cost fuel outperforms standard combined cycles;
- the thermal storage volume is generally reduced.

As evident from the rest of this Chapter, this is the only framework where the Gridsol hub composed of CSP and integrating a gas engine enter the European scene. Its hourly functioning is analysed in Chapter 8.

6.5 CSP+ and CSP breakthrough

In this Section, the object of the sensitivity analysis is CSP. It reviews the impact of a consistent decrease in its overnight costs: - 25 and - 40 % in the CSP+ and CSP breakthrough scenarios respectively, for each component of the CSP block. The other assumptions behind these setups are identical to the 1.5 degrees configuration (Figure 5.2). The cumulative installed power capacity reaches 63 [GW] in 2050 in the CSP+ scenario, a number that nearly doubles in case of a further cost drop (115 [GW], CSP breakthrough). Italy towers above the other countries in each setup and year, except in 2050 in the CSP breakthrough scenario, where the total CSP capacity totals up to 50 [GW] in France, 2 [GW] more than in Italy. France is also the only country where a small amount of Gridsol gas capacity is installed despite the high CO_2 prices (0.4 and 0.04 [GW] in the CSP breakthrough and CSP+ scenarios respectively, from 2040 on).

The case of Portugal is extremely interesting, since the country was shown to be unattractive for CSP because of the strong competition with solar PV, the sound bond with Spain and the low spot prices. It is the only location in all scenarios where CSP appears in 2025 (along with Greece, but with a much more modest capacity), helped by the considerable cost reduction of the CSP breakthrough scenario. The 4.1 [GW] of new CSP capacity occur simultaneously with an observed jump from 360 to 9200 [GWh] of exports to Spain (CSP+ vs. CSP breakthrough, Figure 6.16): the reason is to be found in the better DNI resource (Table 4.3), which offsets the transmission costs towards Spain.

The generation shares for the Gridsol countries, reported in Figure 6.17 for the scenarios in object, back up the previous considerations and strengthen the quality of the DNI resource in Portugal, which is the country benefiting the most from the CSP breakthrough favourable costs (60 % of the total national generation, largely exported). Figure 6.17 allows to grasp

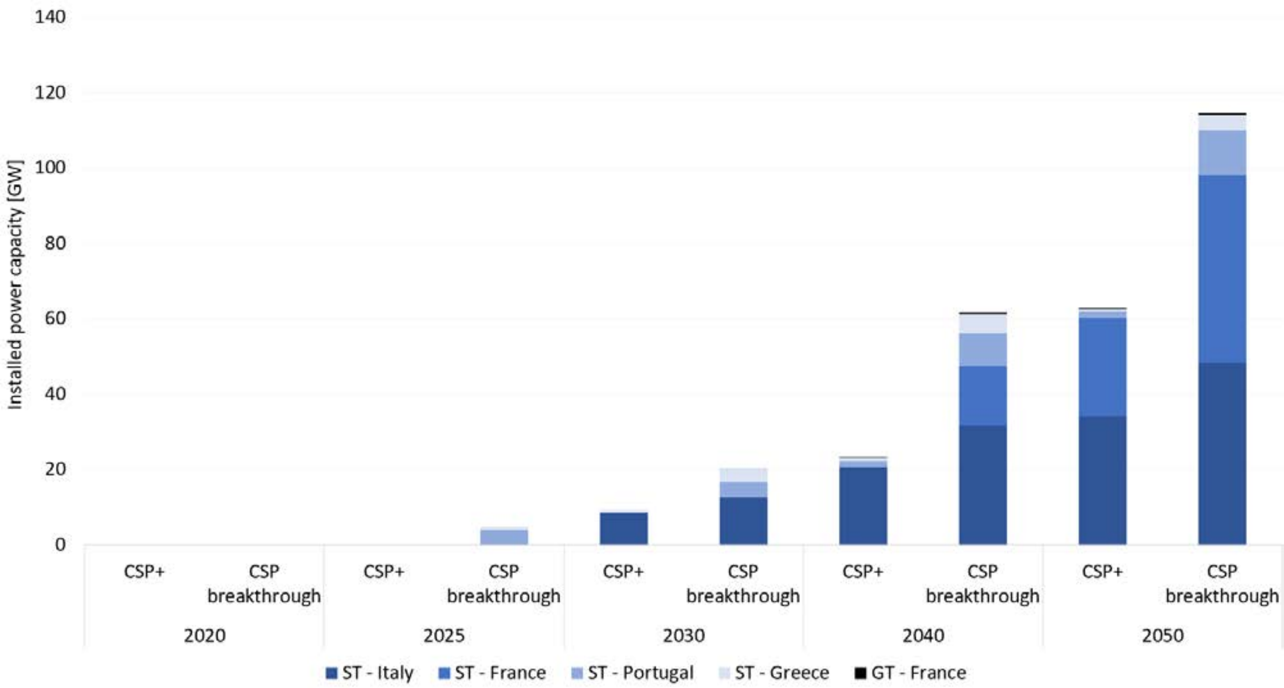


Figure 6.15: Evolution of the installed CSP and GT capacity in the CSP+ and CSP breakthrough scenarios.

which technologies are primarily affected by the spreading of CSP (and, therefore, are its competitors): in all countries, CSP emerges to the disadvantage of solar PV, whose share is consistently reduced. With the exception of Portugal (an odd case), the wind share is left untouched and so is hydropower. Biomass loses a part of its generation and in France nuclear does as well.

The role of CSP as a base-load supplier is also proved by its full load hours development across the scenarios, which has an increasing trend as shown in Figure 6.18. The growth is particularly evident in the CSP breakthrough configuration, i.e. where CSP has a consistent market share. When the cost reduction increases, CSP can boost its full load hours without compromising its market attractiveness, i.e. it remains in the 'profitable region' of a MV-LCOE plane, Figure 6.20.

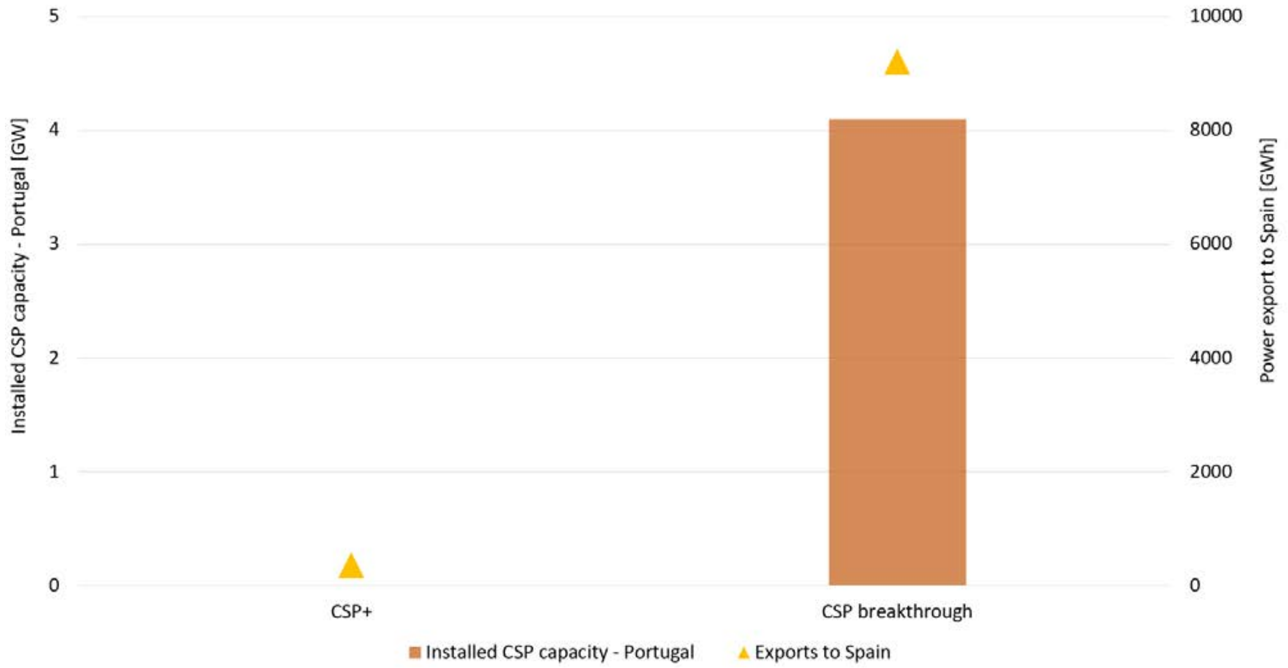


Figure 6.16: Portugal, 2025: the CSP installation occurs concurrently to a jump in the power transfer to Spain.

6.6 Economics of CSP. Competition in the Gridsol countries

The attractiveness of a technology subject only to the market rules is measured by its ability to supply power at a cost that equals or is inferior to that of the marginal unit clearing the market. In reality other mechanisms need to be taken into account, e.g. the strategic behaviour of participants or market imperfections, but as a general rule a unit must be able to at least recover the initial and operational financial outlay over its entire lifetime. In other words, the average market price at which the player sells the electricity it produces (Market Value, MV) must at least match the long-term marginal cost of generation (LCOE). This is true in absence of subsidies and assuming perfect competition in electricity markets.
The results have shown the weaknesses of the Gridsol concept in a setting characterised by high CO_2 and fuel prices. Hence, the discussion that follows concentrate on the economic worth of only CSP. The LCOE definition given in Section 2.1 relates the long-term marginal costs of generation to the fixed and variable expenditures and the energy production; the two determine the competitiveness of any technology at any point in time. More precisely, the parameters

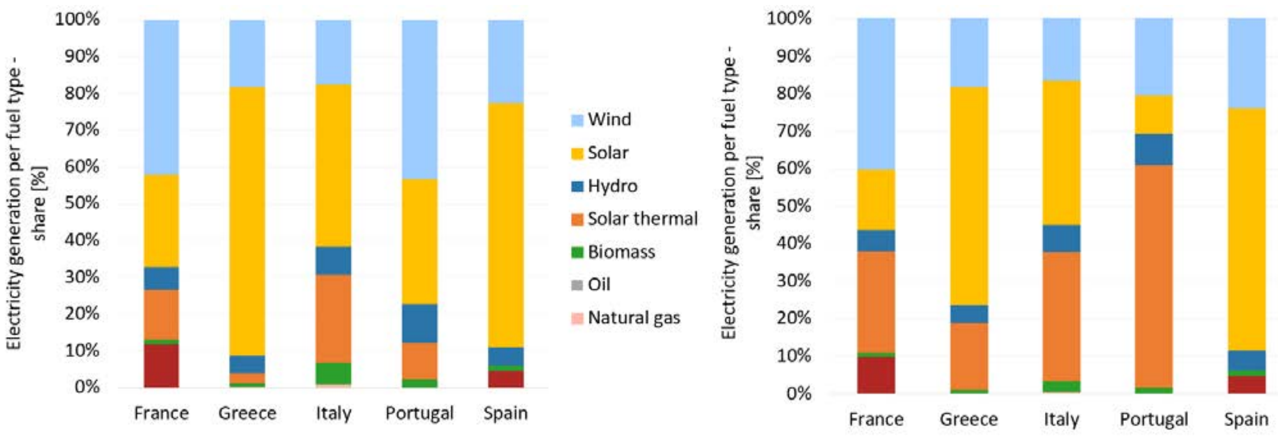


Figure 6.17: Electricity generation per fuel type in the CSP+ (left) and CSP breakthrough (right) scenarios. Data is for 2050 and for the Gridsol countries.

that exert the greatest influence on the profitability of CSP are the overnight expenditures and the turbine full load hours. The latter do not directly contribute to the operational expenses (no variable OPEX is assigned to the steam turbine), yet they influence the yearly energy production at a given installed nominal capacity; it was in fact found and reported in this Chapter that the steam turbine FLH never drop below 4000 [h], i.e. the turbine virtually runs at nominal power for at least half a year.

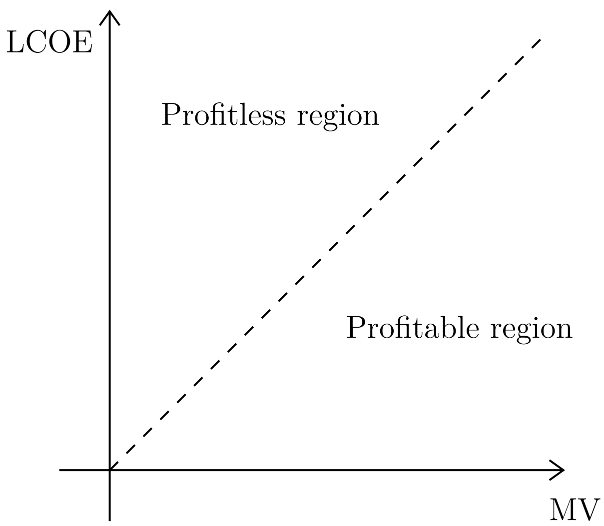


Figure 6.19: In a MV-LCOE plane the profitability of a technology is clearly visualised.

High FLH contain the LCOE of capital intensive technologies, yet they inevitably expose units to periods of relatively low spot prices (this is the necessary consequence of supplying base-load power). This is another argument for considering the relationship between Market Value and Levelised Cost of Electricity, which can be visually inspected with a plane as the one in Figure 6.19. The bisector splits the plane into two regions, the one above being characterised by profitless investment options and the one below by cost-

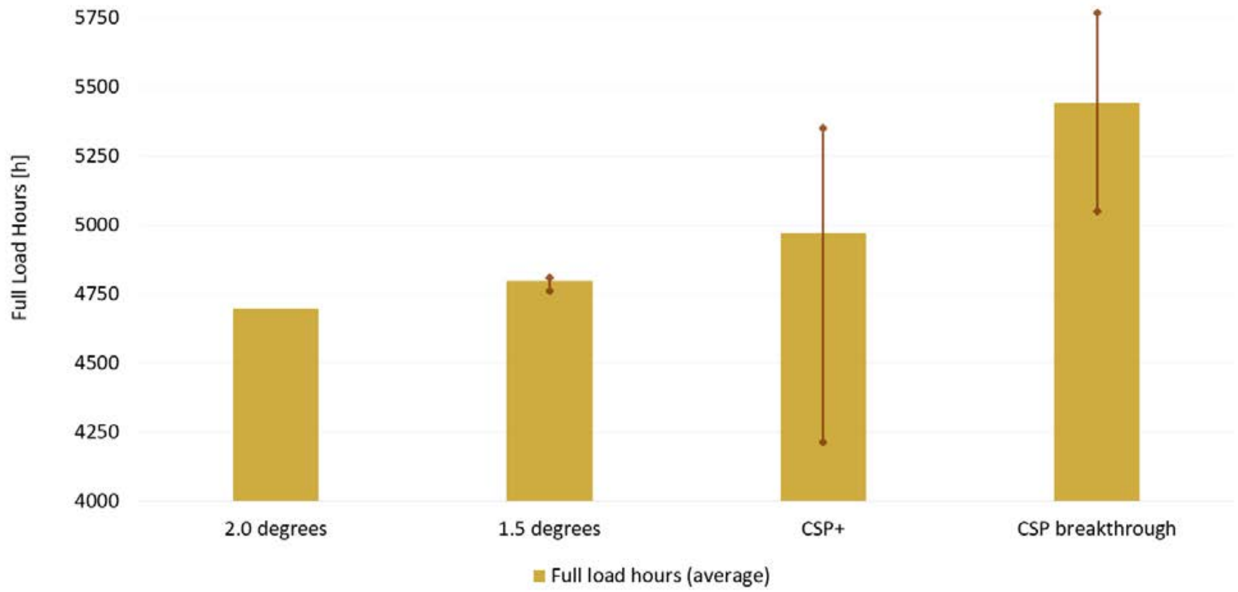


Figure 6.18: Full Load Hours comparison among the four scenarios (averaged over the countries). The tiny bars identify the FLH range in the countries where CSP appears.

attractive opportunities. To include the temporal dimension in the analysis, it is possible to define a parametric curve σ(y) whose components are the MV and the LCOE as a function of the year y:

$$\sigma(y) = (MV(y), LCOE(y)) \tag{6.1}$$

Such curve is defined whenever *MV(y)* exists, i.e. when the model invests on the technology under consideration. Figure 6.20 exemplifies how the plane can be utilised to analyse the market presence of CSP in three cases where it appears. France and Italy are both favourable locations for the technology in the CSP breakthrough scenario, but the operational details are different in the two countries. In France CSP units run for 5285 and 5768 FLH in 2040 and 2050 respectively, while in Italy they settle at 4764 and 5051 FLH in the same years. The higher FLH reduce the Market Value of CSP in France, but they concurrently decrease the LCOE at a faster pace: this is a conclusion that can be drawn by looking at the vertical distance from each point to the bisector, which measures the profitability of the technology in a specific year (earnings per [MWh]). It is also possible to see that lower investment costs make CSP more attractive. The difference can be quantified for Italy in 2050, since the vertical gap to the bisector is 3 [EUR/MWh] larger in the CSP breakthrough scenario than it is in the CSP+.

The parametric curve gives however more information. A key function is the curve discrete *velocity*, which represents how fast the technology moves towards a new (MV, LCOE) point over a specific period of time:

$$\frac{\Delta\sigma(y)}{\Delta y} = (\frac{\Delta MV(y)}{\Delta y}, \frac{\Delta LCOE(y)}{\Delta y}) \tag{6.2}$$

Its module $|\ \Delta\ \sigma$(y)/ Δy $|$ synthesises how fast the technology develops with the years and moves in the context where it operates. When both components in $\Delta\ \sigma$(y)/ Δy are negative (this is always the case in this analysis), a technology acquires attractiveness if the slope LCOE/MV between two years is in $(+1, +\infty)$. In the proposed example, Italy (CSP+ scenario) has the highest velocity between 2040 and 2050; this aspect emerges from the graph. This is not only due to the technological advancements concerning CSP, but also to the system development. In principle simulations can be run for every year, so that the time horizon is densely discretised and the future picture is more complete. In conclusion, the above-described method can give meaningful insights on the future attractiveness of renewable technologies[1].

The LCOE values utilised to construct Figure 6.20 are the outcome of a simplified calculation that assumes the energy production constant over the power plant lifetime. The financial parameters were described in Section 4.3. The LCOE varies greatly with the years, with the scenario and with the steam turbine full load hours: the first two act on the cost component, the second on the energy production. Figure 6.21 visualises how the LCOE for Concentrating Solar Power is consistently influenced by the plant operational details. The blue field identifies which range the LCOE encompasses across all the possible scenarios (from the Baseline to the CSP breakthrough) if the plant runs for 4000 FLH a year; conversely, the yellow field shows how the LCOE values stretch under the hypothesis of 5500 FLH per year[2]. The hypothesised

[1]The definition of the function σ can be extended so as to provide a view of the dynamics in the 'profitless region'. In this case MV is not available, but it can be substituted with the average regional spot price in a specific year. The resulting piece-wise function, defined also when MV(y) is not calculable, can for instance quantify how big the gap is (as measured by the vertical distance to the bisector) for the investment in the technology to break even.

[2]The results have shown that most CSP units run in this range of FLH, regardless of the scenario.

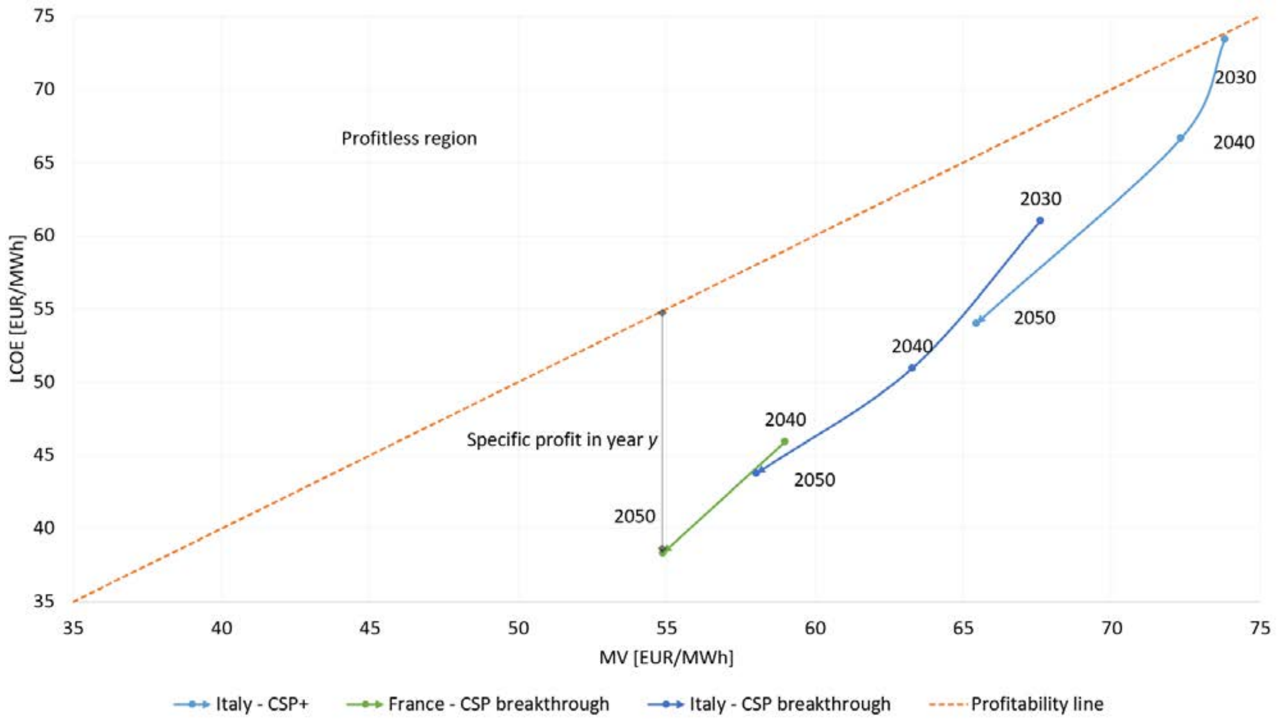


Figure 6.20: Example of use of the MV-LCOE plane with the thesis data (CSP+ and CSP breathrough scenarios).

CSP cost reductions (- 25 % in the CSP+ and - 40 % in the CSP breakthrough with respect to the partners projections) produce bigger effects at low FLH, where the LCOE can range from 109 [EUR/MWh] to 75 [EUR/MWh] already in 2020. The gap between scenarios thins down as the European system heads towards 2050: at this point in time the LCOE spans between 88 and 40 [EUR/MWh] (4000 FLH with partners costs and 5500 FLH with CSP breakthrough assumptions respectively). 40 [EUR/MWh] is the lowest LCOE CSP with thermal storage can attain with the cost trajectories adopted in this thesis and under the hypothesis of high capacity factors. It is interesting to notice that with the same 40 % cost reduction with respect to the partners costs, a drop of 1500 FLH causes the LCOE to rise from 40 to 57 [EUR/MWh] in 2050. As clear from the chart, the two fields partially overlap: the LCOE for a 4000 FLH plant but with the CSP breakthrough assumptions is constantly lower that the LCOE of a unit running 5500 FLH a year at the partners costs.

In light of the foregoing considerations, it is not surprising to ascertain the absence of CSP in the Iberian countries with the costs projected by the Gridsol partners. Figure 6.11 showed that the average spot price can get as high as 50 [EUR/MWh] in the 1.5 degrees scenario in 2050 in Portugal, that is 7 [EUR/MWh] below the lowest LCOE achievable with the partners costs. The price trajectories presented in Figure 6.11 for the 1.5 degrees pathway can be extended also to the CSP+ and CSP breakthrough scenarios, as the system assumptions are identical. Hence, it is easy to justify why Concentrating Solar Power becomes attractive in Portugal at the end of the investigated time horizon (CSP breakthrough scenario assumptions): the average spot price is higher than the LCOE of a high-capacity-factor CSP plant.

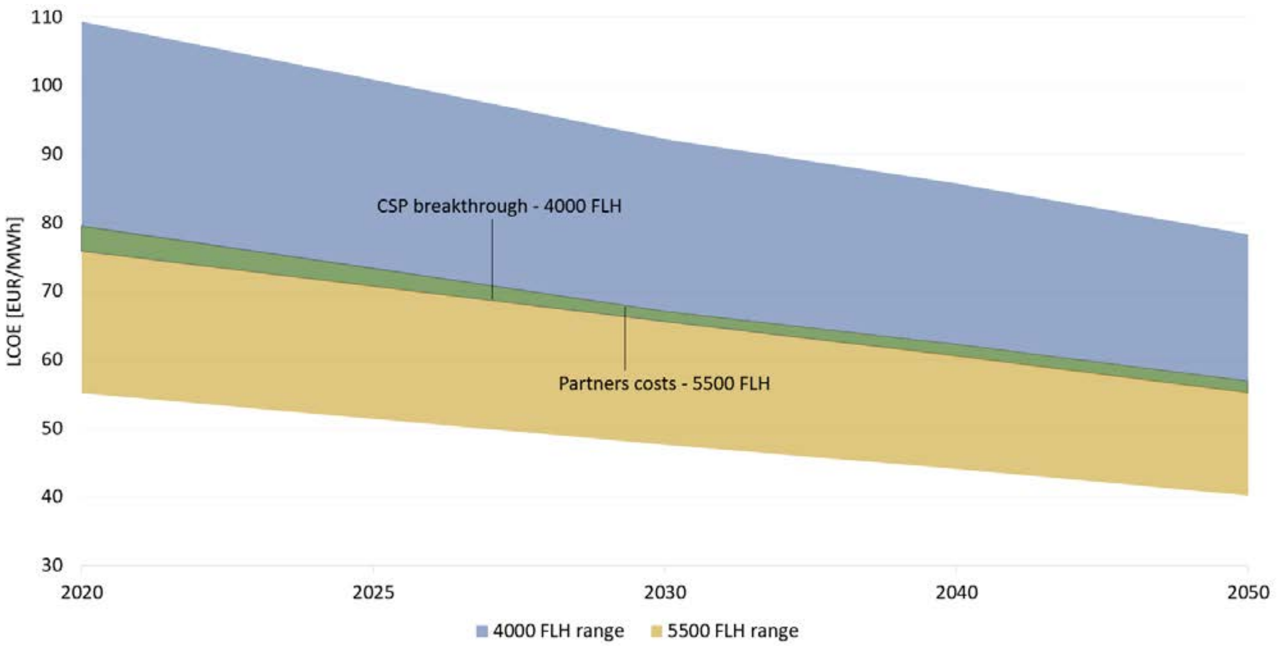


Figure 6.21: LCOE ranges for the CSP technology depending on the scenario and on the steam turbine Full Load Hours (FLH). The storage volume is assumed to be 18 [h] and it only marginally affects the final value.

Chapter 7

Results. Smart Renewable Hubs

7.1 Preliminary considerations

The worth of Smart Renewable Hubs (SRHs) can derive from their ability to carry out auxiliary functions locally (balancing duties, firm production etc.); the same functions would otherwise be fulfilled in other parts of the grid. These are however out of the scope of this thesis, which focuses on the hypothetical hub configuration that minimises the total system costs from a socio-economic perspective. The aspect that differentiates SRHs from the rest of the generation fleet is identified in the reduced grid connection costs (Section 4.2), which are equally subtracted from all the investment options connected to the bus minus one, Section 4.2. However, should the model invest only in a small subgroup of these options, the cost reduction would be unrepresentative of the hub in object[1]; in these cases the results are scarcely significant. In other words, solar PV benefit from a 37 500 [EUR/MW] investment discount in SRHs, but this holds true in reality only if the hub is composed of several units (and not only PV or PV+BESS). Balmorel would in fact take advantage of the component cost reduction with respect to the Main Region to overinvest therein. This process goes on until the costs of investing in new capacity in the Main Region are inferior to the loss (electricity curtailment) due to the limited transmission capacity between the SRH and the Main Region.

[1]When in the SRH Region only one or two technologies, e.g. PV or PV+BESS, are selected, the principle adopted to deduct grid connection costs (four units sharing the connection to the bus) is unmet.

The unwanted overinvestments are certainly present also in case of hubs composed by three or more units, but in this last instance the principle that assigns the cost reduction to the components is reflected into the model choices. To summarise, the investments are thus influenced by a hypothesis whose realisation is uncertain: the next Sections actually show that this hypothesis is rarely verified. The overinvestments in the hub have also an implication on the capacity factors (CFs), which turn out to constitute underestimations (Equation 4.5).
Owing to these reasons, the amount of installed capacity is not reported here. The purpose of this Section is to identify how the hub composition varies with time and with the assumptions underlying the scenarios. Four setups are chosen: the Baseline, the 1.5 degrees biogas, the CSP+ and CSP breakthrough. The next Section reviews the general findings related to these cases.

7.2 General overview

In Figure 7.1 the evolution of the nature of SRHs with time is visualised: a box is allocated to every scenario and year and it is further split into five sub-slots; each of them refers to one of the five Gridsol locations considered for this study.
The phenomena outlined in the introduction to this Chapter appear in a large amount of cases. In 2020, only solar PV benefit from the hub advantageous conditions (regardless of the scenario), while in half of the total number of cases PV and batteries (BESS) seem to be the preferred solution. In these instances, the preset grid connection discount favours only a small sub-group of the investment options and therefore there do not hold the conditions for the existence of a Smart Renewable Hub.
The context is different for the other combinations, where at least three generators arise. There appear four possible configurations, where solar PV and batteries come up beside: wind; the Gridsol gas and steam turbines (GT and ST); wind and the Gridsol gas and steam turbines; only the Gridsol steam turbine. The first and last combinations are most commonly found: the approach tends to penalise hubs with several generators.

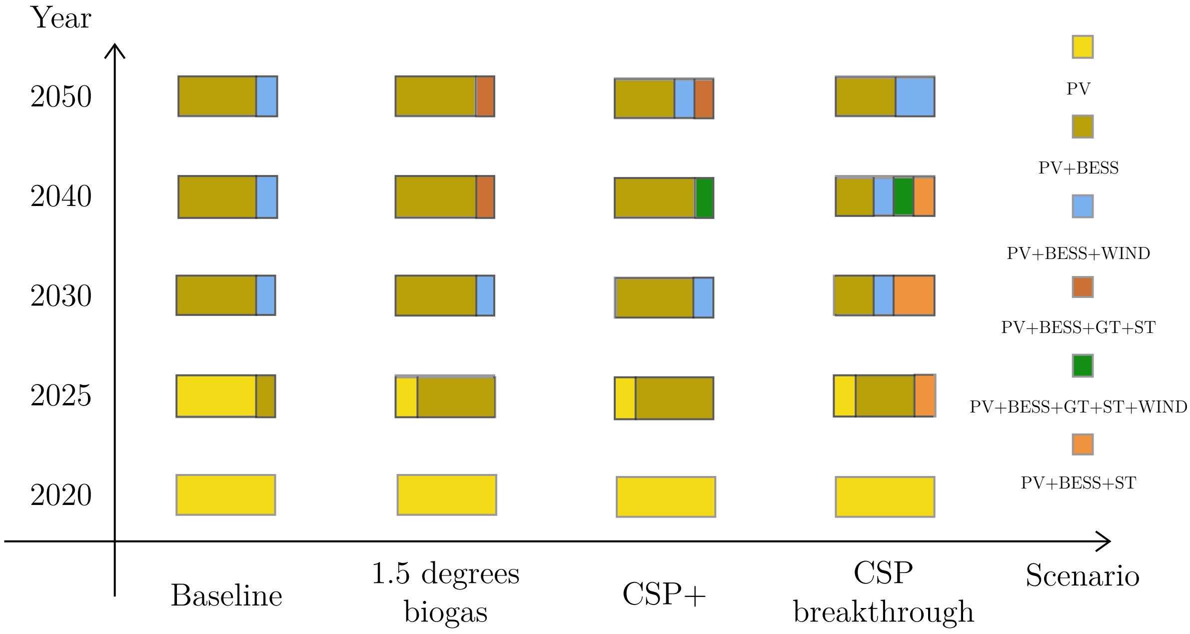


Figure 7.1: Overview of SRHs installations across the four scenarios for the five milestone years.

The couple PV+BESS is challenged as the system progresses towards 2050 and as CSP benefits from investment cost reductions. However, it can be noticed that in the CSP breakthrough scenario, year 2050, CSP is not part of the Smart Renewable Hub. This occurs because:

- despite the large share of CSP in the Main national Region, the largest part of the investments in the technology happen before 2050. CSP is already fully competitive at an earlier point in time (2030-40); the model anticipate the investments in the CSP units and chooses different options for 2050. The outcome is that the existing generation fleet is saturated with CSP in 2050 so that Smart Renewable Hubs, when including technologies other than PV and batteries, contain wind turbines;

- regardless of the circumstances, CSP is penalised by the comparatively higher fixed OPEX with respect to the other technologies, see Table 4.8. For a generic, specific cost discount x [EUR/MW] applied to the investment options within Smart Renewable Hubs, the LCOE can be written as:

$$LCOE = \frac{(I_0 - x) + \sum_{y=1}^{n} \frac{OPEX_y}{(1+r)^y}}{\sum_{y=1}^{n} \frac{E_y}{(1+r)^y}} \tag{7.1}$$

so that the OPEX component is unaffected by this modelling refinement. The LCOE reduction is therefore not linear and uniform for all the hub technologies: options with lower I_0 and lower fixed OPEX have a comparative advantage. This is the case of PV and wind turbines with respect to CSP[2].

In the 1.5 degrees biogas scenario, the relatively low biogas price fosters also the hub investments in the Gridsol technology, but only in the gas cycle. The steam turbine is installed to recover the waste heat from the gas turbine and CSP field installations do not appear. It is possible to state that in such a case PV and batteries come up beside a combined cycle, whose competitiveness is driven by a cost discount that affects both the topping (GT) and bottoming (ST) cycles.

However imperfect, the proposed approach gives an outlook on the evolution of hybrid power plants under different hypotheses and relates the hub investments to the national and European energy mix. In addition, it allows for the analysis of a hub made up of several components. The next Chapter characterises the hybrid power plant output by looking at generation levels and the mutual relationships among components.

7.3 Economics. The example of a five-piece Smart Renewable Hub

This Section gives a concise overview of the cost breakdown for each component in a five-piece Smart Renewable Hub, i.e. made of a Gridsol gas turbine, a CSP block, wind turbines, solar PV and batteries. The specific costs shown in Figure 7.2 refer to one unit of installed power capacity; in the case of Gridsol this means the sum of the gas and steam capacity. 28 % of the total Gridsol costs are due to the gas turbine alone; nevertheless the total figure remains consistently higher than that of solar PV and batteries. A relevant part of the total Gridsol costs is due to the fixed O&M assigned to the steam turbine.

[2]Wind turbines pay also the existence of variable OPEX, but an easy calculation can show that the sum of the fixed and the variable components is always inferior to that of a steam turbine, no matter how high the wind turbine full load hours are.

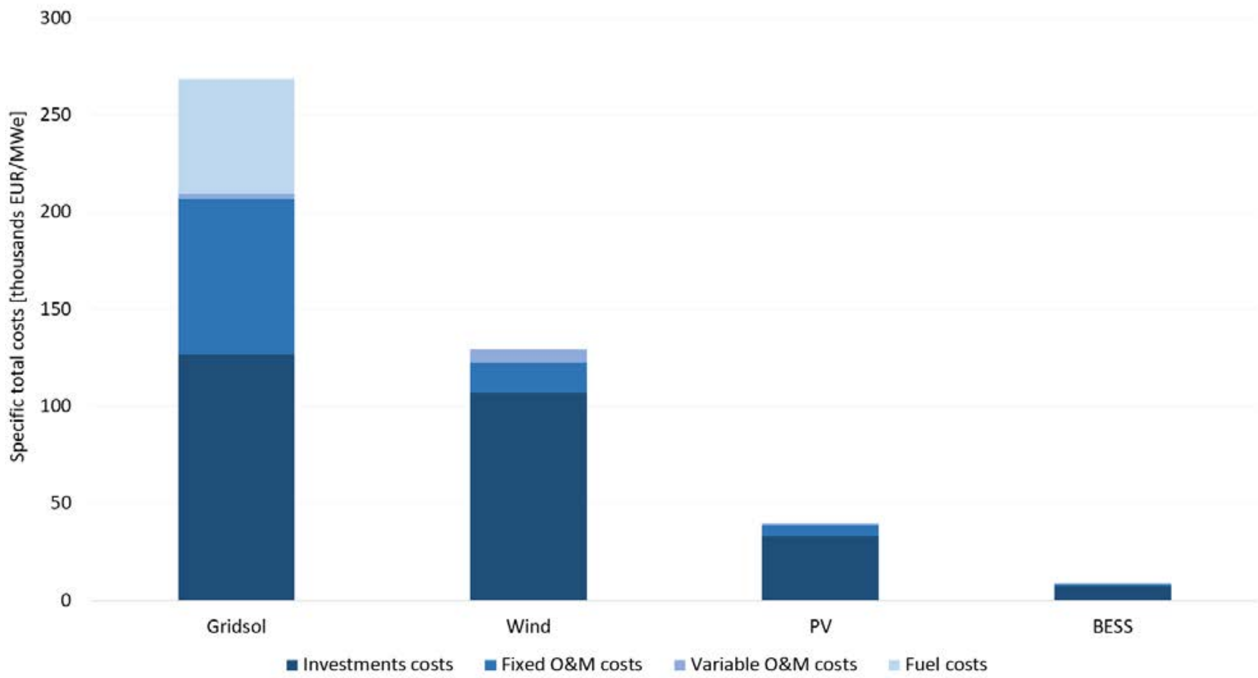


Figure 7.2: Cost breakdown for the Smart Renewable Hub components (2040).

Chapter 8

Results. CSP and hub functioning

This Chapter further details the functioning of CSP and Gridsol hub installations. First, the Italian CSP installations are considered, as part of the results from the 1.5 degrees scenario; second, the Gridsol hub installed in France is analysed (1.5 degrees biogas); eventually, the operations of a five-piece Smart Renewable Hub are detailed. The aim of this Chapter is to outline the mutual relationships among plant/hub components, with a link to the setting where the plant operates. The electricity price changes in connection to the activation of the hub units, which are often the marginal producers in the merit-order curves.

8.1 CSP power plants. The case of Italy

The average weekly generation from the Italian CSP plants is reported in Figure 8.1. The data is from 1.5 degrees scenario, where the cumulative installed power capacity was found to be 17.9 [GW] in 2050. A bell shape can be recognised in the graph, with some irregularities reflecting the intermittent nature of the solar profiles. The electricity production reaches its highest between week 20 and 37 (mid-May to early September), while dropping at the graph extremes.

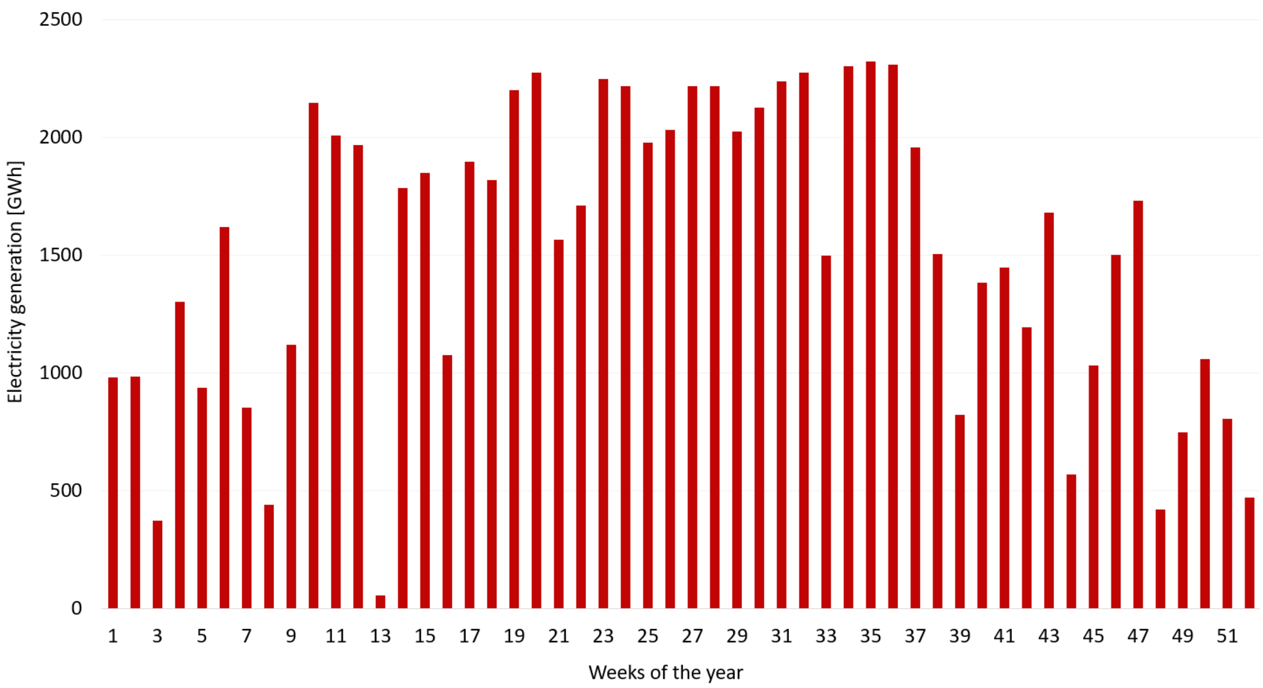


Figure 8.1: Weekly generation for the Italian CSP units. Scenario: 1.5 degrees. Year: 2050.

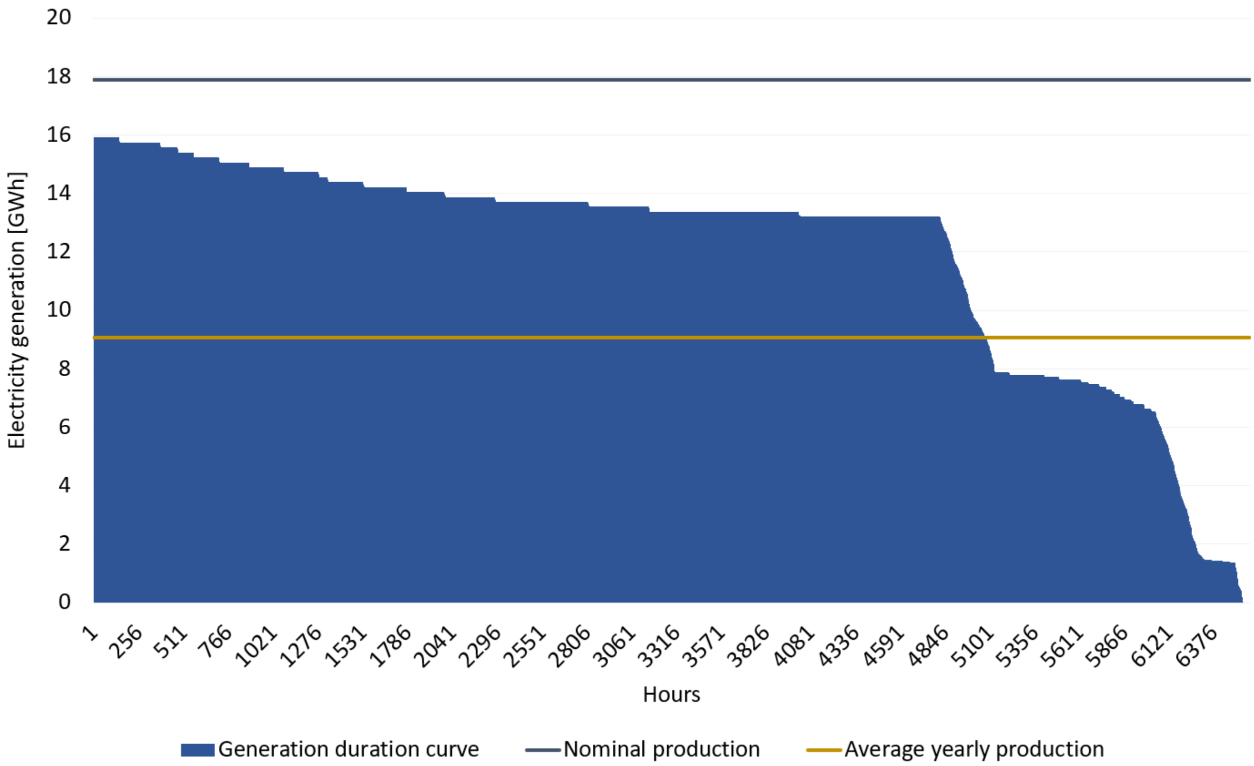


Figure 8.2: Generation duration curve for the CSP units in Italy. Nominal and average production are also shown.

The generation duration curve shows that the CSP steam turbines work for nearly 5000 hours at a relatively high load (> 70 % of their nominal capacity) and that they overall are in operation for 6500 hours a year. The average hourly production over the entire year settles at around 9 [GWh], i.e. at 51 % of the energy the units would generate if running at full power all the time. This value is rather high considering that steam turbines have a utilisation factor implemented in Balmorel, which accounts for scheduled and unscheduled operation and maintenance duties. The graph with the utilisation factors can be found in the Appendix (Figure C2): a minimum of 0.76 is reached in summertime, when scheduled maintenance is supposed to affect more units; the yearly average is set to 0.86. The CSP block has therefore base/intermediate-load characteristics, with its full load hours rising up to 4800 [h] (Figure 6.18).

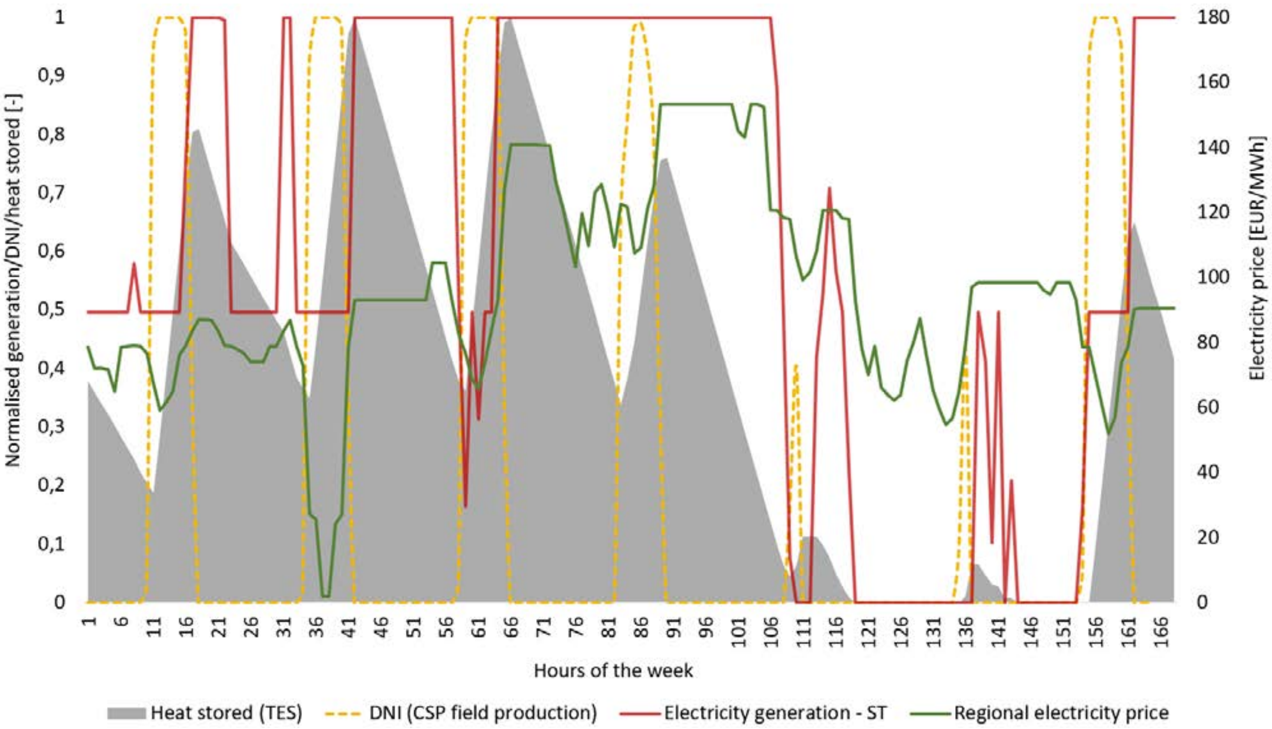


Figure 8.3: Hourly functioning in Week 4.

The weekly functioning is exemplified in Figure 8.3, where the electricity generation from the steam turbine ST is shown along with the heat stored in the thermal energy storage, the DNI trend and the regional electricity price. Values are normalised with respect to the weekly maximum (except for the electricity price): the steam turbines peak at 15.7 [GWh] and the energy content of the storage at 902 [GWh]. It can be seen that there is generally a delay between the daily DNI peak and the steam turbine production, which generally starts operating when the storage has reached its highest daily energy content. This does not hold true for days 3 and 4, where the turbine runs at high load (88 %) also all night long, until the energy content in the storage is almost null. This weekly profile shows also that the steam turbine running at high load empties the almost fully-loaded TES in two days, provided that the second day is characterised by a good solar resource: this is consistent with the findings reported in Section 6.3 (Table 6.6), where the storage volume was found to be over 20 hours. The operational details suggest that the CSP unit dispatches when the evening demand peak occurs and, in general, its functioning is related to medium-high electricity prices; the regional price drops when CSP units are not online. It emerges that the role of CSP is complementary to that of solar PV: on the whole CSP generates also after the daily maximum GHI (whose profile does not differ substantially from the DNI) is attained.

8.2 The Gridsol hub. The case of France

The functioning of the Gridsol hub in France for 2050 (1.5 degrees biogas scenario) is analysed in the following. Figure 8.4 displays the weekly generation from the gas (blue) and steam (red) turbine in the hub. The power production from gas accounts for 31 % of the yearly hub output, a share that is roughly complementary to the gas installed capacity (63 %): this proves that its role is that of a peak load supplier, with temporary generation spikes during the year. The gas engine is rarely active between Week 14 and 21, and its output is relatively lower during summertime, when the CSP block benefits from a good solar resource. In November, the demand profile incentivises the hub operations, especially from the gas turbine.

The generation duration curve of Figure 8.5 visualises how the gas engine covers the peak-load demand for a limited amount of hours ($\sim$ 1400) and with a net output substantially higher than that of the steam turbine; conversely, the base-load functioning of the latter is apparent. Aside from the periodic efficient reduction coefficients (Figure C2), the steam turbine produces at constant output for more than 5000 hours a year. The resulting duration curve has intermediate characteristics, which make Gridsol a peculiar and resilient technology. It

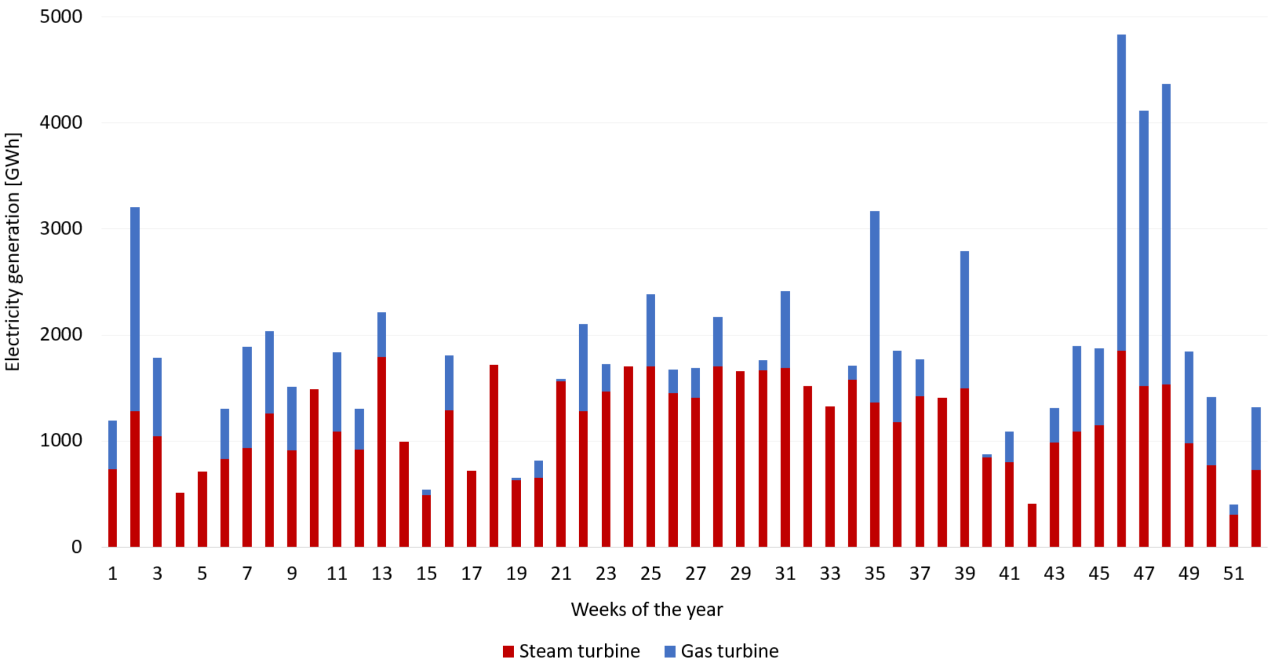


Figure 8.4: Weekly generation for the French Gridsol units. Scenario: 1.5 degrees biogas. Year: 2050.

is important to notice that the hub duration curve is often coincident with the hour-by-hour vertical sum of its components, i.e. that the two units produce simultaneously at nominal power.

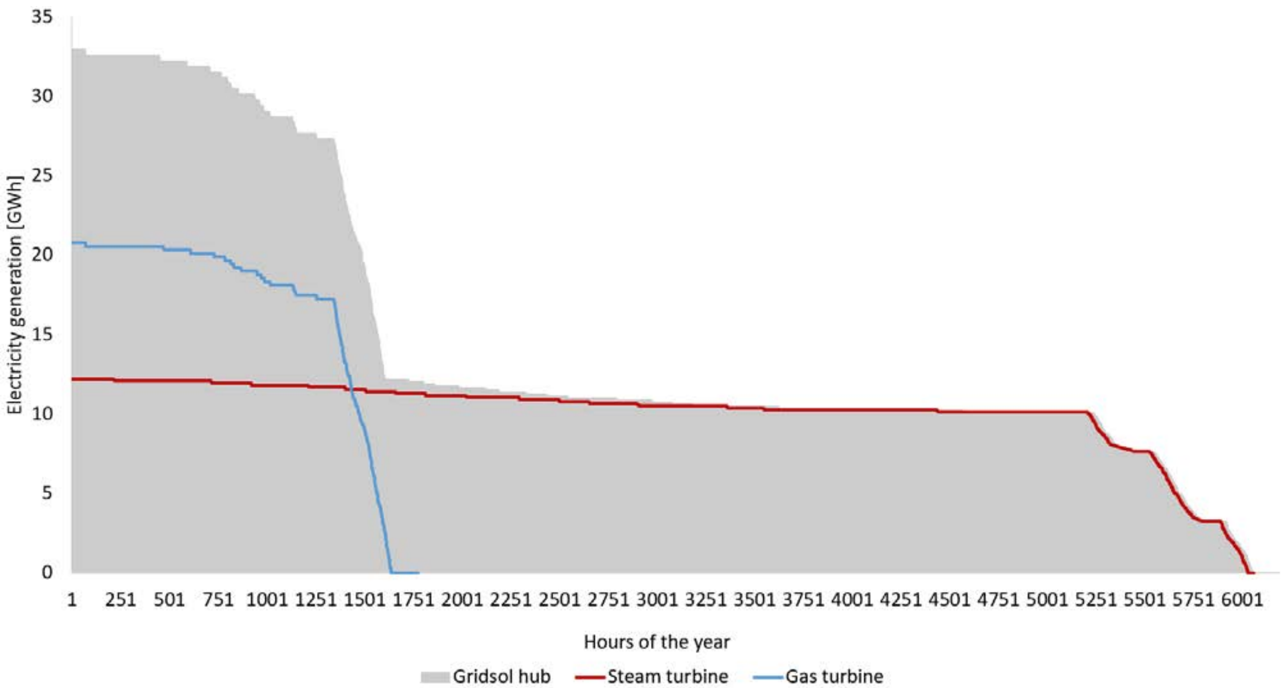


Figure 8.5: Generation duration curve for the Gridsol hub in France. The duration curves for the components are also shown.

The weekly functioning is exemplified for Week 12 (Figure 8.6); values are normalised as in the foregoing description. The gas turbine heat recovery system can be seen to contribute to the storage energy content, as it smooths the decline in the tank level when the steam turbine runs at high load. The graph provides also an insight on the reciprocal action of the two generators, which are shown to run at the same time (this is the 'no complementarity' principle discussed in Section 4.1 and subsequently used in Section 6.4 to characterise the relationship among components). The gas turbine supplies power in the evening, night and early morning when needed, in conjunction with high wholesale market prices. In general, both engines tend to run at rated power. As in the previous example, the CSP field production is seen to increase the energy content of the storage, followed by a later activation of the steam turbine. The latter works in periods of medium/high electricity prices and, with a few exceptions, until the storage is emptied.

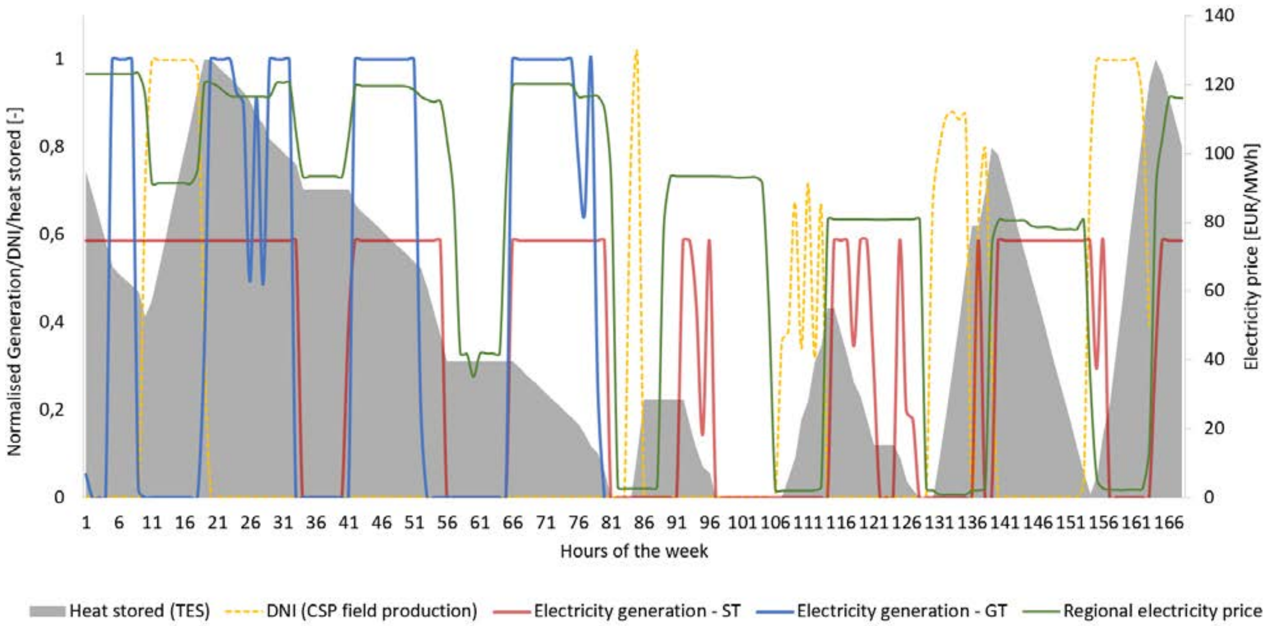


Figure 8.6: Hourly functioning in Week 12.

The outcomes presented in this Chapter do not intend to be exhaustive of all the different operational characteristics of the Gridsol hub, but they allow to draw some general conclusions, which can be summarised into the following:

- the steam and gas turbine often produce simultaneously; the gas engine contribute to the heat content in the storage and therefore can prolong the operations of the steam turbine, which frequently runs at nominal power;

- the steam turbine benefits from higher capture prices when the gas turbine operates and this constitutes an advantage for the repayment of a capital-intensive technology;

- the activation of the CSP power block is always deferred with respect to the availability of the solar resource. Both CSP and the gas turbine tend to run in the evening or at night;

- the two units composing the hub contribute to the *price polarisation* phenomenon, i.e. an accentuated difference between short-run marginal costs of generation in consecutive hours. This is already evident in Week 12 (Figure 8.6), but it is even more prominent during summertime.

8.3 A five-piece Smart Renewable Hub: the functioning

The Smart Renewable Hub installed in France in 2040 (CSP breakthrough scenario) is chosen as the example for analysing the generation patterns of the units therein. Such hub includes Gridsol and integrates also solar photovoltaics, wind turbines and an electric storage system. The seasonal functioning of this five-piece Smart Renewable Hub is reported in Figure 8.7, which shows the monthly power output from each generator (shares). PV arrays contribute to the biggest relative share in each period of the year: they supply less power during the winter months, reaching a low of 48 % in January; they peak during summertime, when their share gets as high as 71 % (August). A similar trend is followed by the CSP block, contributing to a minimum of 17 % of the hub output in December and up to 27 % in July. The seasonality of wind energy is also apparent: the 34 % attained in December shrinks to only 5 % in the month of August. This Smart Renewable Hub is representative also of other configurations that are not reported here but have the same strong points highlighted in the foregoing lines: solar and wind resources counterbalance themselves so that they cooperate to increase the stability of the power output throughout the year. At the same time, they limit the utilisation of the gas engine, that when fed with biogas, makes the hub a 100 % clean energy system.

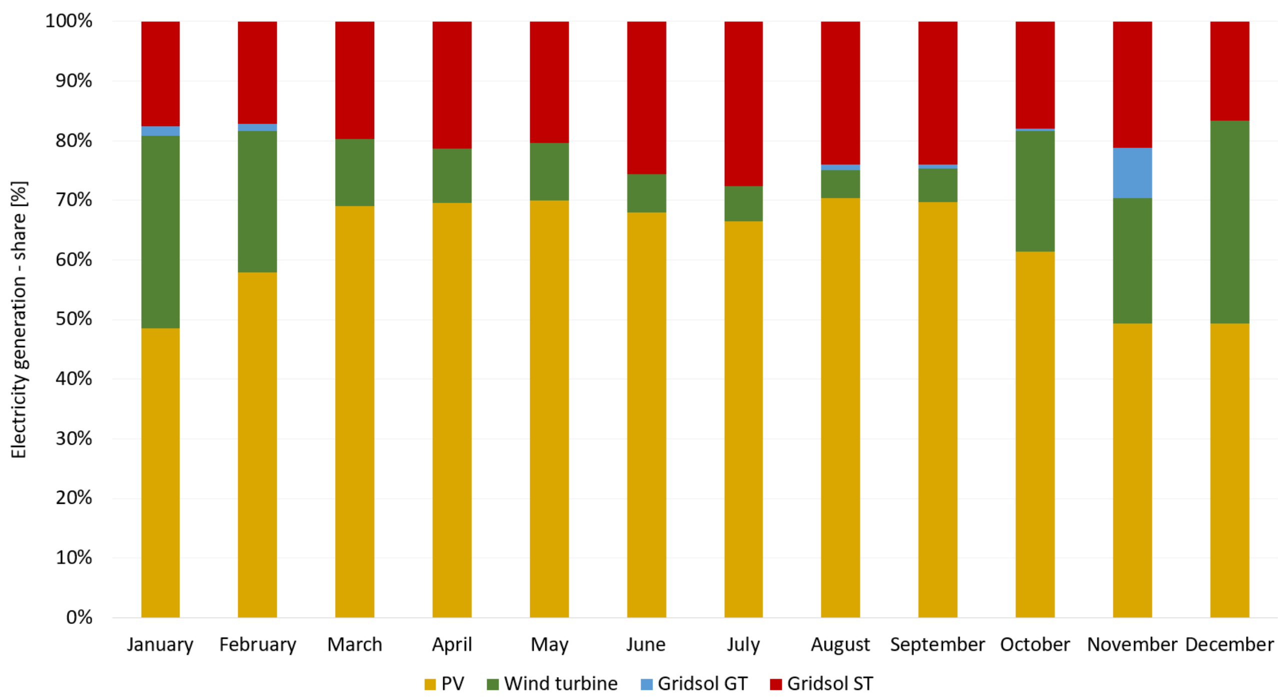


Figure 8.7: Monthly generation per technology for the SRH in object (share).

Figure 8.8 displays the generation duration curves for each unit in the Smart Renewable Hub. The system is driven by the large share of solar PV capacity; its duration curve is characterised by a rapidly declining production that ranges over half a year. Conversely, the generation from wind turbines has a smoother profile, with a markedly lower peak but spanning over more than 7000 hours. The technologies composing the Gridsol hub behave in the same manner described in the previous Section: the steam turbine (CSP) acts as a base-load generator for 5000 hours a year, while the gas engine covers demand spikes for roughly 500 hours a year. Its production curve is flat.

The hub total generation is constrained by the 200 [MW] interconnector; the temporary excess production is stored in the battery energy storage system (BESS) and released in hours of scarce natural resources. The grey area well highlights how the combination of solar PV (installed in excess with respect to a chosen nominal output) and batteries can provide a stable output for more than 2000 hours a year. The strength of CSP coupled with large thermal energy storage lies in the ability to yield a constant output for more than twice the same amount of hours.

Finally, the hub capacity factor, as calculated from Equation 4.5, is 30 %, but this is an underestimation due to the overinvestment bias that follows the proposed modelling approach.

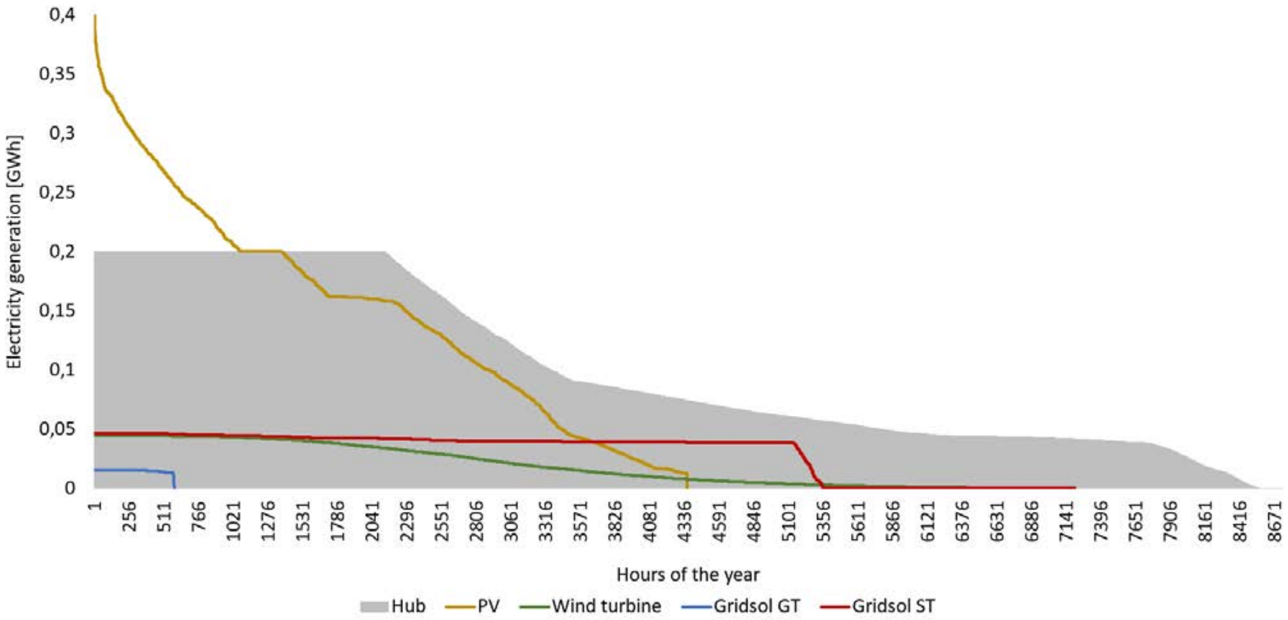


Figure 8.8: Generation duration curve for the hub in object.

It is interesting to notice that the thermal (TES) and battery (BESS) energy storage systems do not behave differently on average: this is evident from Figure 8.9, which depicts the average weekly energy contents of the two types of storage. Both units are loaded in the central hours of the day and discharge in the late afternoon/evening. This fact corroborates the existence of a strong competition between the two energy systems.

While the thermal power is immediately used by the steam turbine to produce electricity, the energy withheld by the batteries is discharged more gradually, with momentary increases in the electricity contents. The local morning peaks at the weekend (around 9-10 a.m. of Saturday and Sunday) are related to a change in the Main Region demand level: this is lower at the weekends than during working days. As a consequence, the electricity price profile varies (Figure 8.10) and the flexibility given by the storage system allows to dispatch energy when more profitable. Finally, it is worthy to stress that the electricity stored in the batteries primarily comes from solar PV, as evident from the daily trends. This fact confirms the strong interdependence of the two not only in hybrid power plants, but in the power sector in general.

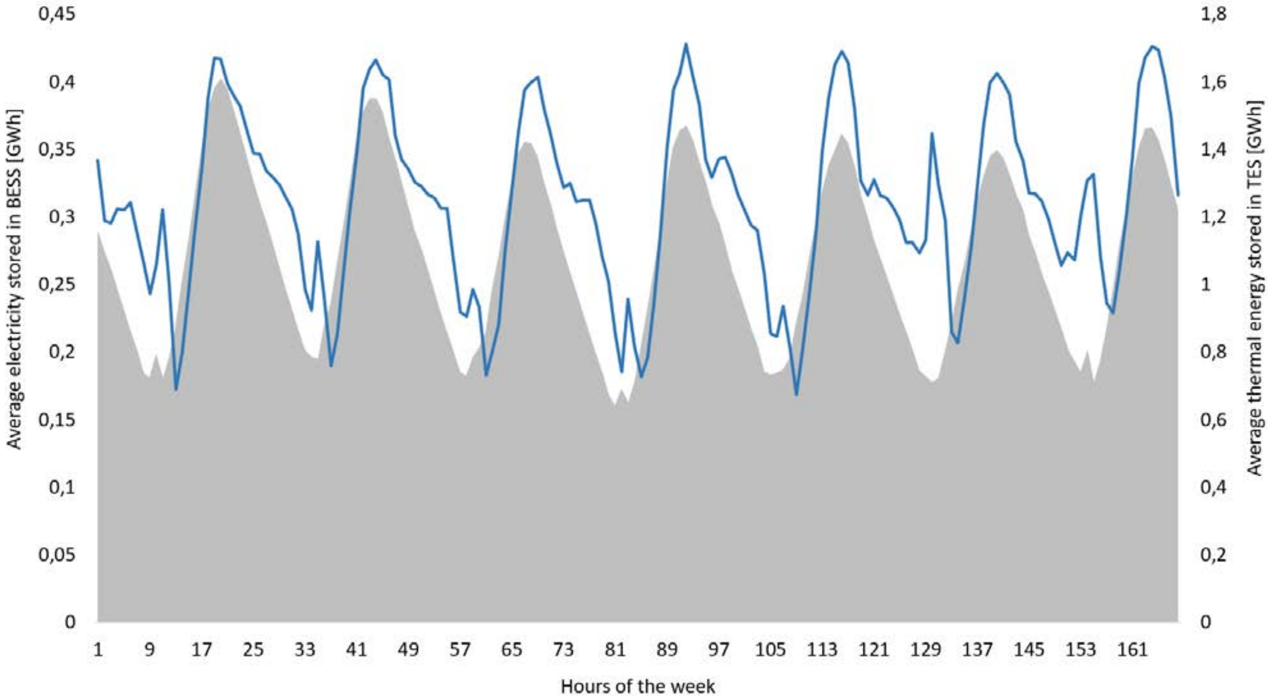


Figure 8.9: Average weekly energy contents in batteries (BESS) and thermal energy storage systems (TES).

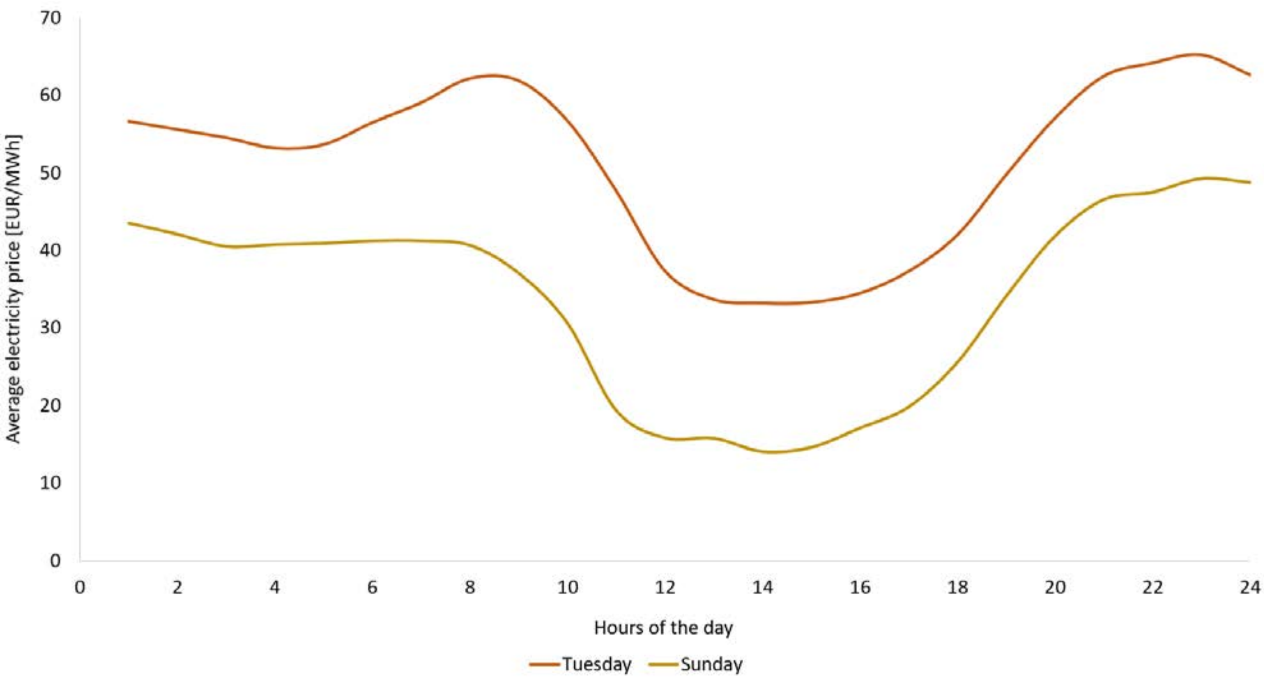


Figure 8.10: Average electricity price in France (Main Region) on Tuesday and Sunday. The so-called duck curve as well as the weekend scale-down are pronounced.

The characterisation of different energy hubs containing CSP and Gridsol has highlighted the following main aspects:

- the base-load functioning of the CSP steam turbine, that operates at nominal power for more than 5000 hours a year; conversely, the gas turbine runs for a more limited amount of hours and it is found to add its power output (nominal) to that of steam turbine. In other words, the two units obey the 'no complementarity' principle;
- the similar functioning of CSP and the couple PV+BESS, which is proved to be the strongest competitor of CSP units. The large thermal energy storage allows for shifting the CSP steam turbine production towards the late afternoon/evening hours, and so do the batteries.

Chapter 9

Discussion

9.1 Results overview

9.1.1 CSP, Gridsol and the EU Climate Strategy

The CO_2 price trajectories adopted to push the future power sector towards different high levels of decarbonisation have shown to produce consistent effects on the emission cut in the 2020-30 decade; in the 20-100 [EUR/t] price range, the power sector contributes to the abatement of more than 850 [Mt] of CO_2, thereby bringing the carbon emissions down to - 94 % with respect to 1990. With the partners cost assumptions, this setting is not fertile for CSP to spread in Europe, even in the hypothesis of a higher gross electricity demand. Scattered investments appear in France and Italy, where the cumulative installed power capacity settles at 5 and 18 [GW] respectively in 2050. The relatively high electricity price, which is above the EU average in those two countries, allows for recovering capital and operational expenditures. Conversely, the large share of PV plants and wind farms makes CSP unattractive in Greece and in the Iberian countries. The Gridsol hub is thus not a preferred option to pursue either the 2.0 or the 1.5 degrees targets set by the Paris Agreement.

9.1.2 Sensitivity on the biogas price

Under the hypothesis of methanisation costs lower than 17.45 [EUR/GJ], the Gridsol hub composed of a CSP block and a gas engine with heat recovery becomes a cost-competitive option in France, Italy and - to a lesser extent - Greece. In the 1.5 degrees scenario, the cumulative hub capacity settles at 35, 40 and 1.7 [GW] respectively in the above-mentioned countries. These figures account for 5 and 8 % of the entire generation fleet in France and Italy. The low biogas price is crucial for the appearance of Gridsol in Greece and it drives also the CSP field installations in France. This is only setup where the Gridsol hub finds a fertile ground for a consistent deployment. It is also demonstrated that Gridsol working in combined cycle mode is more attractive than standard combined cycles fed with the same fuel and with a 60 % electrical efficiency.

9.1.3 Sensitivity on the CSP costs

The 25 and 40 % reduction in the CSP investment costs lower the LCOE to the point that the technology becomes attractive also in Portugal, but not in Spain. The higher quality of the CSP resource brings the model to invest in 4.1 [GW] already in 2025 in Portugal (- 40 % cost reduction); concurrently the exports to Spain increase by nearly 9000 [GWh]. The spreading of CSP is notable in most favourable scenario (CSP breakthrough), with generation shares of over 15 % in all the Gridsol countries except Spain. At the same time, the production from solar PV, nuclear and biomass undergoes a contraction.

9.1.4 Technical and economic features

CSP plants are cost-competitive only when coupled with large thermal energy storage, whose volume gets as big as 21 hours in Italy. This allows for the supply of base-load power for almost a day. The size of the storage diminishes when CSP is integrated with a gas turbine with heat recovery (Gridsol hub); in this case the volume is reduced by 1 to 3 hours. This is due to the gas turbine generating in hours previously covered by the CSP block.

The CSP field is oversized with respect to the steam turbine nominal thermal input. The solar multiple always exceeds 2 for both CSP alone and Gridsol under the 'no complementarity' principle. Greece is an exception: the optimal solar multiple is found to be 1.82 in the Peloponnese. The CSP full load hours are always above 4000, with peaks over 5500; CSP units are characterised by high capacity factors (48 % $<$ CF $<$ 66 %), as their function is primarily that of an intermediate/base-load supplier. The high full load hours contribute to lower the LCOE of the technology, down to 57 [EUR/MWh] with the partners cost projections and even to 40 [EUR/MWh] with a further 40 % reduction in the investment costs (2050). These values set the minimum average price at which the technology can dispatch (market value) to recover its lifetime costs.

9.1.5 Smart Renewable Hubs

Smart Renewable Hubs integrating CSP and the Gridsol technology are a preferred solution in those countries where CSP appears in the national mix. In the four presented scenarios, CSP is always coupled with solar PV and batteries, occasionally with wind and gas turbines. It is argued that in hybrid power plants, the grid connection savings increase the disparity between solar PV and CSP, as the relative LCOE decrease is greater for technologies with lower fixed O&M costs (solar PV).

9.1.6 Units functioning

The seasonal and hourly functioning of CSP have shown how the steam turbine takes advantage of the thermal energy storage to shift the production to the late afternoon/evening hours, when the demand spikes and solar PV does not generate. The power block runs at rated capacity most of the time: roughly 5000 hours in the proposed example and accounting for the steam turbine utilisation factor; for an additional 1500 hours it works at partial load.

In the Gridsol hub, the gas engine produces mainly during wintertime and almost always simultaneously with the steam turbine. Therefore, the hub covers demand spikes and acts also as an intermediate/base-load supplier.

The proposed five-piece Smart Renewable Hub (Gridsol, PV, wind turbine and BESS) summarises the operational characteristics of Gridsol and the other renewable technologies: the battery storage system forms a semi-dispatchable group with solar PV and its functioning is similar to that of CSP with large thermal storage.

9.2 Comments

A capital-intensive technology like CSP needs to undergo robust technological advancements to contribute to the emission reduction in the years to come. The analysis around the influence of carbon prices and the rise of a demand for synthetic fuels on the spreading of Gridsol (Sections 6.1, 6.2, 6.3) has highlighted the existence of a rather narrow margin for the hub long-term success. Surely, the CO_2 trajectories identified in this work may not reflect the exact development of the EU ETS in the years to come, but they provide meaningful insights into the effect of a cap-and-trade system for the development of both CSP and a hybrid concept such as Gridsol. It is argued that the effects of high CO_2 prices on the profitability of both technologies is limited, as soaring carbon prices are also detrimental for the cost-competitiveness of gas engines. The assumptions outlined in the Modelling and Scenario Chapters (4, 5) exert a doubtless influence on the results; they are discussed within certain limits, like in the case of the biogas price trajectory (Section 5.2.3), but they are conclusively set in other circumstances. This is the case of the hydrogen demand, whose level is determined from the Climate Strategy projections and afterwards split equally into the EU countries on the basis of the final electricity consumption. However, to the author the biggest and most influencing assumption lies in the hydrogen demand profile shape. The modelling comprised a flat curve, uniform over the year and, therefore, over the 24 hours of a day. This sets a competitive advantage for CSP, that can benefit from the cheap thermal storage to supply the electrolysers at night. However flexible because equipped with storage, the hydrogen demand might be unmet at night if only solar

panels and batteries (which are proved to be the most direct competitors) are available. At present, the volume of the electric storage is far from being comparable to that of a thermal facility; yet, this and many other assumptions related to hydrogen modelling enclose a spectrum of uncertainties that is hardly quantifiable in size.
As a whole, the need for new fuels has represented the chance to diversify the demand shape in the future. No sensitivity connected to the demand is proposed, but a system that tends towards increasing flexibility might favour changes in cosumption pattern

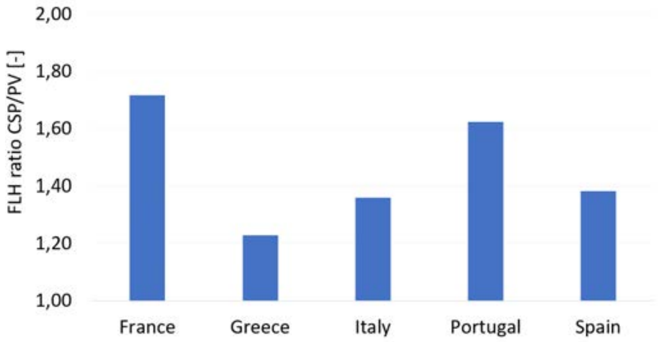
The Results Chapters have also highlighted key factors which can change the hub future prospects. The biogas price is one of these, it depending on methanisation (upgrade) costs; in addition, biogas makes Gridsol a 100 % carbon-free concept. In some locations (Greece, France), the gas turbine has proved to drive also the CSP investments in the hub. The two units influence each other doubtlessly, but both need to overcome important economic barriers: a high initial outlay for CSP, a consistent operational disbursal for the gas engine fuel.
The impact of a drop in the CSP investment costs is doubtlessly significant. The industry is still at an early stage, especially for the solar tower concept, and a possible breakthrough in Europe would also depend on support schemes incentivising CSP or hybrid power plant installations.

9.3 Limitations of this analysis. Further Considerations

One of the main limitations of this analysis regards the scarce differentiation among local resources. The Gridsol and Smart Renewable Hub locations carry accurate local data as far as the DNI profiles are concerned, but the solar and wind profiles are the same of those defined in the Main national Area; these generally denote a national average. It is difficult to quantify the impact of such an assumption, which probably slightly drifts the resulting investments towards less accurate combinations. Table 6.18 reported the Full Load Hours for PV and CSP in the five Gridsol countries; the ratio between the two is uneven across the locations (Figure 9.1).

The ratio between DNI and GHI is not supposed to be same with a change of location, since the diffuse component can vary from one site to another. However, Figure 9.1 appears to suggest that France and Portugal are comparatively advantaged with respect to other countries, Greece in particular. Considering the poor performance of CSP in Portugal, at least with the cost projections provided by the partners, these discrepancies are not deemed crucial for the results.

Figure 9.1: Ratio between CSP and PV Full Load Hours in the five locations.



Portugal is the country with the greatest DNI resource. In this regard, the model showed to be rather generous in the construction of new transmission lines, to the point that under the hypothesis of a consistent cost drop for CSP, the entire generation in the Iberian peninsula would come from Portugal; in this case, new transmission capacity should be built to transfer power first to Spain and then, possibly, to other European countries. The construction, adoption and use of a large-scale model as the one at the core of this thesis necessarily brings about a series of simplifications that might influence the results. For this reason and for the inherent uncertainty that a study covering a long temporal horizon carries along, the results are quantified when the figures are deemed meaningful; otherwise, a qualitative explanation is provided.

The technical simplifications affect also the functioning of the units, whose partial load behaviour and start-up costs are not accounted for. These would require the adoption of mixed-integer programming techniques; the time they demand is however prohibitive, provided that machines have enough computational power to perform the simulations. It is finally to be kept in mind that models, however accurate, provide a simplified representation of reality. The present analysis does not account for the regulatory framework, for physical or geographical constraints. The practical realisation of a five-piece Smart Renewable Hub of the kind presented in the Results Chapters requires the availability of the resources in one unique site. It may possible that locations with good solar characteristics do not turn out to be suitable for wind energy for instance.

Chapter 10

Conclusion

The stringent climate issues and the ambitious decarbonisation targets inspired by the Paris Agreement will challenge the European grid in the future. In a system that heads towards high shares of renewables, the need to stabilise and balance the generation from stochastic sources will favour the installation of flexible and reliable energy conversion technologies. This work has analysed the potential of CSP as one of these in five Southern European countries until 2050: France, Greece, Italy, Portugal and Spain. The solar thermal technology could come as a single-source power plant or integrated into Gridsol and larger Smart Renewable Hubs.
A context characterised by progressively stricter rules governing the EU ETS, the increasing CO_2 prices and the rising need for new fuels (e.g. hydrogen) have proved to foster scattered investments in CSP, otherwise left out of the energy mix to the advantage of other renewables. Wind and especially solar PV are becoming increasingly attractive also because of the projected low costs of electric storage. In countries where the solar resource is more abundant (Greece, Portugal, Spain), the installation of great amounts of solar PV and batteries causes the electricity price to plummet, down even to 40 [EUR/MWh] in Spain in 2050 under the hypothesis of high carbon prices. Conversely, where the irradiation is poorer, the persistence of relatively costly generators (nuclear plants in France, combined cycles in Italy) favours a moderate spreading of CSP technologies.
In all cases the CSP units are provided with large thermal energy storage facilities: in Italy

the storage volume exceeds 20 hours in 2050. This is possible because the CSP field is oversized with respect to the steam turbine nominal power: the solar multiple is above 2 in most instances.
Large thermal energy storage is needed to supply intermediate/base-load power for extended periods; in this manner a stable output is guaranteed. Moreover, the functioning of the steam turbine is deferred with respect to the DNI daily peak, so that the energy can be dispatched in the late afternoon/evening, when demand and prices spike. This is not the only element that assures the payback on the investment; the simultaneous activation of the gas turbine in the Gridsol hub in hours of high demand is found to raise the hourly spot price. Hence, the concurrent functioning of the solar thermal system and the gas engine increases the revenues for CSP and returns a resilient hub duration curve: the stable, base production is ensured for more than 5000 hours a year and a higher yield is obtained for a smaller period of time ($\sim$ 1000/1500).
When Gridsol is integrated with other renewables into larger Smart Renewable Hubs, the coordination with solar PV and batteries extends the plant operational time: the hub is left idle for only a small number of yearly hours. The suitability of CSP into hybrid power plants is related to the system evolution; its presence is stronger with relatively low fuel prices and with the progress in the industry.

This study has assessed the future perspectives of CSP in areas with medium/low solar resources. The results quantify the attractiveness and impact of CSP in an interconnected system that is pushed towards a fast but convenient and feasible change; a complete outlook on the impact of ambitious climate targets is provided. Finally, this work can help to frame the potential, barriers and operational features of market-competitive CSP installations in Europe.

10.1 Future Work

The thesis has proved that the existing national mix conditions the type of investment in new generators. The generation fleet is in rapid evolution and the climate issue pushes for new, constantly revised national strategies. This requires an ongoing update of the models, e.g. with announced shut-downs of power plants to be permanently substituted. The recent Spanish Energy Strategy has outlined the possibility of a progressive replacement of nuclear power plants. These make up for more than 8 % of the domestic generation and CSP may take advantage of this decision.

A revision of the parameters regulating the power transmission between neighbouring countries is needed to ensure that the national results are not biased by the exploitation of resources in other States.

A sensitivity analysis on the cost of electric energy storage could give back a clearer picture on their weight in the deployment of solar PV in Southern Europe.

Finally, a richer and more accurate analysis around Smart Renewable Hubs can originate from more precise, location-specific data for solar and wind resources; moreover, a careful determination and allocation of all the benefits related to the construction of hybrid power plants can be modelled. In this manner, the methodology presented in this thesis can be extended to the analysis of any hybrid concept within an interconnected system.

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Appendices

A Appendix A - Time aggregation

A.1 Residual demand during summertime - Saturdays and Sundays

Figure A1 shows the difference in residual demand [GWh] between Saturdays and Sundays for two summer weeks. The plots are a clear representation of the intermediate characteristics of Saturdays during summertime, in that they exhibit an *rd* that lies between Sundays and another working day. Figure A1 shows the Saturday line being in between working days and Sunday in week 26; in week 30, the Saturday profile even blends in the other working days.

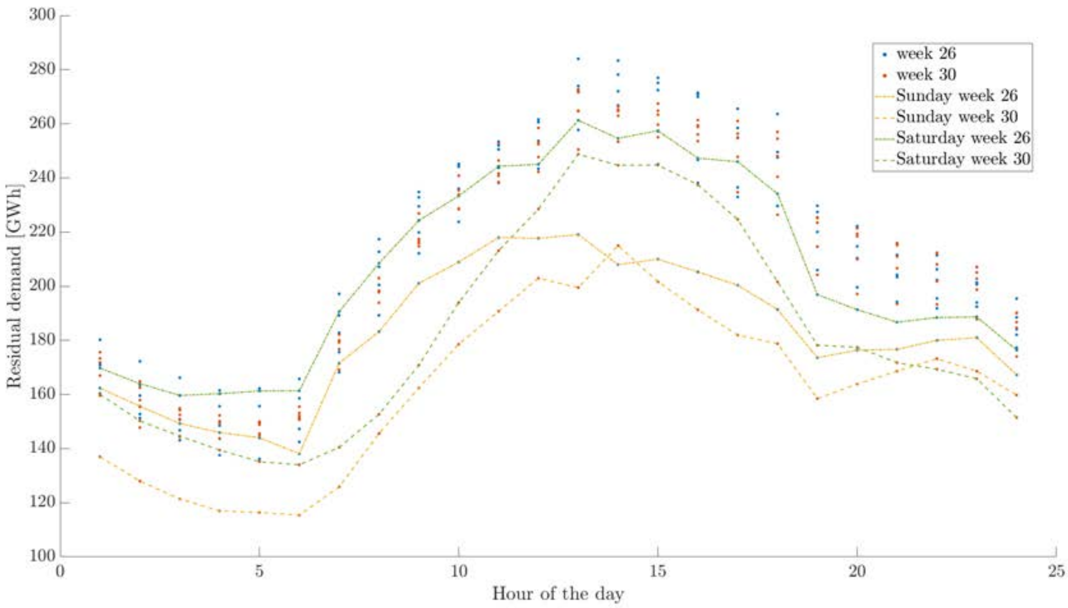

Figure A1: Residual demand in weeks 26 and 30. Working days are dotted, weekend points linked by lines.

A.2 A comparison with the previous aggregation scheme

This section discusses the improvements obtained with the new aggregation scheme with respect to the previous configuration. Ea Energy Analyses adopted different solar PV profiles in conjunction with the previous time aggregation; the new ones are smoother and more accurate (an example can be found in Figure 3.1) and take 2014 instead of 2005 as the reference year. It is found that the quality of the indicators k, and especially the market value, is highly dependent on the shape of the input profiles; this is shown in Figure A2 by comparing the electricity curtailment across the three following cases:

- old time aggregation scheme and old solar profiles;
- old time aggregation scheme and new solar profiles;
- new time aggregation scheme and new solar profiles.

The figures refer to all the 36 European Regions under consideration. Figure A3 is constructed in the same manner, but displays values for only Spain and Italy, which account for more than 80 % of the projected European solar curtailment in 2030.

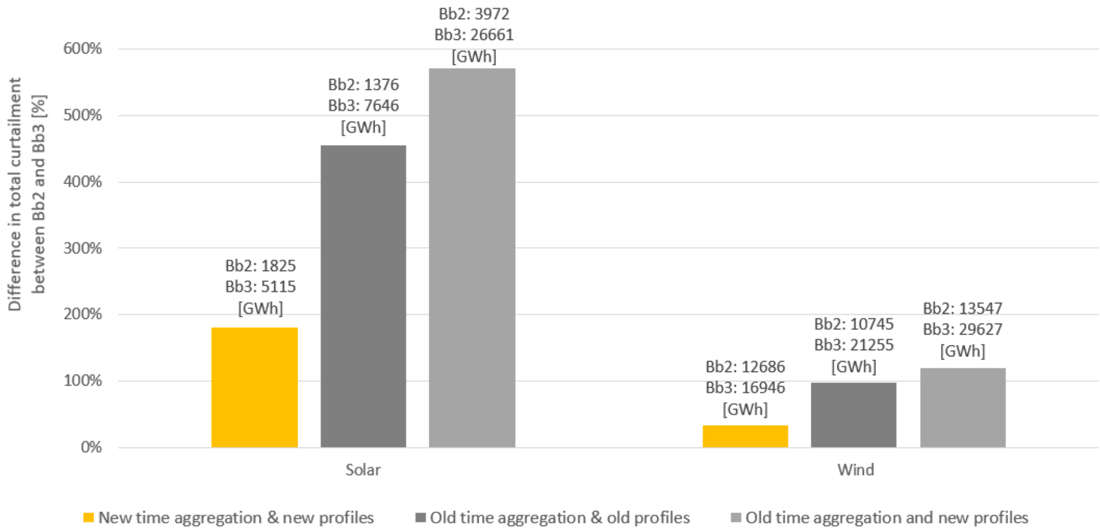

Figure A2: Relative and absolute difference in curtailment level between Bb2 and related Bb3 run and across the three set-ups. The plot shows figures for the entire Europe.

The main reason why the solar PV curtailment is higher in the full time resolution run is to be found in the aggregation process. By taking the illustrative example of Figure 3.2, it is possible to see that an aggregate run sees prolonged peaks in the input profiles, that is

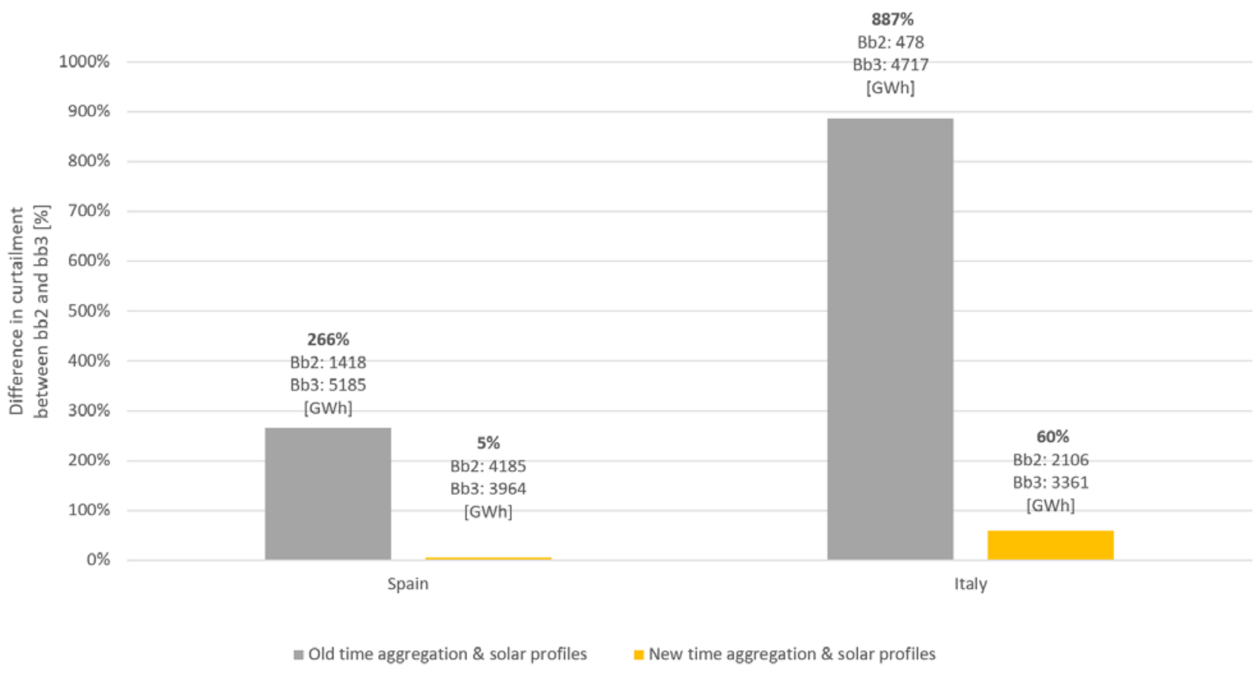

Figure A3: Relative and absolute difference in curtailment level for Spain and Italy between old and new setup.

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a distorted availability of natural resources. In other words, a higher curtailment is a sign of overinvestments. In principle, it is not possible to know which is the right curtailment level; this is why only a comparison between results from the two simulation types can give meaningful insights. Overall, the improvement with respect to the previous aggregation scheme is noticeable, for both solar and wind power; it is achieved by a raise in the Bb2 curtailment level and a contemporary decrease in the Bb3 mode. There persists a consistent relative difference for solar PV technologies, but the absolute figures show that the gap is wider for wind energy. The new scheme brings benefits also to the latter, which sees its Bb2-Bb3 gap more than halved.

If the previous scheme was applied to the new, more accurate profiles, the result would be the one represented in light grey. This solution yields the poorest performance among all cases and according to every indicator. It shows how a change in the input profiles conditions the quality of the results, if no action is taken on the aggregation scheme. This is why a preliminary data analysis is necessary to identify patterns and similarities; there clearly exists a relationship between quality of the aggregate data and quality of the results. However, due to the wide geography under consideration, the quality of aggregate data as measured with a method based on the correlation coefficient (such as the one presented in this Chapter) is not always directly linked to the quality of indicators in the results' domain. However the limitations, four simulations are compared in Figure A4. The number of time steps is fixed at 11 whilst the number of Seasons varies among 10, 12, 24 and 26. The average correlation coefficients ρ are taken from Table 3.1. Even if the number of simulated cases is not ample, a linear descending relationship can be identified between average correlation coefficient in input and relative difference in market value (R-squared equal to 98.52 %). This finding strengthens the role of a well-thought out processing of the input data.

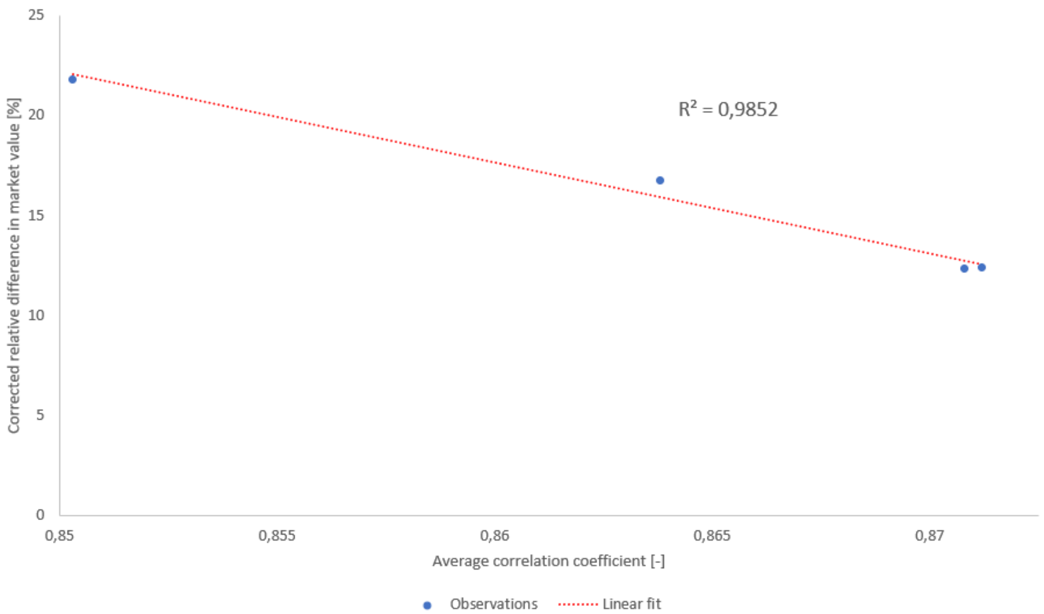

Figure A4: Relationship between the input profiles' average ρ and the corrected Δmv.

B Appendix B - Mehod

Figure B1 represents the storage and fuel production capacity across all EU scenarios. It can be seen that the projected hydrogen capacity is very small; therefore it is assumed that 2030 is the first year with a positive demand.

C Appendix C - Results

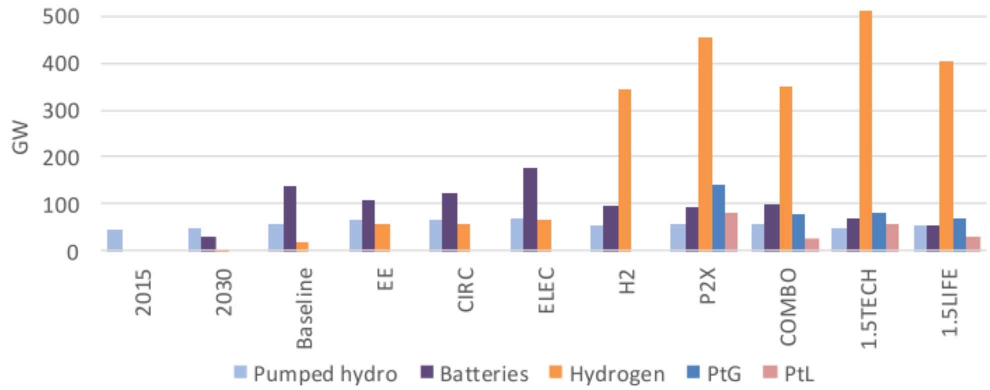

Figure B1: Evolution of storage and fuel production capacities across the nine EU scenarios. Source: [17].

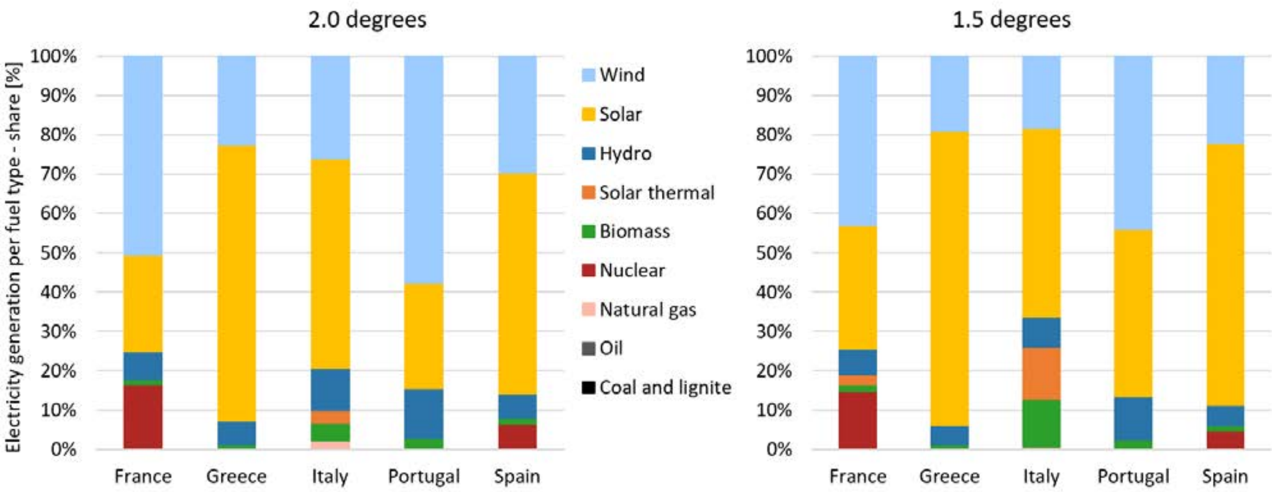

Figure C1: Generation per fuel type in the five Southern European countries (share). Data is for 2050.

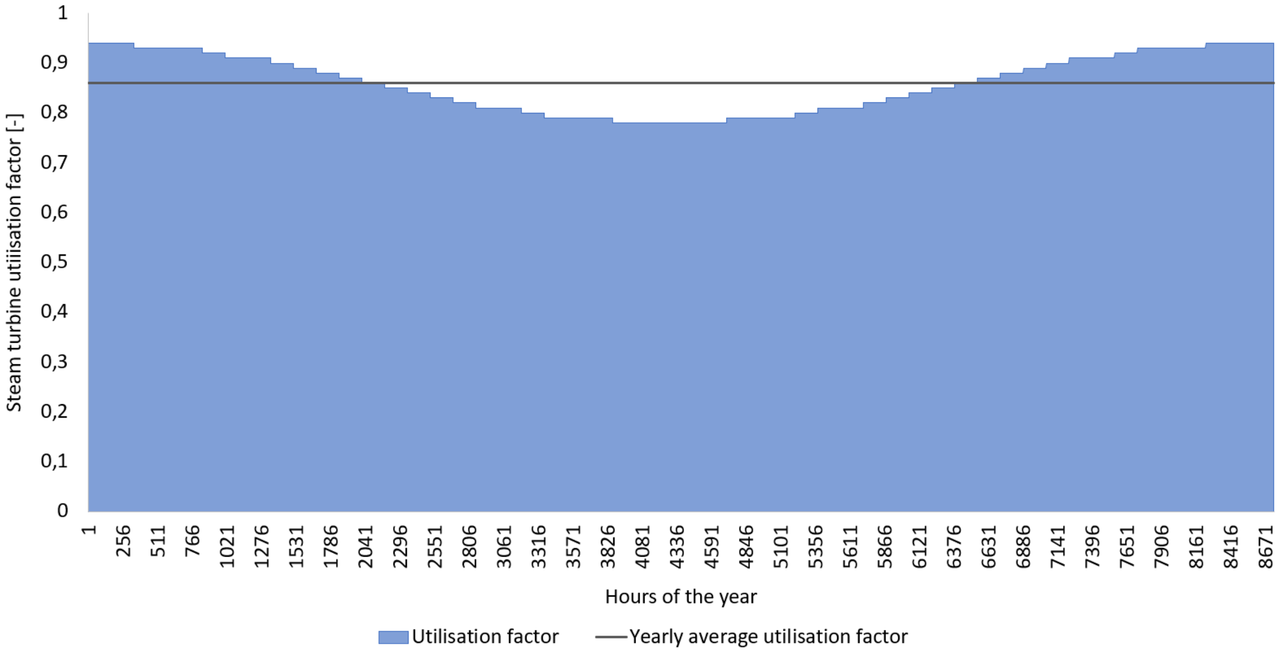

Figure C2: Utilisation factor for steam turbines.