The European Power System in 2030: Flexibility Challenges and Integration Benefits

An Analysis with a Focus on the Pentalateral Energy Forum Region

ANALYSIS

Agora Energiewende

Fraunhofer IWES

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IMPRINT

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COMMISSIONED BY

Agora Energiewende
Rosenstrasse 2 | 10178 Berlin | Germany

Project lead:
Christian Redl
christian.redl@agora-energiewende.de

Dimitri Pescia
dimitri.pescia@agora-energiewende.de

Editor: Mara Marthe Kleiner

STUDY BY

Fraunhofer-Institute for Wind Energy and Energy System Technology (IWES)
Königstor 59 | 34119 Kassel | Germany

Authors:
Mirjam Stappel, Ann-Katrin Gerlach, Angela Scholz, Carsten Pape

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Preface

Dear reader,

As part of its strategy to become a low-carbon region, the European Union aims to draw at least 27 percent of its energy from renewables by 2030. This translates into a share of some 50 percent in the power sector. Solar photovoltaics and wind power – driven by significant cost reductions – will almost certainly contribute to more than half of this share. As wind and solar depend on weather, future power systems will be characterised by fundamentally different generation patterns to those observed today, significantly increasing the need for flexibility and back-up capacity.

In meeting the flexibility challenge, regional cooperation and power system integration offer important ways forward. Indeed, several regional power market initiatives exist throughout Europe that "live" cooperation on a daily basis. One of these initiatives is the Pentalateral Energy Forum (PLEF), a set of seven countries in Central Western Europe – Austria, Belgium, France, Germany, Luxembourg, the Netherlands and Switzerland – that already have a track record of regional cooperation, coupled wholesale markets and a relatively high level of physical interconnection.

Against this background, we commissioned experts from Fraunhofer IWES to look deeper into the future of regional market integration for power systems with high shares of wind and solar: What kinds of flexibility requirements arise from the projected growth of these two technologies? And to what extent can further power market integration within and beyond PLEF countries help meet the challenge?

Some answers – and a few open questions – can be found here.

Yours sincerely,

Dr. Patrick Graichen
Director Agora Energiewende

Key findings at a glance

1. **Wind and solar PV drive power system development.** As part of Europe's renewable energy expansion plans, the PLEF countries will strive to draw 32 to 34 percent of their electricity from wind and solar by 2030. The weather dependency of these technologies impacts power systems, making increased system flexibility crucial.

2. **Regional European power system integration mitigates flexibility needs from increasing shares of wind and solar.** Different weather patterns across Europe will decorrelate single power generation peaks, yielding geographical smoothing effects. Wind and solar output is generally much less volatile at an aggregated level and extremely high and low values disappear. For example, in France the maximum hourly ramp resulting from wind fluctuation in 2030 is 21 percent of installed wind capacity, while the Europe-wide maximum is only at 10 percent of installed capacity.

3. **Cross-border exchange minimises surplus renewables generation.** When no trading options exist, hours with high domestic wind and solar generation require that generation from renewables be stored or curtailed in part. With market integration, decorrelated production peaks across countries enable exports to regions where the load is not covered. By contrast, a hypothetical national autarchy case has storage or curtailment requirements that are ten times as high.

4. **Conventional power plants need to be flexible partners of wind and solar output.** A more flexible power system is required for the transition to a low-carbon system. Challenging situations are manifold, comprising the ability to react over shorter and longer periods. To handle these challenges, the structure of the conventional power plant park and the way power plants operate will need to change. Renewables, conventional generation, grids, the demand side and storage technologies must all become more responsive to provide flexibility.

Contents

Executive summary

In the future, power systems in Europe will increasingly be shaped by renewable energies. Legally binding targets stipulate that by 2030 renewable energy must make up 27 percent of Europe's power mix, or roughly 50 percent of the power sector.[1] Due to significant cost reductions in recent years, most of the future's additional generation capacity is expected to come from wind power and photovoltaics (PV). In 2014 almost 74 percent of all conventional and renewable investments in European generation assets went to wind power and PV.[2] As these technologies are variable in their output ranging from almost zero to nearly full installed capacity, depending on the weather, they bring with them an increased need for flexibility in the power system. Further integration of European power markets is a crucial flexibility enabler.

In trying to understand the specific effects of wind power and PV deployment[3] on flexibility needs as well as the benefits of regional and European market integration to mitigate these flexibility requirements, Agora Energiewende commissioned Fraunhofer IWES to conduct an in-depth, model-based analysis of future scenarios in the European power system. Given that European power market integration is also fostered by bottom-up regional initiatives, the Fraunhofer study specifically focuses on the Pentalateral Energy Forum (PLEF) region, a set of countries with a track record of regional cooperation, advanced power market integration and a relatively high level of physical interconnection.[4] The study's main findings are presented below.

1 EC (2014). Impact assessment accompanying the communication: A policy framework for climate and energy in the period from 2020 up to 2030.

2 EWEA (2015). Wind in power. 2014 European statistics. February 2015.

3 Below we refer to these as variable renewables (vRES).

4 The Pentalateral Energy Forum consists of six full members (Austria, Belgium, France, Germany, Luxembourg, the Netherlands) and one observer (Switzerland).

The European power mix in 2030: Renewables as the main generation source

Though situations can vary quite a bit from country to country due to differing domestic resource availability (hydropower, say), renewables are expected to be "mainstream" by 2030 throughout Europe. Such a scenario is shown in Figure S 1. The figure depicts both the share of renewables in total power generation and the specific generation mix for the countries simulated in this study.[5] The Europe-wide generation share of renewables amounts to 50 percent, with wind power and PV accounting for 30 percent of the total. For the PLEF region, the shares are 54 percent and 34 percent, respectively.

The increasing share of wind power and PV deployment will induce a fundamental transformation of our power systems. We begin by discussing the effect on flexibility needs.

Geographical smoothing mitigates flexibility needs

Owing to its variability, increasing vRES output is associated with the need for enhanced power system flexibility. Spatial smoothing facilitated by strong electricity grids represents one of the keys to integrating high shares of vRES. Different weather regimes across Europe serve as the basis for smoothing effects at the generation side.

Consider, first, instantaneous wind power generation. Wind power output assessed over a larger area is smoother than any single generation unit. When working in combination, the sum of individual generation profiles provides more stable generation easing wind integration. But strong national power grids and integration of the national power markets are crucial to benefit from this effect.

5 Data has been taken from national energy strategies or scenarios of the European Commission and ENTSO-E in line with medium- and long-term decarbonisation targets.

Share of RES in national net power generation and breakdown of the generation mix in 2030. Figure S1

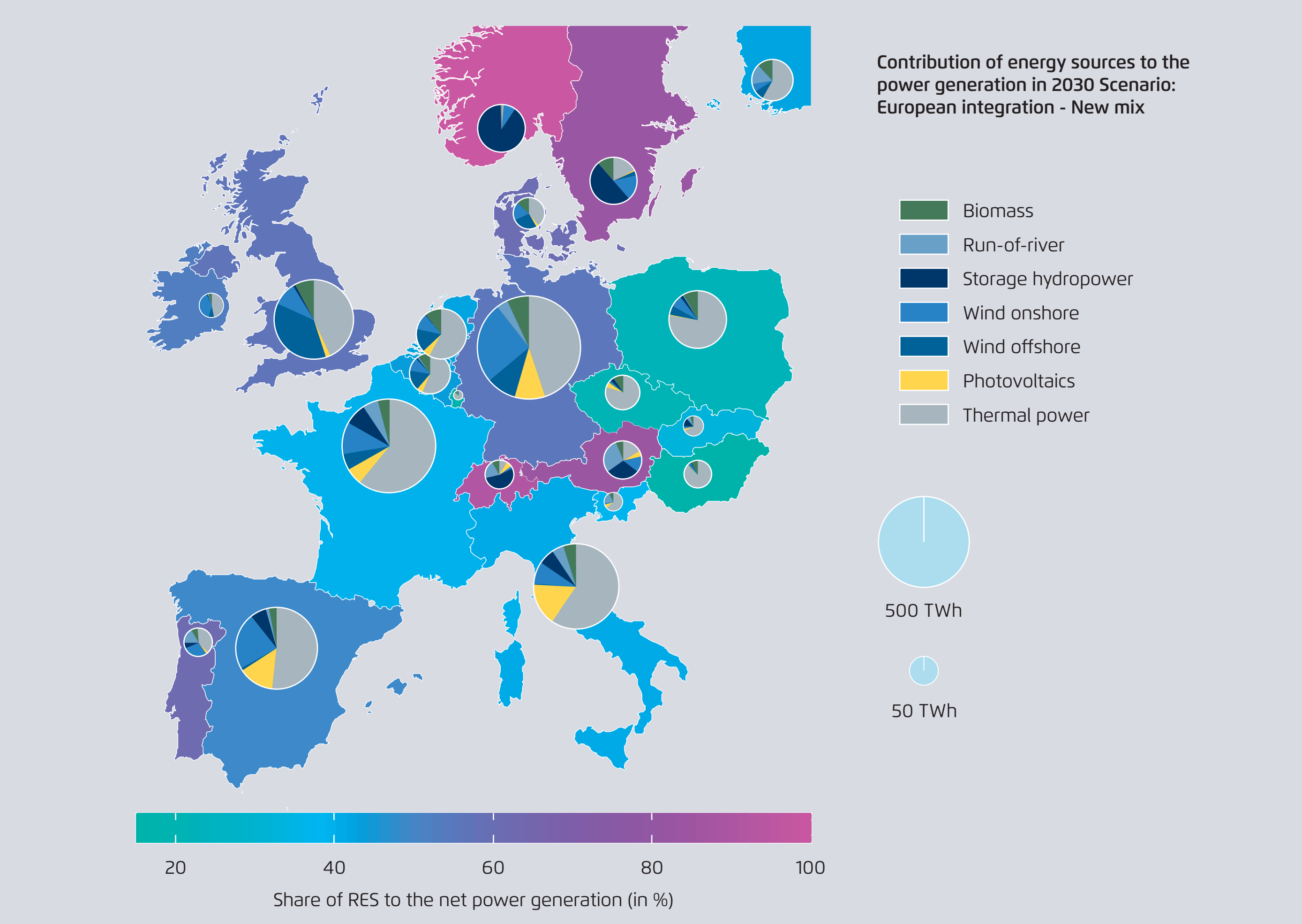

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Figure S 2 depicts generation time series of onshore wind power for different geographical aggregation levels (from an area of ~ 8 km² to Europe as a whole). At the European level, the instantaneous total wind power output is generally much less volatile, and lacks extremely high and low values. For onshore wind, the Europe-wide aggregation yields hourly output changes exceeding 5 percent of installed capacity for only 23 hours of the year. The single largest hourly ramp is -10 percent of installed capacity.

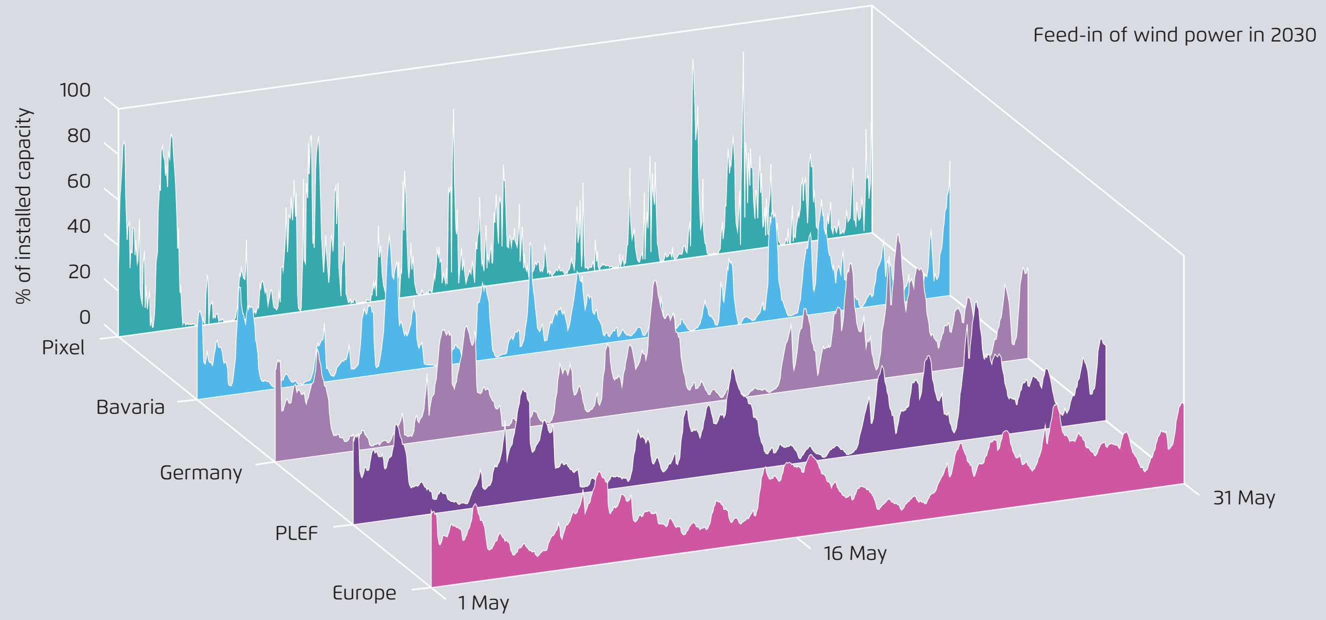
Moreover, one observes a matching pattern of monthly wind power and PV generation caused by seasonal weather variance, which also yields a more stable total vRES output. Figure S 3 illustrates an example for Europe.

Another aspect of geographical smoothing concerns load. Different activity profiles, due to cultural differences and slight shifts in daylight hours bring about non-simultaneous electricity demands. Each region has its annual peak load at different times of the day and year, whereby, for example, the peak load of the entire PLEF region in 2011 is 2-3 percent smaller than the sum of individual country peak loads.

Cross-border exchange minimises renewables curtailment

Because of geographical vRES smoothing effects, the times when there is no or little power are less frequent and to-

Time series of onshore wind power generation in a simulation for May 2030 at different levels of aggregation (as a percentage of the installed capacity at the specific aggregation level). Note that one pixel is equivalent to an area of 2.8 x 2.8 km. Figure S2



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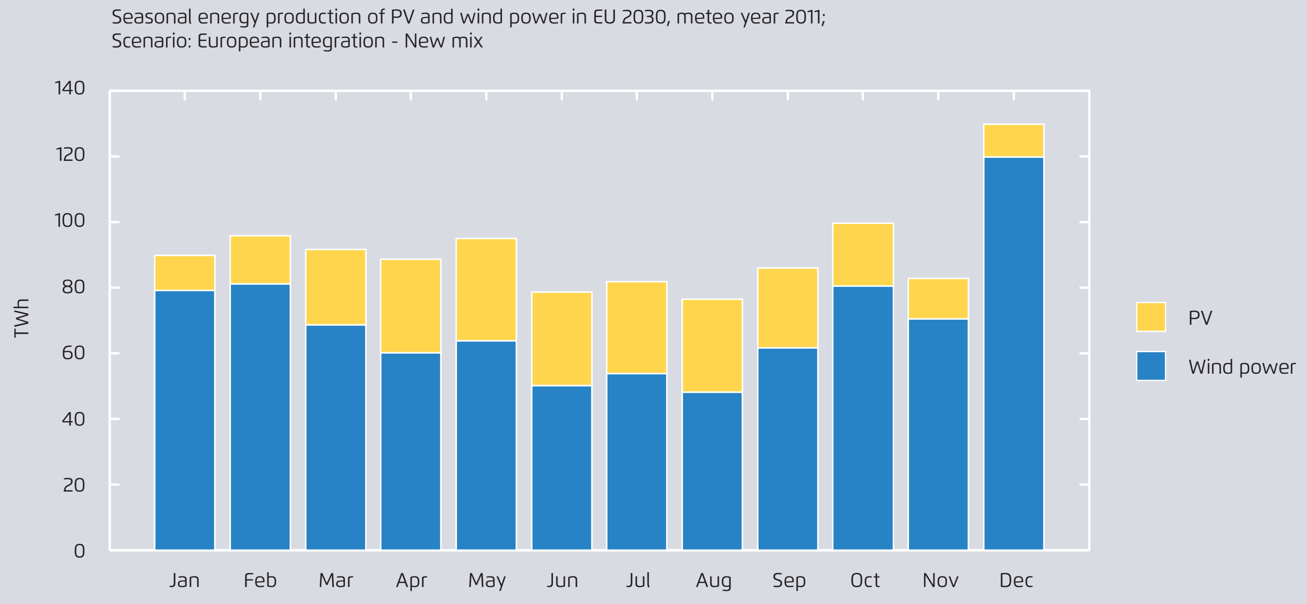
Monthly wind power and PV generation in Europe in 2030. Figure S3



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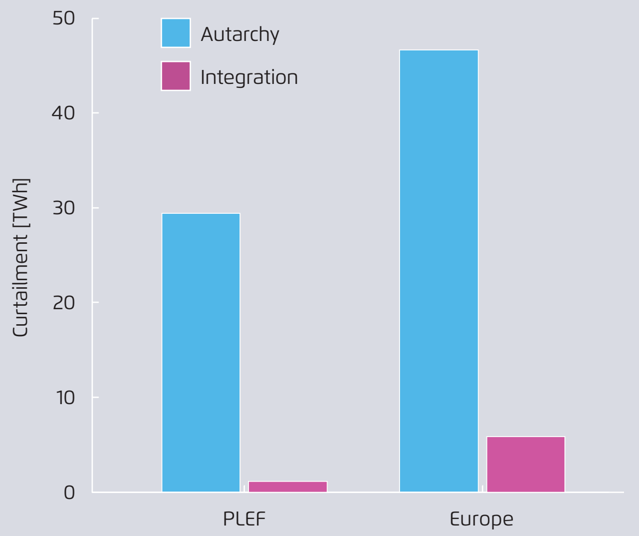
tal output changes become softer and slower. These effects contribute importantly to lower flexibility requirements. That is, less balancing power has to be provided and fewer capacities backed up. Furthermore, less electricity must be curtailed (or stored) at times with high vRES-E feed-in.[6] Instead, it can be exported to regions where the load is not yet covered. Advancing grid integration makes it possible to benefit from this potential.

Figure S 4 shows the amount of curtailed vRES energy within the PLEF region and Europe simulated for 2030 for two scenarios: autarchy and integration.[7] The curtailment in the autarchy case is about ten times higher due to the lack of exchange options with other regions. Note that avoiding curtailment altogether would be difficult to achieve just by increasing transfer capacities, as highly correlated feed-in situations can still occur.

Interestingly, not only the amount of curtailed energy is lower in the integration scenario, but also the number of hours in which power is curtailed decreases significantly. In autarchic national power systems on the Europe-wide level, curtailment would occur almost every hour of the year (7217 hours). In the integration case – here the number of interconnector levels is projected to increase Europe-wide by 41 percent by 2030 – curtailment is necessary for 2150 hours. All other hours with local surpluses can be balanced through integration (which is to say, through exports). In the PLEF region, limited curtailment takes place only for 205 hours of the year.

Power system integration, crucial for smoothing regional output and mitigating flexibility needs, relies on cross-border power flows. The imports and exports of PLEF countries with their neighbours are shown in Figure S 5. All seven countries show transfer activity in both import and export directions. Austria, France and Germany are net exporters and Switzerland and the Benelux countries are net importers.

Curtailment of vRES within the PLEF region and Europe in autarchy and integration scenarios — Figure S4



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Renewables generation and consequences for the conventional power generation system

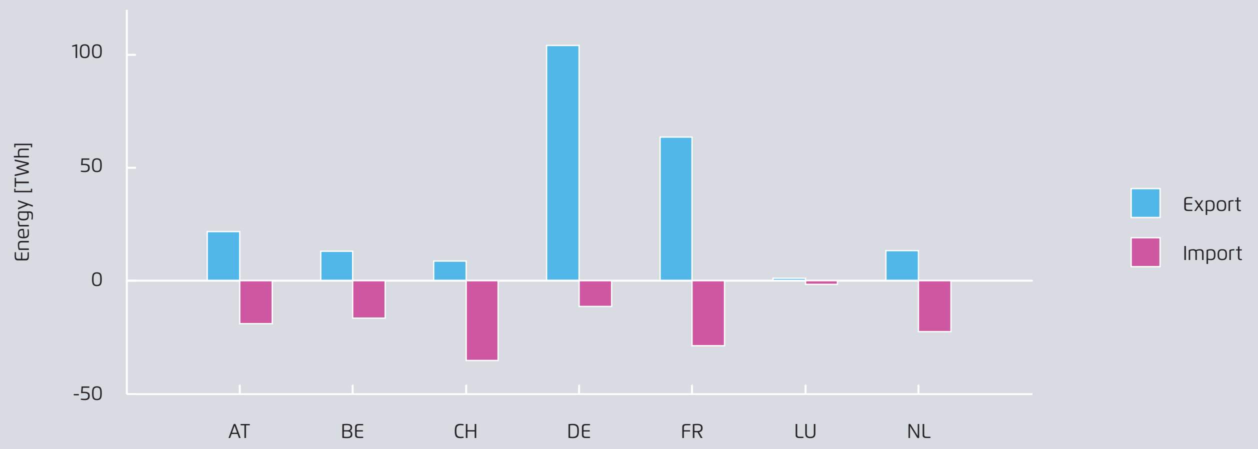
vRES deployment affects the role played and the contribution made by the remainder of the overall power generation portfolio, known as the "residual power plant park". Many challenging situations arise when it comes to the flexibility in the residual generation mix, comprising the ability to react over both shorter and longer periods.

Figure S 6 provides a snapshot of PLEF power systems in 2030 for a week with high PV generation. The graph shows for every hour of the week the prevailing load in GW (equivalent to the hourly power demand in GWh) along with the renewable and conventional power generation. During the day, when the load is usually higher, the load pattern aligns well with the PV feed-in. When PV generation is low – dur-

6 Curtailment of vRES occurs when the feed-in of vRES exceeds the prevailing domestic load and when cross-border interconnection lines are already fully utilised (so that no additional exports can take place).

7 Autarchy means that the countries are not interconnected. For the integration scenario, we assumed a plausible development of cross-border interconnector capacities (with interconnector capacities increasing Europe-wide by 41 percent by 2030).

Imports and exports of electricity in 2030 for the PLEF countries in the integration scenario. Figure S5



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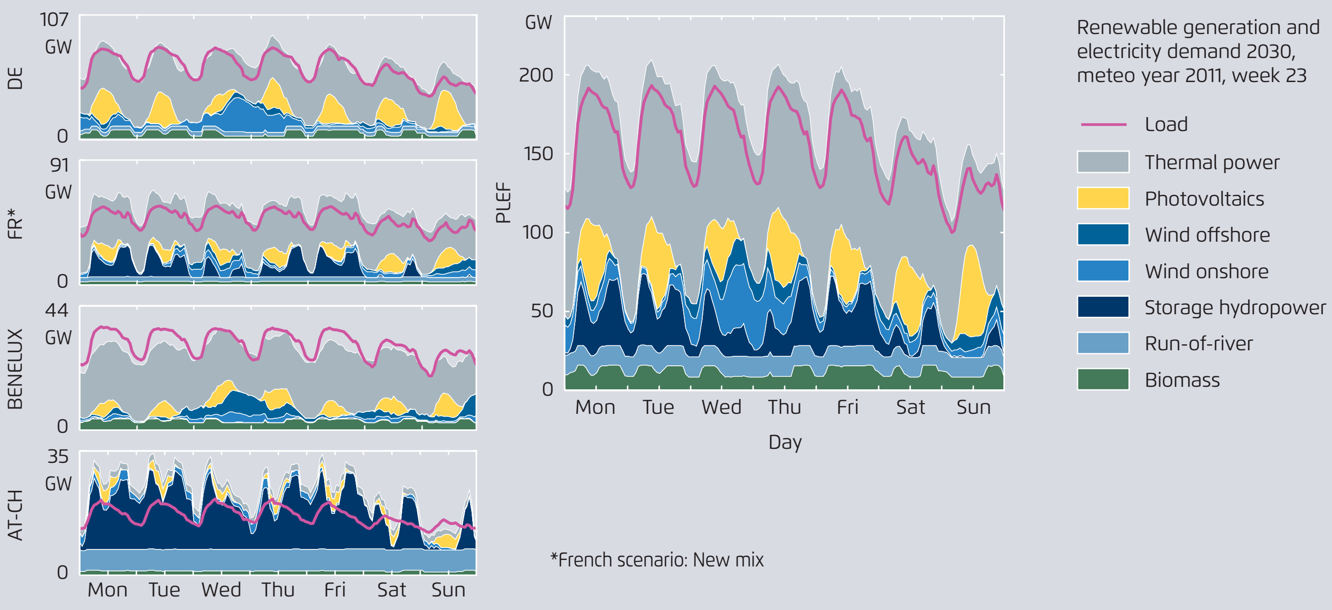
Power generation and demand for calendar week 23 (high share of PV) in 2030, for each PLEF region as well as in the aggregate. Figure S6



*French scenario: New mix

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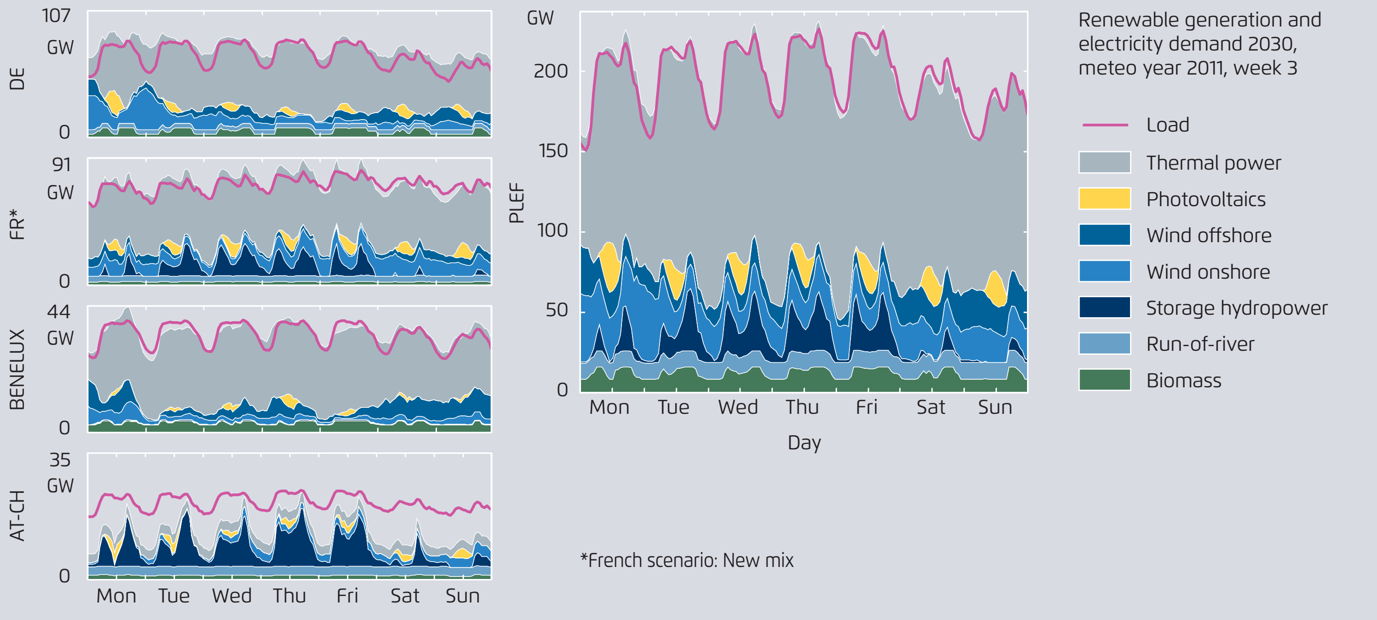
Power generation and demand for calendar week 3 (low share of vRES) in 2030, for each PLEF region as well as in the aggregate.

Figure S7



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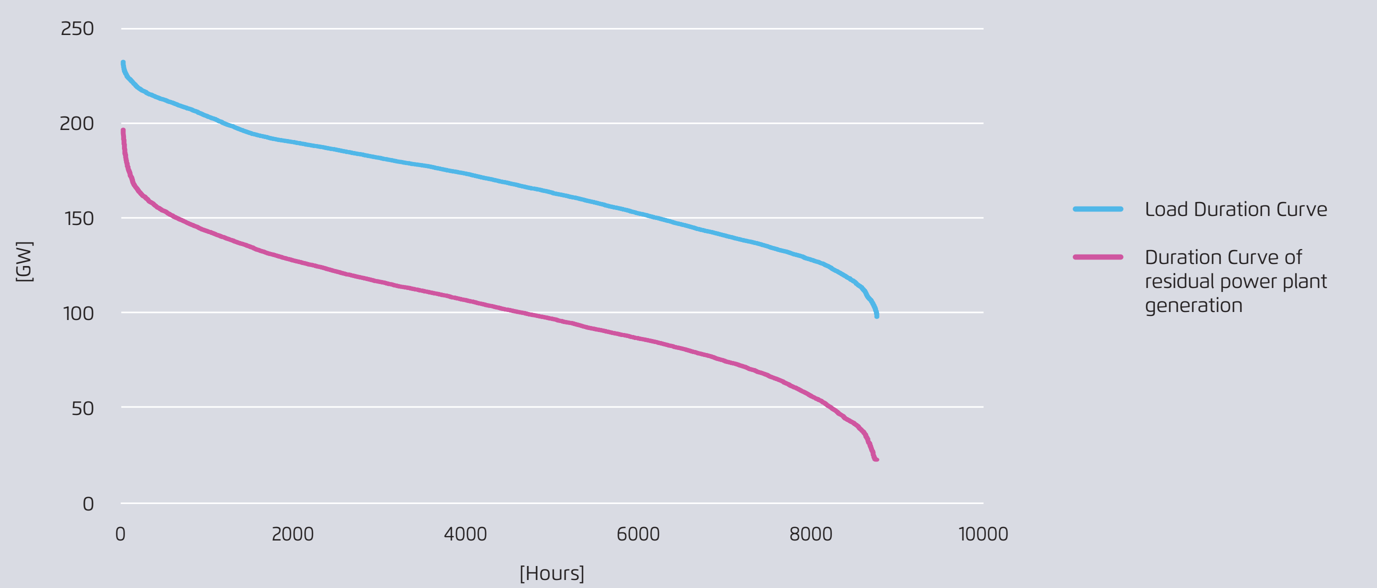
Load duration curve (blue) and duration curve for the generation of the residual power plant park (pink) for the aggregated PLEF region in 2030. The difference between the load duration curve and the duration curve of residual power plant generation is the generation of variable renewables.

Figure S8



Agora Energiewende, based on Fraunhofer IWES

ing the steep load changes, especially in the morning and evening – there is increased use of storage hydropower in Austria, France and Switzerland. It is also in these hours when the level of conventional thermal generation and the number of flexible biomass plants increase throughout the PLEF region. With the overall high share of renewables in the week depicted, thermal capacities can additionally contribute to exports to neighbouring regions (as shown by total generation in the PLEF region exceeding the load).

Figure S 7 shows a week with low PV and wind power feed-in. Here load is mainly covered by thermal power plants. To support thermal power plants, hydro storage power plants in Austria, France and Switzerland are deployed in the morning and evening hours of the day, when power demand increases. At certain hours, when total generation in the PLEF region is below the prevailing load, imports contribute to meet PLEF power demand.

In addition to the above weekly snapshots, the impact of vRES on the requirements of the residual power plant system can be illustrated via duration curves, as shown in Figure S 8. The figure shows for the PLEF region the duration curves (sorting hourly values for a full year from the highest to the lowest value) for load and for generation from the residual power plant park (load minus vRES generation plus net exports).[8] Through these duration curves, the number of hours per year a certain load or generation level is exceeded can be derived. As can be seen, the residual generation curve runs considerably lower than the load curve. The difference between the load duration curve and the duration curve of the residual power plant generation is equal to variable renewables generation.

For few peak hours situations occur, in which the gap between the two duration curves is small. This implies that situations can occur in which conventional power plants and imports must cover almost the entire load, regardless of the capacity share of vRES.

The residual load – the difference between load and vRES feed-in – becomes the relevant power system determinant and driver for flexibility requirements of the power system and the conventional power plant park. This is contrary to today's situation, where load determines the conventional power plant park.

The reduced generation of conventional power plants implies that the power plant park has a different structure and composition. Base load capacities will decrease relative to those of today, while peak load and mid-merit capacities will increase.

Alongside changes to the structure and amount of installed capacities comes an altered operational pattern for the residual power plant park. Figure S 9 compares hourly ramps (the change in output from one hour to the next) of the German residual power plant park with the prevailing generation level for 2013 and 2030.[9]

One important difference to today's hourly ramps of the conventional power plant park in 2030 is that moderate to larger hourly ramps already frequently occur at low output levels, as shown in Figure S 9 for Germany. This challenges the way conventional power plants are operated and implies increased ramping of the residual power plant park at partial load operation and more short-term starts and stops. The situation is especially challenging in Germany because it has the highest share of vRES in PLEF countries. Conventional power plant parks in other countries need to provide somewhat smaller and fewer output changes to the market.

These changes get even stronger if we look at ramps occurring over longer time periods. On a daily basis (i.e. changes in generation from one day to the next), larger parts of residual power plant park will need to be turned on and off more frequently.

8 Because vRES do not burn fuel, their short-run generation costs are essentially zero. From a market perspective (the so-called merit-order principle), vRES are thus dispatched before (residual) thermal generation sources. Hence, when assessing residual power plant generation we subtract vRES from the load.

9 This assumes a 5 GW must-run level of conventional capacities for Germany in 2030.

Hourly ramps of the German residual power plant park vs. prevailing generation level for 2013 (top figure) and 2030 (bottom figure) for the integration scenario.

Figure S9

Agora Energiewende, based on data from Fraunhofer IWES

Country and regional outlook – implications and recommendations

The simulations described above stress the increasing flexibility requirements in future power systems caused by the rising share of wind power and PV. To manage this, renewables, conventional generation capacities, grids and storage technologies will all need to become more responsive. We pointed out the role of interconnectors and improved market integration for facilitating imports and exports as flexibility options. Besides being beneficial for renewables integration, an interconnected power system lowers total generation costs.[10]

10 See, for instance, Booz&Co et al., 2013, Benefits of an Integrated European Energy Market. Final Report

The new power system requires a mix of flexible resources for high reliability – and a significant transformation of today's power system. On the supply side, more peak and mid-merit and less inflexible base load plants will be needed implying both a different mix and operational pattern. In addition, activating the flexibility potential of the demand side will be crucial in all European countries. Both an active demand side and an adjusted power plant park will help manage flexibility challenges.

The German power system will – according to official targets – see RES-E as main generation source in 2030, with wind power and PV representing the main renewable sources. Targeting flexibility, back-up options and regional integration are thus crucial for high reliability levels. vRES deployment challenges the way other power plants (as well as storage and demand response) are operated. It will require increased ramping of the residual system at partial load and more starts and stops of power plants.

The French power system will remain characterised by a high share of nuclear power must-run capacities. Incorporating 40 percent renewables will require some resizing of the nuclear park. Yet the load-following capabilities of the French nuclear fleet can technically respond in part to increasing flexibility needs. Several other flexibility options, hydropower in particular, will help reduce the conflict between high nuclear must-run and a high share of variable renewables. A long-term energy transition strategy – based on renewable energy deployment, nuclear fleet re-optimisation and the development of flexibility potential – will be key for meeting the 2030 targets in French power mix diversification and for minimising costs.

Hydro storage plays and will continue to play an important role in the Alpine countries of Austria and Switzerland in tackling flexibility challenges. The two countries have the potential to generate more hydropower at once than their annual peak load and can also provide flexibility to neighbours in the region. In addition, because hydro storage (and pumped storage) is not constrained by a must-run generation level, high imports are possible as well.

The BENELUX countries serve as an important "power hub" thanks to their central location in Northwest Europe. Yet because their geography is mostly flat, with little potential for (storage) hydropower plants, the BENELUX countries require well-developed interconnectors to cope with flexibility challenges. Frequently changing power flow directions underline the benefit of regional integration for all countries.

Looking at the PLEF region in the aggregate, one can conclude that, alongside grid reinforcement, the diverse mix of available technologies can facilitate the integration of vRES. It is important to note that domestic network development is mandatory if European integration benefits are to be utilised. This is why the PLEF region's central location in the interconnected European power system is highly beneficial for vRES integration.

The performed analysis neglected several additional enablers of flexibility, such as pumped hydro storage, demand-side management (including power-to-heat) and new power consumers (e.g. electric vehicles). The modelling also did not consider that renewables can and will take an active role in contributing to system services (such as the provision of balancing energy). System-friendly deployment (e.g. east/west orientation of PV) can also be part of the solution. Hence, the flexibility potential from other sources is large, but its development will require proactive policies and a favourable framework.

To sum up, improved integration of the power system can help meet future flexibility needs. The flexibility challenge is manageable from a technical standpoint, yet it is important to note that economic effects outside the scope of this study may affect the magnitude of the changes depicted here. In particular, power market design must provide economic incentives for investments in flexibility options. A timely, supportive regulatory framework needs to be enacted if a flexible power system is to arise.

prepared for Directorate-General Energy European Commission; and ECF, 2011. Power Perspectives 2030.

1. Renewables fuel European power system developments

A look at national energy strategies reveals an accelerating trend: Future power systems in Europe will increasingly be transformed by wind power and PV deployment. Despite all the differences in national generation mixes and energy policies, PV and wind power are expected to significantly shape the future power supply systems of most European countries. Germany has been at the forefront of the trend.

The move towards decarbonised power systems is a key measure for reducing global warming and its growing threat to global living conditions. The European Union recently adopted a new EU Energy and Climate framework, which targets a greenhouse gas reduction of 40 percent below 1990 levels and a 27 percent share of renewables in the EU energy mix by 2030. This translates into a renewable energy percentage of 45 to 53 percent in the power sector.[11]

Photovoltaic and wind energy are expected to be the pillar of this transformation. Both technologies have already experienced significant cost reductions through scale effects and are currently competitive with new conventional power plant technologies (in terms of levelised costs of energy generation - LCOE). Several studies (see infra) have found that a system based on PV and wind power – including back-up capacities – is a cost-effective option for decarbonisation.[12,13]
These technologies are expected to represent a significant share of the European energy mix by 2030.

11 See, e.g., European Commission (2011): Energy Roadmap 2050; IEA (2013): The Power of Transformation; EC (2014). Impact Assessment Accompanying the Communication A policy framework for climate and energy in the period from 2020 up to 2030.

12 Agora Energiewende (2013): Comparing the Costs of Low-Carbon Technologies; IRENA (2015): Renewable power generation costs in 2014; Fraunhofer ISE (2015): Current and Future Cost of Photovoltaics. Long-term Scenarios for Market Development, System Prices and LCOE of Utility-Scale PV Systems. Study on behalf of Agora Energiewende.

13 In order to compare the full costs of different technologies, one must think beyond the LCOE concept and take into account the integration costs (grid, back-up, balancing and "profile" costs).

Trends and targets in the countries of the Pentalateral Energy Forum

The increasing importance of PV and wind power is reflected in the national strategies of EU member states, particularly in the National Renewable Energy Action Plans (NREAP 2010) mandated by the European Commission, which set capacity targets for all renewable energy sources from 2010 until 2020. Figure 1 and Figure 2 indicate the respective PV and wind energy targets in the member countries of the Pentalateral Energy Forum (PLEF), as well as the current levels.[14,15] The dynamic growth between 2010 and 2013 corroborates the importance of wind power and PV, with 2013 targets being outstripped by development, especially for PV.

Recent national strategies for the development of renewable energy sources (RES) supplement the NREAPs. In 2014, Germany adopted a national target of 40-45 percent renewable energies in electricity consumption by 2025 and of 55-60 percent by 2035. In order to reach these objectives, the revised German Renewable Energy Act (EEG 2014) introduced an "expansion corridor" with yearly capacity expansion targets[16] of 2,500 MW p.a. for wind onshore (net) and 2,500 MW p.a. for PV (gross).

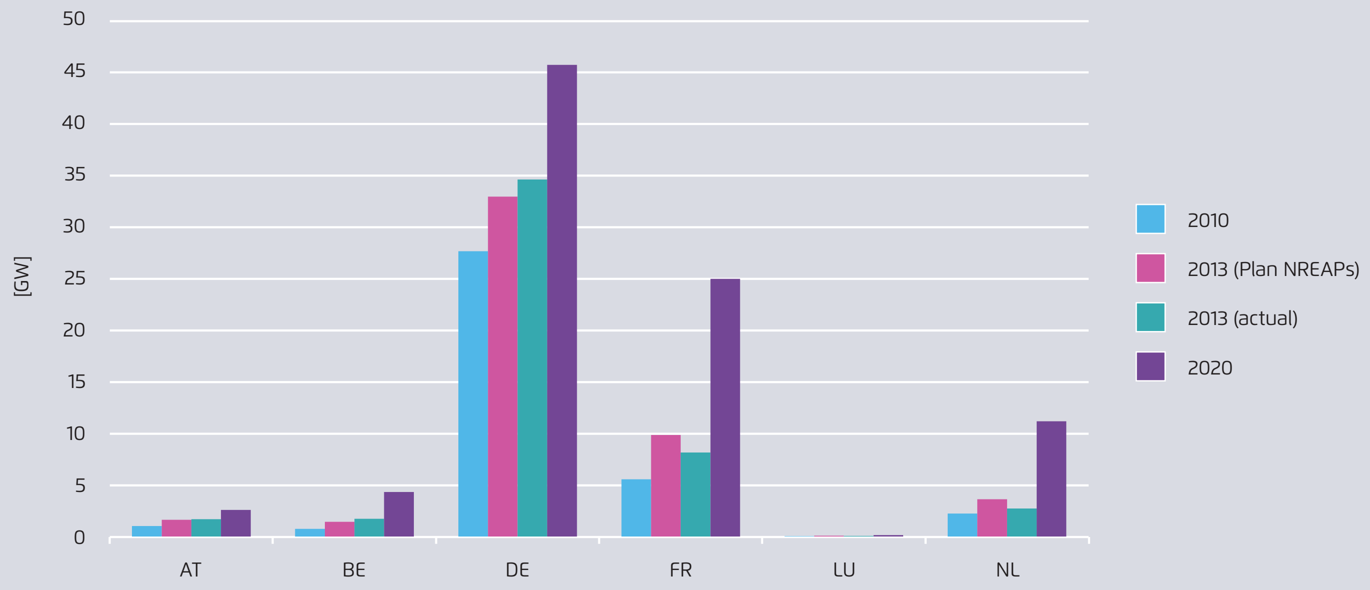
France also adopted new ambitious targets to diversify its power mix. In summer 2014, the French government adopted a bill for energy transition towards green growth, which among other things sets targets to reduce the share

14 Switzerland, an observer in the PLEF, is not depicted in Figure 1 and 2 as it is not an EU member and thus has no obligations to develop an NREAP.

15 Data for the current share of PV and wind power are from the Photovoltaic barometer (2014) and the Wind energy barometer (2014) by EUROBSERV'ER (www.eurobserv-er.org).

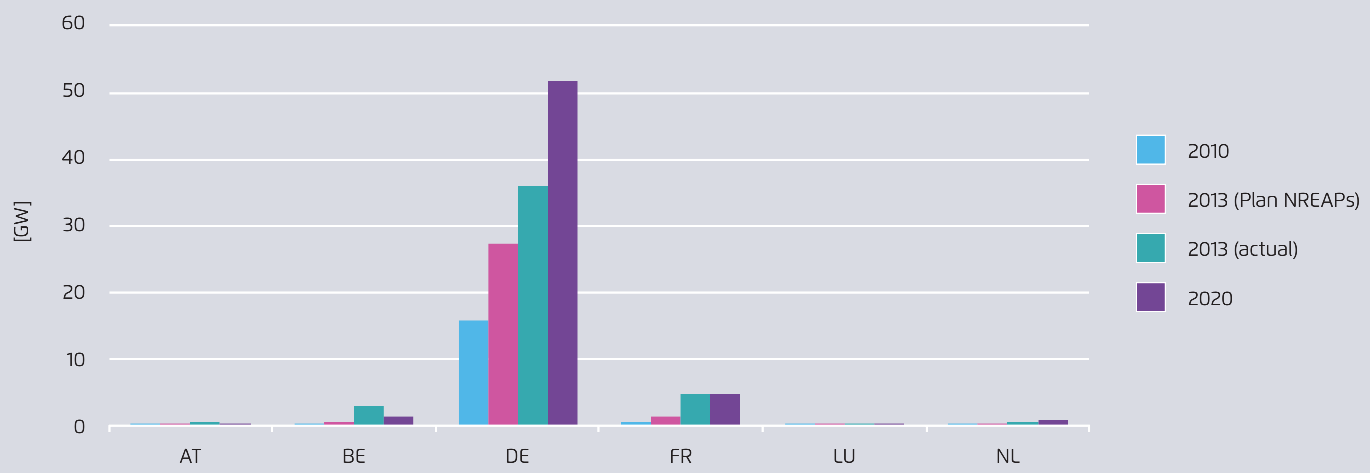
16 A flexible system for setting the remunerations allows an adjustment of the deployment in case the capacities miss the targeted expansion path.

Installed capacities for wind power (onshore and offshore) according to the NREAPs and actual 2013 values. Figure 1



Fraunhofer IWES, based on NREAPs and Wind Energy Barometer 2014

Installed capacities for PV according to NREAPs and actual 2013 values. Figure 2



Fraunhofer IWES, based on NREAPs and Photovoltaic Barometer 2014 of nuclear energy in the power mix to 50 percent by 2025 (as opposed to 72 percent in 2012) and to increase renewable energy in final energy consumption to 32 percent by 2030 (2012: 16 percent). In the power sector, a multi-annual energy plan – to be adopted by the end of 2015 – will set concrete objectives for installed capacities of renewable energies. This could mean a share of about 40 percent renewables in electricity consumption by 2030.

Similar trends can be observed in the other PLEF countries. In Austria, the installed capacity of wind power and PV amounted to 1.1 and 0.24 GW in 2011, respectively. Recent TSO forecasts project 4 GW of wind onshore and some 3 GW of PV by 2030. The Swiss energy strategy 2050, currently being discussed in parliament, foresees a 25 percent share of renewables other than hydropower in final electricity consumption by 2030 and a 45 percent share by 2050.[17]

As for the BENELUX countries, the Netherlands envisages an increase in the share of renewables in the domestic energy mix from 4.5 percent in 2013 to 16 percent in 2023. Obviously, the share in the electricity mix is higher relative to the respective share in the energy mix. Recent and planned policy measures indicate a 50 percent RES-E share in the electricity generation mix by 2030.[18] For Belgium, scenarios for the realisable potential of RES-E in 2030 final energy consumption show values ranging from 32 to 43 percent. Luxembourg cannot easily be compared with the other countries of the PLEF region with regard to energy strategies and according developments, due to its size and location. Like the other BENELUX countries (and Austria and Switzerland), binding energy policy targets do not yet exist for 2030.

Input data for our scenario analysis

This study assesses the power system transformation of PLEF countries in the context of political momentum and economic trends in favour of renewable energies. Data from national energy strategies, national grid development plans and ENTSO-E's recent Scenario Outlook & Adequacy Forecast (SO&AF) served as input for our study.[19] These data are summarised in Figure 3, which shows the installed capacities of wind power (onshore and offshore) and PV in the countries of PLEF for 2030, along with the expected peak load. Since France is currently reshaping its energy and climate policy, we decided to consider two different scenarios for the transformation of the French power system based on the recent forecasts given by the French TSO RTE.[20] One ambitious scenario, called "new mix", shows a share of renewable energies in power consumption of about 40 percent by 2030. This scenario is the reference scenario for the general scope of this study. A second, "diversification" scenario envisages a share of renewable energies of 30 percent in the French power system. This scenario will be discussed specifically in the section devoted to France (Section 5.2).

As can be seen from Figure 3, in all countries of the PLEF region, wind power and PV installed capacities will reach levels close to or even above the national peak load. The simulations project that by 2030 some 35 percent of annual net electricity consumption will be met by wind power and PV in PLEF countries. This illustrates the importance of these technologies for future PLEF power systems. Though energy policies have been enacted that are committed to PV and wind power, their development may be facing public resistance, slowing down the achievement of national targets.

17 68% of final electricity consumption is projected to be met by hydropower in 2035.

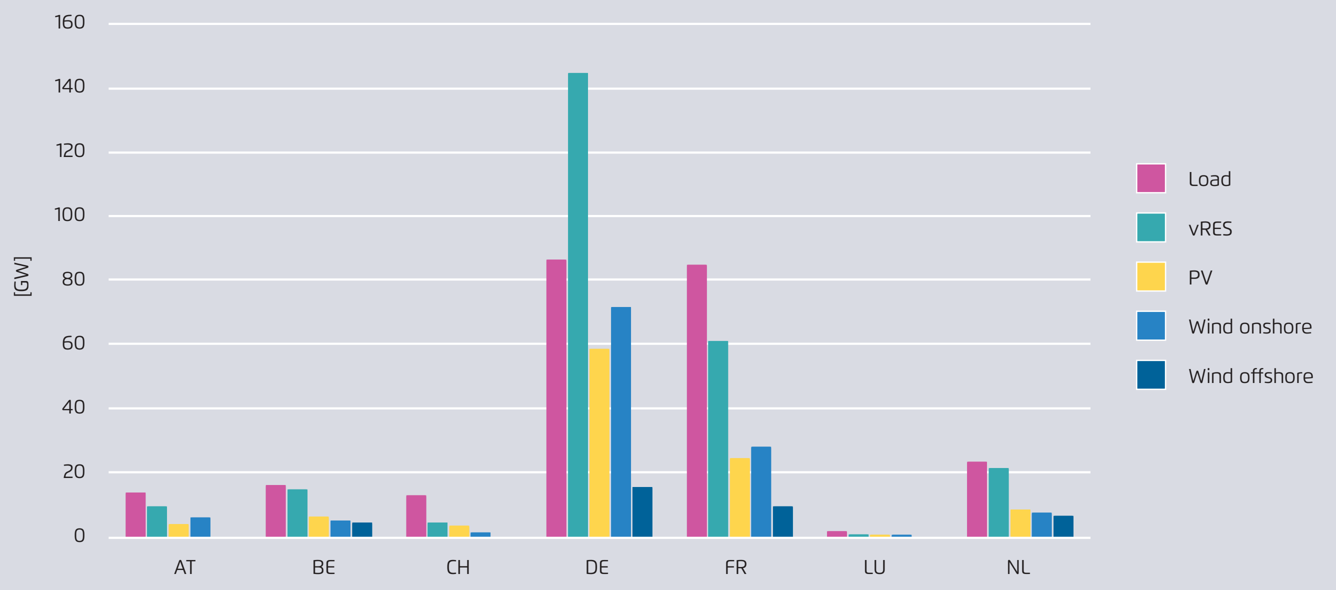
18 ECN and PBL, 2014. Nationale Energieverkenning 2014, Petten.

19 See the appendix on input data and scenario selection for detailed information.

20 RTE, 2014. Generation adequacy report on the electricity supply-demand balance in France.

2030 installed wind onshore, wind offshore and PV capacities and peak loads in the countries of the Pentalateral Energy Forum. For France, values for the "new mix" scenario are shown.

Figure 3



ENTSO-E (2014), national strategy documents

The box presents more details about the applied input data.

Aside from wind power and PV, there are other important renewable energies that will contribute to a decarbonised energy system. Hydropower has been used for many years and currently provides a significant share of power production in Scandinavia and the Alpine countries. In conjunction with pumps, hydropower can serve as energy storage (helping integrate weather-dependent variable renewables (vRES) such as PV and wind power). Even without distinct pumps, hydropower provides flexible storage and dispatchable power. During times of excess generation from vRES, the utilisation of stored hydropower can be reduced to save hydro energy for later use. In most countries, however, hydropower potential is limited and will not increase considerably in the future.

Another potential technology is biomass, which can be used to complement weather dependent vRES. Yet biomass has become controversial in recent years due to conflicts with food production, costs of biomass production and environ-

Input data for the simulated scenarios

Country level input data was compiled to perform the simulations. The data comprises annual electricity consumption, annual peak load, installed renewables capacities and net transfer interconnector capacities. The data was derived from national energy strategies, national grid development plans and, for countries where such information was lacking, from ENTSO-E's recent Scenario Outlook & Adequacy Forecast (SO&AF) 2014-2030 and ENTSO-E's Ten-Year Network Development Plan.

The input data sources yield little changes of the peak load levels, but show strong increases in wind power and PV capacities (contributing to some 54 percent of annual net electricity consumption being met by RES in the PLEF in 2030). This assumes a 41 percent increase in interconnector capacity across Europe by 2030 relative to today. Since PLEF countries currently show above-average internal interconnector capacities, the interconnection level between PLEF countries will increase by 22 percent, whereas the interconnection level between the PLEF and remaining EU countries will increase by 76 percent. For more information, see the appendix on input data and scenario selection.

mental impact (including concerns about the carbon footprint left by biomass production). Energy technologies such as tidal power, wave power and energy from osmosis are still in the research stage and not yet ready for large-scale deployment.

In the sections that follow, the projected 2030 levels of renewable generation capacities will serve as a starting point for our simulations of the European power system. Unsurprisingly, power system operations are significantly affected by increasing shares of variable renewables. What is especially crucial is increased system flexibility. Continuing to link power systems across borders is an important part of mitigating flexibility needs.

2. Geographical smoothing effects: Mitigating flexibility needs from vRES deployment

Section 1 provided a snapshot of the future European power system as well as its installed capacities. We will see that increasing output from fluctuating renewables is associated with the need for enhanced power system flexibility. Spatial smoothing, facilitated by strong electricity grids, plays a key role in integrating high shares of vRES. This section shows that integrating vRES over larger geographical areas is made easier by geographical smoothing effects – at the levels of both generation and demand. Smoothing effects from generation arise from different weather regimes across Europe (Section 2.1). Decorrelation between load profiles across countries also permits some (less pronounced) smoothing effects on the demand side (Section 2.2). We conclude with a short outlook (Section 2.3).

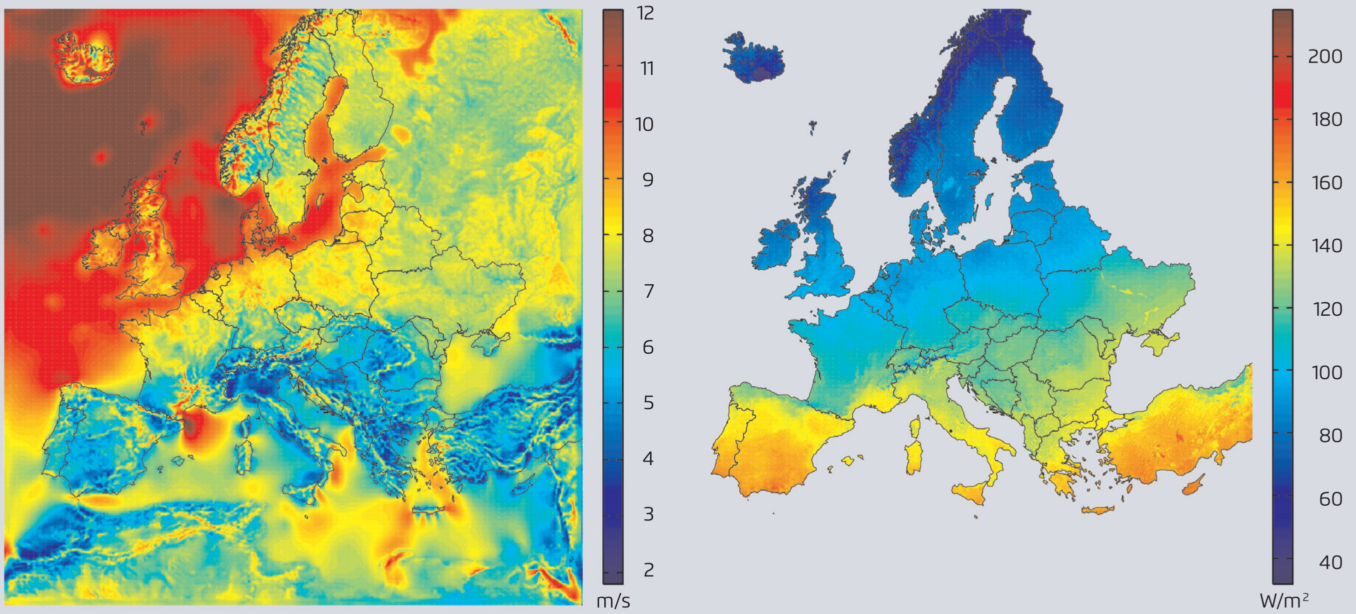
2.1 Smoothing effects of wind and PV

The effects of different weather patterns

Several reasons contribute to the geographical smoothing of vRES, notably wind power and PV generation. Wind and sun patterns have a tendency to be balanced in Europe: locations with good wind conditions in Northern Europe are characterised by low levels of irradiation and less windy locations in Southern Europe are more likely to be sunny (see Figure 4). The monthly amounts of PV and wind power production for Europe are depicted in Figure 5, showing that decreasing wind power output in the summer is offset by higher PV generation and vice versa, with only slight differences between monthly output levels. Note that the only values that stand out are those for wind power in December. This is because the wind speeds in December 2011, on which the

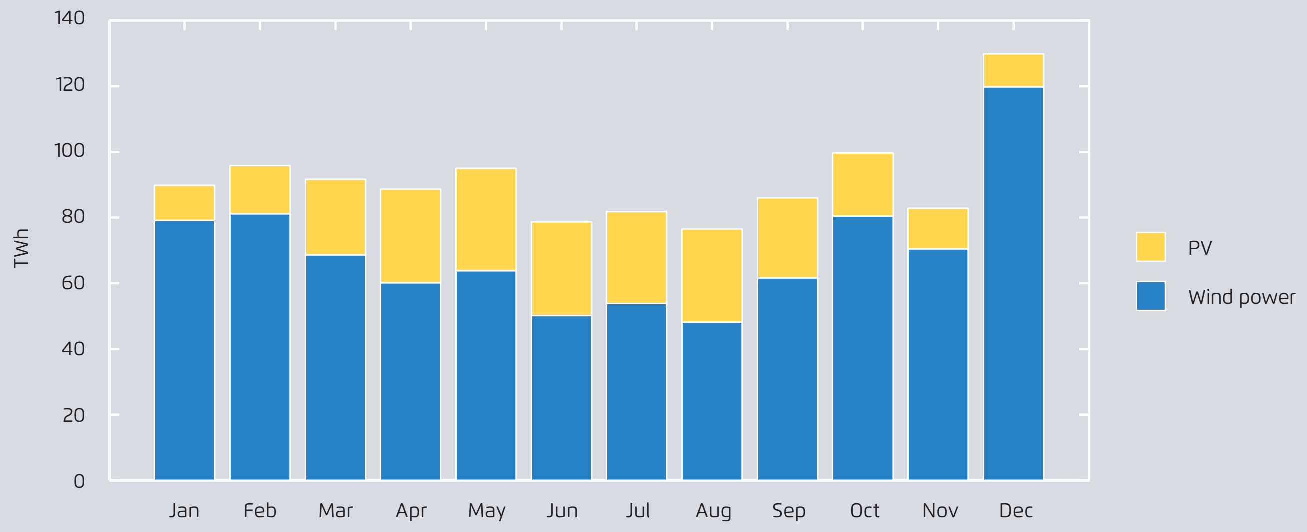
Wind and solar resource throughout Europe for the year 2007. Average wind speed approx. 70 m above the ground (left) and average global horizontal irradiation (right).

Figure 4



Fraunhofer IWES, based on COSMO-EU data from the German Meteorological Service

Seasonal energy production of PV and wind power in EU 2030. Figure 5



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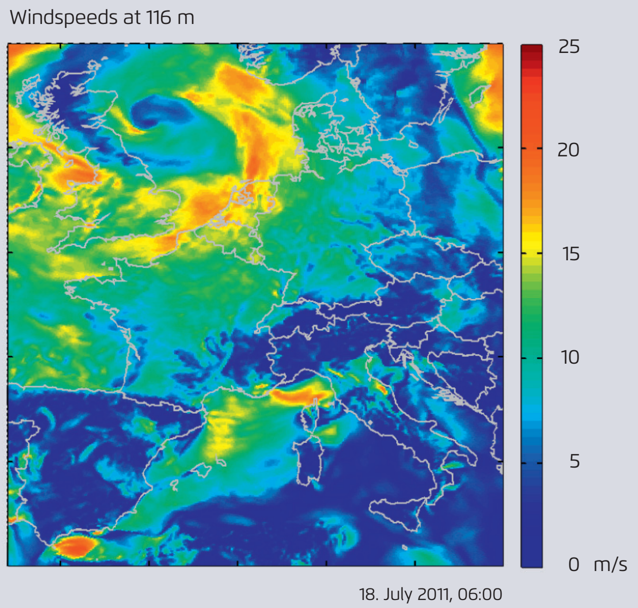
Wind speeds over Europe on 18 July 2011 between 6 AM to 7 AM at a height of 116 m. Figure 6



Fraunhofer IWES, based on COSMO-EU data from the German Meteorological Service

simulation was based, were exceptionally high. But aside from statistical outliers, the aggregated monthly vRES output is more or less evenly distributed over the year.

A second source of smoothing arises from the unequal distribution of wind speeds at the EU scale, as shown in Figure 6. Air masses flow from a high-pressure area to a low-pressure area while being deflected by the Coriolis force. This leads to circular regions of increased wind speeds over the North Sea, affecting the Benelux countries, Germany and France. By contrast, the Alpine countries, Spain, Italy and Eastern Europe have relatively low speeds.

In some areas so-called thermal winds can be caused by temperature gradients between neighbouring regions. Examples for such thermal winds are land and sea breezes as well as mountain and valley winds caused by certain geographic formations. An additional smoothing effect is expected from wind power installations in these regions, where winds are less correlated with dominating wind patterns due to flows between high and low pressure systems.

Usually, within an area as large as Europe, there are regions where, at times, wind power production is high, yielding high total generation, and other regions where it is low at the same time (the latter using imports or thermal generation to meet demand).

Quantifying the smoothing effect

Several parameters capture the geographical smoothing effect of vRES generation.

One parameter showing the geographical smoothing effect for vRES is the simultaneity factor, which is the maximum (highest occurring) value of feed-in relative to the installed capacity (P_{max} / P_{nom}). For a single renewable generation unit, this factor is equal or close to 100 percent, and decreases as the area of power plant distribution grows larger. Table 1 shows the simultaneity factors of PV and wind onshore for individual PLEF countries, the PLEF region as a whole and for all modelled European countries. As the table shows, these factors are higher for individual countries than for groups of countries. This implies that, in the aggregate, single power generation peaks are smoothed out and hence easier to integrate. With PV and wind onshore taken together, the smoothing effect becomes even more pronounced.

Another indicator of geographic smoothing is power generation as a percentage of installed capacity. Figure 7 presents the indicator for wind power at different aggregation levels for May 2030, based on weather in 2011. The time series for a single pixel (representating an area of ~8 km²) fluctuates heavily, with high peaks as well as times of almost no production. The larger the aggegation gets, the smoother the time series become. At the European level, instantaneous wind power output is generally much less volatile, so that extremly high or low values disappear. In Table 2, the coefficients of variation for wind power feed-in are shown at different levels of aggregation. The coefficient of variation is a standardised measure for the statistical variation of a data set. A high coefficient of variation indicates data spread over a wide range around the mean value. The values decrease as the area increases. For Europe, the coefficient of variation is only one third the value of a single pixel.

Figure 8 takes this analysis further and expands it to a full year. It depicts the relative frequency of wind power generation as a percentage of installed capacity for 2030. For smaller areas, feed-in close to zero occurs frequently, but also extremely high values close to the installed capacity do happen. The larger the considered area, the fewer extreme values. The prevailing feed-in values are located mainly in the centre of the spectrum.

This smoothing effect becomes even clearer when considering the gradients (the changes in output from one hour to the next) of the wind power feed-in for the year 2030. Figure 9 depicts the relative frequencies of onshore wind power feed-in gradients for different levels of aggregation. For a single pixel, high ramps of about 20 percent of the installed capacity do occur, while smaller ramps happen less

Simultaneity factors of vRES in PLEF countries and Europe simulated for 2030 (based on meteorological data of 2011). The values indicate that single generation peaks are mitigated over larger areas. Table 1

	AT	BE	CH	DE	FR	LU	NL	PLEF	Europe
PV	77 %	71 %	76 %	73 %	69 %	71 %	72 %	71 %	67 %
Wind onshore	88 %	93 %	84 %	89 %	83 %	93 %	91 %	82 %	66 %
PV + Wind	71 %	62 %	64 %	62 %	59 %	72 %	65 %	54 %	46 %

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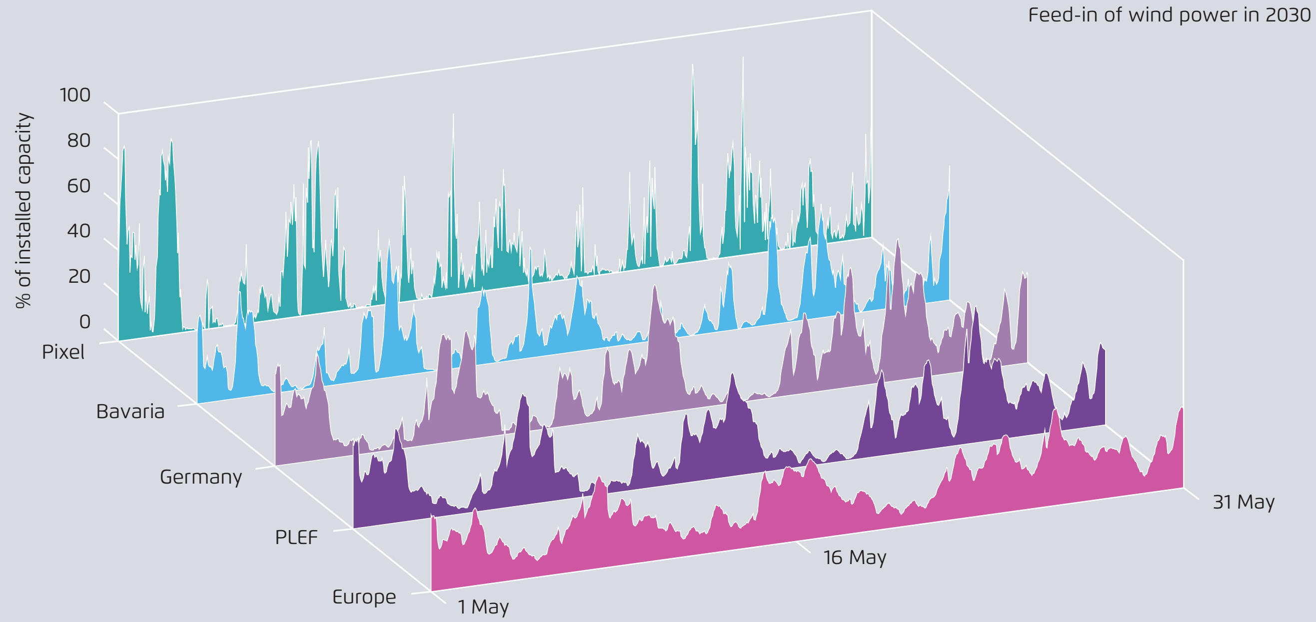
Time series of onshore wind power generation in a simulation for May 2030 at different levels of aggregation (as a percentage of the installed capacity). One pixel is equivalent to an area of 2.8 x 2.8 km. Figure 7



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Coefficient of variation of onshore wind power generation based on the average feed-in for different levels of aggregation in May 2030. Table 2

May 2030	Pixel	Bavaria	Germany	PLEF	Europe
Coefficient of variation	1.20	0.98	0.78	0.68	0.41

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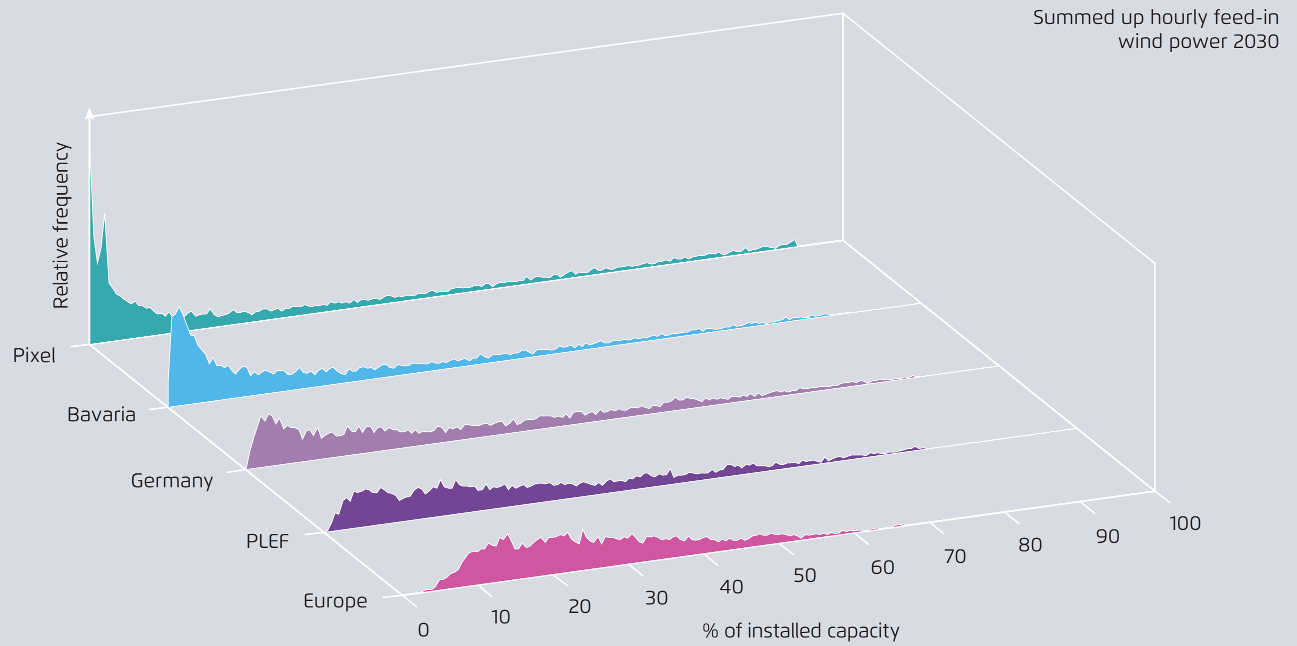
frequently relative to regions with larger surface area. The larger the aggregation area, the rarer high ramps become. For Europe, gradients larger than +-5 percent of installed capacity occur only during 23 hours of the year. The single largest occurring hourly ramp is -10 percent of installed capacity. For residual generation, which balances changes from the vRES feed-in, the technical requirements for steep ramps are challenging and result in higher power generation costs. This means that grid stability and modest electricity production costs are strengthened by a smoothed power feed-in with low gradients, as result from widely spread vRES power plants.

The main factor determining power output of PV installations is solar irradiance. It predominantly depends on the angle between the sun and the PV module as well as on clouds and haziness. Cloud cover and sky clearness are subject to similar meteorological influences as wind speeds. Therefore, similar coherences apply in relation to the geographical smoothing effect. The second factor influencing

Relative frequency of hourly onshore wind power feed-in in 2030 for different levels of aggregation. Figure 8



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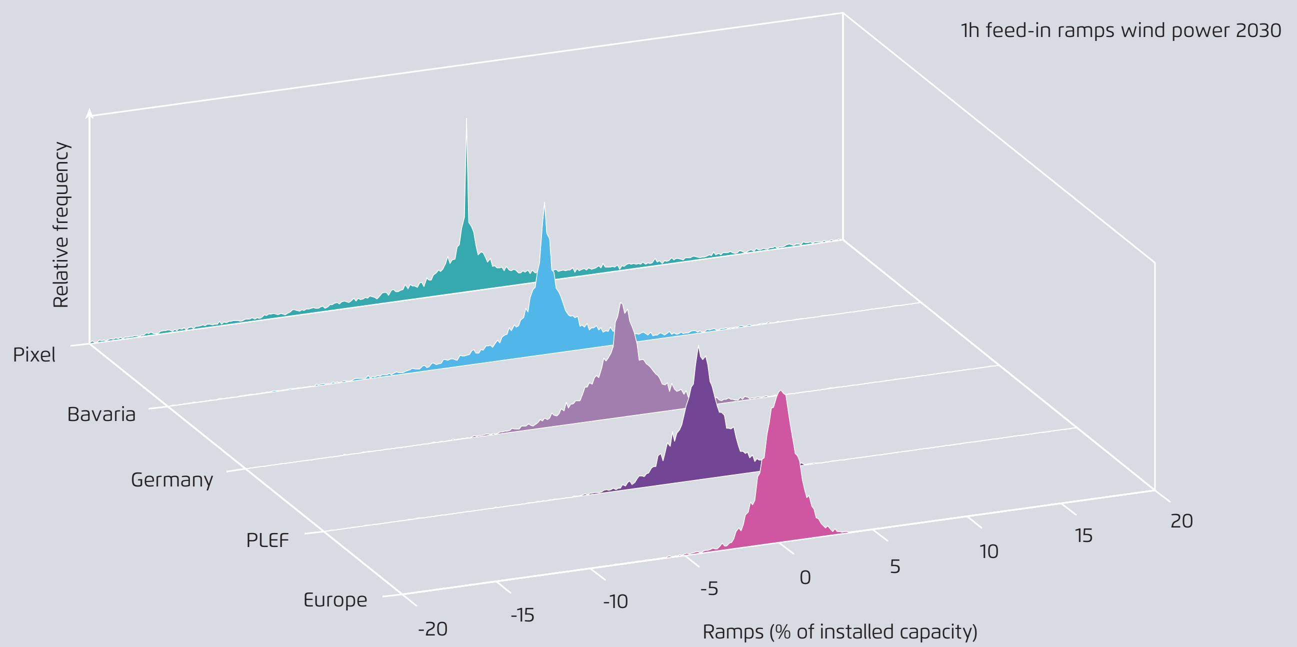
Relative frequencies of hourly changes in onshore wind power output for the year 2030 at different levels of aggregation. Figure 9



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insolation – the position of the sun in relation to the module – affects PV power plants throughout Europe in a comparable fashion.[21] With fixed PV modules, the diurnal and annual course of the sun largely determines PV output. While there are some differences resulting from different geographical latitude as well as some minor temporal shifts due to differences in longitude,[22] daytime and season are the dominating parameters affecting PV output. That explains why PV feed-in follows a very similar pattern in different regions (though some variability remains due to clouds and overcast skies).

21 PV modules are usually installed in a manner to optimise annual yield per installed capacity. That means that open-space installations are commonly facing south and are tilted at an angle around 20-40° (depending on the latitude). With reduced costs for PV modules, east-west-oriented installations have become increasingly popular. While the energy yield per installed capacity decreases, yield increases in relation to surface area. By contrast, orientation of rooftop PV installations varies as a function of available roof area, with those facing to the south being favoured for a higher return of investment.

22 A difference of 15° of longitude (about 1000 kilometers east-west in central Europe) equals a 1-hour shift of time.

For those reasons, the smoothing effect of PV is much less pronounced than for wind power.

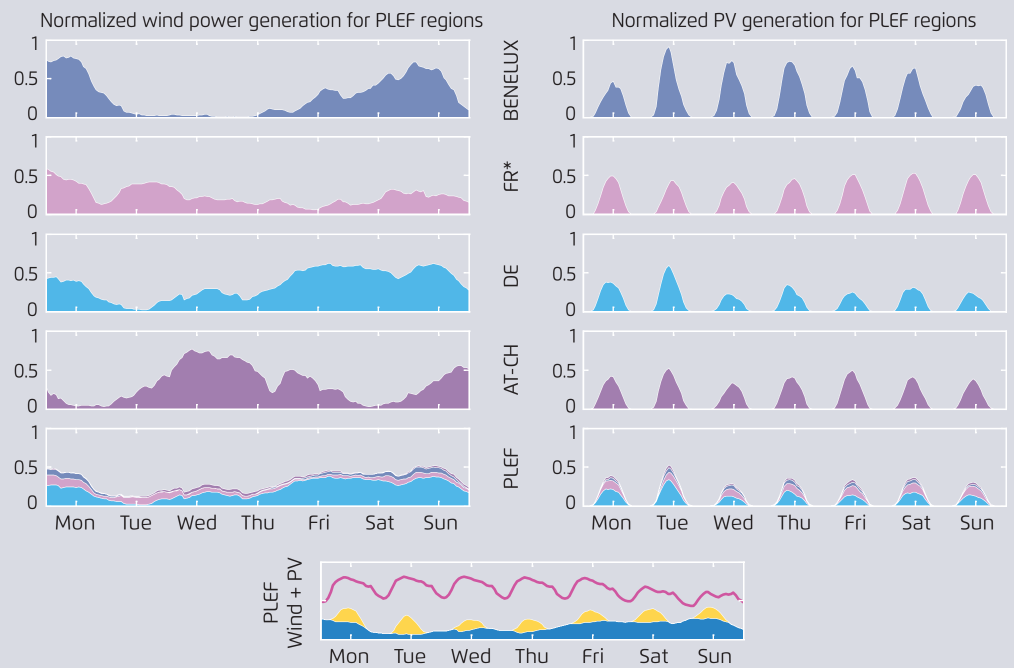
Finally, Figure 10 shows both wind power and PV generation[23] for each PLEF country or subregion as well as aggregated over the whole PLEF region for a selected week in July. Obviously, the total wind power generation is considerably affected by the geographical smoothing effect occurring in the region as a whole; the PV generation profile is mostly determined by the diurnal course of the sun.

2.2 Smoothing effects of electricity demand

Taking a closer look at the smoothing effects on the demand side, we notice that the non-simultaneous pattern of electricity demand is caused in part by different activity profiles. Societal differences and slightly varying hours of

23 This is the potential simulated feed-in without taking into account possible curtailment or transmission losses.

Normalised onshore wind power and PV generation during a week in July for the PLEF region. Figure 10



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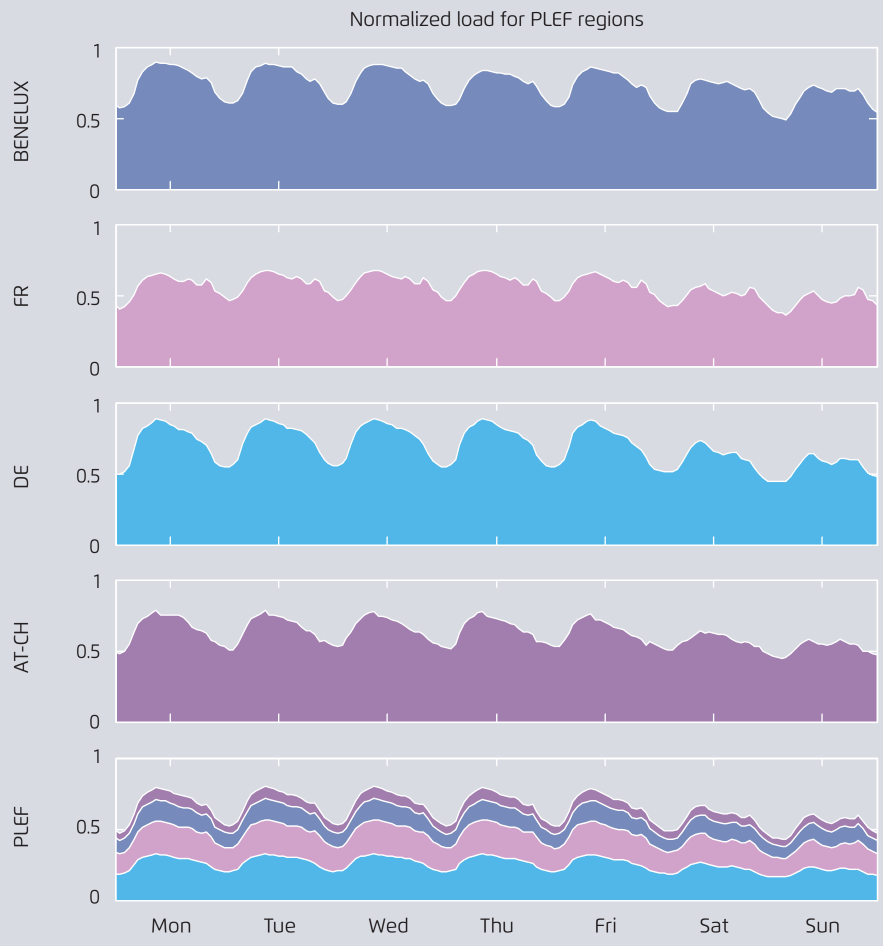
daylight result in annual peak loads in different regions at different daytimes and at different times of the year.

The simultaneity factors for the load, specifically when comparing the peak load of one region with the total peak load (i.e. the sum of all country peak loads, whether or not concurrent), show a small smoothing potential in PLEF countries. For a single country, the value is 100 percent by definition; it is slightly reduced for larger areas. In the 2030 simulation, the simultaneity factor is about 98 percent for the PLEF region and about 97 percent for Europe. Thus, the the peak load of the entire PLEF and EU region is 2 percent and 3 percent respectively lower than the sum of the individual country peak loads.

Figure 11 depicts one-week load profiles for four sub-regions of the PLEF and the aggregated PLEF region. Clear day/night effects can be observed in all profiles. This is not surprising because load is usually higher during daytime. Furthermore, lower energy consumption on weekends is visible in all regions, though the diurnal shapes vary from each other. This smoothes out the triangular shape of the AT-CH load profile and regionally mitigates the evening peak in French power consumption, as shown in the aggregated load profile of the whole PLEF region.

Load profiles as observed in the PLEF region for a week in July, normalised to peak load. Figure 11



Fraunhofer IWES, based on ENTSO-E data

For southern European countries the seasonal load differences are smaller. But load profiles are influenced not only by shifted diurnal activities but also by changing temperatures due to increased heating (northern countries, winter months) and cooling (southern Europe, summer months). Hence, regional differences in ambient temperature also result in a smoothing of temperature-dependent power demand. But since especially cold weather situations (e.g. the "Siberian anticyclone") often affect a large part of Europe, this smoothing effect for the annual peak load is not particularly pronounced.[24]

2.3 Outlook

We showed in this section that smoothing effects occur when aggregating wind power and PV generation over a large area. This results in lower peaks relative to average production, in fewer situations where no or little power is generated and in softer and slower output changes. These factors are of great use because they reduce flexibility requirements. This reduces the balancing power that needs to be provided and the capacities that need to be backed up. It also lowers the amount of energy that needs to be curtailed at times with a high vRES feed-in, freeing more up for export to regions where the load is not yet covered. In the next section we describe the many benefits of increased grid integration.

24 Nevertheless, significant benefits arise from assessing supply security regionally instead of nationally. A more detailed account is beyond the scope of this report.

3. Integration of European power systems: Utilising the vRES potential through cross-border exchange

As seen in section 2, integrating power generation over large areas such as Europe creates smoothing effects for inflexible vRES and load. This section takes a closer look at the impact on the power system as a whole.

Two scenarios were developed, assessed and compared in this study. The first scenario is characterised by electrical autarchy, in which neither imports nor exports take place. Power surpluses have to be curtailed and power deficits have to be balanced with increased production in thermal or hydro storage power plants. This autarchy scenario is purely theoretical, as power flows between countries occur all the time (to the maximum extent available). While unrealistic, the "autarchy vision" of national power systems often frames political and public discussions. We therefore use it as a "reference" scenario to measure the benefit of ongoing integration. In the second scenario (referred to as "integration"), a certain amount of cross-border interconnection capacity is assumed, allowing countries to exchange power on the basis of realistic net transfer capacities (NTCs) between countries through 2030. (See the modelling and data appendices for further details.)

Correlation coefficients (based on Kendall's tau rank) between PLEF countries for load, wind onshore and PV generation. Table 3

Load	AT	BE	CH	DE	FR	LU	NL
AT	100%	72%	57%	82%	57%	57%	74%
BE	72%	100%	63%	73%	66%	57%	70%
CH	57%	63%	100%	54%	73%	43%	48%
DE	82%	73%	54%	100%	52%	61%	77%
FR	57%	66%	73%	52%	100%	43%	49%
LU	57%	57%	43%	61%	43%	100%	54%
NL	74%	70%	48%	77%	49%	54%	100%

Wind	AT	BE	CH	DE	FR	LU	NL
AT	100%	24%	45%	35%	27%	29%	22%
BE	24%	100%	27%	49%	55%	66%	60%
CH	45%	27%	100%	28%	39%	32%	22%
DE	35%	49%	28%	100%	33%	47%	58%
FR	27%	55%	39%	33%	100%	52%	34%
LU	29%	66%	32%	47%	52%	100%	44%
NL	22%	60%	22%	58%	34%	44%	100%

PV	AT	BE	CH	DE	FR	LU	NL
AT	100%	82%	89%	90%	83%	83%	83%
BE	82%	100%	86%	88%	87%	92%	94%
CH	89%	86%	100%	90%	90%	87%	86%
DE	90%	88%	90%	100%	86%	89%	88%
FR	83%	87%	90%	86%	100%	86%	86%
LU	83%	92%	87%	89%	86%	100%	90%
NL	83%	94%	86%	88%	86%	90%	100%

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3.1 Correlation of load, wind and PV across countries

For the autarchy scenario it does not matter how vRES feed-in or load patterns differ between countries as there is no interconnection capacity anyway and geographical smoothing across borders does not occur. In the integration scenario, smoothing effects play an important role. To characterise the scale of smoothing, we calculated the correlation coefficients of load, wind onshore and PV time series for pairs of PLEF countries. The Kendall's tau rank correlation coefficients are depicted for load, wind power and PV generation in Table 3. The Kendall's tau rank correlation coefficient considers both linear and nonlinear dependencies between the normalised time series, providing a comprehensive picture of how similar, or coupled, they are. The correlation of each country's time series with itself is always 100 percent, implying that the compared time series are identical. Two completely random and uncorrelated time series would yield a value close to zero. Accordingly, the benefit of integration over large areas tends to be higher the weaker the correlated load and vRES feed-in patterns are. Looking at the table, one can see that PV generation is most closely correlated between countries, whereas wind power generation is least correlated between countries. Correlations between small neighbouring countries are usually higher than between countries that are more distant. The coefficient communicates information about the link between cross-country outputs in general while leaving out behaviour in specific situations. Feed-in patterns between two countries can be moderately correlated in general (e.g. when assessed over a full year), though the feed-in pattern may be quite similar at times. Accordingly, the benefit of integration decreases as the correlation of simultaneous events increases. Typical situations might be "cold and calm" weather situations in winter caused by high pressure areas, which result in almost no wind power feed-in over large parts of Europe.[25] There are also times when the wind level is high in most countries, leading to surpluses and "congested" interconnectors. We can thus conclude that grid integration is mostly useful for weakly correlated events.

25 Pöyry, 2011. The challenges of intermittency in North West European power markets.

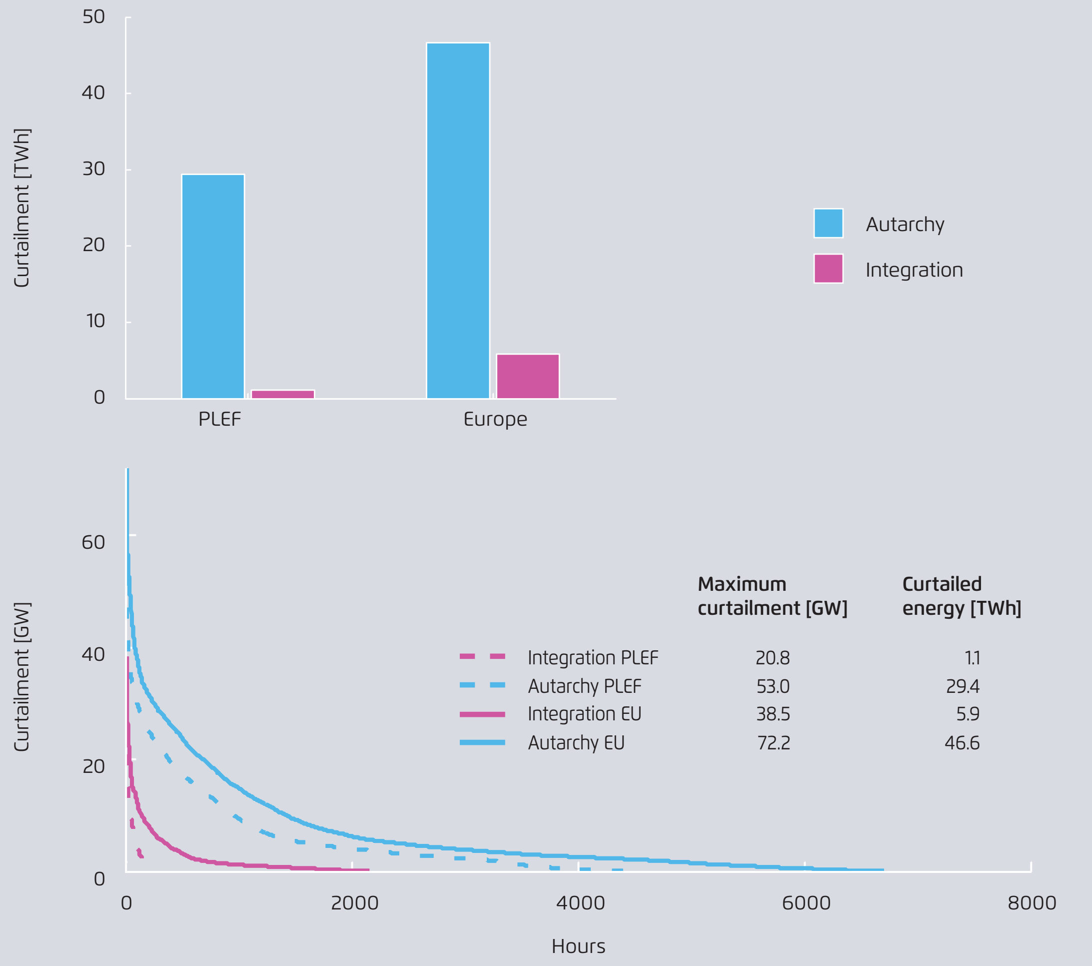
3.2 Renewables curtailment: Integration vs. autarchy

A benefit of power system integration arises from vRES and load being less than perfectly correlated between countries. The mentioned numbers in Figure 12 show the amount of curtailed vRES energy within the simulated year 2030 for both scenarios for the PLEF region and Europe. The curtailment in the autarchy case is about ten times higher due to missing interconnections and exchange options with other regions. Avoiding curtailment generally would be difficult to achieve just by increasing net transfer capacities, as highly correlated feed-in situations might occur. In any case, grid integration prevents a large amount of surplus renewable energy from being "thrown away".[26] Figure 12 shows that in the integration scenario not only is the amount of curtailed energy lower; the hours in which power is curtailed decreases significantly. On the European level without integration, curtailment would occur almost every hour of the year (7217 hrs). Yet, even with grid integration, rare but high feed-in peaks of vRES occur in multiple countries and that cannot fully be balanced by grid integration (Figure 12). In other words, a limited number of hours with curtailment can also be found in the integration scenario. With the presumed expansion of interconnectors in Europe, curtailment is necessary during approx. 2150 hrs. All other hours with local surpluses can be balanced through integration (i.e. by exporting). Through the assumed interconnection levels, limited curtailment takes place in the PLEF region only in 205 hours of the year. The curtailed energy is equivalent to 0.41 percent of European vRES generation and to 0.16 percent of the PLEF region.

It is important to point out that not only is the autarchy scenario hypothetical; also the assessed integration scenario is based on simplifications. It assumes that power transfer within each country benefits from a "copperplate", implying that any grid constraints within a country are not taken into account. Moreover, the model is focused on the simulation of the active power balance, whereas inertia or reactive power demands are not considered. Many existing flexibil-

26 Alternatively, the surplus power could be stored.

Curtailed energy of vRES within the PLEF region and Europe (top figure) and annual curtailment duration curves, maximum curtailed power and annual amount of curtailed energy for the PLEF region and Europe (bottom figure) in both the autarchy and integration scenarios. Figure 12



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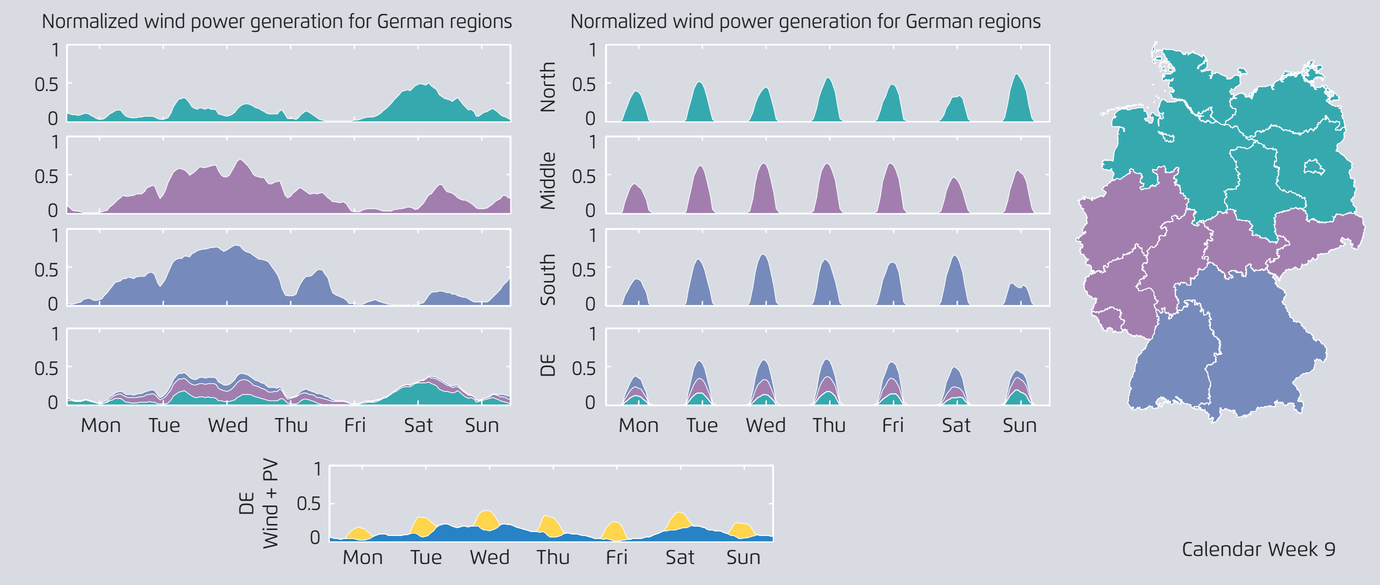
ity options were not considered either, including pumped storage plants, power-to-heat options or demand-side management. These flexibility options would allow surplus power to be utilised instead of curtailed.

Domestic issues for renewables integration

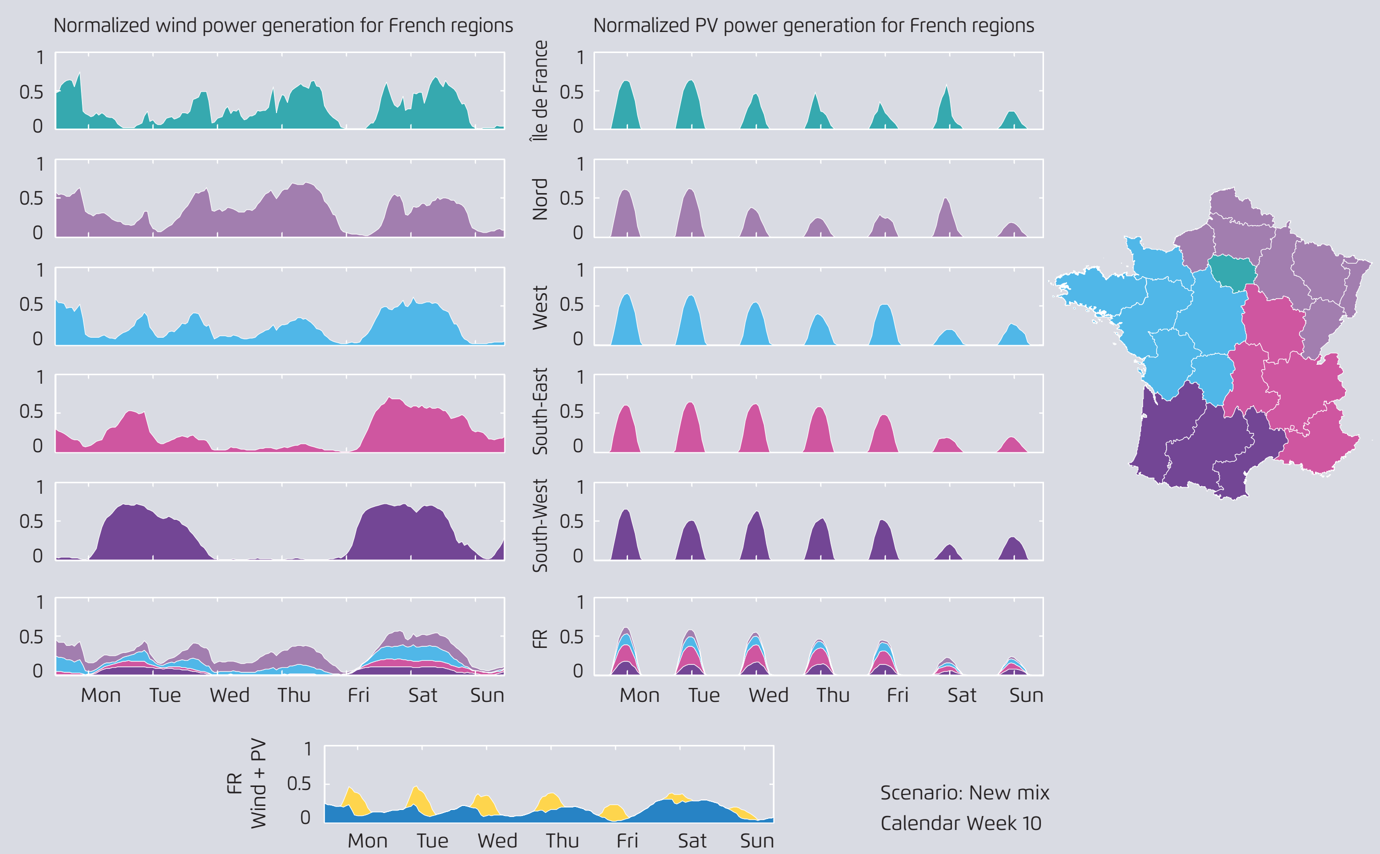
Though we did not model domestic grid constraints, we want to provide a brief glimpse into the integration of domestic renewables. Unsurprisingly, large countries such as France and Germany can benefit from internal smoothing effects. The following graphs point to the benefit of integration within a country (and the importance of domestic grid reinforcement in case of grid congestions within a country). Figure 13 depicts the smoothing effects within Germany, divided into three regions from north to south. The northern part is dominated by wind power; the south has more PV. Figure 14 shows a similar analysis for France across five regions.

The aggregation of the fluctuating wind power feed-in for each region yields a flattened feed-in curve for the whole country. With regard to PV, the domestic smoothing effects create a more homogeneous feed-in curve. Flat-topped or frayed feed-in curves of a single region follow the typical

Smoothing effects of vRES feed-in within Germany for calendar week 9. Figure 13



Smoothing effects for vRES feed-in within France for calendar week 10. Figure 14



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"course of the day" shape, and mostly differ in height. This makes forecasting easier, especially when considering ramps.

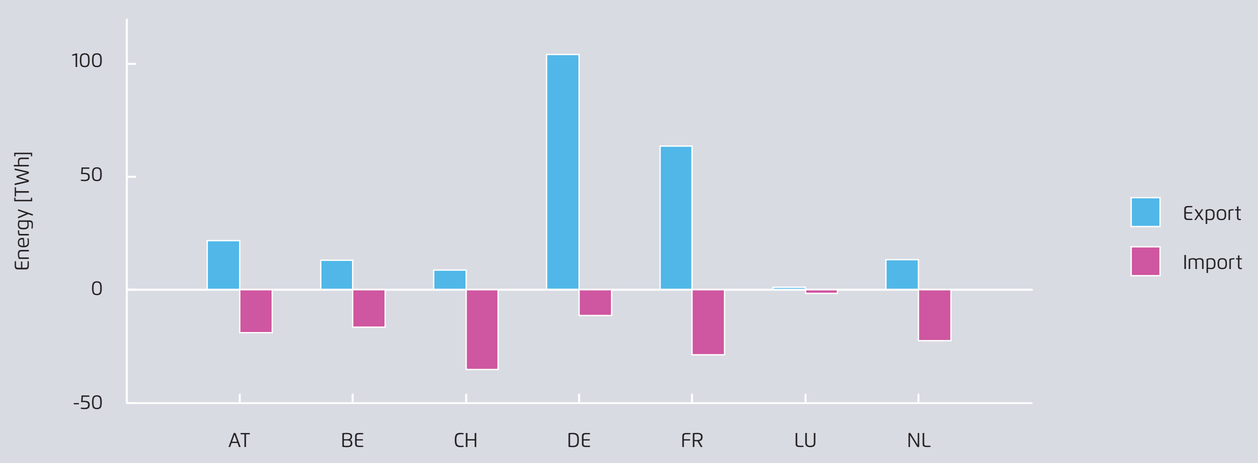
3.3 Cross-border electricity flows

In addition to the assessment of (avoided) renewables curtailment, the amount of electricity imports and exports gives insights into the benefits of integration. The aggregated imports and exports of PLEF countries with their neighbours are shown in Figure 15 (for the integration scenario only). All seven countries show transfer activity in both directions, where Austria, Germany and France are net exporters and Switzerland and the Benelux countries are net importers. For Germany, the exported amount of energy equals more than five times the amount of the curtailed energy in the autarchy scenario. For countries with a lower share of vRES, the relation is even higher. Accordingly, interconnectors between neighbouring countries not only enormously decrease curtailment but also reduce the costs of power generation, as the power plants with the lowest marginal costs can be chosen across country borders.[27]

While Figure 15 showed yearly aggregated numbers, Figure 16 and Figure 17 present snapshots of cross-border power flows within Europe alongside the share of load coverage by vRES. The first figure shows a sunny hour around noon in spring, when countries in southern Europe are able to cover a significant share of their load by PV. Here exports from the South (Spain, France and Italy) tend to flow towards the North. Figure 17 shows a different situation, when Denmark's high wind power feed-in allows power to flow somewhat from north to south. In both situations, Germany and France export domestic surpluses. The BENELUX countries mainly serve as a transit region, providing flexibility. The Alpine countries also provide flexibility insofar as they act as power drains.

27 Note again that a synthetic power plant park was assumed for our simulation, resulting in slightly adulterated power flows.

Imports and exports of electricity in 2030 for the PLEF countries in the integration scenario. Figure 15



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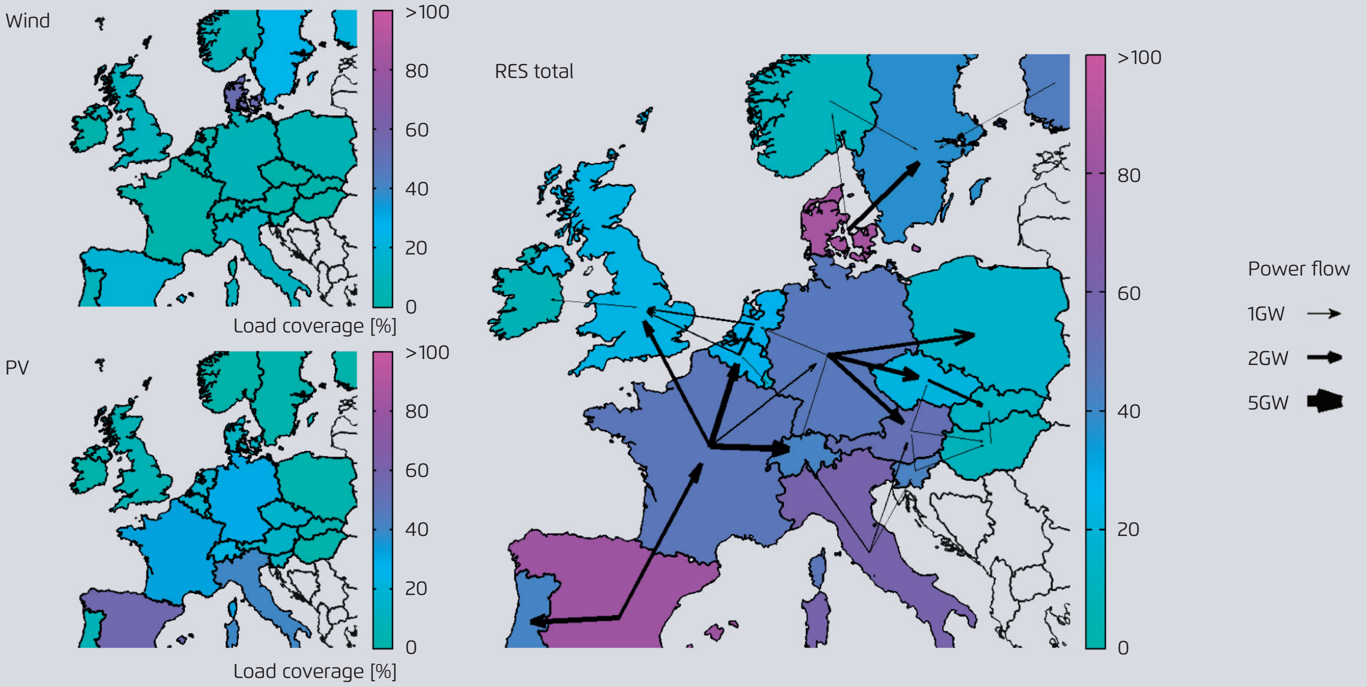
Cross-border power flows in Europe under sunny conditions.

Figure 16



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Cross-border power flows in Europe in windy conditions.

Figure 17

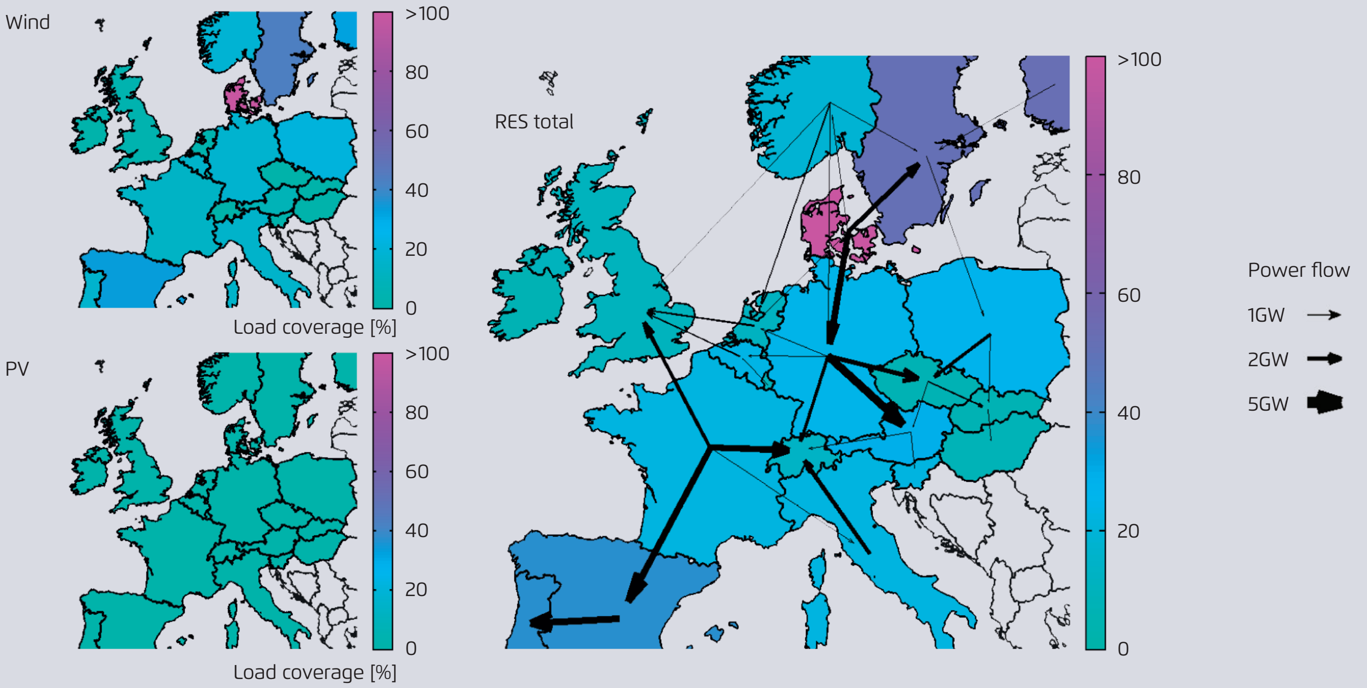

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Figure 17 also shows what happens when cross-border interconnectors between France and Switzerland and between Germany and Switzerland are fully utilised. Due to the congestion, additional power flows to Switzerland via Italy and Austria. Another example is the rather tight connection between France and Spain over the Pyrenees. As the shares of vRES increase, grid reinforcement must become more important for Europe as a whole to reap the benefits of grid integration.

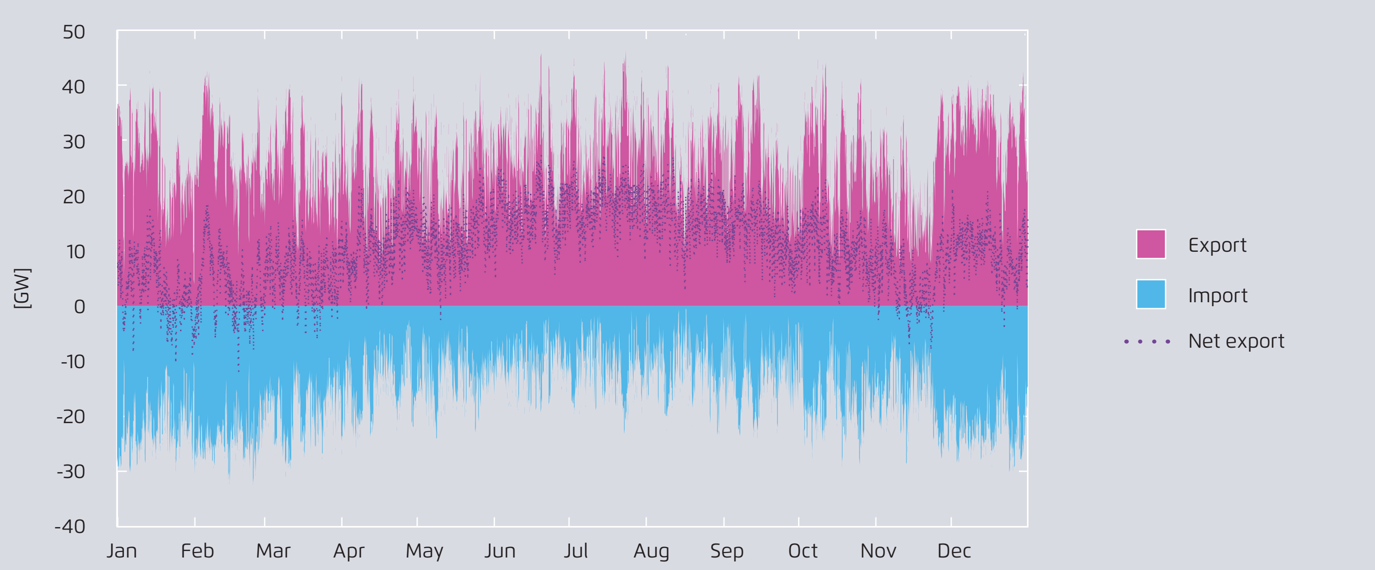
Figure 18 shows the import and export time series at PLEF country borders. We see that a significant share of power is exchanged in import and export directions between the PLEF region and the rest of Europe during every hour of the year. This means that grid integration is not only important between PLEF countries but also within Europe as a whole. Net exports from the PLEF region occur mostly in summer. Plenty of vRES feed-in in all PLEF countries together with a significant conventional must-run level[28] in France and high hydropower availability cause aggregated surpluses, most of which are exported.

In Figure 18 future flow patterns between countries and regions in Europe show pronounced seasonal patterns. Cross-border flow patterns change more dynamically throughout the day and year.

Whereas vRES deployment affects the contribution from the rest of the overall power generation portfolio, power system integration is crucial for exploiting the regional smoothing effects from vRES and load. In the next section, we analyse the subsequent implications and requirements for the residual power plant park.

28 To ensure provision of ancillary services such as reserve power and reactive power, a minimum share of conventional generating units must permanently remain running. Heat (via CHP power plants) is provided largely by units operating when demand for heating prevails, thus providing must-run electricity generation during those times. Technical constraints (such as plants not being capable to reduce output quickly) generate inflexibly, at least in the short run. Other so-called must-run capacities include non-dipatchable renewable energy technologies such as wind power, PV and run-of-river hydropower.

Imports, exports and net exports (difference between exports and imports) at the PLEF borders with the rest of Europe. Figure 18



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4. The variability of RES generation and consequences for the flexibility needs of the power system

In the previous sections, we described the smoothing of vRES feed-in over large areas as well as the effects of cross-border grid integration. Since vRES are weather dependent and non-dispatchable, residual generation has to fill the potential gap between vRES generation and power demand.[29] These dispatchable power plants are represented through a hypothetical conventional power generation system, hydro storage plants and flexible biomass units. Real-life power system incorporates various types of thermal power plants (gas-fired, coal-fired and nuclear) of different efficiencies and performances. Since our study focuses on the flexibility needs of the residual power system, it makes sense to assume a synthetic power plant park that differs in its electrical efficiencies but does not rely on a specific fuel type. (See the Modelling Appendix for further details.)

4.1 Power plant characteristics and power system flexibility

The flexibility of, say, a thermal power plant is determined by its ability to run in partial load as well as by parameters such as ramping rates, start-up time and minimum down time. Good partial load operation capabilities, short startup and minimum down times increase the flexibility of the power plant, allowing it to react quickly to changes in the residual load. In all thermal power plants partial load operation is restricted by a minimum power generation. This especially applies to nuclear power plants, but also to coal- and gas-fired facilities[30]. In sum, the flexibility of a power plant depends on its technology, its age and the state of its equipment. Accordingly, an old power plants' controllability and flexibility may be increased by retrofitting.

There are many challenging situations that arise from the flexibility of the residual generation mix, comprising both the ability to react over shorter and longer periods. Flexibility requirements over short periods are caused by rapid changes in load (which have to be balanced within seconds to minutes to maintain system stability) and vRES feed-in (which need not be correlated to load). Flexibility challenges may occur when wind fronts create precipitous ramps of wind power, when power surpluses take place (e.g. in times of high wind generation at night) and when forecasting errors for vRES generation or load arise. Forecasting errors may increase in the future because of new load technologies[31] and uncertainty about consumption and accumulation of PV-generated power, increasing the need for flexible balancing power.[32] At the same time, the load is expected to become more flexible through demand-side response. These challenges can bring the flexibility potential of the residual load to its limits, particularly when it is restricted by a certain share of residual must-run. Unplanned events of conventional power plants such as sudden trips of generation units also require flexibility.

Longer-lasting challenges can occur during periods of high load and low vRES power generation, as occurs in the "Siberian anticyclone" mentioned above.

29 Please note again that demand-side flexibility was not included in our modelling. Clearly, demand-side response represents a crucial flexibility source and can help alleviate volatile residual load patterns.

30 See section 5.2 for further details.

31 New consumption patterns such as electrical heat pumps, additional air conditioning and e-mobility, partly also participating in demand-side management (DSM), are expected to add their specific load profiles to the overall load, increasing the complexity of its forecasting.

32 Balancing energy is a function of several parameters. Besides vRES deployment, market integration, the size of the balancing area, intraday- and balancing market design, renewable support policy design and the specification of balancing energy products are also important. Curtailment of vRES can be counted as source of negative balancing power as well.

4.2 Firm capacity and the role of conventional and vRES plants

To guarantee the security of supply, the available capacity of the power generation system must exceed maximum load and include a "security margin" for unexpected events. Only a share of the installed capacity of the system can be considered "firm", given the need for maintenance or the possibile unforeseen disturbances. So far, this "firm" capacity has been assessed and considered nationally, without taking into account smoothing effects at the European or regional level. Such a regional approach – as the one performed for the Pentalateral Energy Forum – would reduce the required amount of firm capacity.[33]

Weather dependency of vRES provides a (very) limited contribution to firm capacity. Conventional power capacities are still needed as back-up – the required level is largely unaffected by vRES development – but their utilisation decreases as the share of vRES increases. As these power plants are required for fewer hours of the year, flexible gas turbines (with higher marginal costs) can be used to secure peak load cost-effectively.

It is important to point out that "firm" capacity in a purely "static" sense is not enough to guarantee a power system's security of supply and reliability. Available capacity should also be considered in a "dynamic" manner, namely, by its ability to provide flexibility.[34]

4.3 Impacts of vRES on the structure of residual load

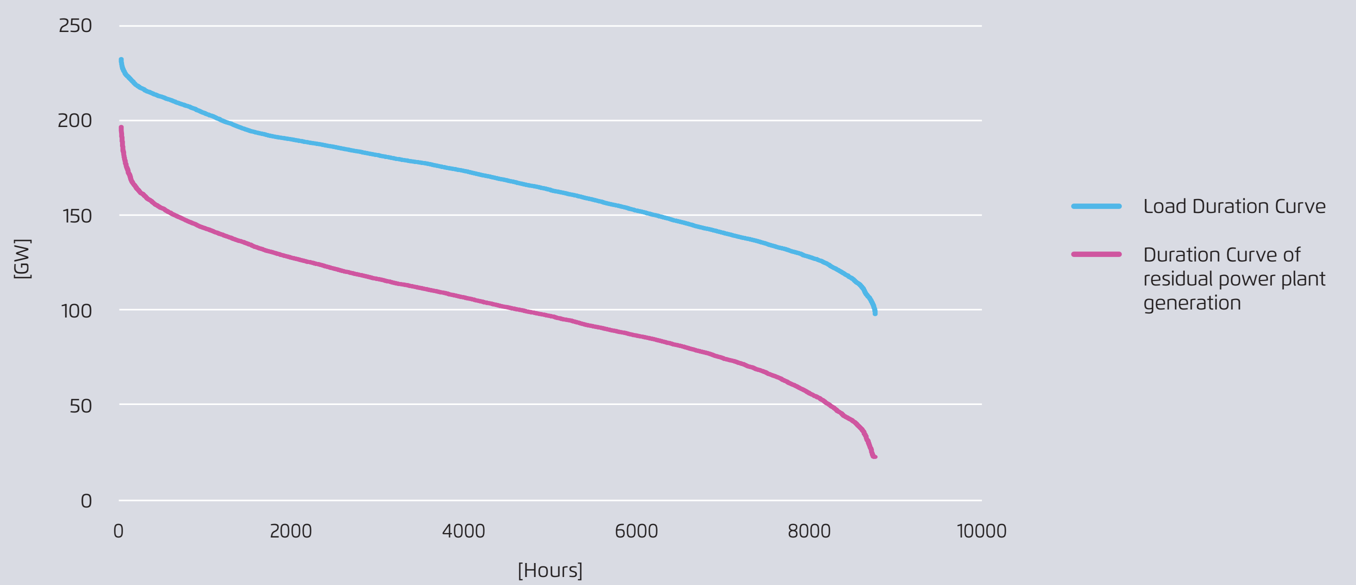
To illustrate the impacts of vRES on the requirement of the residual power plant system, the duration curves shown

33 Elia et al., 2015. Pentalateral Energy Forum Support Group 2 - Generation Adequacy Assessment: Pentalateral generation adequacy probabilistic assessment.

34 For further details, see for instance RAP (2014): Power Market Operations and System Reliability: A contribution to the market design debate in the Pentalateral Energy Forum. Study on behalf of Agora Energiewende.

Load duration curve (blue) and duration curve for the generation of the residual power plant park (pink) for the aggregated PLEF region in 2030.

Figure 19



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in Figure 19 can be useful. The figure shows the duration curves (sorting values from the highest to the lowest), for load and generation of residual power plants[35] for the entire PLEF region. These duration curves allow us to derive the number of hours per year a certain load and residual generation level will be exceeded. The duration curve for dispatachable generation runs considerably lower than the load. For peak situations, however, the gap between the two duration curves becomes small for several hours at a time. This means that situations can occur in which almost the entire load must be covered by conventional power plants, regardless of the high share of vRES capacity.[36]

The implications for the structure of the power system are depicted in Figure 20. It shows the histogram of load and residual (i.e. dispatchable) power generation for the PLEF region. In a "classical" power system, the total load has to be covered by conventional power plants, whose output ranges between peak and minimum load (40 percent below peak value). Some power plants can more or less permanently generate nominal power providing base load. But the power system projected for 2030 is characterised by a wider range of residual loads, from zero to nearly peak load. This range is caused by the varying renewables feed-in. Lower values of residual power generation occur more frequently, and the number of extremely high values decrease, as indicated by the left-shift of the histogram for residual power generation. The fewer number of high values means lower fossil fuel demand. But the very low residual generation values mean that power plants must show a high level of flexibility and reduce their output more frequently. Baseload power plants can thus limit the flexibility potential.

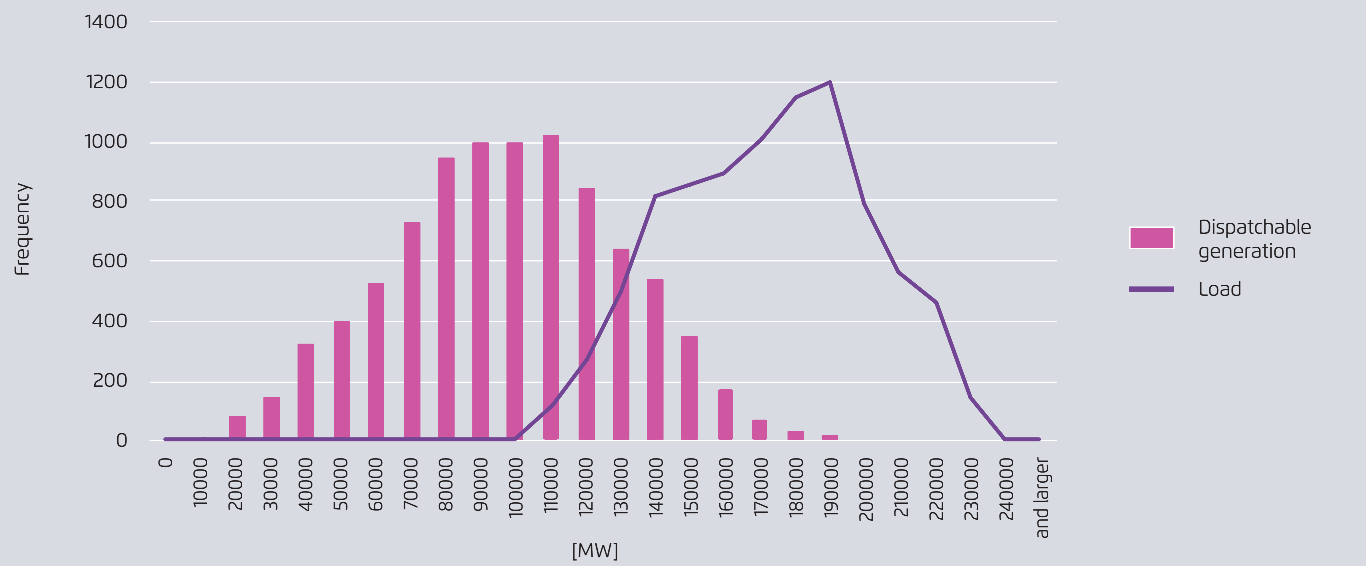
While the duration curves and the histograms of load and residual power generation illustrates the change of the residual power plant park, it has its limits as the time-dependence between hourly (residual) load values is lost. It is

35 In other words: dispatachable generation including its exports.

36 This study only simulates a single year. The peak residual generation may be even higher; had we taken into account additional years, the peak load gap might have been smaller. The gap between peak load and "peak dispatchable generation" is covered by imports (as vRES feed-in is already taken into account).

Histogram of load and residual (i.e. dispatchable) power generation in the PLEF region in 2030. The difference between the two is met by vRES generation.

Figure 20



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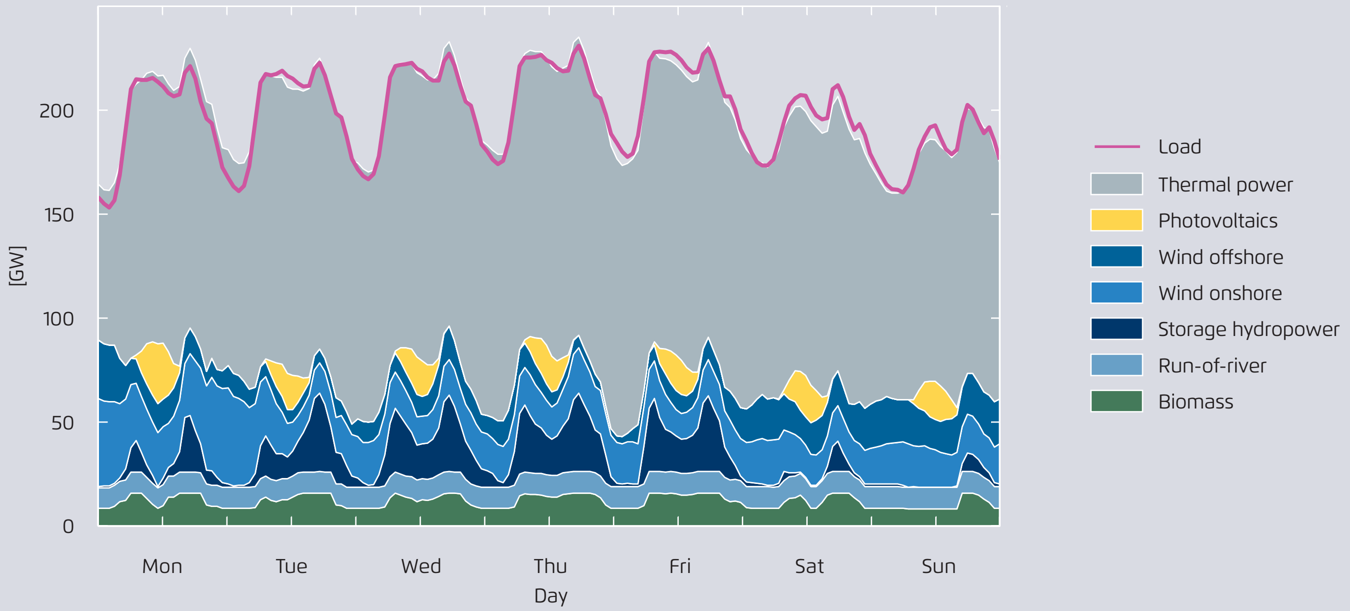
Power generation in the PLEF region with little vRES (calendar week 3).

Figure 21



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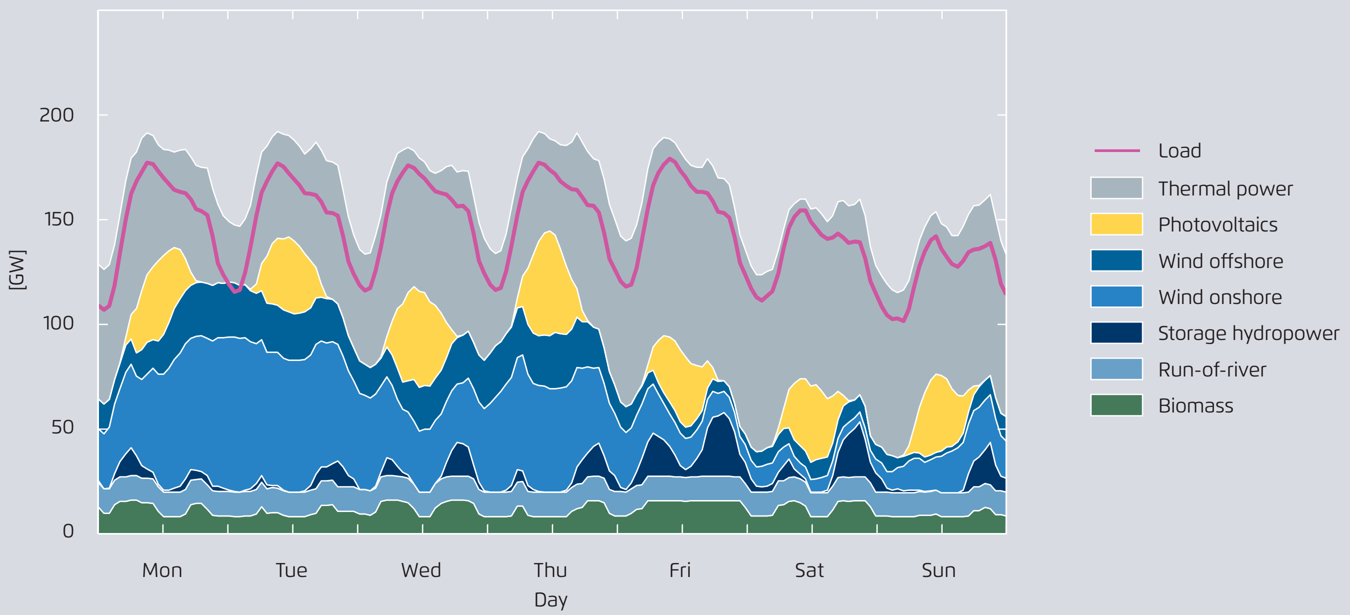
Power generation in the PLEF region with high vRES (calendar week 32).

Figure 22



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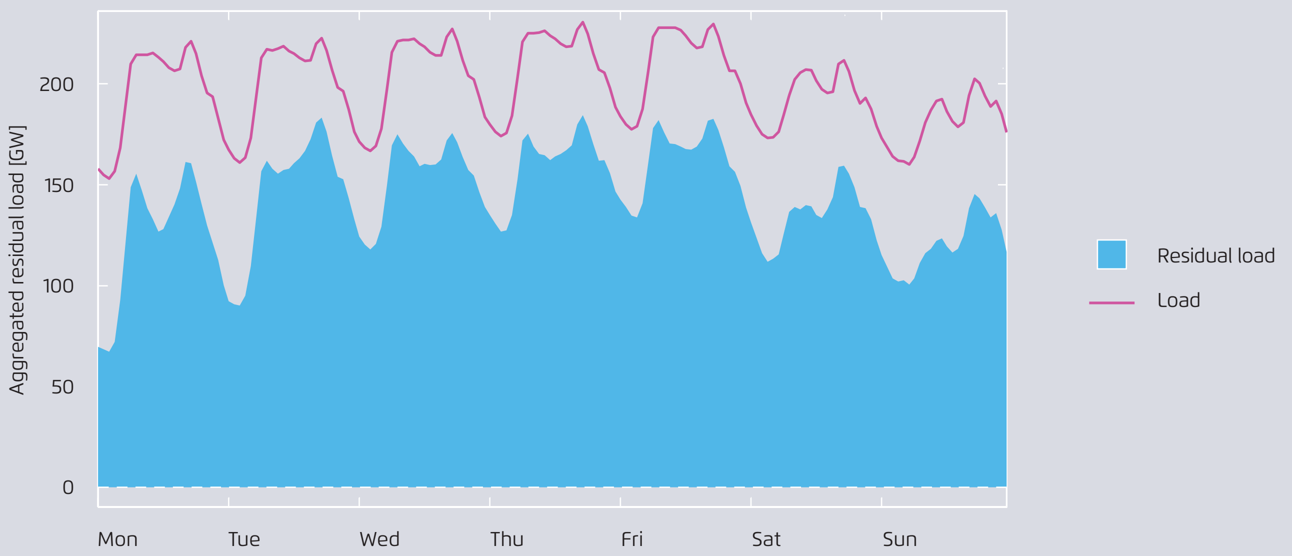
Residual load for calendar week 3 (little vRES generation).

Figure 23



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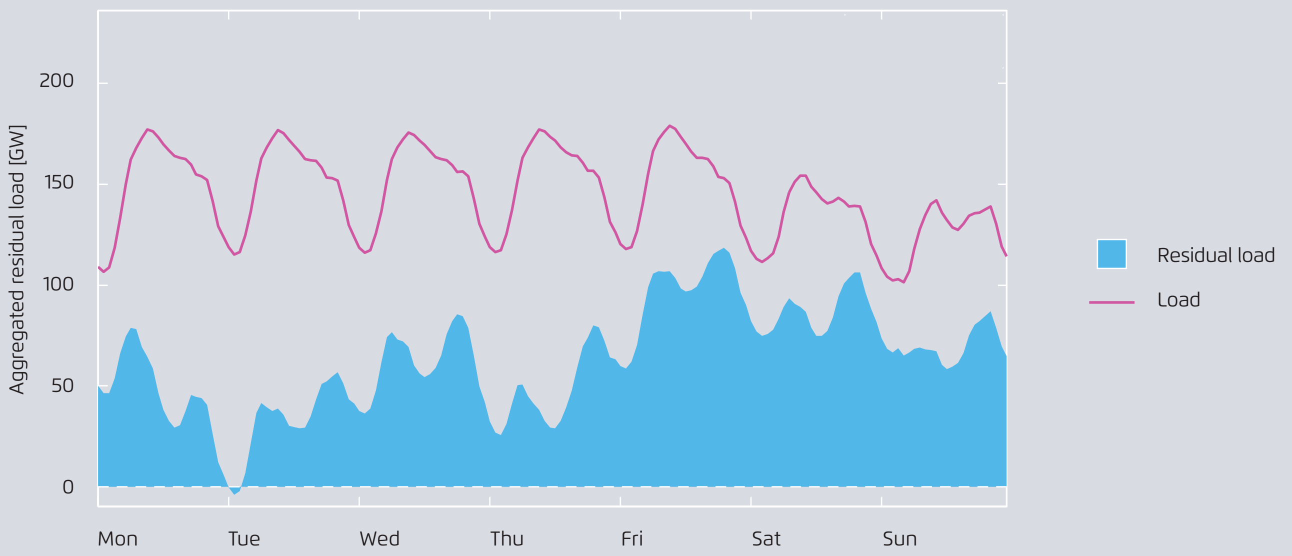
Residual load for calendar week 32 (high vRES generation).

Figure 24



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Maximum ramps for load and residual load within PLEF countries. Figure 25

	1h Ramp		20h Ramp	
	Load	Residual load	Load	Residual load
Max	28	31	64	121
Min	-14	-23	-73	-127

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also important to look at the time series of load and generation in order to further understand the dynamics of the flexibility challenge.

Figure 21 and Figure 22 depict the power generation of two different weeks with a low and a high share of vRES, respectively. The difference between load and vRES generation yields the so-called residual load curve. These resulting residual load curves can be seen in Figure 23 and Figure 24. The week with high vRES power generation goes along with a comparably low share of residual load, and vice versa. During the high vRES feed-in week, negative amounts of the residual load occur, which, together with the must-run share in the conventional power plant park, lead to overall surpluses that must be exported from the PLEF region. For the low vRES feed-in situation, storage hydropower plants add flexibility, balancing peaks and ramps of vRES and thereby contributing to load coverage. The diurnal pattern of load is still visible in the residual load pattern, whereas the fluctuations of residual load in a week with high vRES output occur at a smaller time scale. Specifically, the residual load contains two distinct peaks in the morning and the evening due to high PV generation around noon.

4.4 Residual load as the main driver of flexibility requirements

Figure 23 and Figure 24 also show how the variability of residual load increases with vRES feed-in. This affects the structure of ramps in the power system, challenging the flexibility of operating power plants. In Figure 25 it becomes clear that maximum ramps in 2030 within 1-hour and 20-hour time scales are higher for the residual load than for the load itself. This makes the residual load the new determinant for flexibility requirements and power systems, as opposed to the current situation where it is mainly determined by load.[37]

Section 5 will dive into these issues in more detail, pointing out the specific characteristics of the PLEF regions France, Germany, BENELUX and Austria/Switzerland.

37 It shall again be mentioned that the assumptions in this study tend to be rather conservative, as some flexibility options, e.g. demand side management, pumped hydro storage plants etc., were neglected in the model (see the Modelling Appendix for further details).

5. Country-specific case studies

The above chapters have provided an overview of selected integration effects of vRES in European power systems. The following case studies aim to take this analysis further, diving into specific contents. We have selected sub-regions of the PLEF to highlight these aspects. Figure 26 shows that situations vary quite a bit from country to country – in terms of the share of renewables in overall power generation and in terms of the generation mix.

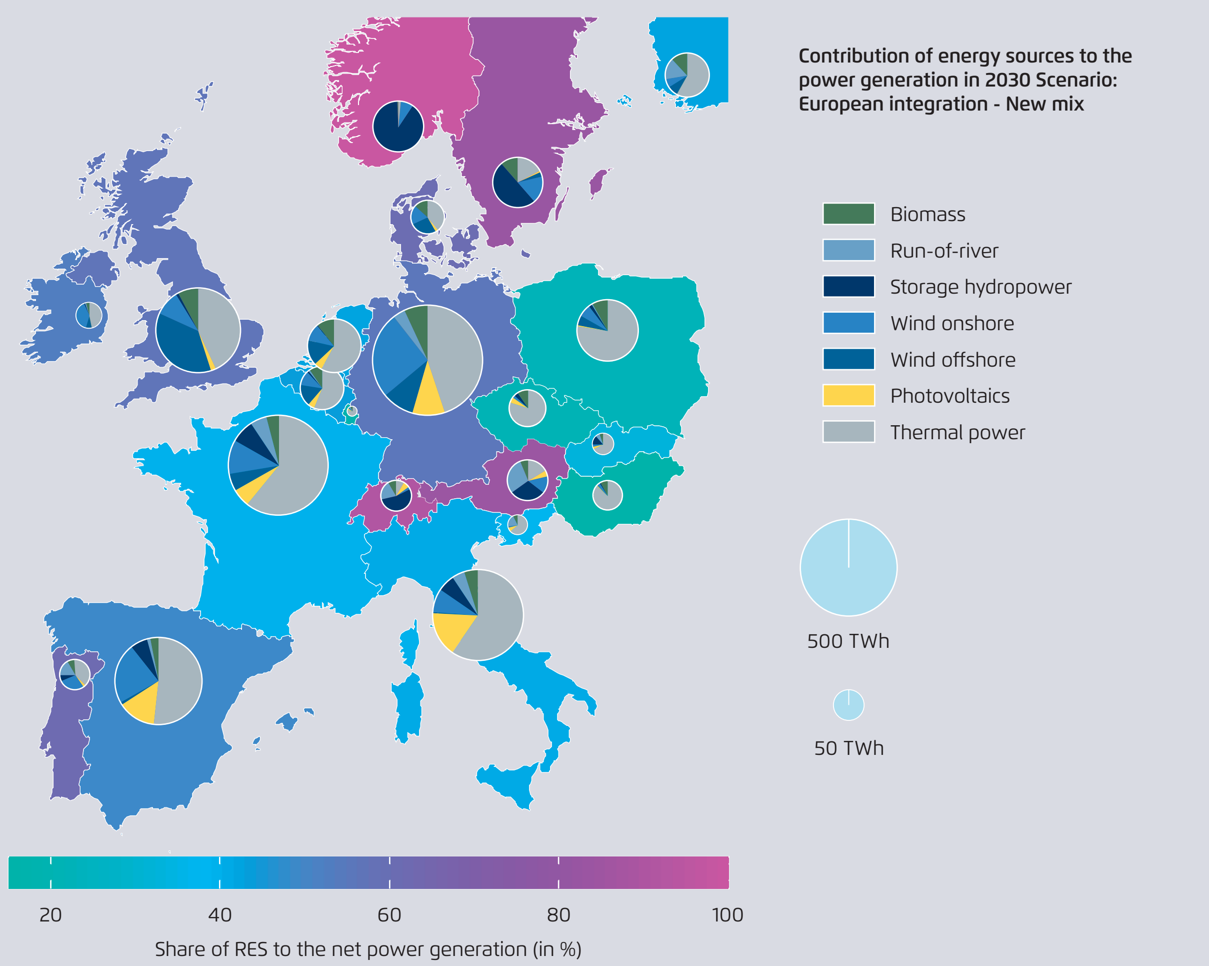
5.1 vRES, flexibility and backup: The German power system

Renewables as the main power generation source

According to current legislation targets, RES-E is to be the main[38] source for meeting domestic power demand in 2030, with wind power and PV being the main renewable sources. The increasing share of fluctuating renewables will break up

38 The upper bound is larger than 50 percent.

Share of renewables in net power generation and breakdown by technology. Figure 26



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generation and demand patterns, forcing renewable energies, demand, flexible generation, grids and storage to become more responsive to the other. The result: a complete transformation of today's power system.

The effects of variability

The simulations project that in 2030 renewables feed-in in Germany will exceed the domestic load for some 1200 hours. The example shown in Figure 27 depicts a week of high wind power feed-in.

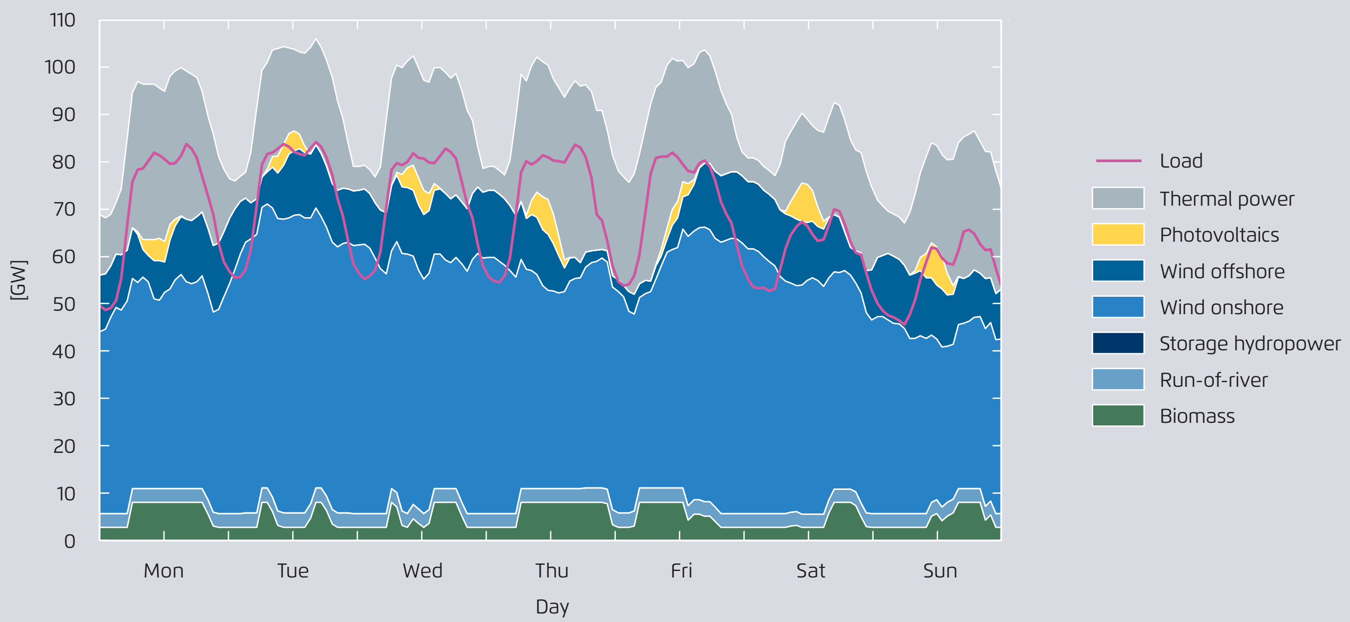
The figure makes clear that without cross-border interconnections, the surplus of renewables power generation would need to be curtailed[39] or stored.

In 2030, the feed-in of fluctuating renewables is not projected to exceed 25 GW (30 percent of peak load) for 200 hours, signifying a residual load larger than 60 GW during that time. This once again points to the importance of an interconnected system in which imports and domestic back-up technologies bridge such gaps whenever they arise (Figure 28).

Renewables generation is reflected in exports and imports, though conventional generation contributes to exports as well (see Figure 27). In times of high renewables generation, must-run technologies keep operating, but economics plays a role. High renewables feed-in in country A (here: Germany) and low renewables generation in another country in the region requires the latter to dispatch also more expensive conventional generation, while country A can provide cheap imports for the other country due to ample conventional generation capacities at that time. Conversely, low renewables feed-in and high deployment of domestic conventional generation capacities leads to imports in country A. This continuous pattern of imports and exports is shown in Figure 29 for Germany in June 2030.

39 See section 3 for a more detailed analysis of curtailment.

Renewables generation and power demand for a high-wind week in Germany (calendar week 50). Figure 27



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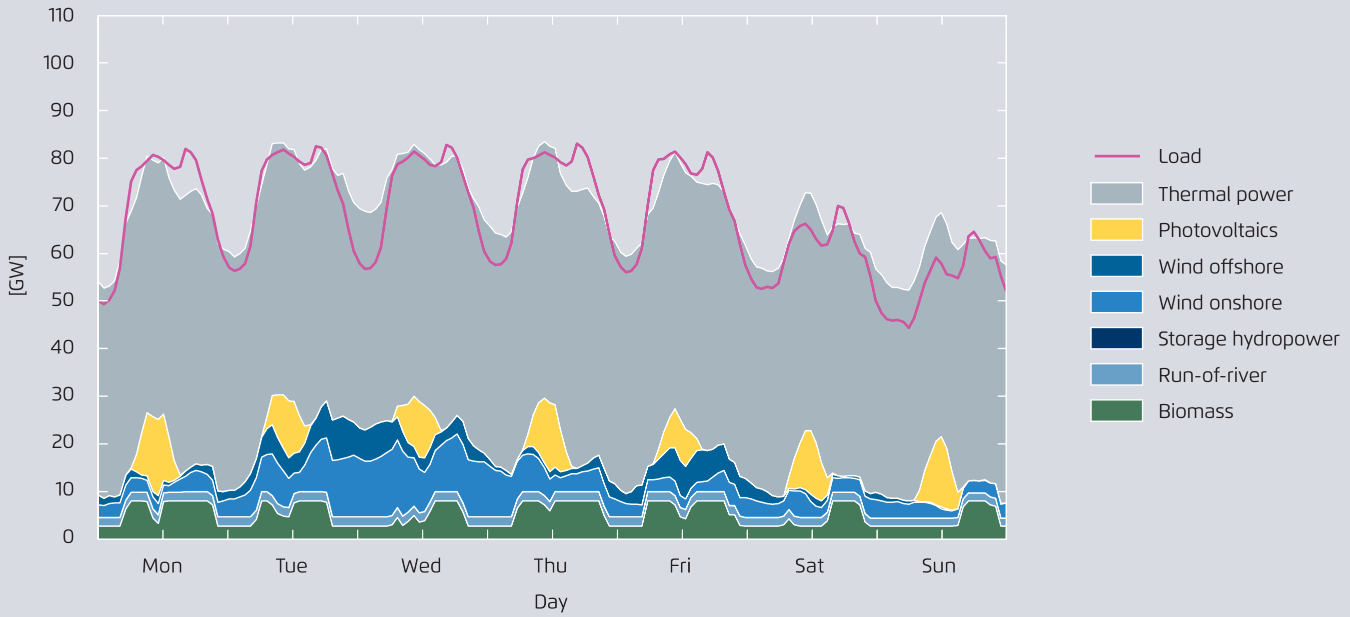
Renewables generation and power demand for a week in Germany with low RES-E feed-in (calendar week 46). Figure 28



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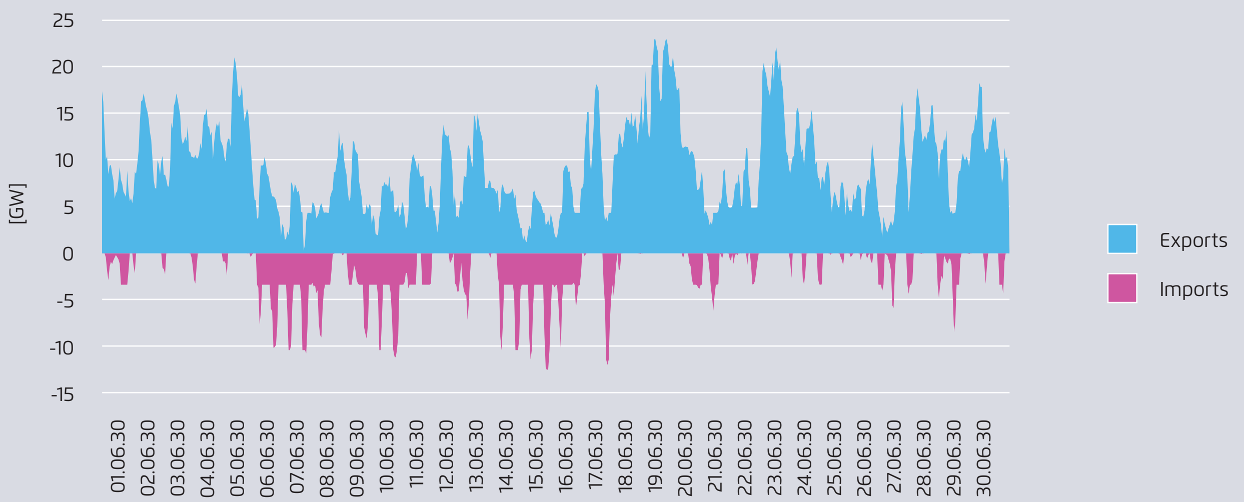
Germany's hourly imports and exports in June 2030. Figure 29



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The residual power plant park: Backup and flexibility source

The difference between the domestic load and the feed-in of fluctuating and non-dispatachable renewables has to be met by conventional generation, demand response[40], storage or imports. This difference is the residual load. As we saw in section 4, it can serve as an important indicator of how the (residual) power plant park must evolve to respond to increasing vRES output.

Figure 30 provides some comparisons of load and residual load duration curves (including and excluding cross-border electricity flows) for 2013 and 2030. For 2013 we can observe that the latter is a "parallel shift" of the former (arising from 25 percent renewables in the system); for 2030 we see more structural change in the residual load curve pattern. The curve is steeper, leading to surpluses in renewables (indicated by negative residual load values). In the (hypothetical) case of an autarchic national power system, these surpluses could be stored, used to cover demand that can be shifted to these surplus situations, or curtailed. Cross-border integration for flexibility reduces renewables curtailment, and the "effective" residual load curve (after taking into account net exports) becomes less steep, as the difference between the dotted and solid pink lines in Figure 30 shows.

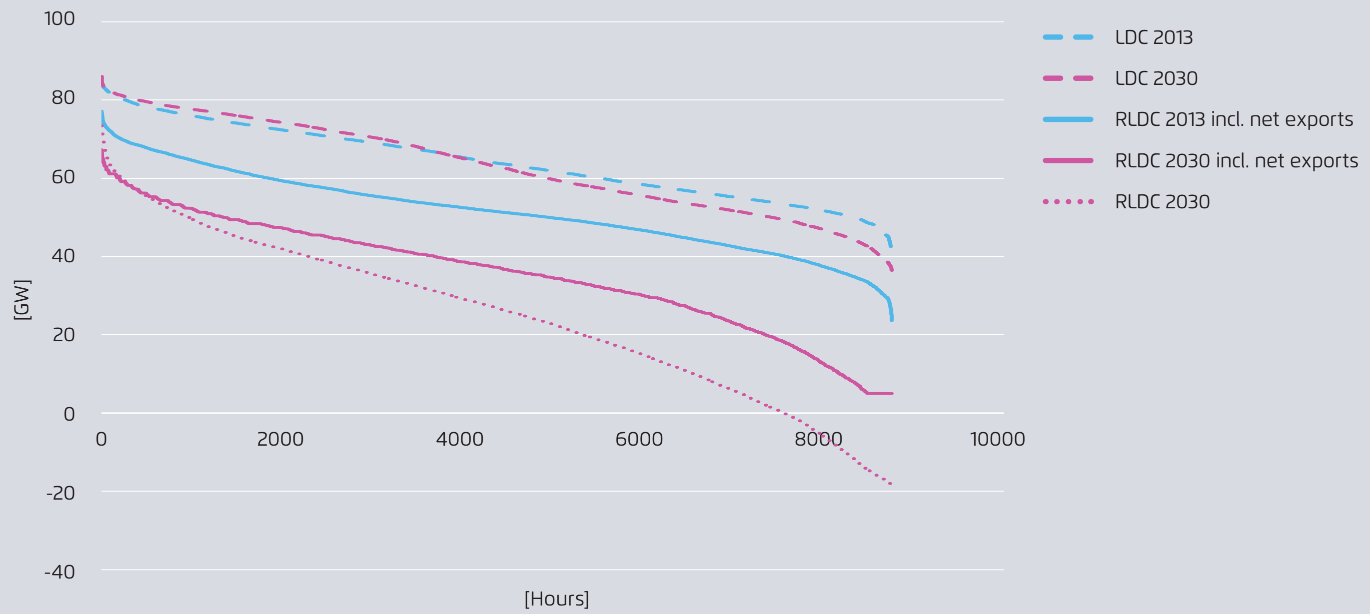
The area below the "effective" residual load curve has to be met by domestic dispatchable generation.[41] The steeper "effective" residual load curve in 2030 (compared to that of 2013) is the first indication of an increased need for mid-merit and peaking capacities and of a decreased need for baseload capacities.

The steeper residual load curve implies that a wider spectrum of residual load levels occur more frequently.

40 Not modelled here.

41 In our modelling, dispatchable generation comprises flexible biomass plants, hydro storage and the synthetic thermal power plant park.

Load duration curves (LDC), residual load duration curves (RLDC) and residual load duration curves including net exports (equivalent to domestic dispatchable generation) for Germany in 2013 and 2030. Figure 30



Agora Energiewende, based on data from Fraunhofer IWES and Agorameter

It can also be observed that the residual load pattern shifts to the left when comparing residual load values for 2030 and 2013. This indicates that the generation volumes of dispatchable power plants contract (an unsurprising consequence of increasing renewables deployment).

A wider spectrum of residual load levels also implies less stability and periodicity for certain load levels. In particular, the clear peak/off-peak pattern, a characteristic of "past" power systems, disappears.[42] Figure 31 compares the frequency of certain load levels with the frequency of certain generation levels of the residual power plant park for Germany in 2030. We can observe that load levels of around 55 GW and 80 GW occur most often, representing typical off-peak and peak regimes. A somewhat more evenly and widely spread pattern emerges for the deployment of the dispatchable residual power plant park.

42 Hers et al., 2013. Energy-only and capacity markets and the economics of the power sector in a simulation of the North-West European Power Market. VGB Power Tech Journal 10/2013.

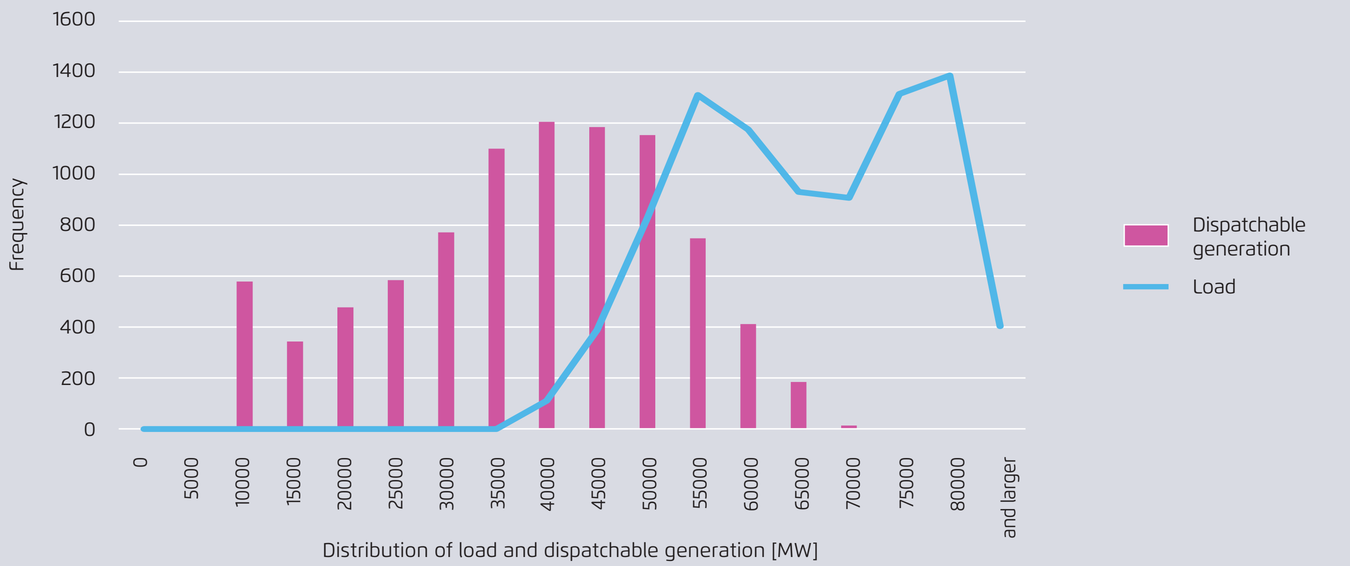
The spread between the maximum and minimum values of the residual load (Table 4) is one characteristic of the system's flexibility needs. While residual load varied between 18 and 77 GW in 2013, our assessed scenario for 2030 projects residual load levels ranging from -18 to +73 GW and a peak load of 86 GW.[43] Positive residual load values in the scenario simulation are supplied by domestic conventional generation, hydro storage and flexible biomass plants and imports.[44] Negative residual load levels are balanced by electricity exports or the curtailment of renewables. As shown by the higher difference between the maximum and minimum values for residual load relative to the residual load plus net exports in Table 4, imports and exports help stabilise generation for the residual power plant mix.[45]

43 Note that our simulation only takes into account one meteorological year. The contribution of vRES to peak load should not be interpreted as a capacity credit.

44 Note that demand side response is not modelled here.

45 Residual load plus net exports equals the generation of the domestic residual power plant park.

Load and domestic dispatchable residual power generation histograms for 2030 in Germany (integration scenario). The stable periodic pattern of load, with its peak/off-peak spread, breaks down after vRES deployment. Figure 31



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Maximum and minimum load, residual load and residual load plus net export values (equivalent to the generation of dispatchable domestic power plants) in 2013 and 2030 for Germany.

Table 4

	Residual load		Residual load plus net exports		Load	
[GW]	2013	2030	2013	2030	2013	2030
Minimum	18	-18	24	5	39	36
Maximum	77	73	77	67	84	86
Delta (Max-Min)	58	92	54	62	46	50

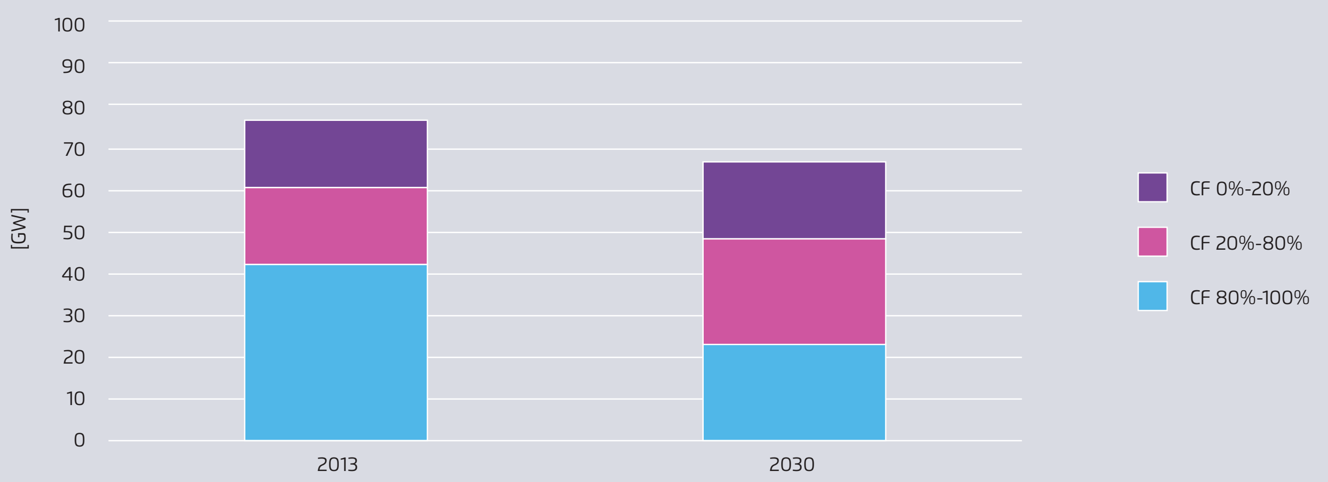
Agora Energiewende, based on data from Fraunhofer IWES, ENTSO-E and Agora Energiewende (2014)

The different residual load pattern clearly has implications for the structure and composition of the residual power plant park. A synthetic residual power plant park can be derived from the duration curve of the residual load plus net exports (shown by the solid pink line in Figure 30) by splitting power plants into three categories by the number of operation hours per year: "baseload", with more than 7000 hours of operation per year (and a capacity factor of 80 percent or larger); "mid-merit", with 1750 to 7000 hours of operation per year (and a capacity factor between 20 percent and 70 percent); and "peak load", with less than 1750 hours of operation a year (and a capacity factor smaller than 20 percent)[46]. Figure 32 shows the structure of the syn-

46 The capacity factors applied here are mainly for illustration. We could have also chosen a capacity factor of 70 or 90 percent

Structure of the residual power plant park in Germany in 2013 and 2030 for the integration scenario. The structure is derived from assumed capacity factor (CF) values: Plants with a capacity factor of 80% or larger (>7000 full load hours), a capacity factor between 20% and 80% (1750-7000 full load hours) and a capacity factor smaller than 20% (<1750 full load hours) are shown.

Figure 32



Agora Energiewende, Fraunhofer IWES

thetic power plant park in Germany for 2013 and 2030. We see that in 2030, 23 GW is projected to run more than 7000 hours a year, but in 2013 the same amount of hours yielded 43 GW. Compared with today, in other words, baseload capacities decrease significantly while peak load and mid-merit capacities increase.

Not only will the structure of installed capacities change, so will the operational pattern of the residual power plant park (e.g. running hours, ramping up and down, number of starts and stops). Table 4 and Figure 32 show how the structure and amount of the installed residual power plant park en-

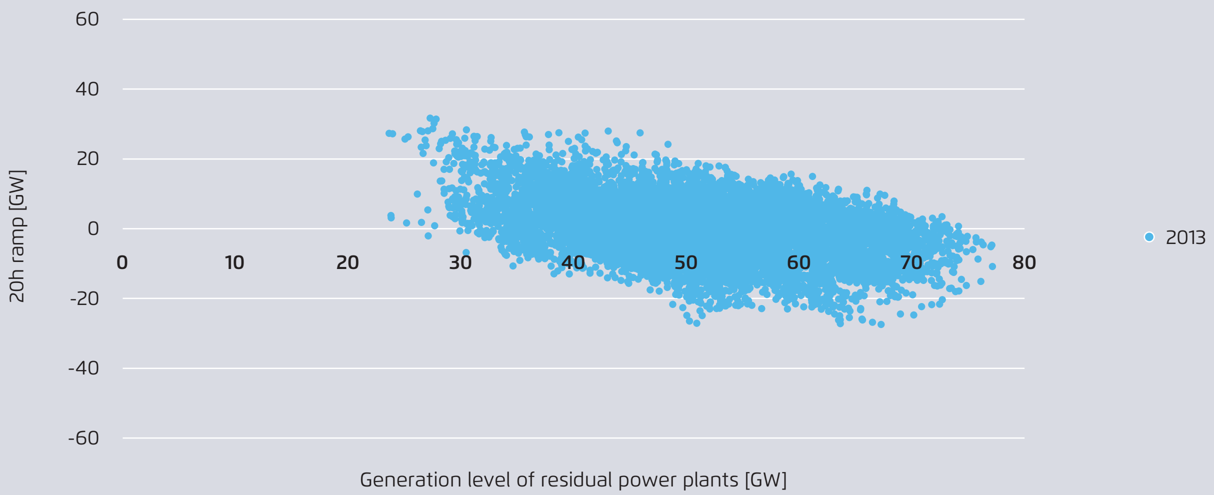
to derive the baseload capacities. The point is this: The higher the capacity factor we assume, the lower the required capacity level in 2030 and the lower the need for "baseload" capacities.

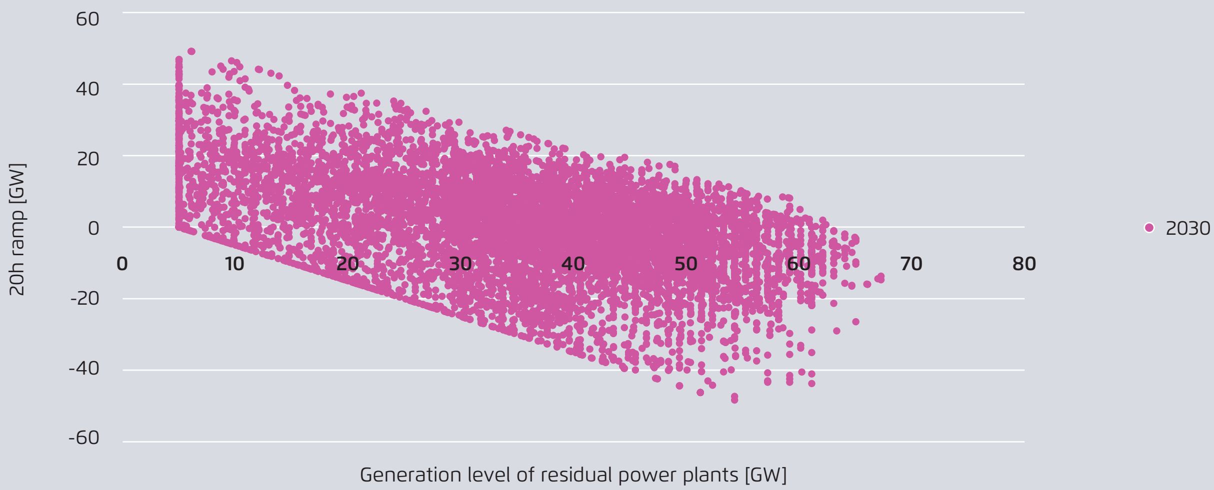
Hourly ramps of the German residual power plant park vs. prevailing generation level for 2013 (top figure) and 2030 (bottom figure) for the integration scenario. Figure 33

Agora Energiewende, based on data from Fraunhofer IWES and Agorameter

20h-changes (i.e. ramps occurring on a 20-hour time-scale) of the residual power plant park in Germany for 2013 (top figure) and 2030 (bottom figure) versus the prevailing generation level.

Figure 34





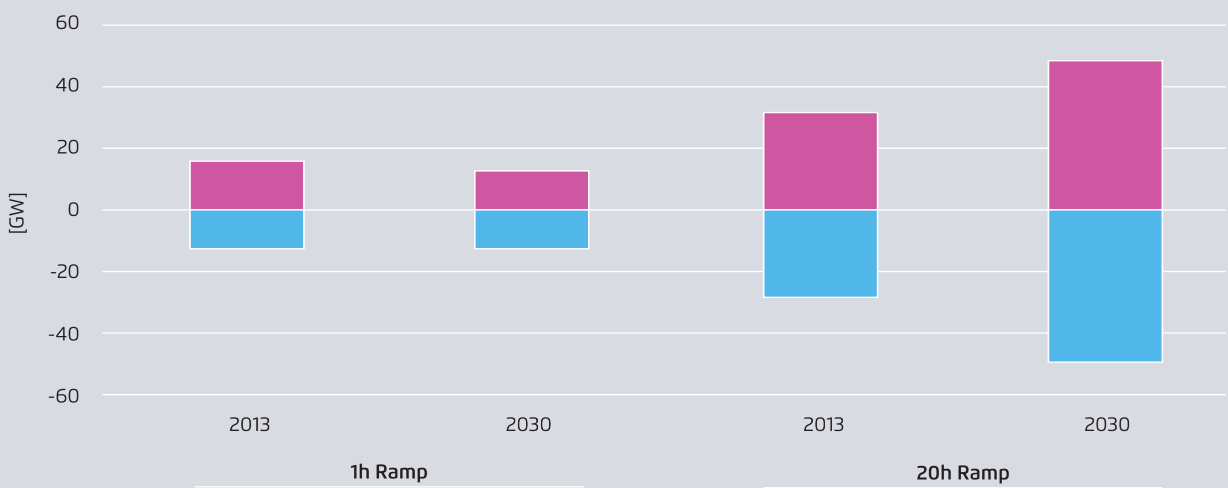
Agora Energiewende, based on data from Fraunhofer IWES and Agorameter

compass the "static" dimension of flexibility needs in 2030. Operational patterns, by contrast, encompasses their "dynamic" dimension. Figure 33 compares the hourly ramps of the residual power plant park with the prevailing generation level for 2013 and 2030.[47] The figure shows that hourly ramps of up to plus 15 GW and minus 10 GW occur at almost all prevailing generation levels of the residual power plant park (the latter ranging from 5 to 67 GW). In 2013 these ramps occur mainly in the output range of 40 to 75 GW.[48]

47 Thus, a data point in the figure at a, say, 5 GW hourly ramp and 20 GW generation level signifies that the residual power plant park is operating at an output level of 20 GW in hour t and has to operate at an output level of 25 GW in hour t+1.

48 In case the reader wonders about the "vertical" and "45° sloped"

Comparison of ramp magnitudes for 2013 and 2030 (integration scenario). The figure shows both hourly ramps (from one hour to the next) and ramps occurring over a 20-hour interval. Figure 35



	1h Ramp 2013	1h Ramp 2030	20h Ramp 2013	20h Ramp 2030
Max	16	32	32	49
Min	-12	-12	-27	-48

Agora Energiewende, Fraunhofer IWES

One important difference to today's hourly ramps is that in 2030 moderate to larger hourly ramps already frequently occur at low output levels. This challenges the way conventional power plants are operated, requiring increased ramping of the residual power plant park at part loading and more short-term start/stops of power plants.

These changes get even stronger if we look at the day-ahead scheduling stage. Frequently, large parts of residual power plant parks need to be turned on/off as reflected in 20 hour ramps. (See Figure 34, which shows the 20-hour ramps of the residual power plant park as a function of the prevailing generation level.) While in 2013 large, positive 20-hour ramps of some 30 GW occur at residual generation levels of 30 to 45 GW, in 2030 ramps of some 30-50 GW occur at generation levels of 5 to 30 GW. The figure also shows that on a day-ahead scale, the residual power plant park often has to shut down completely. This has not been observed for the year 2013.[49]

Figure 35 summarises the maximum (i.e. positive – ramping up) and minimum (i.e. negative – ramping down) ramps over an hourly and 20-hour time interval of the residual power plant park for 2013 and 2030. For hourly periods, the ramps are more or less unchanged when comparing 2013 with 2030[50]; the 20-hour ramps increase significantly in both directions between 2013 and 2030.

"lines" appearing in the scatter plot at low levels of residual generation: Our modelling assumes a 5 GW must-run level for Germany. As such, ramps do not occur below a 5 GW output. In addition, negative ramps cannot be larger than the actual generation level minus a 5 GW must-run, hence the "45°" boundary of the scatter plot for negative ramps.

49 Again, note the "vertical" and "sloped" lines appearing in the scatter plot at lower levels of residual generation. See the footnote above for further explanation.

50 As noted previously, please note that one important difference to today's hourly ramps is that in 2030 moderate to larger hourly ramps already frequently occur at low output levels.

Main challenges as shown by the German case

The simulated scenarios point to the growing flexibility requirements for future power systems. Variable and dispatchable renewables, conventional generation capacities, grids and storage technologies will all need to become more responsive. This section has focussed on the structural changes to be expected in the residual load pattern,[51] and on the role of interconnection in facilitating the flexibility of imports and exports.

The new power system will require a mix of flexible resources if it is to address resource adequacy efficiently. On the supply side, more peak and mid-merit and fewer inflexible base load plants will be needed. Activating the flexibility potential of the demand side will also be crucial. It is important to note that this study does not consider economic effects and power market design, factors that may affect the magnitude of the changes depicted here.

5.2 The diversification strategy for the French power mix: A balance of variable renewables, hydropower and nuclear

In summer 2014, the French government adopted the so-called "energy transition bill for green growth", setting ambitious objectives for power mix diversification and renewable energy growth (see section 1 for further details). Since the concrete trajectory of this power mix transformation has yet to be defined, this study considers two different scenarios based on recent long-term adequacy forecasts by the French TSO[52]. Both scenarios – "diversification" and "new mix" – involve a significant development of variable renewable energy capacities, as shown in Table 6 in the appendix.

Our simulation projects that in 2030 non-dispatchable renewables (wind power, PV, run-of-river hydro and inflexible biomass) will contribute to about a third (new mix) and a fourth (diversification) of the yearly total power consumption in France. Including dispatchable hydro and flexible biomass, the share of renewables in the two scenarios is expected to be just over 40 percent and 30 percent, respectively. Renewables cover at least half of the national load for more than 2,150 hours (or 25 percent of the year) in the new mix scenario and for some 600 hours (or 7 percent of the year) in the diversification scenario. Non-dispatchable renewables (excluding hydro storage and biomass) cover at least 60 percent of the load for 370 hours in the new mix scenario; at the other extreme, they cover less than 15 percent of the load for 620 hours.

Figure 36 and Figure 37 illustrate snapshots of typical weeks in 2030, where the effect of increasing shares of renewables is manifested. Figure 36 represents a sunny week in summer (new mix scenario). On Monday and Thursday, PV generation contributes to meeting more than a third of the load around noon, implying a significantly reduced output of hydropower during these hours. (Hydropower temporarily peaks in the morning, in reponse to an increase of the load, and then peaks again in the evening when PV ramps down.) During these days, the combined generation profile of renewables matches the load profile, facilitating more steady generation from residual power plants. Windy weather conditions during the weekend result in high renewable energy outputs, covering about 60 percent of the overall power consumption during these two days. Over the entire week, the high national power production (from renewable and conventional power plants) yields a generation surplus which could either be exported or stored.[53] On Thursday night, when renewables generation is low, the residual power generation, dominated by nuclear power, covers approximately 80 percent of the load. The 8:00 pm load peak is met with the help of hydropower.

Figure 37 illustrates a typical November week in 2030 for the diversification scenario. We see periods of significant wind power feed-in on Tuesday, Thursday and over the weekend; the wind power output (both onshore and off-

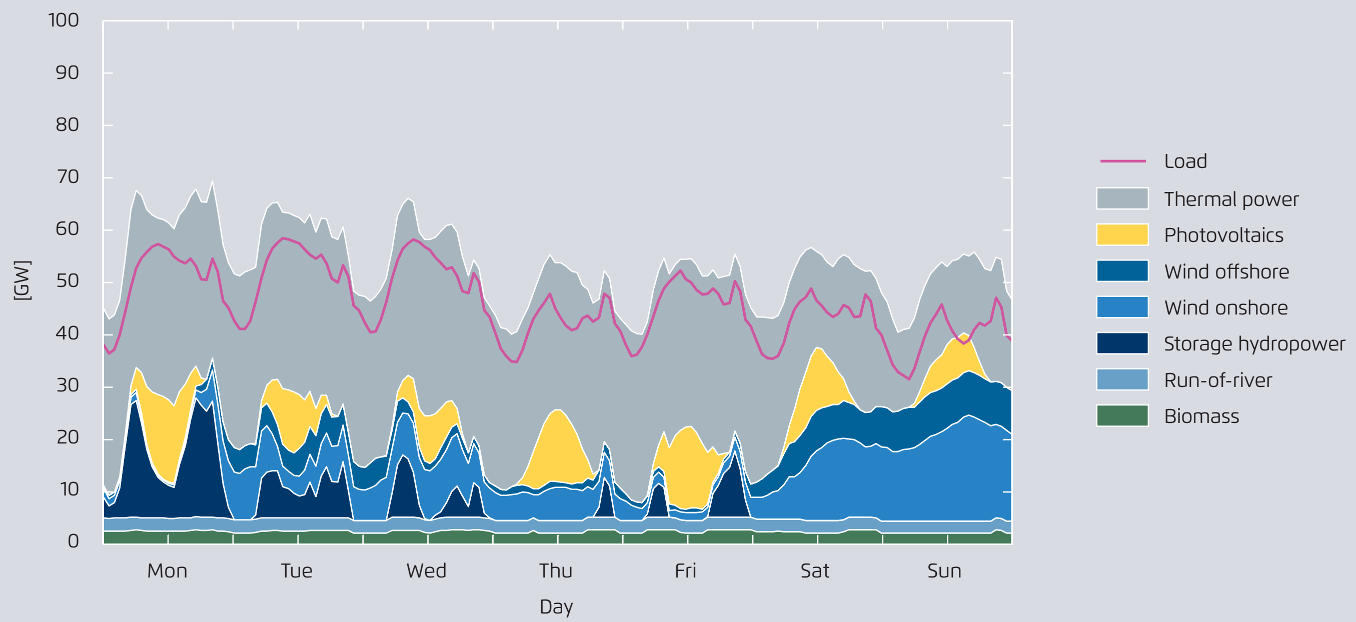
51 Note again that DSM has not been modelled.

52 See RTE (2014).

53 Pumped storage or other forms of demand-side energy storage have not been taken into account in our model, though they will certainly play an increasing role in the future French power system.

Power generation and demand in a sunny mid-July week with high PV feed-in in France (calendar week 28 – new mix scenario) for the year 2030.

Figure 36



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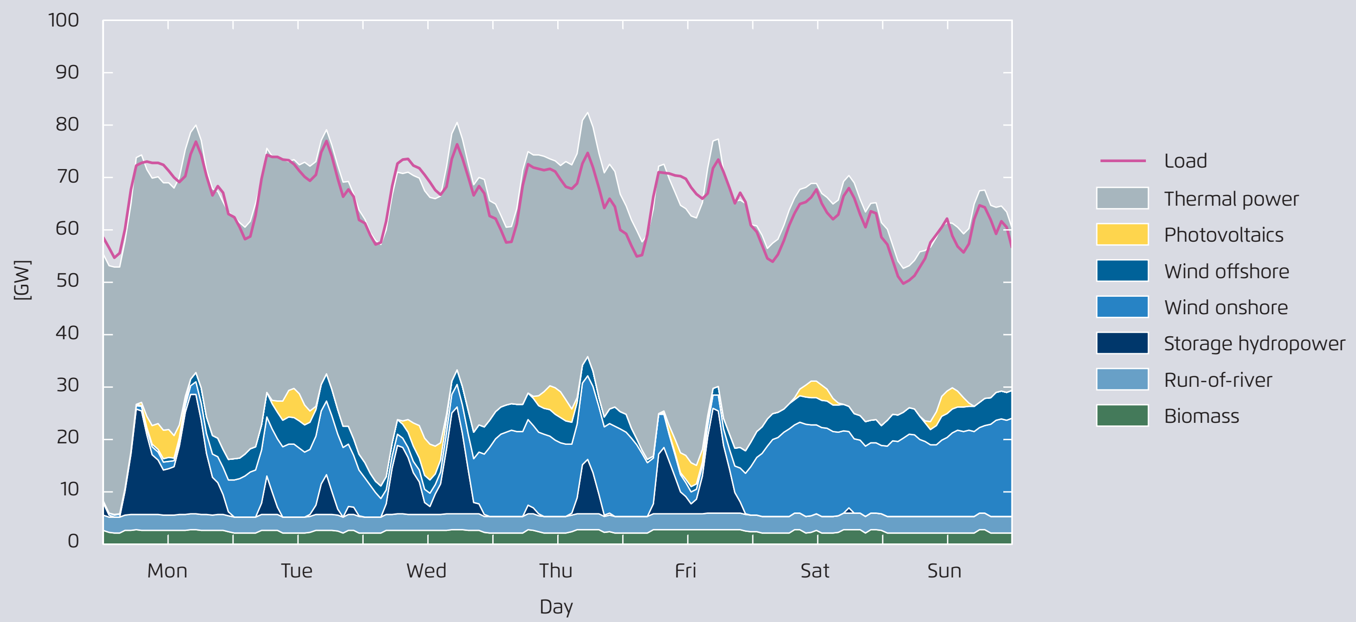
Power generation and demand in France at the end of November (calendar week 48 – diversification scenario) for the year 2030.

Figure 37



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shore) covers more than a third of the load during these three days. PV does not generate much power because it is late autumn and the week is cloudy. It nevertheless contributes to the mid-day load, shifting some output from flexible storage hydropower to morning and evening hours. During the days with low wind power generation (especially on Monday), hydropower is the main source of renewable energy generation. Over the week, the residual power plant park – most of it nuclear – runs at a rather constant level; over the weekend it is partially superseded by a high wind power feed-in.

Hydropower: a flexibility asset in the French power system

France benefits from significant hydropower resources, with more than 25 GW of installed capacities in 2014, including 13 GW run-of-river power stations and 12 GW of flexible storage power plants. This amount of hydropower, the second highest installed capacity in Europe (after Norway), plays a key role in meeting power demand. In 2014, hydropower generated 68 TWh, covering about 15 percent of French power consumption. It provides some 50 percent of the balancing energy.

Though the further expansion of hydropower capacities is limited in France, the current installed capacities are also projected to play a key role in balancing variable renewables in 2030, as seen in Figure 36 and Figure 37. Storage hydropower is partially substituted due to high vRES generation, e.g. by PV power in the middle of sunny days. Yet, it is also dispatched more often in order to compensate fluctuations and steep gradients of power generation and load. As a result, the annual hydro production – 66 TWh in 2030 – stays at similar levels to today. Hence, hydropower remains the main source of flexibility in the French power system, facilitating the integration of higher levels of variable renewables. (This constitutes an important advantage e.g. over Germany, which lacks a comparable level of dispatchable hydropower resources.)

Incorporating 40 percent renewables will require some resizing of the nuclear park but will not fundamentally alter the short-term operation of the residual fleet

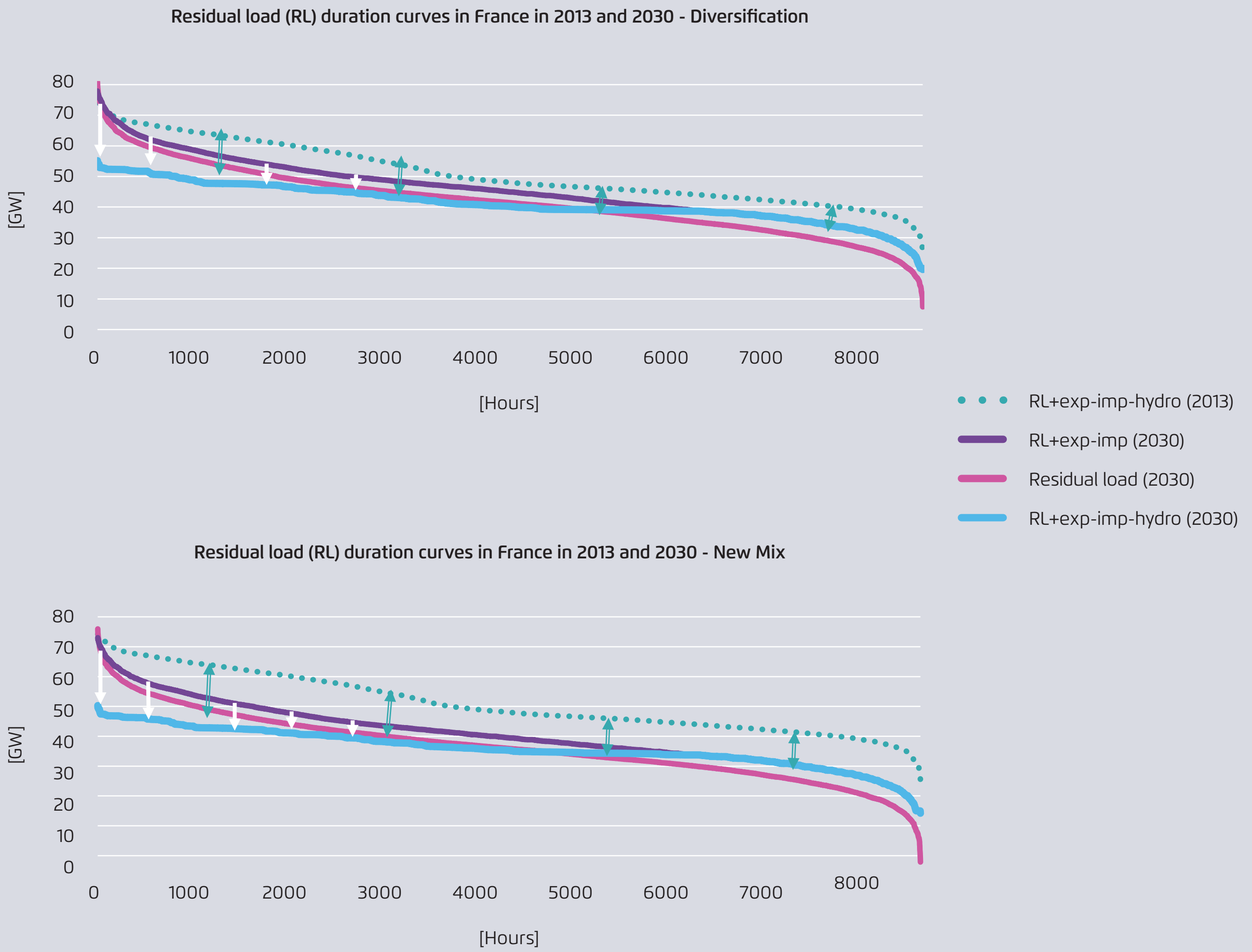
Because the current French power system is dominated by a large share of nuclear power, operating essentially in baseload, integrating large shares of renewable energies in France poses specific challenges to the power system. Figure 38 shows several load and residual load duration curves in 2030 under the two French scenarios (diversification and new mix). The 2013 residual load duration curve is also illustrated for reference (dotted line).

These graphs show several important features of the upcoming system transformation. First, we see the key role played by hydropower. Its ability to follow the load, or to be actively dispatched, significantly decreases the residual peak load (white arrows in Figure 38), reducing the need of additional gas-fired peaking power plants. The conventional thermal generation fleet needs to provide the residual energy (areas below the blue line in 2030 and below the doted line in 2013). Comparing the situations in 2013 and 2030 (green arrows in figure 38) shows that the transformation of the French power system requires a reduction of the conventional thermal capacities, while the shape of the residual load duration curve stays globally unchanged ("parallel-shifting")[54]. This reduction is more pronounced in the new mix scenario than in the diversification scenario[55].

54 It is important to stress that the analysis on the residual load is based on one single weather year. The graph outlines general trends, yet specific features of the analysis may differ with other meteorological years. For example, we see in this graph a stronger flattening of the residual load duration curve in 2030 than in 2013, but we cannot conclude that the combination of hydropower and non-dispatchable RES effectively reduces the need for peakers (as the analysis is based on only one specific weather year).

55 Our model was not designed to assess the optimal share of nuclear power in the French mix. In its long-term adequacy report (RTE 2014), the French TSO foresees a reduction of the nuclear fleet in 2030 to 37.6 GW (new mix scenario) and 47.7 GW (diversification scenario), as opposed to the 63 GW installed today. Our figure indicates a similar, if somewhat lower, need for nuclear reduction.

Residual load duration curves in France in 2013 and 2030. The three solid lines depict the situation in 2030, representing respectively the duration curves of residual load itself, the residual load including net exports and the residual load including net exports but subtracting dispatchable hydropower. The dotted line represents the residual load curve in 2013, including net exports but subtracting dispatchable hydropower. Figure 38



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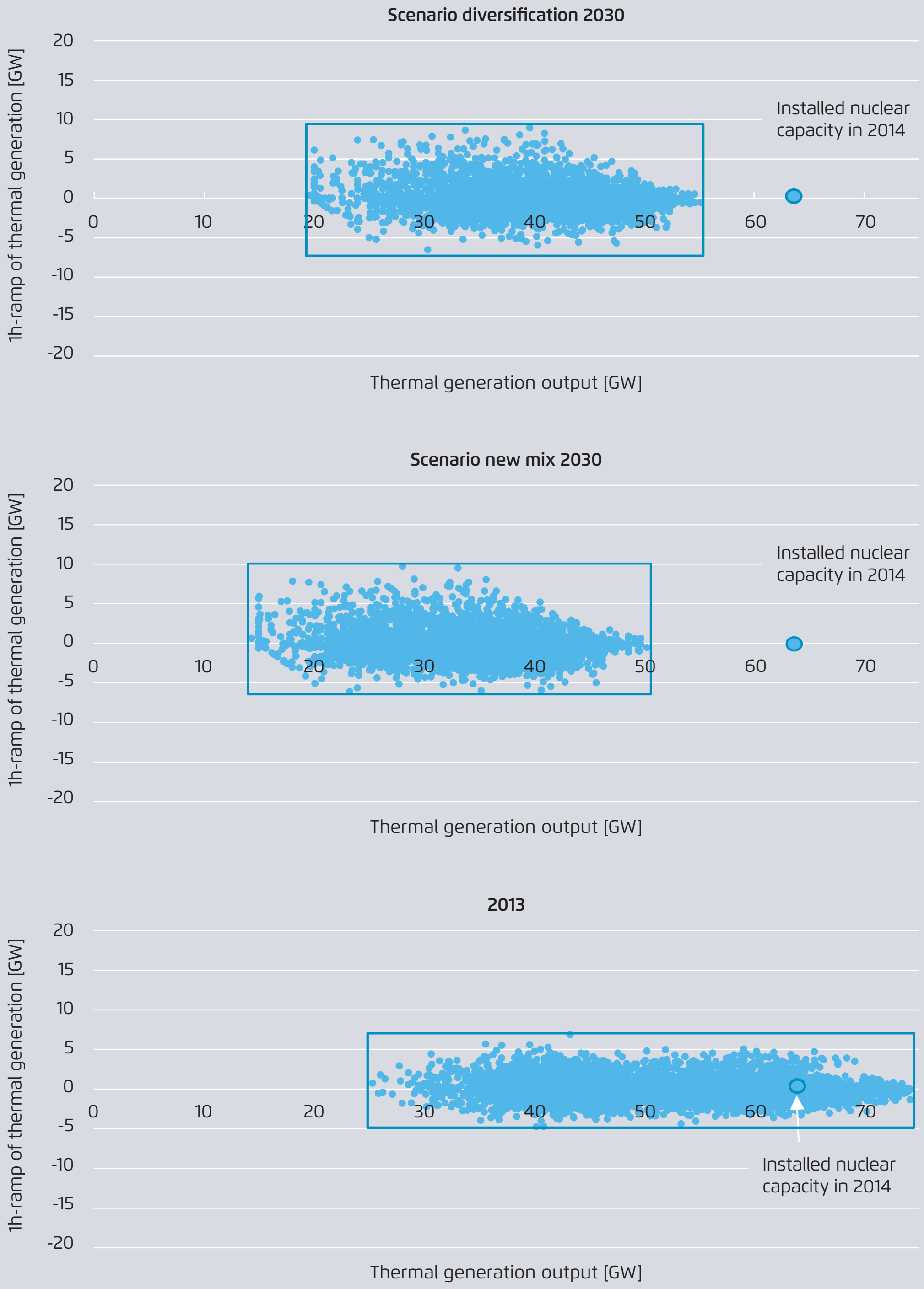
The ramping patterns of the residual load will also change in the future. As can be seen in Figure 39, the operation of thermal capacities shifts to lower outputs (on the x-axis) in 2030. At the same time, the one-hour ramping patterns become more volatile (y-axis), but the changes are relatively moderate.

This analysis shows that integrating 30 to 40 percent of RES requires some reduction of the residual capacity, but only moderate changes in the short-term (1h) operation of the overall fleet. It also shows that, at the 1h time scale, the aggregate patterns of the two scenarios do not differ significantly. High shares of variable RES (especially in the new mix scenario) poses nevertheless a specific flexibility challenge at the power plant level, necessitating a readjustment of traditional operations.

Thermal generation ramping (1-hour ramps) as a function of the generation output in 2013 and 2030 (diversification and new mix scenarios).

Figure 39



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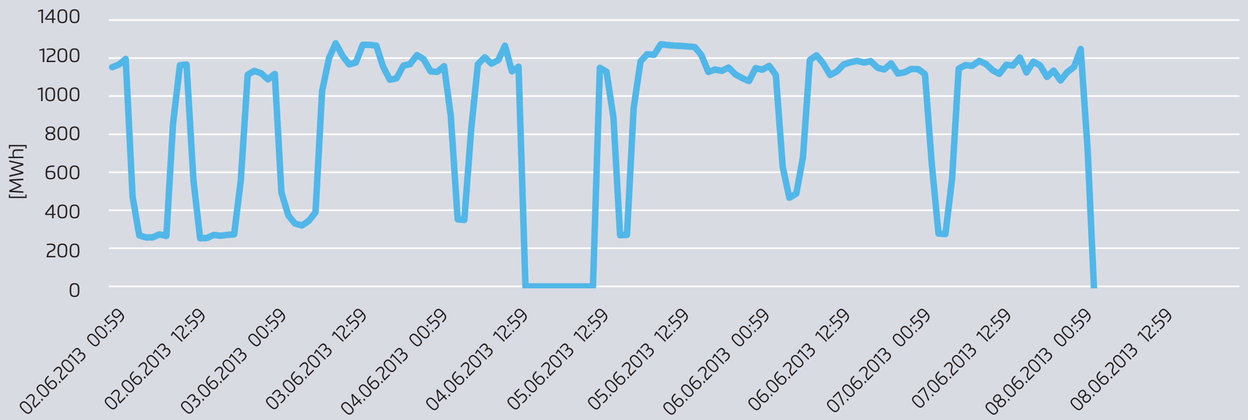
With its load-following capabilities, the French nuclear fleet can respond in part to increasing flexibility needs.

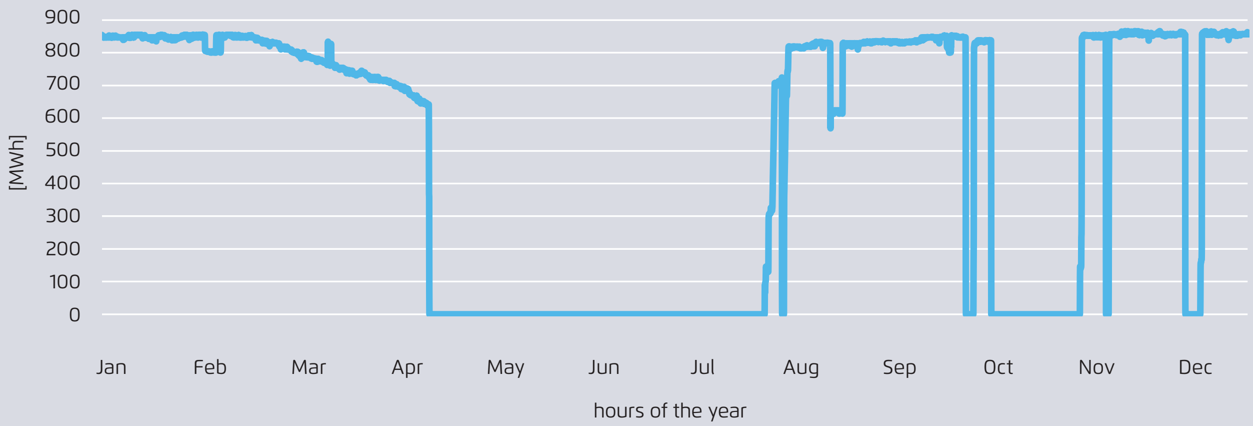
The French power system consists of 58 Pressurised Water Reactors (PWRs), with an overall generation capacity of 63 GW. Nuclear reactors are often portrayed as inflexible technologies and most countries operate them exclusively as baseload generators[56]. But in reality modern reactors have been designed with significant operational flexibility. They can contribute to frequency regulation and balancing[57]

56 This is for reasons of economic efficiency and operational simplicity.

57 This includes both primary and secondary reserves, for a total control margin of about 7 percent of nominal power.

Hourly generation of the French nuclear power plant Golfech 2 over a week in June 2013 (above).
Hourly generation of the nuclear power plant Fessenheim over the entire year 2013 (below). Figure 40





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and are able to adjust daily or weekly generation schedules to adapt to the cyclical variations of demand (i.e adjusting to low demand at night, on Sundays and during holidays). This is especially true in a country like France, where nuclear energy at times covers almost the entire load. As the penetration of vRES increases, the operators of the nuclear portfolio may also have an increased economic interest in load-following operation to respond to higher power price volatility.

Figure 40 illustrates the power output of the Golfech 2 nuclear reactor (operational since 1994) during a week in June 2013. The reactor is able to reduce its power to 20 percent of its maximal output and operate one or two large power changes per day. By contrast, the Fessenheim reactor (the oldest in France) does not operate in load-following mode, as we see in Figure 40.

Load-following capabilities of modern nuclear reactors can in principle contribute to balance high solar or wind power feed-in. In reality, they are bound to certain technical and safety constraints[58] and do not offer the same flexibility features as, say, gas-fired power plants (Table 5). They are nevertheless comparable to those of large coal-fired units[59] (see Table 5 and section 4.1). Not all new reactors will be able to operate flexibly at the power plant level, but an optimisation of the overall nuclear park can help meet flexibility needs. This operating mode requires good design, operation skills and regular maintenance.

A re-optimisation of the nuclear fleet operation is crucial for incorporating higher shares of renewable energies in the French power system.

Currently, the output of the French nuclear fleet is adjusted to match the cyclical changes of the load (daily, weekly, seasonally). Figure 41 shows this for 2013. Power plant outages (for refueling or safety revisions) have been optimised accordingly. The graph also indicates the weekly "nuclear generation corridor", i.e. the minimum and maximum ranges of nuclear output generated every week in 2013. We see that this spread can reach up to 17 GW in the summer (week 26), which represents 40 percent of the minimal nuclear output for that week. Hence, flexible long-term management is already a fundamental requirement for the nuclear industry. It will become increasingly important in the future, when the nuclear power output will be constrained not only by seasonal demand (as is the case today) but also by the level of variable renewable energy production.

58 The maneuverability of nuclear power varies strongly with fuel irradiation. It depends on the reactor's ability to control xenon (easier at the beginning of the cycle when the boron concentration is high). Nuclear units cannot, therefore, be used in load-following mode during the last 5-20 percent of the fuel cycle.

59 For a comprehensive analysis of nuclear load-following capabilities, see NEA (2013).

Load-following ability of dispatchable power plants in comparison. Table 5

	Start-up time	Maximal change in 30 sec	Maximum ramp rate (%/min)
Open cycle gas trubine (OCGT)	10-20 min	20-30%	20%/min
Combined cycle gas turbine (CCGT)	30-60 min	10-20%	5-10%/min
Coal plant	1-10 hours	5-10%	1-5%/min
Nuclear power plant	2 hours - 2 days	up to 5%	1-5%/min

NEA (2011)

Yearly nuclear generation in France in 2013. Figure 41

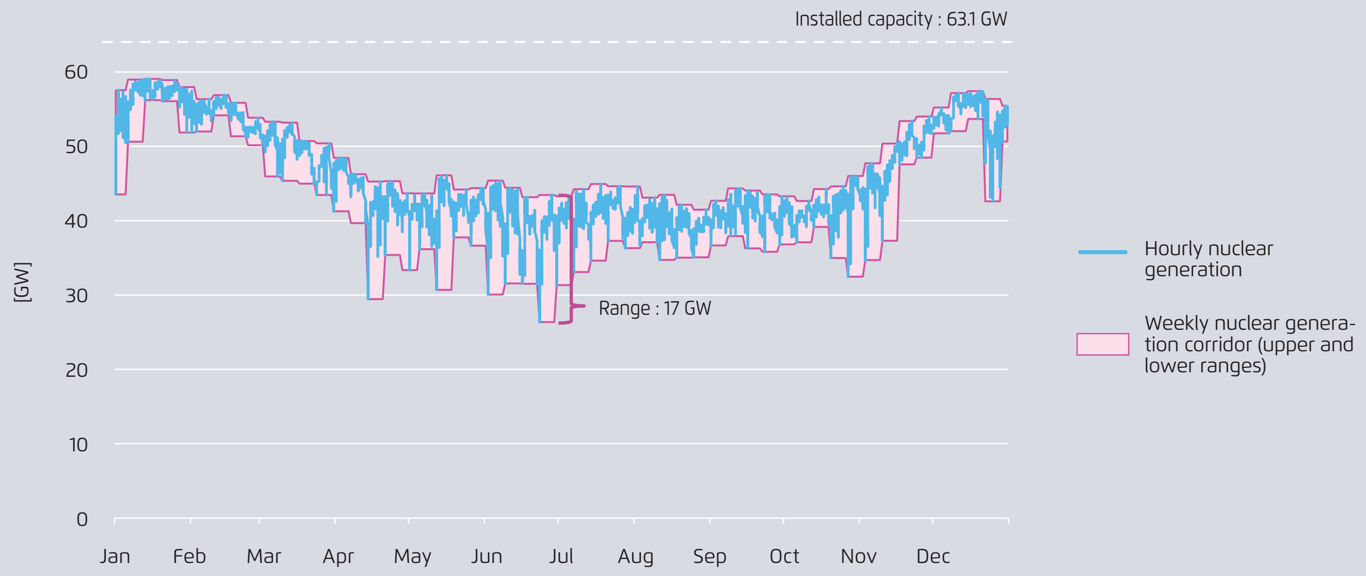

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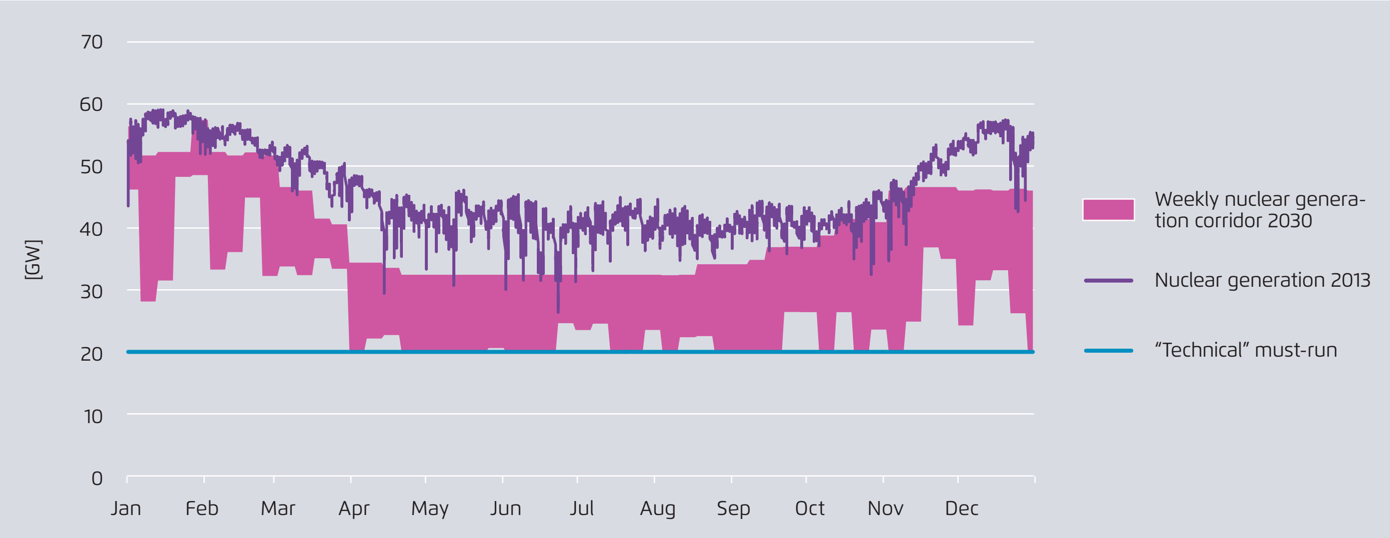
Figure 42 and Figure 43 illustrate the nuclear generation today (2013) compared to the potential situation in 2030 for the two scenarios. For the year 2030, the "nuclear generation corridor"[60] is shown for every week of that year. This analysis allows to capture important features of the challenge provoked by integrating renewable energies into a system with high shares of nuclear base load assets. These scenarios suppose a specific level of the year-round nuclear output for technical reasons (the so-called nuclear must-run). It is set at 20 GW in the diversification scenario and 15 GW in the new mix scenario.

In the diversification scenario (Figure 42), the weekly operation of the nuclear fleet follows a pattern similar to that of today (Figure 41). Twenty-two weeks are characterised by a "nuclear generation corridor" with a spread that is lower than +50 percent of the weekly minimal output. That is, during these weeks, the long-term nuclear operation is contained within a corridor similar to that of today. Nevertheless, in 2030, the cyclical patterns of nuclear power observed in 2013 take a less regular shape, as they are constrained by the level of variable renewable energy generation. This change of operation can be undertaken during these weeks, at least on the technical level (see previous section). Eight weeks are characterised by a range of the generation corridor higher than +75 percent of the minimal weekly output (ranging between 17 and 27 GW).

In the new mix scenario (Figure 43), these extreme situations are more frequent and the spread of the "nuclear generation corridor" – assuming a technical must-run of 15 GW – is more erratic. Twenty-three weeks are characterised by a spread higher than +100 percent of the minimal weekly

60 As described above, the "nuclear generation corridor" is the minimum and maximum ranges of nuclear output that could in principle be provided every week, in order to meet the load plus net exports minus renewables generation. In reality, nuclear will generate less than the maxima of the corridor, especially in times of peak demand. This is because fossil-fueled power plants, especially gas-power plants, wil be dispatched in order to respond to abrupt load changes. This analysis simplifies the situation, as it is based on weather and load data for only one year.

Weekly nuclear production corridor in 2030 (diversification scenario) relative to current nuclear production (2013). Figure 42



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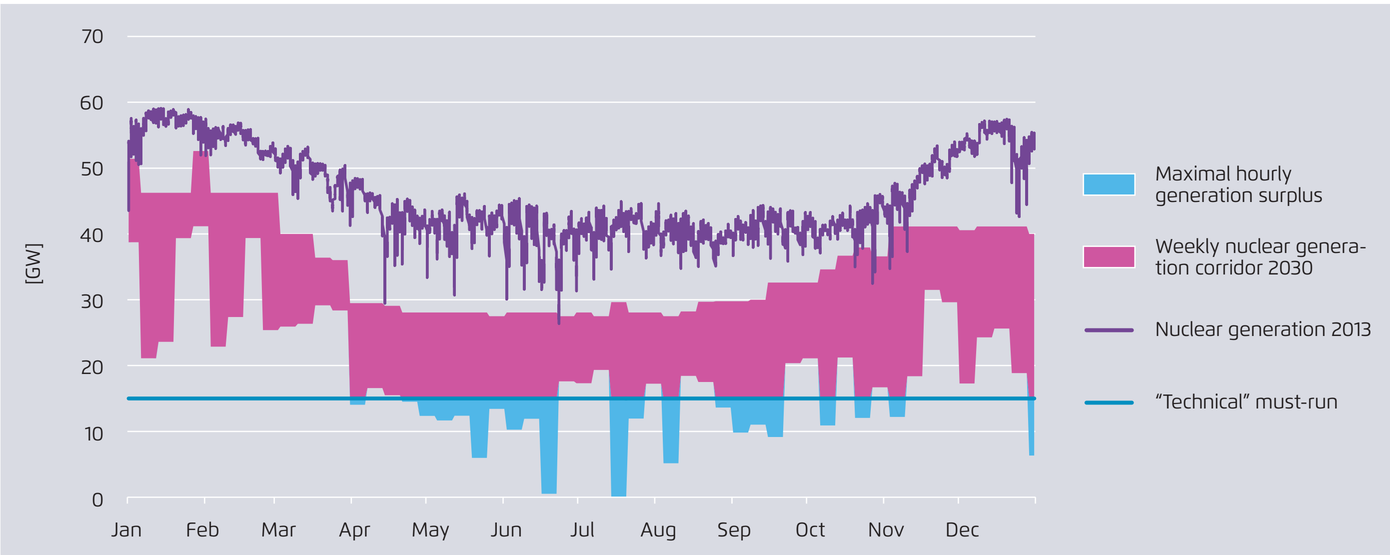
output. That is, if the nuclear fleet needs to match exactly the residual load at all time, its weekly maximal output will be more than twice as high as its minimum output during these weeks. Such extreme situations pose a specific flexibility challenge to the French power system, as we will see in the next sections.

Keeping high nuclear must-run levels (for economic or technical reasons) would exponentially increase the power generation surplus.

Though technically possible[61], reducing the output of the nuclear power fleet to adjust vRES feed-in at all times (Fig-

61 See the (relatively) low must-run level taken in our simulation.

Weekly nuclear production corridor in 2030 (new mix scenario) relative to current nuclear production (2013). Figure 43



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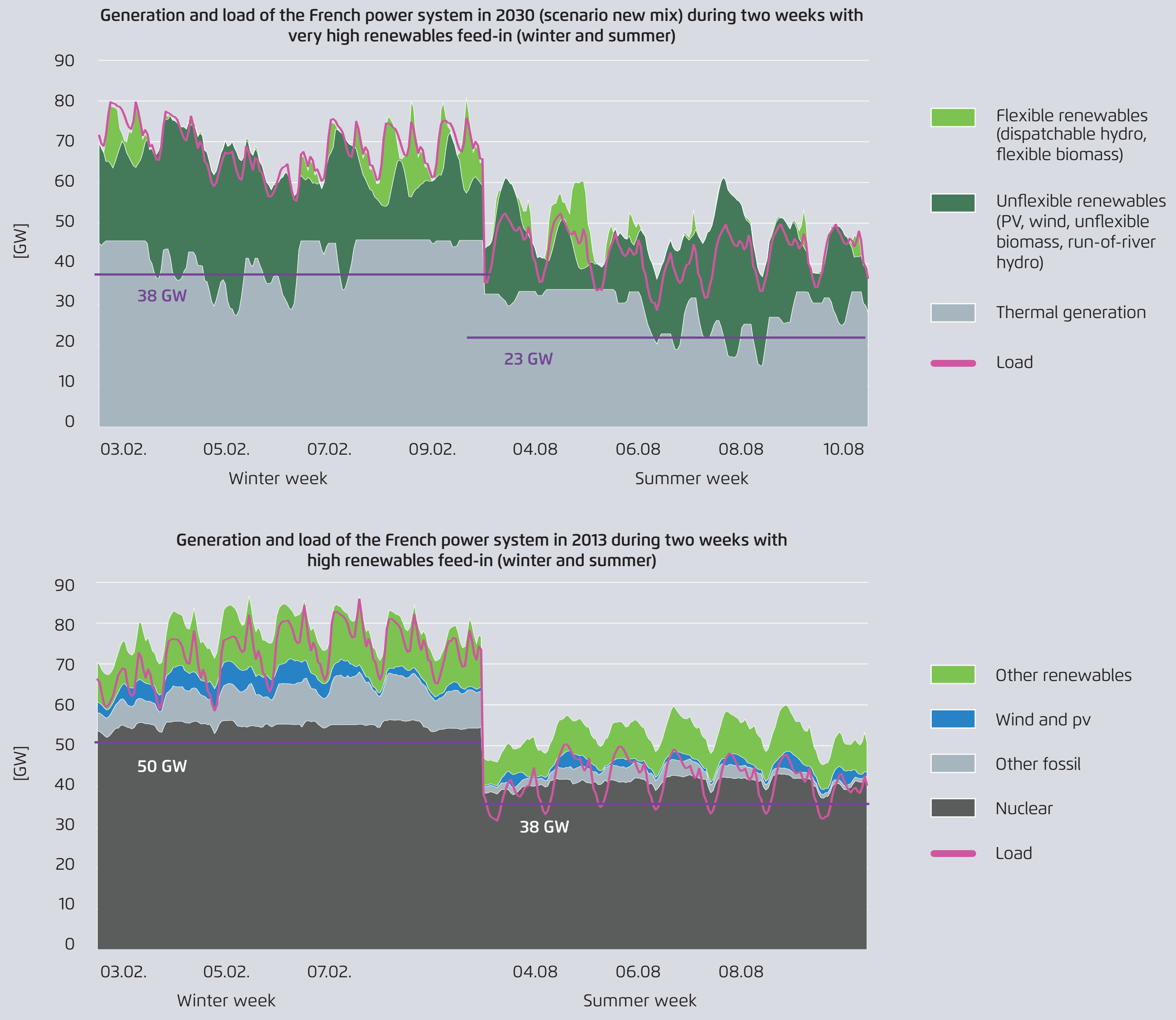
ure 44), would not necessarily make sense at the micro-economic level[62]. Furthemore, in weeks with a highly varying vRES feed-in, operation could pose particular technical challenges. Higher nuclear must-run levels (than the ones used in our simulation[63]) are therefore likely to occur during specific weeks.

In this section, we construct several sensitivity scenarios that investigate the impact of these higher must-run levels.

62 The operator would prefer to increase the load factor and output in order to generate revenues for covering its high capital costs. Profitability of the French nuclear power fleet relies on at least 6000 hours of full-load operation.

63 15 GW must-run in the scenario "new mix" and 20 GW must-run in the scenario "diversification".

Winter and summer weeks with very high feed-in in 2030 (new mix scenario) relative to the current situation. Figure 44



Agora Energiewende, based on RTE data

A higher and steadier generation of nuclear power can lead to power generation surpluses, which need either to be exported, stored or curtailed. These scenarios are illustrated in Figure 45.

The **"business as usual" scenario** represents a situation where the nuclear fleet is running exactly at the same level as today in terms of installed capacity and generation output. This scenario allows us to investigate what would happen if the nuclear park was not resized but renewables share increased. At the other extreme, the **"technical must-run" scenario** represents the situation studied so far, with a constant minimum nuclear output of 15 GW (new mix) and 20 GW (diversification). We then construct a series of intermediary adaptation scenarios, which capture both the seasonal variation of nuclear generation[64] and the need to adapt to the fluctuating generation of non-dispatchable renewable energies[65].

Figure 46 shows the level of domestic generation surplus under the various scenarios, ranging from the "technical must-run" scenario on the far left to the "business as usual" scenario on the far right. We see that the nuclear must-run levels increase the power generation surplus in a non-linear way. With a nuclear must-run of about 30 GW in summer and 35 to 40 GW in winter ("upper bound of the nuclear generation corridor 2030" scenario in the middle of the graph), the level of French domestic generation surplus could mount up to 25 TWh per year in the autarchy case. With a conservative assumption of exports (25 TWh over the year[66]), this generation surplus drops to almost zero. If renewables are incorporated without reoptimising the nuclear fleet ("business at usual" scenario at the right side of the graph), the generation surplus would rise explicitly, even after considering exports (more than 60 TWh p.a. surplus in the new mix scenario and 25 TWh p.a. in the diversification scenario). As the dotted grey line shows, the flexibility option of allowing 5 percent curtailment of variable renewables feed-in would already permit much higher nuclear must-run levels (about 38 GW in summer and 50 GW in winter in the diversification scenario).

Cross-border exchanges and other flexibility options (PtH, punctual curtailment, storage, DSM) can significantly ease the integration of vRES in the French power mix.

Several flexibility options exist to reduce the conflict between keeping a higher share of nuclear power in the power system and reaching a high variable renewables feed-in.

The first and probably cheapest flexibility option is to export the generation surplus to neighbouring countries. In 2030, large exports will continue on days with a high share of renewable energies, as is illustrated in Figure 44. Our simulation projects that France will remain a net power exporter in 2030. Under the conservative assumption of France being able to export about 25 TWh of electricity at times of high vRES generation (see previous section), the level of power generation surplus gets significantly reduced. Hence, stronger interconnection with neighboring countries will make it easier to integrate high shares of renewable energies in the French system.

Other national flexibility measures, especially those facilitated by additional electrification (power-to-heat, storage, electric vehicles), demand-side management and punctual curtailment of variable RES (e.g. <5 percent of annual output), will also facilitate vRES integration while maintaining a high nuclear must-run, enabling a trade-off between the two technologies.

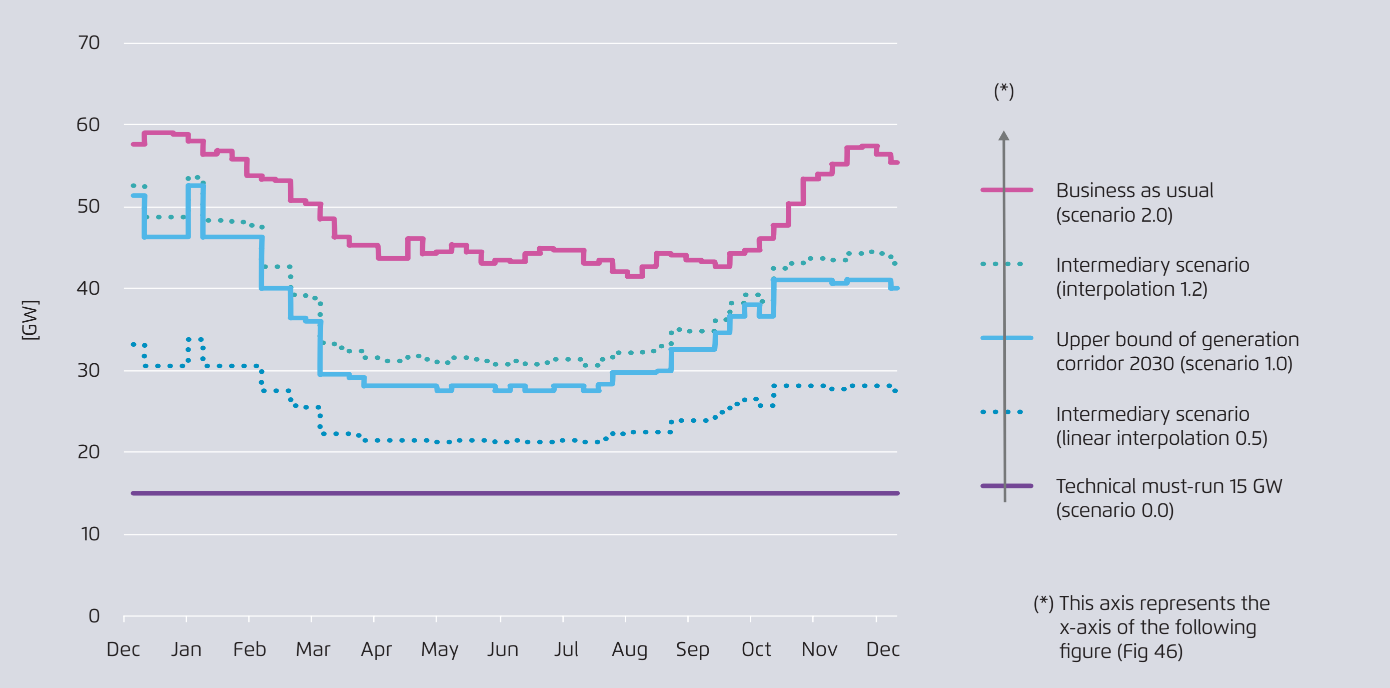
A long-term energy transition strategy based on renewable energies roll-out, nuclear fleet re-optimisation and development of flexibility potential will therefore be key for meeting at lowest cost the 2030 targets set by the French energy transition bill.

64 That is to say, higher output in winter when the demand is high, and lower output in summer when the demand is low.

65 The different scenarios investigated in this study are linear interpolations between the "must-run" scenario (lower bound), the "nuclear generation corridors" (described in the previous section) and the current generation of the French nuclear fleet (upper bound).

66 This export level – which is supposed to occur in time with high renewables feed-in - has to be compared to the 90 TWh exported by the French power system over the year 2013.

Different nuclear must-run scenarios in 2030 (new mix). Figure 45



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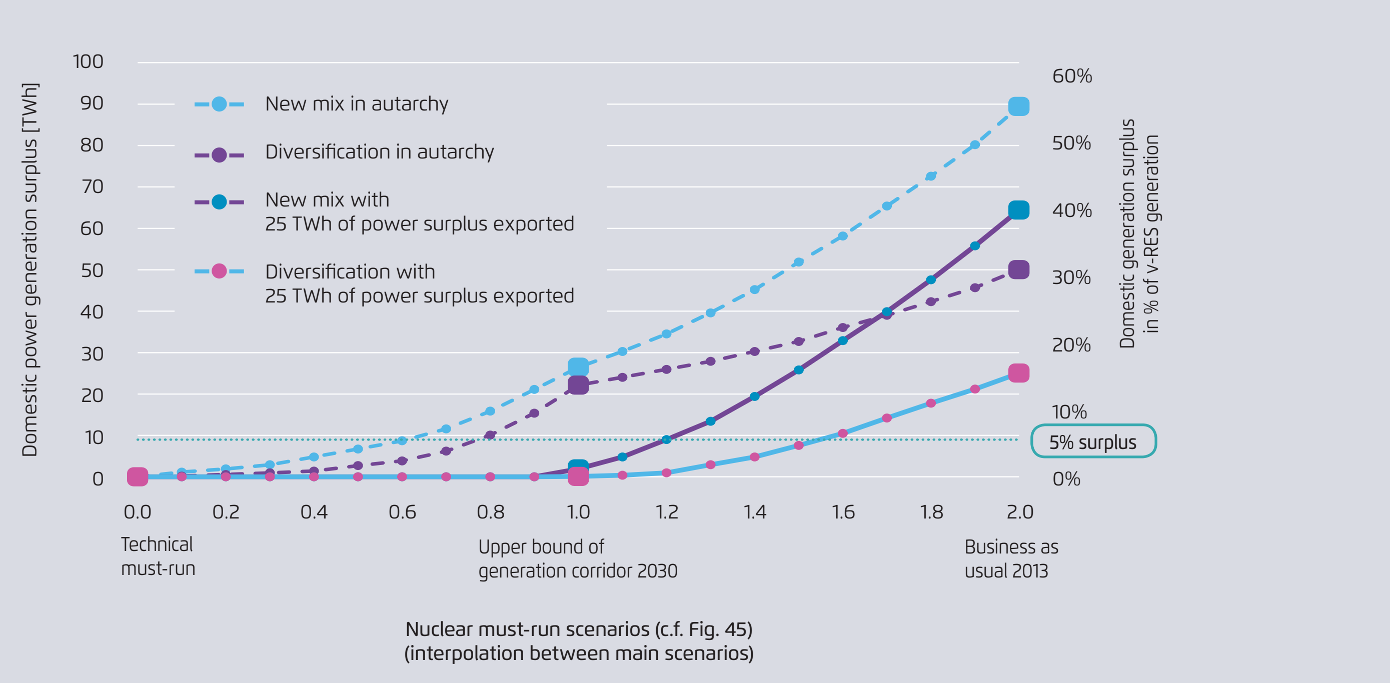
Level of domestic generation surplus under the different must-run scenarios illustrated in Figure 45. Figure 46



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5.3 The role of hydro storage: An alpine case study on the Austrian and Swiss power system

As we showed in the previous section on the French power system, controllable and flexible hydro storage capacities play an important role in existing and future power systems. Unsurprisingly, this role is particularly prominent in the alpine countries Austria and Switzerland. Their power systems are characterised by large capacities of run-of-river and (pumped) hydro storage, the latter enable high flexibility. Although the share of PV and wind power is moderate, especially in Switzerland, the great majority of net power generation comes from renewables in the 2030 scenario, as we see in Figure 26.

Domestic power system characteristics and cross-border flows

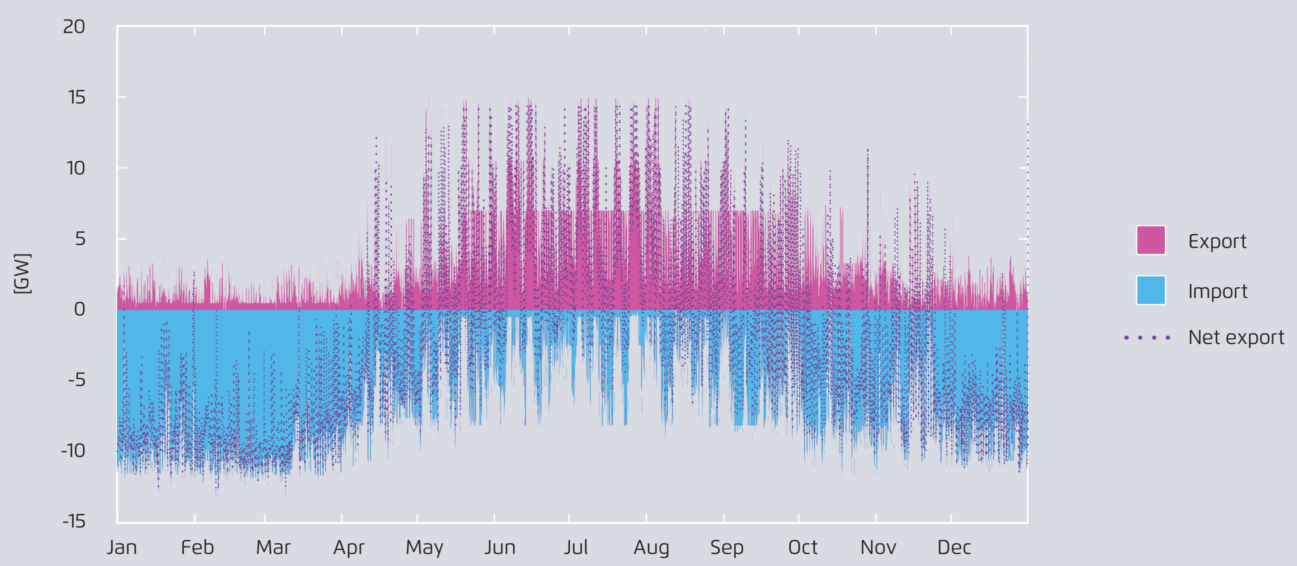
Today, turbine capacities[67] are 7.8 GW in Austria and 10.5 GW in Switzerland, and pumping capacities amount to 3.2 GW in Austria and 1.6 GW in Switzerland.[68] For 2030, we project turbine capacities in Austria and Switzerland of 9.7 GW and 15.9 GW, respectively. These values match the total potential. Comparing them to the peak load modelled for 2030 (Austria: 13.3 GW; Switzerland: 12.4 GW) shows that for Switzerland peak load is exceeded by the installed turbine capacity in storage and pumped storage plants. Furthermore, 61 percent of electricity demand is met from hydropower in Austria and 48 percent in Switzerland in 2030. Altogether, these facts show that the alpine power generation system is specifically designed for flexibility. On paper, the system can instantaneously generate more hydropower than it can consume at peak load[69] and export the surplus to neighbouring countries. The flexibility of its hydropower –

67 This comprises turbines in both storage and pumped storage plants.

68 Sources: Switzerland: http://www.bfe.admin.ch/themen/00490/00491/index.html?lang=de&dossier_id=01049 (BFE, 2014. Statistik der Wasserkraftanlagen der Schweiz); Austria: http://www.e-control.at/de/statistik/strom/bestandsstatistik (E-Control, 2014. Bestandsstatistik) and IWHW, 2014. Energie aus Wasser – Wasserkraft und Wasserkraftwirtschaft.

69 This is limited to the quantity of stored water. In other words, Austria and Switzerland are "energy constrained" rather than "capacity constrained".

Exports and imports of Austria and Switzerland in 2030. Figure 47



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except of course for run-of-river – is not limited by a must-run base, which permits a high level of imports as well.

Figure 47 shows the modelled exports and imports from Austria and Switzerland arising from our power system simulation for 2030[70]. Besides the fact that Austria is a net exporter and Switzerland is a net importer (see section 3.3), a similar trend can be observed in the two countries. During the winter months, both make use of flexibility by importing surpluses from neighbouring countries (due to, say, a high wind power feed-in). During the summer months, by contrast, the alpine hydropower storages are well stocked after the spring snowmelt. This allows Switzerland and Austria to export electricity, e.g. helping meet higher power demands in southern Europe caused by air conditioning.

Below we provide more details on this interplay of national and regional "flexibility exchange".

70 Again, we did not consider pumping capacities in the scenario for 2030. Capacities like these would add further flexibility to the system.

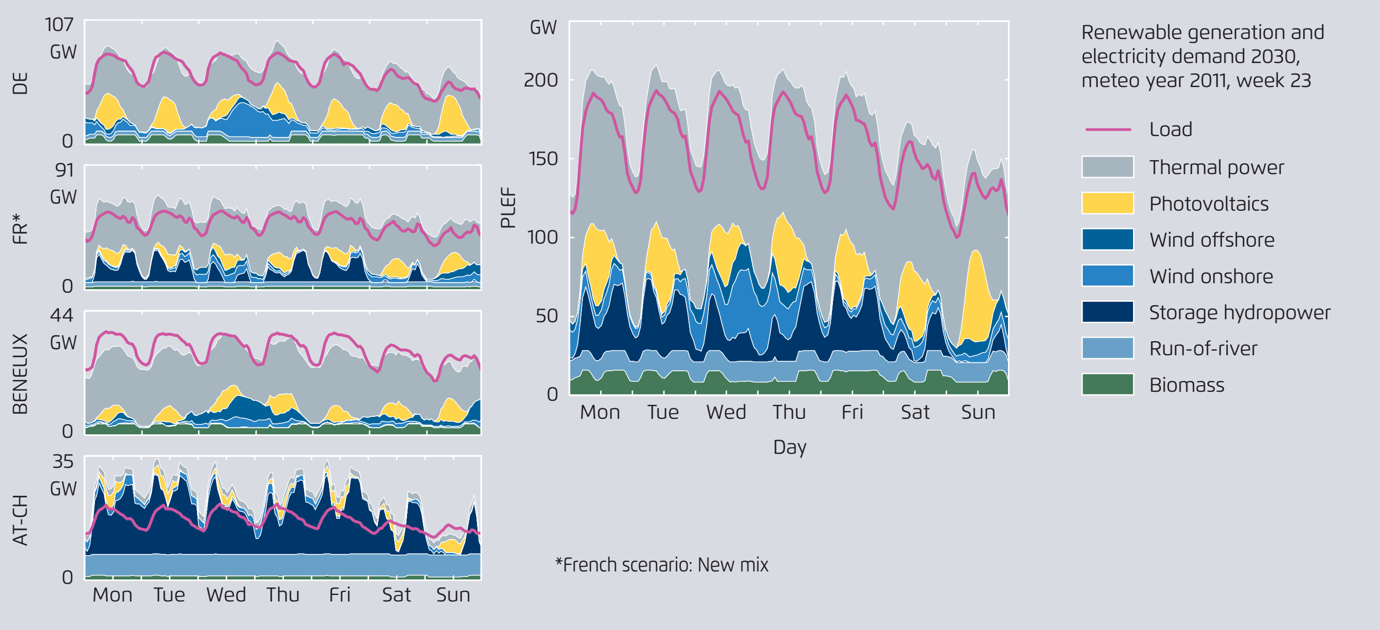
The backup and short-term flexibility function of the residual power plant park

Figure 48 to Figure 50 provide insights into the flexibility and backup potentially available in the alpine countries. Each figure shows a sample week in 2030 characterised by special circumstances.

Figure 48 depicts a week where the share of vRES is shaped by high PV generation in all PLEF countries. Here the load is usually higher during the day than at night, which aligns well with the PV feed-in. The morning ramp of load and evening peaks of load must be balanced when PV generation is low. Storage hydropower in Austria, Switzerland and France (see section 5.2 for more details) is supported by some flexible biomass. Being a week in the summer, water gauges in rivers and storages are high and have to be conveyed to avoid energy losses via the spillways, which explains the enormous amount of storage hydropower combined with the high run-of-river feed-in in the alpine system. Overall, Austria and Switzerland produce more power than they consume. They export the difference as

Power generation and demand for calendar week 23 (high share of PV) in 2030, for each PLEF region as well as in the aggregate.

Figure 48



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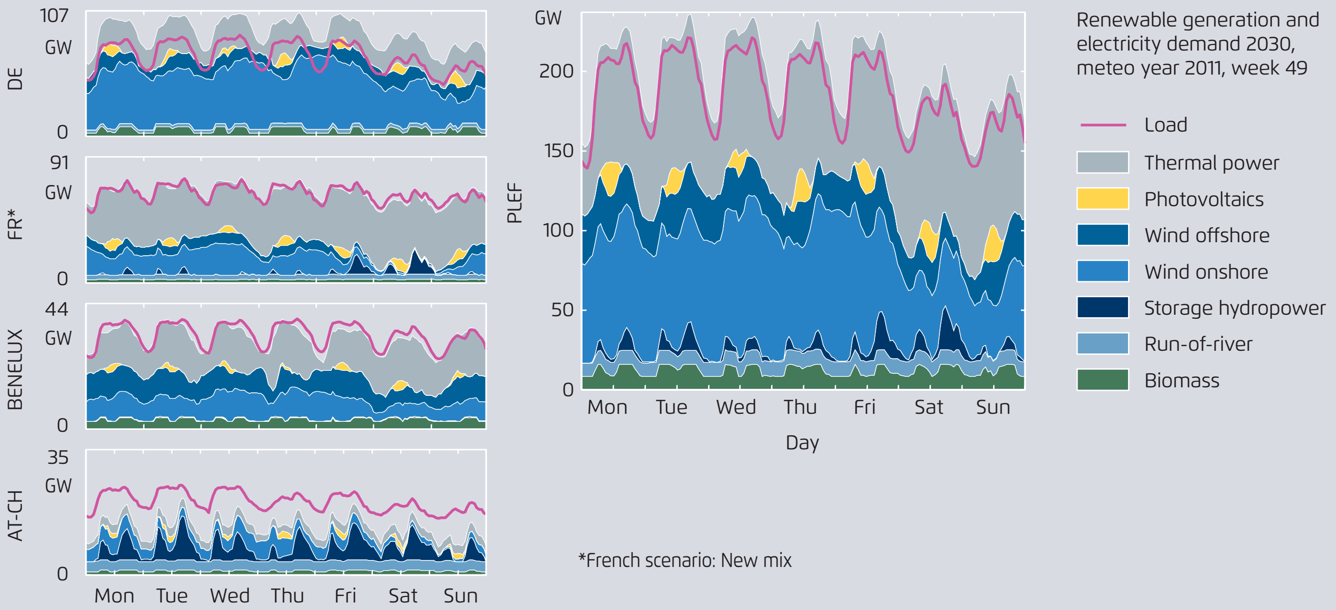
Power generation and demand for calendar week 49 (high share of wind power) in 2030, for each PLEF region as well as in the aggregate.

Figure 49



*French scenario: New mix

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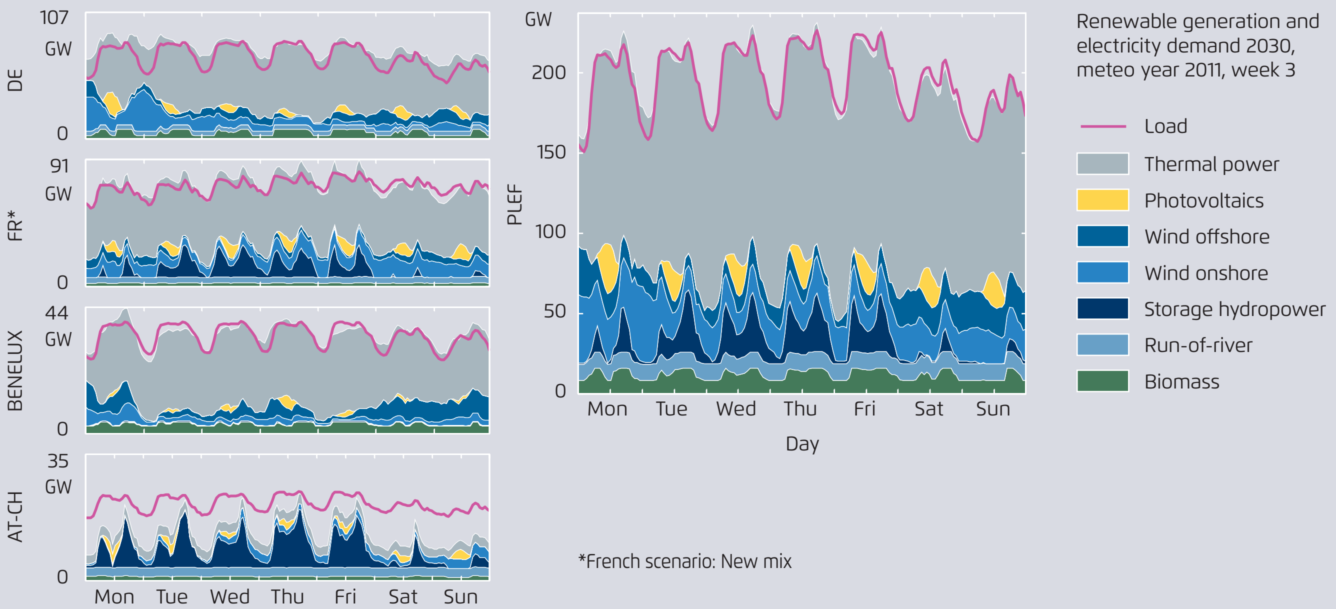
Power generation and demand for calendar week 3 (low share of vRES) in 2030, for each PLEF region as well as in the aggregate.

Figure 50



*French scenario: New mix

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shown in Figure 48, with total generation in the PLEF region exceeding the prevailing PLEF load.

With a non-negligible erratic wind power feed-in, as we see in the middle of the week in Figure 48 or throughout most of the week in Figure 49, the balancing requirements become more complex, although the "cyclical" hydropower support for the morning load ramp and the evening peak load can still be observed. At any rate, the total energy amount provided by hydropower is lower since our simulations factor in more installed wind capacity than PV. Germany, for instance, covers almost its entire load by renewables during the week, exporting e.g. to the Alpine countries. This matches well with higher demand levels: in the winter water gauges are low.

Finally, Figure 50 shows a week with poor PV and wind power feed-in. Load is mostly covered by thermal power plants. To support the latter, flexible hydro storage plants are deployed in the morning and evening hours of the day, when load ramps are steep. In these hours, power demand in the Alpine countries is mostly met by hydropower.

We should point out that all the figures only cover hourly values. Fluctuations that occur within an hour (traded within the intraday or balancing markets) cannot be seen. However, for purposes of system stability it is crucial that power plants are available that are flexible enough to balance these short time variations within seconds or minutes. For instance, hydropower storage plants or gas turbines can meet these balancing needs.

The alpine countries thus play an important role in managing the flexibility challenges described in section 4. They are not only able to balance and back-up their own vRES feed-in; their large hydropower storage and turbine capacities enable power exchange with their neighbours. This provides a buffering function for the entire interconnected power system including countries with high shares of vRES. Today this is mostly Germany, but in the future it will also apply to Italy and France, positively impacting the stability of the entire European power system.

5.4 The BENELUX countries: Integrating renewables in the northwestern European power hub

Belgium, the Netherlands and Luxembourg are situated between and closely linked with their larger neighbours, France and Germany, as well as with countries on the other sides of the North Sea, namely the UK and Scandinavia. It is this central location of the BENELUX countries that gives them a critical position for electricity transit.

In contrast to the alpine countries, the BENELUX countries are mainly flat, with little potential for storage hydropower plants, and must therefore meet flexibility needs differently. The three countries cover a small area with limited potential for geographical smoothing effects within each country. According to the correlation coefficients shown in Section 3, it can be seen that the smoothing effects within the BENELUX countries are fairly modest.

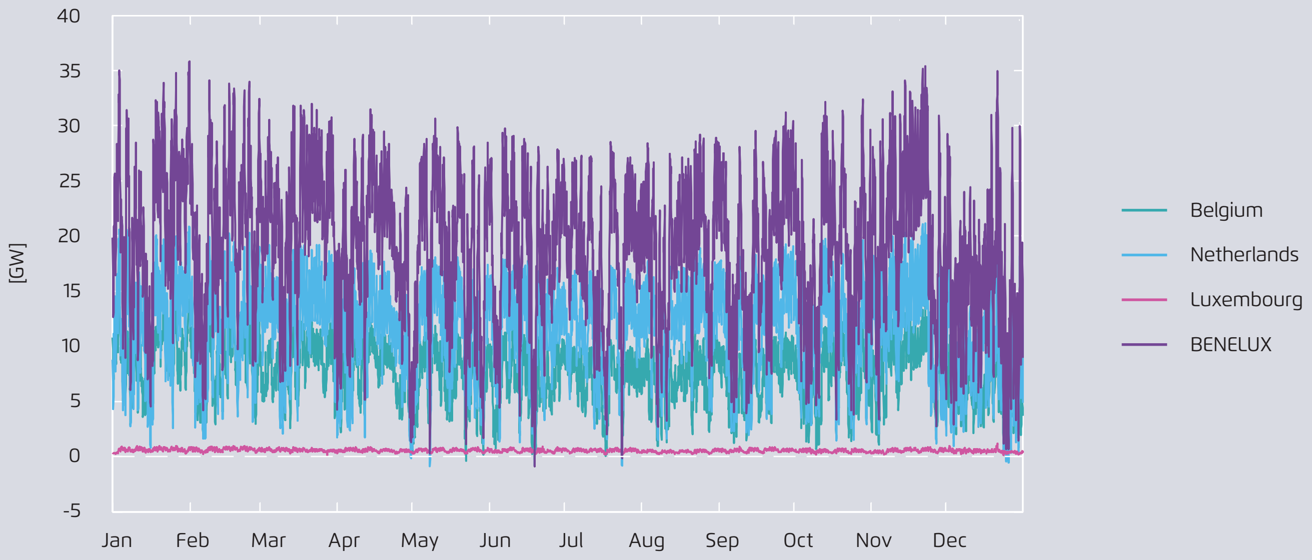
Residual load and RES power generation mix

Figure 51 shows the residual load of the three BENELUX countries. A closer look reveals that the residual load often shows a similar pattern in the three countries. One observes hours in which the residual load is quite low or even slightly negative as well as occasions in which high values of the residual load coincide. Another reason for similar residual load patterns is the similar structure of the Dutch and Belgian renewables mix and power system composition, as Figure 26 shows. For 2030 almost half of the power generation is projected to come from renewables. Wind power, especially offshore, is expected to play the most important role.

Figure 52 depicts the duration curves of Belgian and Dutch onshore and offshore power generation. Both technologies show power generation in almost every hour of the year, though clear differences in the generation structure between onshore and offshore can be observed. The peak onshore production clearly outstrips offshore production,[71] but then decreases rather quickly. By contrast, offshore wind

71 Clearly related to the fact that more onshore capacities are installed.

Time series of the residual load in each BENELUX country and in summation. Figure 51



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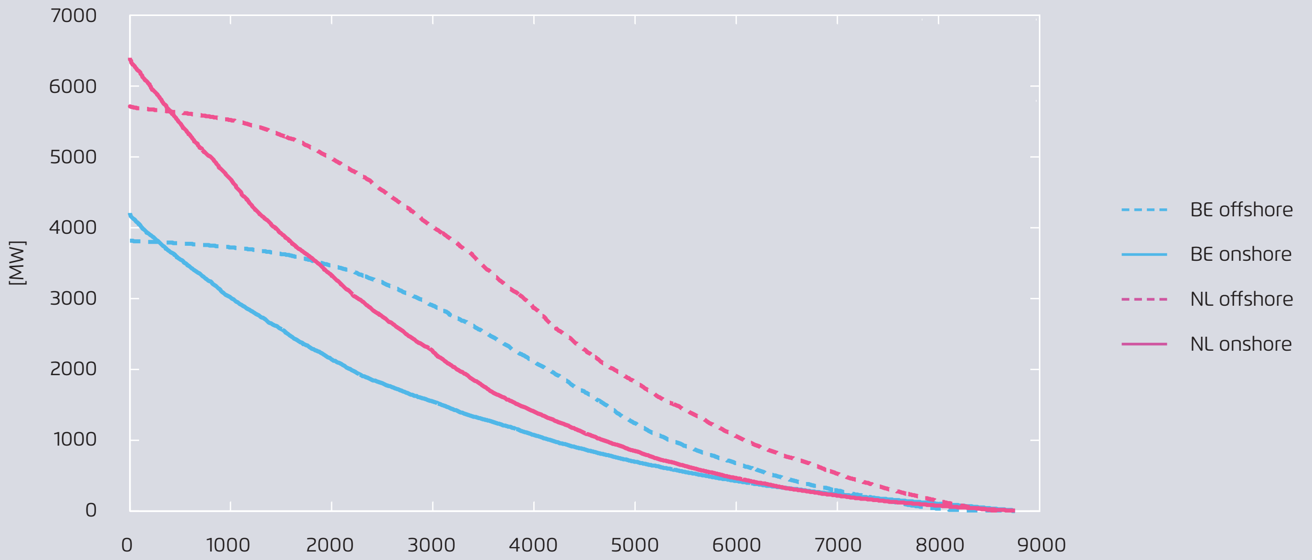
Duration curves of Belgian and Dutch onshore and offshore wind power generation in 2030. Figure 52



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farms deliver power close to rated capacity during some 1,000 to 2,000 hours of 2030. This difference is remarkable, especially for Belgium, as onshore wind farms are usually located in coastal areas, so that a similar behaviour between onshore and offshore might be expected.

However, onshore and offshore wind power generation varies greatly. Due to the high share of onshore and offshore wind power in total power generation, this variation challenges system flexibility.

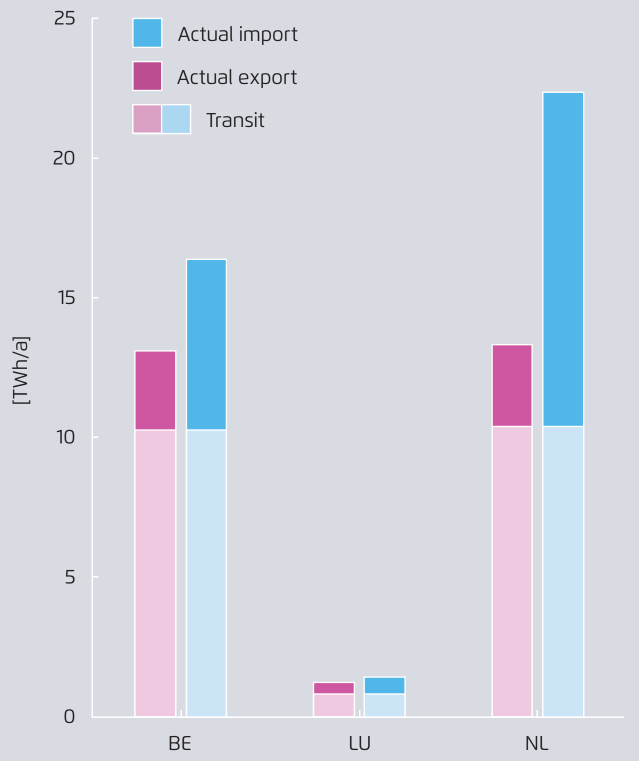
Transit - the BENELUX way of managing the flexibility challenge

Conditions at first seem unfavourable for meeting the flexibility challenge posed by vRES deployment, as there are little geographical smoothing effects within BENELUX countries and the variability of RES power generation is high. Yet, BENELUX countries seem able to handle the challenge. The residual load in Figure 51 contains few hours with negative values, indicating actual (RES) surpluses. As exports occur during these hours, curtailment is not necessary and the full generation potential can be utilised. Moreover, because of its transit levels, the BENELUX region is less vulnerable to flexibility problems: well-developed interconnectors provide further flexibility and ease the situation for neighbouring countries as well.

As Figure 53 shows, the main share of the three countries' imports serves immediate export purposes, effectively becoming transit flows. Less than half of the imports are used for BENELUX load coverage. Domestic excess generation for export makes the smallest contribution to total cross-border flows.

Figure 54 depicts the time series of exports, imports and net exports (the difference between the first two) of the BENELUX countries. It can be seen that during almost every hour both exports and imports occur, emphasising BENELUX's role as a "power hub" or transit region. During winter months exports are somewhat higher than in summer. Yet exports follow a dynamic pattern, yielding net exports with frequently changing directions. This means that BENELUX also plays an important role meeting the flexibility needs for

Imports and exports including transit for Belgium, Luxembourg and the Netherlands. Figure 53



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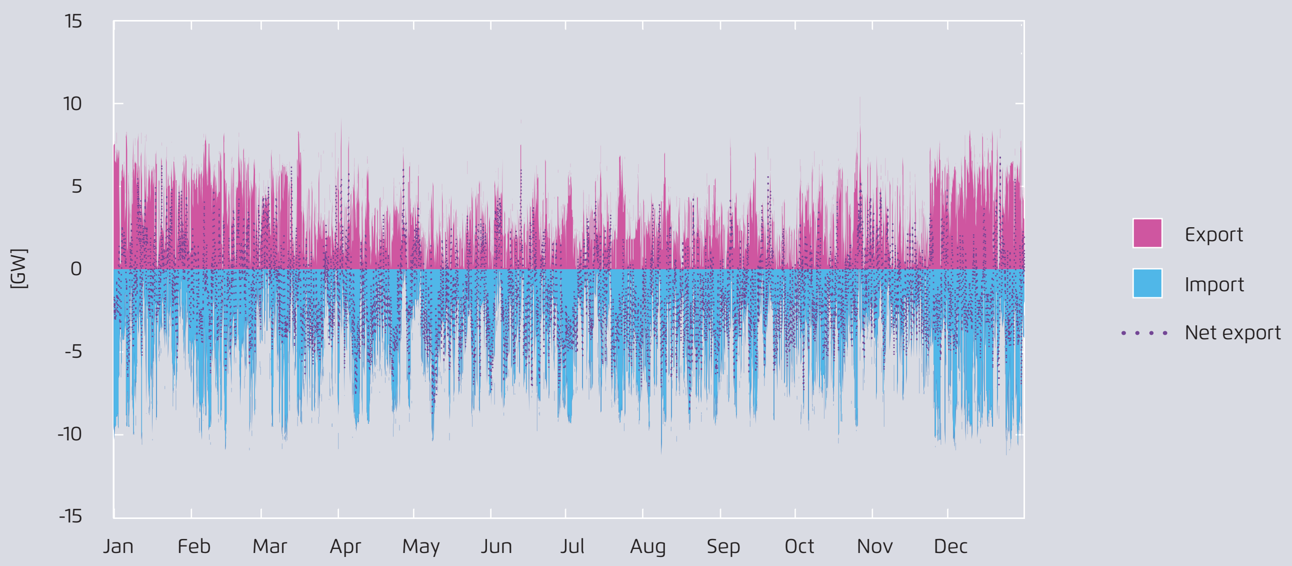
the entire region. The rapid changes in power flow directions indicate optimal use of complementarities between countries facilitated by regional market integration, benefitting everyone involved.

The region exports energy during some 2500 hours of the year; during the remaining hours the region imports more than it exports. Figure 55 shows the according duration curve of BENELUX net exports in 2030. It depicts the flows both in export and import directions sorted from largest export to largest import values.

(Net) exports and imports between BENELUX and its neighbouring countries for the year 2030. Figure 54



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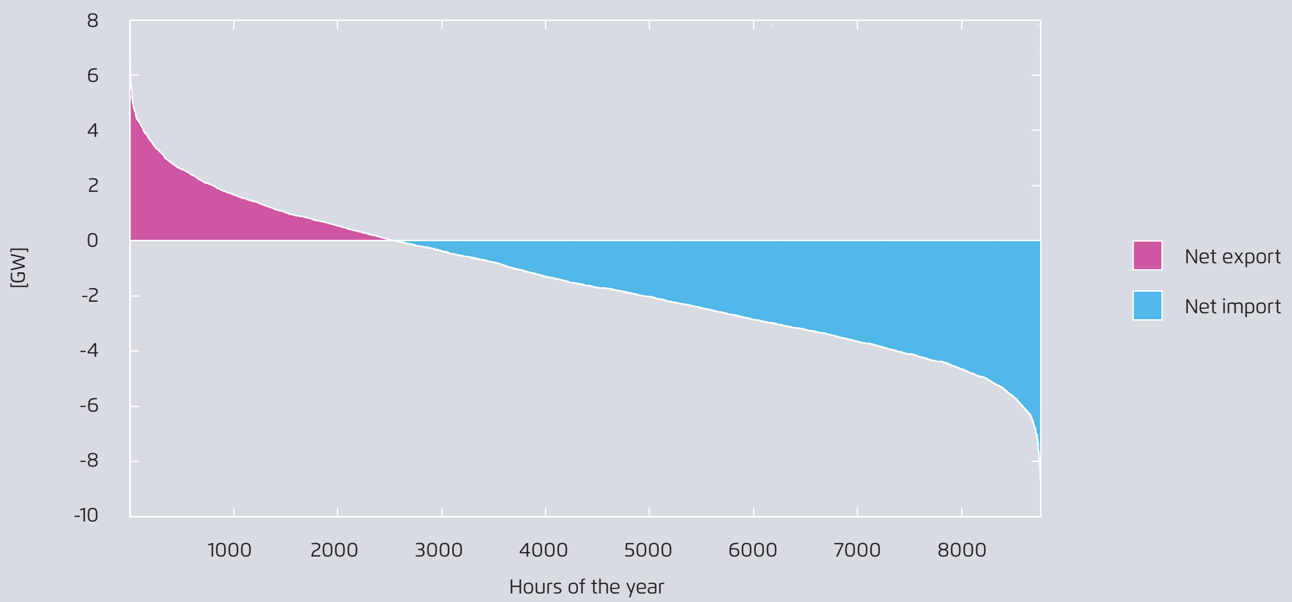
Duration curve of BENELUX net exports in 2030 in the integration scenario. Figure 55



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BENELUX and the Integration of the UK with continental Europe

The BENELUX region electrically links the British Isles to the European continent. To assess interactions between continental Europe with the UK and Ireland, the connection from the UK to France needs to be considered as well. The aggregated imports and exports between Belgium, the Netherlands and France on the one hand and the UK on the other hand are depicted in Figure 56. The exchanges between the three continental countries and the UK show noticeably similar patterns, with few hours when exports flow in both directions. Furthermore, imports and exports show much variation and the available transfer capacity is often fully used. This is not surprising, as the UK is also in a transit position as the only connection to Ireland.

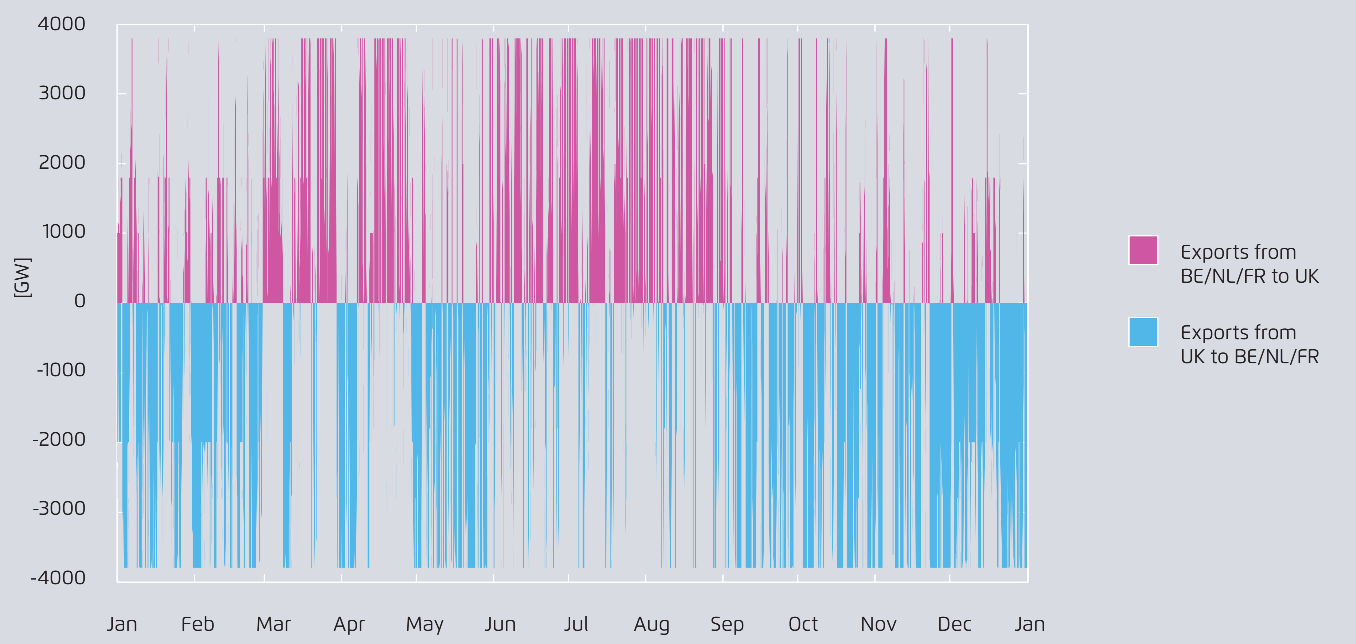
The figure shows that in the winter months the UK exports its surpluses – mostly from its sizeable installed offshore wind capacities[72] – to BENELUX and France, which eventually facilitate electricity transit further south to regions with different wind situations. Conversely, during spring and summer the South exports power surpluses to the British Isles.

In summary, the BENELUX region represents a crucial "power hub" that manages flexibility both for the three countries that constitute it and for the entire PLEF region. What is more, it links North Sea countries with continental Europe. Frequently changing power flow directions underscore the benefit of regional integration from complementing generation and demand conditions between the countries.

72 In our simulations, the UK contains the highest amount of offshore wind capacities.

Imports and exports between between Belgium, the Netherlands, France and the UK in 2030 in the integration scenario.

Figure 56



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6. Country and regional outlook, implications and recommendations

The simulations described above stress the increasing flexibility requirements in future power systems caused by the rising share of wind power and PV. To manage this, renewables, conventional generation capacities, grids and storage technologies will all need to become more responsive. We pointed out the role of interconnectors and improved market integration for facilitating imports and exports as flexibility options. Besides being beneficial for renewables integration, an interconnected power system lowers total generation costs.[73]

The new power system requires a mix of flexible resources for high reliability – and a significant transformation of today's power system. On the supply side, more peak and mid-merit and less inflexible base load plants will be needed implying both a different mix and operational pattern. In addition, activating the flexibility potential of the demand side will be crucial in all European countries. Both an active demand side and an adjusted power plant park will help manage flexibility challenges.

The German power system will – according to official targets – see RES-E as main generation source in 2030, with wind power and PV representing the main renewable sources. Targeting flexibility, back-up options and regional integration are thus crucial for high reliability levels. vRES deployment challenges the way other power plants (as well as storage and demand response) are operated. It will require increased ramping of the residual system at partial load and more starts and stops of power plants.

The French power system will remain characterised by a high share of nuclear power must-run capacities. Incorporating 40 percent renewables will require some resizing of the nuclear park. Yet the load-following capabilities of the French nuclear fleet can technically respond in part to increasing flexibility needs. Several other flexibility options, hydropower in particular, will help reduce the conflict between high nuclear must-run and a high share of variable renewables. A long-term energy transition strategy – based on renewable energy deployment, nuclear fleet reoptimisation and the development of flexibility potential – will be key for meeting the 2030 targets in French power mix diversification and for minimising costs.

Hydro storage plays and will continue to play an important role in the Alpine countries of Austria and Switzerland in tackling flexibility challenges. The two countries have the potential to generate more hydropower at once than their annual peak load and can also provide flexibility to neighbours in the region. In addition, because hydro storage (and pumped storage) is not constrained by a must-run generation level, high imports are possible as well.

The BENELUX countries serve as an important "power hub" thanks to their central location in Northwest Europe. Yet because their geography is mostly flat, with little potential for (storage) hydropower plants, the BENELUX countries require well-developed interconnectors to cope with flexibility challenges. Frequently changing power flow directions underline the benefit of regional integration for all countries.

Looking at the PLEF region in the aggregate, one can conclude that, alongside grid reinforcement, the diverse mix of available technologies can facilitate the integration of vRES. It is important to note that domestic network development is mandatory if European integration benefits are to be utilised. This is why the PLEF region's central location in the interconnected European power system is highly beneficial for vRES integration.

73 See, for instance, Booz&Co et al., 2013, Benefits of an Integrated European Energy Market. Final Report prepared for Directorate-General Energy European Commission; and ECF, 2011. Power Perspectives 2030.

The performed analysis neglected several additional enablers of flexibility, such as pumped hydro storage, demand-side management (including power-to-heat) and new power consumers (e.g. electric vehicles). The modelling also did not consider that renewables can and will take an active role in contributing to system services (such as the provision of balancing energy). System-friendly deployment (e.g. east/west orientation of PV) can also be part of the solution. Hence, the flexibility potential from other sources is large, but its development will require proactive policies and a favourable framework.

To sum up, improved integration of the power system can help meet future flexibility needs. The flexibility challenge is manageable from a technical standpoint, yet it is important to note that economic effects outside the scope of this study may affect the magnitude of the changes depicted here. In particular, power market design must provide economic incentives for investments in flexibility options. A timely, supportive regulatory framework needs to be enacted if a flexible power system is to arise.

Appendix 1: Modelling of the European power system

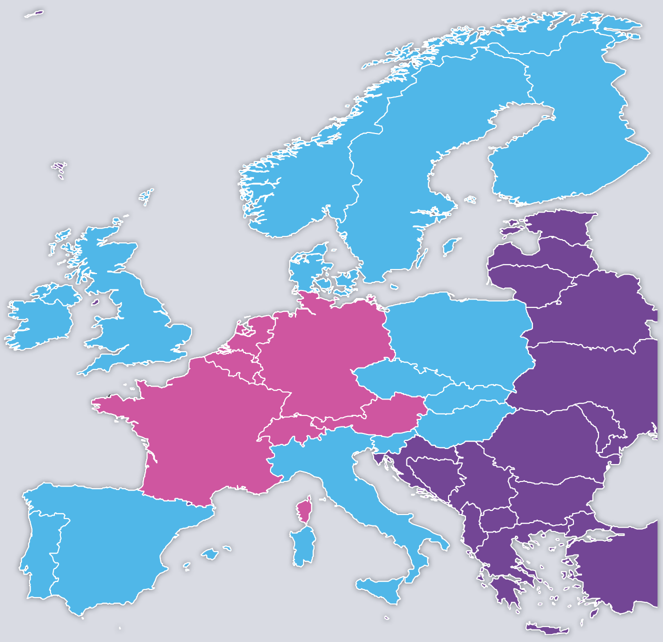
The simulation of the future European power system is based on a model developed at Fraunhofer IWES. The model covers 25 countries (mostly European Union Member States) as illustrated in Figure 57.

Realistic time series of feed-in from wind power and PV are generated by coupling physical wind power and photovoltaics models with data from the meteorological forecast models COSMO-DE (Germany, Benelux, Alpine countries) and COSMO-EU (other countries) from the German Meteorological Service (Deutscher Wetterdienst). Due to the high spatial resolution of the forecast models – ~3 km (COSMO-DE) and ~7 km mesh size (COSMO-EU) – we developed this approach for taking into account smoothing effects from distributed generation more precisely.

Detailed information on the location of wind turbines and PV generators is needed before generating feed-in time series. Publically available data (EEG-Stammdaten, Betreiber-Datenbasis, TheWindpower.net, etc.) provide precise location of many existing generating units. The difference between known installations and installed capacity in the region[74] in the 2030 scenario is allocated by a specific expansion model. Specifically, new generation units are added to suitable sites based on a statistical analysis of recent additions and the prevailing wind and solar resources. Suitable sites are identified by a geographical information system (GIS) analysis based on CORINE and cover data, nature conservations areas, and, in the case of wind power, minimum distances to residential sites (min. 1000 m). Furthermore, this model takes into account the development of wind turbine technologies by making assumptions about increasing

74 The installed capacities are set for Germany by federal state ("Länder") and for France by administrative region ("région"). For all other countries, capacity values are set for the federal level.

Countries of the PLEF region (red) and European countries additionally considered (blue) in the power system model. Figure 57



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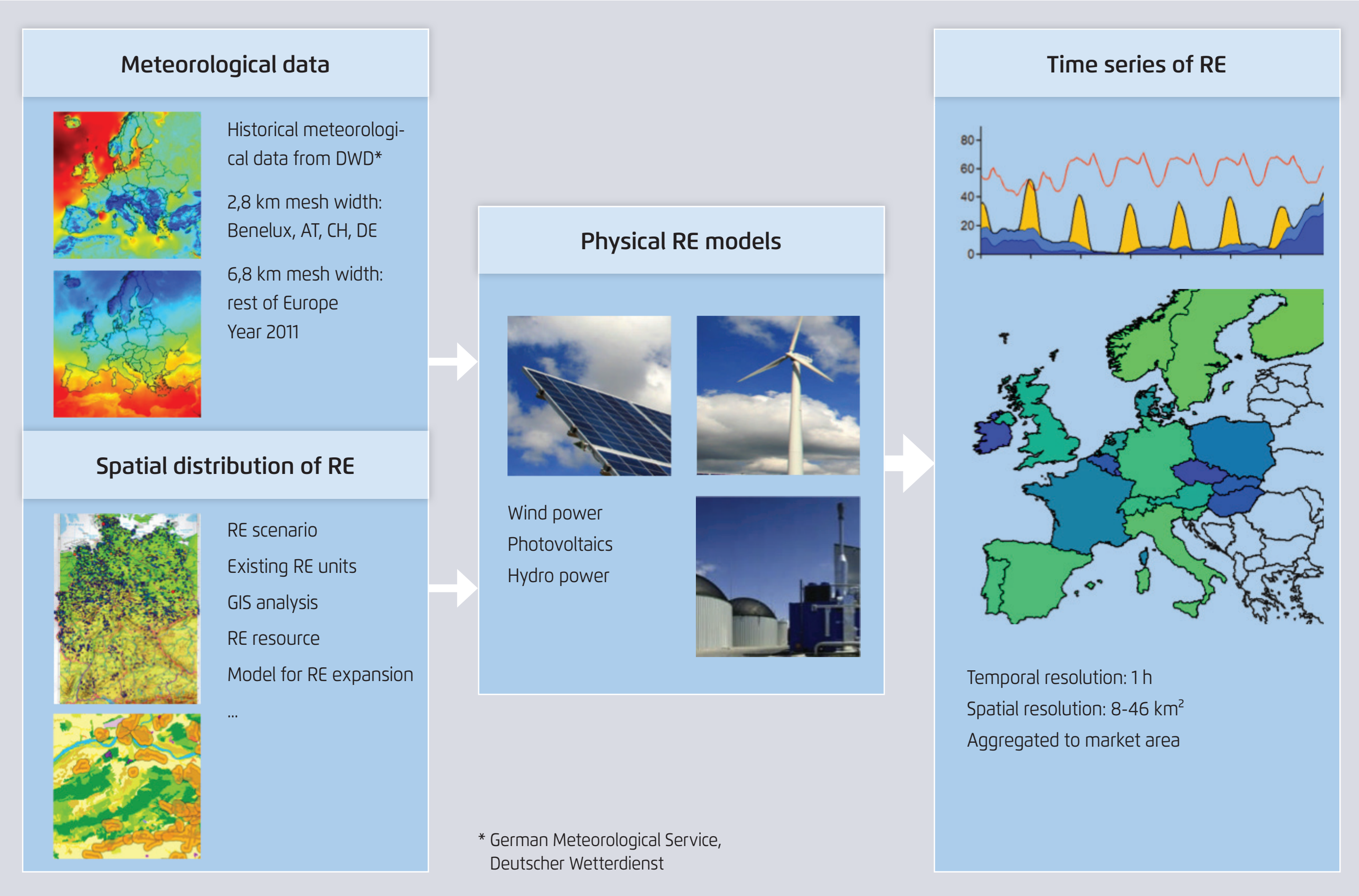
Modelling feed-in from renewable energy sources.

Figure 58



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hub heights and reduced nameplate power in relation to the swept area of the rotor. Both aspects lead to higher load factors for future wind turbines.

To account for the future flexible use of biomass, 75 percent of the expected biogas and bioliquid capacities were modelled as flexible biomass with a (gas) storage of 12 hours and a CHP oversized by a factor of two. All other biomass technologies (solid biomass, sewage gas, landfill gas, biogenic share of waste) were considered together as an inflexible feed-in source (generating "baseload").

Furthermore, flow rates for run-of-river power plants in Germany are based on water levels for the year 2011 logged at measuring points near the power plants. European flow rates were taken from long-term average annual profiles of major rivers. The turbines of storage hydropower plants were modelled based on publically available inflow data, while pumps, which could provide additional flexibility, were omitted. The latter also holds true for the pumped-storage power plants.[75] Figure 58 depicts the applied approach for deriving the renewable feed-in time series.

Historical load profiles from ENTSO-E for each country were scaled to match expected annual peak load and total power consumption. (See the appendix on input data for more information.) These load profiles thus reflect today's

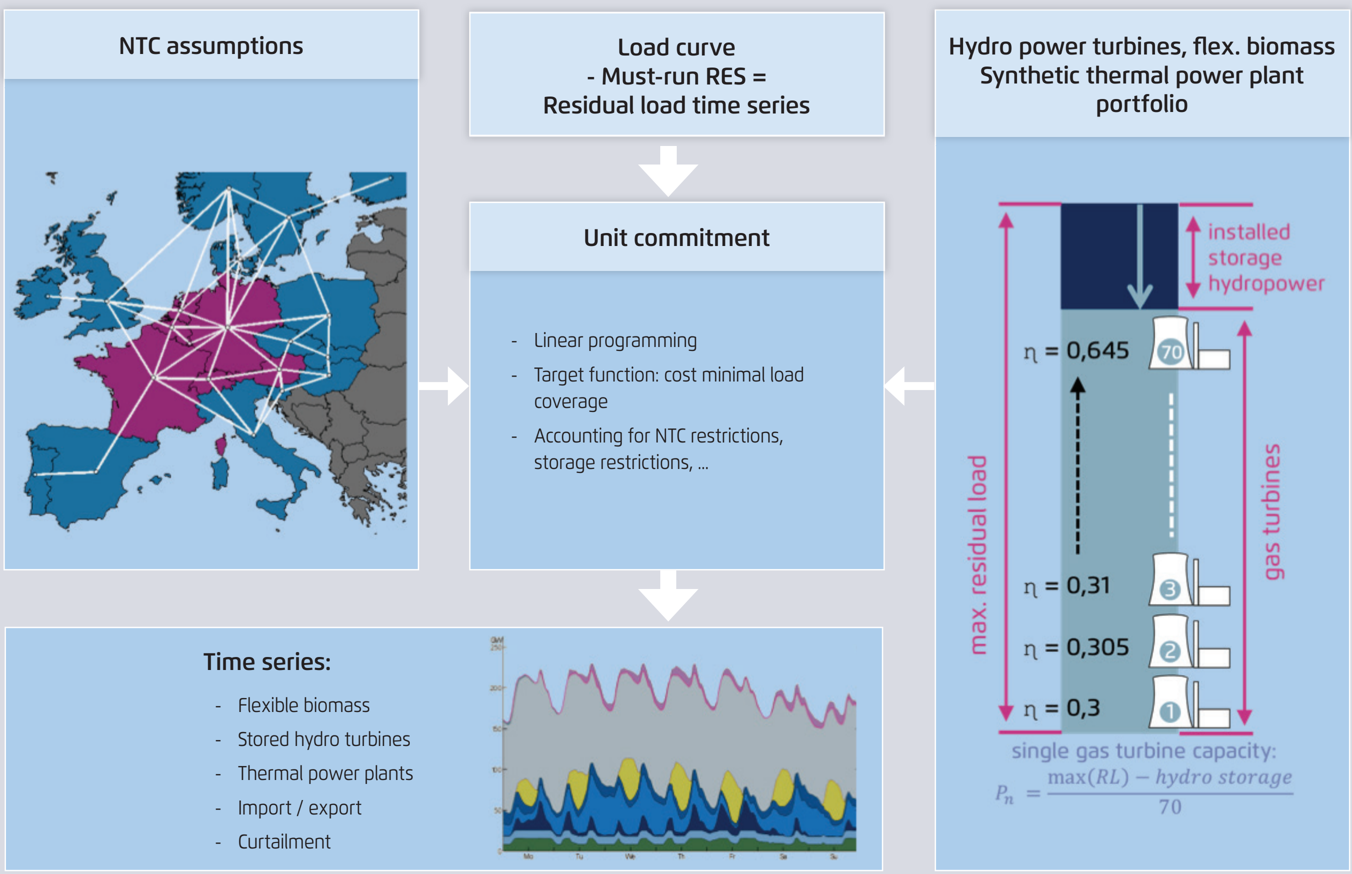
75 In the unit commitment model, a price signal is required for modelling storages. Because of the approach we chose, in which actual power plant portfolios are not modelled, no such scheduling signal for storage is available. Our conservative approach, therefore, underestimates available flexibility in the power system.

power consumption. In 2030, new consumption patterns arising from additional consumers such as electrical heat pumps, additional air conditioning and e-mobility are expected. The new consumers will add their specific profiles to the overall load but would also be expected to (at least partly) participate in demand-side management (DSM) in the future. Neither new consumers nor other DSM or demand-response applications were considered in the modelling, which thereby underestimates flexibility on the demand side. All meteorological input data and corresponding load profiles were from 2011 to ensure consistency in the correlations between load and weather situation.

The next step of the modelling approach comprises the derivation of residual load time series for each country. They were determined by subtracting hourly renewable must-run feed-in time series from the hourly load time series. In the next modelling step, remaining national power deficits (i.e. positive residual load values) had to be balanced with additional power either by dispatching thermal power plants, flexible biomass or storage hydropower plants or by importing power from neighbouring countries. Surplus power can either be exported or, in the absence of export possibilities, curtailed.[76] Balancing residual load at minimum total costs is determined by a European market simulation based on unit commitment and dispatch optimisation (see Figure 59). Assumptions about power plant portfolio and power exchange

76 Surplus power would also be used to charge/load storages, which is not modelled here.

Illustration of the modelling approach. Figure 59



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capacities between countries (NTC- based interconnector capacities) are required as additional input parameters for the unit commitment.

To emphasise the challenges and opportunities of a future European power system without discussing the suitability of the existing power plant park, a "neutral" synthetic power plant park was developed for the unit commitment model.[77] For this purpose, the power plant portfolio of each country consists of 70 thermal generating units ranging in efficiency from 30 percent to 65 percent while their aggregated nameplate power equals the maximum residual load minus the assumed turbine capacity of hydropower storage plants. This approach ensures that each country has a similar residual power plant park with a similar cost structure. To ensure the provision of ancillary services such as reserve power and reactive power provision, a minimum share of conventional generating units must permanently remain running. Moreover, heat demand (via CHP power plants) partially translates into permanently operating units. Together, these so-called must-run capacities are dimensioned as 5 percent of the residual power plant park[78] and are considered as a boundary condition in the unit commitment.

Power exchange between neighbouring countries and European market integration today already play an important role in reducing overall power system costs and in increasing security of supply. In evaluating the benefits of European power system integration, we analysed two variants, a national autarky scenario and an integration scenario ("NTC scenario") with well-developed interconnection capacities. (See the appendix on input data for more information.) So while no imports and exports take place in the autarky scenario, power can be exchanged between interconnected countries to a maximum of the assumed net transfer capacities (NTC) in the integration scenario, allowing imports and exports as well as transit flows. To account for transport losses, we assumed energy losses of ~1 percent per 100 km distance between load centroids[79]. This approach neglects power network congestions within the market areas, implying we applied a "copperplate" approach within countries. (However, a parallel expansion of the power network within the countries is implicitly assumed.) Otherwise, renewably generated power could not be transported to and from the borders for export or import.[80]

Finally, the results generated by the European energy model include, for each country hourly, the time series of consumption, renewable energy generation/curtailment and the dispatch of biomass, storage hydropower, thermal power plant production and cross-border power flows.

77 The idea behind choosing an approach with a generic power plant park was to show benefits and opportunities of further European power system integration without being affected by Europe's existing heterogenous structure. Differences in the marginal costs of each country's power plant portfolio would result in additional power flows and might blur the effects the authors point to.

78 For Germany, we assume a must-run level of 5 GW. The must-run level for France is set to 15 GW in the new mix scenario and 20 GW in the diversification scenario. (See the section on France for more details.)

79 Thus, power consumption in a country is condensed to a point which is located at the centroid of each country's surface area weighted by its population density.

80 The model assumes "perfect" or "full" cross-border cooperation of system operations optimising the power flows on a European wide scale.

Appendix 2: Input data and scenario selection

In order to perform the simulations, we compiled input data by country. This concerned annual electricity consumption, annual peak load, installed renewables capacities and net transfer interconnector capacities. The data was derived from national energy strategies, national grid development plans and, for countries where such information was lacking, from ENTSO-E's recent Scenario Outlook & Adequacy Forecast (SO&AF) 2014-2030 and ENTSO-E's Ten-Year Network Development Plan.

Annual electricity consumption

Figure 60 shows the 2030 electricity consumption levels[81] we assumed for our simulations. For Austria, Germany and France, national grid development plans were used as an input; for the other countries, Vision 3 (Green transition) of ENTSO-E's SO&AF 2014 was applied.

Annual peak load

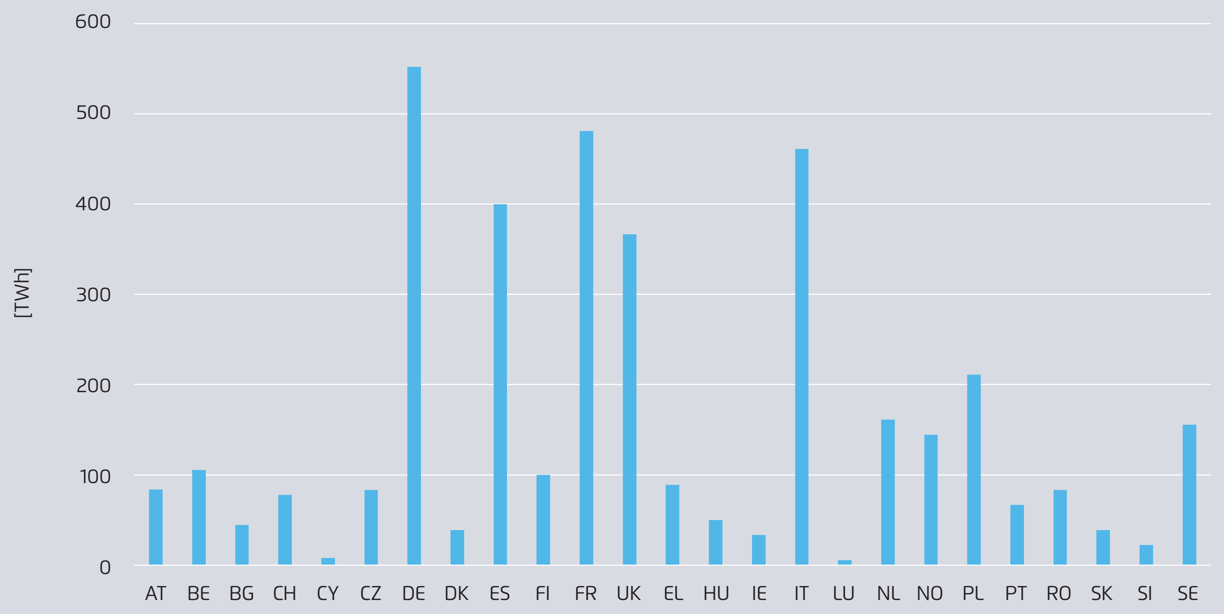
Figure 61 shows the assumed peak load prevailing in the modelled countries in 2030. For Germany and France, national grid development plans were used as an input; for the other countries, Vision 3 (Green transition) of ENTSO-E's SO&AF 2014 was applied. As we can see, the input data sources assume little change to current peak load levels.

Installed renewable energy capacities

Figure 62 shows the assumed installed capacities of wind onshore, wind offshore and PV for the countries of the Pentalateral Energy Forum (PLEF) for 2030 and compares these installation levels with the prevailing peak loads. For Austria, Germany, France and partially the Netherlands, national grid development plans and national energy strategy

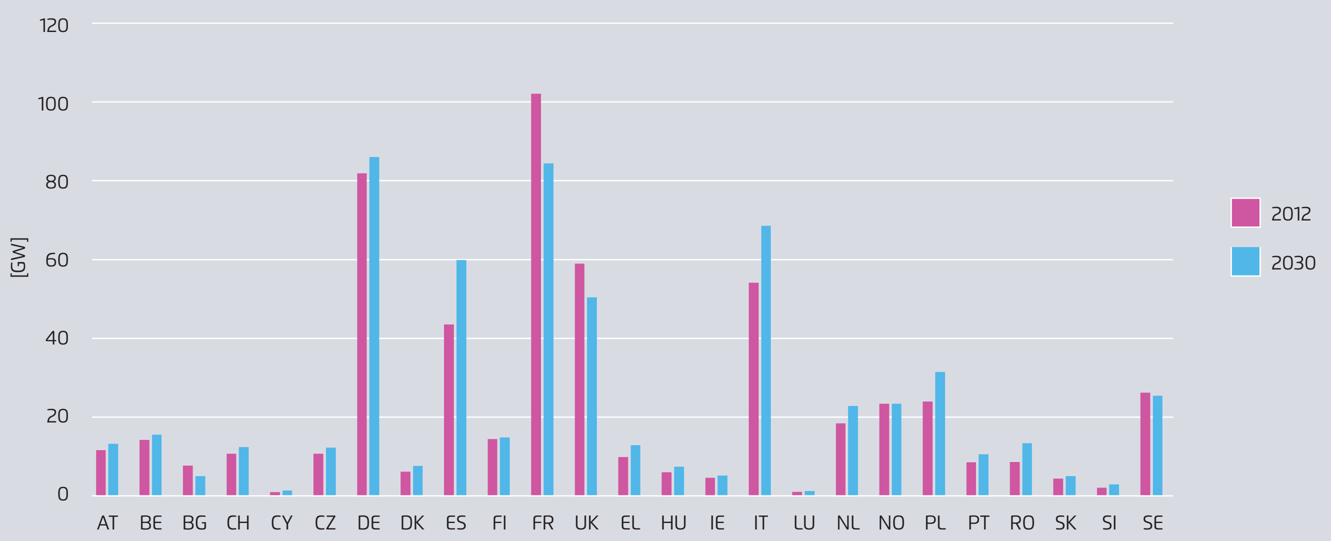
81 We define electricity consumption here as net electricity demand plus grid losses. Hence, power plants' own consumption is not included in the figures stated here.

Net electricity demand (incl. grid losses) in 2030 for the modelled countries. Figure 60



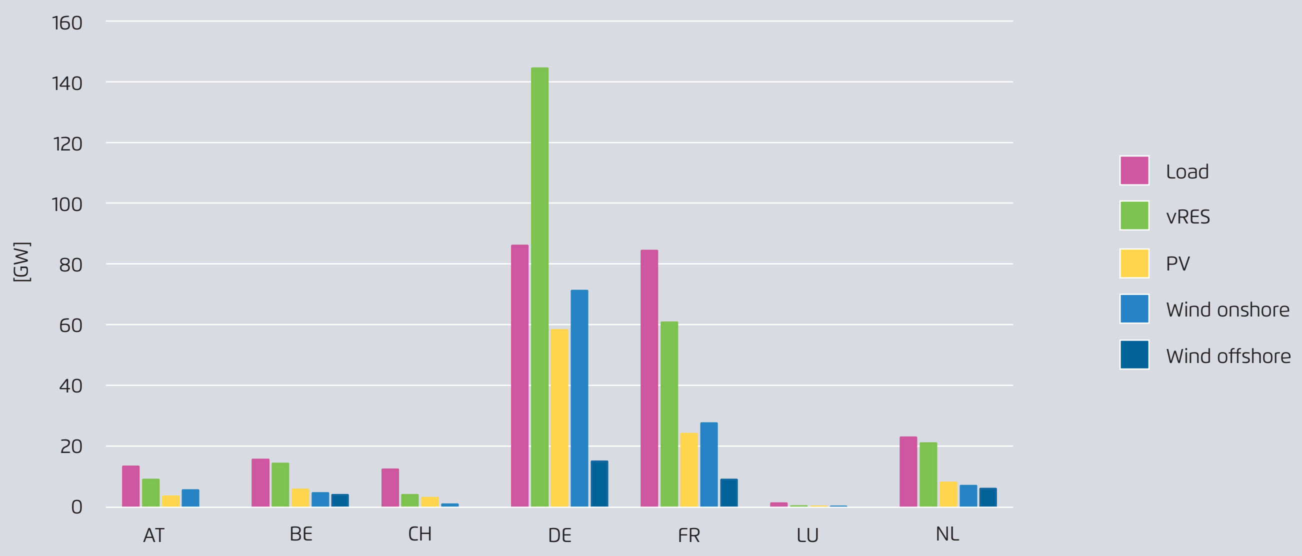
ENTSO-E (2014), national strategy documents

2012 and 2030 system peak loads in the modelled countries. Figure 61



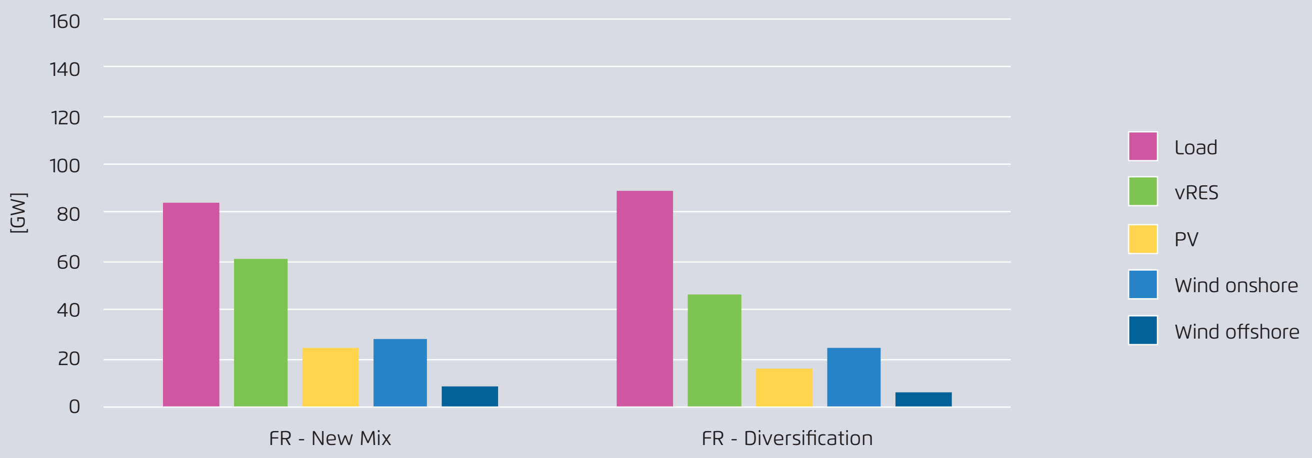
ENTSO-E (2014), national strategy documents

2030 installed wind onshore, wind offshore and PV capacities and peak load in the countries of the Pentalateral Energy Forum. For France, values for the new mix scenario are shown. Figure 62



ENTSO-E (2014), national strategy documents

Scenarios for 2030 installed wind and PV capacities and peak load in France. Figure 63



RTE (2014)

Installed renewable energy capacities in the modelled countries in 2030. For France, values for the new mix scenario are shown. For hydropower, also the provided amount of energy is shown. Table 6

	Wind onshore [MW]	Wind offshore [MW]	PV [MW]	Biomass [MW]	Hydropower [MW]	Hydropower [TWh]
AT	5500		3500	1200	14110	72.81
BE	4540	4000	5740	2290	933	1.91
CH	900		3000	1300	15904	64.29
CZ	860		3620	560	1415	4.82
DE	71200	15000	58200	7700	5200	23.86
DK	4020	3770	1440	3970	10	0.04
ES	46100		37000	4600	24599	53.59
FI	2550	2350	40	3230	3732	14.57
FR	27600	9000	24100	4100	30000	104.78
UK	14000	35150	8274	3430	4290	10.62
HU	1000		200	1140	460	0.33
IE	5150	550	50	550	556	0.83
IT	21100	1000	48900	10570	20867	74.03
LU	180		120	70	145	0.28
NL	7000	6000	8000	2900	80	0.20
NO	5000		0	0	35100	245.00
PL	7300	2700	1000	2400	3409	5.85
PT	6340		720	230	9607	16.26
SK	450		720	440	2850	8.58
SI	240		1120	0	880	4.27
SE	10000	1100	1000	5300	17840	134.46

Fraunhofer IWES, based on ENTSO-E (2014) and national strategy documents

documents were used as an input; for the other countries, Vision 3 (Green transition) of ENTSO-E's SO&AF 2014 was applied. For France, two scenarios were selected. (See section 5.2 for a more detailed analysis.) Figure 63 shows the data for the two French scenarios.

As can be seen, in all countries of the PLEF, wind and PV capacities will reach levels close to or above the national peak load. This is not to say that wind and PV will meet annual consumption – the simulations forecast that approximately 34 percent of annual net electricity consumption will be met by wind and PV in the PLEF in 2030. Rather, it serves to illustrate the importance of wind and PV in future PLEF power systems.

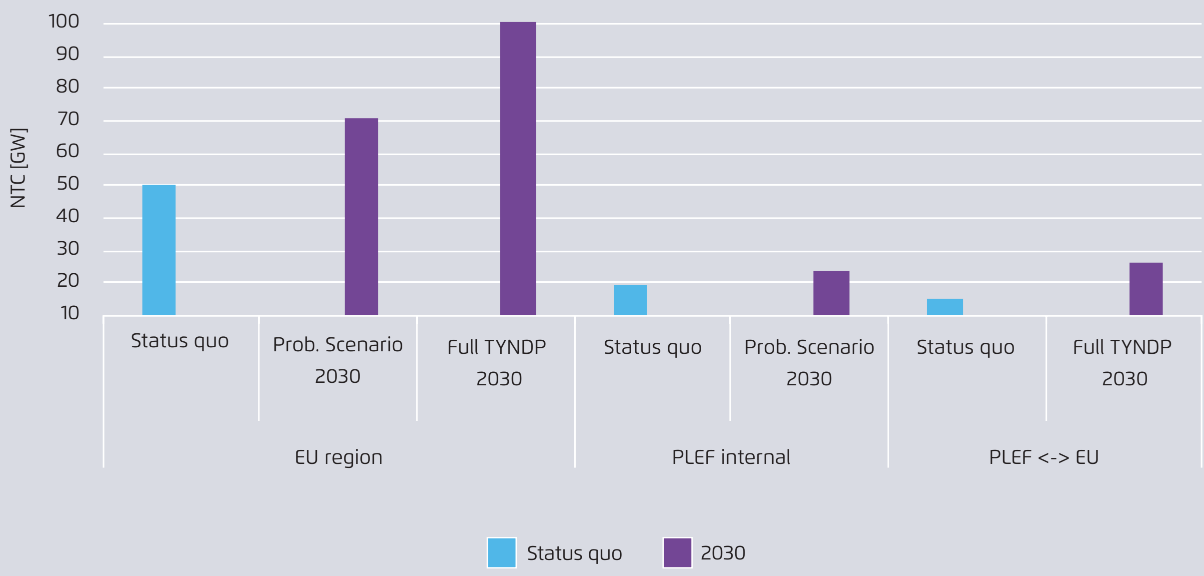
Table 6 provides a technology-specific breakdown of installed renewable energy capacities in all modelled countries in 2030.

Net transfer interconnector capacities

The draft of the Ten-Year Network Development Plan 2014 (TYNDP) (still in consultation when the model runs were performed) served as the starting point for determining NTC interconnection levels between the modelled countries. As can be seen from Figure 64, the full implementation of the TYNDP would double NTCs relative to the status quo. As this seems rather ambitious, we assumed a certain lag rate for the proposed projects. This is in line with experience from earlier TYNDPs, which had a lag rate of 50 percent. We then utilised data from two research projects[82] to crosscheck the NTC data derived from the TYNDP (taking into account lag rate). We selected a "probable scenario 2030", which yields an increase of NTC capacity across Europe of 41 percent by 2030 relative to the status quo. The PLEF countries are currently characterised by above-average interconnector capacities between them. Their interconnection level is projected to increase by 22 percent; the interconnection level between the PLEF and remaining EU countries, by 76 percent.

82 Agora Energiewende (2014), Consentec and IAEW (2012).

Assumed Net Transfer Capacity (NTC) values in 2030 compared with the status quo. Figure 64



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Endbericht einer Studie von der Prognos AG und dem Institut für Elektrische Anlagen und Energiewirtschaft (IAEW)

Power-to-Heat zur Integration von ansonsten abgeregeltem Strom aus Erneuerbaren Energien
Handlungsvorschläge basierend auf einer Analyse von Potenzialen und energiewirtschaftlichen Effekten

Reform des Konzessionsabgabenrechts
Gutachten vorgelegt von Raue LLP

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Agora Energiewende
Rosenstrasse 2 | 10178 Berlin | Germany
T +49 (0)30 284 49 01-00
F +49 (0)30 284 49 01-29
www.agora-energiewende.de
info@agora-energiewende.de

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