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FLEXIBILITY REQUIREMENTS AND THE ROLE OF STORAGE IN FUTURE EUROPEAN POWER SYSTEMS

A 2030 AND 2050 MODELLING ASSESSMENT WITH METIS

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Contents

Abstract

The transition to a climate neutral energy system relies on an increasing share of renewable energy sources in European electricity grids. As the production of renewable energy sources is inherently variable, flexibility requirements to balance supply and demand are expected to grow in the years to come. In this work, we study the flexibility needs in the 2030 and 2050 European power system using the METIS energy system model. We find flexibility requirements to increase significantly at different timescales, with variable renewable energy output as the main driver. We identify those technologies, including storage, which may offer flexibility solutions and we assess the economic value of financial arbitrage for such flexibility technologies in the spot market. We further study, in relation to storage investment costs and available interconnection capacity, the optimal combination of electricity storage solutions to accommodate flexibility needs in future European power systems.

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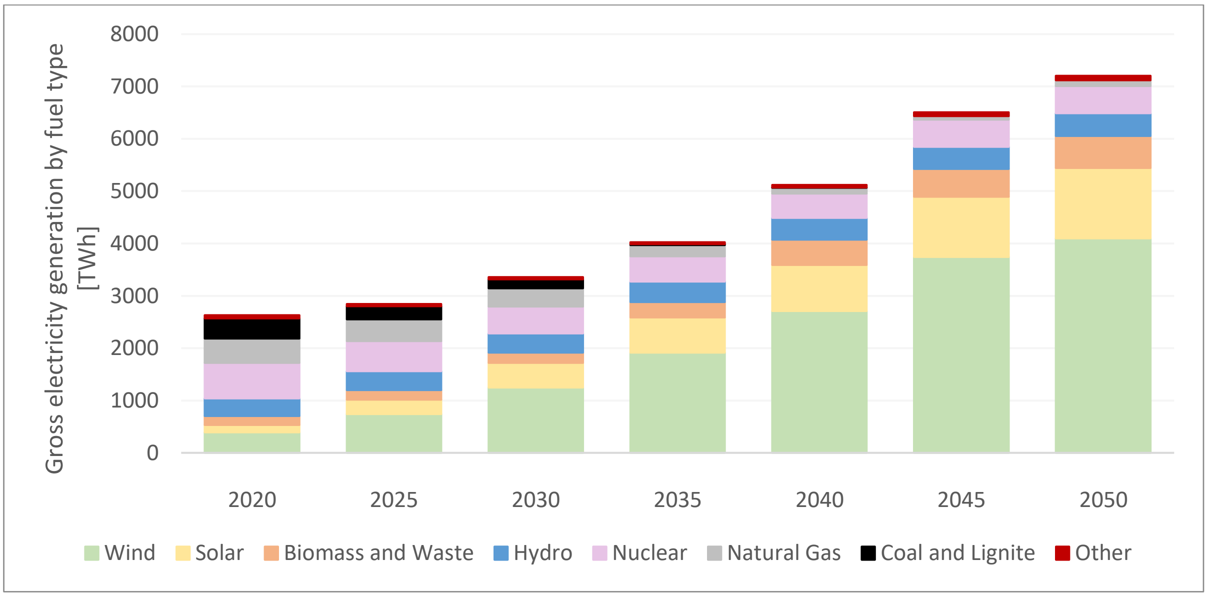
1 Introduction

In July 2021, the European Commission adopted the first Fit-for-55 package of proposals for delivering the European Green Deal, i.e. to make the EU's energy system, land use, transport sector and taxation policies fit for reducing net greenhouse gas (GHG) emissions with at least 55% by 2030 compared to 1990 levels. With the ultimate goal to reach carbon neutrality by 2050, the integration of higher shares of renewable energy plays a pivotal role in these proposals. The package of policy proposals includes an amendment of the Renewable Energy Directive to increase the target of the share of renewable energy to at least 40% of gross final energy consumption by 2030. This proposal, in line with the Energy System Integration, Hydrogen, Offshore Renewable Energy and Biodiversity strategies (European Commission, 2021a), has recently been agreed upon by the European Council (European Council, 2022)[1].

Coherent with the ambition considered in the Fit-for-55 policy proposals, three core policy scenarios have been developed to serve as common analytical tools for the impact assessments across the various policies within the context of the European Green Deal (European Commission, 2021b). This study uses the MIX-H2 scenario, which builds on top of the MIX scenario, the core policy scenario that achieves a net 55% reduction of greenhouse gases and a share of 38%-40% renewable energy sources in gross final energy consumption by 2030[2]. The MIX-H2 scenario builds on the MIX scenario by relying on a higher uptake of hydrogen in final energy demand, which implies a considerable increase of electrolyser capacity (40GW in the EU by 2030), aligned with the goals in the Hydrogen strategy (European Commission, 2020).

Figure 1 shows the gross electricity production by fuel type in the EU for the MIX-H2 scenario. The output of renewable energy sources significantly increases from 2020 to 2050, with the share of electricity from wind generation out of total gross electricity production increasing from 15% to 57% and from solar generation from 5% to 19%. At the same time, the share of fossil fuel-based power generation decreases in the next three decades, from 18% to 2% for natural gas and from 15% to 0% for coal (incl. lignite).

Figure 1: Gross electricity generation by fuel type in EU in the MIX-H2 scenario, in TWh.



Source: JRC analysis.

1 In May 2022, the European Commission announced the REPowerEU plan, with the ambition to rapidly reduce the dependence on Russian fossil fuels and fast forward the green energy transition (European Commission, 2022a). REPowerEU builds on the implementation of the Fit-for-55 proposals by maintaining the ambition of achieving at least 55% net GHG emission reductions by 2030 and envisions increasing the renewable energy target in the Renewable Energy Directive to 45% by 2030. Furthermore, it aims to reduce the EU's gas dependence at a faster pace by adding a total of 15 mt (million tonnes) of renewable hydrogen (of which 5 mt domestically produced). While we only consider the agreed upon Fit-for-55 proposals in this study, REPowerEU may thus further impact the flexibility needs in EU power systems, with increased flexibility requirements driven by the accelerated deployment of renewables and traditional flexibility technologies (e.g. gas-fired power plants) replaced by new forms of flexibility and storage (e.g. respectively electrolysers and batteries).

2 In the MIX scenario, both carbon pricing and energy policy actions are aligned to trigger investments in clean energy technologies and infrastructure.

The integration of renewable energy sources introduces more low marginal costs supply to power markets, typically undercutting conventional producers in the dispatch order of the supply stack as no fuels are needed to produce electricity. At the same time, renewable energy sources like wind and solar also introduce production profiles which are variable by nature. The combination of a decreasing supply of conventional dispatchable producers and a growing share of variable renewable energy sources (VRES) put power system operations under pressure and cause electricity prices to fluctuate heavily. Ensuring a cost-effective integration of VRES while maintaining an adequate level of security of supply therefore calls for the integration of resources, providing flexibility across the power system, from electricity generation and networks, to storage applications and demand-side response.

With variation in generation and demand profiles across different market zones, electricity interconnectors are an important provider of flexibility, allowing electricity to flow dynamically across borders. With sufficient interconnector capacity available, flexibility requirements should therefore be addressed at EU rather than MS level. Moreover, production from conventional flexible technologies (e.g. fossil fuel power stations) is increasingly replaced by production from other flexible technologies (e.g. hydropower), new storage solutions (e.g. batteries) and other opportunities (e.g. electrolysers, demand-side response and heat pumps). It is therefore key for policy makers to adequately address the associated investment and system costs of these new flexibility and storage technologies to ensure an efficient integration within a given market set-up.

In this report, we assess the flexibility requirements and solutions in the 2030 and 2050 EU power system using the METIS electricity model. We first assess the flexibility requirements at different timescales (daily, weekly and monthly). We examine the flexibility requirements in view of increasing market shares of VRES, and discuss those technologies which contribute to addressing these flexibility needs. Then, we explore the economic value of financial arbitrage in the spot market for selected flexibility technologies. Finally we assess the potential role of energy storage technologies to contribute to the flexibility needs, analysing the optimal share of storage solutions in terms of investment and system cost parameters.

1.1 Power system modelling with METIS

We model the European power system with METIS, a mathematical model simulating the operation of the European electricity system, representing each Member State of the EU and relevant neighbouring countries[3]. The model enables to optimise the future development of the electricity system from a system cost perspective, by jointly performing capacity expansion and hourly dispatch simulations.

The METIS energy model simulates the clearing of the short-term power market, using input data on installed capacities and commodity price costs, on an hourly basis over a given year. In the context of this study, the model allows us to address flexibility needs in relation to the variable nature of demand and VRES supply. Next to their variable nature, VRES is also inherently difficult to predict and this uncertainty may create profitable arbitrage trading strategies between sequential short-term markets. As the focus of METIS on a single spot market does not allow to reflect those dynamics, the results on the economic value of flexibility technologies should be considered as a lower bound, targeting flexibility needs arising from variability in production and supply rather than uncertainty in production and supply.

The context[4] developed for this report is based on the results from PRIMES, the EU energy system model that has been used to develop the scenarios for the Fit-for-55 package (European Commission, 2022b). The methodology used to build the METIS model from PRIMES data has been described in detail for 2030 by De Felice (2022). Building on this methodology, the 2050 context further presents some updates:

- The interconnector cross-border capacities of the electricity transmission grid are obtained performing a capacity expansion with the 2030 grid as baseline[5].
- The data for non-EU countries is based on the GECO 2020 1.5 scenario (Keramidas et al., 2021).
- The electricity demand is decomposed in demand for electric vehicles, demand for heat pumps and rest of power demand.

3 For more information, see energy.ec.europa.eu/data-and-analysis/energy-modelling/metis_en
4 In the METIS terminology, a "context" is a specific energy scenario consisting of input data needed for the simulation.
5 The METIS model supports both a simulation mode (optimization of the operational management) and a capacity expansion mode (joint optimization of operational management and investments).

- Electric vehicles (EVs) are modelled in two fleets optimising their charging strategy, using two different charging patterns. This allows us to study the extent to which EVs may provide power system flexibility in a 2050 system.

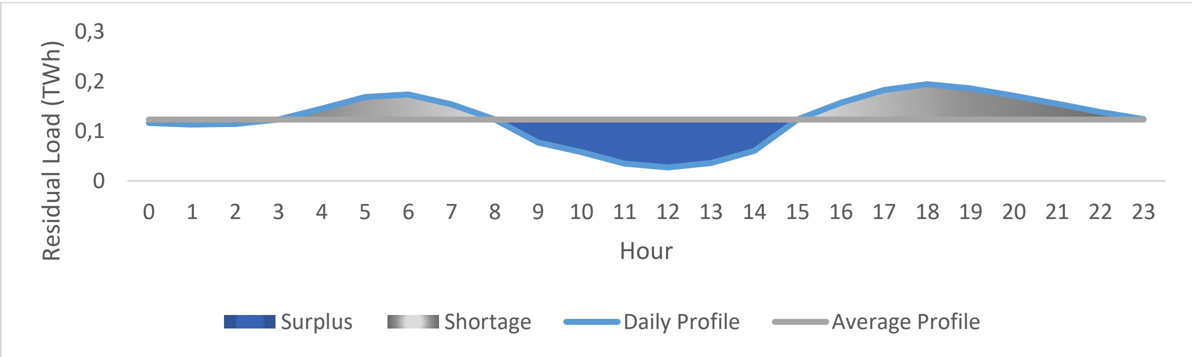
We further note that the time-series used to define the 2050 temperature, hydropower inflows wind and solar capacity factors are the same as those used for the 2030 scenario, i.e. without including any information on climate change projections.

2 Flexibility requirements

In order to accommodate a pronounced increase of VRES, European power systems need to facilitate more flexible and responsive power networks. The intermittent nature of VRES and the resulting dynamics of the residual load creates a need for flexibility ranging from short-term to seasonal time scales. Flexibility solutions will likewise be tailored to such timescales, from batteries - which may provide flexibility solutions at an (sub-)hourly timescale - to seasonal hydro storage providing flexibility at a monthly timescale. We first identify the flexibility requirements at such different timescales, and next relate to the driving factors behind.

Flexibility requirements have been estimated based on the residual load curve. This is defined as the load that can be served by dispatchable technologies (European Commission, DG Energy et al., 2019), and is derived by subtracting must-run and VRES generation from the demand curve[6]. The residual load curve indicates which part of the demand needs to be met by flexible technologies (e.g. thermal generation units, hydro-power, interconnectors, storage etc.). Figure 2 depicts the 2030 residual load curve in the EU, averaged per hour and across all Member States. We observe a peak in the morning and in the evening, in line with hours of increasing demand, and a significant drop during midday when solar PV production reduces the residual load.

Figure 2: Flexibility requirements based on average daily EU residual load curve in 2030 (MIX-H2 scenario)



Source: JRC analysis.

We define FR^T as the yearly flexibility requirements with a granularity of time *T* by[7]:

$$FR^T = \sum_T \frac{1}{2} \sum_t |RL_t - \overline{RL_t}| \tag{1}$$

Where RL_t represents the residual load at time step *t*, and $\overline{RL_t}$ the average residual load over all time steps *t* within *T*. Note that by definition, positive and negative flexibility requirements have to be equal[8]. In this report, we focus on the absolute value of these flexibility requirements, taking half of the sum of both the positive and negative requirements. In other words, the sum of the positive differences over *T* between the residual load at *t* and the average residual load over *T* renders the flexibility requirements over *T*. We sum over all timescales *T* in a year to compare flexibility requirements with a different timescale *T* over one specific year.

Given that flexibility requirements at different timescales require a variety of flexibility technologies and storage solutions to address the flexibility needs (European Commission, DG Energy et al., 2019), we study the flexibility requirements at daily, weekly and monthly timescales. Daily flexibility requirements consider the requirements over a daily timescale and hourly time steps. For example, the grey or blue areas in Figure 1, being equal by definition, both represent the daily flexibility requirements for an average day in the EU, respectively representing the positive and negative daily flexibility requirements. We note that while the size

6 Note that while curtailment of renewable energy generation may also be considered to provide flexibility by reducing production in times of excess power generation, curtailment only offers a flexibility solution to the additional flexibility needs induced by VRES themselves. In this report, we therefore only consider actual VRES generation to derive the residual load curve, in order to assess how the rest of the system will cope with the flexibility needs.

7 Flexibility requirement may also be defined by other metrics. One approach could for example be to look at the necessary ramp-up/ramp-down requirements, as with more VRES production, flexibility requirements as defined in this report could potentially also decrease, while the requirements for ramping-up and down might increase. We note that while equation (1) tends to focus on the energy volume of flexibility requirements, the modelling analysis allows us to translate this back to installed capacities.

8 Whereby we define positive (negative) flexibility requirements as the shortage (surplus) of energy, comparing the average of the residual load (representing a non-flexible base load) over timescale T with the residual load curve at time step t.

of the area indicating a shortage (grey area) and surplus (blue area) are indeed equal, the flexibility requirements do not necessarily have to be met by the same flexibility technologies. We further note that if the daily residual load curve (blue line) and its average (grey line) would be equal, no dispatchable units would be required and the demand could be met with a base load providing a constant power output.

Weekly flexibility requirements are the requirements with the timescale set at a week and the time step put to a day. This means that the average residual load over a day $\overline{RL_t}$ computed for the daily flexibility requirements serves as the residual load RL_t for the weekly flexibility requirements in equation 1. As such the weekly flexibility requirements only capture those flexibility needs on a weekly level that are not already captured by the daily flexibility requirements. Similarly, monthly flexibility requirements are the requirements at a monthly timescale with a weekly time step granularity, capturing the flexibility needs beyond those captured on weekly and daily level. As such, flexibility requirements across all timescales are mutually exclusive, i.e. a technology providing flexibility at one timescale cannot use the same capacity to provide at another timescale at the same moment.

Figure 2 shows for each member state (MS) the daily flexibility requirements, ranked in decreasing order of share of flexibility requirements out of total MS power demand in 2030. We find daily flexibility requirements to increase on average by 133% across all countries between 2021 and 2030 (MIX-H2 scenario). Germany shows the highest daily flexibility requirements for both 2021[9] and 2030 in absolute value, respectively growing from 27.4 to 52.7 TWh, while Italy experiences the largest absolute increase of flexibility requirements (33.8 TWh) between 2021 and 2030. We further observe 2030 daily flexibility requirements to vary between 4% and 17.5% of total demand between Member States. Comparing 2050 to 2030, daily flexibility requirements further increase on average by 250% in the EU. Italy experiences the largest increase with 107 TWh of additional flexibility needs, totalling 159.5 TWh in 2050. We find daily flexibility requirements to increase in all Member States for both 2030 and 2050, indicating that the foreseen developments, such as an increase in VRES in the power system between 2030 and 2050 do not correlate with the residual demand curve. Finally, we find the share of daily flexibility requirements to total demand to increase on average from 10% to 13% from 2030 to 2050 in the EU.

Figure 3 depicts the weekly flexibility requirements, ordered by the 2030 share of flexibility requirements to total MS power demand. We observe the weekly flexibility requirements to increase by 160% between 2021 and 2030. Where Germany has the highest absolute amount of weekly flexibility requirements, growing between 2021 and 2030 from 28.8 TWh to 54.9 TWh, the Netherlands experience the largest relative increase with a significant growth of 30 TWh. Between 2030 and 2050, weekly flexibility requirements increase by an additional on average 340% across the EU. Germany reached the highest flexibility needs in 2050 with 132 TWh, while France has the largest increase with an additional 83.3 TWh. Similar to the daily requirements, weekly flex requirements increase in all Member States and for both 2030 and 2050. Finally, we observe the relative 2030 share of weekly flexibility requirements to total demand to vary between 1.5% and 23%, with the volume-weighted majority between 6% and 10%. From 2030 to 2050, the EU average of this relative share increase from 8% to 11%.

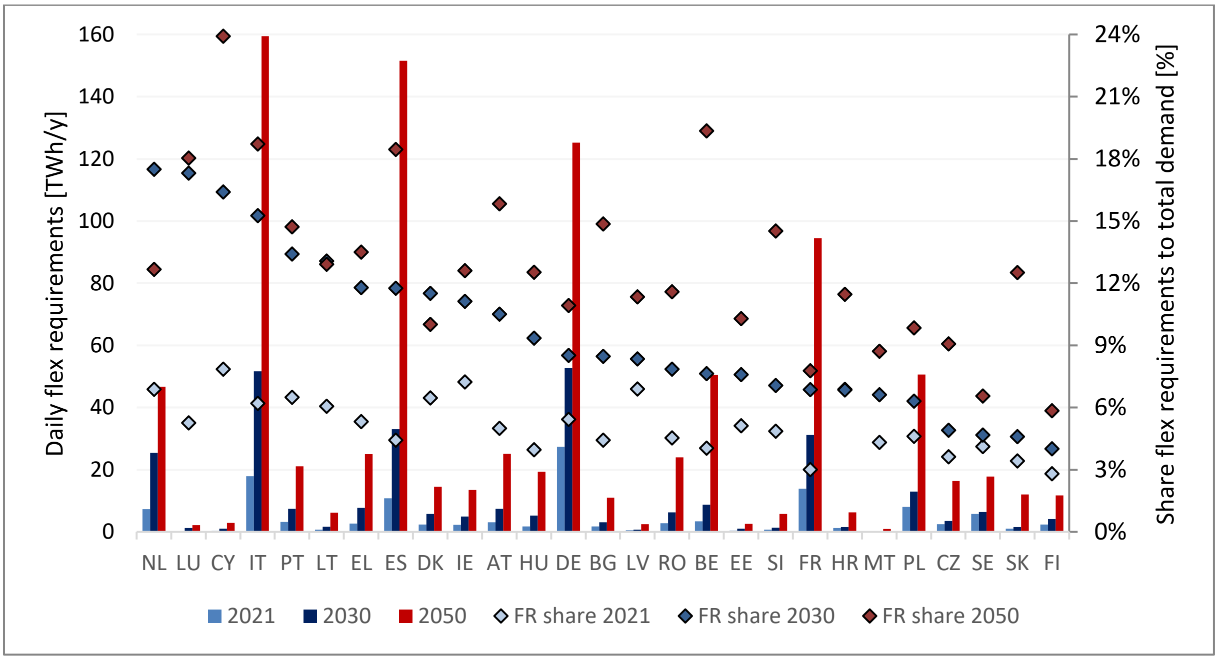
Figure 4 finally shows the monthly flexibility requirements, ordered by the share of flexibility requirements to total MS power demand. Monthly flexibility requirements grow the fastest in the next decade, nearly tripling between from 64 TWh in 2021. Germany experiences the largest growth, from 15.3 TWh to 35.5 TWh, closely followed by the Netherlands growing from 7.3 TWh to 25.4 TWh. Monthly flexibility requirements increase in all Member States except for Bulgaria, where modestly decrease from 0.7 TWh to 0.6 TWh which indicates that the developments in the power system are expected to flatten the national residual load curve[10]. Across all other Member States and timescales, the planned system developments in the next decade exacerbate the flexibility requirements. This is also the case for all Member States comparing 2050 to 2030, with monthly flexibility requirements on average across the EU increasing by 305%. While Germany experience the largest absolute monthly flexibility requirements in 2050 with 84 TWh, France experiences the largest increase from 2030 to 2050 with an additional flex demand of 53 TWh. Finally, the ratio of monthly flexibility requirements to total demand grows from 2030 to 2050 from 5% to 7%.

9 For comparison, we also use the METIS model results data for the year 2021. For a more elaborate discussion on the creation of the current context, see Kanellopoulos et al. (2022).

10 Note that Bulgaria is the only MS to experience a decrease, and only on a monthly timescale from 2021 to 2030. This indicates that during the next decade, the additional VRES correlates on a monthly timescale with the demand, resulting in a flattening of the residual load curve.

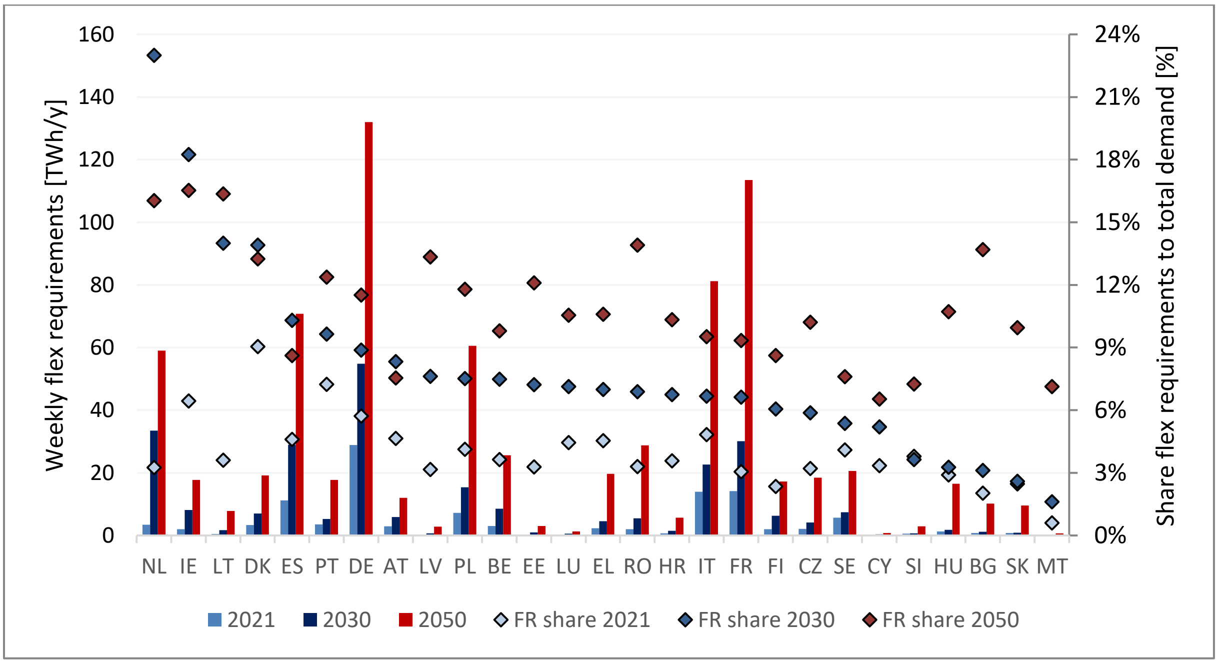
We finally note that seasonality in the demand curve may also present opportunities for very long term duration flexibility[11]. We find yearly seasonal flexibility requirements, defined as the requirements over a yearly timescale with monthly time step, to increase from 154 TWh in 2030 to 336 TWh in 2050.

Figure 3: Daily flexibility requirements in 2021, 2030 and 2050, ordered by 2030 flexibility requirements share to total demand (FR share).



Source: JRC analysis.

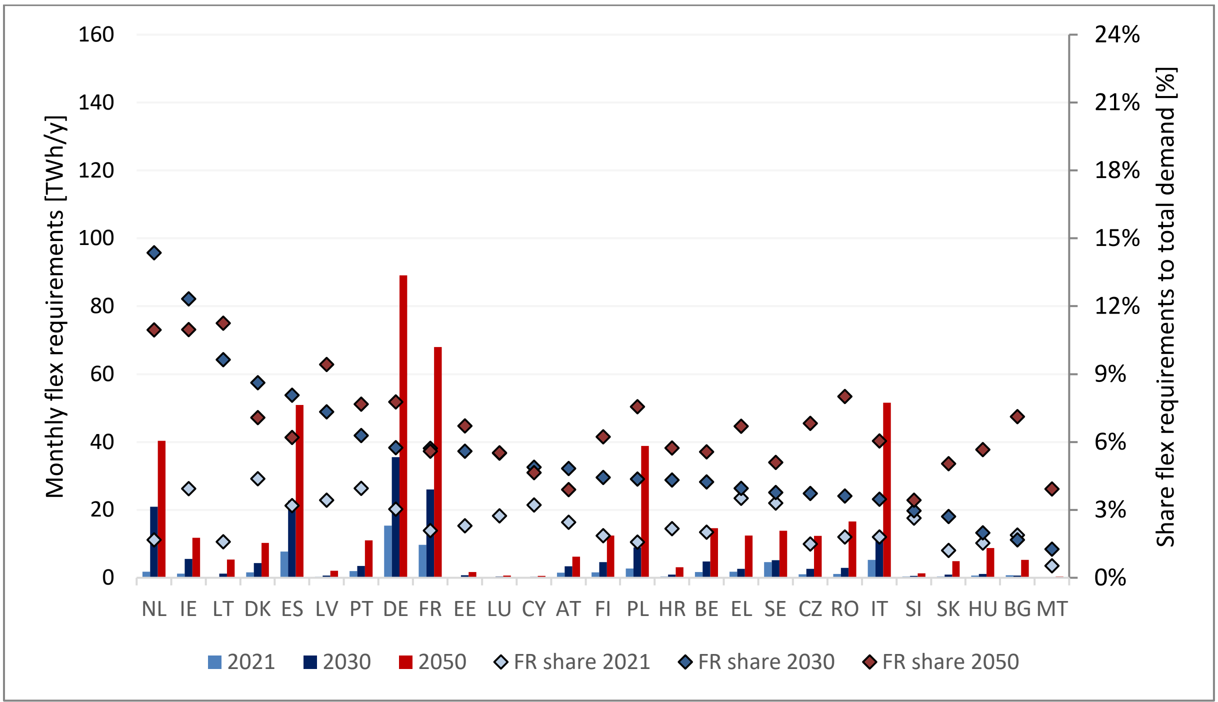
Figure 4: Weekly flexibility requirements in 2021, 2030 and 2050, ordered by 2030 flexibility requirements share to total demand (FR share).



Source: JRC analysis.

11 While seasonality, i.e. seasonal variations in the demand profile, is typically not considered in flexibility assessments due to high associated costs for such long term flexibility solutions, we report the yearly flexibility requirements here to provide a complete picture of all flexibility needs within a given year compared to a fixed yearly baseload.

Figure 5: Monthly flexibility requirements in 2021, 2030 and 2050, ordered by 2030 flexibility requirements share to total demand (FR share).



Source: JRC analysis.

Comparing the flexibility requirements across the three timescales, some Member States stand out. In 2030, the Netherlands, with the largest relative MS share of wind to total demand in 2030, experiences the highest flexibility requirements relative to the total demand on all three timescales. In 2050, the picture is more dispersed, with next to the Netherlands, also Ireland and the Baltic States ranking high in terms of the relation between flexibility requirements to total demand. We find however that the relative share of flexibility requirements for these countries may only increase slightly or even decrease between 2030 and 2050, while countries with a relative low share of flexibility requirements to total demand may see a more pronounced increase of that share moving towards 2050. This is mainly driven by the rate of deployment of VRES relative to total demand from 2030 to 2050 and highlights variations between MSs on the extent to which the uptake of VRES aligns with the changing dynamics of the residual load.

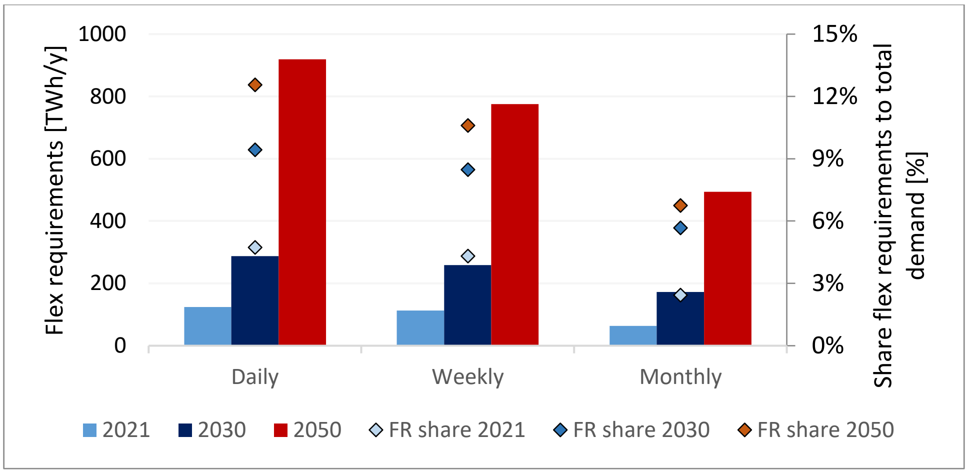
Figure 6 compares the flexibility requirements across the three different timescales across the EU. We observe daily flexibility requirements to be the largest in 2030 with 288 TWh compared to 258 TWh on a weekly and 173 TWh on a monthly basis. In 2050, these flexibility requirements respectively increase on EU level to 919 TWh, 775 TWh and 494 TWh. We further observe that while the increase in absolute terms of the flexibility requirements from 2021 to 2030 may be more modest than from 2030 to 2050, the former represents a much larger increase in the relative share of the flexibility requirements to total demand. This signals that towards 2030 the increase in flexibility requirements may be largely driven by technological advancements endogenous to the power system, while thereafter the increase in flexibility requirements is more in line with an increase proportional to the growth in electricity demand.

Figure 7 and Figure 8 finally portray the distribution of the summed positive and negative flexibility requirements in the EU in 2030, from an hourly and monthly perspective[12]. In Figure 7, we observe daily flexibility requirements to experience a morning and evening peak, driven by the positive flexibility requirements, as indicated in Figure 2, and a more pronounced midday peak driven by the negative flexibility requirements, also indicated in Figure 2. Note that by definition, weekly and monthly flexibility requirements would be equal across all hours of the day. In Figure 8 we observe that weekly and monthly flexibility requirements experience a seasonal shape, experiencing the highest share in the winter months. The figure shows that this EU average varies across Member States, plotting also the monthly flexibility requirements for

12 Taking the absolute value of the flexibility requirements allows us to capture some of the important distribution characteristics of both positive and negative flexibility requirements, which would be lost when averaging the actual values.

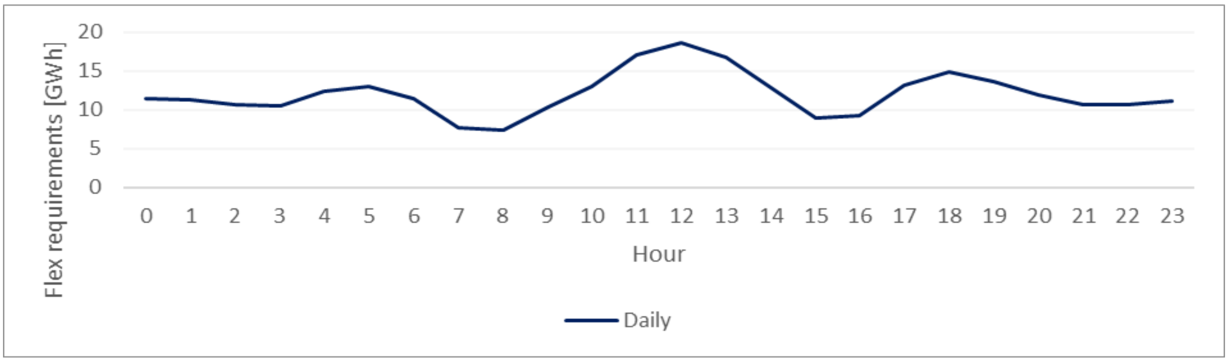
Germany and Italy[13]. First, Germany experiences pronounced winter peaks in its flexibility requirements, mainly related due to the German seasonal pattern in wind generation. Second, Italy has relatively little seasonal variation in its monthly flexibility requirements, although a moderate increase during summer months is observed, mainly related to the respective considerable amount of Italian solar generation.

Figure 6: Daily, weekly and monthly flexibility requirements and their share to total demand (FR share) in the EU for 2021, 2030 and 2050.



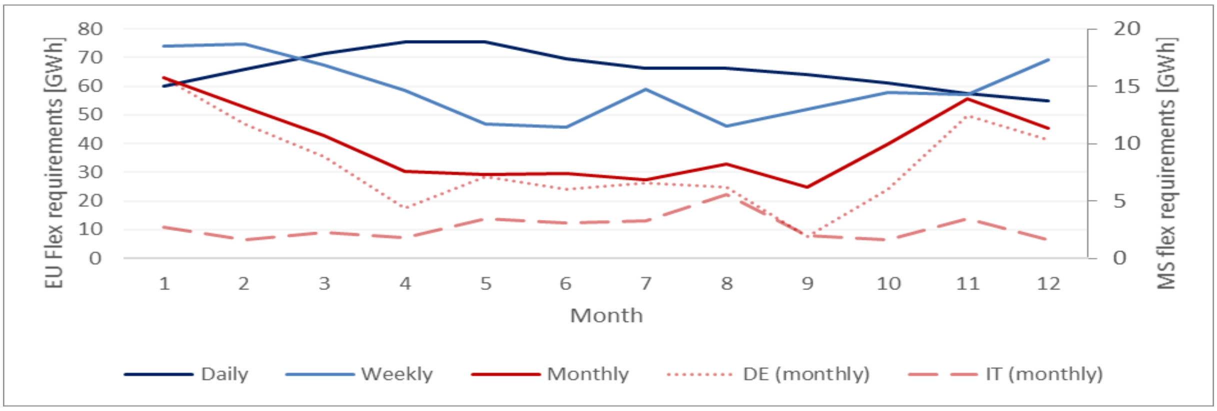
Source: JRC analysis.

Figure 7: Average hourly summed (positive and negative) flexibility requirements in the EU in 2030.



Source: JRC analysis.

Figure 8: Average monthly summed (positive and negative) flexibility requirements in the EU (solid), Germany (dotted) and Italy (dashed) in 2030.

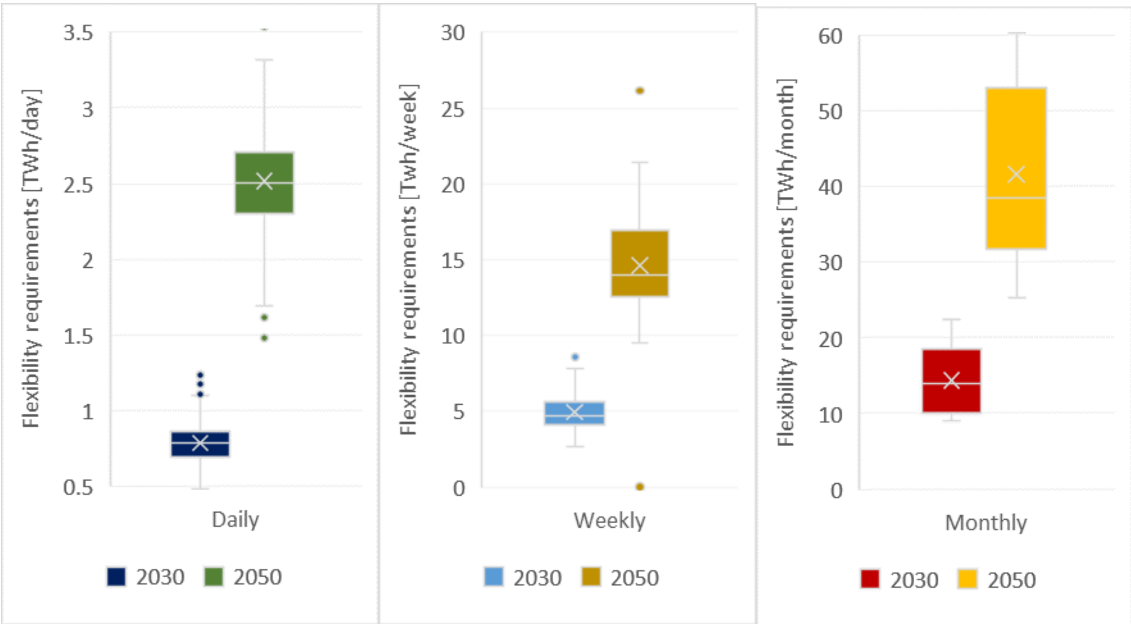


Source: JRC analysis.

13 For illustration purposes, we report the two Member States with the largest solar and wind production relative to the country's market zone demand in 2030, respectively Italy with 30% solar and Germany with 50% wind production, of the major EU economies (power demand > 200 TWh/year).

We finally examine the distribution of the EU flexibility requirements within a given year, i.e. the distribution of all the individual flexibility requirements at timescale *T* before yearly summation[14]. Figure 9 shows distribution boxplots of the daily, weekly and monthly flexibility requirements throughout the year in 2030 and 2050 across all MS. In 2030, we find EU averages of 0.79 TWh/day, 4.93 TWh/week and 14.39 TWh/month for respectively the daily, weekly and monthly flexibility requirements. For 2050, these numbers significantly increase to respectively 2.52 TWh/day, 14.6 TWh/week and 41.68 TWh/month. We observe flexibility requirements to express a wider distribution when moving from daily to monthly flex requirements, with a relatively larger interquartile range compared to the value of flexibility requirements. However, outliers are more present for the daily flexibility requirements, as extreme spikes are averaged out for longer timescales due to increased time step granularity. Finally, interquartile ranges are much wider in 2050 than for 2030, which may result in higher complexity for dimensioning flexibility solutions addressing the maximum respective flexibility requirements.

Figure 9: Boxplots of EU daily, weekly and monthly flexibility requirements distribution per respective timescale, in 2030 and 2050.



Source: JRC analysis.

2.1 Flexibility requirements and renewable energy

We study the relation between flexibility requirements and (the share of) renewable energy sources ceteris paribus via two different approaches. First we explore the individual flexibility requirements of MSs in relation to their national share of VRES. For each of the daily, weekly and monthly timescales, the dots in Figure 10 and Figure 11 each represent one MS. As such the figures display the relation between flexibility requirements and the share of VRES across different EU energy systems, allowing us to study the relation of flexibility requirements to VRES with a variation of underlying fundamentals energy system parameters.

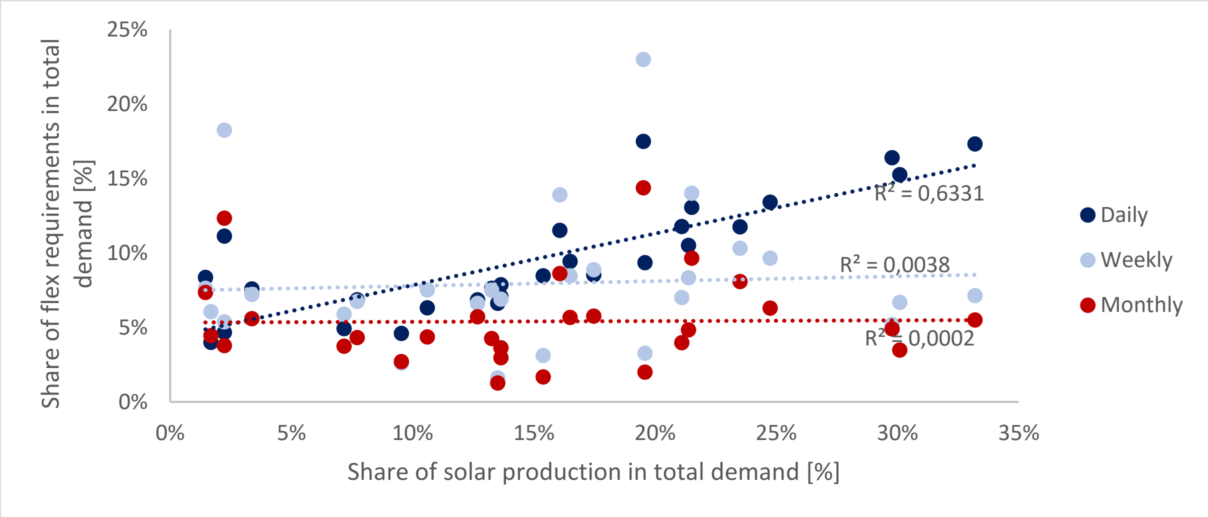
Figure 10 shows the relation between flexibility requirements and the share of solar PV production in total demand. When fitting a linear function, no direct relation can be found with the weekly and monthly flexibility requirements, but R^2 statistics suggest an adequate fit for the daily flexibility requirements. This is in line with expectation, as solar PV production follows a pronounced daily production curve. We further find that any seasonal variation in solar production does not significantly translate back into a shift in monthly flexibility requirements, possibly related to the dominance of the former effect.

Figure 11 shows the relation between flexibility requirements and the share of wind production in total demand[15]. Contrary to the relation of flexibility requirements to solar PV production, the relation of wind production to the flexibility requirements relates much more to the long term flexibility timescales. Fitting

14 In practice, we thus examine the distribution of 365 daily, 53 weekly and 12 monthly flexibility requirements per respective year.
15 Electricity production with wind includes both onshore and offshore wind production.

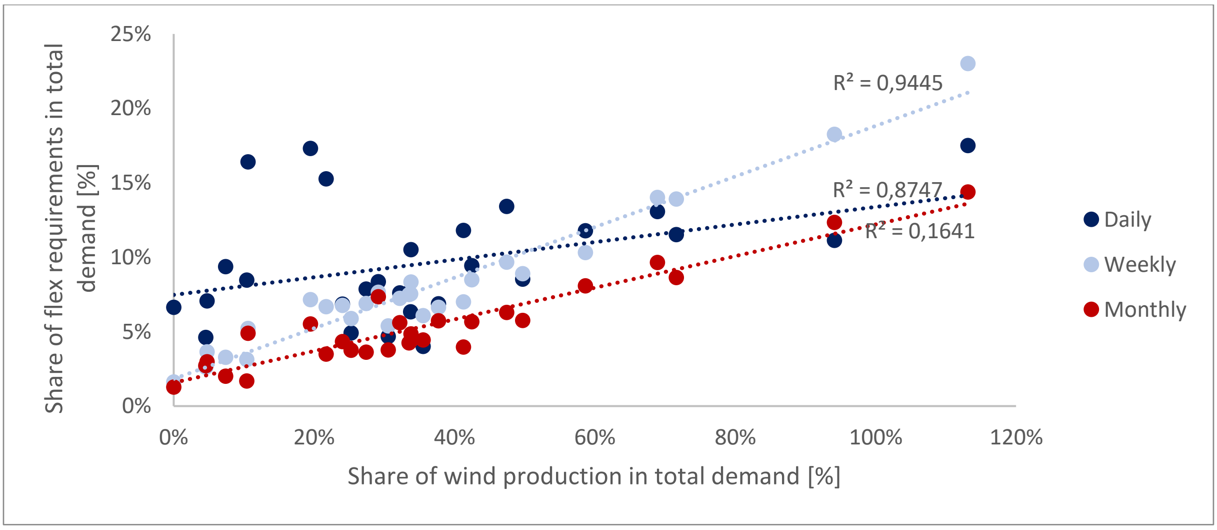
again a linear function to the data, the trend lines suggest a linear increase of the weekly and monthly flexibility requirements with an increasing share of wind production. The relation with daily flexibility requirements is less obvious. This is in line with expectation, as wind production follows clear seasonal patterns (Guerra et al., 2020), and the effect on monthly flexibility requirements propagating into the weekly requirements. As such, we find evidence for a relation between the time-depending production patterns, like seasonality, and the flexibility requirements at the corresponding timescale.

Figure 10: Share of daily, weekly and monthly flexibility requirements in total demand in relation to share of solar production in 2030. Dots represent EU Member States, dotted lines are timescale trend lines.



Source: JRC analysis.

Figure 11: Share of daily, weekly and monthly flexibility requirements in total demand in relation to share of wind production in 2030. Dots represent EU Member States, dotted lines are timescale trend lines.

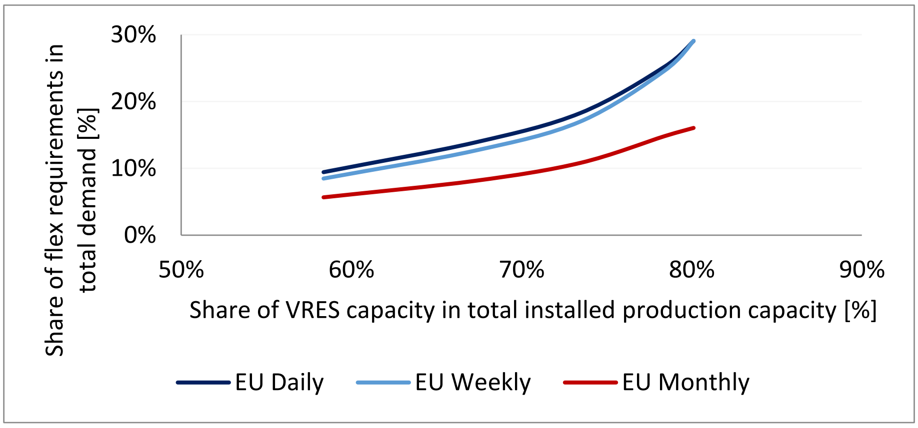


Source: JRC analysis.

Next, we study the effect of VRES on flexibility requirements by increasing the share of VRES across the EU under ceteris paribus conditions. While such a high degree of control allows us to isolate the effect of VRES on flexibility requirements, one has to bear in mind that in reality this would distort the equilibrium in energy systems, resulting in an adaptive shift in underlying production technologies. With an increasing share of VRES, some fossil fuel fired power stations would be dispatched fewer hours, become unprofitable and eventually be closed while other technologies might just become more profitable, triggering investment decisions. Nevertheless, when only focusing on the flexibility requirements, the analysis gives an indication to which extent the system is able to cope with such an increasing share of VRES.

Figure 12 shows the relation between EU flexibility requirements and the share of VRES capacity out of total installed capacity in the EU. We thereby vary per MS the production of solar PV and wind production in lustrum steps of installed capacity in the MIX H2 scenario up to 2050. In other words, all other input parameters being equal, we transpose the future EU installed capacity of VRES on the 2030 EU power system. The figure indicates that with more VRES installed, the flexibility requirements increase. These findings are in line with European Commission et al. (2021). The increasing trend seems to accelerate for the daily and weekly flexibility requirements, with the inflection point for the EU around a VRES capacity share of 74% to total installed capacity, related to the inability of the 2030 power system to cope with the sharp increase of VRES of the following decades. We note that the relative performance of the above finding may vary across different Member States.

Figure 12: Share of daily, weekly and monthly flexibility requirements in total demand in relation to increasing share of VRES capacity in total installed production capacity in the EU.



Source: JRC analysis.

2.2 Storage solutions and technological contributions

We conclude this chapter by studying which technologies contribute to addressing the flexibility requirements. These technologies include dispatchable units, which are able to adjust generation flexibly to satisfy the residual demand, as well as storage, interconnectors and demand-side management technologies[16]. In order to find the individual contribution of each technology, we subtract the net generation of that specific technology from the residual load curve. We then calculate the difference in flexibility requirements with the normal residual load curve to find the contribution of that specific technology[17]. We update equation (1) to:

$$FR^{T,i} = \sum_{T} \frac{1}{2} \sum_{t} |RL_t - \overline{RL_t}| - \sum_{T} \frac{1}{2} \sum_{t} \left|(RL_t - P_t^i) - (\overline{RL_t - P_t^i})\right| \quad (2)$$

Whereby $FR^{T,i}$ represents the contribution of technology *i* to the flexibility requirements at timescale *T*, and the production of technology *i* at time step *t,* and P_t^i the production of technology *i* at time step *t*. Note that by definition, equation 2 indicates the non-additivity of different technologies to the total flexibility requirements. In other words, the sum of the individual contribution of the production of different technologies to the flexibility requirements may differ from the contribution of the sum of the production of those technologies. Whether this difference is higher or lower relates to the correlation between the individual contributions of the technologies to the flexibility requirements.

Figure 13 shows the contributions of the main flexible technologies to the flexibility requirements in the context of our study for the EU, Germany and Italy. We find that interconnectors are one of the main sources offering flexibility, mainly as imports and exports vary according to MS specific flexibility needs. Their relative contribution increases for the EU from 15% for the daily requirements to 33% for the monthly requirements, signalling the important role of interconnectors in dealing with longer duration flexibility. Short-term storage technologies like batteries also offer a considerable contribution to relieve the daily flexibility requirements, but much less to neglectable for the weekly and monthly requirements. While pumped hydro storage (PHS)

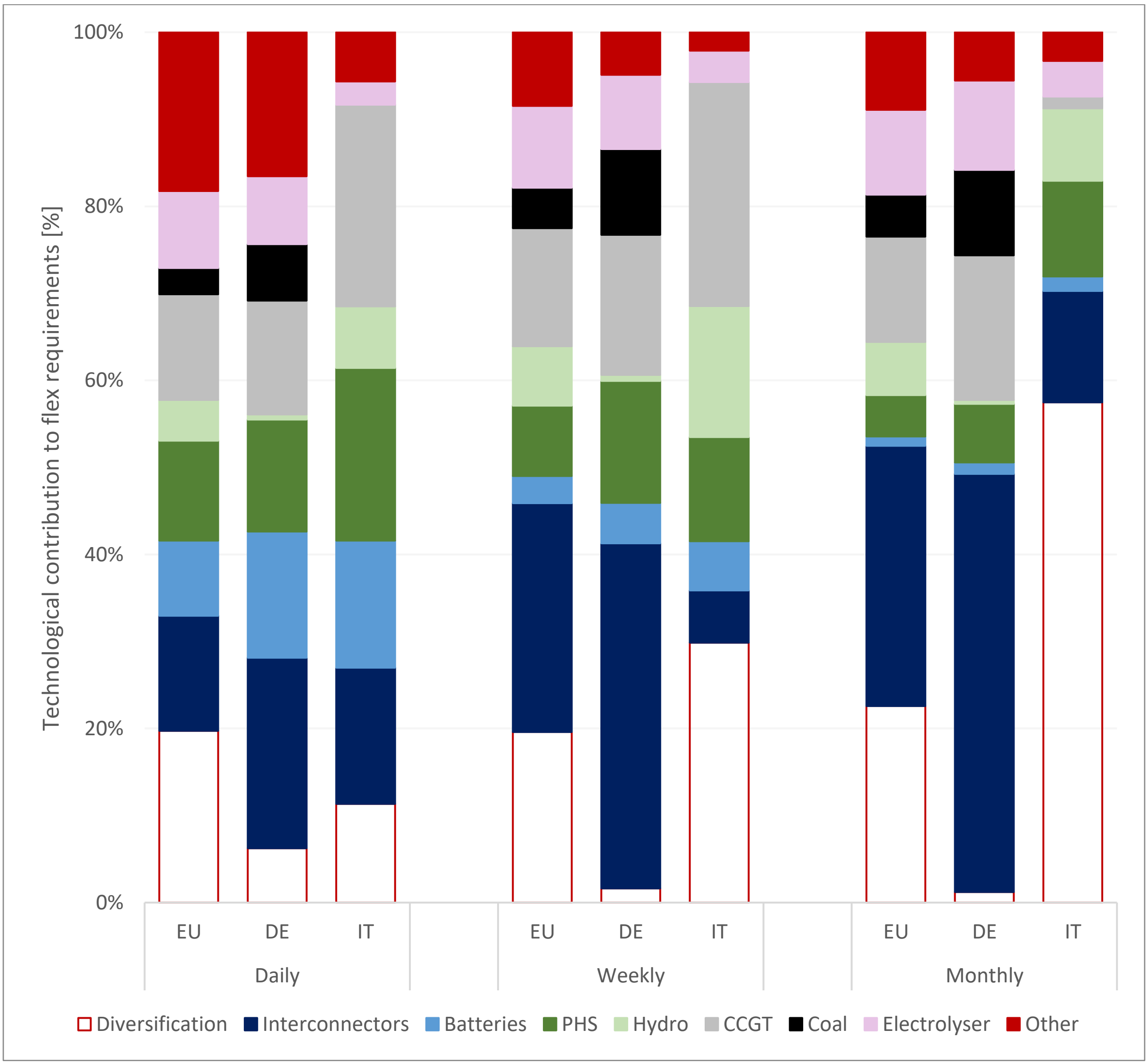
16 Note that CAPEX and OPEX costs are important parameters for the model to dispatch a specific technology. Further accelerated cost reductions, compared to today's projections may thus create opportunities for alternative technologies to provide flexibility solutions.

17 Note that the net generation of a specific technology, and thus also its contribution to the flexibility requirements, as such depends on underlying fundamentals (e.g. fuel prices, technology availabilities, climatic variables, etc) in the energy system.

provides similar flexibility benefits to the system on a daily timescale as batteries, PHS also plays an important role in providing longer-term flexibility solutions on a weekly and monthly timescale. From the thermal generation units, mainly Combined Cycle Gas Turbines (CCGT) contribute in addressing the flexibility requirements, doing so across all timescales. Finally, electrolysers provide a considerable contribution to the flexibility requirements on EU level, consistently addressing 10% of the flexibility requirements across all timescales. The combined role of other technologies, like for example Open Cycle Gas Turbines (OCGT), oil- and biomass-fired power plants, only seems to be of limited importance in addressing the daily flexibility requirements.

We finally note that the diversification effect may compose a significant share of the contribution to the flexibility requirements. Diversification is the effect where the contribution of two technologies to the flexibility requirements are not independent from each other, as the contribution of the sum of different technologies may outperform the contribution of the sum of the individual technologies. We interpret this result by noting that where one individual technology not necessarily addresses the full flexibility requirements on itself, the interplay between different technologies ensures an adequate contribution in meeting the necessary flexibility requirements. We expect this effect to be more pronounced in MS that export a significant amount via interconnectors, as price dynamics may stimulate to contribute to a neighbouring country's flexibility requirements.

Figure 13: Technological contribution to flexibility requirements in the EU, Germany and Italy, 2030.

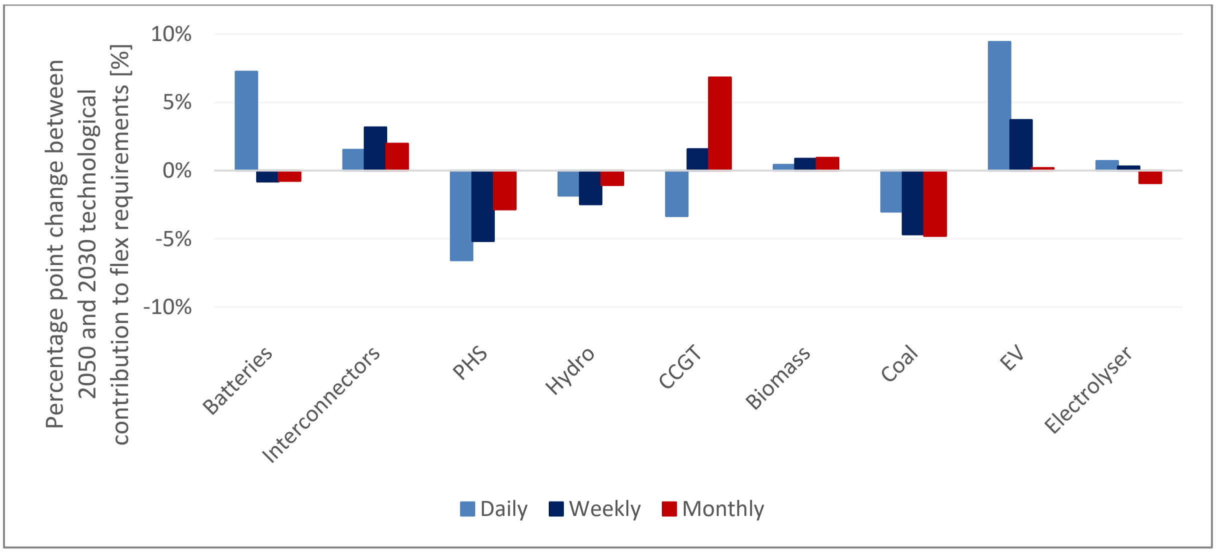


Note:. PHS: Pumped Hydro Storage, CCGT: Combined Cycle Gas Turbine

Source: JRC analysis.

We next compare these 2030 results with the technological contribution to flexibility needs in 2050. Note that, as indicated in section 1.1, the 2050 model includes a number of updates compared to the 2030 model[18]. Figure 14 reports relative changes in technological contributions to the flexibility requirements in percentage point, between 2050 and 2030. Focusing on the main changes, we first find that the role of batteries increases significantly by 2050 for addressing short-term daily flexibility needs. This is mainly related to the pronounced increase in absolute flexibility needs, as well asthe decreased installed capacity of conventional technologies compared to 2030. Second, with increasing flexibility requirements towards 2050 and the potential to expand PHS limited in the EU by geographical constraints, PHS becomes relatively less important in 2050. Third, biomass and biogas fired power stations largely replace respectively coal and natural gas fired electricity generation (cf Figure 1).By 2050, our model indicates that CCGT plants supply less daily but more weekly flexibility requirements, mainly addressing flexibility needs during anticyclonic gloom weather conditions. Finally, we find an important role for EVs to provide flexibility in 2050, mainly for shorter time durations.

Figure 14: Percentage point change of the technological contribution to flex requirements between 2050 vs 2030.



Note:. PHS: Pumped Hydro Storage, CCGT: Combined Cycle Gas Turbine, EV: Electric Vehicle

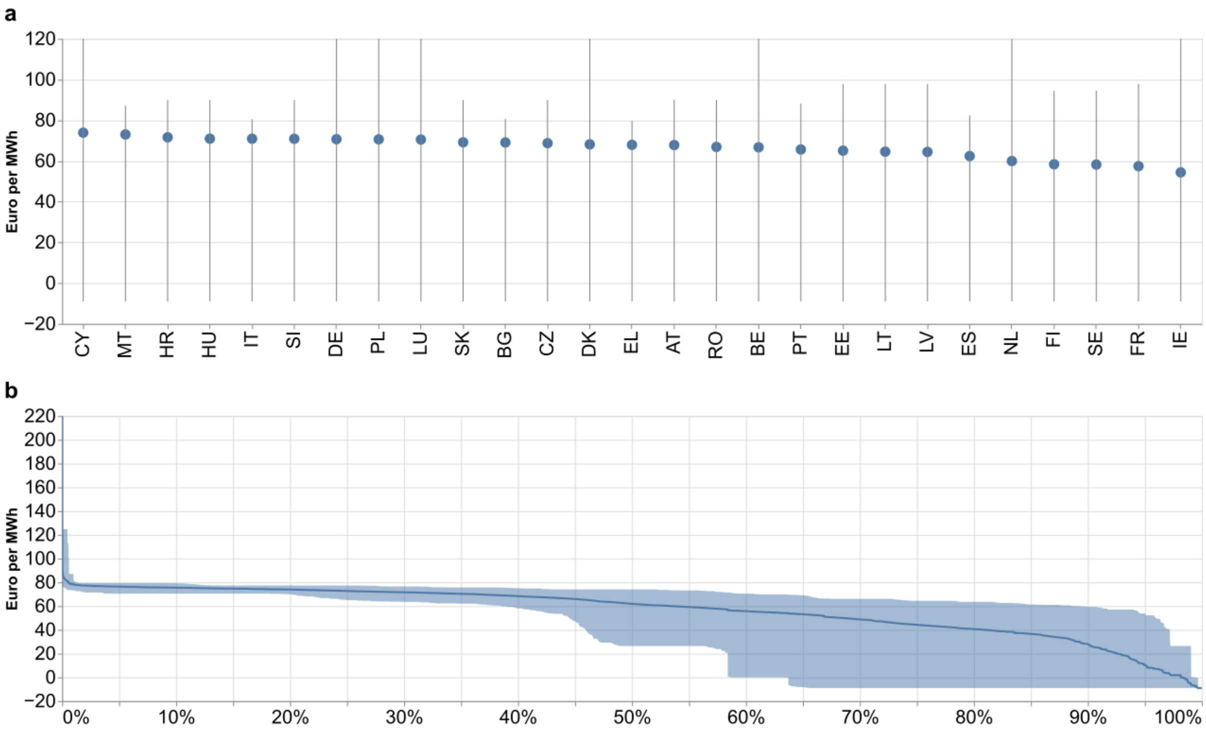
Source: JRC analysis.

18 These specific updates entail a number of cost and strategy assumptions, which may reduce the accuracy of the results.

3 Spot market value of flexibility technologies

From an economic point of view, flexibility requirements present an incentive for flexible technologies to benefit from arbitrage trading strategies. We limit ourselves in this chapter to assessing the well-known value of arbitraging price differences in a single (spot) market at different delivery times (Zhou et al., 2016), given the scope of the METIS model[19]. While the modelled spot market resembles the reference market for wholesale power trading, price differences in sequential power markets[20], arising from risk sharing over spot uncertainty, may also provide investment incentives and trading opportunities for flexibility and storage technologies (Koolen et al., 2022). The findings in this chapter should as such be considered as a lower bound, targeting the economic value of flexibility technologies on the basis of market price variability rather than market price uncertainty.

Figure 15: Electricity prices in the MIX-H2 scenario in 2030. In panel a, circles denote demand-weighted average prices and error bars denote ranges. In panel b, the blue-shaded area denotes the price range of price-duration curves across market zones and the solid blue line denotes the corresponding mean.



Note:. In panel a, price levels beyond 120 EUR per MWh are not displayed for better visibility and error bars are clipped. For those zones maximum price level corresponds to 727 EUR per MWh during a few hours of the year.

Source: JRC analysis.

Building on the flexibility requirements assessment and the contribution of different technologies in the previous chapter, we study the day-ahead spot market arbitrage value that can be earned by two selected storage technologies in 2030, i.e. lithium-ion batteries and pumped-hydro storage[21], and put that into perspective by comparing it to other generation and flexibility assets in the electricity market. Panel a of Figure 15 provides an overview of the electricity price levels across the different modelled market zones, where the blue circles denote the demand-weighted average prices and the error bars the min-max-ranges. Demand-weighted average prices across market zones broadly fall into a range between 55 EUR per MWh to 80 EUR per MWh. These present a significant downward trend compared to the first half of 2022, during which prices have been elevated due to the ongoing energy crisis. We attribute the difference with our 2030

19 The energy economics literature typically refers to the day-ahead market as the spot market, as it is the most liquid market to close positions (Koolen et al., 2022).

20 The price difference between the forward and spot market is called the forward risk premium, typically reflecting risk preferences over spot uncertainty of market agents. Other factors such as limited arbitrage, trading inefficiencies and strategic behaviour further also play a role in the emergence of the forward premium (Koolen et al., 2021).

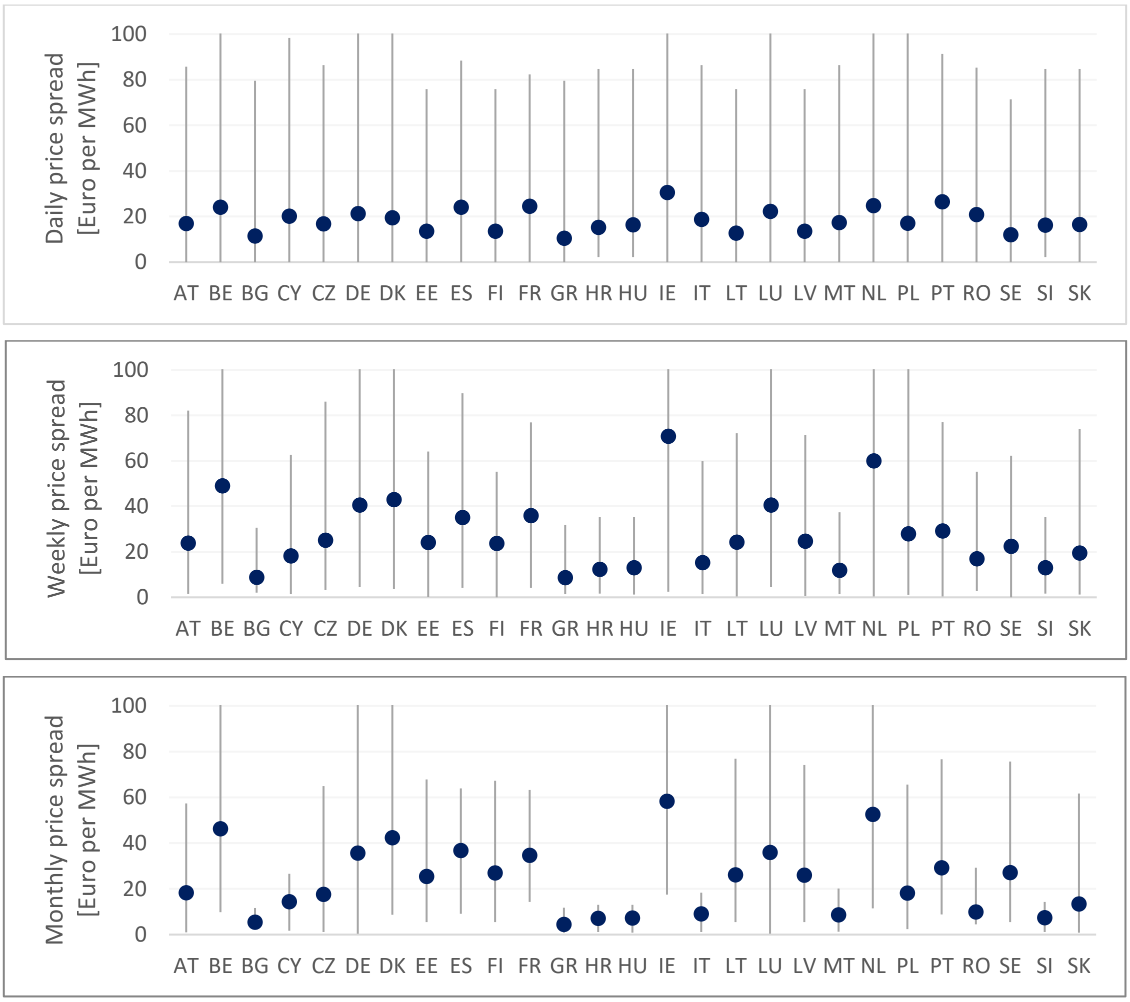
21 Since we consider these two technologies mature enough and different enough to provide a broad picture of the contribution of energy storage technologies.

model to, inter alia, lower fuel price assumptions for thermal power plant fleets and higher shares of variable renewable generation.

A general overview of the occurrence of diverging price levels can be provided by price-duration curves, which are plotted as the range (blue area) and mean (blue solid line) across all market zones in panel b of Figure 15. The plot reveals a slim tail with elevated prices at the left end of the distribution and a relatively narrow price band in the 60-80 EUR per MWh range, stretching over roughly 50% of the time-duration. While the lower price levels at the right tail of the distribution provide opportunities for arbitrage trading strategies, these are not necessarily divided equally across Member States as the higher price range suggests a divergence in price-spreads across market zones.

Figure 16 illustrates the price spread distribution on the daily, weekly and monthly timescale. Price spreads are calculated as the difference between the maximum and minimum market price on the respective timescale. Note that for the weekly price spreads, only average daily prices are taken into account to disregard any price differences already captured at the daily level. Similarly, monthly price spreads indicate the difference between the maximum and minimum weekly price per month. We find daily price spread distributions to vary the most across Member States, with an EU average close to 20 EUR per MWh but maximum values ranging well beyond 80 EUR per MWh. While the average weekly and monthly price spreads are higher, averaging both around 25 EUR per MWh, the distributions become narrower as price spikes leading to extreme price spreads are captured at the daily level.

Figure 16: Daily, weekly and monthly spot price spreads per MS in 2030. Circles denote average demand-weighted price spreads and error bars denote spread ranges.



Note: For illustration purposes, only the spread range between 0 and 100 Euro per MWh is visualised. Spreads above 100 Euro per MWh can be considered outliers.

Source: JRC analysis.

How these hourly price levels are factored into market values depends on the technology-specific generation profiles. We derive net market values per technology by subtracting operational costs from the market revenues. Besides underlying fuel and emission costs, note that for storage technologies, these also include the electricity consumption expenditures for charging. We next compare the net market values with their annualised capital expenditures to estimate profitability ranges per technology. Capital expenditures and technology parameters are derived from the technology assumptions provided for the EU Reference Scenario 2020 (European Commission et al., 2021) and are converted to annualised cost projections for 2030. For storage technologies, these parameters have been complemented and validated through expert assessments provided by the ENTEC consortium (ENTEC, 2022) as well as the work by Schmidt et al. (2019).

The net market values resulting from the modelling and annualised cost ranges are displayed in Figure 17 on the primary vertical axis denoted in EUR per kW. The division of the net market value by the range of annualised costs yields the profitability range displayed on the secondary vertical axis, where a ratio greater or equal to 100% generally indicates full cost recovery and therefore the day-ahead spot market profitability in a given year. We note that the findings are resulting from commodity price assumptions that seem reasonable in the mid-term, but are considerably lower than current price levels. If the price hike in commodity prices observed in 2021 and 2022 persist, the market value for storage technologies would also significantly increase.

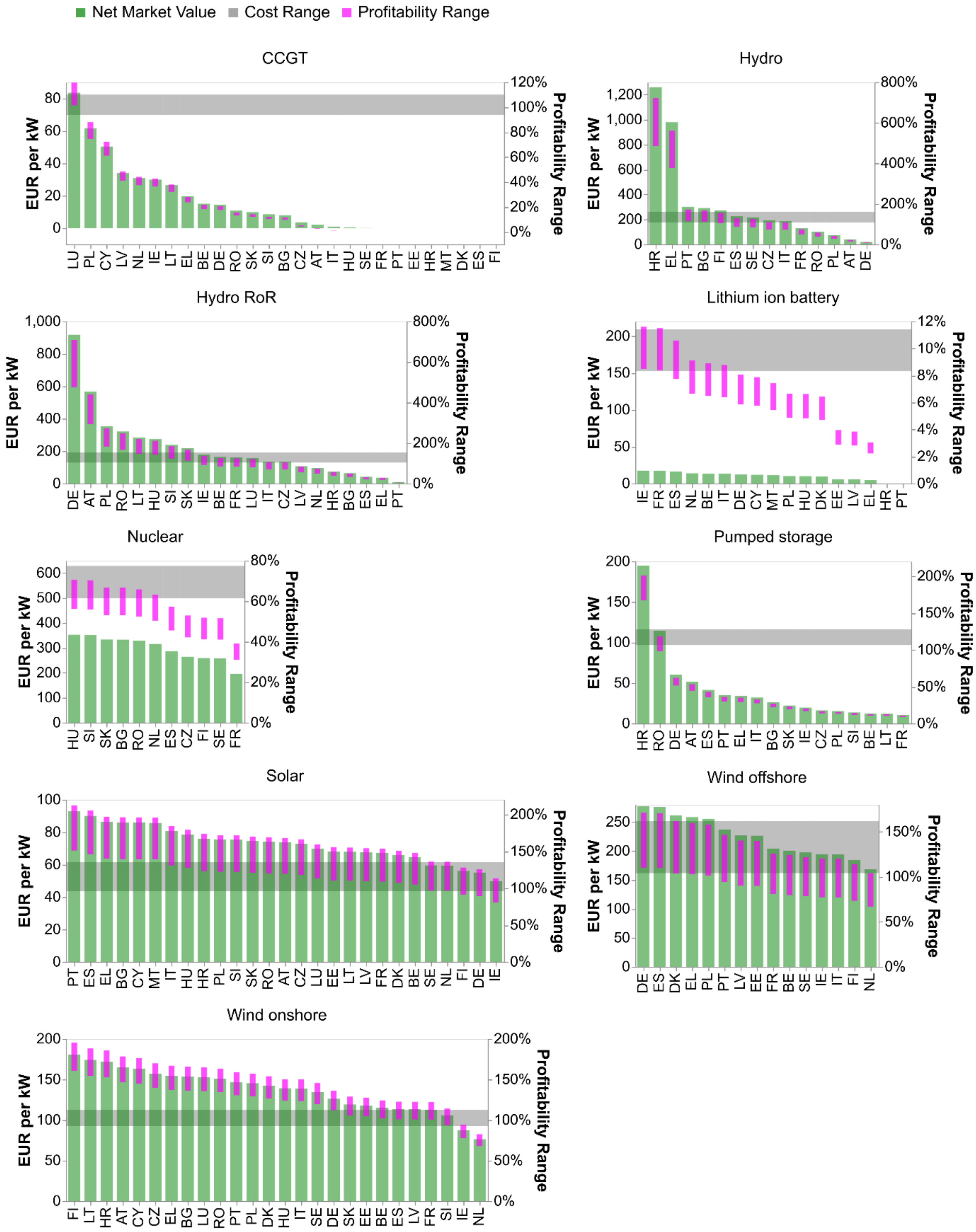
The results should be interpreted in view of the fact that empirically observed price volatility and price mark-ups/opportunistic bidding cannot be (fully) captured by the applied modelling framework, as it does not allow us to capture sequential forward and spot market dynamics[22]. This means that the obtained market revenues, in particular of storage technologies, resemble a lower bound. First, the versatility of storage technologies enables them to provide services and thus gain revenues in addition to energy arbitrage on the day-ahead spot market, allowing partially for revenue-stacking across a range of forward and spot markets. For instance in a survey conducted by ENTEC (2022), service providers of electrochemical storage indicate that at present, revenues from ancillary service markets account for more than half of their revenue streams. Moreover, it excludes profits arising from forward market premiums by exploiting arbitrage trading strategies between forward and spot markets. The results thus represent the economic value of flexibility technologies due to the variability in the residual load curve, rather than the uncertainty in the residual load curve. Finally, further important applications could include grid services or behind the meter customer energy management.

As can be seen from the panels of Figure 17, technologies reveal heterogeneity in terms of their profitability, both across technologies and market zones. In particular, renewable-powered wind and solar technologies reach profitability in a broad set of market conditions. Renewable-powered hydro fleets exhibit a significantly higher variability owing to their inflow patterns, but in general perform broadly favourably in terms of profitability. The nuclear power fleet, being situated in the mid-merit order, achieves profitability ranges in the order of 40%-70%. For the CCGT fleet, the profitability range differs strongly depending on the specific market situation; notably, except for Baltic countries, the zones with the highest profitability ranges for CCGT all experience a limited set of price spikes (cf. Figure 15).

For the two considered storage technologies, the 2030 profitability ranges based on spot market revenues only appear most challenging. For the lithium-ion battery fleet, the profitability range broadly falls into a bandwidth of 3-12%, whereas for the pumped-storage fleet, it looks in comparison more favourable and diverse. The pumped-storage fleets situated in Croatia and Romania exceeding a profitability range of 100% are based on open-loop systems and thus benefit from the patterns of water inflows. In general it can be ascertained that both lithium-ion battery and pumping storage fleets tend to realise comparatively higher profitability ranges in market zones (e.g. Iberian peninsula and central western Europe) with higher shares of VRES and thus higher flexibility requirements (compare e.g. Figure 1).

22 Note that a gap to profitability may persist, even after accounting for sequential market dynamics, due to the model assuming the market only captures short run marginal costs.

Figure 17: Cost ranges and spot market values for specific technologies in 2030 (left-hand axis), representing a lower bound for technological profitability ranges (right-hand axis).



Note:. Net market values are derived as producer surplus from modelling the MIX-H2 scenario with the METIS model and normalised by installed capacity of each technology fleet type. Cost ranges are derived on technology (sub-type) cost assumptions reported for 2030 by the 2020 EU Reference scenario (citation) and complemented by further technology parameters provided by the ENTEC study and www.EnergyStorage.ninja, as well as own assumptions. Conversion to annualised parameters is based on the reported lifetime and WACC values (7.5%-8.5% range).

Profitability ranges are based on (single) spot market values only. For storage technologies, this thus excludes gains from financial arbitrage at forward, intraday or balancing markets as well as gains from arbitrage strategies between such sequential markets.

Source: JRC analysis.

4 Optimising electricity storage in the 2030 EU power system

We next investigate the optimal electric storage fleet in the 2030 European power system. The METIS power system model allows to solve capacity expansion problem, i.e., an optimisation problem focused on finding the optimal combination of generation/storage assets in order to minimise total system costs. The optimisation process allows to understand how to allocate storage capacity across all MSs to minimise the cost of electricity and reduce curtailment and loss of load.

In this section, we explore a set of four optimisation problems to investigate the needs of flexibility under different assumptions (see Table 1 for a summary).

During the initial step we perform a capacity expansion using as baseline the installed capacities provided by PRIMES in the MIX-H2 scenario for the year 2030 (baseline). This step should help to investigate any additional storage needs in the MIX-H2 scenario.

Thus, we carry out an optimisation procedure to investigate the need of flexibility in the MIX-H2 scenario removing the lower bound for batteries, i.e. discarding the values provided by PRIMES (P1). Then, in Section 4.1, we will perform the same procedure varying the CAPEX for the batteries (P2), to investigate the sensitivity of the results to the investment costs. Finally, we carry out the optimisation procedure excluding OCGT technology (P3).

Table 1: Summary of the technologies considered in the optimisation procedures performed in this section.

Optimisation	Batteries	Pumped storage	Gas-peaker (OCGT)
Baseline – MIX-H2 2030	✓	✓	✓
P1 – Three competing technologies in MIX-H2	✓	✓	✓
P2 – The impact of battery CAPEX	✓ (sensitivity analysis on CAPEX)	✓	✓
P3 – Optimisation without gas-peakers	✓	✓	

Based upon an energy storage assessment study by ENTEC (2022), all the optimisation problems consider the following storage options:

1. Lithium-ion batteries with 2.7, 5.1, and 7.6 hours of storage
2. Lead-acid batteries with 3.3, 5.5, and 7.8 hours of storage
3. Redox-flow batteries with 125.8, 250.5, and 372.3 hours of storage
4. Sodium batteries with 3.3, 5.5, and 7.8 hours of storage
5. Closed-loop hydropower pumping with a country-dependent hours of storage

In addition to storage units, we include in the optimisation processes P1 and P2 gas-peaker plants, generation units able to provide flexibility to the system due to their quick response. Furthermore, we removed load shedding from the system, basically introducing an extremely high cost of loss of load (i.e., cost of unserved electricity) in order to focus this analysis only on the flexibility provided by the selected technologies.

The installed power capacity for each technology and country is optimised minimising the system cost, while the storage capacity is set proportional to the installed capacity (e.g., fixed discharging times). The CAPEX and other technical parameters used in the capacity expansion are presented in Table 2. To summarise, the total annualised CAPEX per MW (considering both capacity and the storage with the chosen storage hours) for the four battery technologies are the following:

- Lithium-ion: 152 100, 221 100 and 264 800 EUR per MW
- Lead-acid: 232 000, 320 000 and 412 000 EUR per MW

- Redox-flow: 2 591 000, 5 085 000 and 7 521 000 EUR per MW
- Sodium: 188 200, 287 200 and 390 700 EUR per MW

While for batteries we fixed the amount of hours of available electrical storage (i.e., the discharge time), for pumping storage plants we used a value equal to the discharge time of the plants currently operational, in other words we assume that the discharge time of the new plants will be the same of the existing ones.

Table 2: Energy storage and gas-peaker technologies parameters

Name	**CAPEX capacity** (1000 EUR per MW, annualised)	**CAPEX storage** (1000 EUR per hour, annualised)	**OPEX** (% of CAPEX)	**Storage hours** (h)	**Efficiency** (roundtrip for storage options)	**Source**
Lithium-ion battery	90	23	0.75%	2.7, 5.1, 7.6	88%	ENTEC (2022)
Lead-acid battery	100	40	1.75%	3.3, 5.5, 7.8	85%	ENTEC (2022)
Redox-flow battery	75	20	1%	125.8, 250.5, 372.3	70%	ENTEC (2022)
Sodium battery	39.7	45	1.5%	3.3, 5.5, 7.8	85%	ENTEC (2022)
Closed-loop pumping	47	11.8	1%	Country-specific	81%	ENTEC (2022)
Gas-peaker (OCGT)	28	-	3%	-	35%	European Commission et al., (2020)

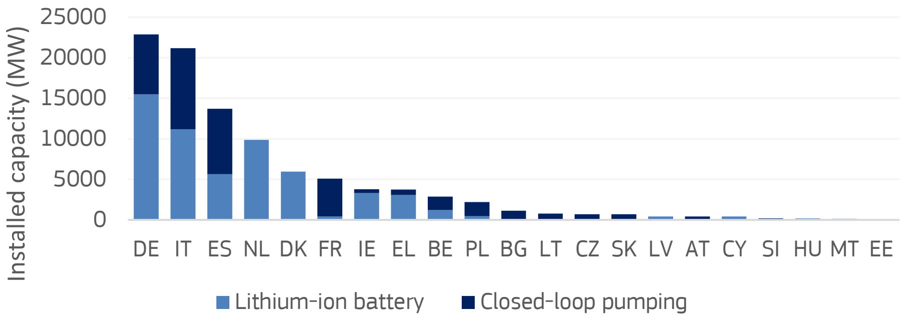
Source: *JRC (based on ENTEC (2022) and European Commission et al. (2020)).*

In this section, we will optimise the capacity of batteries using as baseline (i.e., the lower bound of the solution) the value of 57.7 GW, the amount of batteries installed in the MIX-H2 scenario for the year 2030 (see Figure 18). Given that PRIMES does not consider multiple technologies, we assume that all the capacity installed in its scenario is composted by lithium-ion batteries with 2.7 hours of discharge.

The minimum capacity that the model can install for closed-loop pumping is set to 38.6 GW (the base capacity in the MIX-H2 scenario in the entire EU). The maximum capacity that can be selected by METIS is 40 GW for each country for batteries and for PHS we have chosen 76.5 GW in the entire EU (the maximum value present in the PRIMES data across all future scenarios).

In the case of OCGT, the maximum additional capacity that can be installed for each country is 10 GW.

Figure 18: Closed-loop pumping and lithium-ion batteries installed capacity in the MIX-H2 scenario for the year 2030



Source: JRC analysis.

The results show no additional installation of batteries, gas-peakers or closed-loop pumping, suggesting that the need of flexibility in the European power systems depicted by MIX-H2 scenario for the year 2030 are satisfied.

4.1 Analysing the role of CAPEX

In this part we investigate the flexibility needs discarding the capacity of batteries installed in the MIX-H2 scenario. In other words, we remove any lower bound for the amount of installed batteries. For the other two considered technologies (gas-peakers and pumping hydro), we use the same values.

Three competing technologies in MIX-H2 (P1). The optimal solution of the capacity expansion problem carried out on the entire continent shows no additional batteries/pumping hydro and additional capacity of 16.1 GW of gas-peakers in five EU countries (BE, DE, IE, LU, NL). In other words, the OCGT technology is the most convenient option to provide flexibility using the parameters shown in Table 2.

The predominance of gas-peakers can be explained by the convenience of this technology, able to introduce additional generation capacity to the system due to its relatively-low cost. The cost of natural gas used in our simulations is derived from PRIMES data and it is much lower than today (30 EUR/MWh) and makes gas-fired plants a more cost-efficient option than today.

In addition, there might be two reasons for the lack of installed batteries among the flexibility options:

1. The absence of ancillary services in the METIS modelling: batteries commonly provide ancillary services (e.g. congestion management or frequency balancing) to distribution and transmission grids, as also discussed in the Section 3.
2. The developed METIS context models each country as a single node (so-called copper plate) and this lack of modelling regional distribution and transmission grids might overvalue the benefits of the existing cross-border transmission lines and underestimate the contribution of batteries in dealing with grid congestions and bottlenecks (for a detailed study on the impact of network resolution on power system models see (Frystacki et al, 2021)). This point will be further investigated in Section 4.2.

Taking the above in mind, the value of the CAPEX is the main driver in any capacity expansion problem and in this specific problem the competition between storage solutions (batteries and PHS) and gas-peakers is defined by their costs. However, the uncertainty of the CAPEX of batteries for the year 2030 can lead to wide ranges, as for examples in the study by NREL where the cost projection for 2030 of 4-hour lithium-ion batteries ranges from 35% to 80% of the cost relative to 2018 (Figure ES-1 in Cole & Frezier, 2019) or in a study by IRENA where the upper bound (worst-case) of the energy installation cost for lithium-ion batteries can be more than 4 times the lower bound (best-case) (Annex 1 in IRENA, 2017). To investigate the impact of the CAPEX of batteries in the optimal flexibility mix, we will perform a sensitivity analysis in the following set of simulations (P2).

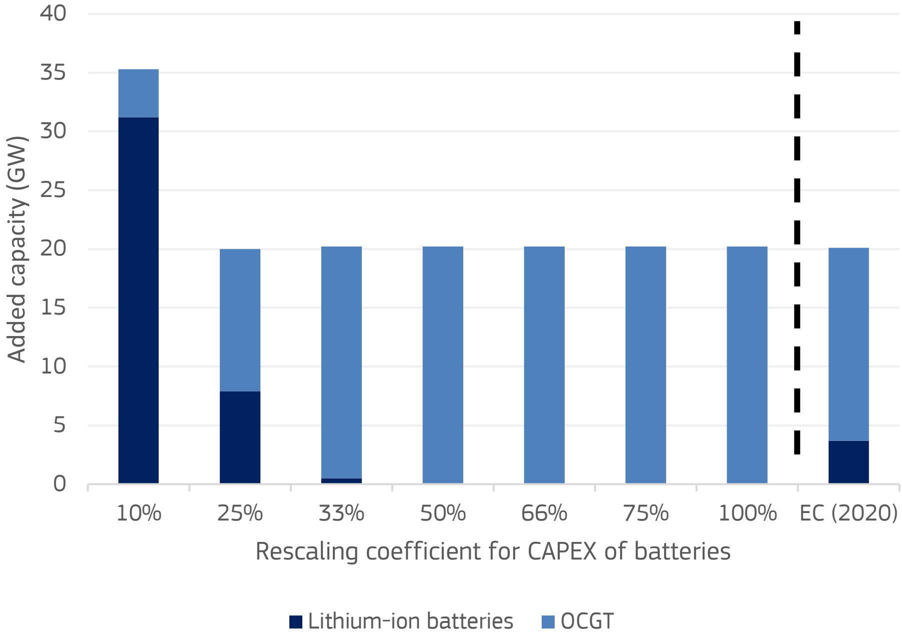
The impact of battery CAPEX (P2). While Table 2 provides the most recent CAPEX estimates to the best of our knowledge, the differences in estimates between different data sources could bias the above result. We therefore carry out an optimisation procedure to investigate how the optimal share of gas-peakers and batteries varies when reducing the CAPEX of all the batteries[23].

A sensitivity analysis based on rescaling the CAPEX of all the battery technologies from 10% to 100% (i.e., no change) shows (Figure 19) that lithium-ion batteries start becoming competitive against OCGT when their CAPEX drops below 33% of the cost we considered for 2030[24]. In the same figure we have included also the results obtained using the CAPEX for lithium-ion batteries used in European Commission et al., (2020), the source of the CAPEX used for OCGT in this section.

23 Indeed, battery CAPEX estimates differ a factor of three between European Commission et al. (2020) and ENTEC (2022).

24 Note that while other battery technologies considered in Table 2 were also considered indeed may have a lower capex per MW than Li-ion, in absolute terms they are more expensive because of their large storage (i.e., high number of discharge hours).

Figure 19: Additional capacity for lithium-ion batteries and gas-peaker (OCGT) plants in EU with respect to the CAPEX of all battery technologies (P2)



Source: JRC analysis.

Optimisation without gas-peakers (P3). Here we explore the results of the optimisation procedure when we exclude gas-peakers from the flexibility options. Figure 20 shows the optimisation results using the same simulation setup but with pumped storage and batteries (all technologies) as only available options. Pumped storage is installed in IE and BE – in all the first case reaching the upper bound. The total additional pumped storage is 1 302 MW (with 4 260 MWh) which must be added to the already existing pumped storage capacity of 38 600 MW (467 GWh) in the EU.

Lithium-ion batteries are the only battery technology selected during the optimisation process, consisting of 14 160 MW of capacity with a total additional storage of 66 245 MWh. Lithium-ion has been chosen due to its low CAPEX and OPEX (as depicted from Table 2).

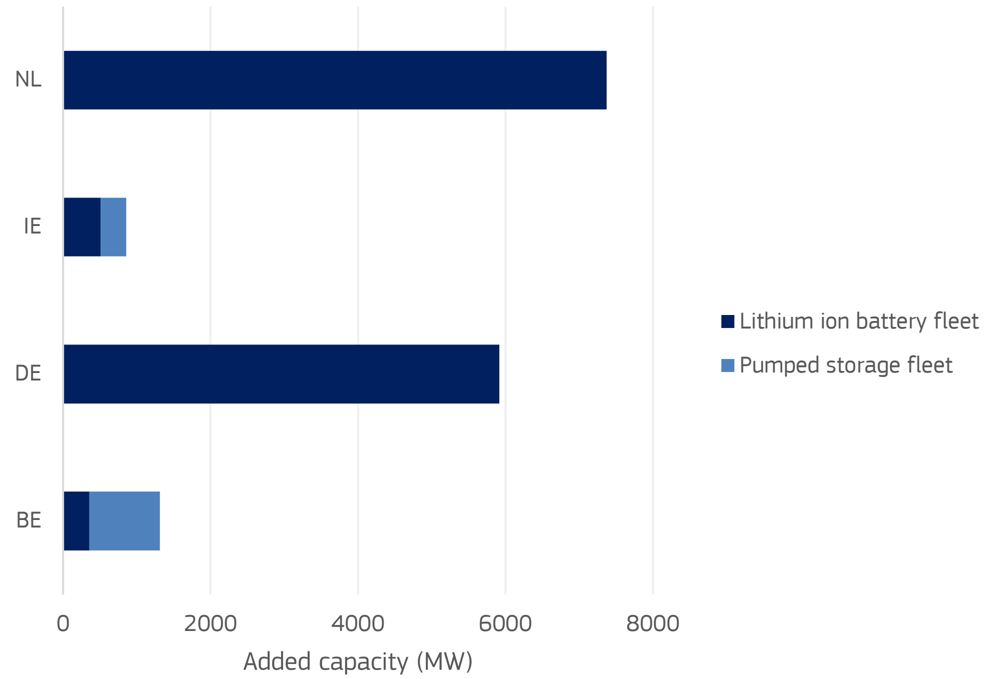
We can summarise the main results from the optimisation procedures in the following way:

1. The EU power systems in the MIX-H2 scenario for the year 2030 do not require additional storage or gas-peakers
2. OCGT is the most cost-efficient technology, with 16.1 GW installed in the EU if we remove any constraints on the minimum capacity of installed batteries
3. Batteries become competitive with gas-peakers when their CAPEX drops below 33% of the CAPEX used in P1 and reported in Table 2
4. If we exclude gas-fired plants from the options, the optimal added capacity of batteries (lithium-ion) is 14.2 GW and 1.3 GW of pumped storage, respectively with an additional storage of 57.9 and 4.3 GWh.

Moreover, in all the optimisation procedures (P1-P3), the results show that additional flexibility is needed in a limited number of countries (maximum five). This result shows that a few countries provide the flexibility for the rest of the countries, possibly suggesting a high usage of electricity interconnectors to import/export electricity from and to the electricity storage.

The modelling setup here used has a country-resolution, possibly overestimating the flexibility of national power systems due to the lack of any modelling of intra-national grids and their bottlenecks. In the next section, we will investigate the relationship between the need of electricity storage and the availability of cross-border interconnectors.

Figure 20: Added battery and pumped storage electrical capacity by METIS model on the MIX-H2 2030 scenario (P3).



Source: JRC analysis.

4.2 Assessing the role of inter-connectors

In this section, we explore the impact of the availability of interconnectors on the optimal battery storage capacity considering the MIX-H2 2030 scenario. Basically, we carry out a set of capacity expansion optimisations reducing the capacity of cross-border interconnectors to see the impact of the change on the optimal mix of installed battery storage. Differently from the analysis in the previous section, here we focus only on batteries, without carrying out any optimisation on pumped storage or on gas-peakers.

We consider eight different coefficients to scale down the capacity of interconnectors from 30% to 100% of the original capacity (Figure 21). The coefficient is used to rescale all the 160 interconnectors in the simulated area, thus reducing the capability of all the countries of importing/exporting electricity. For example, when using a coefficient of 30%, the net transfer capacity of each interconnector in the model is multiplied by 0.3.

In the entire EU, with an interconnector coefficient of 90% the additional batteries capacity is 21 GW (+35% from the baseline) with a total added storage of 131 GWh (+82%). In the most extreme case (30% interconnector coefficient), we see 118 GW of added capacity (9.4 GW from redox flow and the rest from lithium-ion batteries) and 2 000 GWh of added storage (1 180 GWh from redox flow).

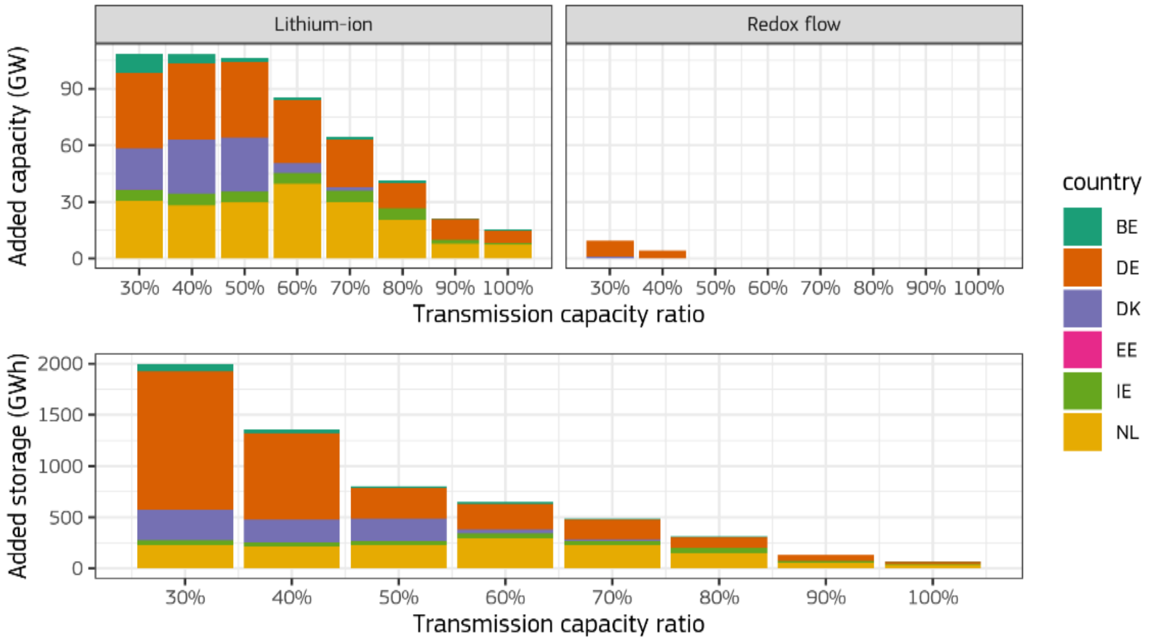
We can see that reducing the capability to exchange electricity increases the needs of local storage, to compensate the lack of flexibility usually provided by interconnectors. On average, in all the six countries the total reduction of 1 GW of interconnectors is replaced with 1.99 GW of batteries.

Four out of the six countries installing additional capacity are the same selected in the analysis in Section 4, with the addition of Denmark (DK) which shows additional storage as soon as the interconnector coefficient is lower than 80% and Estonia (EE) which sees a small amount of capacity added when the coefficient is lower than 50%.

Lithium-ion batteries are the predominant technology and with a scaling coefficient between 50% and 100% it is the only used technology. Redox flow batteries start appearing when the coefficient is 40% (4 300 MW) and 30% (9 380 MW) in Germany and Denmark.

This analysis shows that the main driver for the selection of a technology for batteries is the CAPEX. The results shown so far totally consistent with the CAPEX values observed in Table 2. Batteries with a storage duration longer than a day are selected only in the most extreme cases.

Figure 21: Top panel: Additional battery capacity per country and technology with respect to the variation of the capacity of electricity interconnectors. Bottom panel: total added storage (including all the selected technologies) per country. All the results are based on the MIX-H2 2030 scenario.



Source: JRC analysis.

5 Conclusions

Following the setting of a number of ambitious targets to achieve the transition to a climate-neutral European energy system, the EU is expecting a large increase of renewable energy sources in the electricity system. A significant amount of the production of these renewable energy sources is variable by nature, which in combination with limited storage and variable consumption puts power system operations under pressure and may cause prices to fluctuate heavily. As the associated flexibility requirements increase in European power systems, it also creates opportunities for new storage solutions to accommodate flexibility needs and facilitate the sustainable transition to a climate-neutral Europe.

In this report, we address the flexibility requirements and storage solutions by simulating operations in a 2030 and 2050 EU electricity system with the METIS electricity model. We thereby base our findings on commodity price input assumptions that are reasonable in the mid to long term, but are considerably lower than current price levels. Flexibility requirements, capturing the need for power systems to adapt to the variability of demand and renewable energy production, are computed for three different timescales: daily, weekly and monthly.

We study how the flexibility requirements relate to the market share of VRES and assess which flexible technologies contribute in addressing the flexibility needs. We further examine the arbitrage spot market values of such technologies and present the optimal electric storage fleet in 2030. The presented analysis allows us to reach the following conclusions:

1. Compared to today's levels, flexibility requirements will increase significantly in all EU Member States until 2030 and even more so towards 2050. While for 2030, the requirements increase the most on a daily timescale, with a total flexibility need of 288 TWh in the EU, the increase on a relative basis is the highest on a monthly timescale with 173 TWh. This trend continues towards 2050, with total flexibility requirements reaching a staggering summed amount of 2189 TWh across all timescales. This is equal to 30% of total electrical EU demand in 2050, up from 24% in 2030 and 11% in 2021. These numbers thus present a considerable increase in flexibility requirements, indicating the need for both short-term and long-term flexibility solutions in future European power systems.
2. The market share of variable renewable energy sources directly affects the share of flexibility requirements to total demand. We find evidence for a significant relation between daily flexibility requirements and the share of solar PV production on the one hand, and a significant relation between weekly and monthly flexibility requirements and the share of (onshore and offshore) wind production on the other hand. Indeed, while electricity generated from solar PV plants typically follows a specific daily generation profile, wind production profiles more tend to follow the monthly seasonality. Efficiently integrating both sources of renewable energy sources in the power system thus requires an adequate evaluation of the necessary short-term or long-term flexibility solutions.
3. In terms of technologies offering flexibility solutions, we find that interconnections play a dominant role in addressing flexibility needs in 2030 on all timescales, but particularly on the longer-term timescales. Storage solutions like batteries, electrolysers and pumped hydro also play a significant role, with the former almost exclusively targeting daily flexibility needs but the latter also targeting long-term flexibility needs. Thermal units, of which production can be dispatched, also remain an important contributing factor in the flexibility mix. This shows that while new storage solutions definitely have a role to play, more conventional assets remain important in addressing flexibility.
4. Storage technologies, as compared to other technologies, would only be able to recover a modest fraction of capital expenditure from market revenues gained on the spot market by 2030, and would thus exhibit a strong reliance on income streams from other market segments or further sorts of economic incentives. As the modelling scope does not allow for the incorporation of such benefits, the results on the economic value of flexibility technologies should be considered as a lower bound, targeting flexibility needs arising from spot market variability rather than spot market uncertainty.
5. When running a storage capacity expansion optimisation for the 2030 MIX-H2 context, we find a relatively limited increase of storage capacity. Additional storage capacity is mainly requested when Member States experience congested interconnector capacity over considerable periods of time. If this interconnector capacity were lower than current targets, lithium-ion batteries would be a key source of flexibility by balancing short-term system deviations. Further interconnection constraints would increase the importance of longer duration batteries.

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List of abbreviations and definitions

CCGT	Combined Cycle Gas Turbine
EV	Electric Vehicle
FR	Flexibility Requirements
MS	Member State
OCGT	Open Cycle Gas Turbine
PHS	Pumped Hydro Storage
VRES	Variable Renewable Energy Sources

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Annex 1. Installed capacities and annual demand in EU from PRIMES

The METIS contexts used in this report are based on the PRIMES modelling used for the Fit for 55 scenarios. In this table we summarise the installed capacities and the demand for the entire EU area.

PRIMES category	Unit	MIX 2030	MIX-H2 2030	MIX-H2 2050
Batteries	GW_{elec}	41.4	48.7	207.1
Biomass-waste fired	GW_{elec}	40.6	42.2	55.2
Derived gasses	GW_{elec}	4.9	4.9	1.9
Electrolyzers	GW_{H2}	3.1	40.5	543.9
Geothermal heat	GW_{elec}	0.9	1.9	5.1
Hydro pumping	GW_{elec}	71.8	70.2	87.6
Hydrogen plants	GW_{elec}	0	0	0
Lakes	GW_{elec}	89.5	89.8	92
Natural gas	GW_{elec}	177	164.2	182.8
Nuclear	GW_{elec}	93.9	93.9	69.3
Oil fired	GW_{elec}	13.5	13.3	1.7
Other RES	GW_{elec}	0.2	0.2	8.2
Run of river	GW_{elec}	41.9	42.2	57
Solar	GW_{elec}	383	417.5	1 117.3
Solids fired	GW_{elec}	63.4	63.4	22.2
Wind off-shore	GW_{elec}	66.4	88.7	381.6
Wind on-shore	GW_{elec}	361	393.6	1 097.1
Annual electricity demand	TWh_{elec}	3 041	3 242	6 783
Hydrogen demand	TWh_{H2}	15.6	195.6	2 408

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