METIS Studies

Study S1

Optimal flexibility portfolios for a high-RES 2050 scenario

METIS Studies
December 2018

Prepared by

Arthur Bossavy
Tobias Bossmann
Laurent Fournié
Luc Humberset
Paul Khallouf

Contact: metis.studies@artelys.com

This study was ordered and paid for by the European Commission, Directorate-General for Energy, Contract no. ENER/C2/2014-639. The information and views set out in this study are those of the author(s) and do not necessarily reflect the official opinion of the Commission. The Commission does not guarantee the accuracy of the data included in this study. Neither the Commission nor any person acting on the Commission's behalf may be held responsible for the use which may be made of the information contained therein.

EUROPEAN COMMISSION

Directorate-General for Energy

Directorate A — Energy Policy
Unit A4 — Economic analysis and Financial instruments

Directorate C — Renewables, Research and Innovation, Energy Efficiency
Unit C2 — New energy technologies, innovation and clean coal

E-mail: ENER-METIS@ec.europa.eu

European Commission
B-1049 Brussels

Table of Contents

1. ABBREVIATIONS AND DEFINITIONS

1.1. ABBREVIATIONS

Abbreviation	Definition
BEV	Battery Electric vehicle
CCGT	Combined Cycle Gas Turbine
CF	Capacity Factor
COP	Coefficient Of Performance
EV	Electric Vehicle (covering BEV and PHEV)
GHG	Greenhouse gases
HP	Heat Pump
OCGT	Open Cycle Gas Turbine
PCI	Project of Common Interest
PHEV	Plug-in-Hybrid Electric Vehicle
PHS	Pumped hydro storage
PV	Photovoltaic
RES	Renewable Energy Sources
vRES	Variable Renewable Energy Sources (in this report, vRES only refers to solar PV, wind onshore and offshore)
V2G	Vehicle-to-grid

1.2. DEFINITIONS

Concept	Definition
Biomass-to-CH_4 (biogas)	Conversion of biomass into methane
Power-to-X	Conversion of power from the electricity sector into another energy carrier
Power-to-CH_4 (syngas)	Conversion of power into methane
Residual load	Electricity demand to which the generation from variable renewable power generation is subtracted. It represents the demand that needs to be supplied by conventional generation units, storage or imports.
Vehicle-to-grid	Ability of EVs to inject electricity into the power grid
Green gas	Carbon-neutral gas (biogas or power to gas with carbon-neutral power): net zero carbon emissions is achieved by balancing a measured amount of carbon released during gas combustion with an equivalent amount of carbon used for gas production

1.3. METIS CONFIGURATION

The configuration of the METIS model used in this study is summarised in Table 1.

Table 1: METIS Configuration

METIS Configuration	
Version	METIS v1.4
Modules	Power system, Capacity expansion and demand modules
Scenario	METIS-S1-2050 scenario
Time resolution	Hourly (8760 consecutive time-steps per year)
Spatial granularity	Member State

2. Executive summary

To meet the deep decarbonisation objectives targeted by the European Commission's long-term strategy[1], the power system will have to reach complete carbon neutrality by 2050. Renewable energy sources, in particular solar and wind power, are expected to play a major role in this transition since their cost should continue to decline over the next decades. Reaching carbon neutrality in the power sector is all the more important as it could help decarbonising other energy sectors, either by direct electrification of end-uses or by providing opportunities to generate fuels from carbon free power.

In this context of a high share of variable renewable electricity generation, maintaining the power supply-demand balance at all times will induce significant needs for flexibility solutions. Different technologies are available, or are expected to be by 2050. In addition to conventional flexibility (storage, cross-border exchanges, dispatchable generation units), demand-side management could provide substantial flexibility to the power system. Determining the right portfolio of flexibility solutions to enable given decarbonation objectives is of foremost importance. Previous METIS studies contributed to assess the potential role of heat pumps, power-to-X and electric vehicles, respectively. However, to obtain a complete picture, it is important to jointly analyse the competition and complementarities of all available flexibility solutions.

This study devises an optimal portfolio of flexibility solutions to ease vRES integration and the decarbonisation of the energy system. The investments in flexibility solutions are jointly optimised with the hourly dispatch of power generation, transmission and storage assets as well as demand side management.

The considered scenario, named METIS-S1-2050, is based on the European Commission's EUCO30 scenario. The latter was modified to reach full carbon neutrality of the power sector (by phasing-out fossil fuels from power generation) and to contribute to the decarbonization of other sectors via power-to-gas and power-to-liquid (with a total of 115 TWh of carbon neutral hydrogen produced by water electrolysis). Additional solar PV and wind power capacity are added and an optimal portfolio of flexibility solutions is computed to ensure power security of supply at minimum cost. Biogas is assumed to be available for gas-to-power and heat pump back-ups, along with synthetic gas from power-to-gas. The resulting European power generation is composed of **80% RES** (whereof PV and wind power represent 60%), 17% nuclear (based on EUCO30 scenario) and only 3% of carbon-neutral gas-fired power generation. As a consequence, the **flexibility needs highly increase compared to the EUCO30 scenario for 2030**: +80% for daily flexibility, +60% at the weekly timescale and +50% at the annual timescale.

With a total of 164 GW of interconnection capacities[2], **cross-border exchanges are found to be the main source of flexibility**. They serve in particular weekly flexibility by balancing different wind generation patterns (main driver of the weekly flexibility needs) from neighbouring countries. Interconnections can also be used to export daily PV surpluses from countries with high irradiance levels, contributing to the daily flexibility. Storage appears to be the second most important flexibility source. **Pumped-hydro storage** is particularly useful at the weekly timescale. In countries with high PV shares (like Italy), stationary batteries deliver daily flexibility and facilitate PV integration. Vehicle-to-grid may be an alternative source of short-term flexibility and avoid 14 GW of batteries as well as 7 GW of gas-to-power and 4 GW of pumped-hydro-storage.

[1] https://ec.europa.eu/clima/policies/strategies/2050_en

[2] The ENTSO-E's Best Estimate for 2020 gives a total of 93 GW.

Demand side management is found to provide significant flexibility, saving both operational and investment costs. Since electric vehicle (EV) consumption follows daily patterns, smart charging can easily provide daily flexibility over several hours. Hybrid heat pumps may provide additional flexibility at demand peaks and help reduce system adequacy costs. By equipping heat pumps with gas-fired back-up heaters, part of the power demand peak consumption is shifted to carbon-neutral gas.

Power-to-X can adapt to the residual load patterns within all timeframes, depending on the national power mix in the different countries. Provided that large hydrogen storage capacities are available, the water **electrolysers** production can easily adapt to a country's residual load pattern (featuring daily cycles in countries with high PV integration, or more irregular cycles in wind countries). **Methanation** is only found to be economically relevant in countries with particularly low power prices.

Despite the rising flexibility needs, new flexibility sources effectively complement conventional ones and drive down the need for **dispatchable backup peak units.** In the given scenario, merely **200 GW of gas-fired assets** are installed to meet power demand peaks and cope with inter-seasonal variations in the residual load (to be compared to 450 GW today of coal, gas and fuel units). Furthermore, their utilisation is limited to 3% of the total power generation.

In conclusion, a high-RES European power system may effectively operate without requiring tremendous amounts of gas back-up capacities. Instead, the decarbonisation of other sectors (transport, industry) through hydrogen or new flexible electricity usages adds additional flexibility to the system that facilitates RES integration. Together with an increasingly meshed European power system and the deployment of low-cost storage technologies, the full decarbonisation of the European power sector is feasible. The role of gas remains restricted to the provision of capacity services while the overall gas demand volumes remain very limited and may thus be met by synthetic gas or biogas.

To ensure the stable operation of a fully decarbonised, high-RES EU power system, it is key to grant access for new market actors to existing markets, drive further the R&I activities around new flexibility technologies and pursue the Energy Union's goals and strive for a fully functioning internal energy market.

While this report focuses on system cost aspects, the METIS study S14 "Wholesale market prices, revenues and risks for producers with high shares of variable RES in the power system" builds on the same scenario (namely, METIS-S1-2050) and analyses in details the impacts on market price volatility and producer revenues.

3. INTRODUCTION

By 2050, the European Union aims to reduce its internal greenhouse gas (GHG) emissions by 80-95%, compared to 1990 levels[3]. To get there, the following milestones are targeted: 40% reduction of GHG emissions by 2030 and 60% by 2040. Among all sectors – namely power generation, industry, transport, buildings, construction and agriculture - the power sector is meant to contribute the biggest reduction, down to complete carbon neutrality. The following figure shows the pathway targeted by the European Union at the time of writing this report:

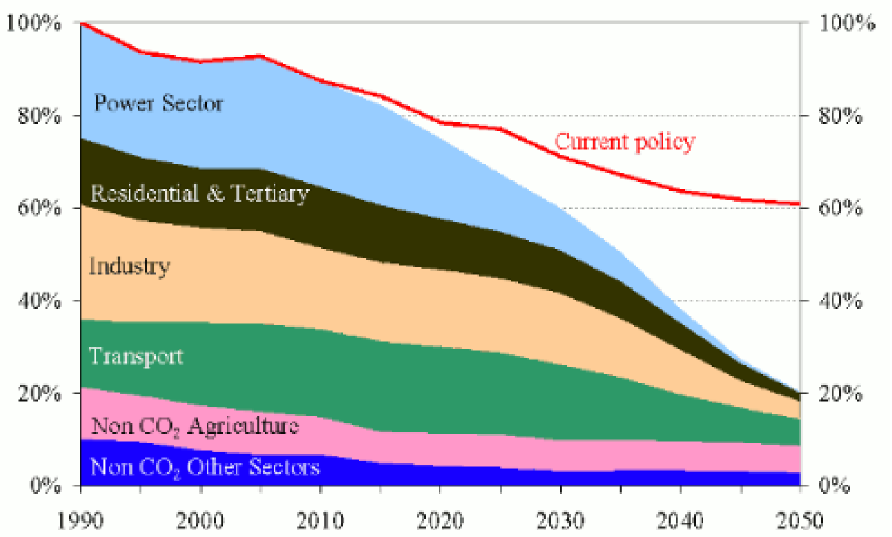


Figure 1- Targeted contributions of each sector to the European Union's objective of 80% reduction in GHG emissions in 2050. Source: [1]

As the full decarbonisation of the power sector by the year 2050 appears to be manageable, part of the final energy use in other sectors could be switched to low-carbon power to decrease their emissions. Fossil gas and liquid fuels in the transport and industry sector count among those energy carriers featuring the highest carbon content and make a fuel shift particularly attractive. Buildings' heating fuelled by fossil energies could also be replaced by power-driven heating (like heat pumps) and benefit from the carbon-neutral power. However, for some usages, the direct shift to electricity may be very costly, if possible at all - take for instance kerosene utilisation in aviation. In such cases, the power sector may still play a role through power-to-X technologies. Power-to-x generates synthetic fuels (gas and liquids) using (carbon-neutral) electricity as infeed energy. Synergies between energy networks then appear to be a promising driver to bring down emissions in sectors that are more difficult to decarbonise than the power sector like the industry, heating and transport sector.

The share of variable renewable power (vRES) in the overall generation will have to significantly increase to 1) displace conventional thermal generation and 2) handle new electricity usages. Conventional thermal generation currently provide large contributions to the system flexibility. Other sources of flexibility are therefore required to balance a power system with large shares of vRES. The interlinkage between the power system and

[3] Since the realisation of this work, new scenarios with more ambitious reductions in carbon emissions have been published in the in-depth analysis of the European Commission's proposal for a long term strategy of decarbonisation of the EU economy – see: https://ec.europa.eu/clima/policies/strategies/2050_en. These scenarios are not integrated in this report.

other energy networks could provide the required flexibility sources, along with power interconnections between countries, storage technologies and demand-side management.

Several previous METIS studies[4] have addressed different demand-side flexibility solutions individually. Their respective main conclusions are described below:

- METIS Study S6 [2] focusses on decentralized power-to-heat solutions, primarily heat pumps. This study shows that decentralised heat pumps in the residential and tertiary sector may significantly reduce carbon emissions compared to decentralised boilers using fossil gas - or even more carbon-intensive fuels. This is essentially due to the high efficiency of heat pumps. The carbon emission abatement increases if the used electricity features a low-carbon content. Ultimately, this study reveals that equipping heat pumps with gas back-up instead or electric back-up heaters may reduce overall power system costs by decreasing the required investments in additional peak power units (this analysis has acted as motivation for our optimisation of the economic trade-off between gas and electric back-up heater, cf 4.2.2).

- METIS Study S8 [3] analyses the potential of several power-to-X technologies (power-to-H_2, power-to-CH_4 and power-to-Liquids). The analysis considers only a marginal development of power-to-X capacities, inducing a marginal impact on the power system. It reveals that the profitability of power-to-X technologies is primarily subject to the availability of low electricity prices, and consequently depends on the national power generation mix.

- METIS Study S13 [4] determines the impact of electric vehicles on the power sector. It has for objective to provide a better understanding of the implications of an increasing number of electric vehicles on the EU power system. Different electric vehicle charging strategies are evaluated in terms of power system impacts, RES integration and CO_2 emissions.

To complement the previous studies, this study aims at providing insights on the opportunities through complementarity and competition between all previously mentioned flexibility solutions in the context of a 2050 scenario with high vRES shares and a large portfolio of flexibility solutions. In a first step, the scenario is designed and all major assumptions in particular with respect to RES uptake and electrification of the liquids and gases are outlined. Such an illustrative scenario of the 2050 European power system – named the METIS-S1-2050 scenario - is presented and analysed in details[5] (cf. Section 4). Subsequently the cost-optimal flexibility portfolio for the given scenario is determined. This includes the flexibility sources considered individually in METIS studies S6, S8 and S13 (namely: heat pumps, electric vehicles smart charging and power-to-X) as well as other conventional sources like interconnections, pumped-hydro-storage, batteries and gas-to-power. The capacities of all technologies are jointly optimised to consider a complete market competition environment (cf. Section 4.2). Figure 2 illustrates the different components of the power system flexibility studied here. The capacity optimisation is combined with an hourly dispatch optimisation of all generation, storage, transmission and demand assets. The resulting power mixes (including power-to-X) are presented in Section 5 with focus on the optimal flexibility solutions deployment. Section 6 illustrates the

---

[4] All METIS studies are available on https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis

[5] It is important to note that the purpose of this study is not to provide a best-estimate scenario for 2050. Instead, this analysis aims at 1) providing an illustrative power mix achieving ambitious decarbonisation targets, 2) demonstrating how the METIS model may contribute to prospective scenario design and flexibility portfolio optimisation.

dynamics of the power system. Finally, Section 7 assesses the respective contributions of all flexible technologies to the system flexibility needs in the METIS-S1-2050 scenario, and Section 8 provides the conclusion and outlook.

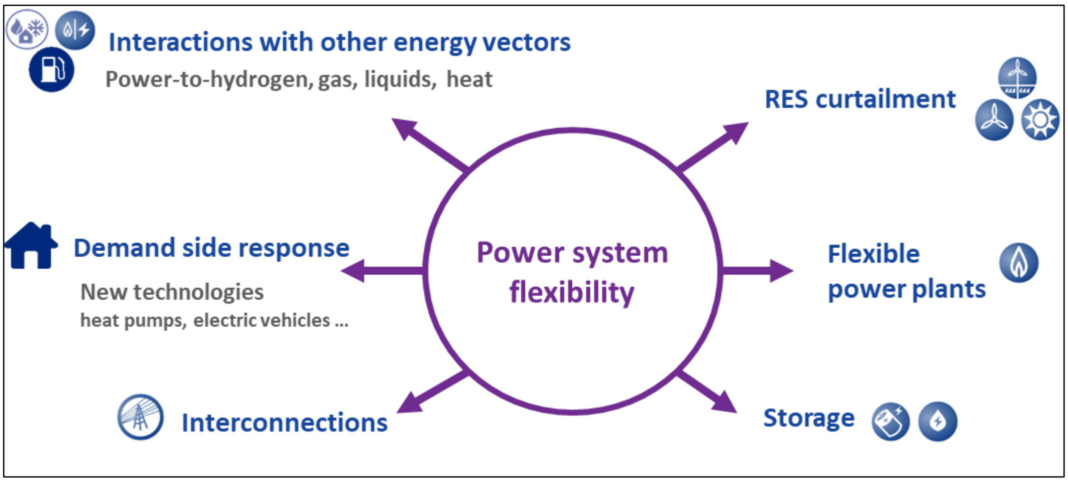


Figure 2 - Flexibility options in the power system

4. DESIGN OF THE METIS-S1-2050 SCENARIO

This study investigates the potential contributions of different flexibility solutions that facilitate a deep decarbonisation of the European power system in 2050. The objective is to reveal the potential synergies and competitions between different types of new flexibility solutions (power-to-X, electric vehicles smart charging, optimised heat pumps) and conventional flexibility providers (storage units, interconnections, clean and dispatchable thermal). In order to do so, a carbon-neutral European power system scenario for 2050 was set up, based on inputs from the European Commission's EUCO30 scenario for the energy consumption and nuclear capacities.

To represent a deep energy system decarbonisation by 2050, several assumptions were made on both generation and consumption levels (see Section 4.1). First, coal and lignite are assumed to be completely phased-out, which is in line with the coal phase-out strategies planned by several European countries (cf. [5] for the national coal phase-out status in December 2017). Variable RES generation (PV and wind energy) is assumed to cover 63% of the power demand and hydro power 13%. Biomass and nuclear capacities are respectively 62 and 123 GW. CCGT and OCGT capacities are optimised along with other flexibility solutions. The whole gas-fired power generation is assumed to be fuelled by biogas and synthetic gas generated via power-to-X.

Besides, the METIS-S1-2050 scenario includes an annual power demand of **140 TWh**[6] for carbon-neutral synthetic fuel generation across Europe, reflecting a partial decarbonation of other energy carriers using power-to-X technologies. All in all, the European power demand reaches up to **4700 TWh**.

The scenario is completed by performing a joint optimisation of flexibility solutions (see Section 4.2) and all power system-related operations.

4.1. GENERAL ASSUMPTIONS FOR A LOW-CARBON SCENARIO

The METIS-S1-2050 scenario includes assumptions taken from the EUCO30 scenario (such as the power demand, the fuel prices, nuclear power capacities, etc.)[7]. In order to cope with the full decarbonisation of the power sector, coal and lignite power plants are phased-out from power generation. Reaching full power sector decarbonisation by 2050 would require an appropriate high CO_2 price, making the operation of coal plants unprofitable. Moreover, some European countries have recently reviewed their energy policy and planned to phase-out coal in the coming years [5]. In line with those trends, a complete coal and lignite phase-out by 2050 in Europe is assumed.

Gas-fired plants (OCGT and CCGT) are also major GHG emitters from the power system, being responsible for 25% of the European power system GHG emissions in 2015. Gas-to-power represents a relevant share in the European power mix (accounting for 10% of the European power generation in the METIS EUCO30 2030 scenario). In order to decarbonise the gas-to-power sector, the consumed **gas can only be fuelled by syngas (generated via power-to-CH_4) or biogas (biomass-to-CH_4).** The final utilisation of (synthetic- or bio-) gas as well as the required capacities of gas power plants are optimised. Both sources

[6] This figure is an exogenous demand assumption and does not include the endogenous synthetic gas consumption for gas-to-power.

[7] For further information, the reader is referred to the EUCO30 scenario's document [6] and to the METIS Technical Note T1 introducing the methodology for the EUCO30 scenario integration into METIS [7].

of green-gas are competing for the supply of gas-fired plants, the respective share of each source being also optimised, as described in Section 4.2.3.

In addition to gas-fired power generation, the gas system is further decarbonised by assuming that **all gas-fired heater used as back-up for decentralised electric heat pumps (HP) are also fuelled by synthetic gas or biogas**. Out of the total heat production from HP installations (with back-up), 5% are supplied by a back-up boiler, however the actual ratio between electric and gas back-up is determined for each country via optimisation. The HP heat production is computed by using a mean HP coefficient of performance (COP) of 3.5 and the HP power consumption is derived from the METIS study S6[8] [2] .

The demand for synthetic methane to feed gas-fired power plants and gas back-up heaters is endogenously determined in the METIS tool and subject to the choice between synthetic gas generation or use of biogas.

The hydrogen supply is also assumed to be partly decarbonized. It is assumed that 28 TWh out of the hydrogen demand for the industry and transport sector are met by hydrogen (generated via power-to-H_2)[9]. The total hydrogen demand is derived from the EUCO30 scenario and the CertifHy project [8], further details about the construction of the hydrogen demand are presented in Appendix A. Furthermore, 90 TWh out of the liquid fuel consumption[10] (in transport, industry, residential, tertiary and agriculture sectors) is assumed to be covered by synthetic liquids (via power-to-liquids processes). The detailed liquid fuels demand can be found in Appendix A. The synthetic fuel generation induces an extra power demand to generate the amount of hydrogen required by electrolysis[11]. **These additional power demands, including both the hydrogen demand for direct use (5% of the hydrogen total demand) and power-to-liquids processes (5% of liquid fuels demand), are aggregated as an annual exogenous hydrogen demand in the METIS modelling**. The country-specific annual volumes are presented in Figure 3.

The resulting demand for synthetic gases (H_2 and CH_4) and fuels in combination with the phase-out of fossil-fuel capacities in power generation imply a need for additional clean power sources. The following section details the process used to compute the corresponding vRES capacities added under the METIS 2050 scenario (compared to the initial EUCO30 scenario).

[8] See METIS study S6 for further details on the HP power consumption.

[9] This corresponds to 5% of the hydrogen demand in the scenario the EUCO30 scenario

[10] This corresponds to 5% of the oil demand in the scenario the EUCO30 scenario

[11] See METIS study S8 for further details on the power-to-liquids processes.

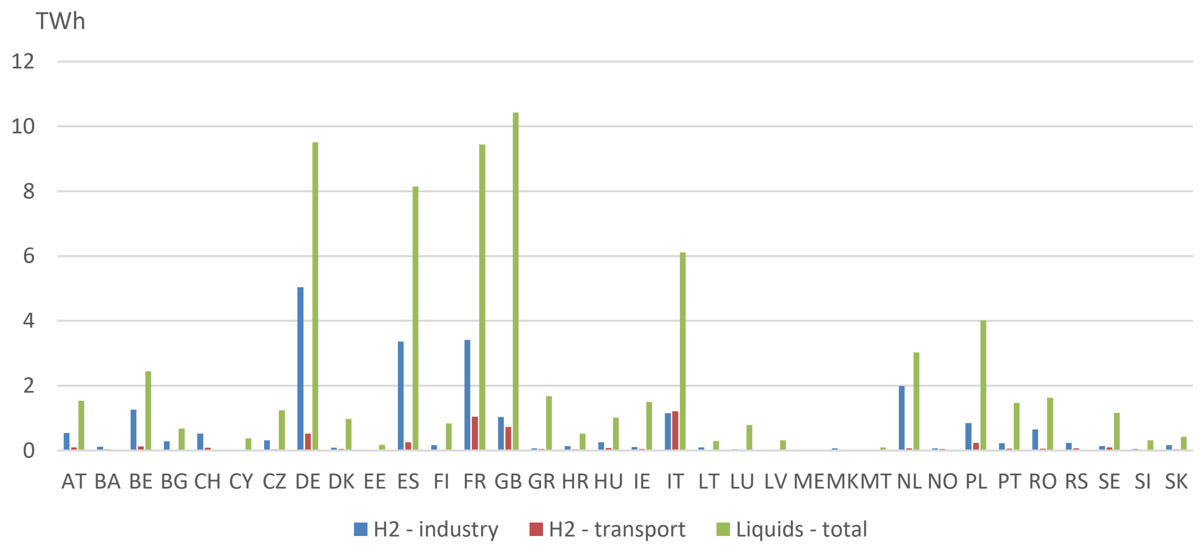


Figure 3 - Synthetic gas/liquids demand according to the assumptions on the decarbonisation of the energy system

Wrap-up: Decarbonisation assumptions of METIS 2050 scenario

- The fossil-fuel generation is almost entirely phase-out and replaced by vRES. Only gas-fired power plants remain available as peakers.
- All remaining gas-fired power supply is fuelled with green gas (syngas or biogas)
- 5% of heat production in decentralised heat pumps based on gas/electric boiler
- All gas-based back-up heating of HPs relies on green gas
- 28 TWh out of the 2050 hydrogen demand is covered by electrolysers
- 90 TWh out of the 2050 liquid fuels consumption is met by synthetic fuels

4.2. Optimisation of the flexibility portfolio

The decarbonisation assumptions on the European power system presented in Section 4.1 lead to increased flexibility needs. Indeed, dispatchable generation units (fossil-fuel power plants) are removed and replaced by non-dispatchable power generation (solar PV and wind power). Moreover, the overall annual demand increases as part of the natural gas and fossil liquids consumption is shifted to synthetic fuels. Additional flexible assets are thus required to balance the power system within different timeframes (from hourly to annual). Thanks to the METIS capacity expansion module, the cost-optimal flexibility portfolio (in terms of installed capacities) is jointly optimised with the hourly dispatch of all generation, storage, transmission and demand assets. The purpose of this section is to list all technologies subject to capacity optimisation and to present the extent to which each of them can be considered as flexible in the METIS power system and demand modules (used to simulate the hourly supply-demand balance).

4.2.1. *METIS POWER SYSTEM MODEL*

METIS[12] is an energy modelling software covering in high granularity (in time and technological detail, as well as representing each Member State of the EU and relevant neighbouring countries) the whole European power system and markets.

METIS includes its own modelling assumptions, datasets and comes with a set of pre-configured scenarios (cf. METIS Technical Note T1 [7]). These scenarios usually rely on the inputs and results from the European Commission's projections of the energy system, for instance with respect to the capacity mix or annual demand. Based on this information, METIS allows to perform the hourly dispatch simulation (for the length of an entire year, i.e. 8760 consecutive time-steps per year). The result consists of the hourly utilisation of all national generation, storage and cross-border capacities as well as demand side response facilities. The modelling of flexibility solutions is described in more detail in the next section. In this study, METIS capacity expansion module is used to optimize some of the asset capacities, as described below.

4.2.2. *FLEXIBILITY SOLUTIONS*

Heat pumps

Generally speaking, the functioning of heat pumps is simulated by optimising the following operations at an hourly granularity: heat production from the heat pump (driven by the mean daily national outside temperature), heat storage injection and withdrawal (driven by the electricity price), heat production by gas-fired or power-driven back-up installations. Heat pumps are aggregated at national level and apply a fixed daily heat demand profile. The heat pump's coefficient of performance (COP) varies as a function of the outside temperature, hence depending on the individual weather year considered. For further details on the relations between outside temperatures, heating demand, COP and back-up heater requirement, see METIS Study S6 [2].

In parallel to the hourly operational optimisation, the ratio in the capacities of gas-fired and power-driven back-ups are co-optimised for each country. In countries where the winter power demand peaks are already high and difficult to meet, the model is likely to favour gas-fired back-up to avoid additional stress for the power system. Conversely, if power prices are low and the system is flexible, a higher share of power-driven back-up avoids the use of syngas or biogas, featuring high variable costs. The heat pump back-up represents 5% of the total heat demand.

Electric Vehicles

EVs are optimised by modelling the smart charging patterns of four categories of EVs depending on the vehicle characteristics (BEV or PHEV) and the user profiles (home-charging/work-charging). Following the EUCO30 scenario, 115 million of BEV and 85 million of PHEV represent the European electric vehicle fleet[13], which corresponds to an annual demand of 54 TWh. For each type of electric vehicle (BEV or PHEV), 50% of EV's number are assumed to be home-charging vehicles, and the remaining 50% are work-charging vehicles. The charging of EVs is optimised for all vehicles connected to the charging point (depending on hourly arrival and departure time series). The optimisation is subject to a set of constraints, such as each EV needs to be fully charged when leaving the charging point and the charging capacity may not exceed a predefined value (see METIS Study S13

---

[12] For further information see: https://ec.europa.eu/energy/en/data-analysis/energy-modelling/metis

[13] For each type of electric vehicle (BEV or PHEV), 50% of EV's number is assumed to be home-charging, and the remainning 50% is assumed to be work-charging

[4] for more details). EVs may also feature a configurable vehicle-to-grid (V2G) functionality, i.e. electricity may be reinjected from the EV battery into the grid.

Power-to-gas
To contribute to the decarbonisation of the whole energy system, hydrogen is produced for hydrogen direct use and for further conversion into synthetic liquids (see 4.1 for details). Annual hydrogen demands are fixed at national level. The national electrolyser capacities and the hourly hydrogen generation profiles are optimised in function of the endogenous electricity price signal. This implies that un-restricted storage capacity is available for hydrogen.

Besides, the model is able to install methanation capacities, fuelled with hydrogen. The resulting methane can then fuel both gas-to-power plants and heat pump gas-fired back-ups. It is recalled that syngas competes in the model with biogas whose production cost in 2050 is assumed to equal 90.5 €/MWh_{CH4}. This value was derived from a literature survey performed in METIS study S8 [10, 16, 17, 18]. Like hydrogen, an un-restricted storage is assumed to be available for methane. Moreover, methane exchanges between the modelled countries are considered unlimited.

Stationary batteries
Batteries might have an important role in the flexibility power system as a short-term storage solution. In the METIS-S1-2050 scenario, three types of batteries are considered in the capacity optimisation, characterised by their respective discharge times: 1, 2 and 4 hours. Technical and economic parameters of battery assets are listed in Table 2.

Pumped hydroelectric energy storage
PHS represents one of the main storage solutions currently operating in Europe. Capacities are optimised in the range given between the country specific numbers given by the TYNDP-2018 Best Estimate scenario for 2025 (51 GW in Europe) and the Global Climate Action scenario for the year 2040 (76 GW in Europe) [19]. A 24h discharge time is assumed for all PHS.

Power-to-gas-to-power
The whole power-to-gas-to-power chain is modelled in the METIS-S1-2050 scenario. As mentioned above, electrolyser capacities are optimised, as well as methanation (H_2-to-CH_4) capacities and gas-fired plants (CCGT and OCGT). No capacity limits are considered on any stage of this transformation chain. All parameters are provided in Table 2.

Interconnectors
Interconnections are optimised starting from the NTC 2027 Reference Grid of the 2018 edition of the TYNDP [19]. It includes the current power grid and the PCIs currently considered. To make sure that the optimised interconnections correspond to real and feasible projects, installed capacities cannot exceed the maximum capacity listed in the TYNDP-2018 scenarios in 2040.

Table 2 - Technical and economic data of the flexibility assets used in METIS-S1-2050 scenario

Technology	CAPEX	OPEX	Efficiency	Sources
Battery	120 €/kW + 120 €/kWh	4.2–4.4%	90% (total cycle)	[20]
PHS	900 €/kW + 13 €/kWh	1.2%	81% (total cycle)	
Power-to-H_2	610 €/kW$_e$	4%	82%	[3]
H_2-to-CH_4	920 €/kW$_e$	6.5%	79%	
CCGT	850 €/kW$_e$	2.5%	63%	[21]
OCGT	550 €/kW$_e$	3%	44%	
Interconnections	Based on line-by-line projects given in the 2016 edition of the TYNDP		100%	[22]

4.2.3. *OPTIMISING THE FLEXIBILITY AT DIFFERENT LEVELS*

The following figure illustrates all levels of optimisation considered in the METIS-S1-2050 scenario: from the flexibility infrastructures to the hourly optimisation of both demand-side and production-side operations. To summarise the modelling environment:

- Conventional flexibility (like pumped-hydro-storage and interconnections) as well as innovative technologies (like power-to-X) are subject to capacity optimisation (illustrated by filled circles in Figure 4)

- For each energy vector, the hourly supply-demand equilibrium is met (represented by squares). The production dispatch between all technologies (in the case of electricity: vRES, nuclear, hydro and gas-fired power plants) is optimised as well as cross-border flows, storage units' operations and different kinds of demand-side responses.

- The supply-demand equilibria of different energy vectors are linked by the assets converting one to another (electrolysis, methanation, CCGTs, OCGTs).

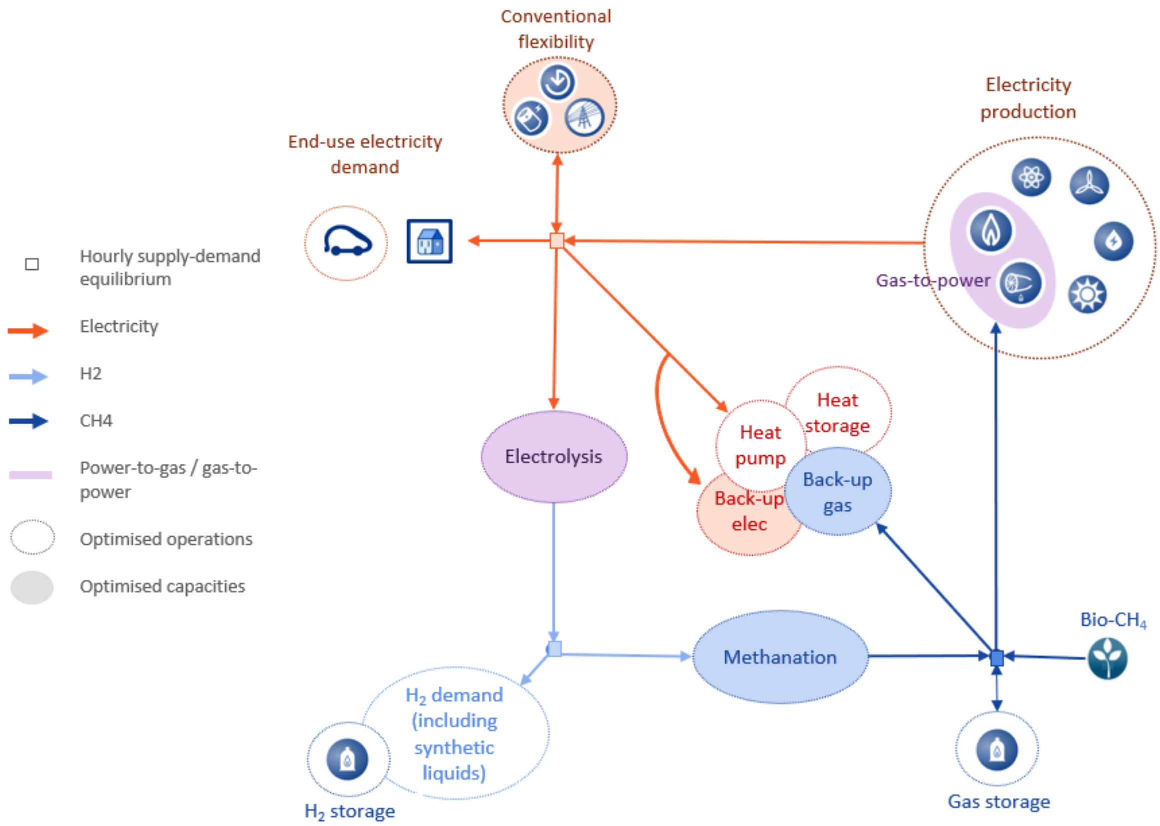


Figure 4 - Schematic overview of the METIS-S1-2050 scenario's modelling structure

5. THE 2050 FLEXIBILITY PORTFOLIO

This section presents the opportunities through and competition between the different flexibility solutions in the context of the high-RES METIS-S1-2050 scenario.

5.1. EUROPEAN CAPACITY MIX

5.1.1. *OVERVIEW OF POWER PRODUCTION*

The METIS-S1-2050 scenario features a total power generation of 4800 TWh_e, 60% of which is supplied by vRES (cf. Figure 5). The overall renewable share (including biomass, and hydro) reaches 80%, in contrast to 65% in the EUCO30 scenario, and 17% is covered by nuclear plants. Gas-to-power, fuelled by 240 TWh of biogas and 40 TWh of synthetic methane, represents only 3% of total power generation, since a large part of the flexibility is provided by other sources, as presented in Section 7. The METIS-S1-2050 power mix reaches full decarbonisation as all power generation above-mentioned are carbon-neutral. The national vRES generation is detailed in Figure 6.

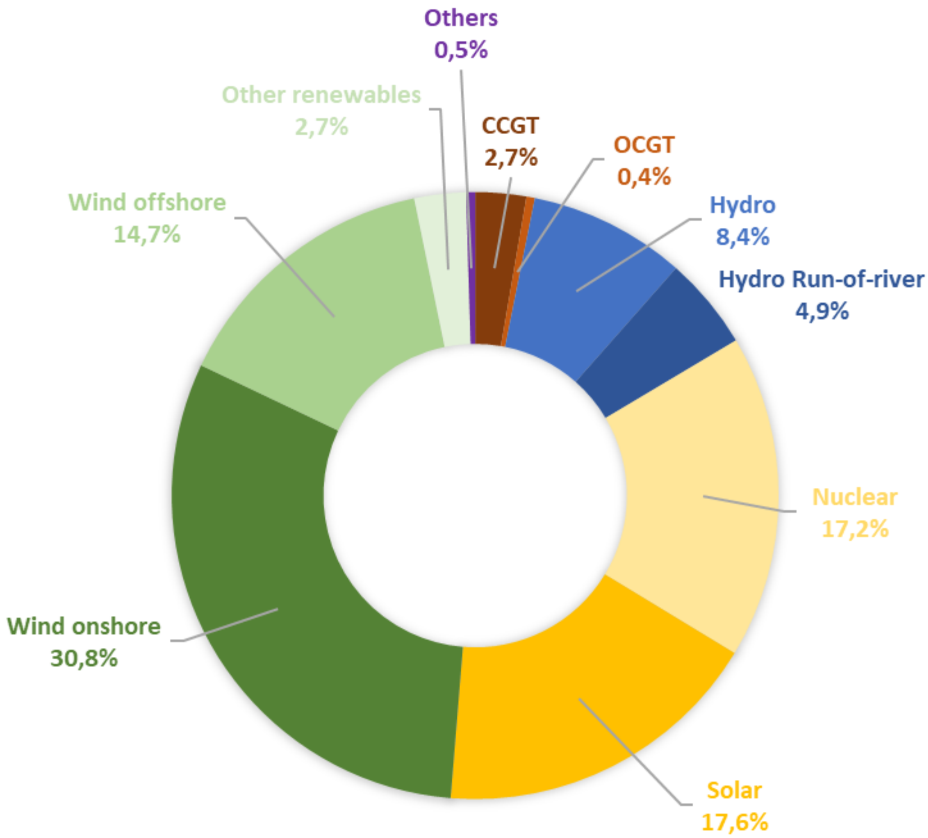


Figure 5 - EU power generation mix in the METIS-S1-2050 scenario

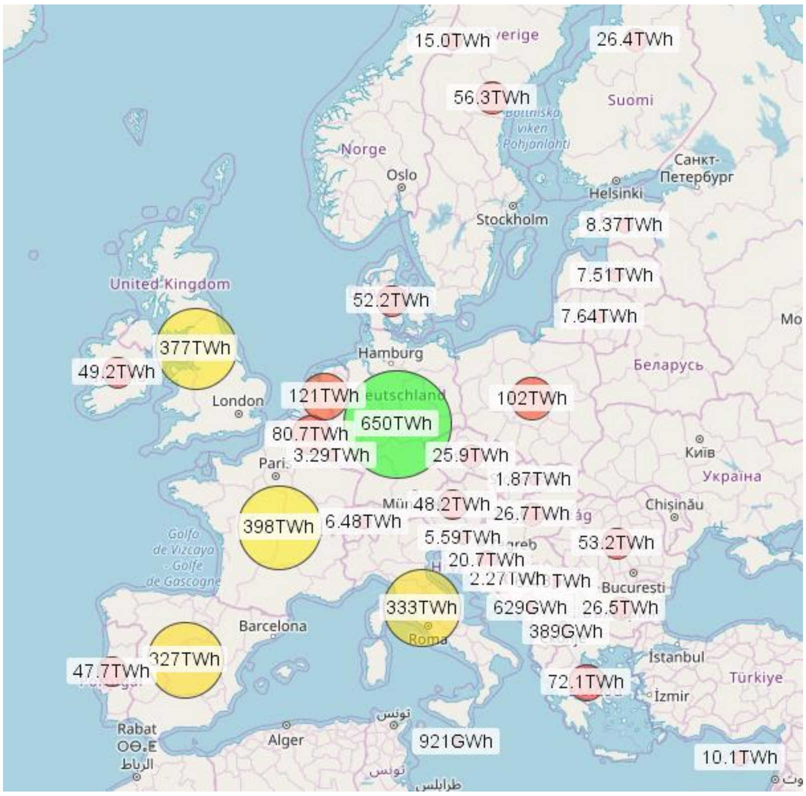


Figure 6 - vRES (solar PV, wind onshore and offshore) production in the METIS-S1-2050 scenario

Four typical power mix patterns can be distinguished[14]. Figure 7 illustrates the differences between those in terms of annual power generation mix and in terms of hourly dynamics.

First, in southern countries with high solar shares – like Spain[15] (represented Figure 7.a) - solar PV generation is concentrated around midday leading to power generation surplus periods lasting for about ten hours (1a) and occurring on a daily basis. Conversely, with high PV shares in the national power production, those countries frequently experience a lack of generation at night-time (2a), especially in winter, requiring the use of storage units or imports.

Another typical power mix is the one of Ireland[16] (see Figure 7.b), dominated by wind power. In those cases, power surplus periods (2b) also alternate with periods featuring lacking power generation (1b) but such periods are less predictable than PV-driven patterns. Instead, the typical recurrent patterns of wind generation may last several days. Interconnections allow to profitably exploit the diversity of wind speed regimes across Europe, smoothing the surplus/shortage alternation. However, due to geographical correlations in climatic conditions, sharp and/or prolongated wind falls may occur simultaneously in several neighbouring countries. As a consequence, other flexible solutions like storage and gas-to-power are still required (3b)[17].

Nordic countries exhibit a more balanced power generation profile due to higher shares of hydropower. Figure 7.c shows the power mix in Sweden with a massive base generation of hydropower that accounts for over 30% of the annual power production. Hydropower

[14] See METIS study S14 [41] for further information on the way similar national power mixes can be clustered.

[15] Other similar MSs are Bulgaria, Greece or Portugal.

[16] France, the UK and Germany may also be cited as examples of MSs with high wind power penetrations.

[17] See section 7 for more details on the different technologies' contributions to system flexibility.

plants serve as the major source of flexibility, balancing the variation in wind power generation and demand.

Finally, Central-European countries do not necessarily have identical power mixes but they present the common characteristics to be well-interconnected and to have intermediate vRES shares in their power mixes (typically less than 50% overall). Figure 7d shows the hourly power mix in Hungary. Imports via cross-border interconnections (represented by the grey area) balance the variation in vRES generation (less pronounced than in Spain or Ireland) and demand.

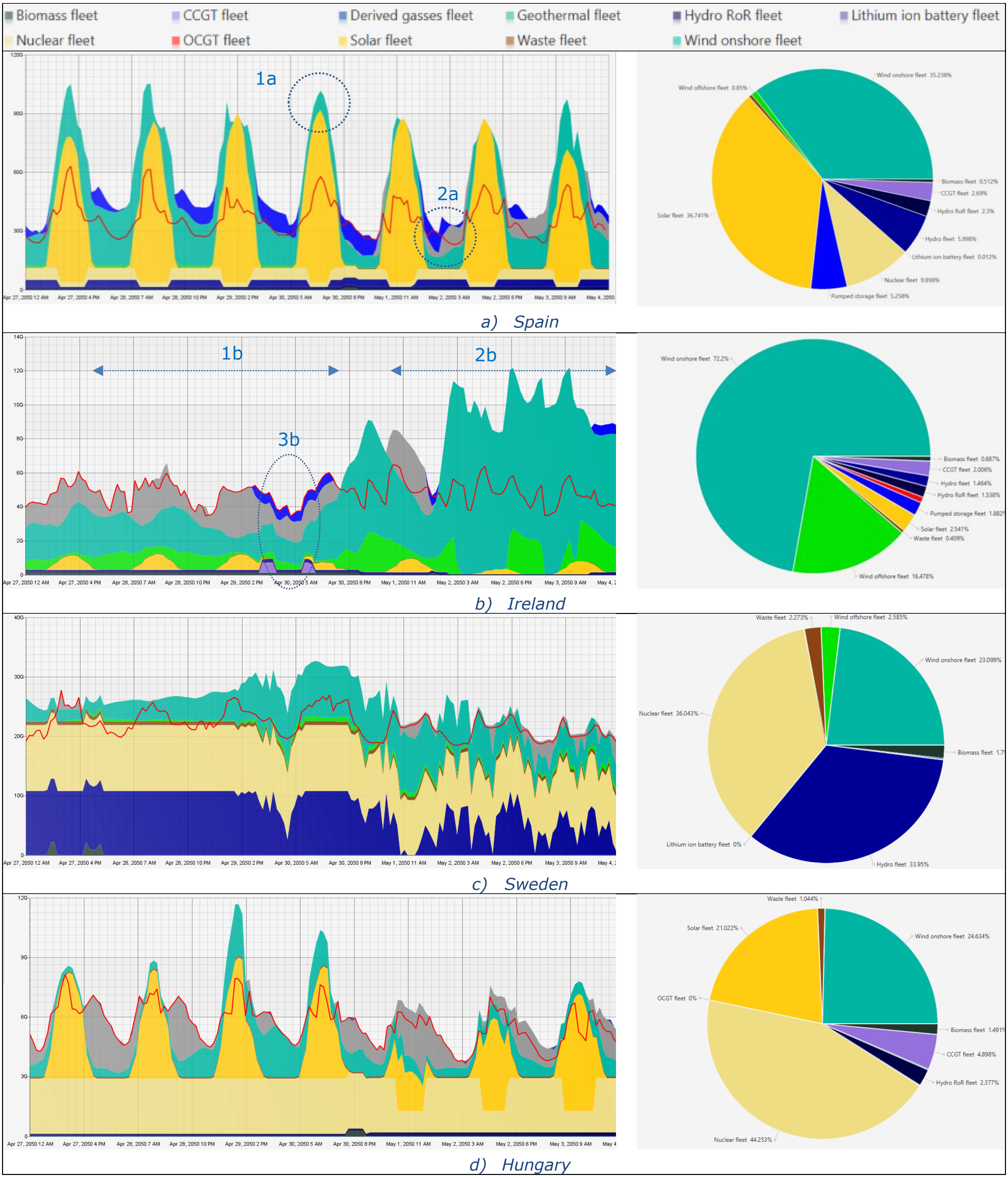


Figure 7 - Cumulative generation by technology and power production mix for four countries in the METIS-S1-2050 scenario (Avril, 27th to May, 4th)

5.1.2. *INTERCONNECTIONS*

In order to handle the high vRES penetrations, **34 GW of interconnections are added beyond the 2027 Reference Grid**[18], which already includes a total of 130 GW cross border capacities. For each country, Figure 8 shows the optimised export capacity (blue dot) as well as the available capacity ranges covered by all the TYNDP projects considered in the optimisation. For comparison, Figure 8 also provides current interconnection capacities (from the Best Estimate for 2020 scenario given by the 2018 edition of the TYNDP [19], which gives a total of 93 GW at EU level).

Two types of countries stand out. In Western Europe countries, nearly all available cross border projects are realised. In other countries, mostly Central-European countries, the model sticks with the TYNDP Reference Grid for 2027[19]. This is due to the fact that these power systems are already sufficiently well interconnected to meet their flexibility needs, as mentioned in section 5.1.1 (these countries also feature lower vRES shares that the European average).

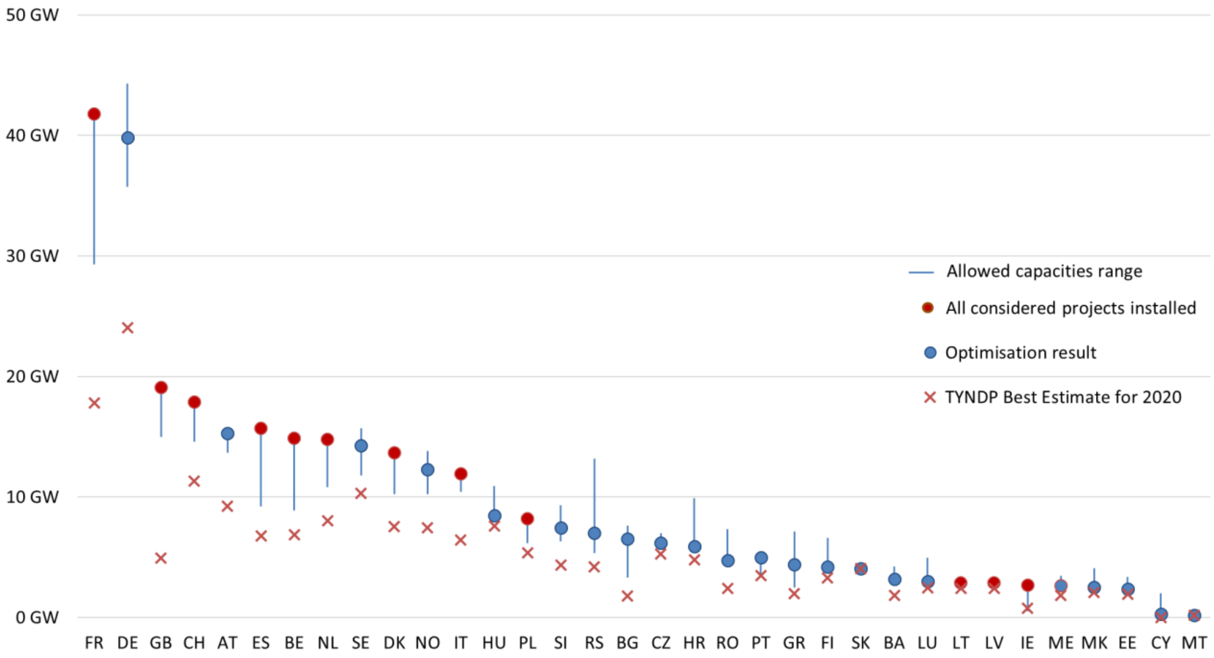


Figure 8 – Power interconnection optimization: assumptions and results

Appendix E shows how the interconnection capacities in METIS-S1-2050 compare with the EC's objectives for 2030 in terms of ratios with production capacities, RES capacities and peak demand[20].

[18] See [19].

[19] See [19]

[20] Details on the EC's interconnection objectives can be found in the report of the Commission Expert Group on electricity interconnection targets [43].

5.1.3. *STORAGE ASSETS*

In order to ensure the power system balance, interconnections are not sufficient and storage solutions are also required. Figure 9 shows the installed capacities of conventional storage solutions (batteries and PHS) as well as gas-fired power plants[21]. The current storage mix (2017) is also exhibited on Figure 10[22].

PHS is often used up to its full available potential, despite high investment costs (see Table 2). Given the long storage duration of up to 24 hours, PHS may significantly increase system flexibility. A total of **75 GW of PHS is installed** by the model (including capacities installed before 2050). For comparison, the total current PHS capacity is 47 GW [23].

On the other hand, whatever the discharge time, batteries are found to be less relevant to the hourly supply-demand balance except in a few southern European countries. Indeed Cyprus, Greece and Italy install 2-hours and 4-hours batteries, which are used to store PV surplus at midday and inject it on the network during the evening demand peaks. At the European level, the METIS-S1-2050 scenario features **300 MW** of 1-hour, **6 GW** of 2-hour and **10 GW** of 4-hour batteries[23]. Note that the battery capacities have been optimised to minimize generation costs (without taking into account potential distribution network savings or client appetence for self-consumption), which can lead to results not in line with current trends for some countries (like Germany).

Gas-fired power plants are used mainly to cover residual demand[24] peaks. 110 GW of CCGT and 90GW of OCGT are installed in Europe by 2050. Several countries do not need to install storage assets, such as Denmark, Finland and Sweden (cf. Figure 9). Despite high vRES shares, these countries are well-interconnected or have access to high capacities of hydropower, which provides a flexible power source as well as large storage facilities.

[21] Due to the nature of the two sources of gas available for gas-fired power plants, they can be considered as regular generation (when fuelled with biogas) or storage assets (when fuelled with syngas produced using power surpluses).

[22] Current gas-fired plants and PHS (mixed and pure PHS are considered) capacities are provided by the ENTSOE [23]. Peaking power plant capacities are taken from the European Commission's Reference Scenario for the year 2020 and the EU28 perimeter.

[23] Note that reserve provisions were not considered here. Since batteries have proven relevant for reserve supply (especially for reserves with small full activation time) in many studies (see notably [40]), these capacities might be underestimated.

[24] Residual demand to vRES

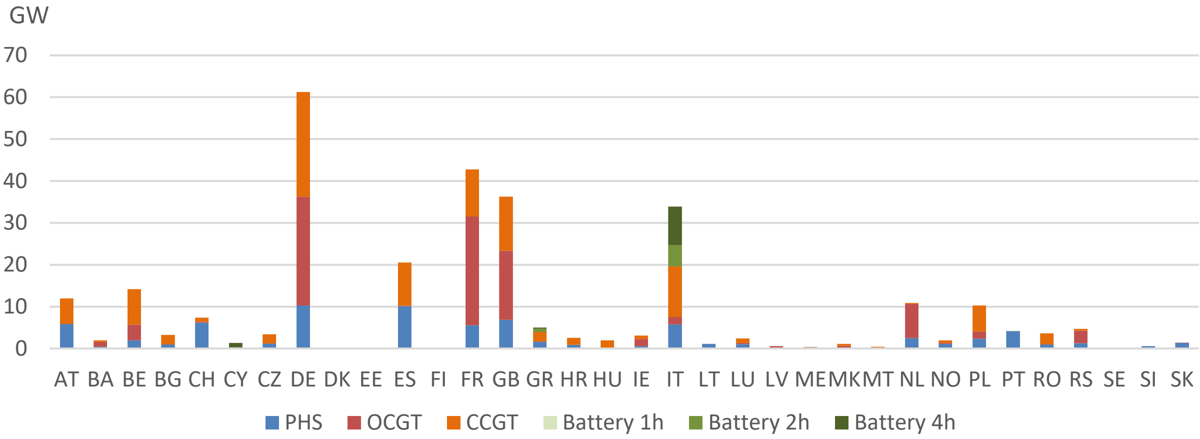


Figure 9 - Installed capacities of storage solutions in the METIS-S1-2050 scenario

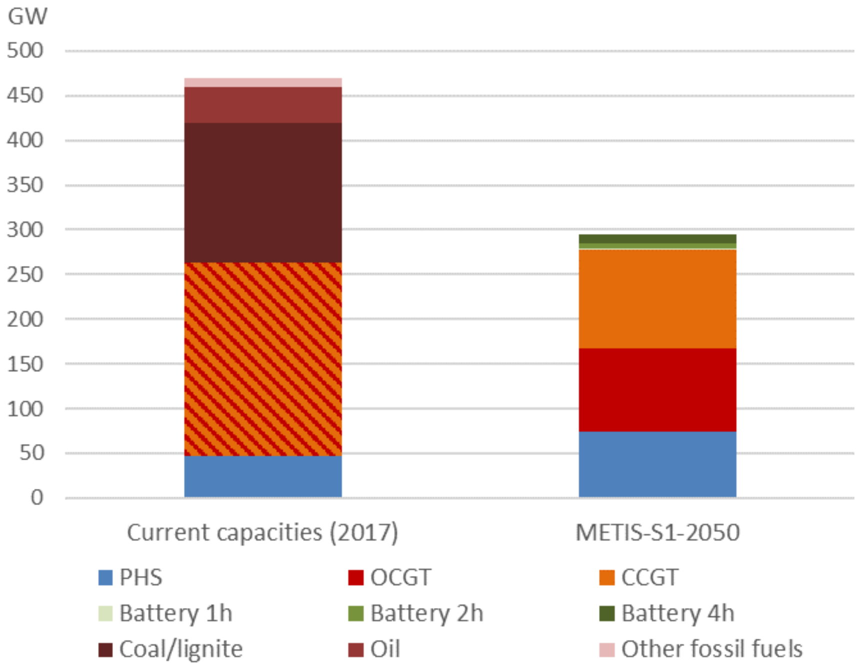


Figure 10 - European storage and fossil fuel-fired capacities in the METIS-S1-2050 scenario and from the current system (2017) [23]

5.1.4. *Demand side response*

On the demand side, the smart energy consumption of flexible usages may help maintaining the hourly supply-demand balance by shifting part of the power demand peaks to periods with lower demand and/or RES surplus or by shedding the load of selected power consumers- such as electrolysers or heat pumps - implying a reduced output. Industrial or domestic load shaving[25] are not considered in this study.

[25] Load shaving consists in cancelling a given consumption use during scarcity periods without recovering the missing consumption in other periods.

Heat pumps

The optimisation allows to fully capture the potential trade-offs between electricity and gas back-up heaters for HPs, taking into account the potential impacts of electric back-up heaters on the hourly electricity demand and thus the overall power system. Figure 11 shows the repartition between electric and gas back-up boilers across all countries. Relying on hybrid heat pumps that are partially equipped with gas back-up boilers can make significant savings. While providing less than 1% of the total heat demand, the total gas boilers capacity in Europe is equivalent to 37 GW of power peak capacity. That is 37 GWh/h of additional power consumption at peak periods can hence be avoided. Northern and Central European countries are especially relying on gas back-up boilers due to their power demand peaks during cold days. The additional costs for hybrid HPs would be around 0.3 bn€/year (gas network cost excluded) and could save up to 2.4 b€/year of investment costs in peaking power plant, in this case gas-fired power plants.

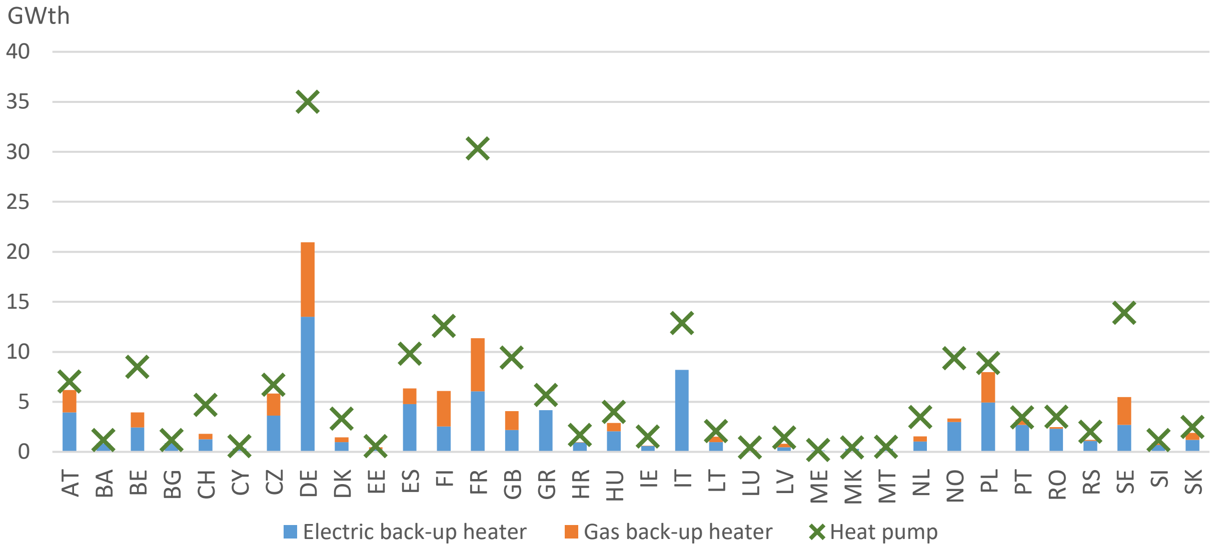


Figure 11 - Heat-pumps backup capacity (GW) in the METIS-S1-2050 scenario

Power-to-X

In order to meet the hydrogen demand, 58 GW of water electrolysers are installed. On the other hand, investments in methanation installations are limited to countries with significant RES or nuclear power generation surplus, mainly Spain, Ireland and France. In total, **9 GW** of methanation capacities are installed across Europe (cf. Figure 12).

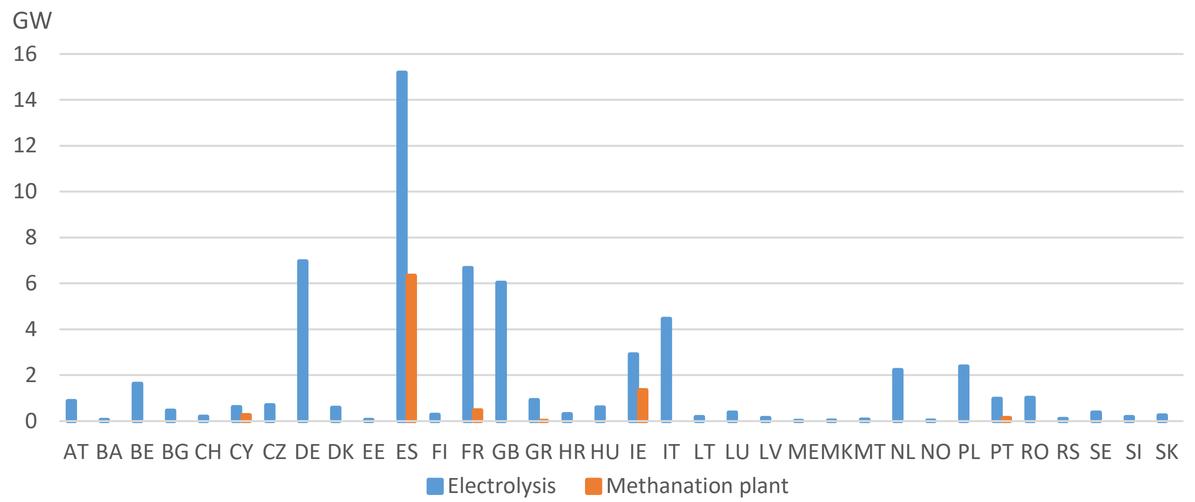


Figure 12 - Electrolysis and methanation plant capacities in the METIS-S1-2050 scenario

5.2. A SENSITIVITY ANALYSIS ON VEHICLE-TO-GRID DEPLOYMENT

5.2.1. *MAIN ASSUMPTIONS*

In the standard METIS-S1-2050 scenario, electric vehicles are able to optimise their consumption (smart charging) but they cannot use their batteries to provide further storage services to the power system (vehicle-to-grid, V2G). Since such ability might have considerable effects on the need for other flexibility solutions, a sensitivity analysis was dedicated to assessing the impact of vehicle-to-grid.

In this sensitivity, 50% of EVs can provide vehicle-to-grid services when they are connected (whether the EV is charging at home or at work) with the daily amount of electricity grid injection being restricted to the equivalent of the mean daily EV electricity consumption. The vehicle battery efficiency for discharge is assumed to be 90%[26]. These assumptions lead to a cumulated daily storage potential of 400 GWh and correspond to a grid injection capacity of 100 GW.

5.2.2. *IMPACTS*

Figure 13 shows the installed capacities of storage assets in the context of vehicle-to-grid deployment, and Figure 14 shows the comparison in the context without vehicle-to-grid system. The main consequence is the extensive substitution of stationary batteries: only **3 GW** of 4-hours batteries remain out of the 17 GW installed in the original METIS-S1-2050 scenario while 1-hour and 2-hours batteries are not installed at all. Moreover, V2G reduces investments in gas-fired power plant (OCGT and CCGT) by **7 GW** and in PHS by **4 GW**.

[26] Current technologies real-condition efficiencies would be less than 80-85% in most cases.

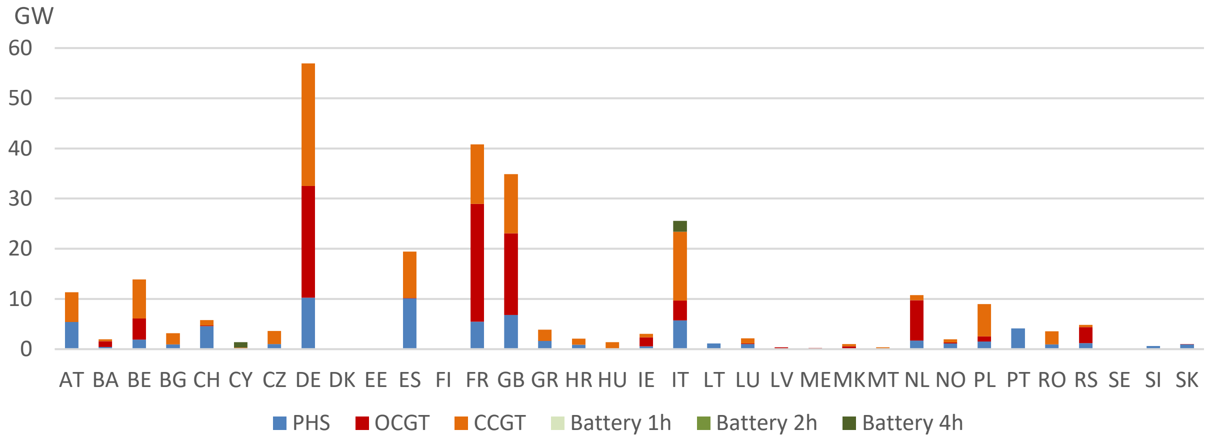


Figure 13 - Installed capacities of storage solutions facing a large deployment of vehicle-to-grid system

As expecting, vehicle-to-grid is found to be in competition with short-term flexibility solutions like stationary batteries and - to a smaller extent - peak generation capacities. Because this technology features the same technical characteristic (similar discharge time) than stationary batteries, the latter could be partially replaced by the former, leading to important savings of investment costs. Yet, the implicit cost of quicker battery wear is difficult to estimate and is consequently not included.

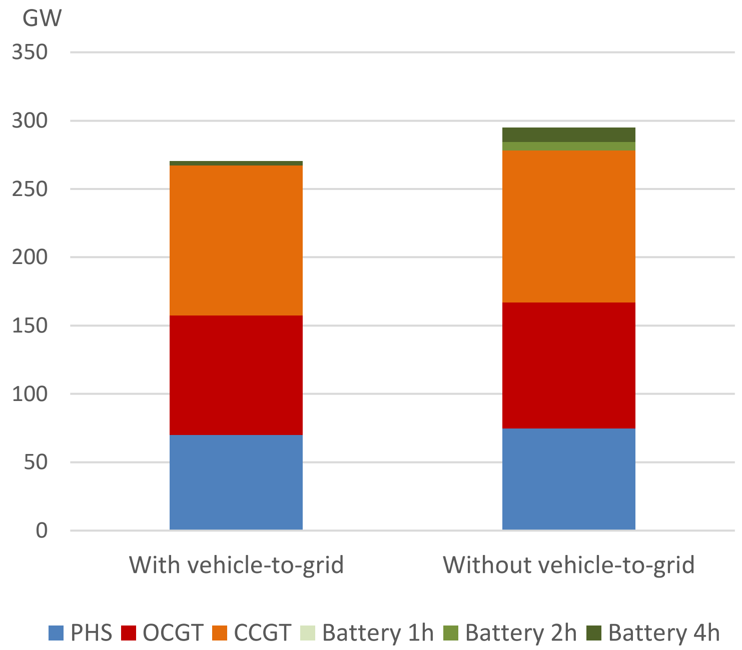


Figure 14 - Storage mix comparison between scenarios without and with vehicle-to-grid system

6. FOCUS ON THE DEMAND-SIDE FLEXIBILITY

This section details the specific operational dynamics of each flexibility solution. As significant flexibility is required at all timescales to balance supply and demand in a high vRES scenario, different timeframes are considered – from hourly to annual.

6.1. POWER-TO-GAS

6.1.1. *ELECTROLYSIS*

The production of hydrogen is optimised in the METIS-S1-2050 scenario under a set of constraints. The annual production has to meet[27] at least the exogenous hydrogen demand for direct use and synthetic liquids demand, and the hourly profile can freely react to the endogenous electricity price signals all year long. Hydrogen can also be produced in order to generate methane and use it for gas-to-power (equivalent to a power storage) or for heat pumps gas-fired back-ups.[28] As one would expect, the production is correlated to low electricity prices. With low levels of residual load[29] being the main driver for low electricity prices, electrolysis operation adapts to the residual load patterns at all timescales and in all countries.

In countries with high solar PV shares in the national electricity production, electrolysers follow the daily pattern of the residual load, mainly driven by PV generation. Figure 15. shows the residual load (power-to-gas excluded from the demand) and the power-to-H_2 production in Greece, during four consecutive days in June. The activation of electrolysers clearly occurs (on a regular basis) in periods of power surplus (i.e. negative residual load) due to PV peak generation.

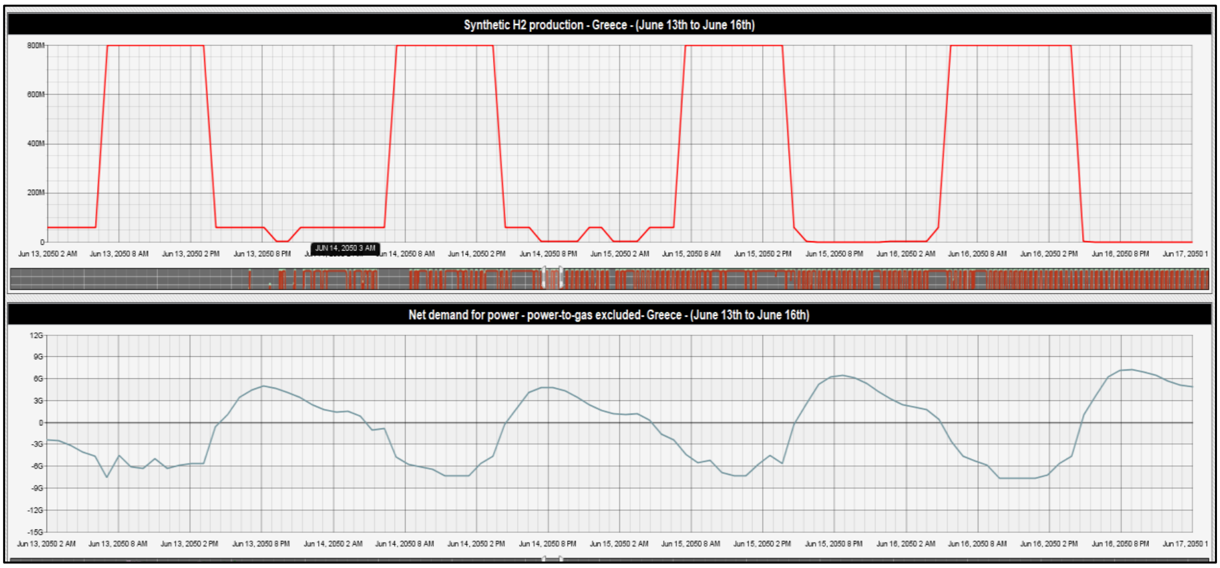


Figure 15 - Utilisation of electrolysers (red, up) vs residual load (blue, down) Greece - June, 13th to June, 16th

The flexibility of hydrogen demand can also adapt to power mixes driven by large shares of wind power like in Ireland. Figure 16 shows the correlation between the activation of

---

27 See Section 4.1 for more details on the hydrogen demand assumptions.

28 The direct use of hydrogen in gas turbines is not studied here.

29 For a detailed definition of the residual load concept, the reader is referred to Appendix C.

electrolysers and power surplus in Ireland, leading to a different hydrogen production profile than in Greece.

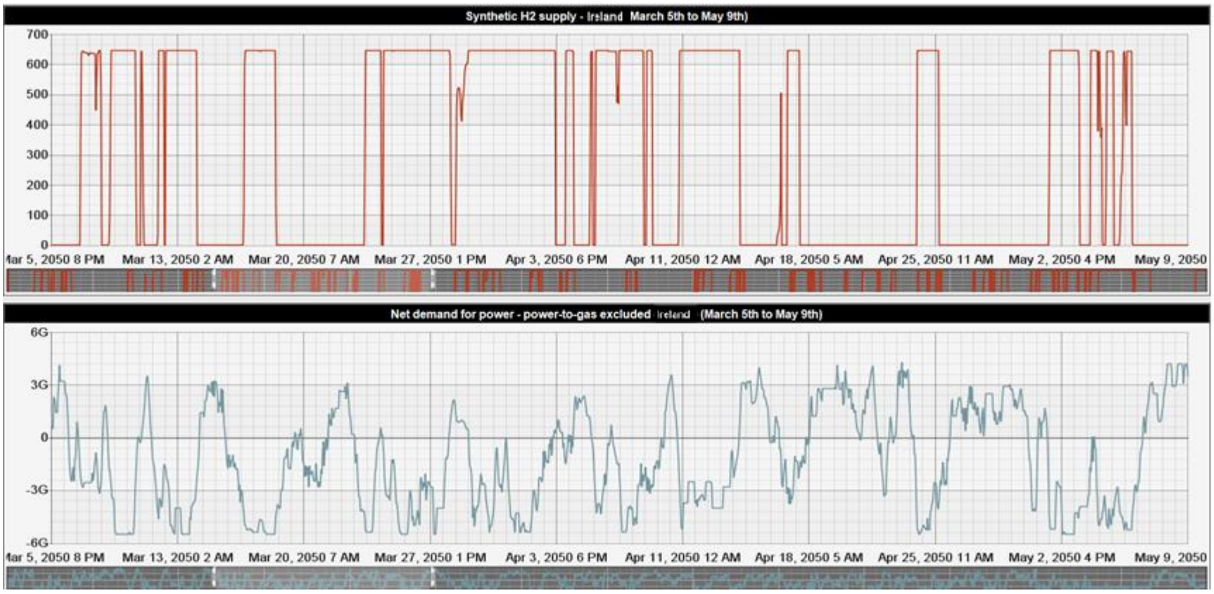


Figure 16: Utilisation of electrolysers (red) vs residual power demand to vRES (blue) Ireland - June, 13th to June, 16th

Figure 17 shows that the relation between electrolysis and residual demand to vRES still holds true at the European level and at a monthly timescale. Power-to-X flexibility can hence also participate to the inter-seasonal load management and vRES integration.

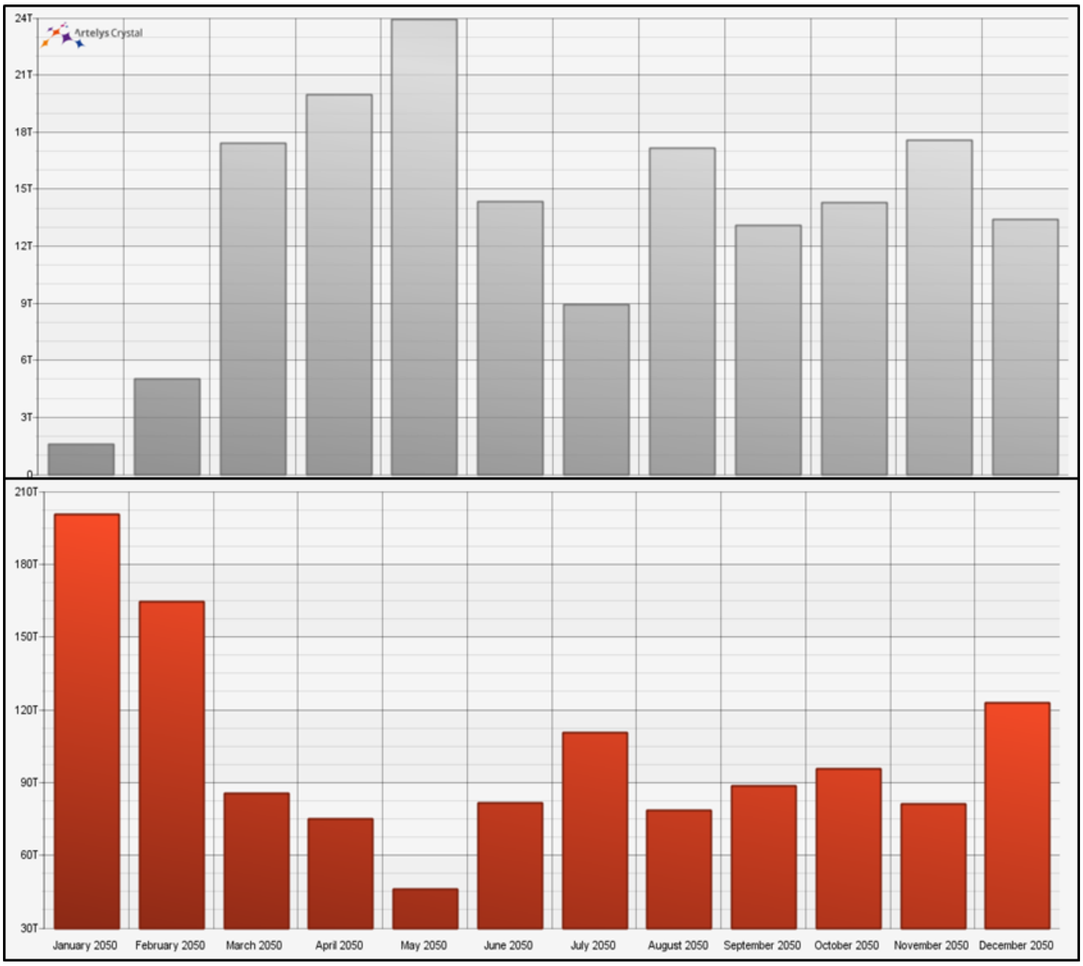


Figure 17 - Monthly utilisation of electrolysers (grey) vs residual power demand to vRES (red) in Europe

6.1.2. *METHANATION*

Electrolysers' utilisation is mainly driven by the exogenous hydrogen demand (direct-use hydrogen and power-to-liquids processes) rather than for endogenous syngas production[30] (cf. Figure 18): 70% of the European hydrogen production is used for the exogenous hydrogen and power-to-liquid demand and 30% to synthetize methane and reduce use of biogas. However, **in countries with significant vRES surpluses like Cyprus, Spain, Ireland and Portugal, the production of syngas constitutes an important economic opportunity** to exploit relevant power volumes with near-zero marginal costs to generate synthetic methane as a substitute for biogas.

Yet, this result is highly dependent on exogeneous assumptions on vRES capacities (which drive the number of hours with low power prices). As further work, a joint optimization of RES capacities and power-to-gas would allow to refine this result by assessing the total cost of synthetic methane production. .

[30] Note that the exogenous hydrogen demand has a forced annual volume in the modelling whereas endogenous syngas production is optimized against alterative low-carbon methane supply (biogas and gas-to-power decline).

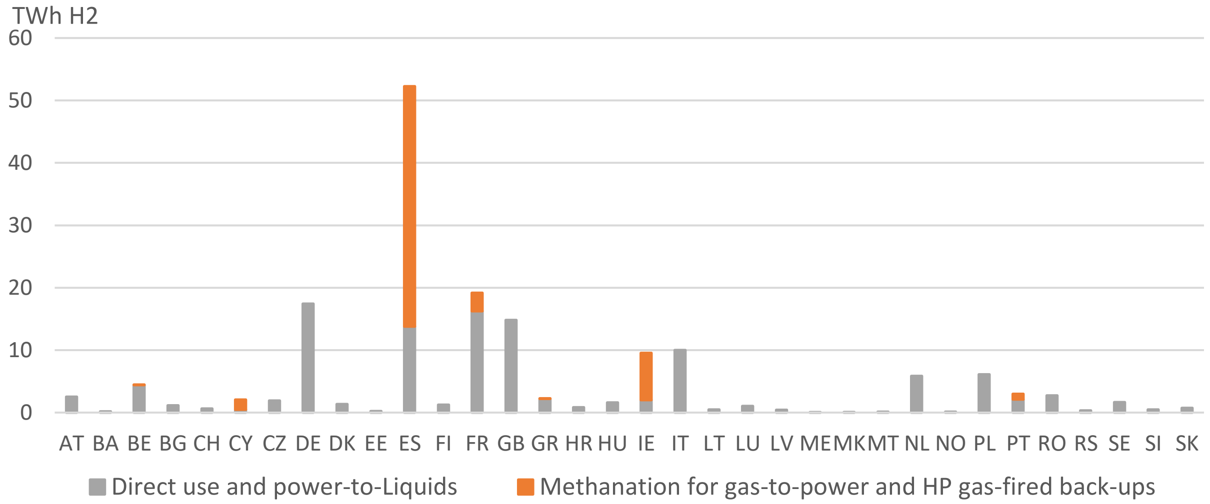


Figure 18 - Hydrogen production drivers in the METIS-S1-2050 scenario

Figure 19 compares the monthly production of electrolysis and methanation. Since methanation is more capital intensive, methanation capacities are used more often, even during periods with higher power prices.

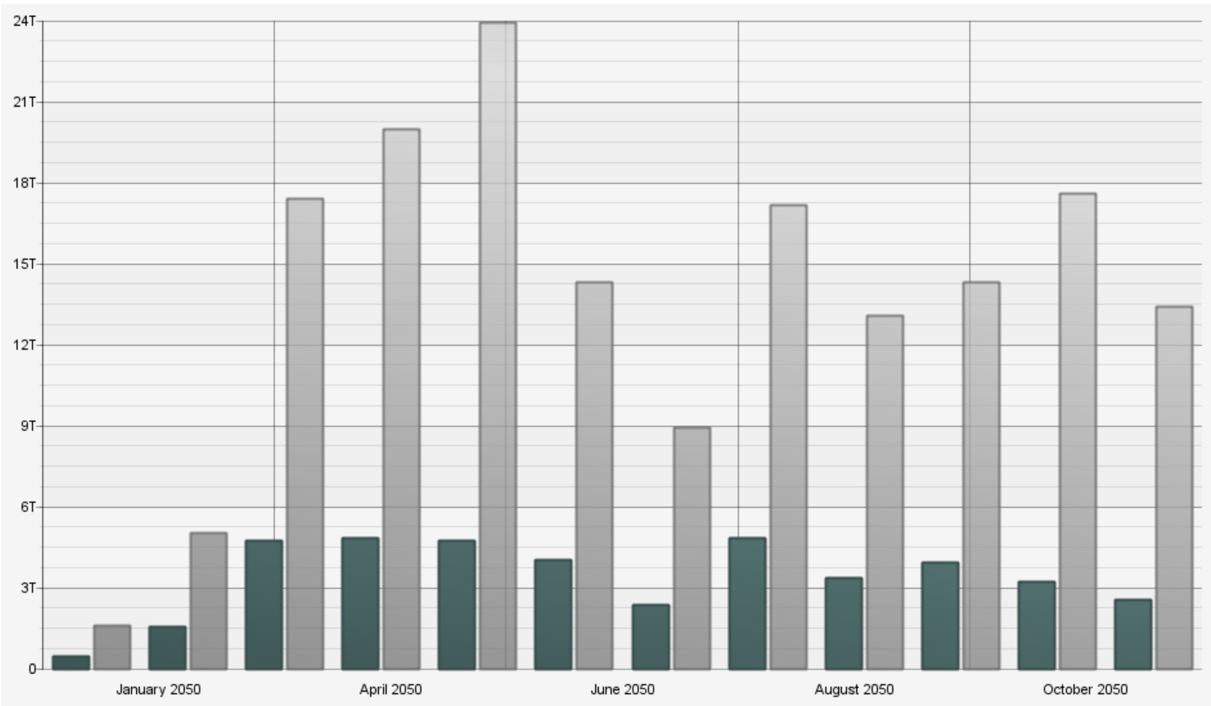


Figure 19: Monthly utilisation of electrolysis (grey) and methanation (blue) in Europe

6.2. Heat-pumps

Figure 20 shows the hourly dynamics of heat pumps in France during a winter week. The **heat pump flexibility is typically used within a daily timeframe**. Indeed, the heat demand obviously varies across the different days as a function of the temperature. Demand valleys occur around midday in correlation with temperature peaks. On the other hand, heat pump efficiency and thus heat maximum output exhibit the opposite dependency on the temperature: the efficiency decreases when the temperature increases. Heat pump low efficiency and heat demand peaks hence occur simultaneously. Consequently, as illustrated for France (cf. Figure 20), the heat pump capacity is occasionally insufficient to meet the demand during winter and back-up heaters are used to complete the heat supply. Indeed, covering the heat demand peaks exclusively with heat pumps would imply a costly over-dimensioning of the heat pump combined with high investments costs. Instead, back-up heaters with low CAPEX are used. Due to high gas prices and comparatively low electricity prices, **electricity back-ups are used most of the time**. However, to avoid significant increase on the power demand peaks, **gas-fired back-ups are also used in power scarcity periods**.

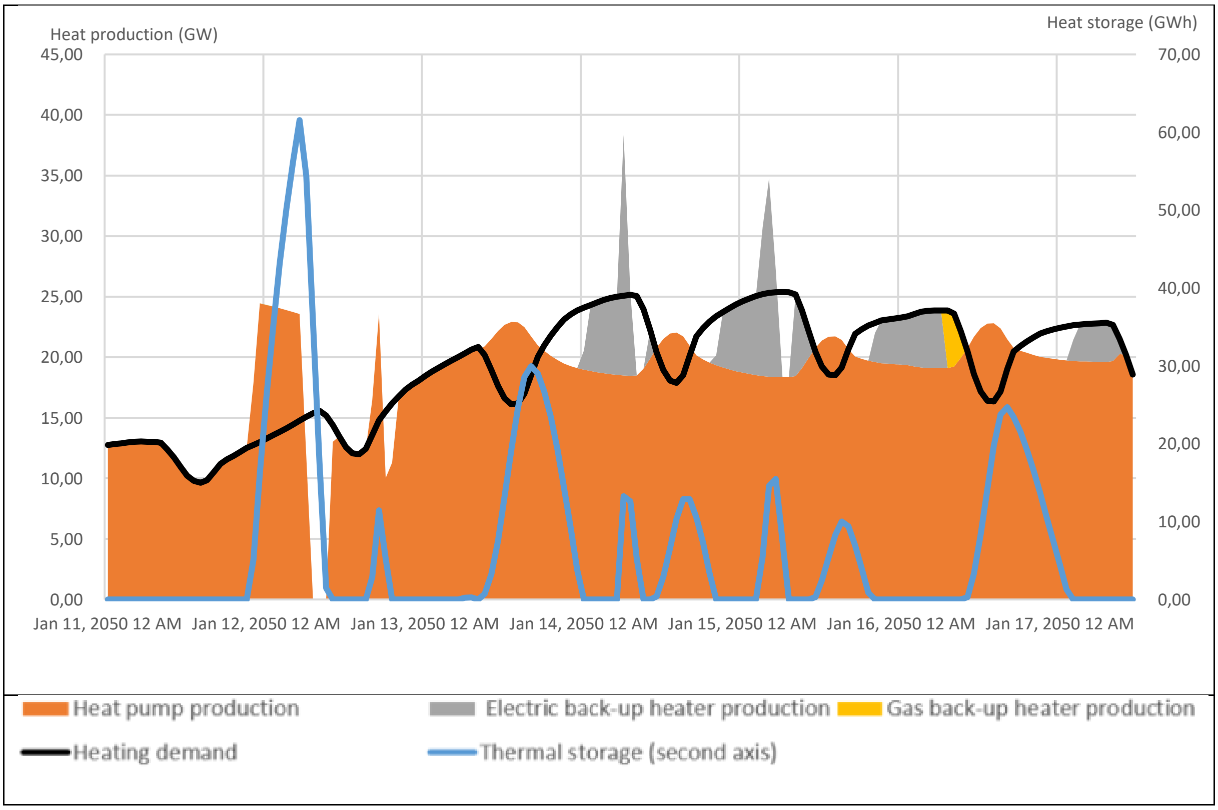


Figure 20 - Typical heat pump utilisation in France during winter

6.3. Electric Vehicles

6.3.1. *Electric Vehicles*

EV demand profiles obviously differ according to the charging behaviour (at home or at work[31]). However, in both cases, since the EV electricity consumption and PV generation exhibit a similar daily periodicity, smart charging tends to concentrate the consumption during the day in order to benefit from PV generation (in particular in summer time and in countries with high PV share). Wind power matches far less EVs' consumption profiles, smart charging is therefore on average mainly driven by PV. Taking Spain as an example, Figure 21 shows that work-charging EVs consumption follows exactly PV generation profile, as hours when EVs are connected at work match hours with high PV generation. In contrast, home-charging is mainly happening just before leaving home (in the morning, when the PV generation starts to ramp-up) or as soon as EVs return home (in the late afternoon, when PV still generates power and before the daily system load peak occurs).

a) EV charging at work *b) EV charging at home*

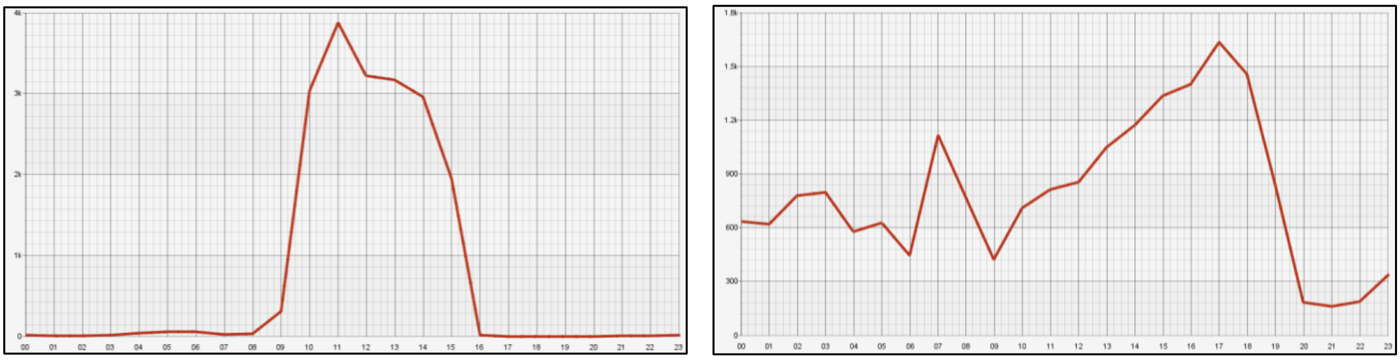


Figure 21 - Annual average hourly of electricity consumption for electric vehicle in Spain

6.3.2. *Stationary batteries*

Stationary batteries are found to be mainly relevant to accommodate the large solar PV capacities installed in southern countries (cf. Figure 9). Indeed, with a few hours of discharge time, (and considering the investment cost ratio between injection/withdrawal and storage capacities) batteries are well adapted to moving the PV production from midday to the evening demand peak. Figure 22 exhibits the typical daily production/consumption profiles (averaged over the year on each hour of the day) of the two battery types installed in Italy.

[31] 50% of EV's total number are assumed to be home-charging vehicles, and the remaining 50% are work-charging vehicles.

a) 2-hours battery *b) 4-hours battery*

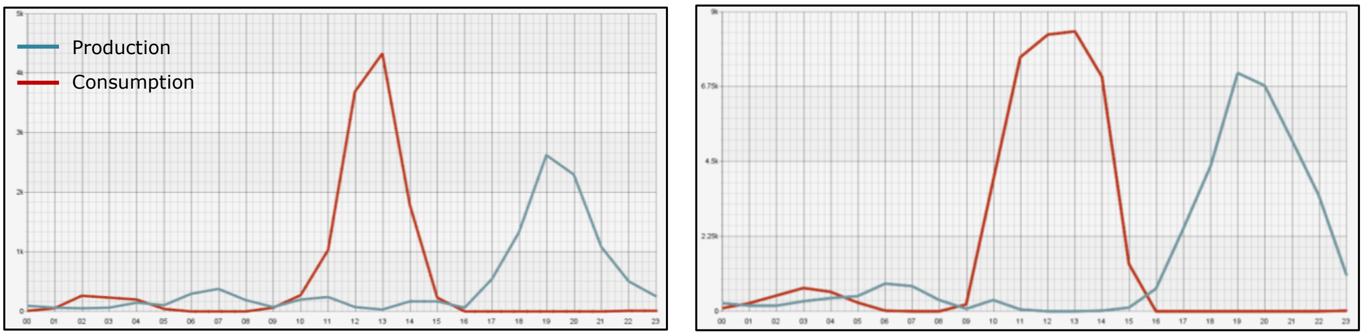


Figure 22 - Daily utilisation profiles of batteries in Italy (averaged over the year)

7. CONTRIBUTION TO THE FLEXIBILITY NEEDS

This section provides a quantitative assessment of the compared contributions of each technology to the systemic flexibility needs at the different timescales (namely daily, weekly and annual).

7.1. FLEXIBILITY NEEDS AND FLEXIBILITY CONTRIBUTION METRICS

Broadly speaking, the power system flexibility can be defined as the ability to continuously balance the variations of the residual load curve at all times. Hence, flexibility needs are assessed by analysing the dynamics of the residual load (i.e. the total load less the production from must-run capacities, mainly vRES). Since such dynamics exhibit different patterns on different timescales, the proposed method can be declined on each timescale. In this study, the following flexibility needs/contributions have been assessed:

- The daily flexibility needs, especially sensitive to the PV integration share
- The weekly flexibility needs, better reflecting wind power dynamics
- The annual flexibility needs, capturing inter-seasonal variations in power demand or weather-driven power generation (such as solar PV, wind power or run-of-river hydro)

Study S11[32] provides methodological elements on flexibility needs, and definitions are provided in Appendix C of this study.

Since the simulations ensure that the supply-demand equilibrium is met at all times, the flexibility needs are fully covered. By examining the dispatch, the contributions from the different available flexible technologies (i.e. dispatchable generation, including storage units and cross-border exchanges) can be identified.

To do so, the flexibility needs are re-computed on the residual load from which the net generation[33] of the considered asset is subtracted. This gives the remaining flexibility needs after the contribution of the considered asset.

The difference between the original flexibility needs and the remaining flexibility needs (after a given asset's contribution) gives the contribution of the considered asset. It measures the extent to which the asset flattens the residual supply-demand imbalance over the daily, weekly and annual timescales.

Appendix D, extracted from [24], describes the computation of all three flexibility needs metrics in more detail.

[32] See [42]

[33] The net generation is defined as the generation time series to which the power consumption time series is subtracted. It is especially important to consider the power consumption in addition to the power generation for storage assets. Indeed, valley-filling, which consists in storing power surpluses, also contributes to the system flexibility.

7.2. DAILY FLEXIBILITY ASSESSMENT[34]

Compared to the EUCO30-2030 scenario, the daily flexibility needs significantly increase in the METIS-S1-2050 scenario: from 220 TWh (EUCO30-2030) to 400 TWh (METIS-S1-2050). However, one may notice in Figure 23 that the total increase is not evenly split between countries. Italy (+44 TWh), Spain (+34 TWh), Germany (+26 TWh), France (+ 15 TWh), Belgium (+9 TWh), the United-Kingdom (+7 TWh) and Greece (+6 TWh) support the bulk of increase: +80% of the total increase in Europe. Those countries also account for nearly 75% of the total needs in the METIS-S1-2050 scenario.

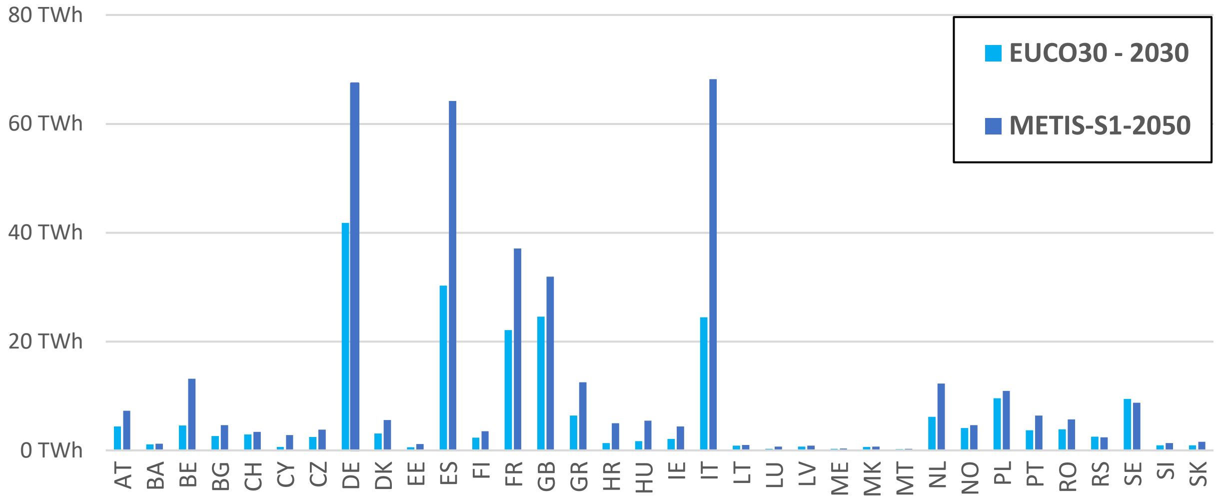


Figure 23: Daily flexibility needs in the EUCO30-2030 and the METIS-S1-2050 scenarios

Solar PV is the main driver for this result. While a limited level of PV generation may first decrease daily flexibility needs thanks to the correlation between PV generation and the midday power demand peak, further PV integration increases the flexibility needs by creating residual load trough (also referred to as "duck curve" or even power surplus during midday hours[35]).

Taking the typical case of Italy, Figure 24 illustrates the extent to which each flexible technology contributes to meeting the daily flexibility needs (see Appendix D for a precise definition of these metrics). By 2050, interconnections are found to be the main daily flexibility provider, along with batteries. As presented in Section 346.3.2, batteries are well adapted to help shift PV-driven power surpluses from midday to the evening demand peak. Interconnections allow to export excessive power supply from countries with high PV shares to countries with lower PV integration (typical maintaining a power demand peak at midday) or to compensate for lacking generation through imports.

One may also notice that, compared to the METIS EUCO30 2030 scenario, in the METIS-S1-2050 scenario interconnections and storage units are found to displace gas-fired plants as major daily flexibility provider.

[34] See Appendix D for a precise definition of these metrics.

[35] For a more detailed analyses of the dependency of the daily flexibility need to the PV share in the power demand, the reader may refer to [24].

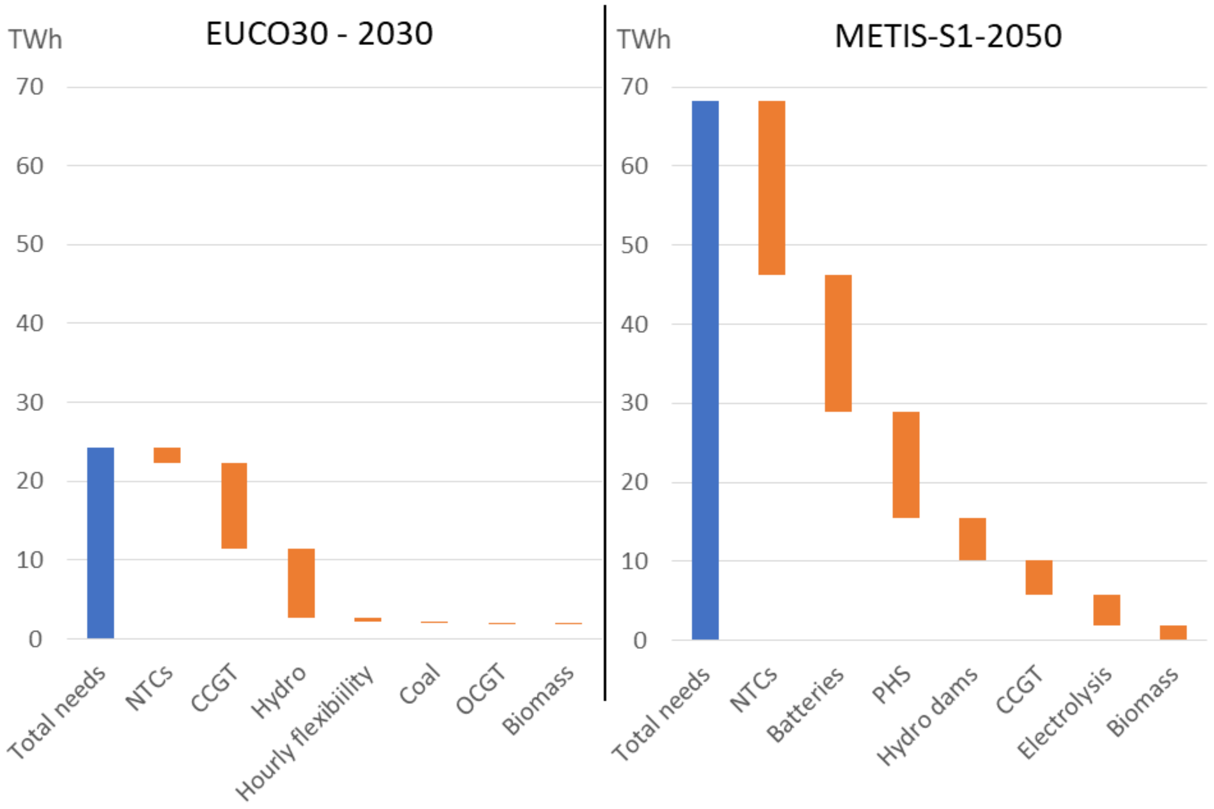


Figure 24: Contributions of flexibility solutions to the daily flexibility needs in Italy

7.3. Weekly flexibility assessment[36]

The weekly flexibility needs are likewise considerably higher in the METIS-S1-2050 scenario than in the EUCO30-2030 scenario, with 310 TWh vs. 190 TWh. Again, the main factor is the integration of variable RES, wind power more specifically, since PV generation does not exhibit a significant weekly variability. When looking at the national weekly flexibility needs on Figure 25, one may see that the United-Kingdom, Germany and France bear the biggest increase – in line with wind power development. In Spain, Italy and Greece the RES development mainly lies on PV, inducing much less additional weekly flexibility needs than additional daily flexibility needs.

[36] See Appendix D for a precise definition of these metrics.

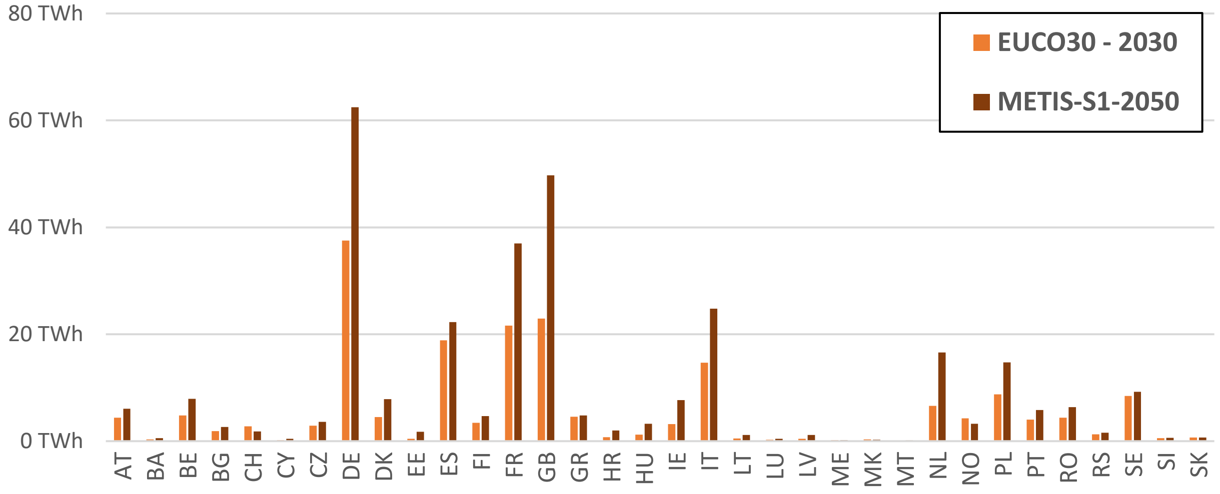


Figure 25: Weekly flexibility needs in the EUCO30-2030 and the METIS-S1-2050 scenarios

Interconnections are the main provider for weekly flexibility as for daily flexibility. Cross-border exchanges can smooth the variable wind patterns over neighbouring countries and lower the wind power generation variation – which are one of the major causes of weekly flexibility needs. The same holds true for power demand patterns, another major cause of weekly flexibility needs. Great Britain is a typical case for countries that feature high weekly flexibility needs and relatively low daily flexibilty needs. As shown in Figure 26, in such a case the cross-borders exchanges can cope with nearly half of the weekly residual load smoothing. The remaing half being handled quite evenly between all other flexibility solutions, namely pumped-hydro-storage, thermal units and demand side flexibility (power-to-gas).

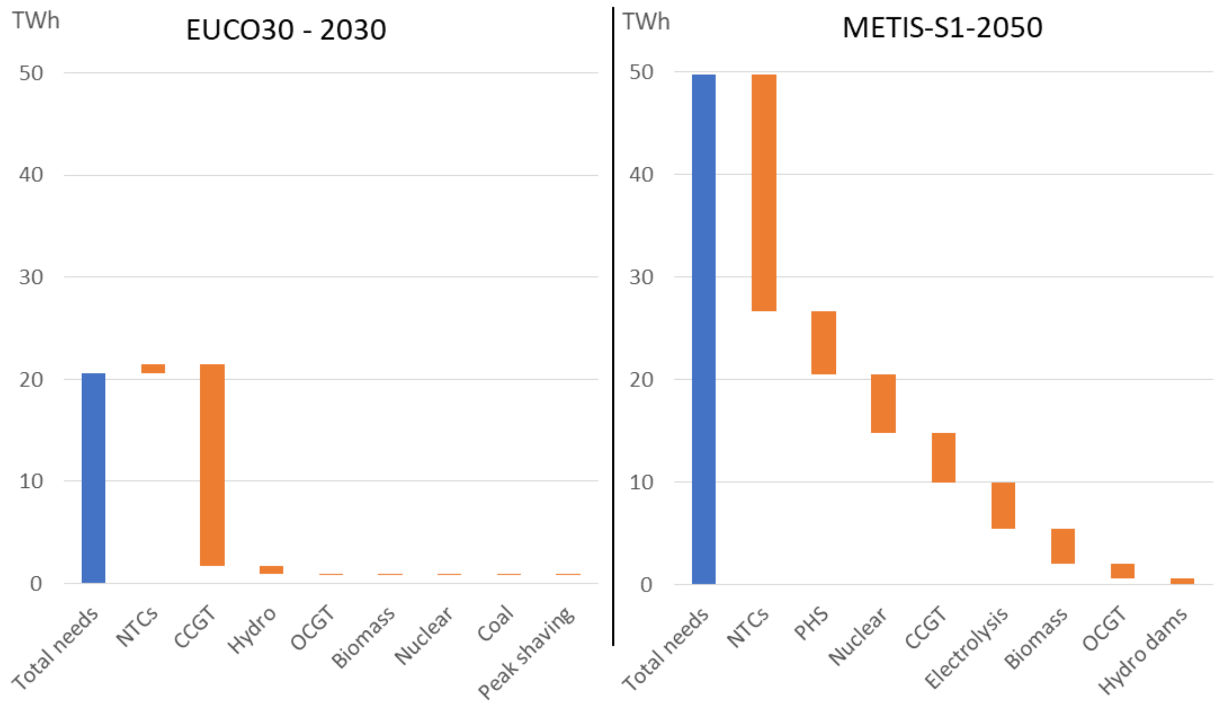


Figure 26: Contributions of flexibility solutions to the weekly flexibility needs in Great Britain

Interconnections and storage units are also found to displace gas-fired plants as main weekly flexibility provider. Like for the daily flexibility, this is mainly due to the fact that in 2050 gas is not expected to be a semi-base generation technology anymore but rather a sheer peaker.

7.4. Annual flexibility assessment[37]

The annual flexibility needs are mainly driven by the thermo-sensitivity of power demand. In addition, PV and wind power generation vary between the different months and seasons. However, their cumulated impacts can compensate each other. Indeed, the wind power generation is higher in winter whereas PV generation is higher in summer. Consequently, increasing wind power shares alone can lower the monthly residual demand variations in countries where the demand is also higher in winter. Increasing PV shares can lower the monthly residual demand variations in countries where the demand is higher in summer (i.e. due to air conditioning). Increasing both PV and wind power shares may have a balanced effect on annual flexibility needs.

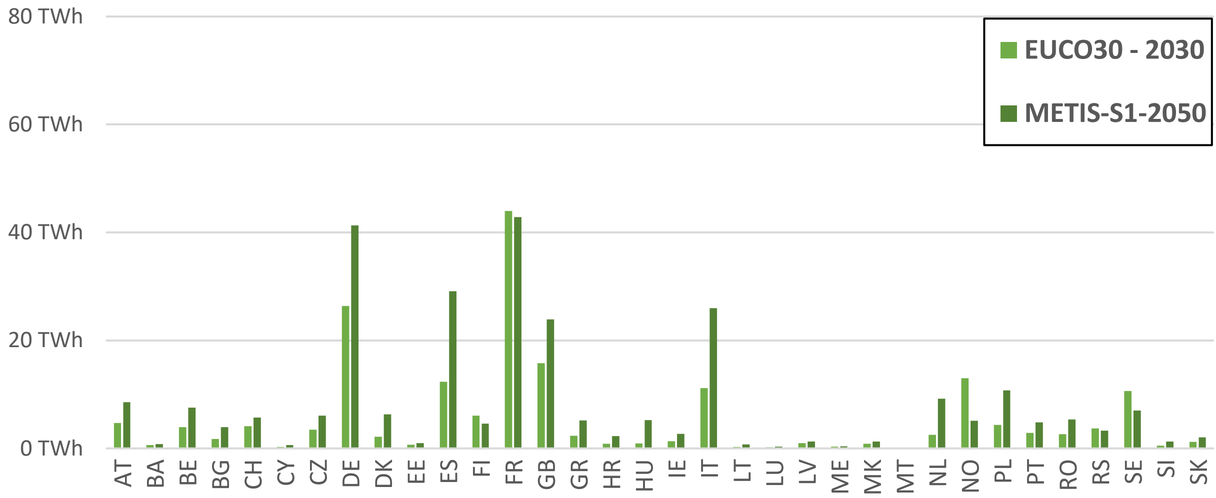


Figure 27: Annual flexibility needs in the EUCO30-2030 and the METIS-S1-2050 scenarios

Figure 28 shows the comparative contributions to the annual flexibility needs in France, whose annual flexibility needs are the biggest in Europe in the METIS-S1-2050 scenario. Thermal capacities represent the primal source of inter-seasonal flexibility, including nuclear, gas-fuelled and biomass plants. Interconnections complete the flexibility provision along with electrolysis and hydro-power.

[37] See Appendix D for a precise definition of these metrics.

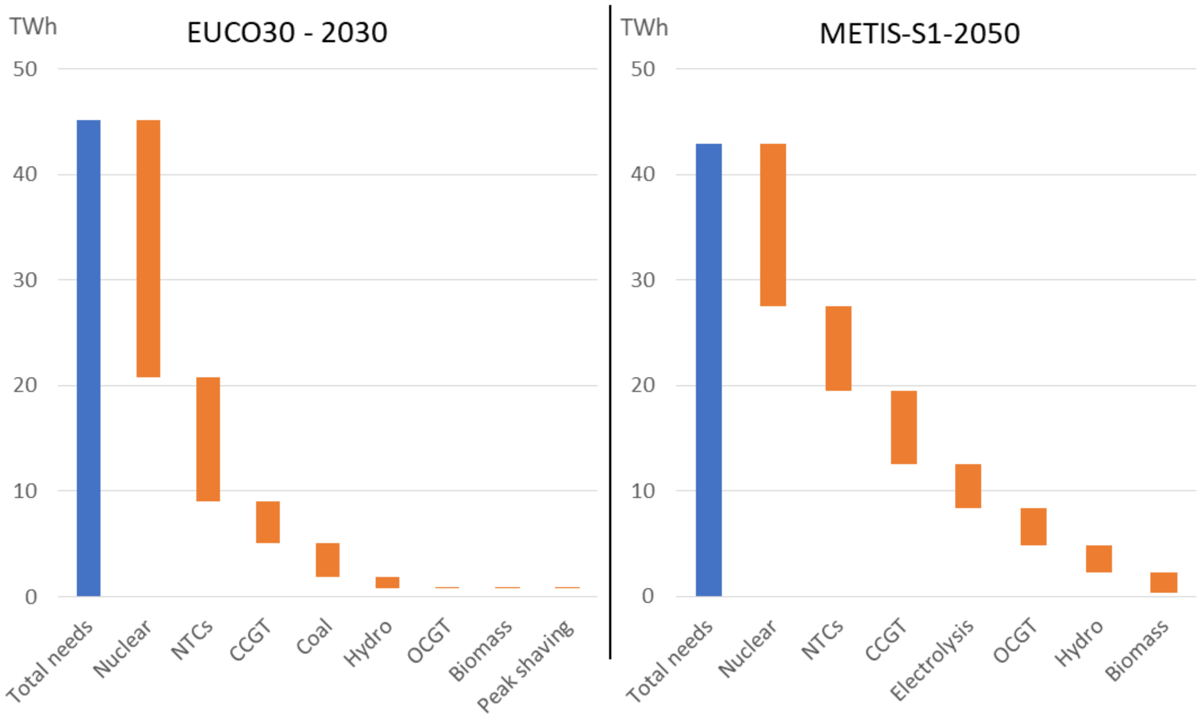


Figure 28: Contributions of flexibility solutions to the annual flexibility needs in France

8. CONCLUSION

The METIS-S1-2050 scenario reaches full carbon neutrality of the power sector, notably by phasing-out fossil fuels from power generation. To cope with the full decarbonation of power generation and the additional electricity need to generate 115 TWh of hydrogen via electrolysis, 960 TWh of solar PV and wind power are added to the original RES level of the EUCO30 scenario. **That is, the European power generation is composed of 80% RES** (among which 60% of PV and wind power), 17% nuclear and only 3% of carbon-neutral gas-fired power generation.

With such levels of vRES generation, the power system requires large amounts of flexibility solutions. Indeed, compared to the EUCO30-2030 scenario, the EU-wide flexibility needs increase in METIS-S1-2050 by 80%, 60% and 50% at the daily, weekly and annual timescales. While thermal units provide the major part of the flexibility today and in the EUCO30-2030 scenario, new types of flexibility appear to be cost-efficient in a high-RES 2050 scenario, reducing the need for thermal back-up.

Interconnections and storage units are the main sources of flexibility in 2050 as they allow to dispatch large vRES generation levels 1) within Europe 2) from low demand periods to demand peaks.

- With a total of 164 GW[38] of interconnection capacities, cross-border exchanges are found to be a major source of flexibility at all timescales. At the weekly timescale, interconnections allow to balance different wind generation patterns. At the daily timescale, interconnectors facilitate the export of PV surplus generation from countries with high irradiance levels to neighbours with high demand peaks at midday.

- Storage is the second most relevant flexibility source. Pumped-hydro storage delivers weekly flexibility while battery systems facilitate PV integration, counterbalancing their daily production cycles.

Demand side management of new electricity consumers is found to provide significant flexibility, saving both operational and investment costs.

- EV smart charging can easily provide flexibility over several hours. In countries where PV shares reach the highest levels, 17 GW of stationary batteries are installed for the daily residual load management. Vehicle-to-grid could further reduce needs of short-term flexibility and avoid 14 GW of stationary batteries as well as 7 GW of gas-to-power and 4 GW of pumped-hydro-storage.

- Hybrid heat pumps may help reduce system adequacy costs. Equipping heat pumps with gas-fired back-up heaters limits electricity load peaks, by shifting demand to (carbon-neutral) gas. This allows for a smaller need of peak power generation capacities.

- Power-to-X can adapt to the residual load patterns within all timeframes, depending on the national power mix in each country. Water electrolysers production can easily adapt to a country's residual load pattern. Methanation is only found to be economically relevant in countries with particularly low power prices.

In sum, the rising flexibility needs may be effectively met by interconnectors, storage and demand side management. The need for dispatchable backup gas units is reduced to a

[38] The ENTSO-E's Best Estimate for 2020 gives a total of 93 GW.

minimum. Merely 200 GW of gas-fired assets are installed to meet power demand peaks and cope with inter-seasonal variations in the residual load. In terms of power generation, the role of gas is limited to 3%. That is the role of gas remains restricted to the provision of capacity services while the overall gas demand volumes remain very limited and can be met by synthetic gas or biogas.

To facilitate the transition towards a fully decarbonised, high-RES EU power system, that may also serve to decarbonise other sectors of the European economy (heating, transport, industry), it is key that:

- The suggestions from the EU's Clean Energy for all Europeans Package are enacted into legislation in order to give new market actors (such as aggregators, industrial consumers) access to the different power markets (including ancillary services markets), and incentivise power consumption and operation of (decentralised) storage in terms of bulk renewable power generation electricity consumers through time-varying price signals and tariff design;

- Further R&I activities are required to ensure a continuous progress in technical maturity and economic competitivity of new flexibility solutions (such as batteries, smart meter and control infrastructure, low-loss power interconnectors) and electrification technologies (such as industrial processes, the production of electricity-based fuels, high-efficient electric heating).

- the Energy Union's goals of a fully functioning internal energy market are further pursued, allowing for a full exploitation of the EU's RES potential through a holistic assessment of required projects of common interest (PCI) which may include non-interconnector projects and a timely and cost-efficient realisation of the PCIs.

The present analysis builds upon an exemplary 2050 EU power system, which is used to illustrate a potential configuration for a fully decarbonised EU power sector. Yet, this scenario does not claim to represent the optimal or desirable power system configuration, given that it was conceived by adapting an existing scenario with exogenous RES capacities. A holistic capacity optimisation with the METIS tool might allow for a more robust assessment of RES investments in terms of technology mix, but also repartition between countries, revealing the optimal power sector configuration in terms of social welfare and system stability.

The assumptions on the electrification of the transport and industry sector were exogenously chosen for the purpose of illustration. Extending the system borders and including the electrification of the different sectors (in comparison to alternative decarbonisation options) in the optimisation would provide an even more complete picture of an ideal decarbonised European economy, in line with the European Commission's proposal for a EU 2050 Long Term Strategy[39].

Last, this study quantifies the flexibility needs and designs a cost-optimal portfolio of flexibility solutions from a market perspective (representing every country as a single node). However, flexibility needs will also rise at the level of distribution and transmission grids. Situations of local grid congestion are likely to occur more frequently. The flexibility solutions considered in this study represent also a promising option for an effective grid

[39] See [44] and [45] for further details concerning the vision for a long-term EU strategy for reducing greenhouse gas emissions.

management. Their effective utilisation may minimize the costly reinforcement of grid infrastructure. But the key question is how to efficiently allocate flexibility resources between markets and grids. This topic is at the heart of the METIS 2 project and will be treated in more detail in this context. Finally, while this report focuses on system cost aspects, the METIS study S14 "Wholesale market prices, revenues and risks for producers with high shares of variable RES in the power system" builds on the same scenario (namely, METIS-S1-2050) and analyses in details the impacts on market price volatility and producer revenues.

9. REFERENCES

[1] European Commission, "website," [Online]. Available: https://ec.europa.eu/clima/policies/strategies/2050_en.

[2] European Commision, "Decentralised heat pumps: system benefits under different technical configurations," 2018.

[3] European Commission, "The role and potential of power-to-X in 2050," 2018.

[4] European Commission, "Effect of electromobility on the power system and the integration of RES," 2018.

[5] Europe Beyond Coal, "Overview: National coal phase-out announcements in Europe," 2017.

[6] European Commission, "Technical report on Member State results of the EUCO policy scenarios," 2016.

[7] European Commission, "Methodology for the integration of PRIMES scenarios into METIS," 2016.

[8] CertifHy, "Generic estimation scenarios of market penetration and demand forecast for "premium" green hydrogen in short, mid and long term," 2016.

[9] IEA, "Technology Roadmap Hydrogen and Fuel Cells," 2015.

[10] ADEME, GRTgaz, GrDF, Etude portant sur l'hydrogène et la méthanation comme procédé de valorisation de l'électricité excédentaire, 2014.

[11] FCHJU, "Study on development of Water Electrolysis in the European Union," 2014.

[12] ENEA, The potential of Power-to-Gas, 2016.

[13] Agora Verkehrswende, Agora Energiewende und Frontier Economics, "The Future Cost of Electricity-Based Synthetic Fuels," 2018.

[14] E3Modelling, Ecofys, Tractebel, Sectoral integration- long term perspective in the EU Energy System, 2018.

[15] European Commission, "Joint Research Center Data Catalogue," [Online]. Available: https://data.jrc.ec.europa.eu/.

[16] IRENA, Biofuels for aviation, 2017.

[17] ENEA, Etat des lieux du biométhane en France, 2017.

[18] IRENA, Biogas for Road Vehicles, Technology brief, 2017.

[19] ENTSOE, "TYNDP 2018 - Scenario Report," [Online]. Available: https://tyndp.entsoe.eu/tyndp2018/scenario-report/.

[20] ADEME, "Rapport sur les données utilisées dans le cadre de l'étude Trajectoires," 2018.

[21] European Commission, "Energy Technology Reference Indicator projections for 2010-2050," 2014.

[22] ENTSOE, “TYNDP 2016 Downloads,” [Online]. Available: https://tyndp.entsoe.eu/2016/reference/#downloads.

[23] ENTSOE, “Statistical factsheet,” 2017.

[24] European Commission, “Mainstreamin RES - Flexibility portfolios,” 2017.

[25] CertifHy, Overview of the market segmentation for hydrogen across potential customer groups, based on key application areas, 2015.

[26] ADEME, “Filière Photovoltaïque Française : Bilan, Perspectives et Stratégie,” 2015.

[27] AFHYPAC, Production et consommation d'hydrogène aujourd'hui, 2016.

[28] ADEME, “Un mix de gaz 100 % renouvelable en 2050 ?,” 2018.

[29] IEA, Technology Roadmap, Biofuels for transport, 2011.

[30] E4tech, Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target, 2015.

[31] DNV GL, “Power-to-gas in a decarbonized European energy system based on renewable energy sources”.

[32] Hydrogen Council, “Hydrogen Scaling-up,” 2017.

[33] Ecofys, Gas for Climate, 2018.

[34] OJ L 140, “Directive 2009/30/EC of the European Parliament and of the Council of 23 April 2009 amending Directive 98/70/EC as regards the specification of petrol, diesel and gas-oil and introducing a mechanism to monitor and reduce greenhouse gas emissions and amend,” 5.6.2009.

[35] OJ L 140, “Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC,” 5.6.2009.

[36] EBA, BioMethane in Transport, 2016.

[37] IRENA, Biomass for power generation, Renewable Energy Technologies: Cost Analysis Series, 2012.

[38] DNV GL, “Flexibility in the power system,” 2017.

[39] RTE, “Bilan Prévisionnel,” 2015.

[40] ATEE, “Etude PEPS4 sur le potentiel national du stockage d'électricité et du power-to-gas,” 2018.

[41] European Commission, “Wholesale market prices, revenues and risks for producers with high shares of variable RES in the power system,” 2018.

[42] E. Commission, “METIS study S11 - Effect of high shares of renewables on power systems,” 2018.

[43] European Commission, “Towards a sustainable and integrated Europe - Report of the Commission Expert Group on electricity interconnection targets,” 2017.

[44] European Commission, “A Clean Planet for all - A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy - COM(2018) 773,” 2018.

[45] European Commission, “A Clean Planet for all - A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy - IN-DEPTH ANALYSIS IN SUPPORT OF THE COMMISSION COMMUNICATION COM(2018) 773,” 2018.

Appendix A

Detailed decarbonisation assumptions in the METIS-S1-2050 scenario

This appendix provides further information on the design of the METIS-S1-2050 scenario. After having depicted the detailed computation of synthetic product demand (cf. Section A.1), the corresponding power generation requirement is presented (cf Section A.2). Finally, in order to calculate the additional vRES capacities, capacity factors used for the computation are provided in Section A.3).

A.1 Computation of synthetic product demand

a) Hydrogen

An annual hydrogen demand is computed for each country including the industry and transport sectors. Data from EUCO30 2050 is used for the transport sector data. Regarding the industry sector, the European demand provided by [25] (for industrial categories of refineries, chemical, metal processing and others) is assumed to be shared between all countries with respect to the national industry gas consumption share in the total European industry gas consumption.

b) Liquid fuels

EUCO30 2050 data is used for the liquids sector using selected sectors (industry, transport, others (agriculture, residential, services) without liquids to power).

c) Gas for power generation

15% of gas-to-power production from the EUCO30 scenario are switched to synthetic methane via power-to-CH_4. The corresponding annual consumptions are provided below for each country.

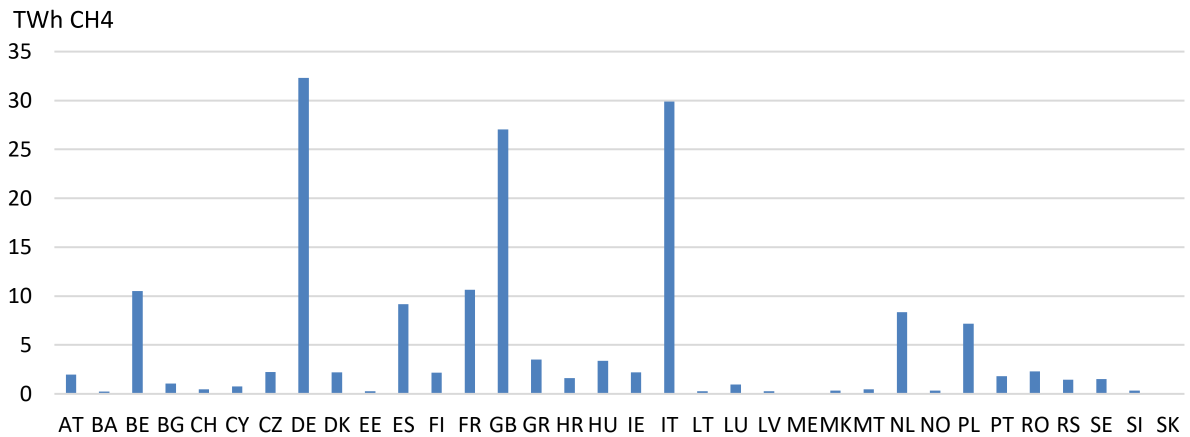


Figure 29 - Synthetic gas demand for gas-to-power sector

d) Countries with no data

For particular countries, no data was available for the construction of synthetic gas and liquid demand. In these specific cases, the value of a neighbouring country was used after proportion scaling to the national populations.

e) Summary table

Table 3 – Synthetic product demand used in the METIS-S1 2050 scenario

	Hydrogen (GWh_{H2})		Gas (GWh_{CH4})	Liquid fuels (GWh_{fuel})
Country	**Industry**	**Transport**	**Gas for power generation**	**Transport, industry, residential, services, agriculture**
AT	537	93	1966	1532
BA	117	33	227	0
BE	1256	130	10523	2445
BG	286	24	1055	683
CH	516	89	469	0
CY	0	2	760	371
CZ	316	40	2250	1242
DE	5038	519	32322	9505
DK	82	43	2190	971
EE	3	1	256	176
ES	3359	257	9182	8147
FI	167	30	2169	835
FR	3415	1040	10655	9443
GB	1037	730	27029	10431
GR	70	49	3509	1670
HR	138	39	1611	522
HU	250	79	3394	1009
IE	108	50	2195	1492
IT	1148	1212	29892	6119

LT	99	3	286	297
LU	33	30	964	787
LV	8	10	258	314
ME	21	6	0	0
MK	69	20	329	0
MT	0	1	460	91
NL	1987	69	8359	3024
NO	71	51	334	0
PL	850	237	7167	4015
PT	226	58	1801	1463
RO	652	59	2286	1625
RS	234	67	1450	0
SE	135	97	1505	1157
SI	49	14	334	310
SK	162	39	6	419
EU28	21411	4956	164383	70095
EU28+6	22439	5222	167192	70095

A.2 Details on required power generation

In the METIS-S1-2050 scenario, additional clean power generation is required to meet different energy sectors decarbonisation assumptions. The following figure shows the extra power production volume (compared to EUCO30 2050) that is included in the METIS-S1-2050 scenario.

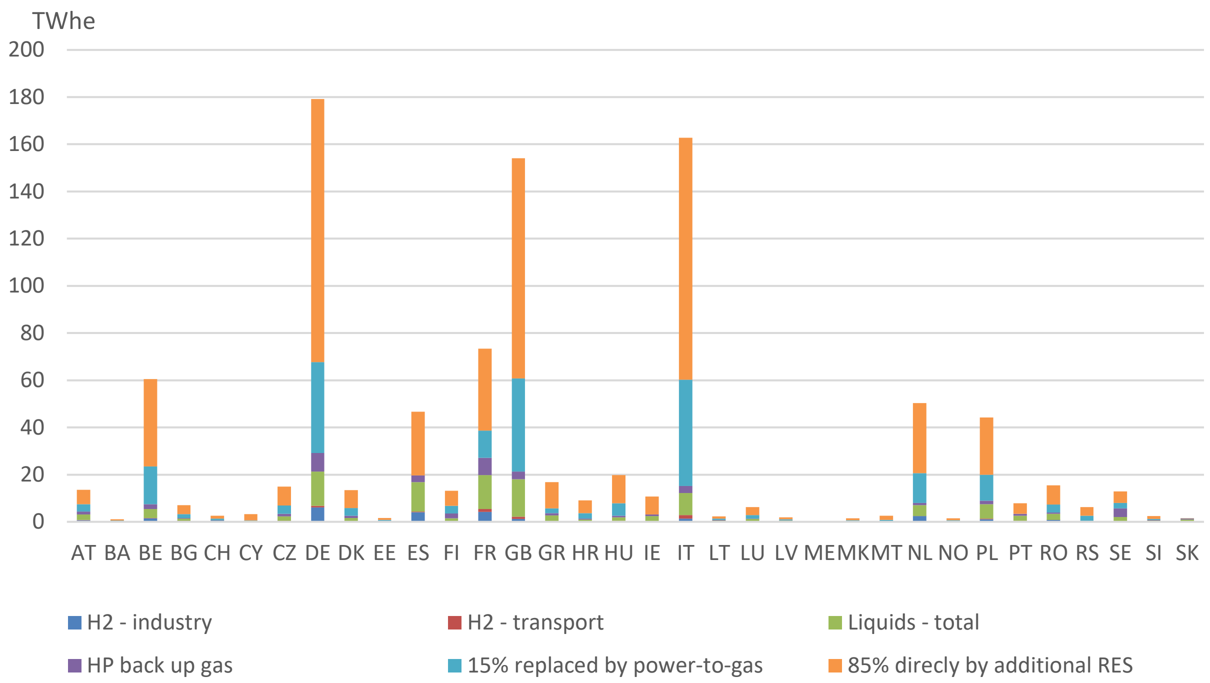


Figure 30 - Additional power production due to decarbonisation of gas/liquids sectors

A.3 vRES Capacity Factors

The additional power generation volumes presented in the previous section are converted into vRES capacities using METIS EUCO30 full load hours. The following figure presents the corresponding capacity factors.

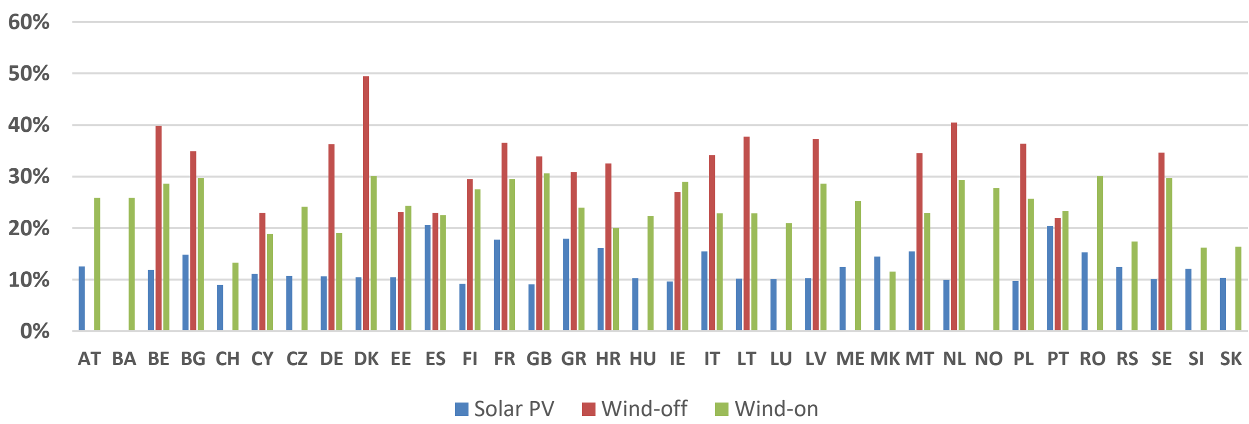


Figure 31: Variable RES capacity factors in EUCO30 2050

Appendix B

RES capacities in the METIS 2050 scenario

B.1 Requirements for additional clean power generation

As described in the previous section, the decarbonisation of the power system and part of the gas/liquids consumption imply requirements in additional carbon-neutral power generation.

First, the annual power generation volume required is derived from the decarbonisation assumptions presented in Section 4.1. Part of the additional power generation is required to compensate the phasing-out of fossil-fuels-fired power plants (based on the EUCO30 scenario, in the case of natural gas, only 85% is directly replaced by vRES). The remaining part of the additional power demand that needs to be covered comes from the substitution of fossil fuels through hydrogen and liquids. The corresponding annual power generation required is computed from the energy volume that is assumed to be decarbonized and the respective efficiencies of the power-to-X processes involved.

Table 4 sums up the efficiencies of considered for the different power-to-X technologies, relying on METIS Study S8 [3] (average projections for 2050). For electrolysers, alkaline and PEM (Proton Exchange Membrane) technologies are taken into account. Regarding the methanation (H_2-to-CH4) and power-to-liquids processes, the data used corresponds respectively to catalytic methanation and Fischer-Tropsch synthesis. For further details on power-to-X technologies, the see METIS Study S8.

Table 4 - Efficiencies of conversion processes for evaluating the additional power production required. Source: METIS study S8

Conversion process	Technology	Efficiency	Sources
Power-to-H_2	Alkaline and PEM electrolysers	82% (Wh_{H2}/Wh_{el})	[9, 10, 11]
H_2-to-CH_4	Catalytic methanation	79% (Wh_{CH4}/Wh_{H2})	[10, 12, 13]
H_2-to-Liquids	Fischer-Tropsch	80% ($Wh_{Liquids}/Wh_{H2}$)	[13, 14]

From the efficiencies, additional power generation required to produce synthetic gas and liquids is computed by using the product demands detailed in Section 4.1. At European level, respectively **35 TWh_{el}** and **105 TWh_{el}** are required to produce the hydrogen for direct hydrogen use and synthetic fuels respectively.

Besides, replacing the natural gas in power generation and heat pump back-up heaters translate into a need for up to 815 TWh[40] of additional power generation. The country-specific power generation demand is presented in Appendix C. It breaks down as follows:

[40] Assuming all remaining gas consumption (for gas-fired power generation and gas-fired heat-pump back-ups) are supplied with syngas (using power-to-gas) rather than biogas.

- **210 TWh$_{el}$** to cover 15% of gas-fired power generation with synthetic gas (140 TWh of syngas requires 210 TWh of electricity to be generated, given the efficiency of power-to-CH_4).

- **45 TWh$_{el}$** to generate synthetic gas for heat pump back-up heaters.

- **560 TWh$_{el}$** to directly replace 85% of gas-fired power generation.

Altogether, the METIS-S1-2050 scenario features nearly **960 TWh** of additional demand for carbon neutral power generation compared to the EUCO30 scenario.

B.2 Additional vRES capacities

To match the needs for additional carbon neutral power generation induced by the decarbonisation targets, extra vRES generation is added under the METIS-S1-2050 scenario compared to the EUCO30 scenario. This section details the assumptions made to translate this extra need for generation into additional solar PV and wind power capacities.

The additional power generation[41] is split between vRES technologies applying the following principles:

- Wind power offshore is assumed to support the biggest increase. The wind offshore capacities increase twice as much as other vRES capacities.

- Wind power onshore and solar PV increase based on their respective shares in the EUCO30 scenario

For each country, the full load hours (FLH) from METIS EUCO30 are used to convert the additional need for power generation into additional RES capacities (see Appendix for further details). The average European FLH is 13% for solar PV, 33% for wind offshore and 24% for wind onshore.

The resulting total RES capacities for each country are compared to the national RES potentials based on JRC database[42] [15] and detailed in Appendix C). If the increase in wind offshore exceeds the available potential, the capacities are adjusted downwards on a case by case basis. The capacity exceeding the national potential is relocated to a neighbouring country. Few countries incur a RES capacity modification. Table 5 indicates all adjustments performed.

Table 5 – Adjustment in vRES capacities increase to meet the national limitations

Country	Technology with adjusted development	Adjustment

[41] Since METIS EUCO30 scenario features high level of vRES curtailment, 80% of this annual curtailment is supposed to be compensated through the additional need for carbon neutral power generation as it already constitutes available energy.

[42] The data publication is forthcoming in the JRC (Joint research Centre) data catalogue: https://data.jrc.ec.europa.eu/

Belgium	Wind power offshore	Wind power offshore capacity increases as much as others vRES. Wind offshore capacity exceeding the potential is added to France's capacity
Germany		Wind power offshore capacity increases as much as others vRES due to high capacity in base year
Luxembourg	All vRES	Full potential is exploited, additional capacities are applied to France
Macedonia		Full potential is exploited, additional capacities are applied to Croatia
Malta		Full potential is exploited, additional capacities are applied to Italy
Slovenia	Solar PV	Full potential is exploited, additional capacities are applied to Italy

At the European level, the METIS-S1-2050 scenario exhibits an increase of 200 GW in solar PV capacities (+46% compared to the EUCO30 scenario), 190 GW in wind onshore capacities (+40%) and 100 GW in wind offshore capacities (+78%). Figure 32 shows the RES installed capacities in both the EUCO30 and METIS-S1-2050 scenarios, for each country.

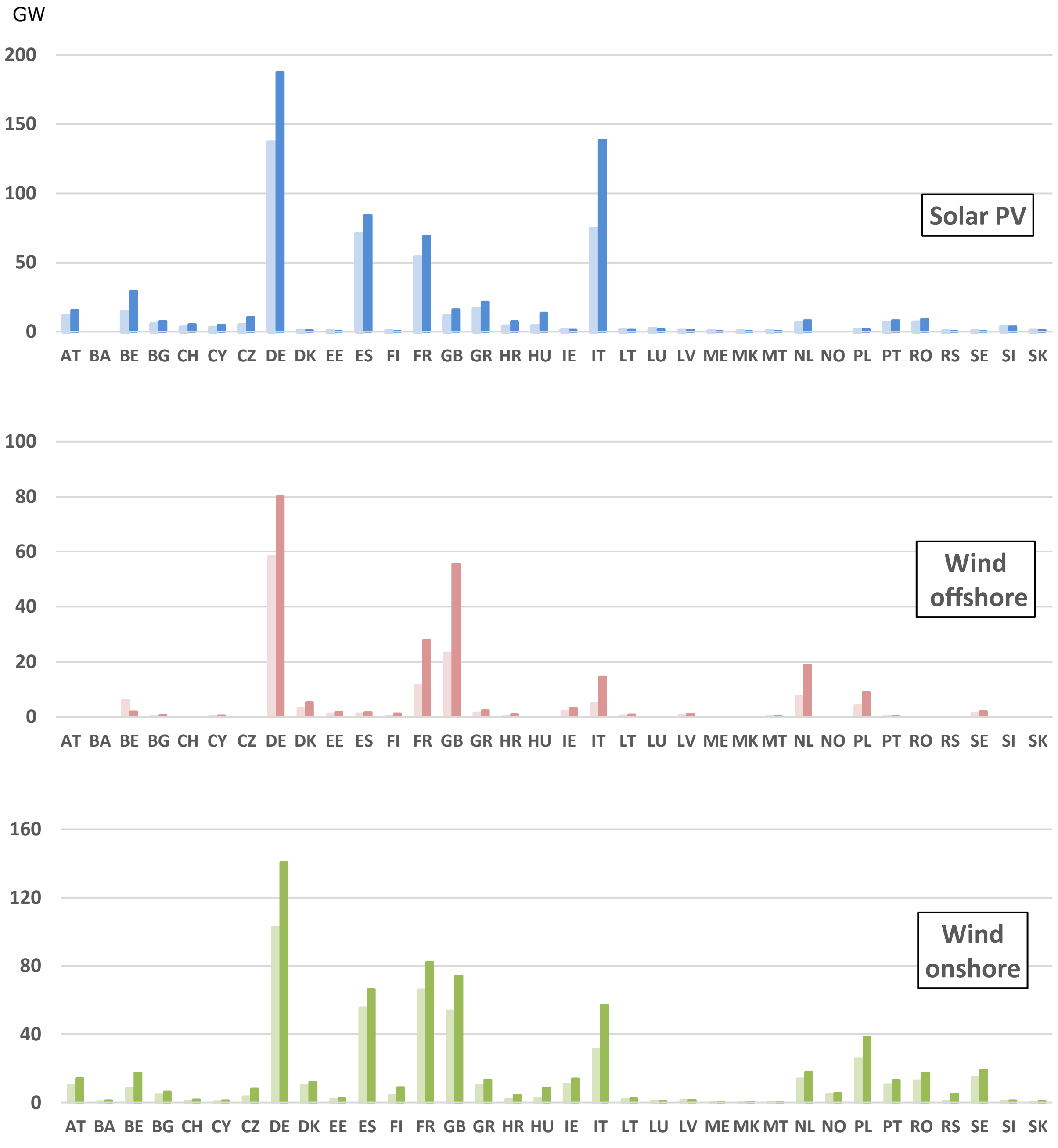


Figure 32 - RES installed capacities in the EUCO30 (light blue, red and green) and in the METIS-S1-2050 scenario (dark blue, red and green).

Appendix C

Detailed computation of the domestic vRES potentials

JRC database [15] was used to compute the national potentials for vRES generation. It includes solar PV and wind power offshore/onshore generation.

In the JRC database, three scenarios are defined for wind power potentials, depending on the public policy regulations: the reference scenario (continuation of current policies), the low-restriction scenario (convergence to high setback) and the high-restriction scenario (convergence to low setback). For each scenario and country, all available areas for different wind power capacity factors (CF) ranges are provided (CF<15%, CF in between 15 and 20%, CF in 20-25%, CF>25%). The underlying assumption from the database is that 5 MW of wind turbine could be installed per km^2. In this study, only potentials corresponding to CFs greater than 15% were used, averaging between the reference and the low-restriction scenarios.

Regarding the solar PV potential, different surface area categories are considered in [15] (cf. Figure 33). Each category is associated with a characteristic irradiation profile based on historical data. Using a country-specific solar PV CF (provided by METIS EUCO30), the solar PV potential for each country and for each surface area category can then be computed.

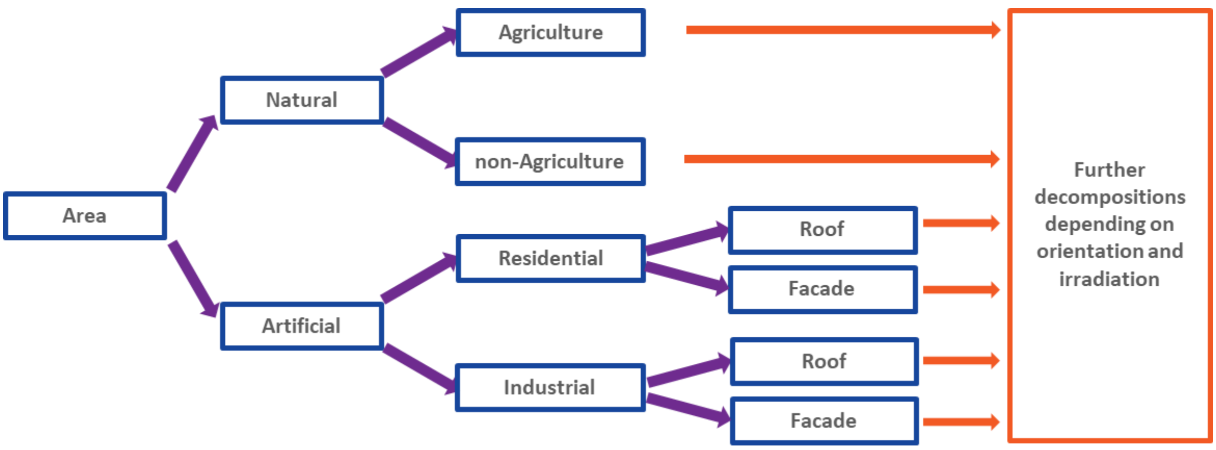


Figure 33 - Area decomposition used in JRC's RES potential database for solar PV potentials

In this study, the following assumptions were made to select a surface ratio for each category (cf. Table 6 for details). The ratios represent the part of the theoretical potential that is considered available for power generation, the remaining part is assumed to be dedicated to other surface usages.

- There is no land competition between solar PV production and agriculture: a 0% ratio is assumed for agriculture area, and the remaining natural areas has a 20% ratio.

- Compared to industrial surface areas, residential surface areas incur a small deployment due to higher costs (cf. [26]). Moreover, it is also assumed for both residential and industrial areas that solar PV roof installations are promoted compared to facade installations.

Table 6 - Assumptions on the surface area categories used for the computation of solar PV potentials.

Area categories		**% of maximal potential**
Natural areas	Agriculture low irradiation	0%
	Agriculture high irradiation	0%
	Non-agriculture low irradiation	20%
	Non-agriculture low irradiation	20%
Residential areas	Roof-top 45 degree south	20%
	Roof-top 45 degree east	20%
	Roof-top 45 degree west	20%
	Roof top latitude tilt	20%
	Facade south	5%
	Facade east	5%
	Façade west	5%
Industrial areas	Roof-top 45 degree south	80%
	Roof-top 45 degree east	80%
	Roof-top 45 degree west	80%
	Roof top latitude tilt	80%
	Facade south	20%
	Facade east	20%
	Façade west	20%

Appendix D

Flexibility needs assessment methodology proposed in [24] (extract from [24] report)

The first step of the methodology is to define how flexible the system needs to become in the presence of a large share of RES-e sources in order to cope with variations in demand and/or in generation. Several effects influence the flexibility needs on different timeframes:

1. At the hourly and sub-hourly levels, the increase of flexibility needs are mostly driven by the required ability to face the imbalances caused by RES-e forecasting errors.

2. At the daily level, the flexibility needs are found to be mostly driven by the daily pattern of the demand and by the daily cycle of solar generation.

3. At the weekly level, the flexibility needs are mostly driven by wind regimes and by the weekday/weekend demand structure.

4. Finally, at the annual level, the flexibility needs are mostly driven by a combination of the solar, wind and demand patterns. The solar production is higher during summertime, while wind generation tends to have an opposite behaviour. The last factor influencing the annual flexibility needs is the load-temperature sensitivity, which can be very contrasting from one Member State to the other depending on the portfolio of heating and cooling technologies.

In the following we define daily, weekly and annual flexibility needs by analysing the dynamics of the residual load on several timescales, so as to take into account all the underlying phenomena that drive the need for flexibility.

Definition – Residual load

The residual load is defined as the load that has to be served by dispatchable technologies (thermal, hydro, storage, demand-response, interconnectors, etc.). It is computed by subtracting the wind, solar and must-run generation from the demand. In order to capture the flexibility needs that are required to perform the analysis recommended in this report, we advise to use an hourly time resolution.
The residual load is illustrated below for a given week. The solid red line represents the demand, the solid blue line the residual load, while the green and yellow areas represent the wind and solar generation.

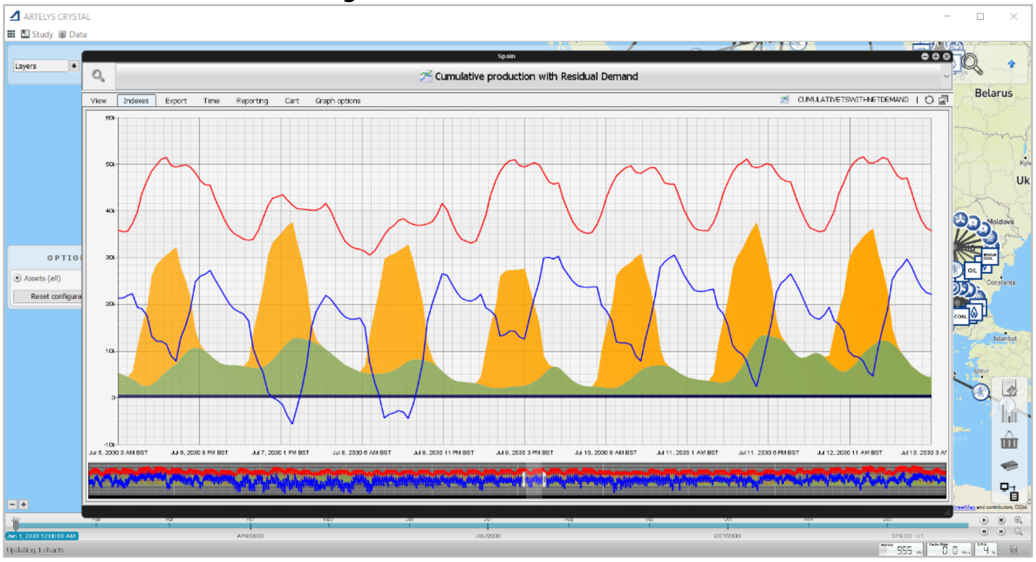


Figure 34 - Residual load illustration in Artelys Crystal Super Grid

Flexibility is defined as the ability of the power system to cope with the variability of the residual load curve at all times. Hence, flexibility needs can be characterised by analysing the residual load curve.

Daily flexibility needs

On a daily basis, if the residual load were to be flat, no flexibility would be required from the dispatchable units. Indeed, in such a situation, the residual demand could be met by baseload units with a constant power output during the whole day. In other words, a flat residual load does not require any flexibility to be provided by dispatchable technologies.
We therefore define the daily flexibility needs of a given day by measuring by how much the residual load differs from a flat residual load. The daily flexibility needs computed in this report are obtained by applying the following procedure:

1. Compute the residual load over the whole year by subtracting variable RES-e generation and must-run generation from the demand
2. Compute the daily average of the residual load (365 values per year)
3. For each day of the year, compute the difference between the residual load and its daily average (the light green area shown on Figure 35). The result is expressed as a volume of energy per day (TWh per day).

4. Sum the result obtained over 365 days. The result is expressed as a volume of energy per year (TWh per year).

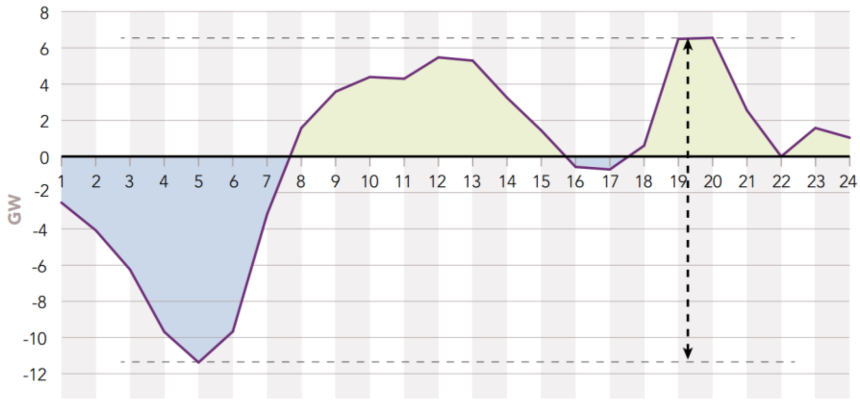


Figure 35 - Illustration of daily flexibility needs (the solid purple line measures the deviation of the residual load from its daily average for a given day). Source: RTE, Bilan prévisionnel de l'équilibre offre-demande, 2015

Weekly flexibility needs

The same reasoning is applied to evaluate the weekly flexibility needs. However, in order not to re-capture the daily phenomena that are already taken into account by the daily flexibility needs indicator, we recommend adopting the following procedure:

1. Compute the residual load over the whole year by subtracting variable RES-e generation and must-run generation from the demand with a daily resolution
2. Compute the weekly average of the residual load (52 values per year)
3. For each week of the year, compute the difference between the residual load (with a daily resolution) and its weekly average (the light green area shown on Figure 36). The result is expressed as a volume of energy per week (TWh per week).
4. Sum the result obtained over 52 weeks. The result is expressed as a volume of energy per year (TWh per year).

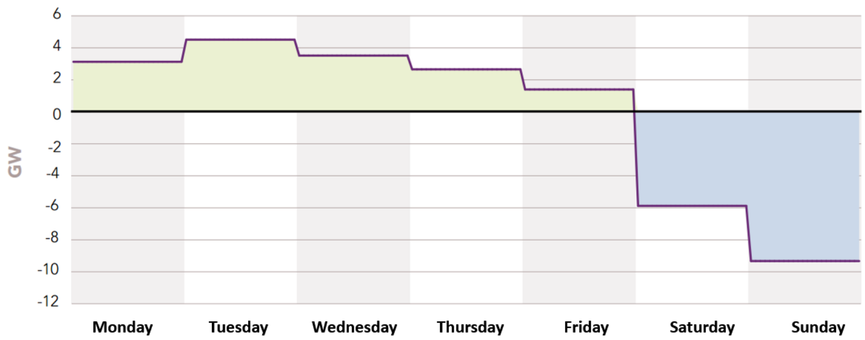


Figure 36 - Illustration of daily flexibility needs (the solid purple line measures the deviation of the residual load from its daily average for a given week). Source: RTE, Bilan prévisionnel de l'équilibre offre-demande, 2015

Annual flexibility needs

Finally, the annual flexibility needs are assessed in a similar way:

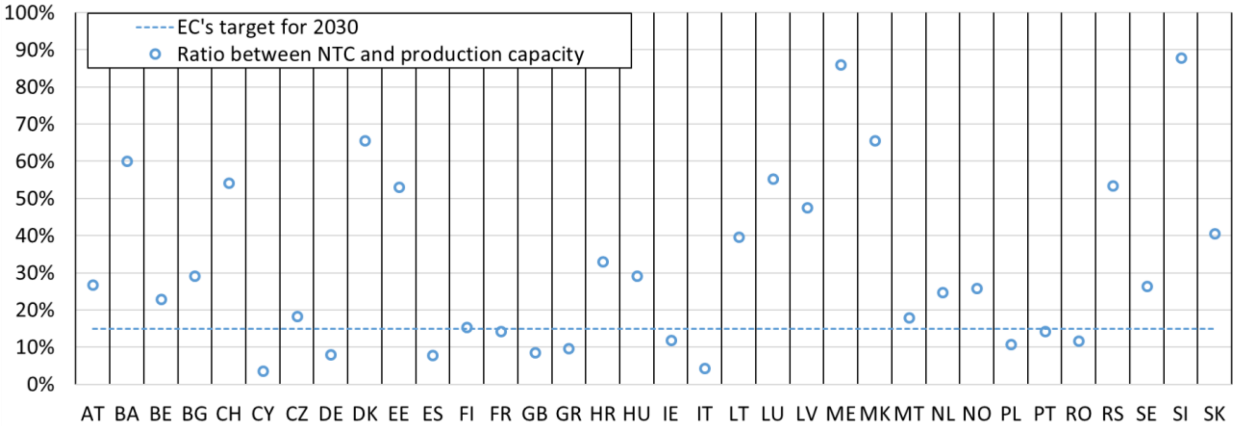
1. Compute the residual load over the whole year by subtracting variable RES-e generation and must-run generation from the demand with a monthly time resolution

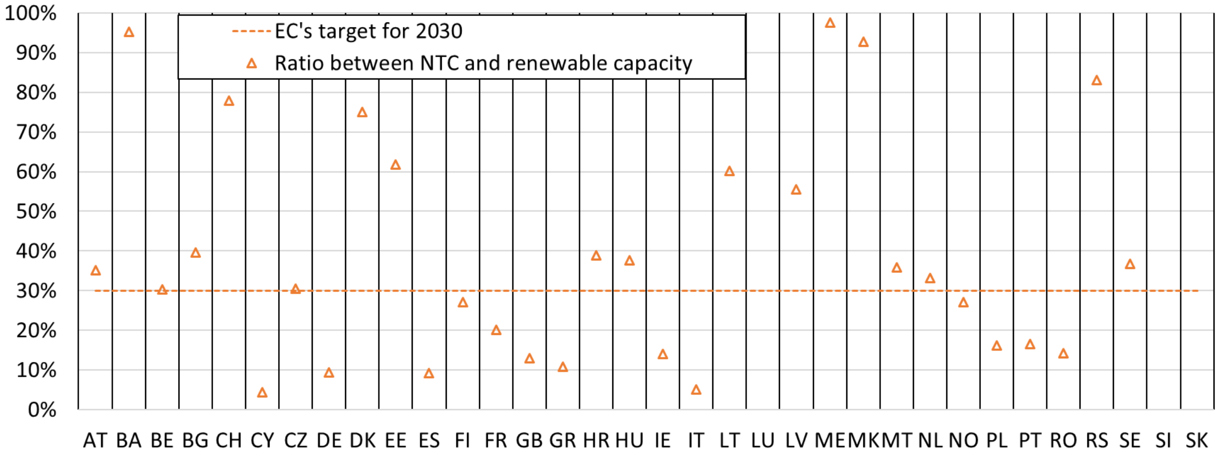
2. Compute the annual average of the residual load
3. Compute the difference between the residual load (with a monthly time resolution) and its annual average. The result is expressed as a volume of energy per year (TWh per year).

Appendix E

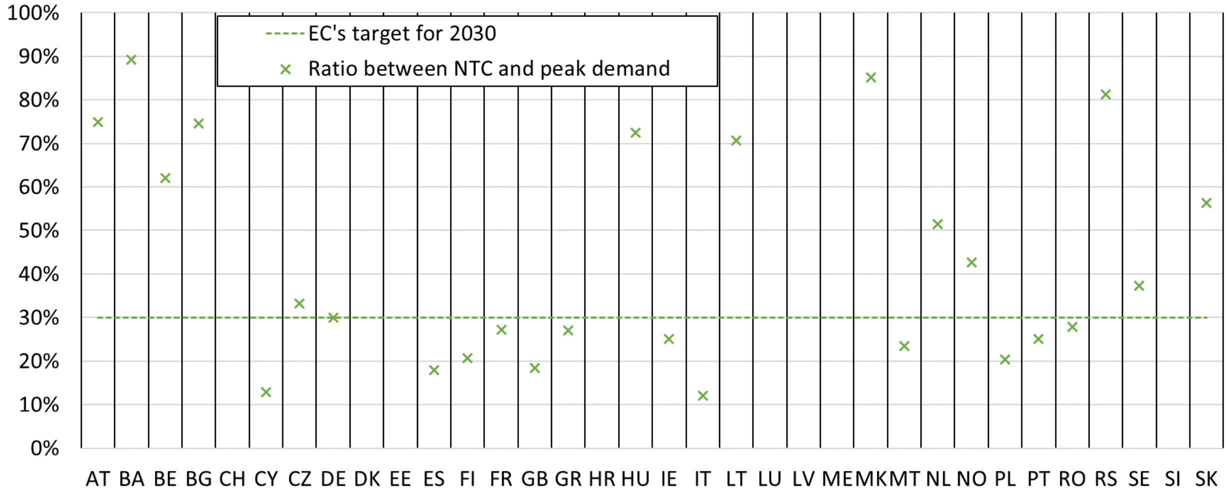
Interconnection levels 2050 compared to the European Commission's 2030 interconnection targets

The following graphs compare the optimal interconnection capacity resulting from the model[43] and the 2030 interconnection targets.





[43] Interconnection capacity reinforcements are limited to the list of projects available in [22], which means that it could be economically optimal to increase further some capacities if additional projects are proposed for specific borders.



100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
EC's target for 2030
Ratio between NTC and peak demand
AT BA BE BG CH CY CZ DE DK EE ES FI FR GB GR HR HU IE IT LT LU LV ME MK MT NL NO PL PT RO RS SE SI SK

Table 7 – Summary of EU's interconnection objectives achieving in the METIS-S1-2050 scenario

All targets are met	**1 target missed**			**2 targets missed**	**All targets are missed**
	Target (a)	Target (b)	Target (c)	Targets (b) and (c)	
AT		NO*	MT	FI	CY
BA*					DE
BE**					ES**
BG					FR**
CH*					GB**
CZ					GR
DK**					IE**
EE					IT**
HR					PL**
HU					PT
LT**					RO
LU					
LV**					
ME*					
MK*					
NL**					
RS*					
SE					
SI					
SK					

* *Non-member states*
** *Member states for which all considered projects are installed in the optimisation*

Target (a): $\frac{\text{NTC}}{\text{Prod capacity}} \geq 15\%$

Target (b): $\frac{\text{NTC}}{\text{RES capacity}} \geq 30\%$

Target (c): $\frac{\text{NTC}}{\text{Peak demand}} \geq 30\%$