SMART RENEWABLE HUBS

FOR FLEXIBLE GENERATION

GRIDSOL

SOLAR GRID STABILITY

D7.3

Power System Impact and GRIDSOL potential

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LIST OF ACRONYMS AND ABBREVIATIONS

ACRONYM	MEANING
BESS	Battery Energy Storage System
CCS	Carbon Capture and Storage
CF	Capacity Factor
CSP	Concentrated Solar Power
DNI	Direct Normal Irradiation
ETS	Emission Trading System
EU	European Union
FIT	Feed-In Tariff
FLH	Full load hours
GHG	Greenhouse gas
GT	Gas Turbine
H_2	Hydrogen
HFO	Heavy Fuel Oil
HPP	Hybrid Power Plant
LCoE	Levelised Cost of Electricity
NG	Natural Gas
NTC	Net Transfer Capacity
PPA	Power Purchase Agreements
PPP	Public-Private Partnership
SM	Solar Multiple
SRH	Smart Renewable Hub
VF	Value Factor
VRES	Variable Renewable Energy Sources

EXECUTIVE SUMMARY AND KEY FINDINGS

The growing market share of renewable energy technologies in the European power sector and the compelling long-term climate mitigation targets taken on by the EU and its Member States require a well-thought-out planning and grid integration of new generation facilities as well as an appropriate expansion of the grid infrastructure.

The undersigning of the Paris Agreement led to the formulation of a renewed European Climate Strategy in November 2018. With the aim of being at forefront of climate change mitigation, Europe pledged to act for a prompt transition towards a carbon-neutral economy. The power sector is already well-underway with its specific environmental targets as emissions have been cut by more than 40% with respect to 1990.

Wind and solar PV are fully mature technologies and they are set to provide bulk generation in the future. Other renewables hold a smaller market share, but can fulfil an essential role in guaranteeing system stability and firm electricity provision. Among these, Concentrating Solar Power (CSP) is expanding in regions of the world where a high DNI resource is available; at the end of 2018, the global installed capacity settled at 5.5 GW.

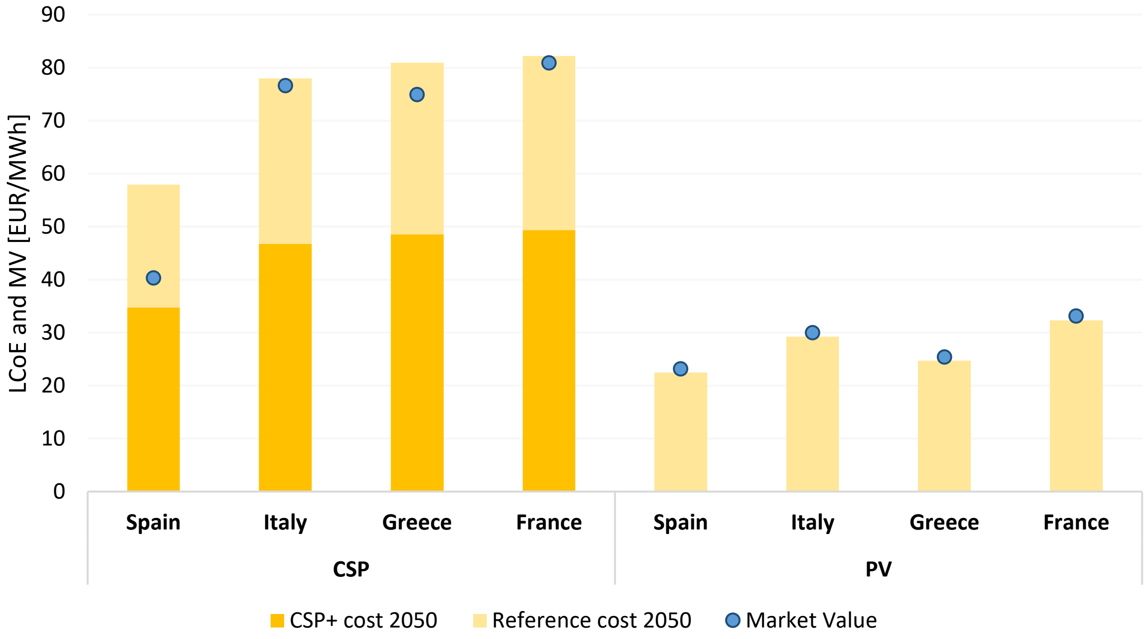
Despite being a technology in the early development stage, CSP has seen notable cost reductions in recent years due to improved design and efficiency of the solar field and industrial advancements. In locations characterised by good solar resources, the LCoE of new plants is falling under 100 EUR/MWh. With sites where the DNI overreaches 2000 kWh/m^2, Southern Europe and islands in the Mediterranean hold the potential for deployment of new solar thermal capacity.

New technology concepts for CSP have recently been developed and can enhance the further penetration of CSP units in the European power fleet, including off-grid systems. In the Gridsol hub, a CSP-powered steam turbine with thermal storage is combined with a gas turbine with heat recovery. The motivations to add several units together into one single hybrid power plant are manifold including dispatchability, reduction of grid connection cost and provision of balancing and other ancillary services. Smart Renewable Hubs (SRHs) and Gridsol are among these hybrid solutions, where CSP-based generation, variable renewable energy sources (VREs) and energy storage are coordinated by an intelligent dispatch manager.

The evolution of the European power sector, the potential of CSP-based generation and the composition of Smart Renewable Hubs until 2050 are assessed from a socio-economic perspective, in a market setting without subsidies and under different possible decarbonisation pathways based on the European Commission's *Strategic long-term vision for a prosperous, modern, competitive and climate neutral economy by 2050*: the *Baseline* (continuation of current policies); the *2.0* and *1.5 degrees* (with reference to the objectives rolled out in the Paris Agreement). An additional scenario (*CSP+*) hypothesizes a fast development of the CSP industry and has a further cost reduction for the related components. Moreover, the potential for CSP in a non-interconnected power system is analysed based on the example of simulations for Crete, including an assessment of the impact of a potential interconnection to mainland Greece.

KEY FINDINGS

- **VRES will cover more than 70% of the 2050 gross electricity demand in all scenarios**. Hydro, nuclear and other renewables will contribute with around 20-25% whereas conventional generation (mainly from natural gas) will account for 0-3% of the total supply.
- **A large uptake of CSP in Europe is possible only with bigger cost reductions than expected by the industry**. For new installations to be competitive in 2020-30, the price of CSP power plants needs to be reduced by over 1 million EUR/MW.
- **Solar PV and batteries are the main competitors to CSP and Gridsol.** PV is expected to more-than-halve its investment costs from 2018 to 2050 and electric storage can defer dispatch to evening and night hours as does thermal storage in CSP plants.
- Despite the lower DNI, CSP is more competitive in **France and Italy**, better interconnected countries in which the electricity price is higher and the competition with PV and batteries less pronounced.
- **CSP and Gridsol have a higher cost but the value of the electricity generated (Market Value) is much higher than PV**, therefore they can still be competitive concepts.

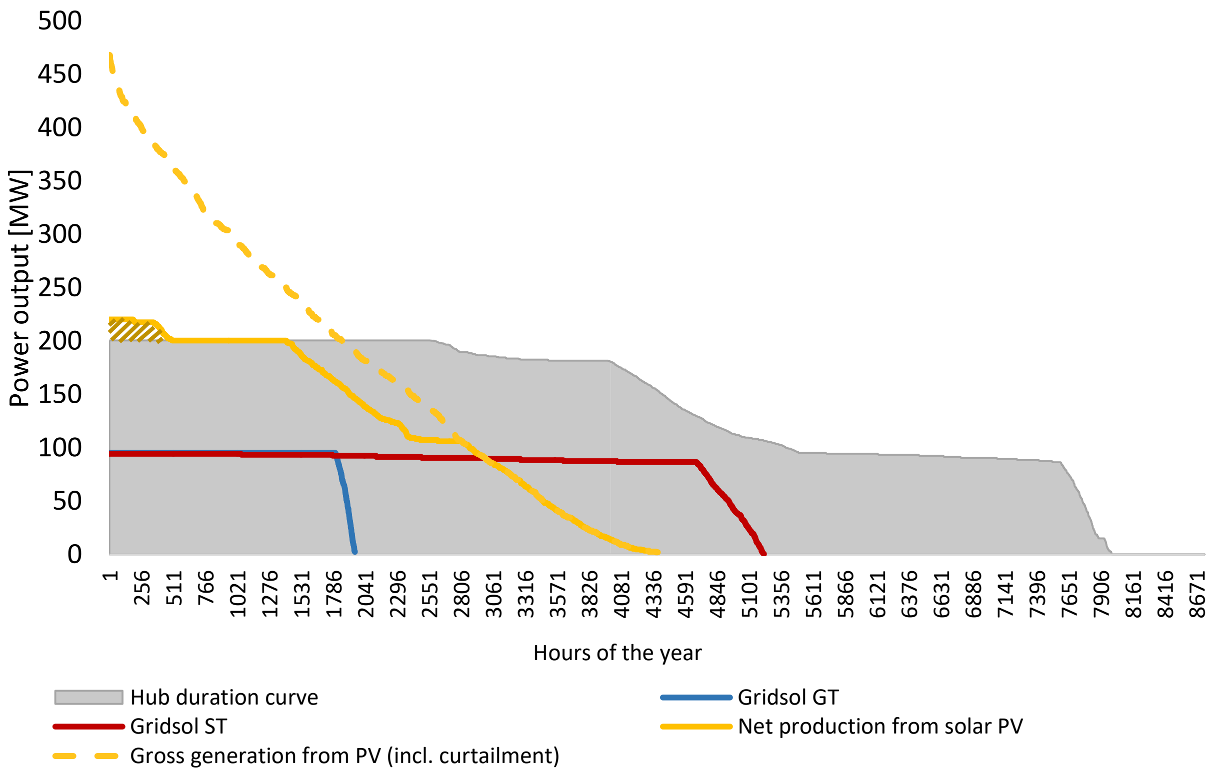


COMPARISON BETWEEN LCOE AND MARKET VALUE (MV) OF CSP AND PV (2050).

- The **gas (or biogas) turbine plays a marginal role** in the CSP-gas groups and is mainly installed as a backup for times of supply shortage. The use of the turbine in the hub is however more competitive compared to a normal combined cycle or a peaker, since the cost of the steam turbine is shared with the CSP and can take advantage of the storage system.
- **The configuration of new CSP power plants must include large solar fields and thermal storage to allow intra- and inter-day shifting of power production.** Storage volumes for more than 20 hours of generation ensure continuous, nearly-nominal evening and night dispatch with the possibility of

extending operations on cloudy days**. The steam turbine operates as an intermediate/base-load unit, with full load hours up to 6400.**

- **Thermal storage inside CSP plants have a much lower cost per volume installed** compared to batteries. Therefore, thermal storage is cost efficient when large amounts of solar energy has to be stored for an extended time horizon beyond 4-10 hours.
- **The strong need for firm and dispatchable generation makes CSP hybrid groups extremely competitive in island systems**. Simulations for the isolated power system on Crete show shares of CSP in the generation of 35% in 2040. Interconnection to mainland Greece reduces the competitiveness of CSP and diminishes the optimal CSP capacity by over 200 MW.
- **Interconnection lowers electricity prices and reduces curtailment in off-grid systems**. On Crete, the electricity price drops by 24 EUR/MWh in 2050 if interconnection is established. Moreover, solar curtailment falls below 5% and wind curtailment is cut by 40% with respect to an off-grid scenario.
- **Smart Renewable Hubs are predominantly large PV plants in the short-term and semi-dispatchable groups composed of PV and batteries in the long-term.** CSP-based generation can be part of the hubs under the hypothesis of large cost reductions.
- In a Smart Renewable Hub, **PV benefits the most from sharing the cost of grid connection**, as its investment and operational costs are proportionally reduced more than for other technologies.
- **The integration of storage facilities and the overplanting of PV boosts the hybrid power plant's capacity factors**, which reaches values around 80% in 2050.



HUB DURATION CURVE - CSP+ SCENARIO, 2050, ITALY.

1. INTRODUCTION & OUTLINE

The present analysis is part of the H2020 Project **"GRIDSOL - Smart Renewable Hubs For Flexible Generation: Solar Grid Stability"**. The overall objective of the project is to develop a new solution combining synchronous and asynchronous-like generators at a power plant level, which will allow the increase of renewable energy sources (RES) share in electricity generation using a new approach: Smart Renewable Hubs. The proposed core of these hybrid hubs is a concept called Gridsol.

1.1. What are Smart Renewable Hubs and Gridsol?

Smart Renewable Hubs (SRHs) are hybrid power plants coordinated by an intelligent dispatch manager (DOME, Dynamic Output Manager of Energy). The **Gridsol** concept (Figure 1) is a specific type of Smart Renewable Hub that incorporates both synchronous and non-synchronous generators. The synchronous component (Figure 2) is constituted by a Concentrated Solar Power (CSP) power cycle and one or more Gas Turbines (GT) with heat recovery. The solar field is composed of many heliostats which concentrate the Direct Normal Irradiation (DNI) into one or more central towers, depending on the field size. The heat medium is a molten salt mixture, which flows into a hot and cold tank system where sensible heat can be stored. The thermal energy contained into the GT exhaust gas is also recovered through a heat exchanger and contributes to heating up the salt mixture in the hot tank. The power block of the CSP cycle consists of a sub-critical Rankine cycle, where steam is generated from the high-temperature salt mixture. The gas turbine can be fed by either natural gas or biogas and gives flexibility to the Gridsol hub. The Rankine cycle is ultimately the bottoming section of a combined cycle, where the gas turbine serves as the topping part. When fed with biogas, the CSP-gas group relies entirely on renewable energy.

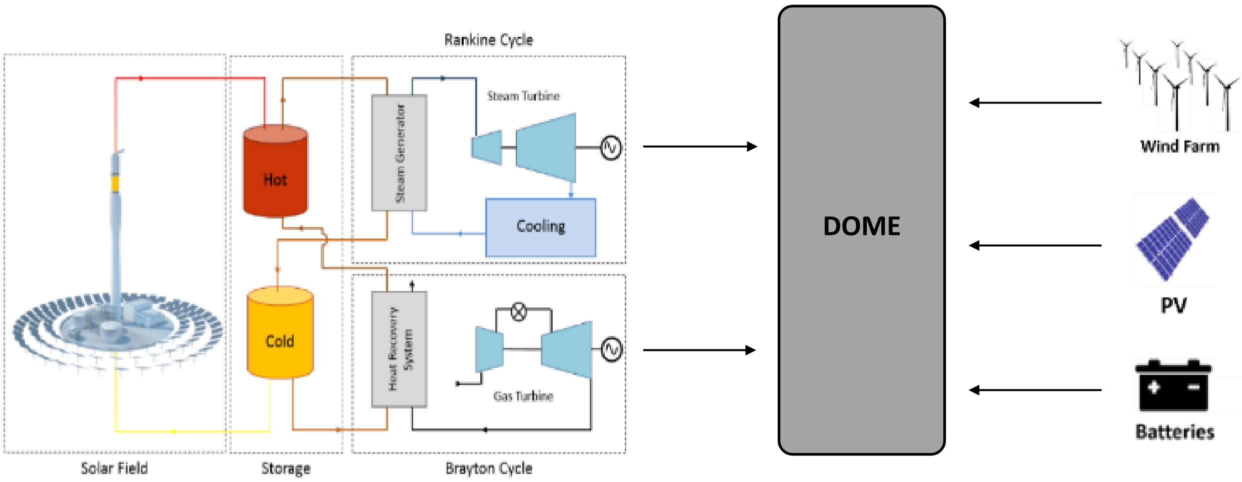


Figure 1. Gridsol hub.

SRH is therefore a general term to identify a hybrid power plant which may or may not integrate the CSP-gas hybrid group. The other technologies that can be installed in the hub are PV arrays and wind turbines along with electric storage (BESS); the latter reduces the energy curtailed from the VRES generators and shifts production to hours with higher prices, in order to boost revenues. The units are coordinated by an intelligent Domestic Output Manager of Energy (DOME), which minimises the revenue loss endured by non-dispatchable generators and optimises the system functioning.

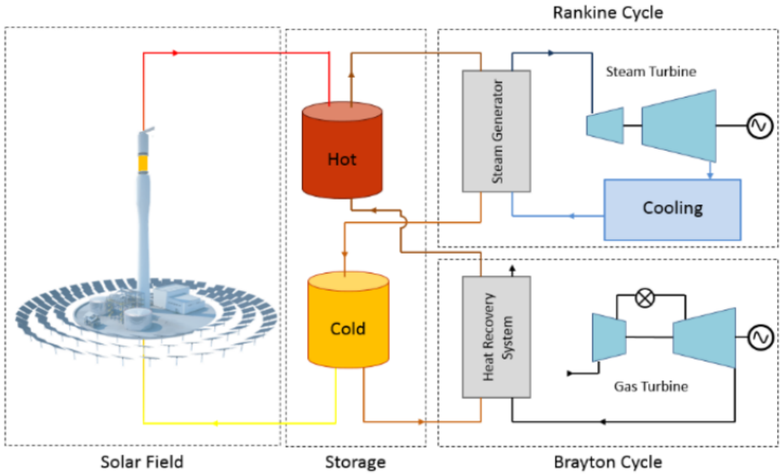


FIGURE 2. CSP-GAS HYBRID GROUP.

Altogether, the SRHs are able to ensure dispatchability and firmness with high Capacity Factors (CF) and minimum balancing penalties. In addition, the hub relies only on renewable energy sources when biogas is available. The increasing presence of VRES in the system, which are characterised by uncertain generation prognoses, supports the attractiveness of a firm, dispatchable plant such as Gridsol (Figure 3).

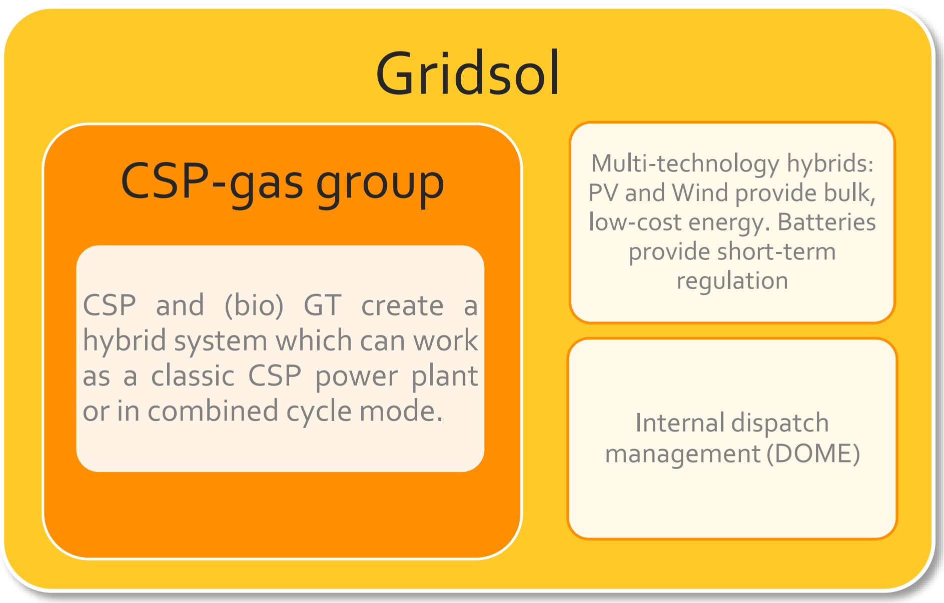


FIGURE 3. GRIDSOL CONCEPT.

1.2. Scope of the analysis

The work carried out in this study complement and add on other analyses performed in previous work packages.

Work package 5 (WP5) focused on analysing whether Gridsol and SRHs can be a solution in terms of adequacy of the transmission grid and included both a profitability assessment in 2030 and an analysis of the grid impact. Work package 6 (WP6) looked at the case of non-interconnected European islands and whether Gridsol can be an alternative supply of electricity. An analysis of Gridsol in the current power system in Crete was carried out for the year 2017 and several islands were analysed for 2030.

This work package (WP7) explores how CSP-based power plants, i.e. the distinctive component of Gridsol, may contribute to the long-term decarbonisation of the European power system; the study therefore investigates the optimal evolution of the generation fleet under technical and market constraints that reflect the ambitious and compelling targets set for the year 2050. It is in this changing landscape that the potential of Gridsol and Smart Renewable Hubs is assessed specifically: the long-term transition of the European energy sector towards a system that entirely relies on renewable technologies demands the strategic reorganisation and expansion of the power fleet.

The analyses takes a **socio-economic** perspective and disregards national taxation schemes, renewable energy subsidy and differences in cost of capital among between European countries. The CO_2 costs are internalized by using a quota price that represents the different potential evolutions of the EU ETS system.

The analytical focus is twofold, as it covers both **continental Europe and an island system**. Crete is chosen in the latter case due to its favourable solar conditions and in order to study how a potential interconnection with the mainland (Greece) would affect the role and profitability of CSP.

In continental Europe, France, Greece, Italy, Spain, Portugal are found to have a sufficient solar resource to consider the installation of large CSP units. However, the model analyses cover a much greater geographic area in order to properly account for the power flows between countries.

The analysis develops on two levels:

- the future potential of CSP-based power plants and the evaluation of their impact on both the European interconnected grid and on off-grid systems;
- the optimisation of the composition of Smart Renewable Hubs including an assessment of their strengths and operational features.

The distinctive features of CSP generation are clarified. In particular, the identification of directly competing technologies allows to shed light on the conditions that make CSP more attractive in the years to come. The thermal energy storage transforms CSP into a dispatchable technology and it is the most reliable, cheap and feasible solution to decouple resource availability and power dispatch for renewable generators. A thorough comparison between CSP with thermal storage and PV with BESS is part of the assessment.

1.3. EU 2050 SCENARIOS AND DECARBONISATION PATHWAYS

Following on the undersigning of the Paris Agreement in 2015, the European Commission agreed upon revising the Union's Climate Strategy to commit to the ambitious "well-below two degrees" and "1.5 degrees" targets.

In November 2018, the new EU Climate Strategy was published presenting different pathways envisioned to achieve a decarbonised economy by 2050. These trajectories ensure the development of such an economy in a socially-fair but cost-efficient manner [1]. The scenarios outlined in the new strategy lead to a more robust emissions cut than projected in the Baseline, which represents the mere continuation of current policies (65% reduction with respect to 1990).

This document represents a **new reference when looking at the future development of power system** in Europe and will set the framework for discussions on the future climate and energy policy. In addition, it is a relevant source of assumptions for analyses and will be the starting point for evaluating energy investments going forward.

The five "**well-below two degrees**" pathways feature reductions up to 80% (from 1990), while the two "**1.5 degrees**" trajectories deliver a fully carbon-free economy by 2050. The COMBO framework serves as a bridge between the two targets and combines elements of the other pathways. The power sector is expected to continue to be on the forefront with respect to decarbonisation. Due to the tightening of the EU ETS rules, progress in the efficiency of energy conversion systems and refined market models for the renewables' integration, emissions are expected to fall more rapidly than in any other sector. No matter the final decarbonisation target, the power sector shall be nearly decarbonised by 2050, with any residual emissions neutralized by Carbon Capture and Storage (CCS) [2].

While the soaring CO_2 prices provide the right signals for investments in renewable energy technologies, the substitution of fossil fuels with **hydrogen and other synthetic products** guarantees a progressive switch also in the heavy industry and in the transport sector. The ongoing improvements in the efficiency of electrolysers and fuel cells allow clean hydrogen to be a viable, scalable and cost-effective option for the future. Depending on the specific pathway, the deployment of a hydrogen infrastructure and economy is more or less pronounced. The Commission foresees at least 57 GW of electrolysers capacity installed by 2050, with the possibility of reaching 500 GW in case of a massive uptake of the H_2 economy.

The EU commission scenarios are used as a starting point and the main assumptions included in the design of the scenarios to be analysed. The main parameters considered from the decarbonisation scenarios, which creates the framework for this analysis are the following:

- **Price of CO_2**
- **Evolution of power demand**
- **Level of hydrogen production**

To simplify the setup, a synthesis of the different assumptions across scenarios has been carried out, given the large number of scenarios in the EU commission report.

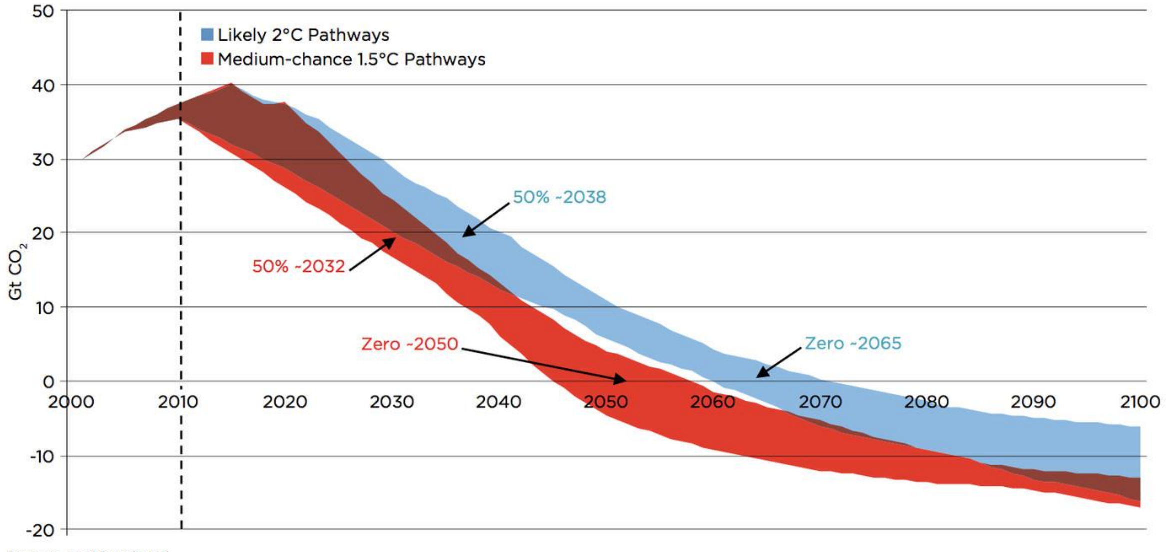
TEXT BOX.
THE DECARBONISATION OF THE ENERGY SYSTEM IN RELATION TO GLOBAL WARMING

The **Paris Agreement**, for the first time, brought all nations into a common cause to undertake ambitious efforts to combat climate change and adapt to its effects, with enhanced support to assist developing countries to do so. Its central aim is to strengthen the global response to the threat of climate change by keeping a global temperature rise this century well below 2 degrees Celsius above pre-industrial levels and to pursue efforts to limit the temperature increase even further to 1.5 degrees Celsius [23].

Experts from the Intergovernmental Panel on Climate Change (IPCC) expects climate-related risks for natural and human systems are higher for global warming of 1.5°C than at present, but consistently lower than at 2°C [24].

In order to stay in line with a scenario having a medium chance of limiting the temperature increase to 1.5 degrees, net zero emissions have to be achieved by 2050. Conversely, a less ambitious target of keeping a 2 degree likely trajectory would mean achieving zero emissions by 2065.

Figure 1: Range of Global Emissions Pathways in Scenarios Consistent with Likely Chance of 2°C or Medium Chance of 1.5°C[18]



Sources: Joeri Rogelj et al

2. INTERCONNECTED EUROPEAN SYSTEM

2.1. Status of the Power system in Europe

Growing RE in the mix, slowly declining coal

In the EU 28, the gross electricity consumption settled at 3,249 TWh in 2018. The largest share of generation came from conventional thermal units (46%), followed by nuclear reactors (25%). The electricity production from renewable sources was 28% (hydro, wind, solar and geothermal combined). Renewable energy generation has increased by 74 TWh compared to 2017, at the expense of coal and natural gas generation (Figure 4). In particular, coal and lignite generation slowly but steadily declined in the last few years, driving down CO_2 emissions from the power sector.

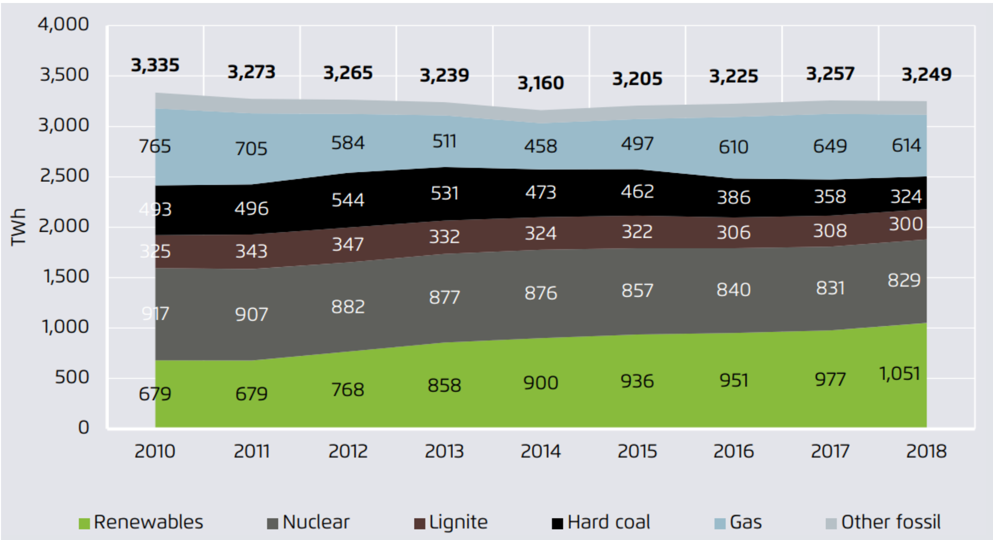


Figure 4. Development of EU28 generation overtime. Source: [3].

Europe plans on abating carbon dioxide emissions by 40% in 2030 with respect to 1990 levels. Specifically, the sectors covered by the EU ETS must meet a stringent 43% reduction with respect to 2005, where greenhouse gas emissions were 1711 Mt. According to a recent report by Agora Energiewende [3] the power sector has already met this requirement. In 2018 the emissions level fell down to 985 Mt, marking a 43% reduction relative to 2005.

Electrification of end-use sectors and diversification of the power demand

While the electricity demand has been growing for the fourth year in a row, the level is still lower than it was in 2010, testifying that conventional demand growth has reached a phase in which it is overall stagnant in the continent [3]. The final demand for electricity is expected to grow in the coming years due to the electrification of sectors like transport and the light industry. The booming market for heat pumps in conjunction with electric heating will foster the electricity use in households and data centres will account for an increasingly larger share of electricity use in the tertiary sector. The expectation from the

Deep decarbonisation scenarios of the European Commission is that by 2030 the demand rise 18% [2]. The rise in demand will be met mostly by VRES, due to the aforementioned limits related to conventional generators and the price of carbon dioxide emissions.

More ambitious targets for 2030 and coal phase-out

The EU Regulation and task force mandate 32% renewable generation in gross total energy consumption by 2030 and carbon neutrality by 2050. The power sector is set to continue driving the emission cut in the EU ETS thanks to more and more variable renewable energy in the European system. Moreover, through national programmes, many Member States have planned for the phase-out of lignite-fired and coal-fired units. Figure 5 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. The rest of Europe splits into Western and Eastern (including Balkan) countries; the latter have not 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. Overall, roughly 40 GW of installed coal capacity is going to be replaced in the countries that have announced the coal phase-out [4].

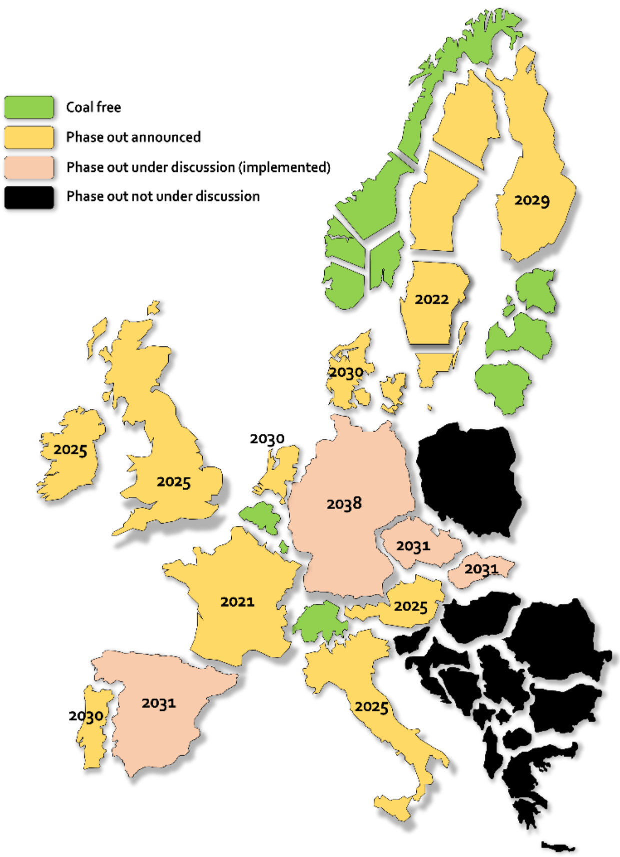


Figure 5. Status of coal phase-out in Europe. Elaboration based on data from (Europe Beyond Coal, 2019b).

The specific emission reduction targets and the renewable energy goals for the five Gridsol countries (France, Greece, Italy, Portugal, Spain) are reported in Table 1.

TABLE 1. GHG REDUCTION AND RENEWABLE ENERGY TARGETS FOR 2030 AND 2050.

Goals[1]					
	France	**Greece**	**Italy**	**Portugal**	**Spain**
2030 GHG reduction (compared to 2005 level)	40%	43%	33%	45-55%	32%
2030 Final energy consumption from RES	32%	32%	30%	47%	42%
2030 Electricity generation from RES	40%	56.4%	55.4%	80%	74%
2050 GHG reduction (compared to 2005 level)	100%	100%	100%	100%	100%
2050 Electricity generation from RES	100%	100%	100%	100%	100%

SOARING CO_2 PRICES IN THE EU ETS SECTOR

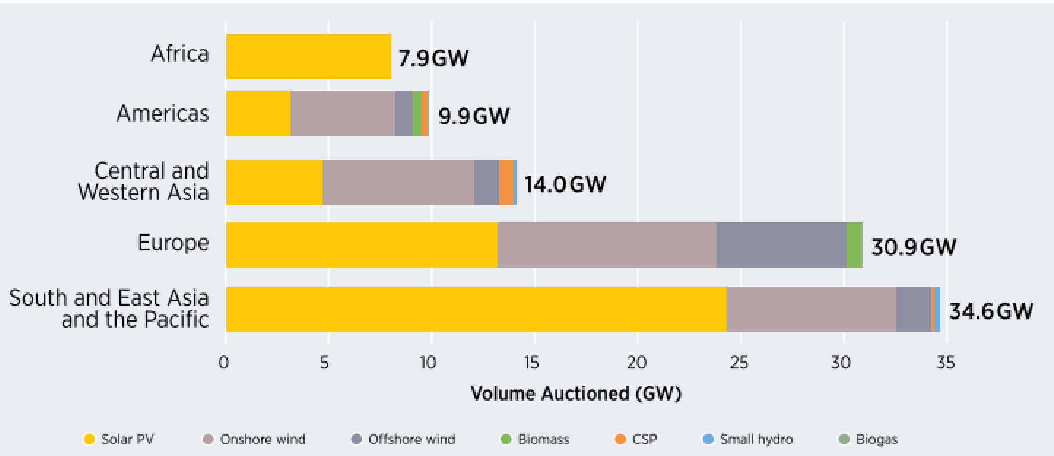
A paramount means to achieve the medium and long-term decarbonisation targets is the European Emission Trading System (EU ETS). The fourth phase (2021-2030) is going to see the implementation of a tighter linear reduction factor for the carbon cap, up from 1.74% to 2.20%. The system will act in conjunction with the newly designed Market Stability Reserve, which progressively lessens the number of allowances available for trade. As a consequence, the CO_2 quota price is set to substantially jack up in the years to come so as to provide the right signals for the phase-out of conventional generators and their replacement with renewable technologies. The new reforms affecting the EU ETS are expected to limit price oscillations and collapses, as recorded after the 2008 financial crisis (Figure 6).

FIGURE 6. EVOLUTION OF THE CARBON PRICE IN THE EU ETS SYSTEM (2008-2019).

[1] Source: National Energy Plans.

2.2. Status of Concentrated Solar Power (CSP) in Europe and the world

Over 2017-2018, 97.5 GW of renewable energy capacity were auctioned globally. Winning bids were almost exclusively solar PV and wind projects, accounting in total for more than 97% of the total volume [5]. As a not-yet-mature concept, CSP had a hard time keeping with the increased competitiveness of more established technologies. Less than 1% of the auctioned volume went for CSP capacity, predominantly in America and Asia, where the abundance of natural resources drive the generation costs down and, consequently, let CSP compete with other renewables (Figure 7). In these countries different types of public support have incentivised the spread of CSP and convenient financial frameworks have been adopted for renewables (including CSP) to achieve grid parity: they all aim at mitigating the risk connected to the realisation of a new CSP project and they include Power Purchase Agreements (PPA), Public-Private Partnerships (PPP) and other types of market-based tariffs and incentives. The size of recently built solar thermal power plants has increased to take advantage of economy of scale; it is in this framework that the solar tower concept is gaining momentum, particularly in sites with great solar potentials and devoid of land-use constraints. On the contrary, most of the existing CSP plants in Europe rely on the parabolic trough concept, though scattered installations lean on linear Fresnel and solar tower fields. The vast majority of these plants are found in Spain, where the installation of CSP units was incentivised through the use of a Feed-in Tariff (FIT) and lead to the rapid evolution of an industry with no prior experience in Europe. Among the Spanish solar thermal fleet, the Gemasolar plant constitutes an example of the central tower concept, with a remarkable storage volume (15 hours) that guarantees capacity factors up to 55%[2].



Note: PV = photovoltaic, CSP = concentrated solar power

Figure 7. Auctions in 2017-18: winning technologies per region. Source: IRENA.

In Europe, most Member States have used tenders to ensure new renewable energy installations. Different tendering designs have been put into place. In some contexts (the Netherlands, Spain, Poland, Portugal, the UK) technology-neutral auctions have been mandated, whereas in other cases governments have awarded the right to build new generation capacity to specific technologies. Solar PV and onshore wind have been the most widely auctioned technologies [6]. CSP was reserved a minor role in the integration of new capacity and the few recent technology-based tenders in France and Italy (below 100

[2] Source: NREL.

MW) led to scant bid volumes, insufficient to cover the assigned capacity. In the case of France, winning projects have had low realisation rates. Concentrated Solar Power suffers from the competition with more mature and established technologies, especially in locations characterised by a medium-low solar potential such as Europe. However, the current European CSP industry established in the course of few years and achieved a notable degree of maturity. New business models have seen the light, such as integrated, hybrid plants that incorporate solar thermal technologies into innovative plant layouts. Gridsol and Smart Renewable Hubs are an example.

ENABLERS FOR GRIDSOL AND CONCENTRATED SOLAR POWER

Despite the fierce competition with more mature technologies, the evolving European power sector sets potentially favourable conditions for the spreading of CSP and SRHs. The ambitious climate targets the European Union undersigned and the possible development of new markets (ancillary services) call for a faster replacement of conventional technologies and at the same time for a progressive need for more capacity; these are driven by the electrification of other energy and end-use sectors, namely the gas supply and the industry, in addition to the rising demand for new fuels (hydrogen and other P2X gases). Provided that sufficient cost reductions are achieved and new business models and financial frameworks are designed, CSP represents a competitive alternative in Southern Europe as it addresses market segments that traditional VRES do not fill.

Figure 8 shows that CSP auction prices are falling below 100 EUR/MWh in the world, due to technological advancements and a rather fast industrial uptake. As of 2019, the lowest bid on CSP technologies was set in the United Arab Emirates, where the Levelized Cost of Electricity (LCoE[3]) was estimated to be 72 USD/MWh [5]. Sites with an average DNI between 2000 and 2500 kWh/m^2 are expected to see notable

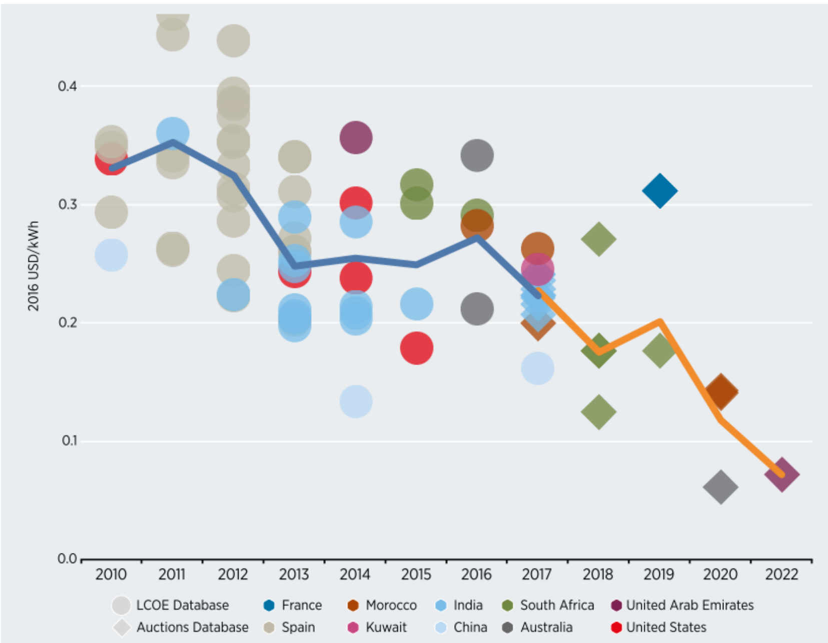


FIGURE 8. AUCTION RESULTS FOR CSP.

[3] The Levelized Cost of Electricity (LCoE) expresses the cost of the megawatt-hours generated during the lifetime of the plant, and it represents a life cycle cost. A definition is available in the Glossary.

LCoE cost reductions in future years; by 2035, these locations could host CSP power plants with average costs of generation under 60 EUR/MWh [7]. While locations with higher solar resources are certainly favoured, it is uncertain to which extent the industry will develop in future years. Little literature on the solar tower technology development exists, and learning rates (LRs) are difficult to identify with accuracy. Researchers envision LRs of 5 up to 20% [7], [8], but the ongoing standardisation of industrial processes may speed up the cost cut.

Competitiveness is the result of the progress within the industry and the evolution of system surrounding it. The aforementioned decommissioning of conventional power plants and the progressive nuclear shelving will leave a big room for new dispatchable technologies such as CSP and Smart Renewable Hubs. Indeed, the intelligent management and complementarity of the hub units can ensure a higher degree of flexibility compared to wind and solar. System operators across the continent will also see increased requirements in terms of system services and inertia of the fleet; these are nowadays provided by conventional fossil-fuel generators but their replacement can be a key-driver for CSP in both interconnected and island systems.

An additional enabler for concentrated solar power in the system will be the increasing exposure of wind and solar to market dynamics, which makes investments riskier and the lifelong coverage of financial layouts more uncertain. This is due to the abandonment of Feed-In Tariff (FIT) systems in favour of premiums or contract for differences awarded through auctions [9]. Flexible generators such as CSP with thermal energy storage are able to decouple resource availability and dispatch and can therefore profit from higher power prices.

Another consideration related to the market exposure is that when one type of variable renewable technology acquires large market shares, the average economic returns are progressively reduced. This is a consequence of VRES not being able to dispatch. The resulting low wholesale market prices in hours of high production challenge the competitiveness of solution that might be cheaper in terms of LCoE, like solar PV will be in the next future. Figure 9 stresses the dependence of the Value Factor (VF) on the renewables market shares. VF is defined as the ratio between the market value of a generator and the average wholesale market price. As the market penetration of a certain type of renewable increases, the VF drops.

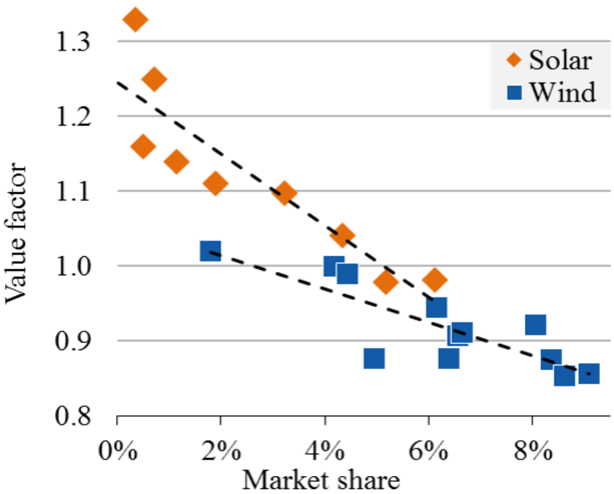


FIGURE 9. REDUCTION IN THE VALUE FACTOR (VF) FOR WIND AND SOLAR TECHNOLOGIES. SOURCE: [25].

2.3. Analysis and scenario setup

Research questions

The analysis identifies the key-drivers at the basis of a long-term CSP deployment in continental Europe. The technology can be integrated into the electric grid in the following manners:

- As a single-source technology;
- Combined with a gas turbine with heat recovery;
- Installed alongside other renewable units to form a hybrid power plant (Gridsol as a particular type of Smart Renewable Hub).

This work gives an overall picture of what is the market attractiveness of each of the previous concepts, when applied to decarbonisation pathways. More in detail, this deliverable answers to the ensuing questions:

- What is the role of CSP and Gridsol in the decarbonisation of the future European power sector?
- What are the factors influencing the profitability of CSP and Gridsol in different years and geographies?
- What role does CSP have in the electricity dispatch? What are the main competing technologies?
- What is the added value of flexible generation in a high VRES system and who can provide the flexibility?

Scenario analysis

In order to answer the research questions and take into account a range of possible developments of the power system in the future, a scenario analysis is conducted. In a scenario analysis, different possible outcomes are analysed considering potential "alternative futures" based on a range of input parameters.

The main focus for the choice of the scenarios in this analysis is related to **the extent of decarbonisation of the energy system**, measured with respect to the degrees of global warming. Specifically, the framework draws on the aforementioned Deep decarbonisation pathways from the European Commission (ref) presented in Section 1.3.

Given the uncertainty in the evolution of CSP and **Gridsol costs** in the medium- to long-term future, due to the lack of a solid number of projects and the relatively novel nature of the technology, the cost of CSP represents another dimension of the scenario framework. Specifically, a scenario with a further cost reduction compared to the baseline cost development is analysed.

The scenarios chosen for the analysis are the following (Figure 10):

- **Baseline**: represents a development of the European system with relatively moderate decarbonisation efforts and consequently a low price of CO_2. It follows the main assumptions from the EU commission Reference scenario from 2016 [10];

- **2.0 degrees**: follows main assumptions from the 2 degrees scenarios of the *Deep decarbonisation study* and aims at limiting the greenhouse gas emissions of Europe in order to be in line with a global temperature rise of "well-below" 2 degrees;

- **1.5 degrees**: follows main assumptions from the 1.5 degrees scenarios of the *Deep decarbonisation study* and aims at limiting the greenhouse gas emissions of Europe in order to be in line with a global temperature rise of no more than 1.5 degrees (corresponding to a close to 100% reduction of CO2 emission in Europe by 2050);

- **CSP+**: has the same overall framework as the 1.5 degree scenario, but considers a further 40% reduction of the OPEX and CAPEX of CSP compared to the rest of the scenarios (which use the Gridsol project reference cost projections).

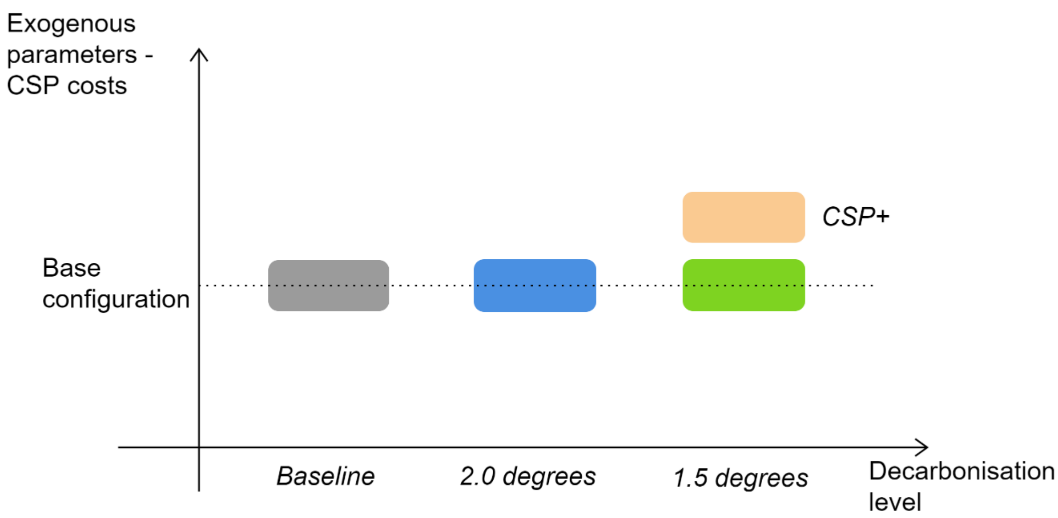


FIGURE 10. SCENARIO OVERVIEW.

Another important parameter related to the decarbonisation ambitions of the European energy sector is the utilization of electricity to produce hydrogen and other synthetic gases. These gases can be used to substitute fossil fuels in sectors that are harder to electrify or to convert to renewables, such as heavy transport, aviation and industry. Not surprisingly, the more decarbonized the energy sector is, the more the **demand for hydrogen** increases, and so does the electricity demand needed for its production through electrolysis processes. While in the Baseline, for the EU-28 countries alone, it reaches a value of 4 Mtoe in 2050, this increases to 20 and 80 Mtoe respectively for the 2.0 degrees and the 1.5 degrees scenarios respectively. To give an idea of the magnitude of the power demand top-up, 80 Mtoe of hydrogen correspond to a minimum power demand increase of around 1200 TWh, corresponding to roughly 38% of today's European electricity consumption. As a consequence, the amount of power plants needed to fulfil this demand greatly increases in the more extreme decarbonisation scenarios.

Table 2 gives an overview and a recap of the main assumptions in the four scenarios analysed.

Table 2. Scenario characterisation.

Scenario	GHG reduction target (all sectors)	CO_2 price (2050) [EUR/t]	H_2 demand in EU-28 (2050) [TWh]	CSP cost projections
Baseline	65%	91	47	Gridsol project reference
2.0 degrees	80-85%	251	233	
1.5 degrees	~ 100%	366	930	
CSP+				-40% CAPEX and OPEX compared to reference

Text box. CSP cost projections

The CSP+ scenario assumes a 40% cost reduction with respect to projections foreseen by the CSP industry. The literature available on the topic reflects these assumptions, but a rapid uptake of CSP could reduce and totally bridge the existing gap. Concretely, this means technological advancements should cut costs for 1.2 million EUR per MW_e installed already by 2030, assuming a solar multiple of 2.5 (Figure 11). Automation, improved technical design and an efficient industrial supply chain can contribute to this drop (in the figure, future costs are normalized with respect to 2018 costs).

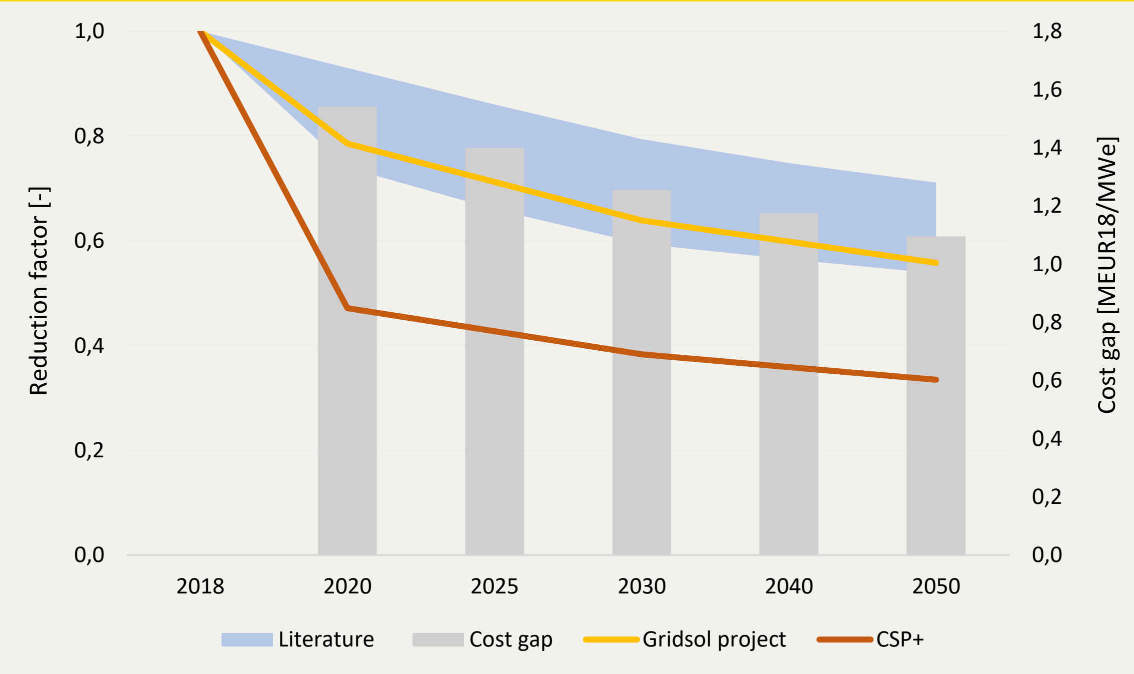


Figure 11. CSP cost assumptions in the scenarios under study.

The model: Balmorel

To carry out the analysis, the **Balmorel model**[4] is used. It is an open-source, bottom-up, fundamental model which optimises the investments and the operations of large-scale energy systems, more specifically in the power and heat sectors, with a resolution down to the hourly level.

The simulations cover the years between 2020 and 2050, with 2018 being the reference year and intermediate simulations for 2030 and 2040. For each year the model optimized the development of the system in terms of generation fleet, as well as the dispatch of power plants to fulfil demand at the lowest cost.

The geography considered in this study comprises the EU 28 plus Bosnia, Kosovo, Macedonia, Montenegro, Norway, Serbia and Switzerland (Figure 12). The five Gridsol countries, in which investment in the CSP and SRHs are allowed, are highlighted. Countries can be divided into several Regions reflecting the local structure of the electricity market or to better represent conversion technologies and the grid infrastructure.

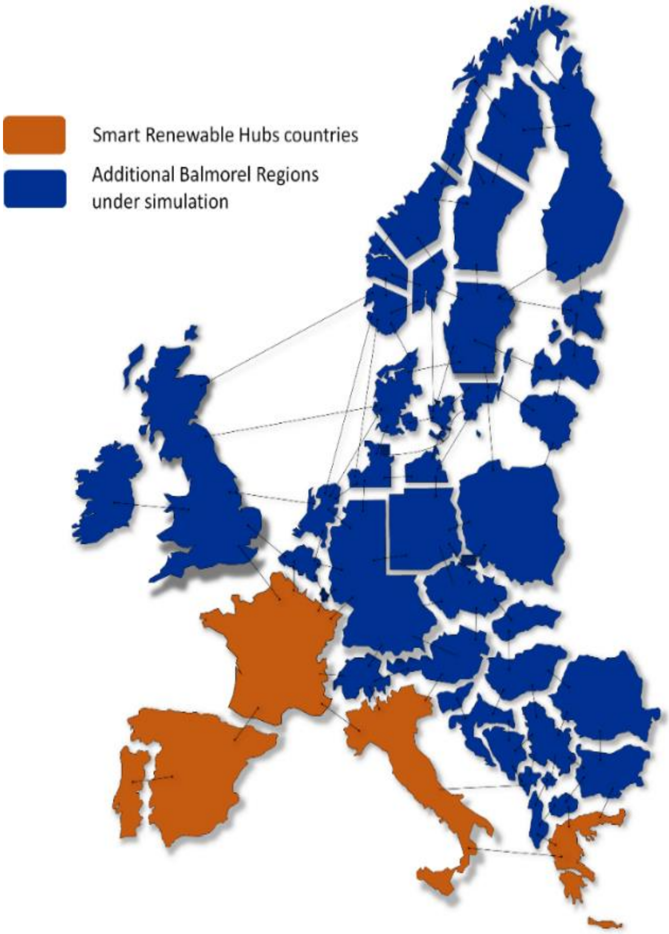


Figure 12. Geographical scope of the model.

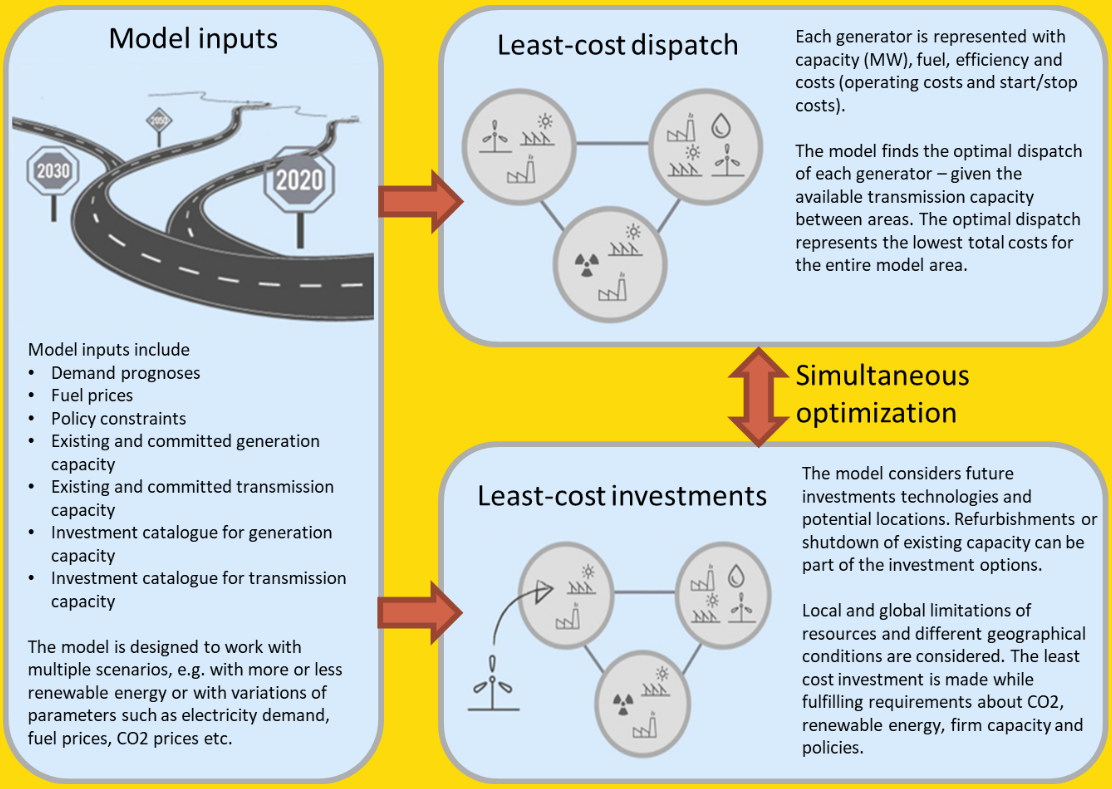
[4] More details on the model characteristics can be found in the text box below. The Appendix include a more detailed overview of the assumptions behind the modelling.

Text box. The Balmorel Model

Balmorel is an open-source, bottom-up, fundamental model which optimises the investments and the operations of large-scale energy systems, more specifically in the power and heat sectors; it is coded in GAMS (Generalised Algebraic Modelling System) and converges to the optimal solution by means of linear programming techniques. For unit commitment problems, integer variables can be introduced as well. 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. The goal of the 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 and operational expenditures (CAPEX and OPEX) plus any other cost the system incurs:

$$\min_{s,o} z = \min_{s,o}(a \cdot CAPEX_{s,o} + OPEX_{s,o} + other\ expenditures_{s,o})$$

where *z* represents the problem's objective function and *a* the factor the annualises capital expenditures. The optimal solution yields the least-cost dispatch and the least-cost investments, both generation- and transmission-wise. Finally the model is deterministic and perfect foresight is assumed in the various optimisation/simulation modes.



2.4. Results for the European power system

What is needed to decarbonise Europe?

Given the cost drop experienced by variable renewable energy, moderate CO_2 prices, lower than 100 EUR/t, are sufficient to achieve a long-term deep decarbonisation of the power sector. This level is not enough for the rest of the economy.

The EU Climate Strategy published in November 2018 envisions very high CO_2 prices in the EU ETS if the 2.0 and 1.5 degrees targets were to be pursued (Table 3). This is necessary to achieve high levels of decarbonisation in the entire economy, but the power sector may need less. A quota price of 100 EUR/t leads to a 94% and a 95% emissions cut in the 1.5 and 2.0 degrees scenarios already and the Baseline a price of 91 EUR/t in 2050 is enough to reach a 94% emissions cut with respect to 1990.

In 2020, the 21 EUR/t price brings the European power sector beneath the 1000 Mt threshold, down 26% from 2015 and down 48% from 1990. The power sector moves towards decarbonisation more or less rapidly, with the 1.5 degrees pathway reaching a 98.2% reduction in 2050 (Table 3). For this to become true in a pure market setting, carbon quotas should reach a price of 366 EUR/t in 2050. It is important to notice that a modest 60 Mt additional cut is achieved through a consistent jump of the CO_2 quota price (+275 EUR/t in 2050 from the Baseline to the 1.5 degrees setup).

It can be stated that in highly-decarbonised visions there is a larger need to replace fossil-fuel units in the short- and medium-term: this is a key period for the integration of renewables into the power sector. As 2050 approaches, fossil fuels are progressively driven out of the system due to the decarbonisation efforts, represented by a growing carbon price (Figure 13), and CSP is competing only with other carbon-free sources of power.

Table 3. CO2 emissions reduction in 2050 with respect to 1990 and 2015.

Pathway	2050 CO_2 reduction [%] with respect to		CO_2 emissions (2050) [Mt]
	1990	2015	
Baseline	95.7	94.0	80
2.0 degrees	98.3	97.6	32
1.5 degrees	98.7	98.2	20

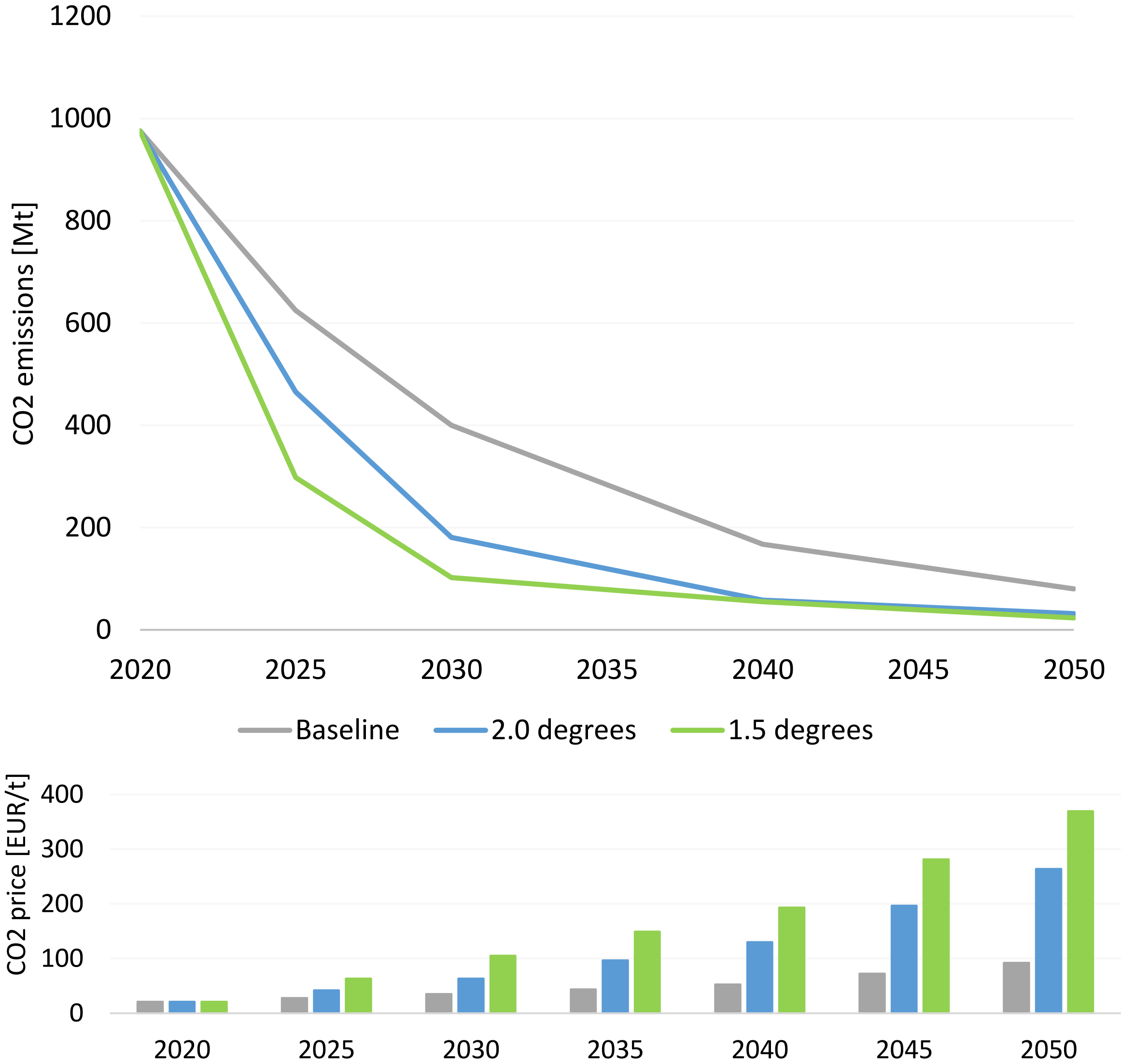


FIGURE 13. CO2 EMISSIONS REDUCTION IN THE THREE PATHWAYS (ABOVE) AND ASSUMED CO2 QUOTA PRICE OVER THE YEARS (BELOW).

SHELVING CONVENTIONAL TECHNOLOGIES IN FAVOUR OF A SYSTEM BASED ON VRES

By 2040 more than 90% of the gross electricity demand will be supplied by renewables and nuclear power plants already in the Baseline scenario. Decarbonisation is also supported by national commitments to the phase-out of coal units.

As medium-range CO_2 prices are enough the achieve high levels of decarbonisation, the Baseline scenario reaches a high penetration of renewables at the end of the investigated horizon. Wind and solar power supply more than 70% of the gross demand in 2050. Coal generation is set aside in favour of natural gas technologies in the short-term, but medium CO_2 prices of around 100 EUR/t and renewable alternatives downscale generation from gas in 2050 to 20% of the 2018 generation (Figure 14).

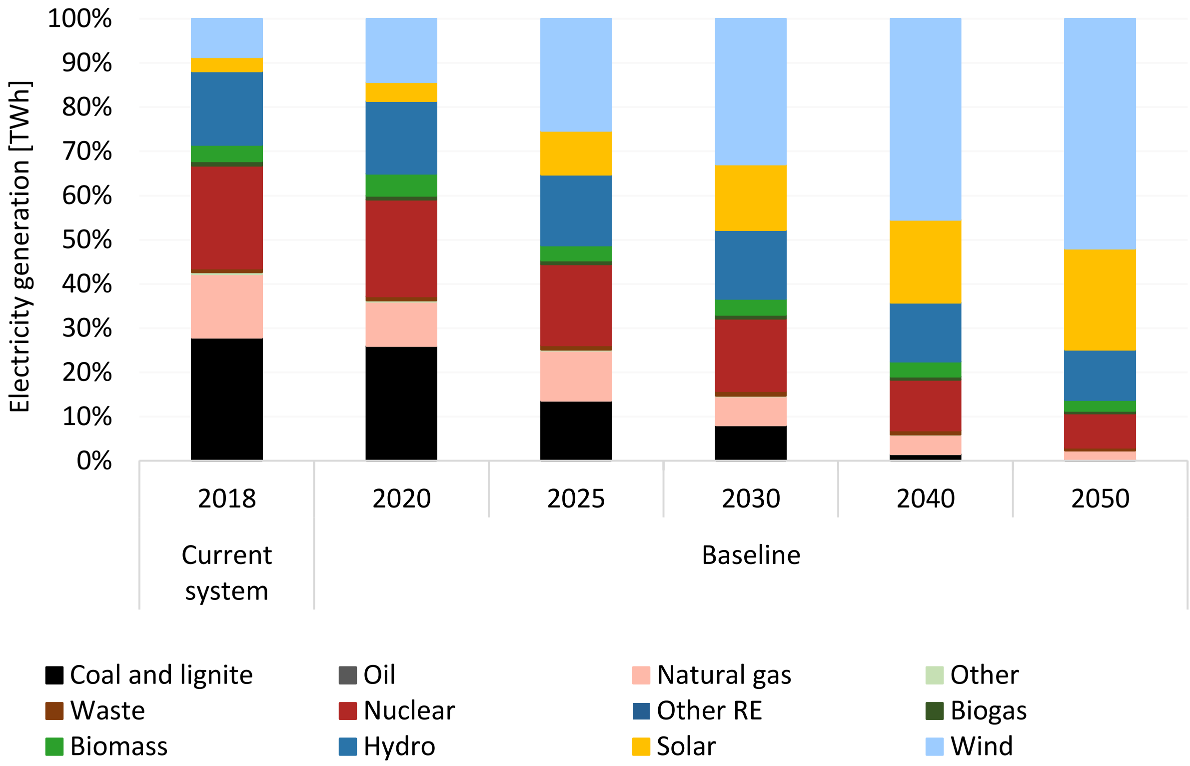


FIGURE 14. ELECTRICITY GENERATION IN EUROPE IN THE BASELINE SCENARIO.

The share of renewable energy in the generation mix increases as cost for renewable energy decreases and the CO_2 price soars in the different scenarios (Table 4). Following the national plans of decommissioning of nuclear power reactors across Europe[5], nuclear power plants are limited to a narrow market participation, which shrinks down to 4.5% in 2050. Contrary to the few natural gas peakers remaining, nuclear units dispatch base-load power and run for a high amount of full load hours, above 5000 hours for every simulated year.

TABLE 4.RENEWABLES AND NUCLEAR GENERATION SHARES ACROSS SCENARIOS (2050).

2050 generation shares	**Baseline**	**2.0 degrees**	**1.5 degrees**	**CSP+**
Share of renewables [%]	89.3	92.6	94.5	95.0
- *VRES (solar and wind) [%]*	74.8	77.9	78.3	73.1
- *Hydro, biomass, biogas, CSP [%]*	14.4	14.7	16.2	21.8
Share of nuclear energy [%]	7.7	6.4	5.0	4.5
Share of non-renewables [%]	3.0	1.0	0.5	0.5

[5] The development of nuclear capacity in Europe is not optimized by the model but based on national plans, since its deployment is based on a number of factors other than the economic profitability.

Electrification and green hydrogen behind surge in power demand

With hydrogen demand reaching up to 930 TWh in 2050 in the most decarbonized pathway, the gross electricity demand and the installed capacity would more than double with respect to today. Electrolysers will produce hydrogen by using cheap power from VRES, mainly coming from solar PV.

If CO_2 prices provide the appropriate signals to replace fossil-fuel units with renewables until the 100 EUR/t threshold, it is the rise of a new demand for hydrogen and higher electrification targets that can boost additional investments in renewable capacity. In the Baseline scenario, the demand in 2050 reaches 5368 TWh, 63% more than in 2018, while in the 1.5 degrees scenario it increases by 134% with respect to the same year (Figure 15). Since in all scenarios end-use demand is increasing slowly overtime due to counter effect of energy efficiency, this additional electricity demand is entirely due to hydrogen production and electrification of industry, transport and heating.

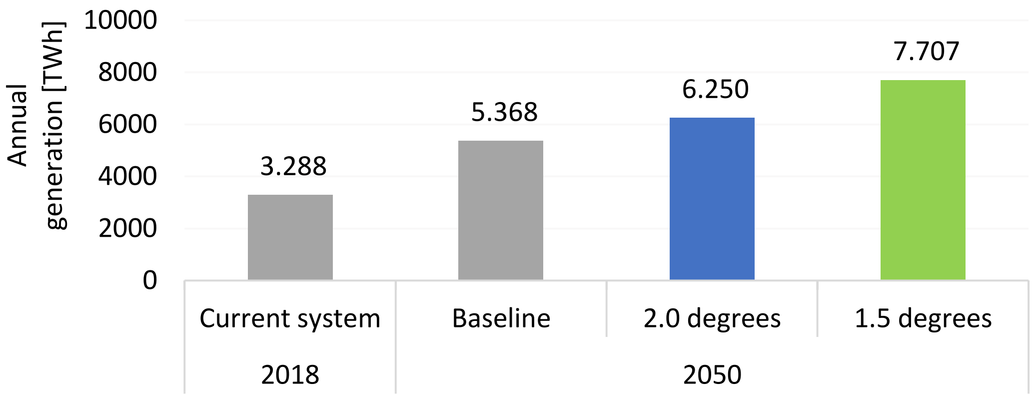


Figure 15. Annual demand in 2050 compared to 2018.

In order to cope with this surge in demand, a larger buildout in power infrastructure is needed, both in terms of generation and transmission. The combined average annual solar and wind buildout in the period 2020-2050 increases from 122 GW in the Baseline to around 180 GW in the 1.5 degree scenarios, with the solar quota almost doubled (Figure 16). In the CSP+ scenario, less solar PV capacity is built to the benefit of CSP.

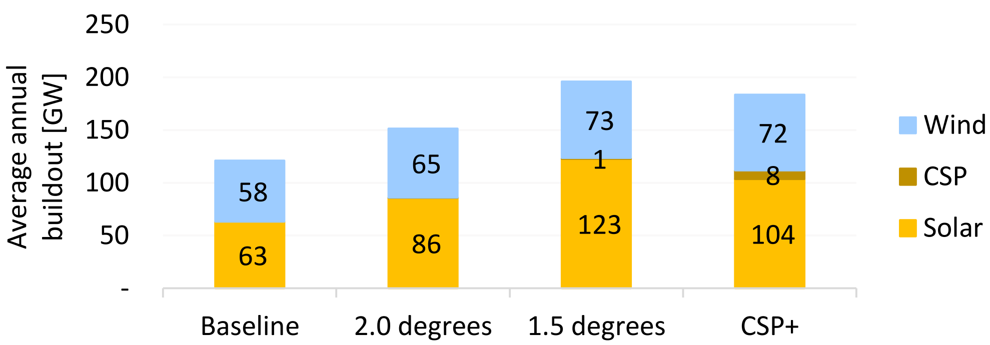


Figure 16. Average annual buildout of wind and solar capacity.

The fast-unfolding solar generation

Lead by large cost reductions and increasingly efficient photovoltaic modules, in 30 years solar energy will account for almost 30% of the electricity generation in Europe, with national shares above 50% in Southern Europe. Batteries will be needed to balance generation and provide flexibility.

The cost of solar PV modules has been steadily declining in the last 10 years, driven by larger deployment, competitive procurement through auctions and efficiency improvement in manufacturing. As testified by the latest analyses on the cost of RE worldwide [11], the expenditures related to the installation of PV last year were a fourth compared to the 2010 level, that is around 1.03 MEUR/MW (1210 USD/kW) compared to 3.93 MEUR/MW (4621 USD/kW) (Figure 17).

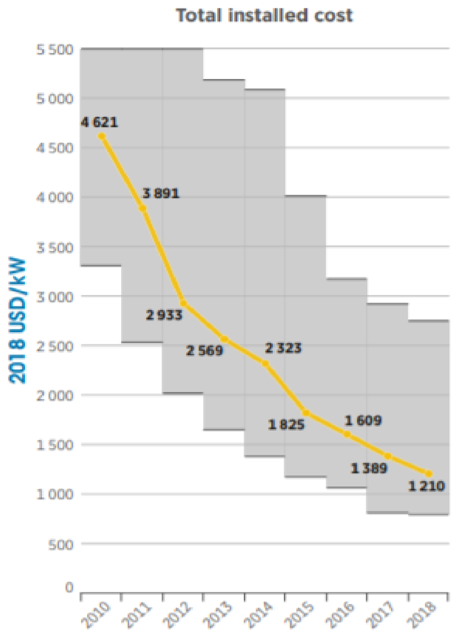


Figure 17. Historical decline in cost of PV.

The cost of PV is expected to further drop as a result of increased worldwide deployment. In the performed analysis, the cost of solar is assumed to develop following assumptions in the technology catalogue of generation technologies[6]. The expected decline in cost of PV is lower than what experienced historically and the value goes from 0.65 in 2020 to 0.43 MEUR/MW in 2050.

The latest record-low bids for PV auctions fortify the narrative that PV will become the cheap bulk electricity source for the power systems of the future. In 2019, the lowest bids for PV were awarded in Portugal and Dubai, with tariff levels of 14.8 and 15.4 EUR/MWh [12].

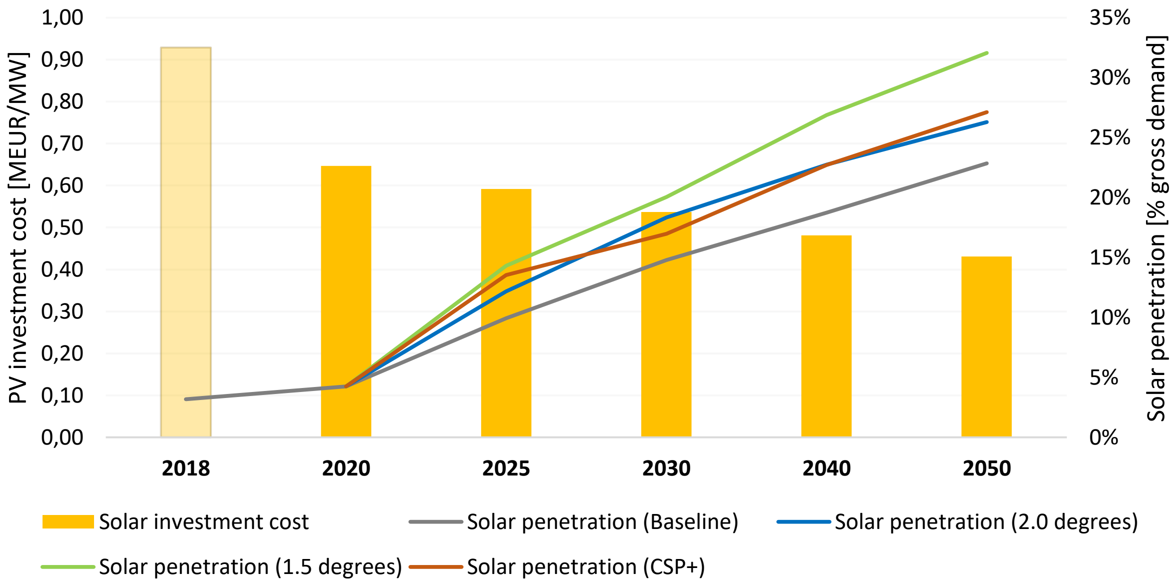


Figure 18. Development of PV costs and system penetration.

[6] The technology catalogue of generation technologies is updated regularly by the Danish Energy Agency and contains financial and technical data regarding generation technology for the power sector, based on latest auction results and developments worldwide.

As the cost of solar declines, penetration at EU level surges, reaching between 23% and 32% in 2050 across scenarios (Figure 18). This is a significant level considering the fact that solar generation is concentrated in the central part of the day, in which demand is not at its highest, and any excess must be shifted to other hours of the day using storage or flexible demand. To give an idea of the magnitude, the installed capacity in Italy and Spain reaches more than 200 GW in 2050 (Table 5).

Table 5. Installed solar PV capacity in the four scenarios.

Country	Year	Baseline	2.0 degrees	1.5 degrees	CSP+
Italy	2030	89	110	123	89
	2050	189	212	283	232
Spain	2030	84	96	103	75
	2050	166	220	298	253
France	2030	31	31	31	31
	2050	91	157	250	164

The countries with the largest amount of solar generation in 2018 are Italy (8%) followed by Greece and Germany (7%) and Spain (5%) [3].

In the modelled period, i.e. between 2020 and 2050, solar PV becomes the cheapest source of generation in most of the countries in central-south Europe. This is reflected in a progressive increase in the share of solar in the generation fleet, reaching above 50% in countries like Portugal, Italy and Spain in 2050 (Figure 19).

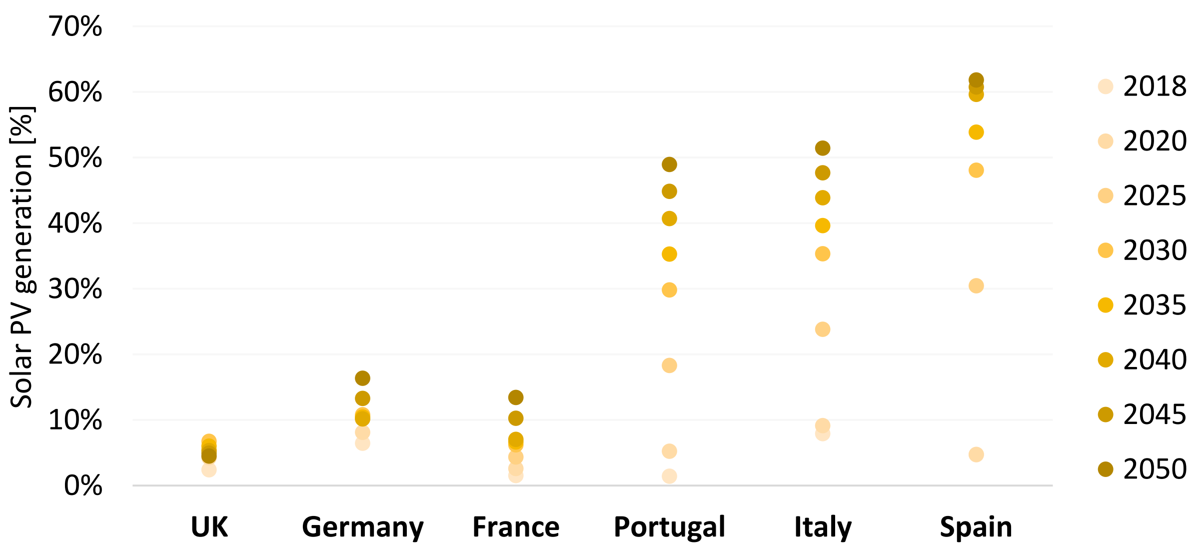


Figure 19. Share of solar PV generation in selected countries in the baseline scenario.

The evolution of the wholesale power price with low marginal cost generation

Wholesale electricity prices tend to become more volatile throughout the day and the year for the opposing effect of the CO_2 price surge and the storage on one hand and growing share of zero-marginal cost RE on the other. Countries with high solar irradiation like Spain experience a price drop overtime, as penetration increases.

The assumption behind the analysis and the modelling performed is that the power market in Europe will keep functioning as an energy-only market, that power markets are coupled internationally and that price signals will be enough to attract the adequate supply, be it in the form of new generators, transmission or storage technologies.

Among the various factors affecting the hour-by-hour wholesale electricity price in the day-ahead market, the **increasing CO_2 price** and the **progressive increase of VRES** in the system are the most influencing. While the former drives up the short-run marginal cost of conventional generators, the latter contributes to the reduction of prices at times of high RE feed-in from low marginal cost sources.

As shown in Figure 20, prices increase in the very short term and they then stabilize towards 2050. The Gridsol countries follow however different price trends. In Italy and France, that are the countries with the lowest irradiation out of the five considered, the wholesale market price ends up being higher than the EU average after 2040. Conversely, the price in Spain, Portugal and Greece exhibits a different long-term trend: the surge in solar penetration drives average prices down. Moreover, Italy is a net importer in the scenario displayed, as shown in Table 6.

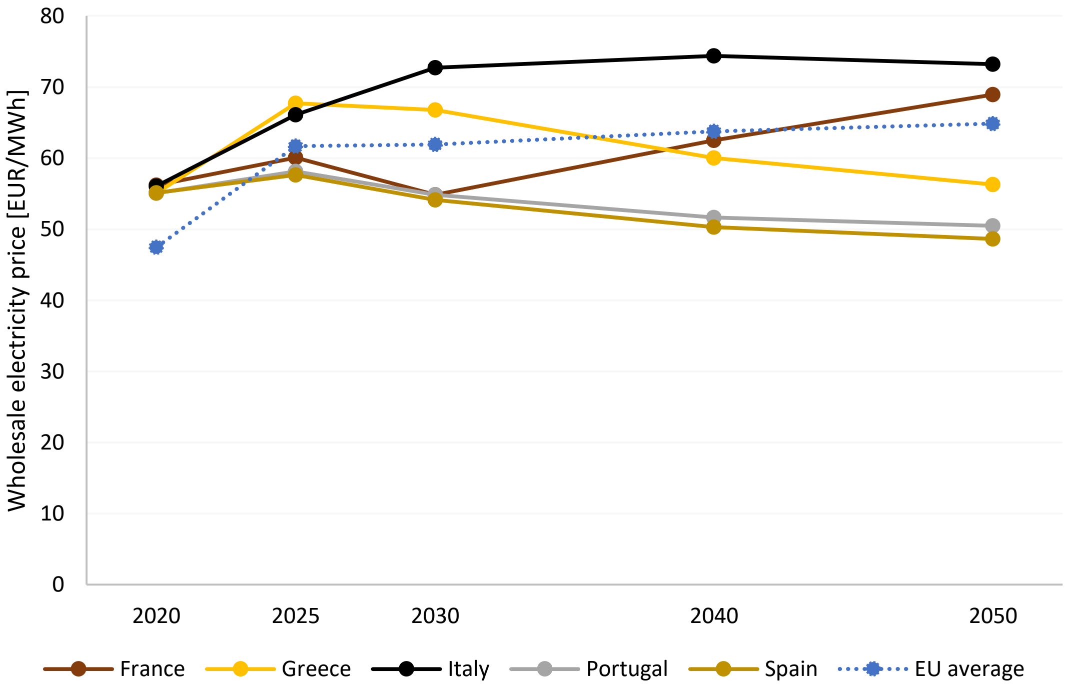


Figure 20. Development of the wholesale market price in the Gridsol countries and EU average - 1.5 degrees scenario.

TABLE 6. NET EXPORTS IN THE GRIDSOL COUNTRIES. SCENARIO 1.5 DEGREES - 2050.

	France	Spain	Greece	Italy	Portugal
Net exports [TWh]	124	82	4	-19	-18

A cross-scenario comparison (Figure 21) shows that as climate ambition escalates (Baseline → 2 degrees → 1.5 degrees) the electricity price increases in all countries. It is also worth noting that in the CSP+ scenario, which has the same overall assumptions of the 1.5 degrees scenario, the price drops quite significantly. In Italy and France the **price drop due to CSP** is significant and equals 11 and 6 EUR/MWh respectively. In CSP+ scenario, the investment in a higher amount of CSP due to the lower cost estimates reduces wholesale power prices significantly.

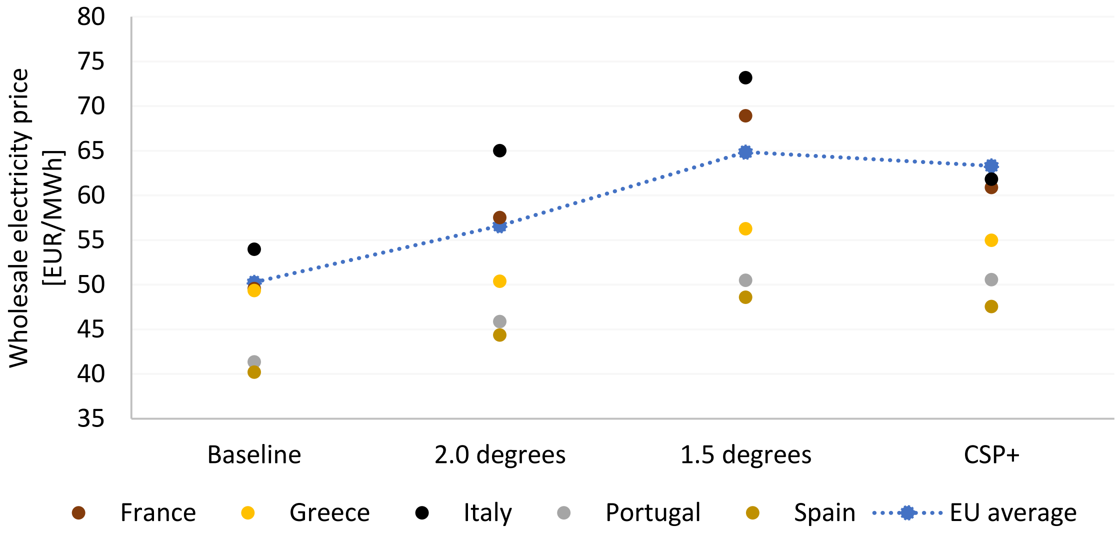


FIGURE 21. WHOLESALE PRICES IN 2050 ACROSS SCENARIOS FOR THE GRIDSOL COUNTRIES AND EU AVERAGE.

By taking a closer look at price dynamics, and specifically at the hourly price duration curve[7], an **increased price volatility** can be noted towards 2050: the number of hours with very low prices increases. In Spain (Figure 22), if the price profile is rather flat in 2020, there appear around 1000 hours with nearly-zero price in 2030, more than 2000 hours in 2040 and 3000 in 2050. At the other extreme of the curve, values soar for the combined effect of higher CO_2 prices and the cost of establishing storage facilities.

[7] A price duration curve shows the number of hours over the year (x-axis) when the power price was above a certain value (y-axis). It practically represent all the hourly prices in a year ordered from highest to lowest.

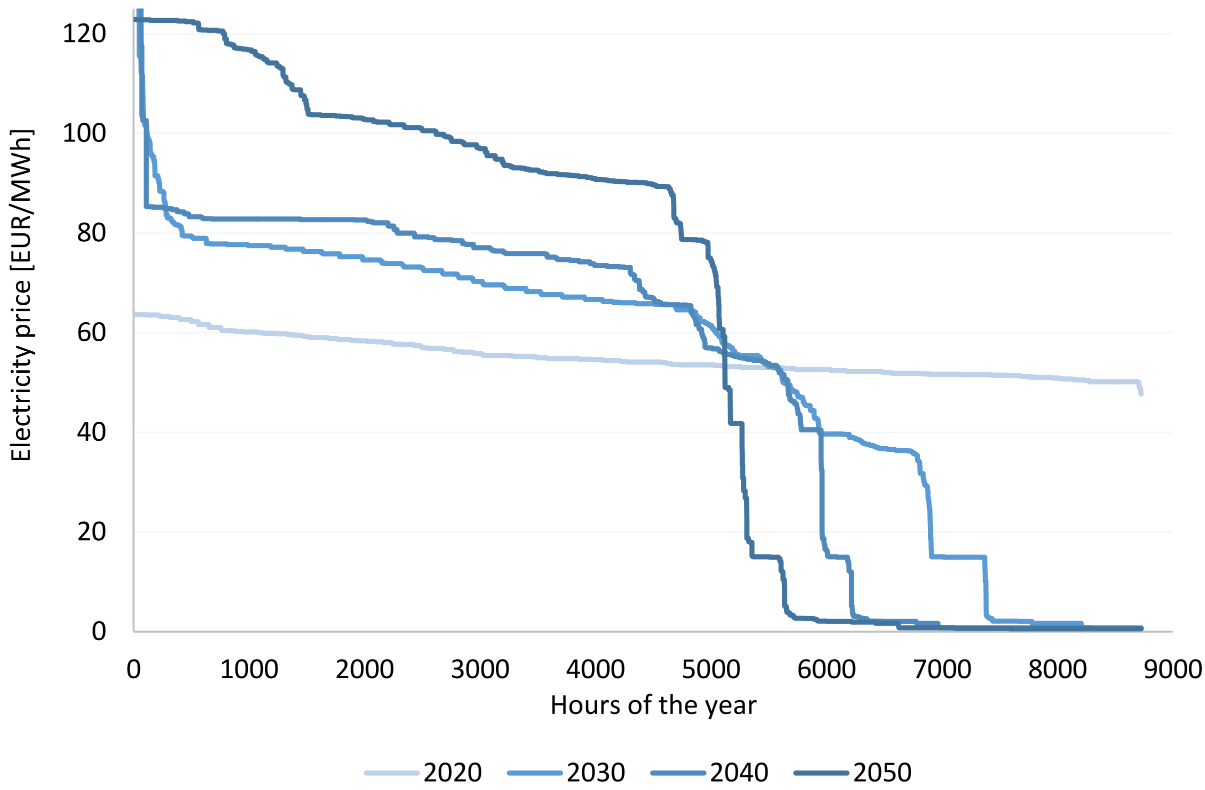


FIGURE 22. PRICE DURATION CURVES FOR SPAIN OVER THE TIME HORIZON - CSP+ SCENARIO.

Among the factors affecting the price formation in the wholesale electricity market are the irradiation and wind speeds, electricity demand dynamics, available generators in neighbouring countries and flow through interconnectors. Figure 23 shows an example of price and energy flow dynamics across the simulated regions for 2050 (1.5 degrees scenario). Just like today, the Nordic countries maintain a lower price compared to continental Europe thanks to a large amount of hydro and wind generation. Great Britain benefits from the large wind penetration thanks to the abundant offshore wind potential and southern European countries have lower prices thanks to the large solar power penetration in the system. Among these countries, Italy is an exception, with a relatively higher price mainly due to the fact that it is a net importer of energy on an annual level and that it has a relatively low potential for RE other than solar.

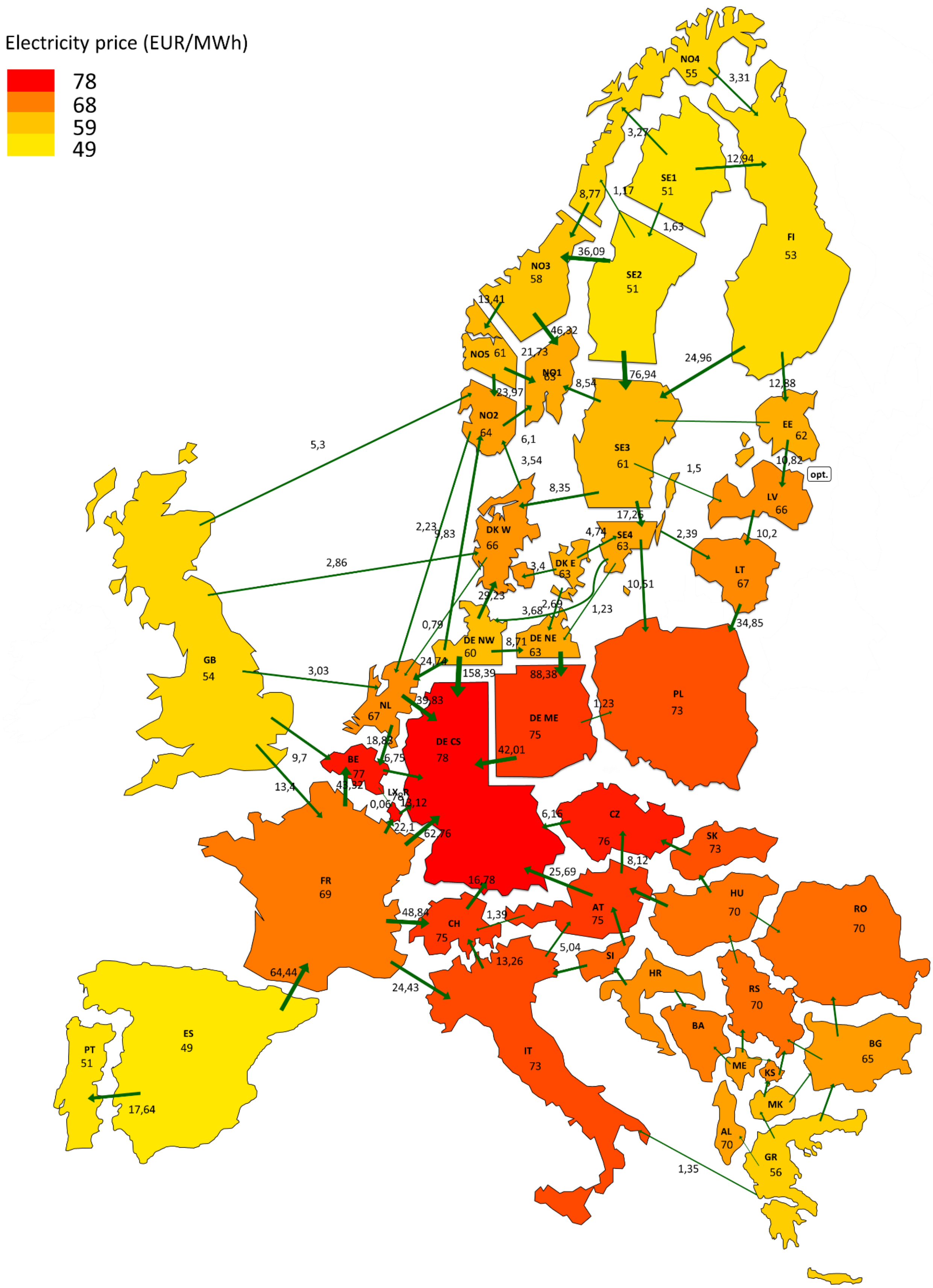


FIGURE 23. POWER PRICE AND ELECTRICITY FLOW IN INTERCONNECTORS. SCENARIO 1.5 DEGREES - 2050.

INCREASED INTERCONNECTION IN EUROPE TO INTEGRATE MORE FLUCTUATING RE

Up to 2050, large investments in interconnection capacity are expected enabling an efficient RE integration: in the long-term, Continental Europe imports large amounts of wind from the North and solar power from the South. The power exchanges become more complex with daily cycles following the variations of the resources, particularly solar.

Interconnectors are a key component of the power system and essential to the functioning of the European electricity markets. They allow to exchange power between different market zones and reduce the cost of supply in the total system.

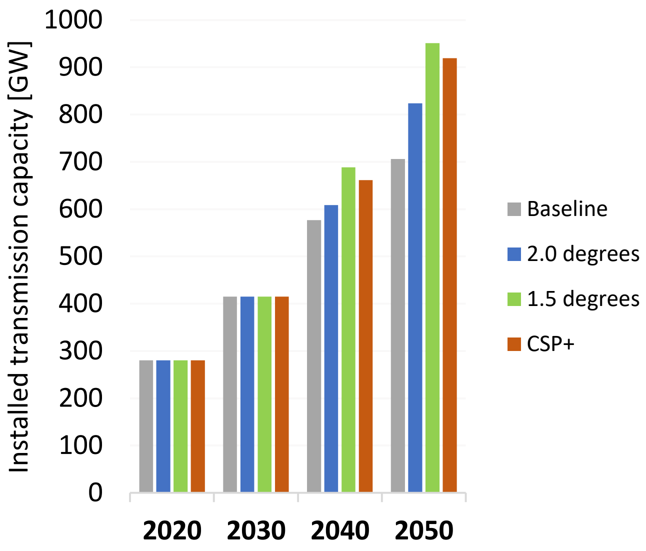


FIGURE 24. EXPANSION OF TRANSMISSION CAPACITY PER SCENARIO.

The growing share of renewable energy calls for stronger cross-national bonds in the European interconnected grid. ENTSO-E estimated that the cost of making no effort towards a more interlinked system (including national reinforcements) would be around 43 billion EUR per year [13]. New investments are required to efficiently integrate new renewable energy and reduce total system costs. For this reason, a large number of new interconnection projects is currently under construction or under consideration by the various Transmission System Operators (TSOs) of the continent. The European Network of TSOs (ENTSO-E), regularly publishes an overview of all the planned projects named TYNDP (Ten Year Network Development Plan).

In this analysis all the planned projects from the latest TYNDP 2018 [14] have been included until 2030 for all scenarios, while after the same year, the expansion is optimized by the model alongside with the power plant capacity additions.

The TYNDP expects an increase in the total capacity of power transmission lines in Europe from 237 GW in 2018 to more than 400 GW by 2030. In the following years the model results indicate that the **transmission buildout is even more massive**, reaching a peak of around 950 GW in 2050 (Figure 24). The bigger the ambition in the decarbonisation efforts (and the higher the power demand as a consequence), the more transmission capacity is needed in the long term: a difference of more than 200 GW exists between the Baseline and the 1.5 degrees scenario in 2050. In the CSP+, the interconnector buildout is reduced by around 30 GW in both 2040 and 2050, corresponding to roughly 3.5% of the total capacity.

The power flows across countries evolve throughout the analysed time horizon. Some trends can be underlined when looking at the power exchanges between European macro areas (Figure 25). In 2020, Central Europe is a net exporter: the countries import power from Northern Europe and export mostly to Southern Europe. More and more towards 2050, **Central Europe become a large importing area**, with increasing flows from the North in the form of wind power and hydro, as well as solar generation from the South. However, the imports from the North are almost twice as those from the South: wind power covers a larger share of the total demand in Europe and it is in general better suited for being integrated through interconnectors. Solar PV, on the other hand, is more concentrated in the central hours of the day and that results in a high line utilization only during a relatively reduced portion of time, making additional interconnection too expensive. Energy storage, in the form of batteries and pumped-hydro is better suited for the integration of solar generation.

As discussed in relation to the electricity prices, Italy is a special case among countries in Southern Europe: despite the higher than average solar irradiation, it remains a net importer towards 2050 in all scenarios (apart from the CSP+ scenario). On an annual basis, Italy imports a large amount of energy from France and a lower amount from Greece and exports part of it to both Austria and Switzerland.

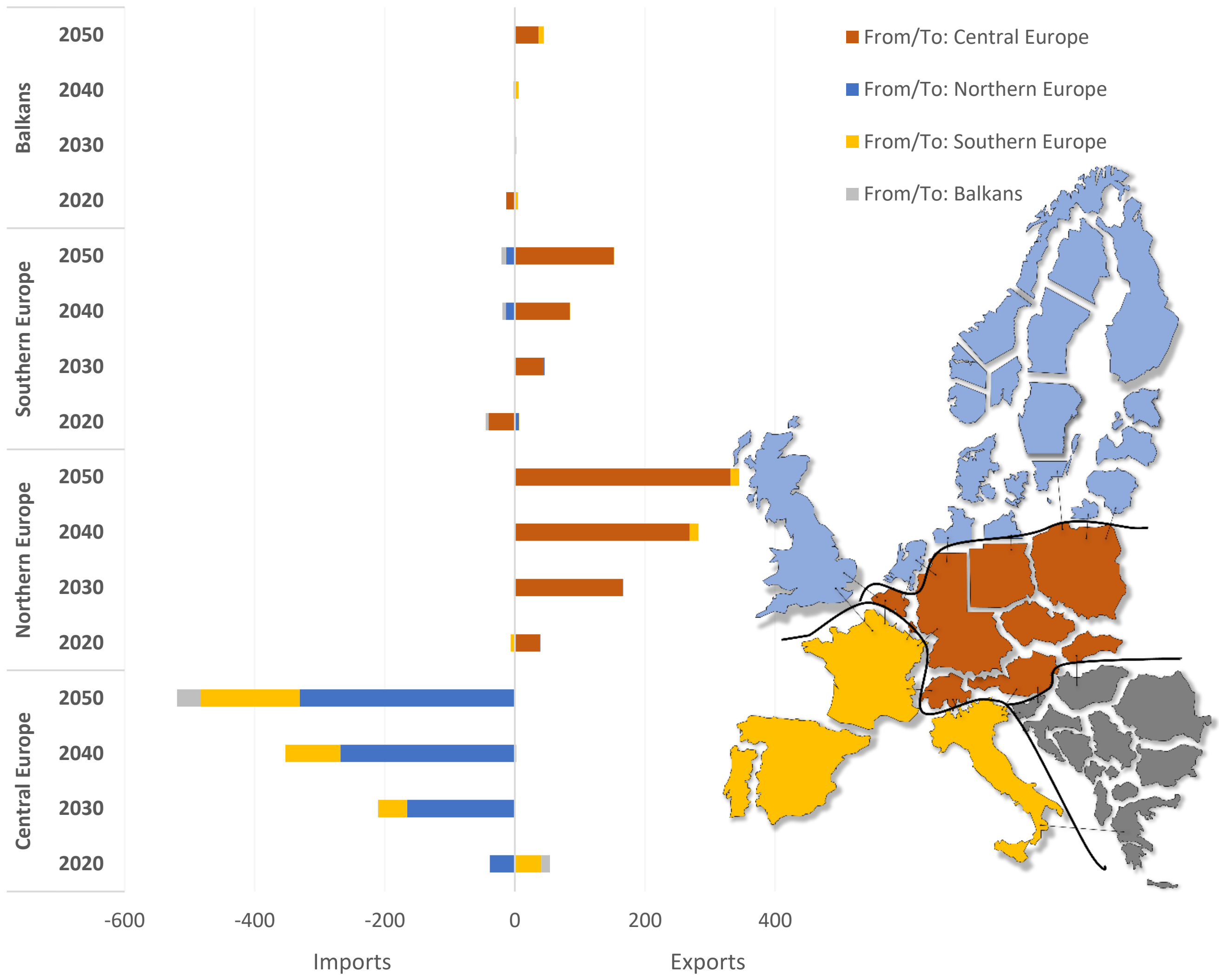


FIGURE 25. EVOLUTION OF POWER FLOW DYNAMICS BETWEEN EUROPEAN MACRO REGIONS. 1.5 DEGREES SCENARIO.

The complexity of power flows increases in the long term: as an example, nowadays and in the first part of the modelling horizon, imports supply the baseload in Italy, which is cheaper than running national combined cycle power plants. The flow is unidirectional and reflects the lower marginal generation costs in other countries. In the long-term instead, the availability of fluctuating renewables and the presence of daily/seasonal cycles determine the direction of power flows. The fluxes can revert on a daily and/or seasonal basis. Indeed, in decarbonised scenarios, countries where the price gap between day and night is consistent tend to increase the volumes of both exported and imported energy. This is the case of Italy and France (Figure 26, 2050): after the progressive shut-down of nuclear power plants, announced in the recent French energy strategies [15], the higher volatility of the national generation intensifies the exchange with Italy, that becomes an **exporter when solar PV produces**. Conversely, at night the wind resource is stronger in France, which supplies power to Italy also during the evening peak. The interconnection between market zones levels off price discrepancies between regions and contributes to bridge the resource disparity within the continent.

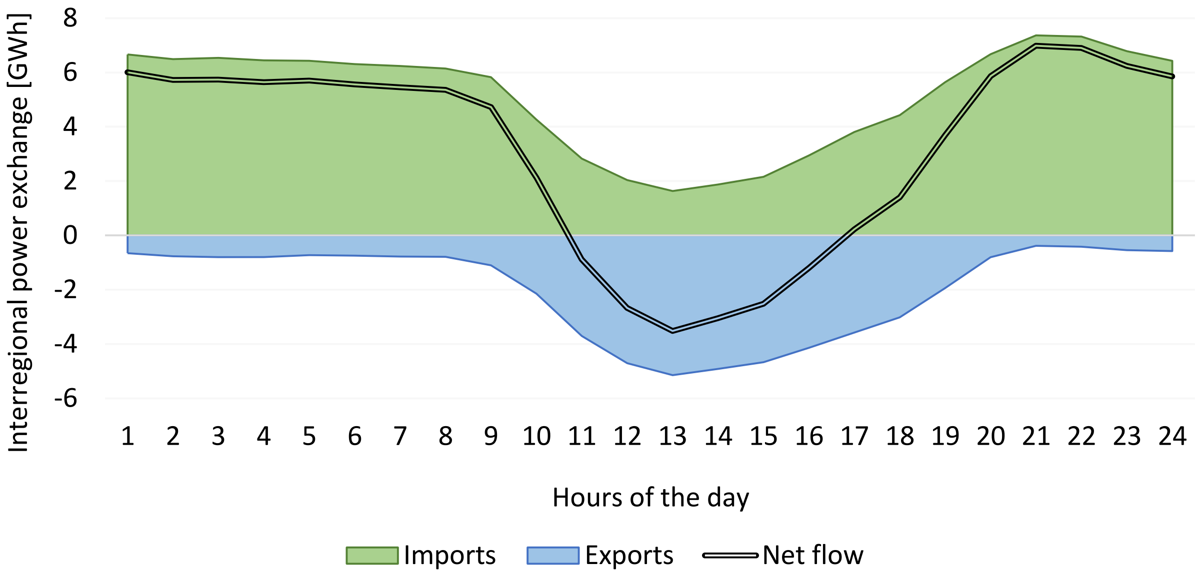


FIGURE 26. AVERAGE DAILY CROSS-BORDER FLOWS BETWEEN ITALY AND FRANCE (IMPORTS FROM AND EXPORTS TO FRANCE) - CSP+ SCENARIO, 2050.

System need for flexibility: storage (and demand side) contributes to VRES integration

Storage systems are set to become determinant to match supply and demand in a cost-effective manner. They serve the growing request for system flexibility along with interconnectors and demand side contribution (electric vehicles, demand response, heat pumps, hydrogen production). In Spain, Greece and Portugal the high solar capacity is complemented with large amounts of batteries, while in France and Italy less batteries are needed due to better interconnections and the higher deployment of CSP.

With the power system evolving towards a VRES-dominated one, matching supply and demand becomes increasingly challenging. Other sources of flexibility beside the increase in interconnectors pertain to the demand-side and among these, the most important ones are:

- *Conventional demand flexibility and demand response.*
  In the model we assume that towards 2050 a certain percentage of consumers will be able to react to large price fluctuations and optimize their consumption in order to reduce the cost of the electricity bill. The share of total power demand characterised by flexibility increases linearly overtime and reaches around 40 GW in 2050. The level of flexibility varies from country to country with an overall level equal to 8% of the average traditional European demand (calculations are based on TYNDP18).

- *Smart charging of electric vehicles and shifted functioning of heat pumps.*
  The progressive electrification of the transport and heating sectors not only increases the electricity demand in the long term, but provide a potential source of flexibility. Indeed, electric vehicles charging and heat pumps functioning could be shifted to times of lower prices and enhance the integration of wind and solar. Our assumption, following those included in TYNDP18, is that by 2050 EVs and HPs in the system will require around 4% and 5% of the conventional power demand respectively.

- *Flexibility in the production of hydrogen.*
  The model need to guarantee a certain production of hydrogen through electrolysers, but there is the option to decouple demand and supply using hydrogen storage. In this way, the production of hydrogen is flexible and electrolysers can be used when the RE supply is high and the power prices are lower.

These demand-side flexibility options help integrating the high share of VRES in the system but are not enough to guarantee a smooth and optimal operation of the system. Additional flexibility is needed from the supply side.

In the scenarios analysed, a sizable amount of storage in the form of lithium-ion batteries is deployed in Europe (Figure 27). Overtime not only the amount of battery storage capacity increases, but so does the volume with respect to the unloading capacity. This underlines the **growing need for flexibility and time shifting services in the system**. The scenario with the highest amount of storage is the 1.5 scenario, with 450 GW (and 1770 GWh) of batteries in 2050. Interestingly, the cost drop envisioned for CSP components in the CSP+ scenario, the optimal amount of battery storage is reduced by 123 GW. This corresponds to a 27% decrease with respect to the analogous 1.5 degrees scenario. The thermal storage and the biogas turbines take over some of the flexibility needs.

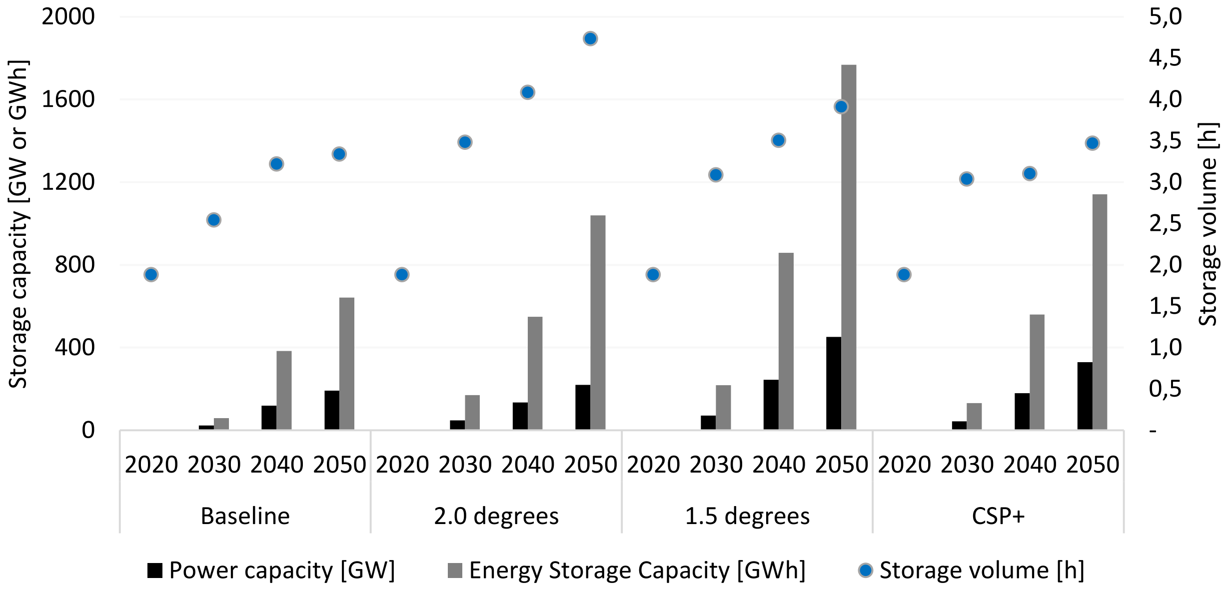


FIGURE 27. BATTERY STORAGE CAPACITY AND VOLUME ACROSS SCENARIOS.

Consistently across scenarios, the two **countries with the highest amount of battery capacity are Spain and Greece**. The former with 46-110 GW and the latter with 12-41 GW depending on the scenario. Both countries have a very high solar irradiation and consenquently a high installation of solar PV and their location at the extreme West and East of the European power system results in a lower level of interconnection from/to neighboring countries.

When looking at the solar and battery storage capacity installed in all Gridsol countries, Spain, Greece and Portugal tend to couple the development of solar with additional energy storage capacity; Italy and France have the large capacities as well, but they require the installation of less storage (Figure 28).

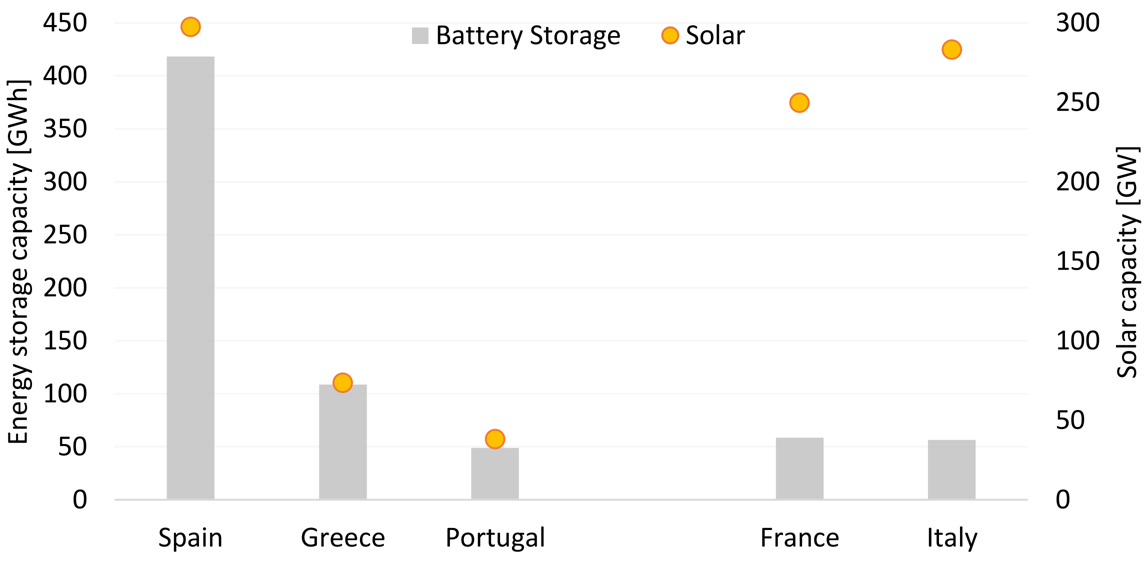


FIGURE 28. BATTERY STORAGE CAPACITY WITH RESPECT TO SOLAR INSTALLATIONS.

This is certainly due to a better position and interconnection of France (and particularly Italy) with the rest of the continent. An additional explanation is related to the higher capacity of CSP-based power plants in the two countries, as discussed later. The average behaviour of electricity storage on a daily basis, displayed in Figure 29, is slightly different in Spain (left) and France (right). In the former, the large amount of batteries are used in combination with solar PV to dispatch power at night. In France, while the loading during solar hour is also evident, a much lower amount of storage is installed and it is occasionally loaded also during the night.

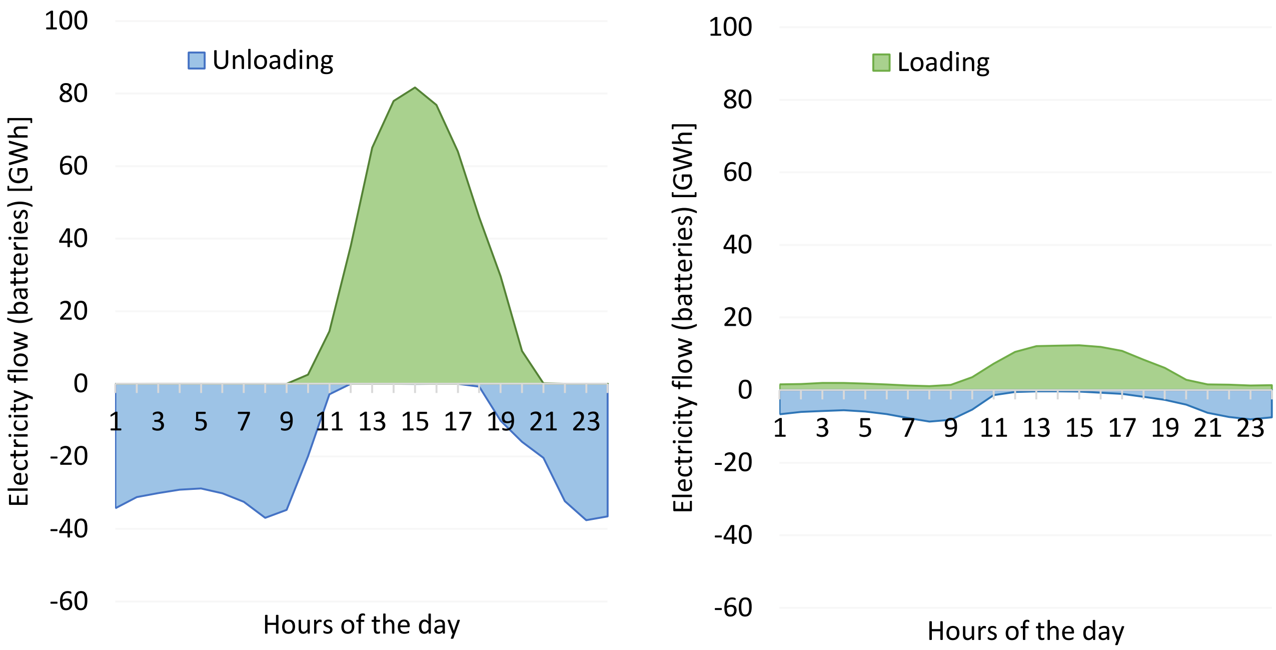


FIGURE 29. LOADING AND UNLOADING OF BATTERY STORAGE. SPAIN (LEFT) AND FRANCE (RIGHT) – CSP+ SCENARIO, 2050.

Concentrated Solar Power: potentials and competitors

CSP suffers from high financial outlays, the competition with more mature technologies and an industry still on the drawing board. With the exception of Italy and France, where new fuels and high CO_2 prices are strong-enough conditions to achieve a moderate deployment, big cost reductions are needed to expand in the market. The competitors are gas cycles and especially PV and batteries.

The profitability of CSP power plants is influenced by technical, industrial, geographical and market constraints. The first two relate to the organisation and development of the CSP industry, while the latter reflect the potential of the concept from an energy system perspective. A great DNI resource is not a compelling reason to prefer CSP over other technologies, especially if the competitor is solar PV. It is actually found that **CSP finds more space where the DNI is not the highest** in Europe (Figure 30). Italy and France prove to be the most attractive locations for CSP power plants in decarbonised scenarios. In 2050, the hybrid CSP-gas turbine installations total more than 15 and 40 GW in the 2.0 and 1.5 degrees scenarios respectively and they all occur in France and Italy. The additional cost reduction embedded in the CSP+ scenario brings the potential capacity of CSP-based generation to 120 GW in Europe, including 8.5 GW in Spain and 4.5 GW in Greece.

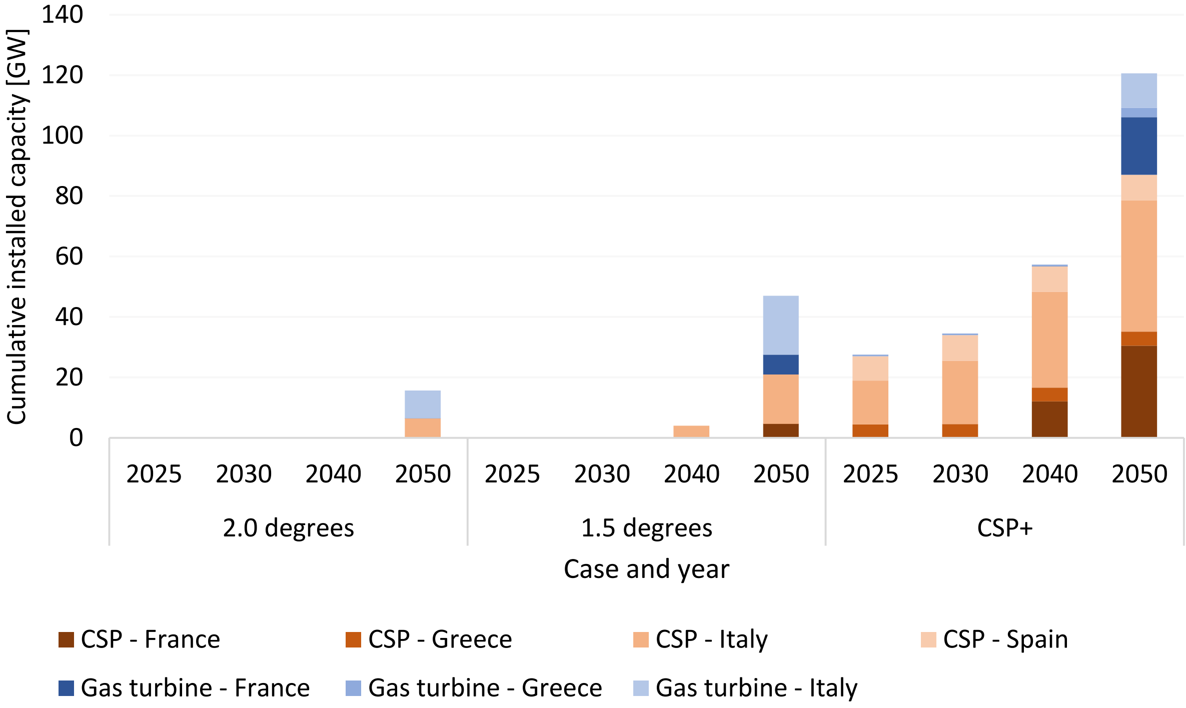


Figure 30. Cumulative installed capacity for CSP-based generation units.

Under the hypothesis of a fast and substantial development of the industry (as assumed in the CSP+ scenario), new solar tower CSP units are already competitive in 2025 in a market setting. The immediate surge in the CO_2 quota price implemented in the 1.5 degrees scenario requires the substitution of existing fossil-fuel units with renewable technologies; in the next decade, competition is driven by this need for replacement: the case of Spain (Figure 31) is representative for all the Gridsol countries and highlights how in 2025, with current cost projections, combined cycles and solar PV plants constitute the optimal mix after the shut-down of coal generators. The situation changes in case of a robust cost reduction as the one envisioned in the CSP+ scenario: in this case CSP may take over in the short term, when electric storage is not yet an economical option.

Figure 31 (right) displays also how in the CSP-gas hybrid group the two turbines are present in different relative terms across scenarios and countries. Until 2040, this group is not a winning concept, as the installed power **capacity is almost exclusively CSP without gas turbines**. The integration of the latter is optimal only in 2050 and occurs differently in the three involved countries (France, Greece and Italy). With standard CSP costs, the gas turbine installed capacity always exceeds that of the steam turbine: the ST/GT ratio spans from 0.70 and 0.84 in France and Italy depending on the scenario (Figure 31). Conversely, in the CSP+ setup the situation is overturned. The same ratio ranges from 1.50 (France, Greece) to 3.78 (Italy). Aside from the CSP cost disparity, which influences the ratio across scenarios, the values stress the different system needs as the location changes. Similar ST/GT ratios hide also a different functioning. In particular, the ST full load hours are 2000 hours lower in Greece than in France (5800 vs. 3800, CSP+ scenario) as the gas component does not contribute to new CSP investments in the first country (see Figure 31, right).

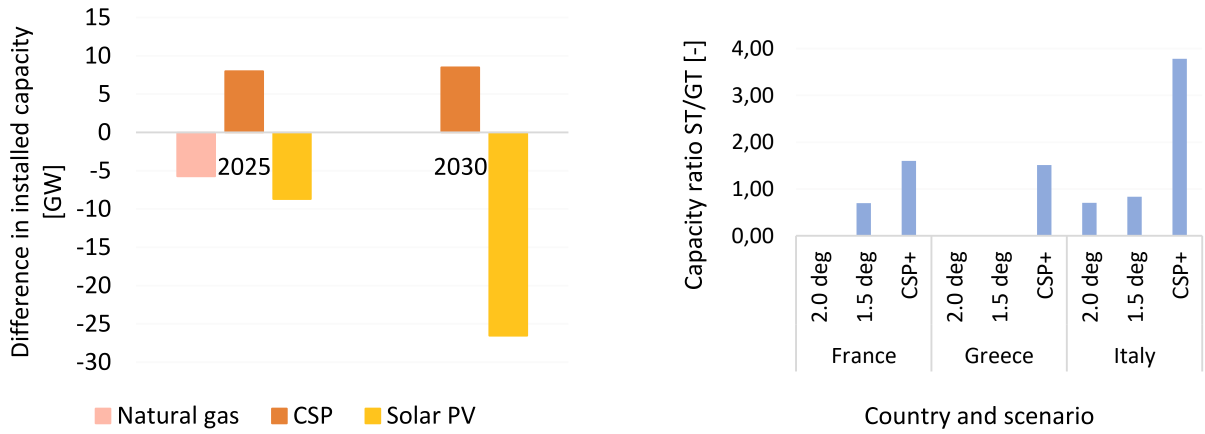


FIGURE 31. LEFT: DIFFERENCE IN INSTALLED POWER CAPACITY BETWEEN 1.5 DEGREES AND CSP+ SCENARIOS (SPAIN). RIGHT: CAPACITY RATIO BETWEEN ST AND GT IN THE CSP-GAS GROUPS (2050).

A further insight on the competition between CSP and the other market players can be inferred from the generation mixes of the five Gridsol countries in Figure 32. The larger market penetration of solar thermal technologies primarily reduces the PV share in the system in 2050. Nuclear power is also partially reduced in France, whilst biomass and wind energy are weakly affected. The cost reduction embedded in the CSP+ scenario leads the total generation technologies up to 34% in Italy and 20% in France in 2050.

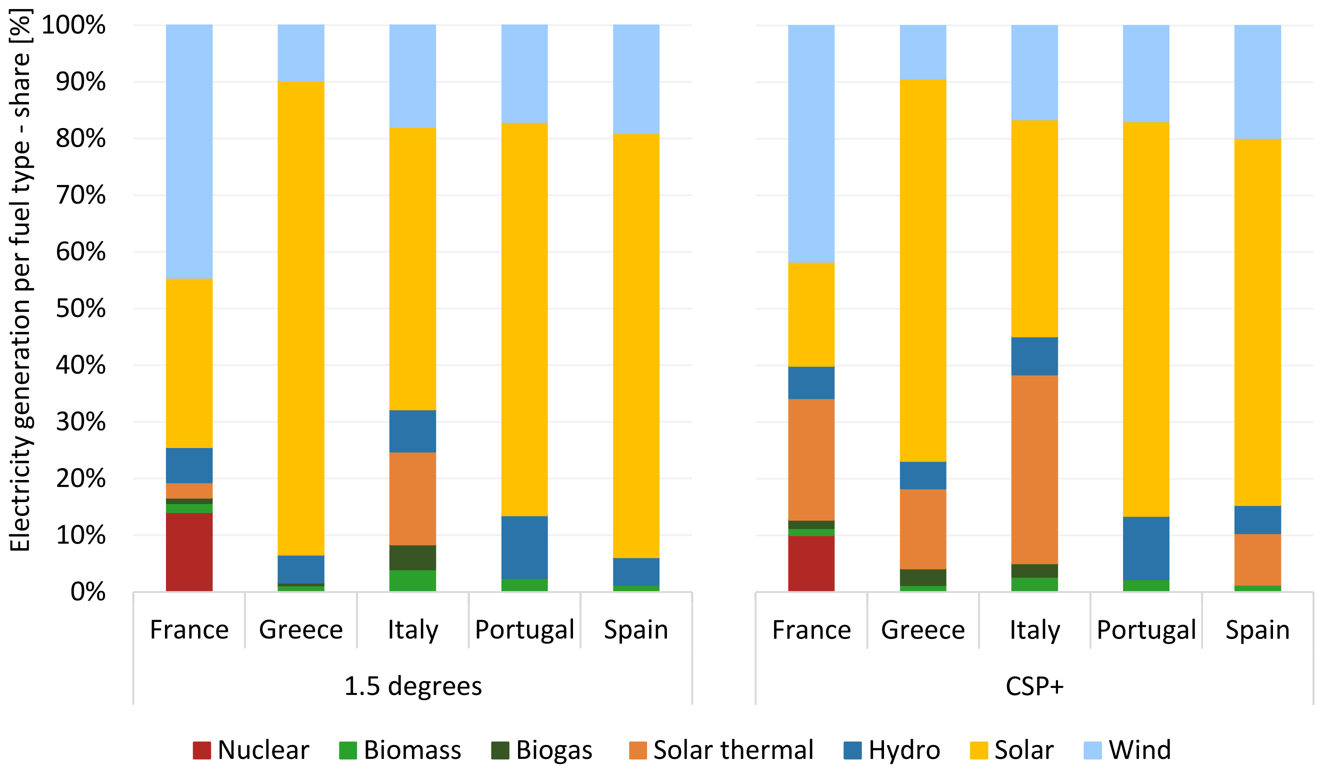


FIGURE 32. GENERATION MIX IN THE FIVE GRIDSOL COUNTRIES - 1.5 DEGREES AND CSP+ SCENARIOS, 2050.

What drives CSP?

The potential for CSP is determined not only by the economic performance of CSP, but to a large extent the competition in the local power market and the local power market features. CSP is viable in systems with a high need for flexibility if the time horizon for the needed flexibility is sufficiently large. In 2050 and under the hypotheses of sizable cost reductions and long operational times, CSP can reach an LCoE below 40 EUR/MWh.

The LCoE of CSP are projected to decrease by more than 50% towards 2050 (Figure 33). The cost depend on the solar resource as well as the system configuration (ratio between thermal receiver, thermal storage and steam turbine and operation in the power system (full load hours). Further synergies can be achieved when combining the thermal storage with gas turbines, as it can improve the utilization of the steam turbine. LCoE for CSP spans from 128 EUR/MWh in 2020 to 88 EUR/MWh in 2050; by increasing the operational time to 6000 FLH the LCoE gets cut by one third. On the other side, should the favourable cost projections envisioned in the CSP+ scenario materialise, the LCoE is driven **down to 36 EUR/MWh** under the assumption of 6000 FLH (2050). This is the lowest average return CSP can generate for.

Good solar resources are a requirement for feasibility of CPS. However, good solar resources also reduce the cost of PV, which – in combination with batteries – is a major competitor for CSP. Regardless of the economic projections for CSP used in this analysis, CSP will have a higher LCoE than PV excluding consideration of storage options.

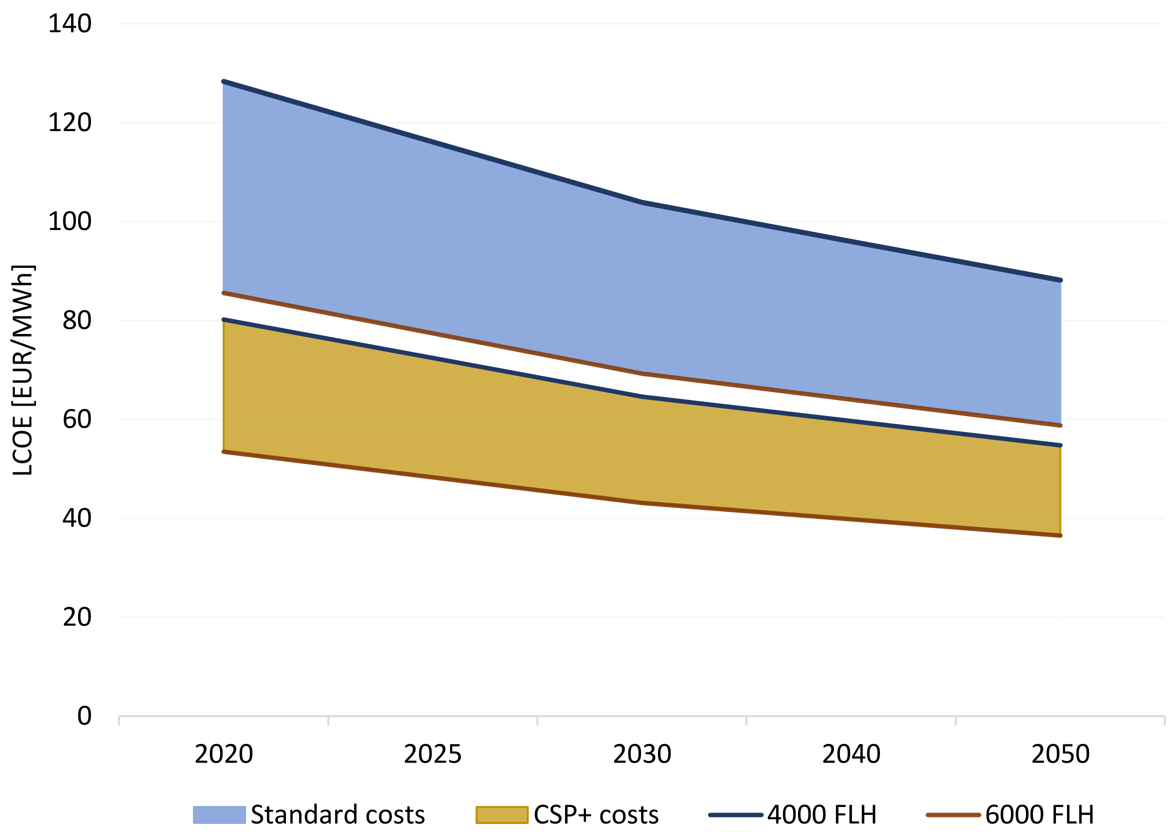


Figure 33. LCoE projections for CSP under different FLH assumptions.

The model analyses show that the best solar resources found in Spain not necessarily ensure the competitiveness of CSP. Contrary, CSP can have a role in the Italian power system, even though solar resources are lower, and thereby cost for both PV and CSP are higher. A combination of the following aspects explain this situation:

- The solar resource in Spain has a more uniform seasonal distribution, meaning PV can contribute significantly to supply demand directly, also in winter time.
- PV in Spain has a competitive advantage compared to the rest of Europe due to the good solar resource, and the model simulation project Spain to be a net exporter with low average power prices in 2050.
- The Italian power system imports energy on an annual basis and has a high need for flexibility. As a result, power prices in Italy are more volatile, with high prices at night.
- The time horizon for the needed flexibility to supply those high price hours is higher in Italy than in Spain. Therefore thermal storage options achieve a lower number of annual cycles in Italy and have a higher energy (volume) component (Figure 34), compared to unloading capacity. This storage need supports CSP, while batteries are better suited for a higher unloading capacity component and higher number of cycles. The number of cycles is also dependent on the CSP-based power plant configuration, in that, when the CSP-gas group is installed, the bigger the gas capacity, the lower the number of yearly cycles.

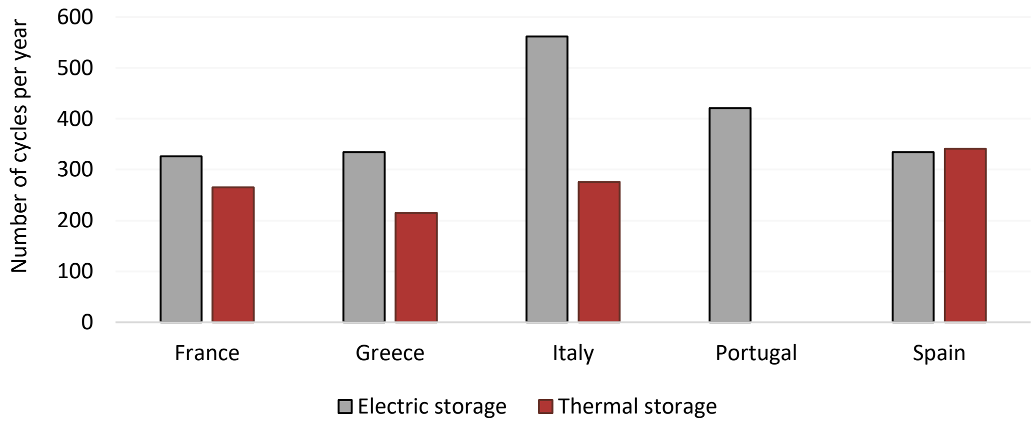


FIGURE 34. EQUIVALENT NUMBER OF CYCLES PER YEAR FOR ELECTRIC AND THERMAL STORAGE. SCENARIO CSP+ - 2050.

The penetration of PV in different parts of the system is determined by the cost (depending on the resource level, see Figure 35) and value of generation, which is in parts dependent on the seasonal and daily variation patterns, and in parts on the remaining system composition. The low cost and good seasonal distribution of PV generation explains, why Spain becomes a net exporter of electricity, leaving little room for CSP.

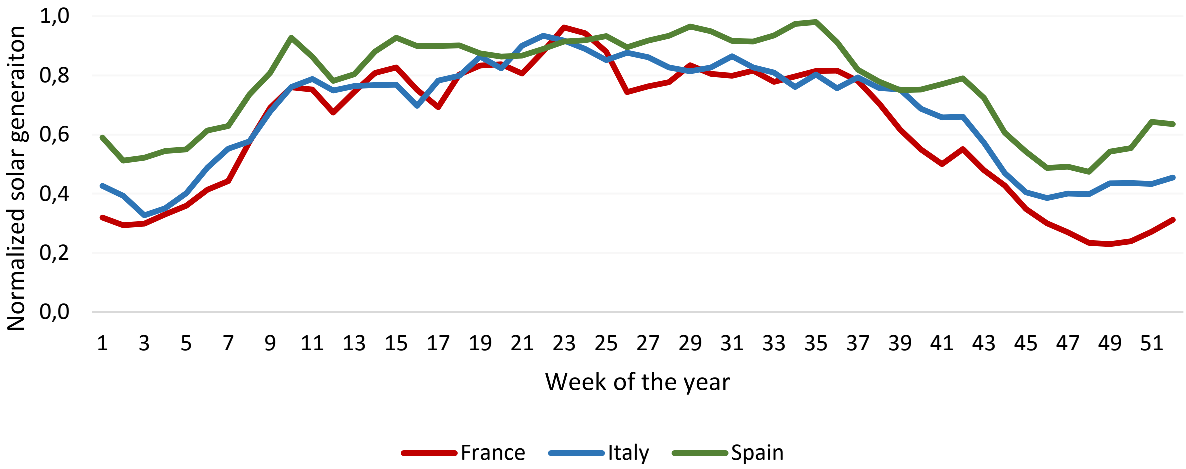


FIGURE 35. WEEKLY PATTERN OF SOLAR PV GENERATION.

The price duration curves displayed in Figure 36 for France, Italy and Spain show how the three markets offer different opportunities for CSP, and how the large penetration of PV in Spain affects the power market. In 2050, Spain will be characterised by an average spot price that is 20 to 30 EUR/MWh lower than France and Italy; moreover, more than 4000 hours a year see marginal costs of generation approaching zero, due to the strong investments in solar PV.

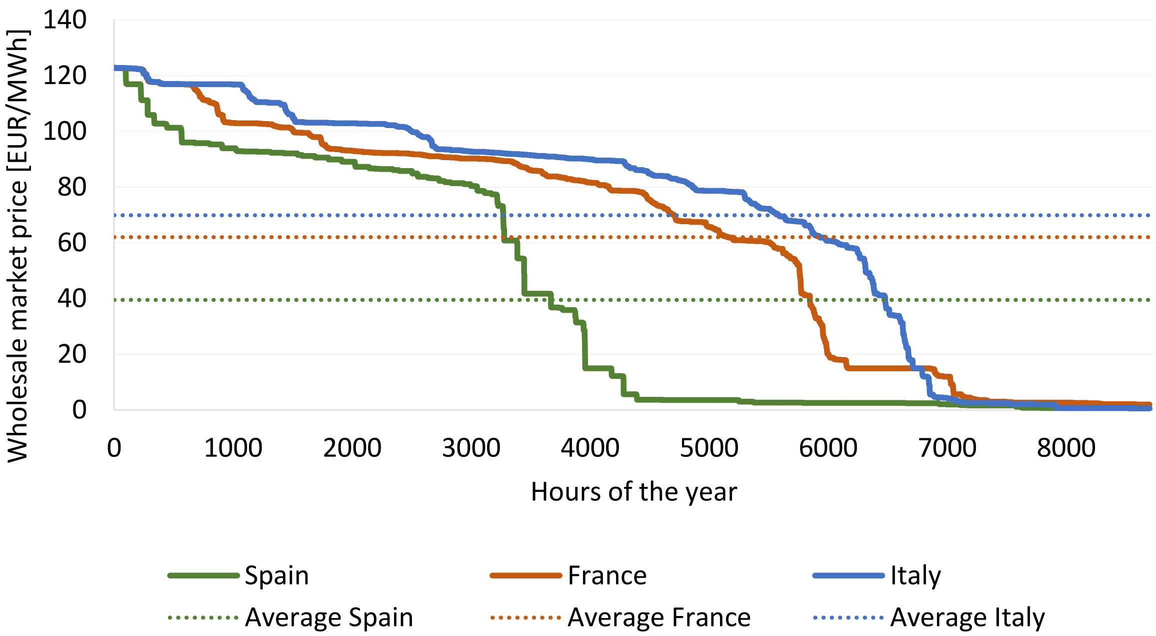


FIGURE 36. PRICE DURATION CURVES FOR SPAIN, FRANCE AND ITALY - CSP+ SCENARIO, 2050.

Both Italy and Spain undergo deep transformations due to the progressive decarbonisation of the power sector. The power price variations in Spain and Italy are further illustrated in Figure 37 and Figure 38. A general trend to low prices during the day and higher prices at night are apparent in both countries. However, while in Italy time accentuates the price polarisation effect between night and daytime, in Spain this effect is stronger in the medium term (2030), and alleviated in the long term. In 2050, the average difference is only 7 EUR/MWh between night hours and the afternoon; in Italy the same gap settles at 50 EUR/MWh on average.

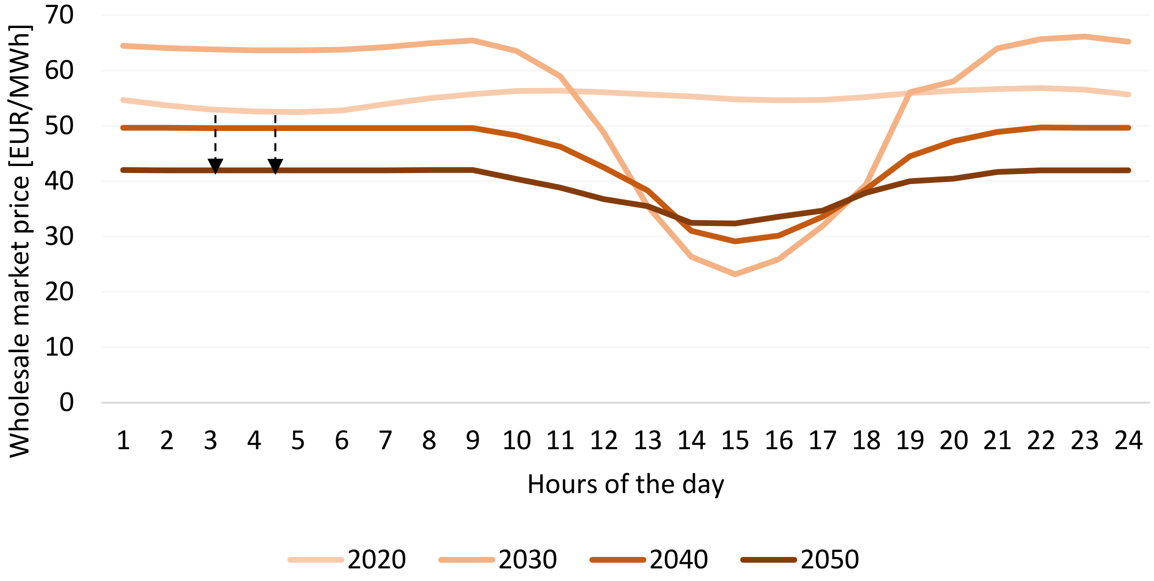


FIGURE 37. AVERAGE HOURLY MARKET PRICE - CSP+ SCENARIO, SPAIN, 2050.

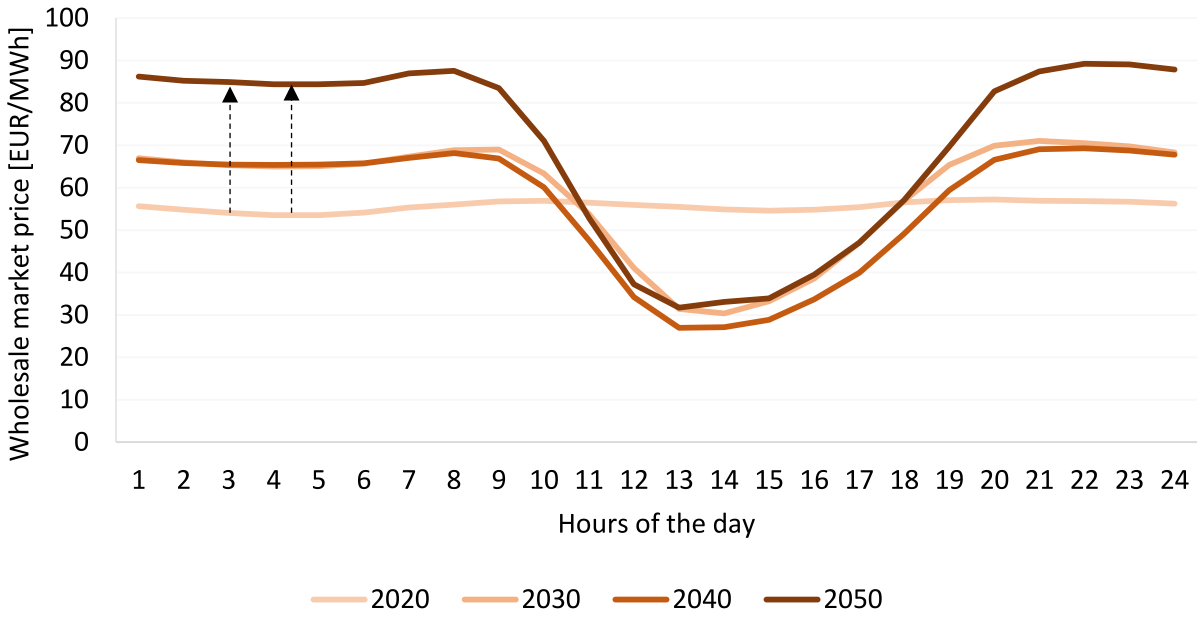


FIGURE 38. AVERAGE HOURLY MARKET PRICE - CSP+ SCENARIO, ITALY, 2050.

The competitiveness of CSP technologies is linked to the integration of large thermal storage in the plant. The benefits connected to the presence of the TES are twofold:

- It enables to shift production to peak hours, when marginal costs of generation are higher (dispatchability);
- It enables higher utilization of the steam turbine helping to cover investment cost and fixed O&M (increase of full load hours).

Since LCoE of CSP is projected to be higher than LCoE of solar PV without storage, CSP will only have a role in the future power system if equipped with large thermal storage. However, batteries can equip PV with similar characteristics. Batteries have a relatively high cost for storing energy (volume), but a relatively low cost for the capacity of the inverter for power generation (power). The thermal storage on the other hand has a low cost option for storing energy (volume), and a high cost for the steam turbine (power) (Table 7). For the thermal storage to be cost efficient compared to batteries a high ratio between volume and capacity is needed. This ensures maximisation of the storage cost advantage and high utilization times the capacity.

TABLE 7. COST FOR VOLUME AND CAPACITY OF THERMAL AND ELECTRIC STORAGE.

	Volume (EUR/kWh)	Capacity (EUR/kW)
Batteries	78	62
Thermal storage*	25	1.087

** Thermal storage volume cost shown with respect to potential electricity generation (i.e. electric efficiency of steam turbine taken into account).*

Figure 39. illustrates the economic performance of PV in combination with batteries, compared to the performance of CSP and thermal storage. Across all analysed countries CSP cannot compete with PV on pure LCOE. However, where high storage ratios are needed, CSP has an economic advantage, while PV and batteries are more cost effective at low storage levels.[8] For Italy, storage ratios above 7-8 give an advantage to CSP with the base cost assumptions. Further cost reductions in the CSP+ scenario reduces this threshold to around 3. Model simulations reflect this by showing very low investments in batteries in Italy in the CSP+ scenario.

The need for storage is reflected in higher market values, for technologies providing the storage. While the LCoE for CSP proves to be the lowest in Spain, the market value for CSP is higher in Italy and France (Figure 40). Therefore, CSP has a bigger role in those countries. At high cost reductions in the CSP+ scenario, CSP gets economically viable also in Spain and takes on a baseload role in the Spanish system (around 6000 full load hours), while it remains to provide a higher degree of flexibility in Italy and France at lower full load hours. The market value of CSP is reduced accordingly in the CSP+-scenario, but stays well above the market value of PV.

[8] The economic performance is further influenced by the utilisation of the capacity part (inverter/steam turbine). For illustrative reasons, this is kept constant (except if limited by the installed solar receiver) on the graph shown, but is reflected in model simulations. This fact further increases the difference in economic performance for CSP at low and high storage levels.

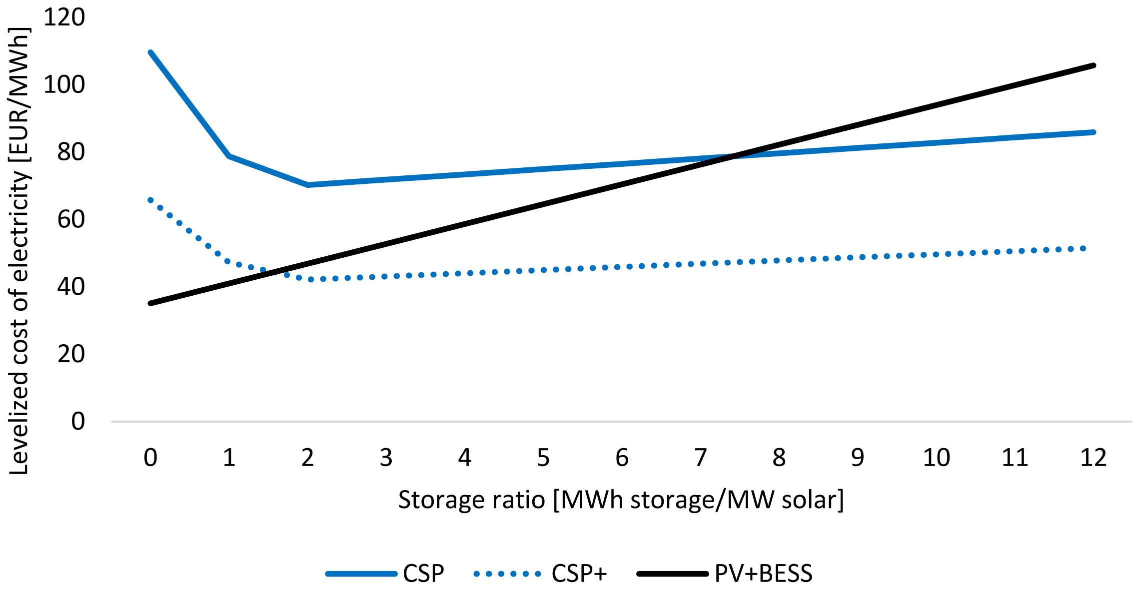


FIGURE 39. LCOE OF SOLAR PV AND CSP TECHNOLOGIES FOR DIFFERENT VALUES OF THE STORAGE RATIO (ITALY, 2050).

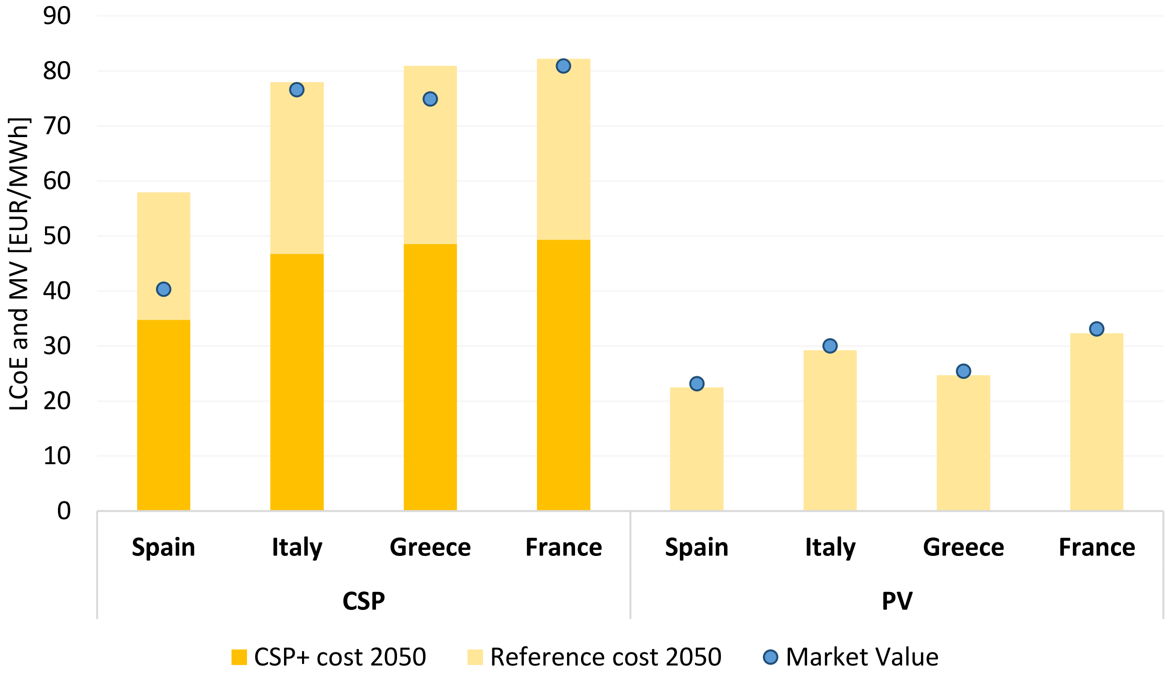


FIGURE 40. COMPARISON BETWEEN LCOE AND MARKET VALUE (MV) OF CSP AND PV (2050).

CSP FUNCTIONING

Thermal energy storage allows CSP to supply dispatchable power at night-time. Storage volumes over 20 hours guarantee night dispatch for several consecutive days even with part-load production from the solar field and contribute to increase the nominal operations of the CSP block. In hybrid CSP-gas groups, the gas turbine produces alongside the steam turbine.

With large thermal storage, CSP can boost its full load hours even over 6000 hours a year, depending on the systems need and existing generation mix. The evolution of CSP units in highly decarbonised scenarios is visible from Table 8, which reports the technical features of solar thermal technologies in 2030 and 2050 for Spain (no gas engine is installed). In the course of 20 years, the competition with PV and electric storage require CSP to gain in flexibility: the optimal storage volume grows by 6 hours and the solar field nominal thermal output is found to increase by roughly 50%, while the steam turbine capacity is stable. This allows the plant full load hours to increase up to 6351 at the end of the investigated time frame, meaning that the capacity factor exceeds 70%.

TABLE 8. TECHNICAL FEATURES OF CSP INSTALLATIONS IN SPAIN OVER THE YEARS – CSP+ SCENARIO.

Year	Solar multiple [-]	Storage volume [hours]	Full load hours [hours]
2030	2.47	16.3	4631
2050	3.56	22.7	6351

From an operational point of view, the larger solar field and thermal storage have different effects on the weekly dispatch of CSP units (Figure 41). During wintertime, the dispatched volume increases in size, but the overall profile is almost left untouched: the CSP units behave in the same manner. Instead, during summertime, the additional thermal output and the boosted storage flexibility allow to keep an even production over the course of three months. The added value lies in the constant output and therefore in the augmented full load hours rather than in the absolute growth of the maximum weekly generation (which is small for a pair of weeks). This finds support in the generation duration curve in Figure 42, where it is clearly visible how the larger storage increases nearly-nominal load functioning by 2000 hours a year and minimises the off-design behaviour. The operational time grows by 1000 hours a year as well.

Another relevant characteristic of CSP units is the heat curtailment (or heat dumping) in the solar field. As shown in Table 9 for Spain, the heat curtailed increases over the analysed period and is an effect of the larger power point flexibility. The expansion of the thermal energy storage volume is not enough to store the entire production from increasingly larger solar fields. Therefore, a growing share of thermal power is curtailed, up to 16% in the case of Spain in 2050. This phenomenon is also to be motivated with the dispatch strategy of the steam turbine, as the thermal storage empties only in hours when relatively high market prices can be attained. The average market price captured by the unit (or market value) must cover the long-run marginal cost of generation (or LCoE).

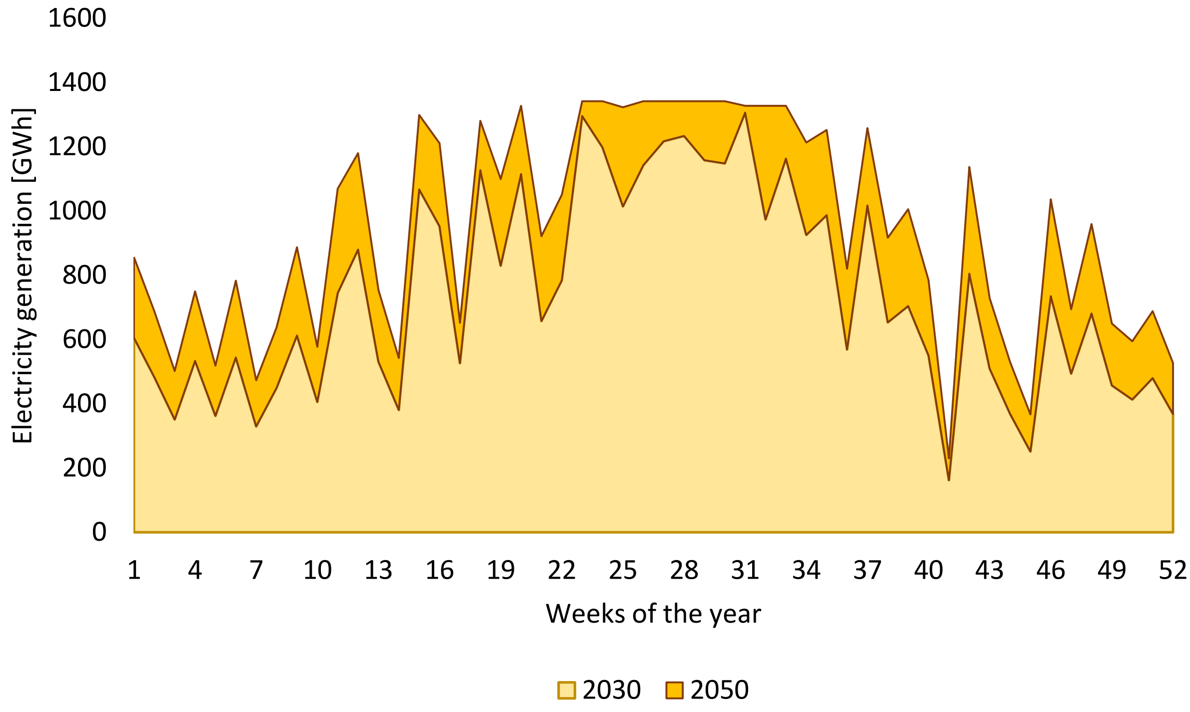


FIGURE 41. DIFFERENCE IN THE WEEKLY DISPATCH OF CSP UNITS FOR SPAIN IN 2030 AND 2050 - CSP+ SCENARIO.

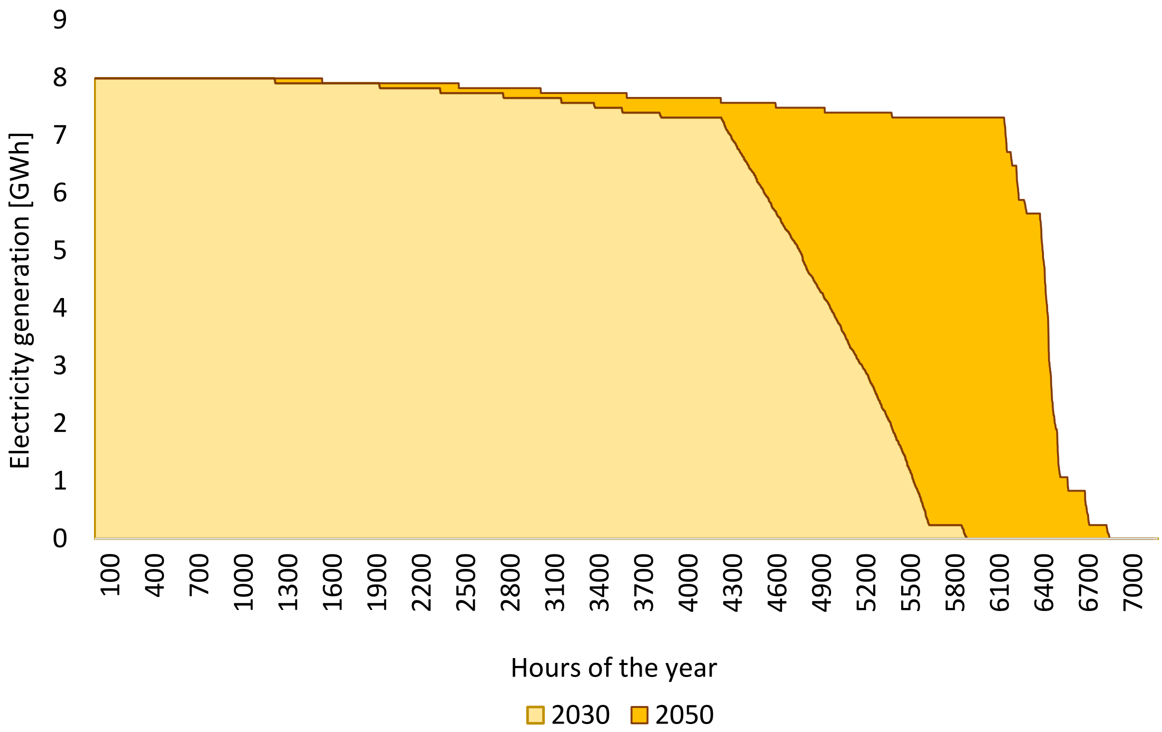


FIGURE 42. GENERATION DURATION CURVE FOR CSP IN 2030 AND 2050 - CSP+ SCENARIO.

TABLE 9. HEAT CURTAILED IN SPAIN - CSP+ SCENARIO.

	2025	2030	2040	2050
Heat Curtailed [%]	7%	9%	12%	16%

Where the CSP-gas group is installed (France, Greece, Italy), the gas turbine dispatches in hours of peak demand, limitedly to a small set of time segments and usually alongside the steam turbine (Figure 43 and Figure 44). The operations are confined to Autumn and Winter weeks. The short-term marginal costs of generation is usually high for a gas engine than for a CSP unit (117 EUR/MWh in 2050 for the gas turbine), even when large storage volumes are added to CSP units; when the two generators operate together, **the gas turbine contributes to increase profits for the CSP power block**.

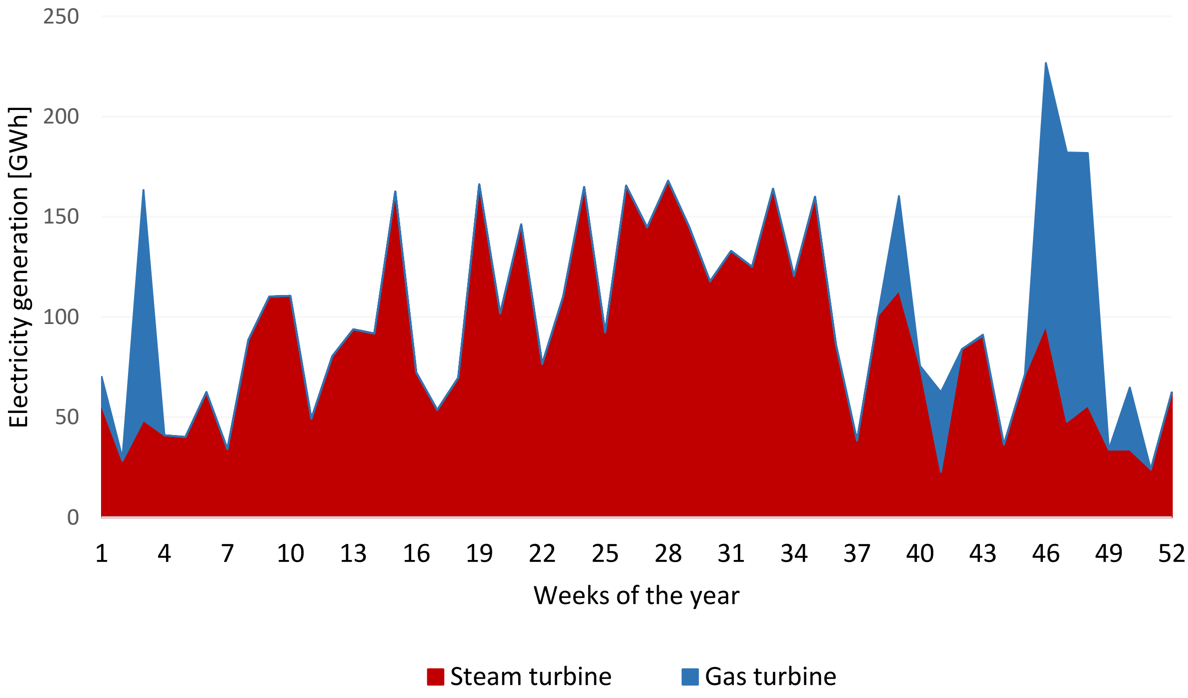


FIGURE 43. SEASONAL DISPATCH FROM THE STEAM AND GAS TURBINES IN CSP HYBRID GROUPS - CSP+ SCENARIO, ITALY, 2050.

The operations of the hybrid group are detailed in Figure 44, for an Autumn week in Italy (2050 – CSP+ scenario). CSP is typically operational from the late afternoon to the early morning, thanks to the large thermal storage. In these hours, the electricity price is relatively high and a gap of minimum 25 (but up to 80) EUR/MWh is detected with the central hours of the day (*price polarisation*). The latter are characterised by solar PV production, which has low marginal costs of generation. As CSP does not generally dispatch continuously along the day, the large storage allows to operate the unit for several days at nearly-nominal load with little or no irradiation. When the gas turbine generates, the heat recovery system fills the storage hot tank.

The price polarisation effect is clearly visible from the duck curve in Figure 45, where the effect of the increasing solar penetration is highlighted through a comparison between 2030 and 2050. Higher CO_2 prices tend to raise the hourly spot prices, but this effect is compensated by a larger solar penetration in the central hours of the day. At night, the electricity price takes up by 20 EUR/MWh in 20 years on average, despite the power exchanges with neighbouring countries (Figure 26). This effect is visible all year long, including the Autumn week considered for the hourly dispatch in Figure 44. In this instance, the scarcer solar resource causes an upward shift of the duck curve.

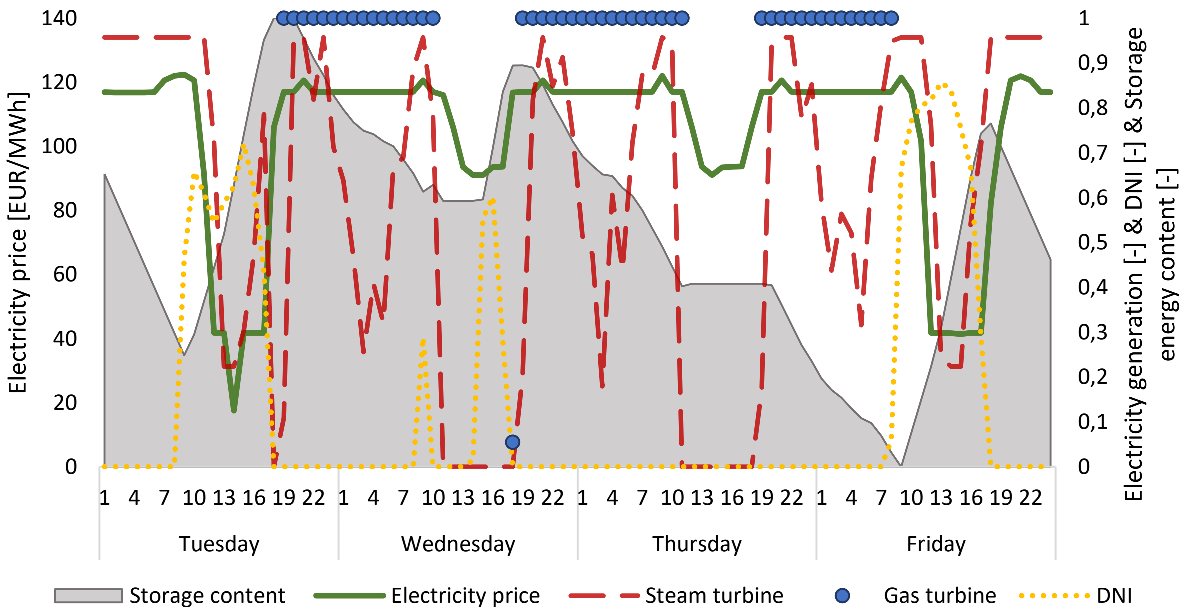


FIGURE 44. EXAMPLE OF THE HYBRID GROUP HOURLY DISPATCH - CSP+ SCENARIO, ITALY, 2050.

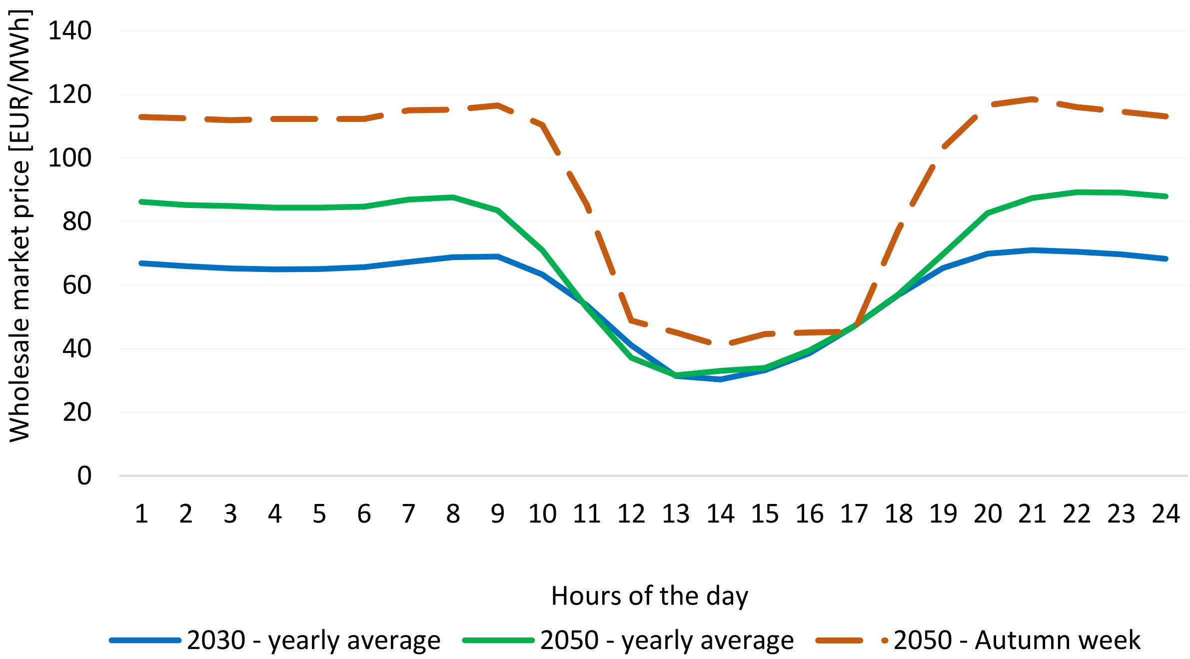


FIGURE 45. AVERAGE HOURLY ELECTRICITY PRICE IN ITALY - CSP+ SCENARIO, 2030 AND 2050.

3. SMART RENEWABLE HUBS

3.1. STATUS OF SRH AND HYBRID PLANTS

Hybrid Power Plants (HPPs) have so far come across several barriers and a lack of proper legislation that values their services. HPPs can provide ancillary services, frequency control and grid stability while maximising the utilisation of local electric equipment (power electronics, cables). The absence of a suitable framework that valorises these advantages and eliminates double taxation and grid charges hinders a wider spread of HPPs, which could provide economic and social benefits.

A recent report by Wind Europe identifies few wind-hybridised renewable parks in Europe, mainly concentrated in Greece and Spain. The sites are most often characterised by a good wind-solar resource complementarity (seasonal and diurnal negative correlation) which guarantee a high utilisation of the grid connection [16]. The lack of support schemes and *ad hoc* tendering for HPPs constitute a further problem for their grid integration, as in most cases HPPs are legally considered in the same manner as other single-source renewables. Greece and Poland are an exception: the regulatory framework explicitly mentions and envisages the participation of HPPs in tendering operations. In Greece, HPPs are required to guarantee a minimum power output and, when equipped with storage, withstand a limitation in their arbitrage activity (no more than 30% of the storage volume can be charged with the grid on an annual basis). A new solar PV-wind project is under construction in the Netherlands.

Overall, HPPs offer the following advantages with respect to single-source installations [17]:

- Reduced CAPEX and OPEX due to the shared grid connection and more contained maintenance effort (lower labour costs);
- Enhanced power output stability and smoother power ramps;
- The provision of ancillary services;
- A limitation in the penalties stemming from forecast errors when storage is present;
- Effective risk hedging for the assets owner;
- Curtailment reduction.

Several manufacturers are considering the integration of wind and solar technologies in sites characterised by good resource complementarity. The options to reduce grid connection costs through shared power electronics and transformer stations are manifold and the most suitable alternative depends on the specific project conditions [17]. In areas of the world characterised by excellent solar conditions, PV and CSP units can offer stable output and good technological complementarity; these solutions have been developed in China and Chile for instance.

Smart Renewable Hubs and Gridsol specifically are particular hybrid power plants that can provide all the above-mentioned benefits; DOME perfects the coordination among the units and minimises the revenue loss due to flawed predictions in the electricity markets.

3.2. Smart Renewable Hubs modelling

In previous WPs, in particular WP2, the composition of smart renewable hubs have been optimised for different European countries using price profiles (continental system) and demand profiles (island systems) from the year 2030 from WP5 and WP6 respectively. In this analysis, we expand the optimisation of the configuration of SRH to assess how the composition of the hub changes overtime up to 2050 and in different system conditions.

SRHs are here modelled as specific regions in the model from which power can flow out to meet the national electricity demand; the model can freely choose to install a CSP block considering a tower configuration with thermal energy storage (TES), possibly integrating a gas turbine (GT) with heat recovery, solar PV, wind turbines and BESS. The capacity of each element in the hub is unconstrained, but the grid connection capacity is fixed at 200 MW (Figure 46). The size of the hub components depends on the specific location, i.e. on the quality of the natural resource available therein, on the demand profile and on the interaction with other existing generators. For each of the countries indicated in orange in Figure 12, a reference SRH is optimized to find the optimal capacity composition of the hub. Further details on the hub modelling and assumptions can be found in [18].

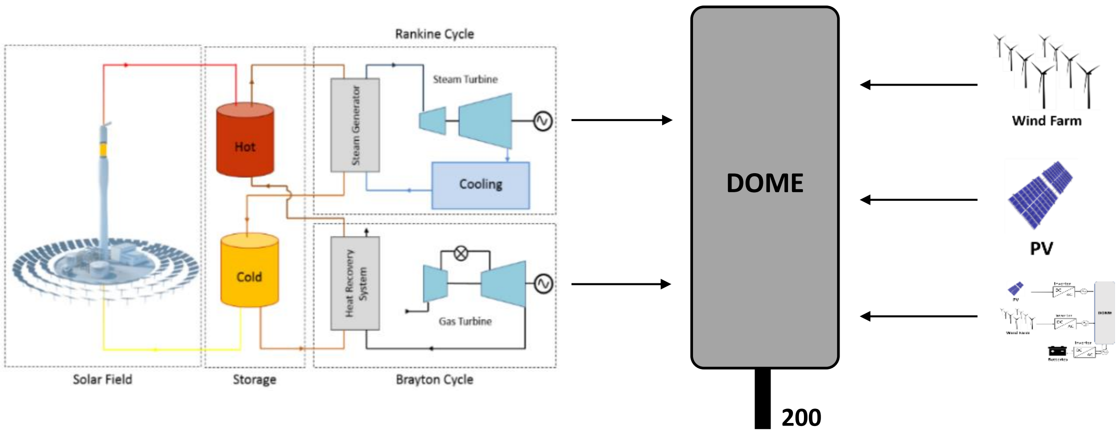


Figure 46. Overview of SRH technologies.

Synergies in the cost of connection

One of the potential benefits of combining different generators in a hybrid plant is the opportunity to share part of the grid connection costs for the SRHs; this leads to cost savings with respect to conventional single-source installations. The synergies relate mostly to the step-up transformer, connection, switchboard and potentially other grid related expenditures, such as grid reinforcement of the adjacent grid. No synergy in terms of sharing the power conversion equipment is considered in this study. In Europe, the legislation on grid connection costs is not uniform (Agora Energiewende, 2016): some countries adopt a shallow cost allocation principle, i.e. new installations need only to bear the expenditures for being connected to the system; others require to contribute also to the reinforcement of the grid (deep cost allocation). On the whole, these costs can range between 2 and 8% of the capital expenditures (Stennett, 2010). In this study, a connection cost of 40 000 EUR/MW is considered and the SRH components connected to the bus thus benefit from a specific investment cost discount compared to similar technologies installed outside a hybrid configuration. These include the CSP steam turbine, the gas turbine, solar PV, wind turbines and the BESS. This assumption implies that the cost savings for solar projects are in the range of 3-9%, in line with figures found in a study about co-location of solar and wind farms in Australia (AECOM Australia, 2016).

3.3. SRHs RESULTS

DOMINANCE OF PV+BESS CONFIGURATIONS

In Smart Renewable Hubs, the reduced grid connection costs favour particularly solar PV and batteries. The combination of the two is predominant in all scenarios but the CSP+, where CSP appear in a set of different configurations. The ratio between electric storage volume and installed PV capacity is higher where the solar resource is stronger and where CSP does not appear.

Figure 47 displays the resulting composition of the SRHs for the four scenarios and the five milestone years under consideration; each box is subdivided into five slots that represent one of the SRH locations.

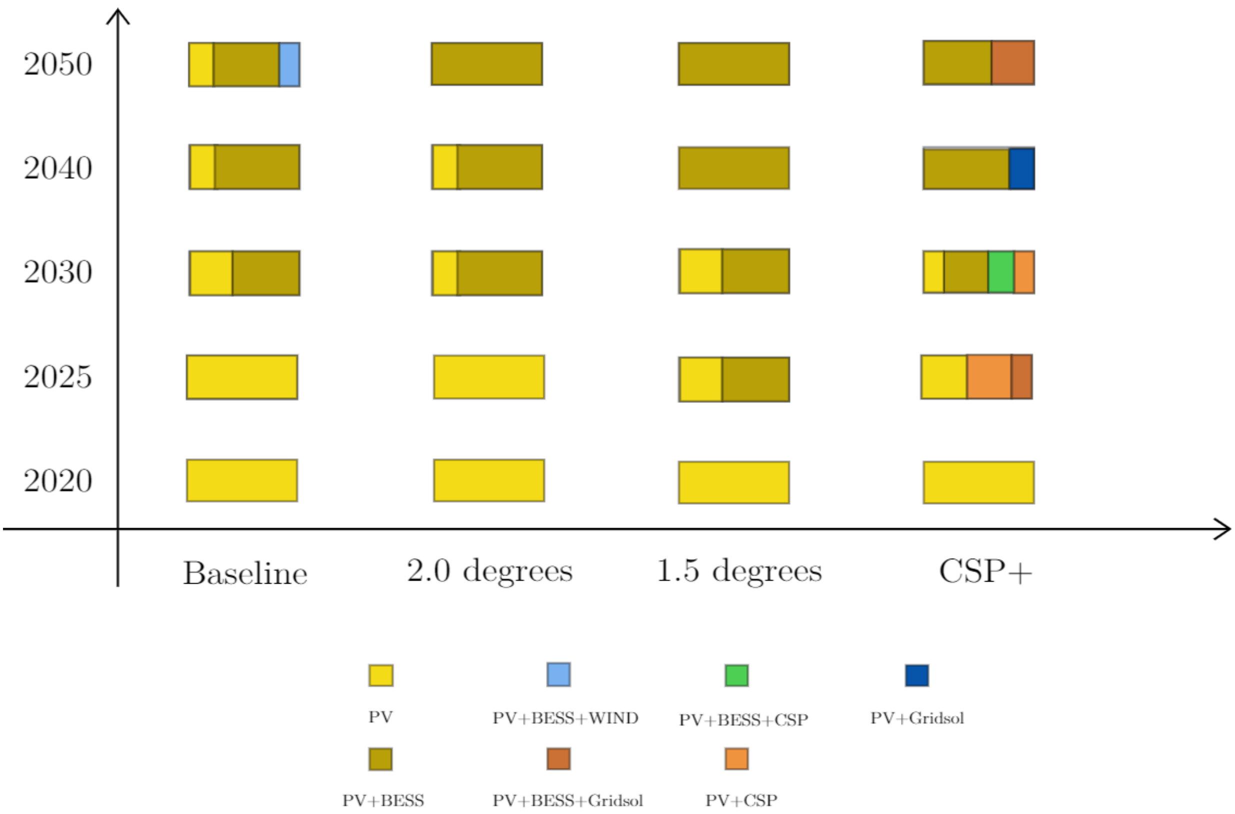


FIGURE 47. SMART RENEWABLE HUBS CONFIGURATIONS ACROSS THE FOUR SCENARIOS.

Solar PV is the only hub component in 2020, regardless of the scenario, and is present with increasing storage volumes as the system approaches 2050. SRHs are primarily composed of the semi-dispatchable group PV + batteries (BESS), with selected instances in which other components are added. In Italy and France, SRHs integrate also CSP components, which increase the hybrid power plant yield during wintertime. Wind energy is seldom a preferred choice and it appears only in one out of 20 cases. Two possible CSP-based combinations are allowed: a CSP-only power plant and a CSP-gas hybrid group. These two combinations find room in different locations: Spain incorporates only the CSP plant and Italy the hybrid group. Overall, **the integration of units other than PV + batteries can only materialise in favourable cost scenarios for CSP units.**

Besides the already low investment cost, PV further benefit from the hybridisation with other technologies. The grid connection cost reduction has a higher impact on the profitability of PV generation than on other technological options in the SRH[9]. For example, the steam turbine that is part of the CSP block has relatively high O&M costs and a higher specific investment cost; therefore, the grid connection savings have a relatively higher weight on PV than CSP.

Another advantage of solar PV is that the resource is more constant across locations than it is for DNI or wind speeds. This makes it a flexible component to hybridize existing plants or to be added to CSP or wind plants, which are generally installed in a specific location to harvest a high resource.

The **centrality of solar PV** in the composition of SRHs is evident from Figure 48, which characterises the hubs by geography. In hybrid power plants storage provides energy shifting services so as to maximise the

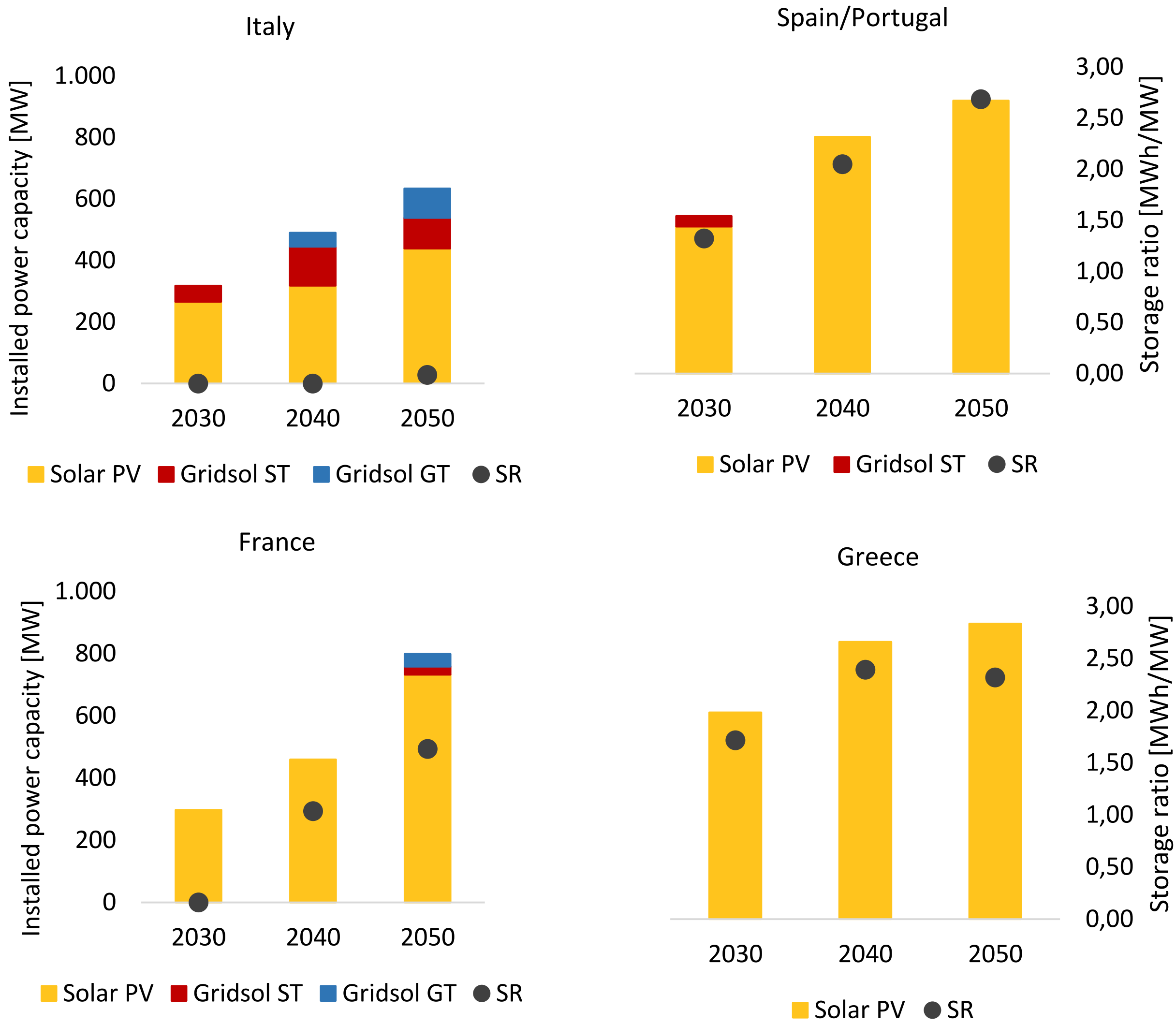


FIGURE 48. SRHS COMPOSITION BY GEOGRAPHY - CSP+ SCENARIO.

[9] This is due to the non-linear relationship between capital costs and LCoE.

hub profits and the stability of the output. The hub composition and the storage ratios (SRs), which we define as the amount of storage volume over the PV installed capacity, hinge on the main national mix and different trends can be observed for the Gridsol countries. The SR is higher where the solar resource is higher (Spain/Portugal and Greece have SRs above 2 in 2040 and 2050) and it generally increases with the years. In addition, Greece and the Iberian peninsula constitute peripherical regions of the continent and therefore tend to fill the lack of interconnectors with storage. Locations with a poorer solar resource have a more limited amount of storage per unit of installed capacity (France) or even nearly-zero storage in the case of Italy. In this last case, it is CSP with thermal storage that provide energy shifting services.

LARGE DEPLOYMENT OF STORAGE BOOSTS CAPACITY FACTORS

The integration of storage facilities cuts curtailment and boosts the hybrid power plant's full load hours. The capacity factors span from 20-24% in 2020 to over 80% in 2050, depending on the location and on the optimal amount of storage.

In all cases the **evolving configuration of SRHs boosts the capacity factor of the plant**, as shown in Figure 49. Scenario differences are represented by the vertical bars. In 2020, when Smart Renewable Hubs are only composed of PV arrays, the resulting CFs all lie around in the 20-24% range. The CF growth is not uniform overtime in the five countries under study. Depending on the specific country and regardless of the particular scenario, where the solar resource is more contained (France and Italy) the hub is left idle for a higher amount of hours (see for comparison the cases of Italy and Portugal highlighted in Figure 49). In 2050 the CFs range between 33 and 91% (Italy, Baseline scenario with only solar PV installed; Spain, CSP+ scenario with solar PV and batteries installed respectively).

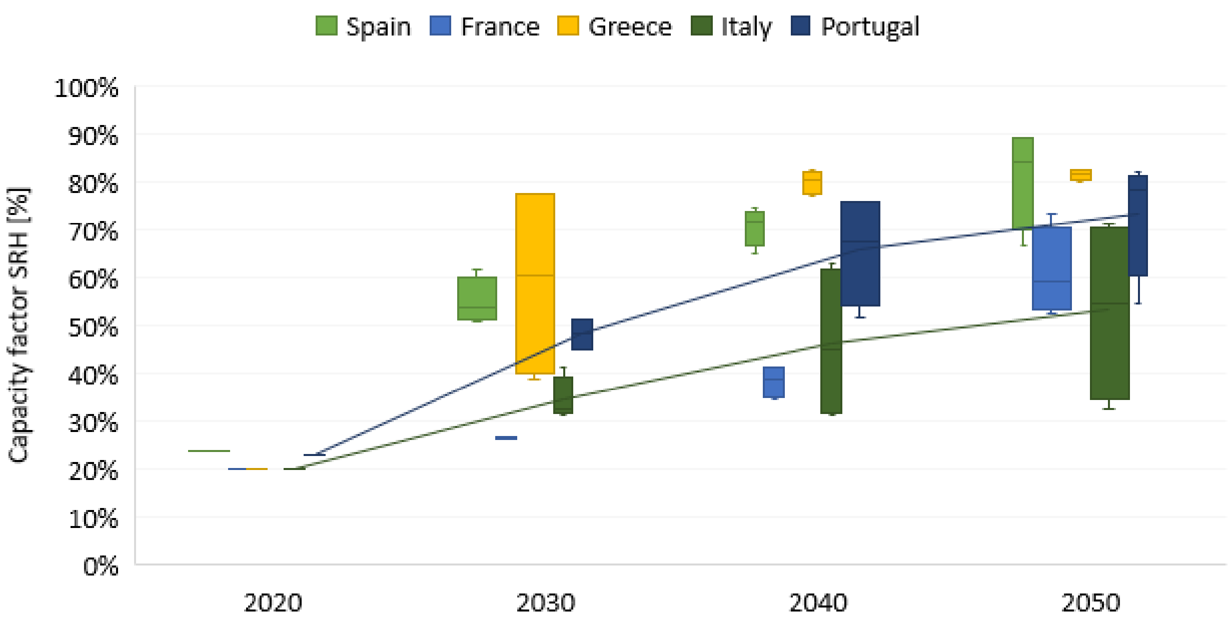


FIGURE 49. EVOLUTION OF CAPACITY FACTORS FOR THE FIVE GRIDSOL LOCATIONS.

SRHs FUNCTIONING

The interaction among technologies and the overplanting of PV boost the full load hours of Smart Renewable Hubs, which are left idle for a limited amount of hours per year. Electric and thermal storage are utilised to shift production to the late afternoon/evening peak, but follow different weekly patterns.

Smart Renewable Hubs are characterised by a total installed capacity that is higher than the maximum possible flow out of the hybrid power plant. **Solar PV is overplanted** and the energy exceeding the power station capacity at the grid connection point is either curtailed or stored in batteries depending on the economic viability of the investment. This way, the hub electricity can be dispatched during peak hours to increase the financial return.

Figure 50 shows the hub generation duration curve for a SRH installed in Italy in 2050 (CSP+ scenario). The hub includes a small amount of electric storage (Figure 48). The solar PV capacity surpasses 450 MW and the hourly production is mostly curtailed (only the dashed area in the figure is energy stored in batteries). Concentrating Solar Power provides a stable output for over4500 hours, whereas the gas turbine operates for less roughly 1800 hours and seldom at part-load. Through the use of energy storage (primarily thermal in this case) the hub reaches a 55% capacity factor at the grid connection point.

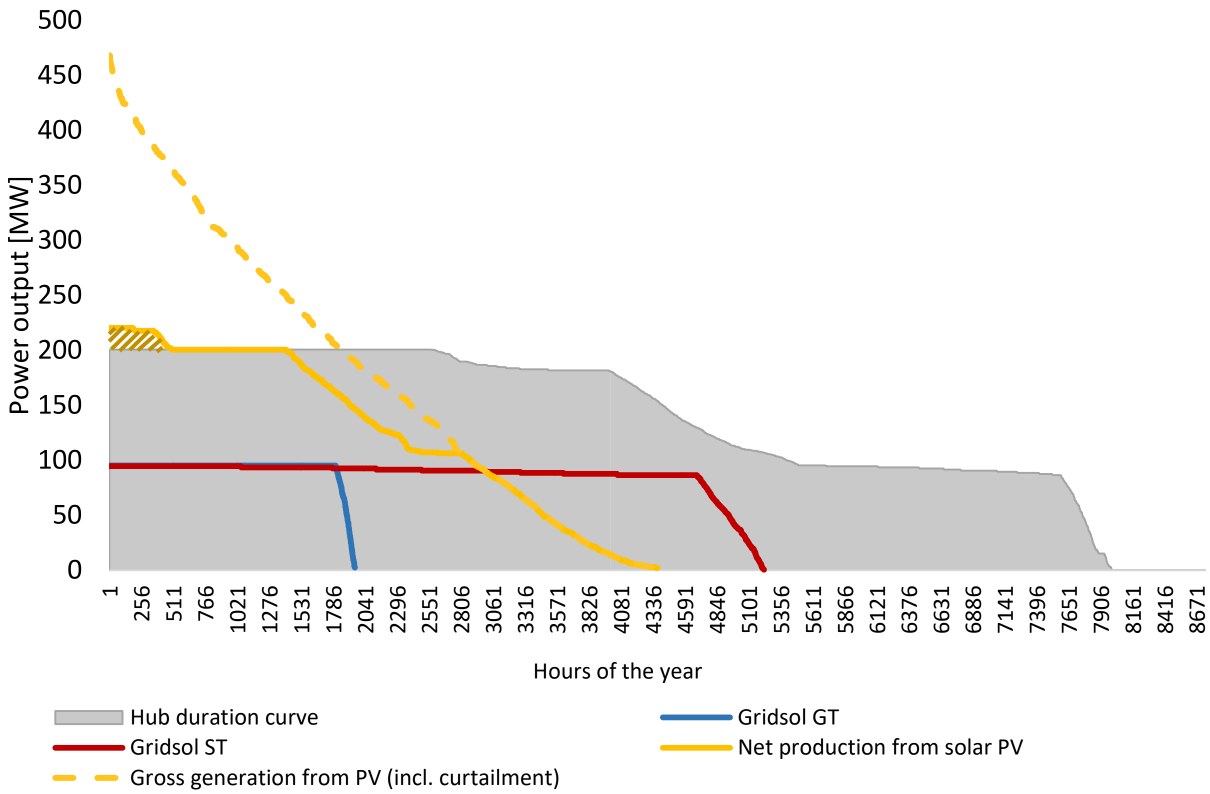


FIGURE 50. HUB DURATION CURVE - CSP+ SCENARIO, 2050, ITALY.

Figure 51 highlights the differences between thermal and electric storage. The thermal storage is generally loaded until the evening demand peak and emptied through the night and early morning. Batteries display a similar behaviour, but **shifted by 1-2 hours in time:** they do not contribute to the peak load fulfilment and they simply unload at night-time. It is important to notice that, unlike thermal storage, batteries exhibit a weekly pattern that is caused by the demand profile. A large penetration of solar PV technologies ultimately brings to the installation of enough solar capacity to cover the entire demand in hours characterised by good irradiation: at the weekend, when demand drops, electric storage is fully loaded and its peak daily content decreases along the week. Batteries are therefore used also for the inter-day shifting of the dispatch.

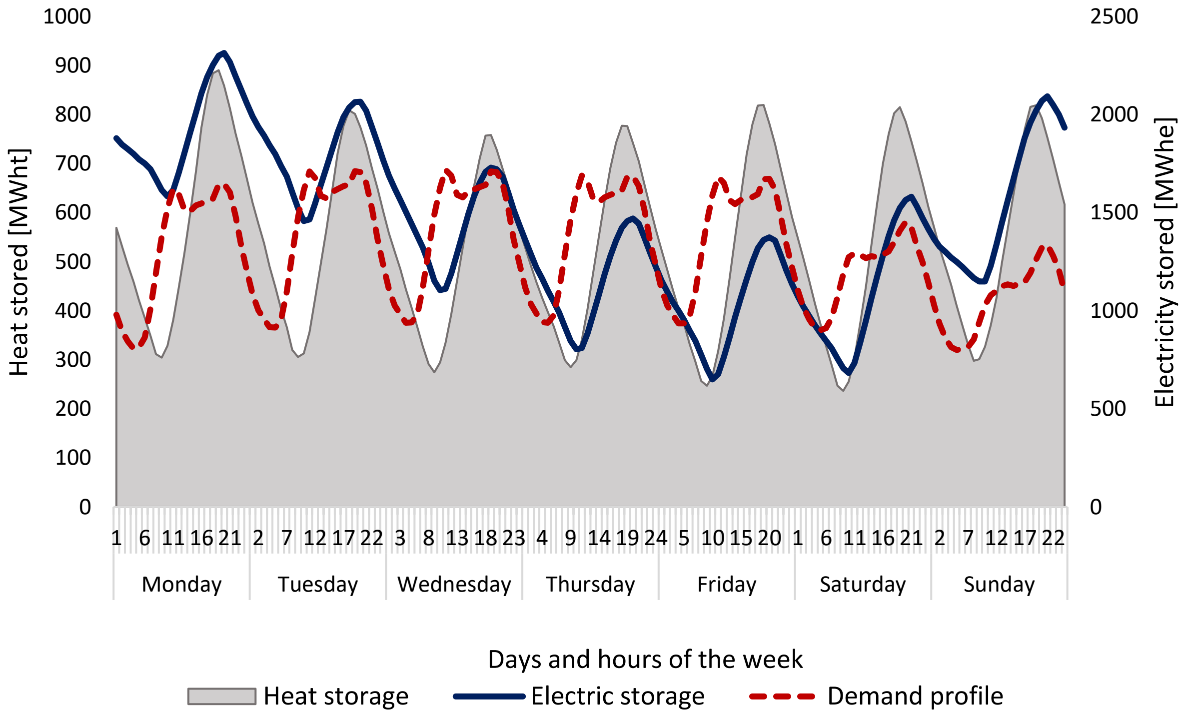


FIGURE 51. AVERAGE WEEKLY BEHAVIOUR FOR THERMAL AND ELECTRIC STORAGE IN SRHS – CSP+ SCENARIO, ITALY, 2050.

4. ISLAND SYSTEMS: THE CASE OF CRETE

The analysis of the non-interconnected islands complements the one on the larger interconnected European power system by focusing on Crete as a test case. The questions to be answered with the analysis are:

- What is the best solution to decarbonize medium/big islands given the progressive tightening of the European and national carbon budgets? Can CSP play a role?
- What is the impact of an interconnection to mainland for the development of the system and for the profitability of CSP-based generation?

In order to answer these questions, a simulation of the optimal capacity expansion and dispatch is carried out using the Balmorel model in two distinct cases which underlie the 1.5 degrees scenario assumptions:

- One with **no interconnection to the mainland** until 2050, where Crete act as an electrical isolated system;
- One with the **planned interconnector link** to mainland Greece of 1400 MW, built between 2021 and 2024.

Islands systems are characterized by stricter security of supply requirements, as they are not connected to the European continental grid. Crete is an example of these islands; in addition, the supplementary demand for electricity during summertime requires the seasonal provision of extra generators to back the ageing, fossil fuel generation fleet. The Greek government prioritizes the interconnection of Crete to the mainland and approved the strategic installation of the EuroAsia link. The cable will be able to carry up to **1400 MW** and is expected to be built in the period between 2021 and 2024 on and marks a decisive step for the emission reduction in the country (Figure 52)[10].

FIGURE 52. THE EUROASIA INTERCONNECTOR WILL LINK CRETE AND MAINLAND GREECE FROM 2022. SOURCE: 4C OFFSHORE.

[10] Source: 4C Offshore.

THE EXISTING SYSTEM RELIES ON FOSSIL FUELS, BUT RE IS GROWING

Crete currently relies on ageing oil-fired power plants and a smaller share of onshore wind farms and solar PV modules, mainly installed on roofs. The large resource potential can enhance the transition towards decarbonisation, but future planning must include storage systems to ensure load coverage along the day.

Crete is characterised by a varying load profile throughout the year (Figure 53). The peak demand occurs in the month of July and is caused by the touristic influx during summertime; this additional supply is normally ensured by leased fossil-fuel generators. The base-load requirement is close to 300 MW in 2025, when the new interconnector may be under operation. We assume the yearly electricity demand to increase by 38% from 2015 to 2050, based on historical data and assumptions from ENTSO-E [19], and the load profile to shift upwards accordingly.

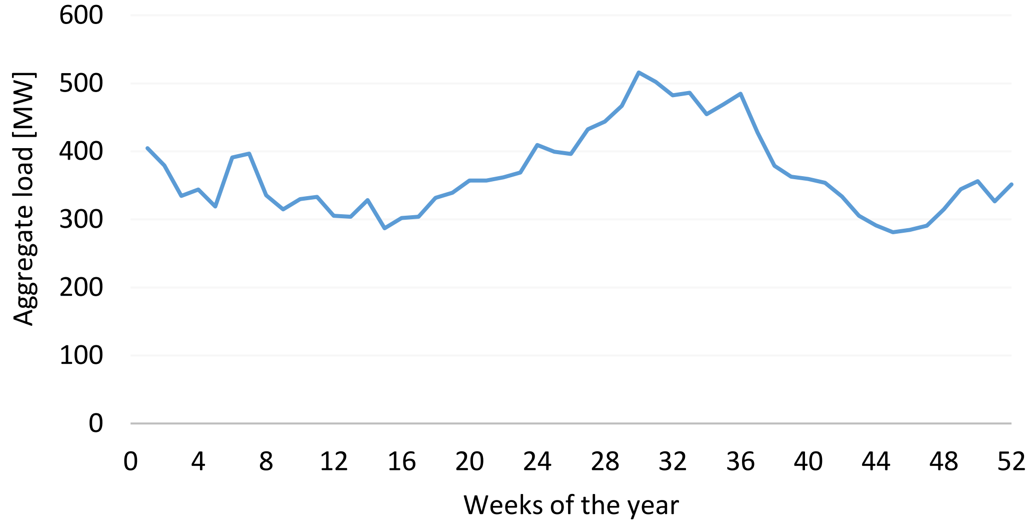


FIGURE 53. YEARLY LOAD PROFILE FOR CRETE (2025).

In 2018, 27% of the all-year-long available capacity was ascribable to renewables; the units mainly exploit the wind and solar resources, with only minor contributions from hydro (300 kW) and biomass (500 kW). The rest of the generation fleet is composed by heavy fuel oil (HFO) and diesel engines, which were mostly put into operation in the 20th century. The Greek government has already given the green light to a first-of-its-kind project called M.I.N.O.S., which is leading to the technical development and grid integration of a 52 MW_e CSP plant in the island, set to begin the operations already in 2020. Revenues are guaranteed by a feed-in tariff under a 25-year Power Purchase Agreement (PPA) with the Greek government. The solar field is of the central tower type.

Fossil-fuel power plants make up for more than 70% of the total installed capacity. Table 10 shows that these units supply more than 80% of the total electricity demand of the island; renewable technologies are characterised by lower capacity factors (Figure 54). The bulk generation is provided by HFO engines; these benefit from relatively lower OPEX than diesel generators. The solar capacity mainly contributes to cover the late-morning peak in the island, while it is conventional generators that dispatch in the evening; in the same time span, diesel engines boost their production by 30-40 GWh on average, thereby acting as peakers.

TABLE 10. CAPACITY AND GENERATION SHARES FOR CRETE – EXISTING SYSTEM.

	Heavy fuel oil	Diesel	Solar PV	Hydro	Onshore wind	Biomass
Installed capacity [%]	31.6	40.8	8.9	< 0.1%	18.7	< 0.1%
Electricity generation [%]	48.8	33.9	4.8	< 0.1%	12.5	< 0.1%

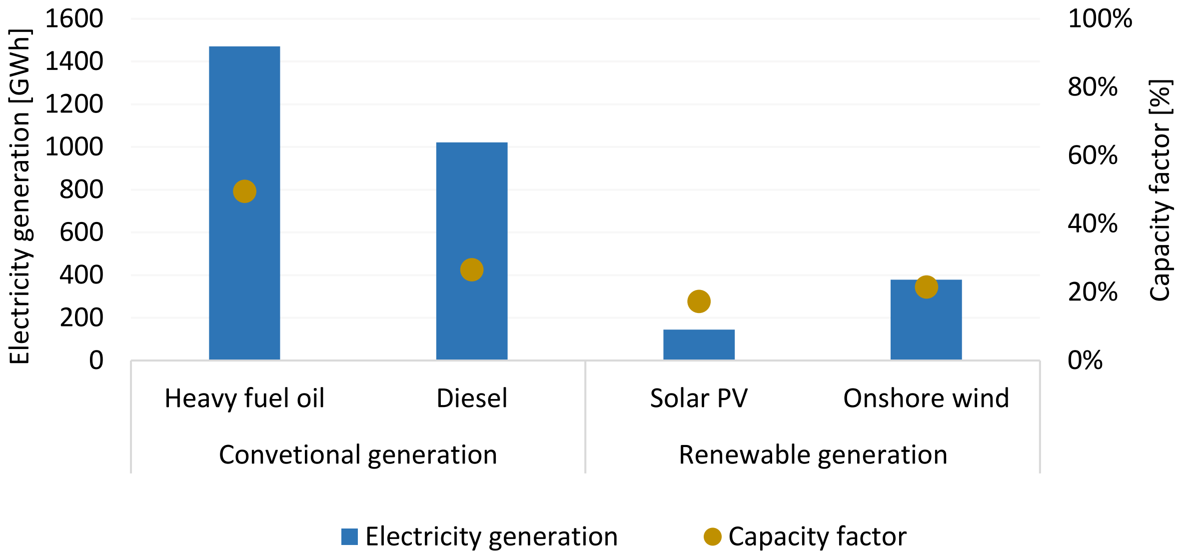


FIGURE 54. ANNUAL ELECTRICITY GENERATION PER FUEL TYPE – EXISTING SYSTEM.

Wind energy has a more constant profile (Figure 55). The energy transition on the island is conditional on the creation of a flexible and reliable fleet, able to meet the demand during both the low and the summer season.

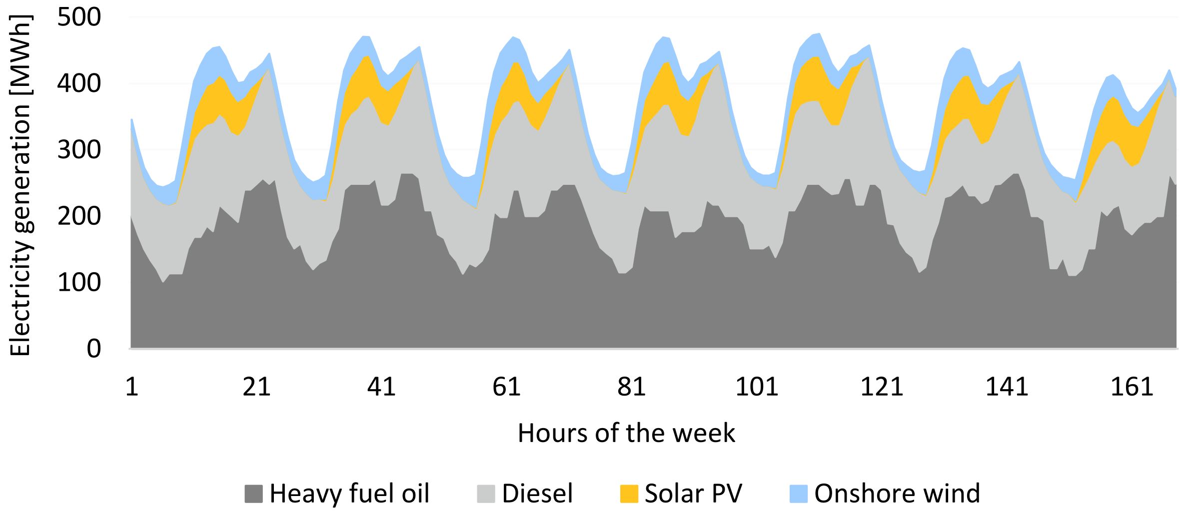


FIGURE 55. ELECTRICITY DISPATCH FOR A SUMMER WEEK - EXISTING SYSTEM.

Crete as a non-interconnected system

A long-term plan to decarbonise Crete should include a transition to natural gas in the immediate future, in the form of LNG. The rapidly dropping cost of electric storage will provide additional flexibility only from 2030 onwards.

The introduction of high CO_2 prices to fulfil the European environmental targets lead to a progressive phase-out of the HFO and diesel units, which are partly replaced by natural gas in the short/medium-term (Figure 56). The switch to natural gas falls also within the PPC[11] commitments to convert the existing units into NG-fired ones, but the plan is conditional on the development of a costly LNG infrastructure, including transmission and distribution pipelines. The transition may be fostered by the yet unexplored gas wells off the coast of Crete. For this reason, a reduced share of the existing oil units would continue to supply power in the next years. **Natural gas installations are operative from 2025 and they account for 278 MW, of which 118 MW are found in the CSP hybrid group.**

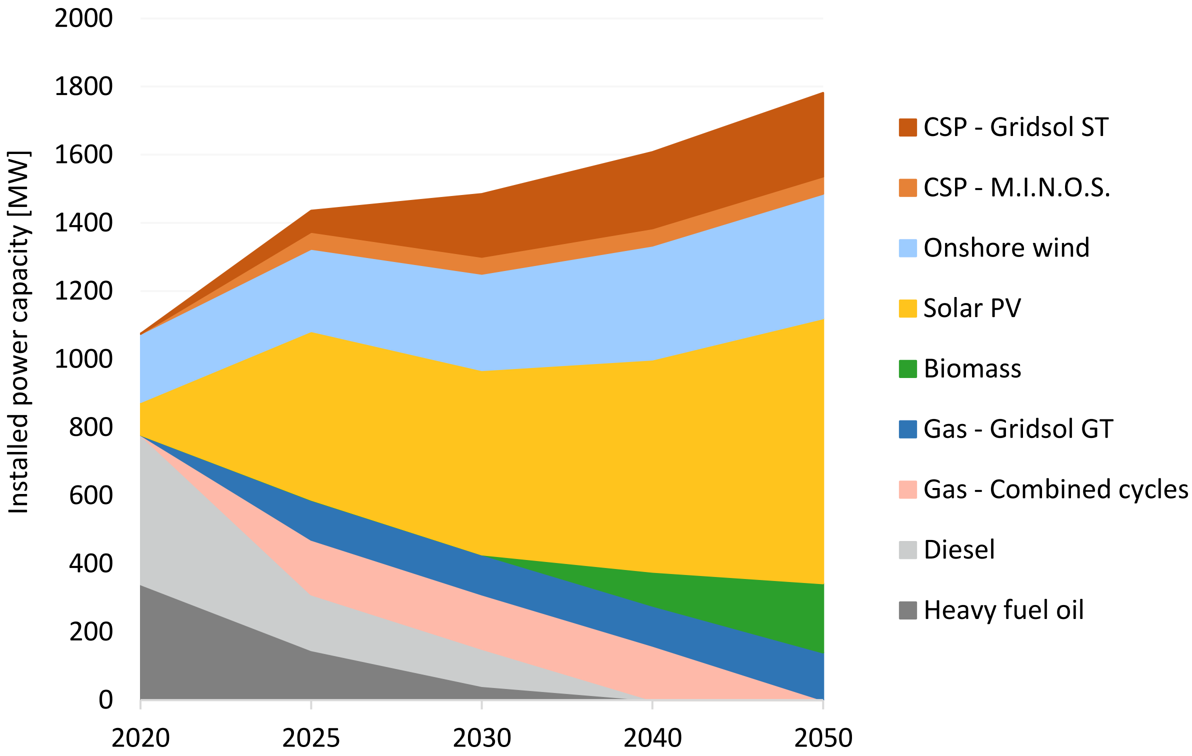


Figure 56. Evolution of the installed capacity in Crete until 2050.

Renewables increase their penetration ever more; wind and solar PV units account for over 1.1 GW of the capacity in 2050 (two-thirds of the total) and they thereby are the major contributors to the **700 MW increase in capacity** the island would need in 30 years. Biomass plants represent 200 MW of the generation fleet in 2050 and they could exploit the copious agricultural residues, whose energy potential is estimated to be 6000 TJ/year [20]. The capacity buildout is regular from 2030 (Figure 57), but **the**

[11] PPC is the power utility managing the island's units.

necessary investments to ensure an economically optimal long-term decarbonisation should occur in the immediate future.

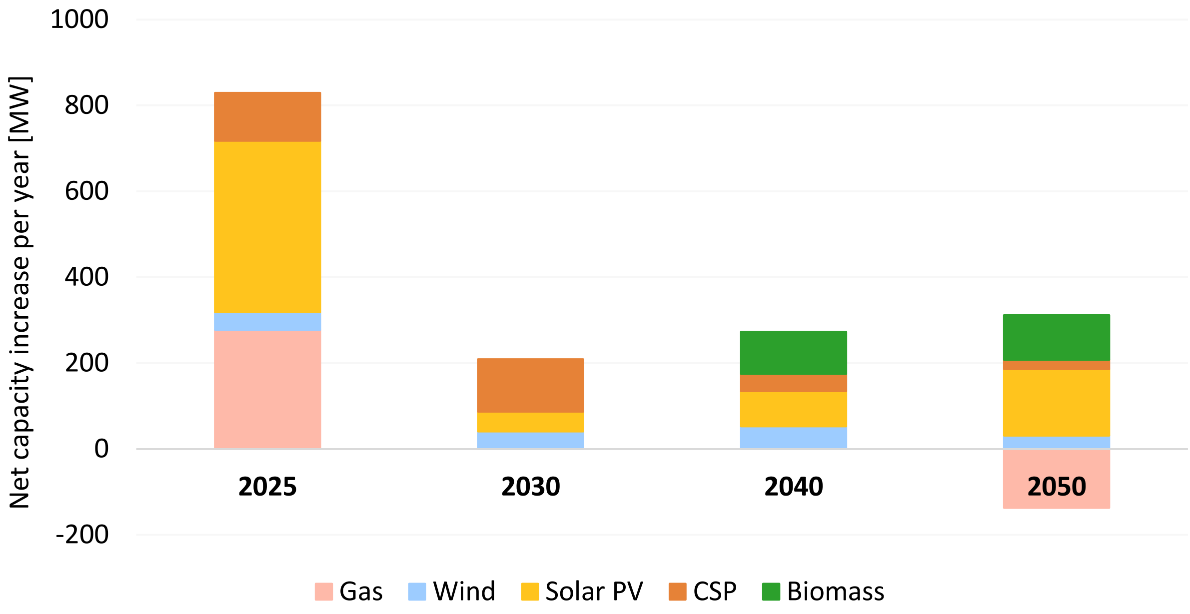


FIGURE 57. CAPACITY BUILDOUT AND DECOMMISSIONING UNTIL 2050 (OIL UNITS EXCLUDED).

The M.I.N.O.S. project and additional CSP installations would find room already from 2025, when an additional 60 MW solar tower plant results economically optimal. **The total CSP power capacity grows to 300 MW in 2050**, thereby making up **17% of Crete's fleet** (Table 11).

TABLE 11. GENERATION AND CAPACITY SHARES IN CRETE (2050).

	Gas	Biomass	Solar PV	Wind	CSP
Capacity – share [%]	6.7	11.4	42.6	22.2	17.1
Generation – share [%]	1.1	18.9	26.5	15.0	38.5

The gas capacity covers the peak demand, whereas biomass and CSP units serve as dispatchable generators: their generation share is more than twice their capacity share. An increase of the CSP market penetration can only be achieved by an expansion of the storage facility: Figure 59 displays that a solar multiple *SM*[12] of around 3 and a storage volume of 20 hours are required for CSP to substitute conventional technologies. The other advantage of using large thermal energy storage is the possibility of keeping a high generation levels during wintertime as well, as Figure 58 (top) shows.

[12] The solar multiple *SM* [-] is defined as the ratio between the nominal output from the solar field and the nominal input of the steam turbine.

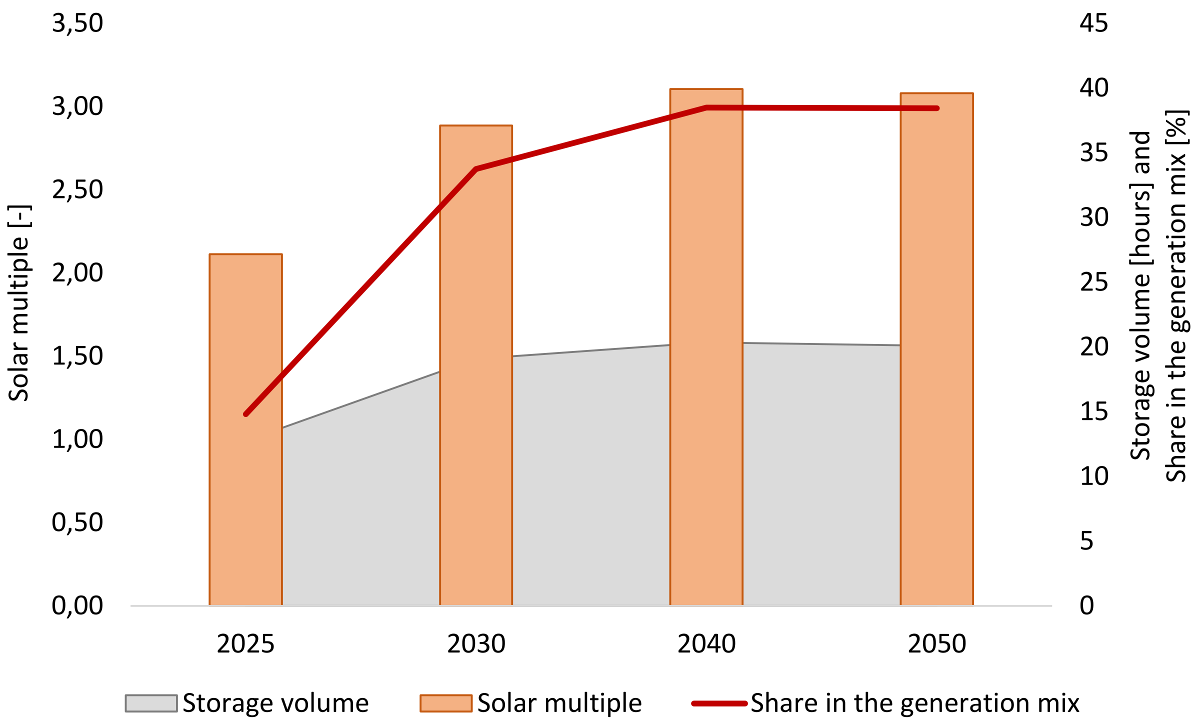


FIGURE 59. TECHNICAL CHARACTERISTICS OF CSP INSTALLATIONS ON CRETE.

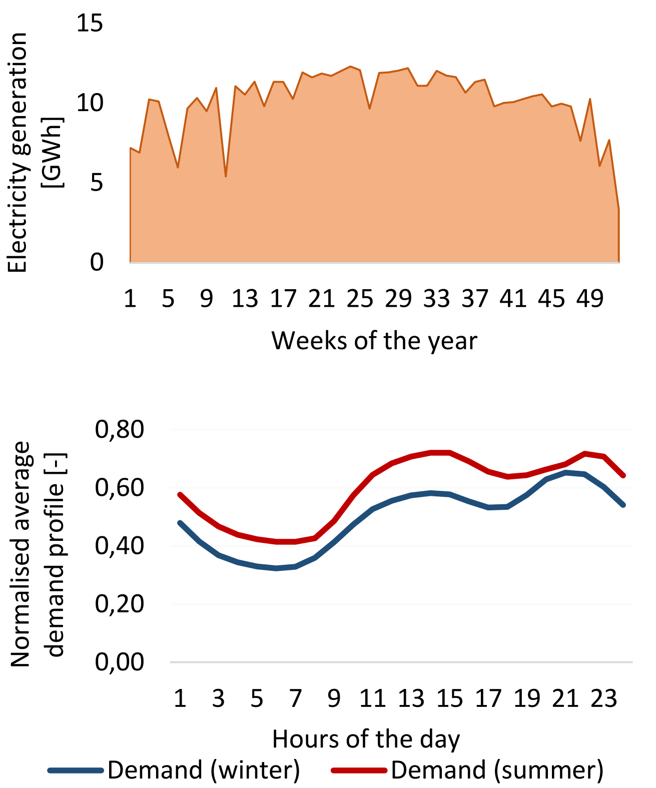


FIGURE 58. TOP: ELECTRICITY GENERATION ON A WEEKLY BASIS (2050).
BOTTOM: AVERAGE DAILY LOAD PROFILE.

Batteries allow to store excess energy from VRES when not needed; these units typically unload in the evening, when the peak demand occurs (Figure 58, bottom). Electric storage is mainly loaded by solar PV, but partly also by wind farms at night (Figure 60). By managing electricity generated at low marginal costs, the combination of VRES and batteries reduces the need for expensive gas peakers, which are limited to only 1.1% of the total electricity dispatched. CSP and biomass units substitute fossil-fuel base-load generators, but they suffer from the competition with low-cost marginal units such as wind and solar PV (Figure 61). As a consequence of the declining cost of electric storage, new CSP and biomass plants see their full load hours reduced. The effect is less noticeable for CSP, as large thermal storage provides standout flexibility: its operations range between 5000 and 6000 FLH a year.

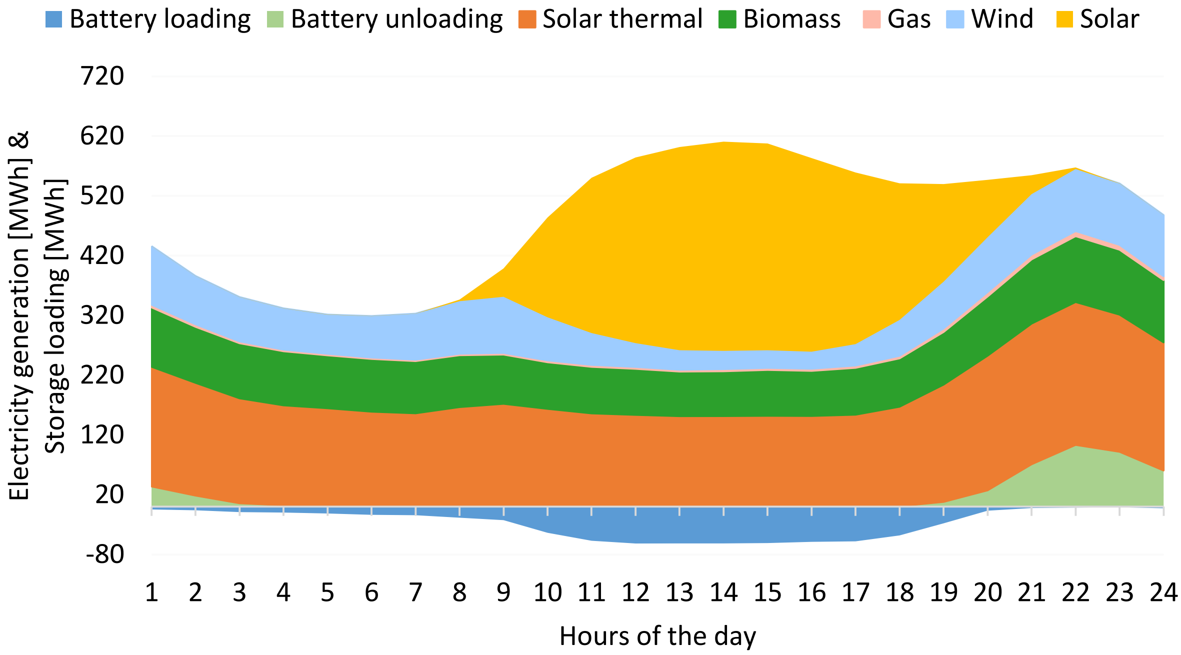


FIGURE 60. AVERAGE DAILY DISPATCH – NON-INTERCONNECTED SYSTEM, 2050.

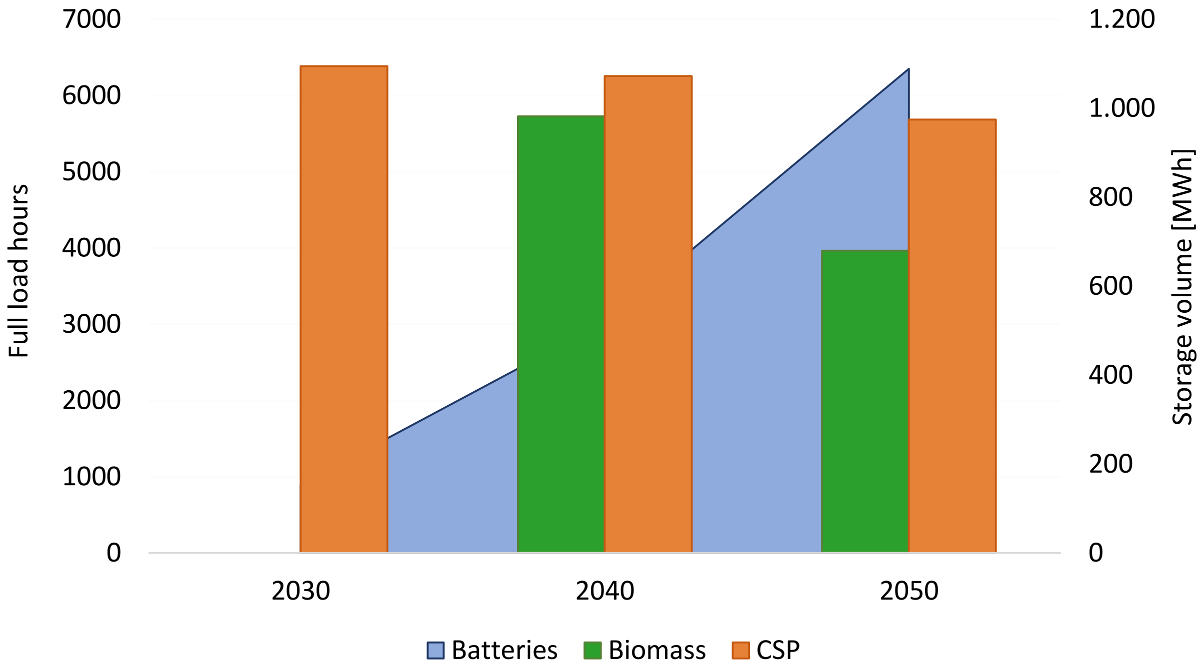


FIGURE 61. FULL LOAD HOURS OF CSP AND BIOMASS POWER PLANTS. THE EXPANSION OF THE STORAGE VOLUME IS REPORTED AS WELL.

Interconnection drives prices down and penalises CSP

A submarine cable is projected to link the island with mainland Greece from 2024 with a nominal capacity of 1400 MW. In the short-term, Crete imports electricity from Greece, but the gradual installation of wind and solar technologies in the island, where resources are better, will make Crete an exporter in the long-run. Thanks to the interconnection, on Crete the spot price falls by 24 EUR/MWh in 2050 compared to an off-grid setting but CSP units result largely downscaled.

The submarine cable linking Crete with the mainland is a strategic project that is projected to be in operation from 2024 with a capacity of 1400 MW (built in two chunks). This will lead to the progressive buildout of additional VRES on the island, coupled with moderate amounts of storage. The cable is utilised for 10% of the maximum yearly transferrable power in 2025 to import energy from Greece, while the flow in the opposite direction is limited. This equilibrium is reverted in the long-term, when the richer natural renewable resources on the island turn Greece into an importer (Table 12).

Table 12. Submarine cable utilisation factor [%].

Line utilisation factor [%]	2025	2030	2040	2050
Crete to Greece	2	13	39	44
Greece to Crete	10	6	4	2

The new link has a remarkable effect on the future development of Crete's generation fleet. The forthcoming transition to natural gas proves to be unprofitable and part of the existing oil-fired units are kept in operation in 2025 (Figure 62Figure 62. Capacity increase (per fuel type) in the interconnected scenario.); when needed, energy is imported from Greece at a lower cost than that of establishing new gas capacity. Dispatchable generators are affected by the interconnector the most. Besides fossil-fired power plants, steam turbines running on CSP are downsized (60 MW against the 300 MW present in the off-grid scenario) and biomass generation disappears. The installed solar capacity reaches 3 GW in 2050 while wind energy totals up to 1.6 GW. The main findings related to the establishment of new interconnection capacity lie in: **a poor short-term utilisation of the link given the island peak load demand and the interconnector capacity**, which nonetheless sets back the conversion of existing oil-fired units to natural gas ones; **a long-term deployment of wind and solar PV energy alongside electric storage on the island**, to the point that the total installed capacity nearly triples in 2050 with respect to an off-grid scenario; **the reduced attractiveness of dispatchable generators including CSP**, whose capacity is largely downsized.

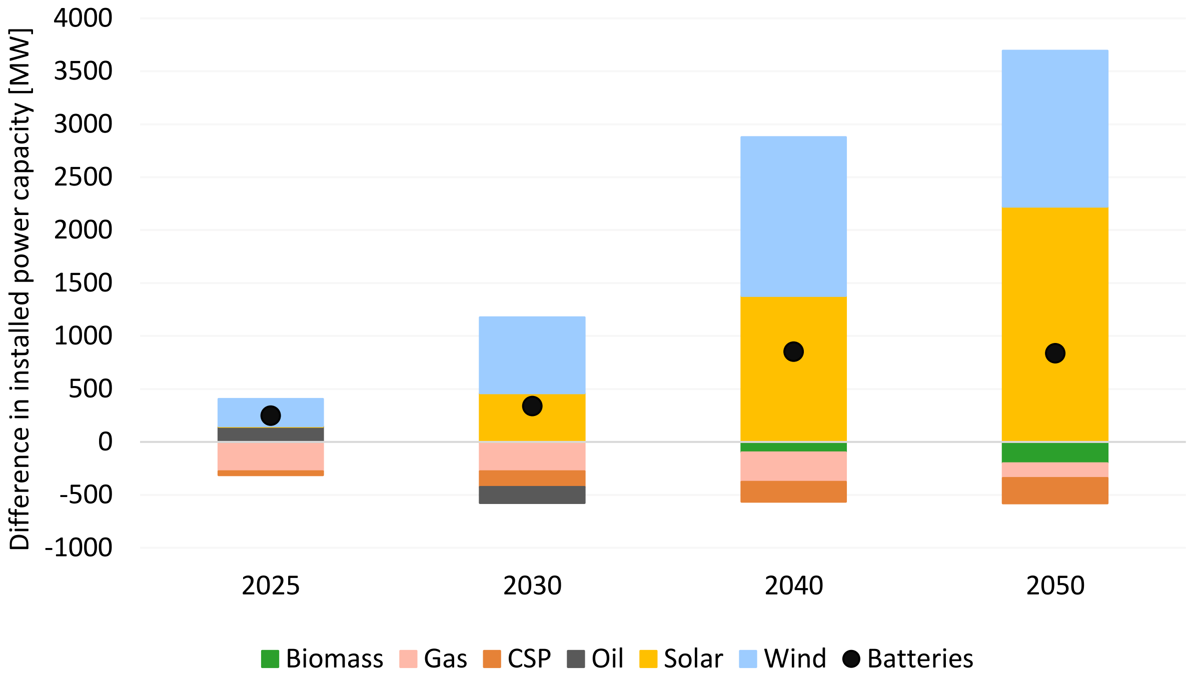


FIGURE 62. CAPACITY INCREASE (PER FUEL TYPE) IN THE INTERCONNECTED SCENARIO.

Solar capacity is favoured over wind turbines and the excess energy is exported to Greece. Electricity curtailment increases in relative terms with years, mainly due to reduced investment costs. Wind energy is consistently curtailed on the island, up to 40% of the overall wind generation in 2050 in an off-design scenario. This figure gets reduced to 27% in the event of interconnection. In the same context, less solar energy is also wasted, as the related curtailment falls from 15% to 4% in 2050 thanks to the cable (Figure 63).

The solar buildout, which would lead to a capacity of 500 MW already installed in 2025 in both the off-grid and interconnected scenarios, is meant to cover the seasonal increase in demand due to tourism. Figure 64 shows that in 2025, soon after the new cable to Greece is built, most imports occur in wintertime, when the solar resource is poorer. Instead, the exports to the mainland are rather stable during the year with a low during summer, when the demand peaks. **If investments in renewables are carried out, Greece contributes to the fulfilment of Crete's winter demand in the short term**. However, as Table 12 showed, the situation reverts with the years, with Crete becoming a net exporter.

The CSP units on the island ensure stable and prolonged generation in absence of natural resources in an off-grid scenario; big solar multiples and large TES volumes ensure the availability of steam to run the turbine for nearly a day at nominal load. The competitiveness of CSP generation is largely reduced in an interconnected system, as the firmness guaranteed by these units is overcome by cheaper electricity imports. In the event of no interconnection, most of the CSP capacity is built between 2025 and 2030; in the same years the cable is mostly utilised from Greece to Crete in the interconnected scenario. The CSP installed capacity drops by 237 MW between the two hypothesised development of Crete's fleet (one fifth of the off-grid optimal capacity); the TES volume is reduced even more and consequently are the full load hours, which get reduced by more than 400 (Table 13).

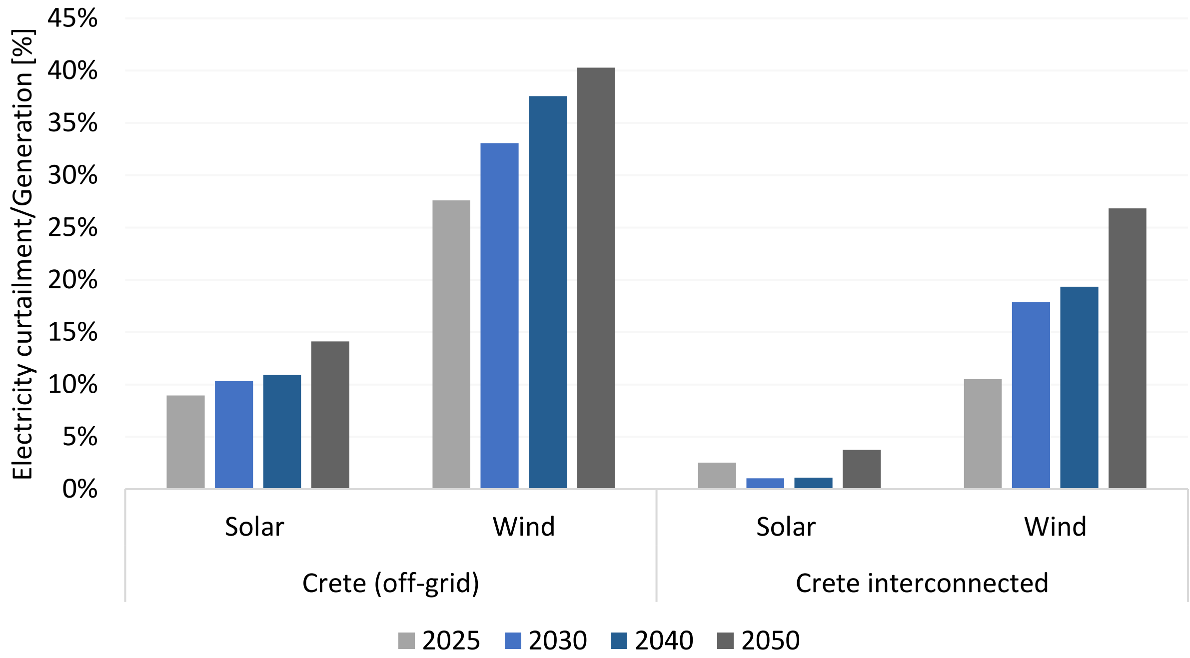


Figure 63. Electricity curtailment in the two scenarios for Crete.

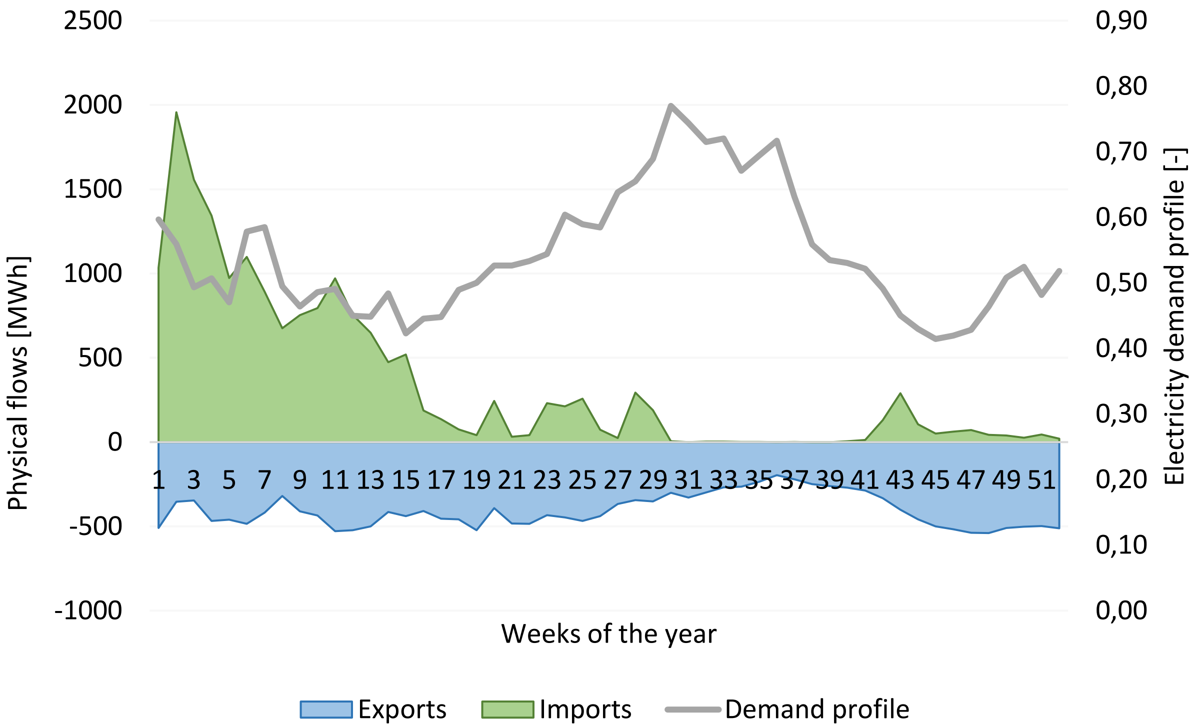


Figure 64. Cross-border physical flows from Crete's perspective – 2025.

TABLE 13. OPERATIONAL FEATURES OF CSP UNITS IN THE TWO SCENARIOS.

	Installed capacity [MWe]	TES volume [h]	Full load hours
Non-interconnected system	296	21	5199
Interconnected system	59	15	4731

An important socio-economic benefit that derives from the installation of the submarine cable is connected to the lower market prices. The gap between the two scenarios enlarges with the years, until the average yearly cost of electricity in the market is 24 EUR/MWh lower with the interconnector (Figure 65).

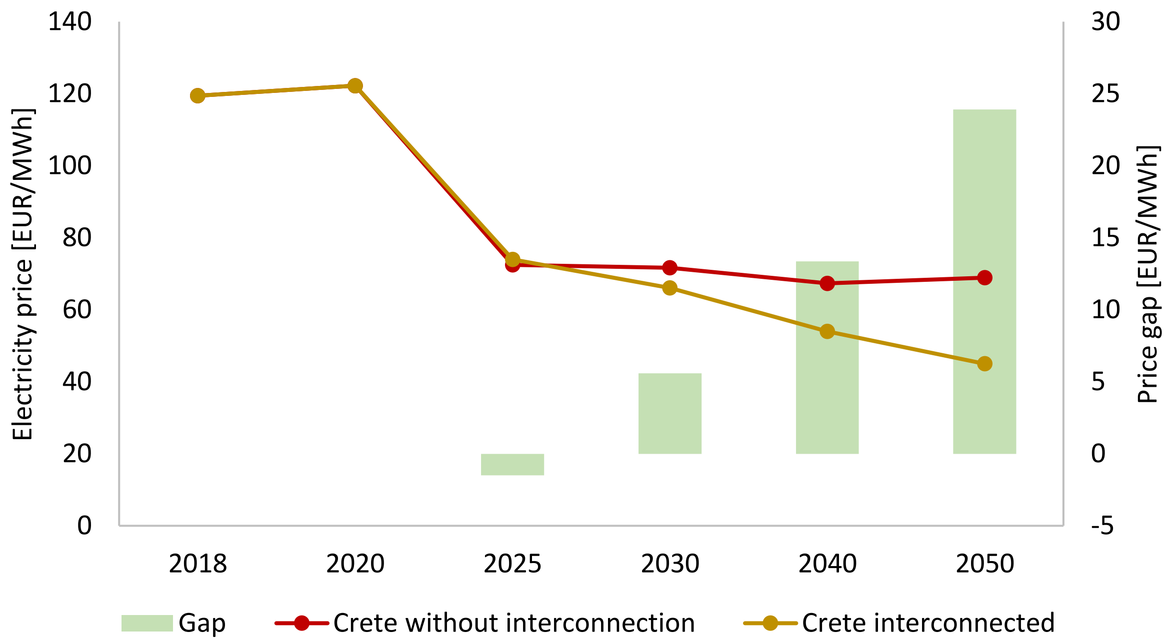


FIGURE 65. AVERAGE YEARLY ELECTRICITY PRICES IN THE TWO SCENARIOS.

A comparison between the off-grid and the interconnected scenario shows how **islands provide an attractive framework for the installation of CSP**. The technology ensures dispatchability at a competitive cost, due to the inexpensive thermal energy storage. The results can be transferred to any other island with similar resources and site availability and underline the significant role of CSP in the energy transition of such contexts. On the other hand, **interconnection penalises CSP** as the country imports at wintertime, when CSP was found to dispatch in a rather stable manner (Figure 58). The electricity price in the interconnected system reaches a low of 40 EUR/MWh, which is surely below the LCoE of CSP technologies in the 5000 full load hours range and with no further cost reductions with the industry projections, as reported in Figure 33 and Table 13. As the zonal electricity price is crucial to assess the competitiveness of a technology, we expect that **under the 40% cost reduction assumptions CSP would cover a rather bigger role and already from 2025/2030 even in the interconnected scenario**, as the spot price is still above 60 EUR/MWh on average (Figure 65).

5. CONCLUSIONS

Ambitious decarbonisation targets can favour the spreading of CSP in the European power sector, as the lack of dispatchability which characterises VRES generation calls for the installation of flexible generation technologies integrating energy storage. The expected high cost-competitiveness of PV and batteries, which can account for between 20 and 30% of the EU generation mix in 2050 depending on the scenario (up to 50% in Southern Europe), limits the prospects for CSP power plants equipped with thermal energy storage. The increase in gross electricity demand due to a possible development of the hydrogen economy is mainly supplied by low marginal cost generation. The system characteristics and the nature of the solar resource make CSP-based generation more attractive in Italy and France, where in the 2.0 and in the 1.5 degrees scenarios the cumulative installed capacity reaches 15 and 40 GW respectively in 2050; The additional cost reduction embedded in the CSP+ scenario further increases the potential of CSP, which appears already in 2025 in all the focus countries with the exception of Portugal. The 2050 potential is identified to be around 120 GW with these assumptions. The main competitors are solar PV + batteries groups as well as gas cycles.

CSP is equipped with large thermal energy storage facilities (over 20 hours in selected locations) and a solar field which is oversized with respect to the steam turbine nominal capacity (by a factor of 2 to 3). This feature ensures dispatchability and possibility to shift production to late afternoon, evening and night hours in conjunction with high electricity prices and the scarce availability of low marginal cost generation. In the hybrid groups, the gas engine operates for less than 1000 hours a year and predominantly in Autumn and Winter months.

Using the same scenario framework, the island of Crete has been analysed in two scenarios: with and without interconnection to mainland Greece. The profitability of CSP is negatively affected by interconnection. Should a cable connect Crete to the mainland, the optimal CSP-based capacity would be reduced to 20% of the non-interconnected case. Islands are characterised by higher spot prices than interconnected systems and are therefore an attractive context to host CSP-based power plants. On Crete, CSP-based power plants can reduce the need to a short-term conversion of the existing units to natural gas; in addition, the existence of an interconnector to the mainland and the comparatively higher quality of natural resources can turn the island into a net exporter after 2030.

For each country under focus, a 200 MW hybrid plant has been optimized, with the option of investing in PV, storage, wind power and a group composed of integrated CSP and gas technologies. The role of CSP in hybrid power plants is limited to selected instances, under the assumption of large cost reductions for CSP components and only where CSP finds room in the corresponding national mix. Grid connection savings go to the advantage of units with comparatively low investment and operational costs; for this reason PV is favoured over CSP, wind and gas engines. Smart Renewable Hubs are large solar PV fields in the short-term and mainly composed of solar PV and batteries in the long-term. This combination yields the highest capacity factors, which overreach 80% in 2050. PV is overplanted with respect to the hub nominal output and the excess energy is stored in batteries. The key-presence of storage facilities limits idleness in Smart Renewable Hubs and sharpens the response of units to price signals.

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GLOSSARY

Solar Multiple

The solar multiple SM [-] is defined as the ratio between the nominal energy output from the solar field and the nominal energy input of the steam turbine:

$$SM = \frac{E_{nom\ th,SF}}{E_{nom\ th,ST}}$$

Market Value of wind

Expressed in EUR/MWh is the ratio between the revenue of a generator in the market in a certain time period and its potential production including curtailment. It represents the average revenue per energy unit produced. In order to capture the potential seasonal variations, market value is usually expressed in a yearly time frame.

$$MV_{g,z} = \frac{\sum_t^T p_{t,z} \cdot E_{t,g,z}}{\sum_t^T E_{t,g,z}} = \bar{p}_{g,z}$$

where:
t = timestep (1, …, T)
g = technology (onshore wind, offshore wind, solar, CSP …)
z = market zone or country considered (Spain, Greece, France, …)
T = total timesteps in the period considered (8760 if a year is assumed)
E = potential energy production, including production that is curtailed
p = market price in the zone/country considered

Levelized cost of electricity

This parameter expresses the cost of the MWh generated during the lifetime of the plant and it represent a life-cycle cost. It can be calculated as:

$$LCoE = \frac{I_0 + \sum_{t=1}^{N} \frac{V_t}{(1+i)^t}}{\sum_{t=1}^{N} \frac{E_t}{(1+i)^t}}$$

where:
I_0 *= Overnight cost or Investment cost [EUR]*
N = Technical lifetime of the plant [years]
V = Variable cost including O&M, fuel, CO_2 *costs [EUR in year t]*
E = Electricity produced in the year t [kWh in year t]
i = real discount rate [%]

APPENDIX: MODEL SETUP AND DETAILED ASSUMPTIONS

BALMOREL: GENERAL DESCRIPTION

Balmorel is a detailed techno-economical partial equilibrium model suited for analyses of electricity as well as combined heat and power markets. It is capable of both, investment and dispatch optimisation. In investment mode, it is able to simultaneously determine the optimal level of investments, refurbishment and decommissioning of electricity and heat generation and storage technologies as well as transmission capacity between predefined regions.

In dispatch optimisation mode, it determines the market optimal utilisation of available generation and transmission capacity. It is capable of both time aggregated as well as hourly modelling, which allows for a high level of geographical, technical and temporal detail. It is particularly strong in addressing the interdependency between heat and electricity production of combined heat and power (CHP) generators.

The mathematical principle behind Balmorel is based on finding a least cost solution for the dispatch and investments within the regarded interrelated electricity and district heating markets. By doing so, Balmorel takes into account developments of electricity and heat demand, grid constraints, technical and economic characteristics for each kind of production unit, fuel prices, spatial and temporal availability of primary renewable energy, etc.

The model allows for detailed simulation of heat market, which is particularly important in countries and regions, where combined heat and power is noticeable.

Two technology types represent CPH units; extraction units and backpressure units. The capacities in the model are given as net capacities for either electricity or heat. For extraction units, the capacity is given as the electrical capacity in condensing mode; while for backpressure units it is given as the electricity capacity in co-generation mode. In full cogeneration mode at CHP units, the Cb-value specifies the ratio between electricity and heat. For extraction units, the Cv-value specifies the loss in electricity when producing heat for maintained fuel consumption. The fuel efficiencies in the model are for CHP units given as the fuel efficiency in condensing mode for extraction units and the total fuel efficiency in CHP mode for back-pressure units.

The model also includes heat only generation technologies without simultaneous electricity generation, for example heat only boilers and electricity-to-heat units (heat pumps, electric boilers). With increasing shares of renewable in power systems, electricity to heat technologies become important for system integration.

BALMOREL: INPUT DATA

The model has a technology catalogue with a set of new power generation technologies that it can invest in according to the input data. The investment module allows the model to invest in a range of different technologies including coal power, gas power (combined cycle plants and gas engines), straw and wood-based power plants, wind power (on and off-shore) and solar PV. The model is also able to rebuild existing thermal power plants from the existing fuel to another. At a lower cost than building a new power station, the model can choose to rebuild a coal-fired plant to a wood pellets or wood chips, and convert natural gas fired plants to biogas.

The technology assumptions develop from now to 2050, that meaning costs and efficiencies develop according to learning curves for the specific technology. Technology assumptions are largely based on the Danish Energy Agency's technology catalogues (https://ens.dk/en/our-services/projections-and-models/technology-data).

The development of the existing generation capacity is subject to uncertainty. The reason is that similar to new investment, the lifetime of existing capacities is subject to economic optimisation and thus dependent on the development of electricity prices. However, other factors also play a role, and these can be harder to reflect in the model optimisation. They include: Environmental legislation on emissions effectively ruling out older power plants; various national subsidies to support certain power plants or type of power plants due to either concerns about the security of supply or national priorities (e.g. importance of power plants for regional economy and labour), optimisation of fixed cost as a result of changing operational patterns.

The decommissioning of thermal power plants can happen both exogenously and endogenously in the model. The exogenous approach is based on data about the year of commissioning of power plants and assumptions about typical technical lifetime. Moreover, the model can decide to decommission a power plant when it is no longer economical profitable to operate (endogenous decommissioning). This work incorporates up-to-date assumptions (exogenous) on the decommissioning plans of coal power in the European countries.. The model both invests and decommissions myopically, i.e. only based on the information of the given year, not taking into account estimates for the future. This applies to parameters such as fuel and CO_2 prices.

- **Investments:** The model invests in a technology when its projected annual revenue can cover all costs including capital costs, fixed O&M. The model investments have been allowed after 2017, the base year of the model runs.
- **Decommissioning:** The model decommissions a technology when the revenue can no longer recover fixed O&M. Exogenous capacity is kept constant (except if better data for expected decommissioning year is available) unless it is decommissioned by the model. The model has been allowed to decommission capacity after 2020.

Development of electricity demand is based on the ENTSO-E scenarios in the TYNDP 2018. For 2020 and 2025, the Best Estimates (BE) are used. For 2030, demand is based on the Sustainable Transition (ST) 2030 scenario. For 2050, the demand is further extrapolated from the ST 2040 scenario. As for the RE developments, the ST scenario is more in line with the BE scenarios compared to the EUCO (European Commission) scenario. These projections are aligned with what is foreseen by the EU Climate Strategy published in 2018 [21].

The electricity demands for future years also includes:

- Individual heating
- Electric vehicles
- Electricity for district heating

- Electricity for process heat (industry)

Electricity used in district heating, for industrial heat and production and for hydrogen is determined endogenously in the model simulations.

Demand flexibility (demand response) can be an important measure for integration of renewable energy in the power system. However, current experiences with demand flexibility are limited and projections are highly uncertain.

As a cautious assumption, it is assumed here that 10% of the average nominal demand throughout the year is flexible and can be shifted in time by up to 4 hours. This leads to a demand response capacity of 27 GW by 2050 and the option to "store" 108 GWh. Additional demand flexibility related to electric vehicles is also included.

Modelling Gridsol

The Gridsol hub was described early in this document. The scheme representing the Balmorel layout is reported in Figure 66. 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. For a more detailed description of the hub and the Balmorel setup see [18].

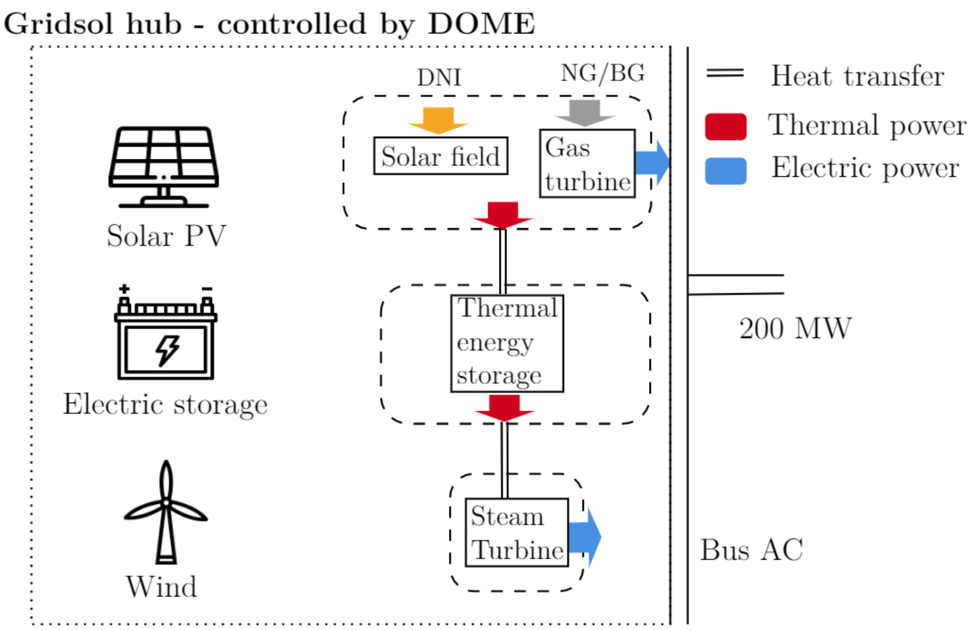

Figure 66. Gridsol hub schematic.

The technical details of the Gridsol hub are described in Table 14. These inputs are provided by the other work packages. C_b represents the ratio between thermal and electric power produced by a back-pressure technology. Some efficiencies are predicted to rise within the investigated time frame; their development is discussed in detail in [18].

TABLE 14. TECHNICAL FEATURES OF THE GRIDSOL HUB (2018 VALUES). NG/BG: NATURAL GAS/BIOGAS [18].

Unit	Technology type	Input(s)	Output(s)	Efficiency [-]	Other technical features
CSP solar 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	
PV modules	GHI to power	Irradiance	Electric	-	
Wind turbines	Wind speed to power	Wind speed Max. output Inflexion wind speed Max. slope Smoothening factor Offset	Electric	-	
Electric storage	Power to power	Electric	Electric	0.91 (round-trip)	

Table 15 shows the investment and fixed operation and maintenance costs for Gridsol hub technologies. CSP costs assume a configuration with a storage volume of 15 hours and a solar multiple of 2. The CSP+ scenario embeds a further 40% cost reduction for CSP components, therefore a hypothetical CSP power plant such as the one used in Table 15 would cost 40% less.

TABLE 15. COSTS OF SMART RENEWABLE HUB TECHNOLOGIES. ALL COSTS ARE IN MILLION EUR15/MW_{EL}, EXCEPT FOR STORAGE (EUR15/MWH_{EL}).

	2020		2030		2050	
	CAPEX	OPEX (fixed)	CAPEX	OPEX (fixed)	CAPEX	OPEX (fixed)
CSP[13]	5.022	136.48	3.945	110.65	3.360	89.57
Gas turbine	0.585	13.270	0.497	12.507	0.439	11.897
Solar PV	0.591	7.475	0.484	4.503	0.381	5.022
Wind	1.414	16.724	1.402	16.436	1.251	14.490
Batteries	0.437	1.629	0.306	1.629	0.137	1.629

SCENARIO DEVELOPMENT: GAS PRICES

The CO2 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 [18]:

- 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 + emissions, except when methanation costs are lower. There exists one unique gas price that satisfies the following:

$$p_{gas} = \begin{cases} p_{naturalgas} + p_{CO2} \cdot \delta_{ng} & , \quad p_{naturalgas} + p_{CO2} \cdot \delta_{ng} < p_{methanation} \\ p_{methanation} & , \quad p_{naturalgas} + p_{CO2} \cdot \delta_{ng} \geq p_{methanation} \end{cases} \quad \text{[EUR/GJ]}$$

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.

Figure 67 shows the price trend for gas until 2050 in the three decarbonisation scenarios. The natural gas (NG) price projections are taken from the 2018 World Energy Outlook. This assumption simplifies the set of events relating the two fuels; for instance, it is likely that sometime before the end of the investigated

[13] We hereby assume a 15h storage and a solar multiple of 2.

horizon biogas becomes cheaper than natural gas, especially in scenarios with high CO2 prices. This process is also influenced by the potential reduction of methanation costs, which in turn depend on the electricity price. In a 2017 report by Ea Energy Analyses [22], 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 [DKK/GJ] (= 17.45 [EUR/GJ]) and a 2050 price of 120 [DKK/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 + CO2 price when this is lower than the biogas price, on the biogas price elsewhere.

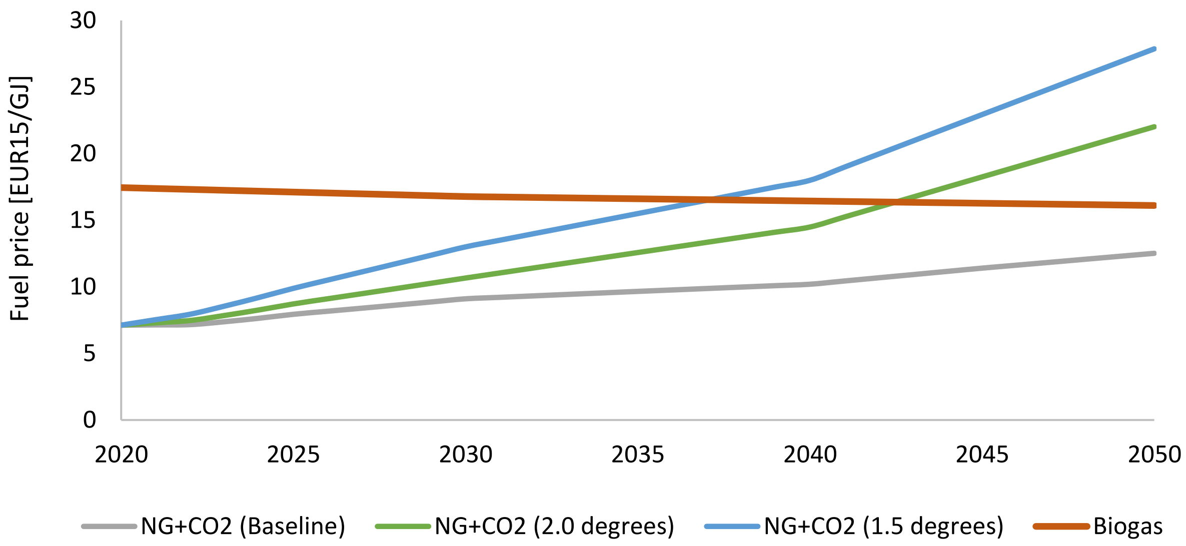

FIGURE 67. GAS PRICES IN THE SIMULATIONS.

SCENARIO DEVELOPMENT: HYDROGEN DEMAND PROGNOSES

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 68 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 pathway. Considering the high variance within the 2.0 degrees framework, the hydrogen demand is arbitrarily set to 20 [Mtoe] for the scope of this analysis; this also 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 (see Reference [21]) suggests that a very small demand is forecast for that year. This is common to all scenarios, as a differentiation occurs after 2030. The demand increases linearly starting from this year until 2050.

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 hydrogen as the only output.

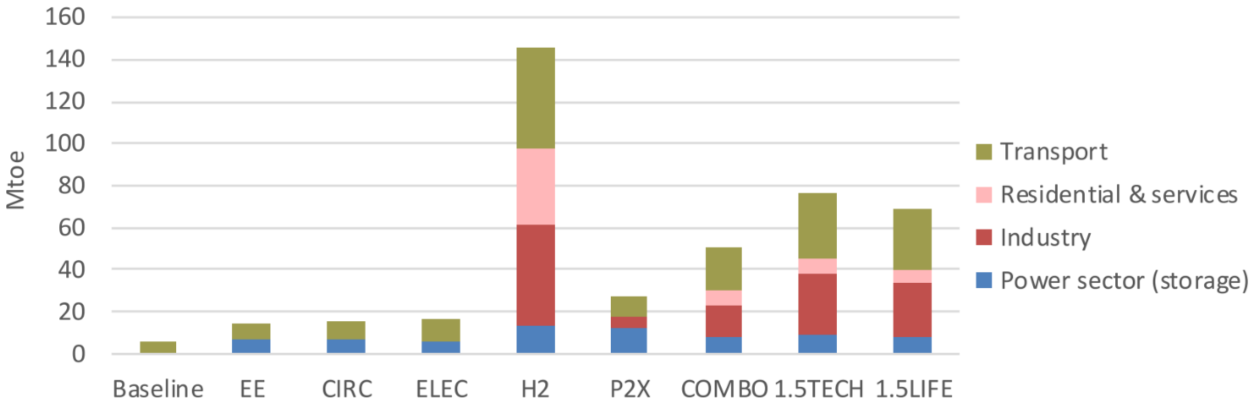

FIGURE 68. HYDROGEN DEMAND PROGNOSES FOR THE DECARBONISATION PATHWAYS ENVISIONED IN THE EU CLIMATE STRATEGY.