TRANSNET BW

ADEQUACY 2050

Security of supply in the power system

CONTENTS

1.0

AT A GLANCE

ABOUT THE STUDY

/ **Topic:** Long-term **system adequacy** in a climate-neutral energy system in Germany and Europe until 2045 / 2050, considering both **resource** and **transmission adequacy** in an integrated framework.

/ **Objective:** To test the robustness of the **German Network Development Plan (NEP 2023)** under consideration of the **impact of climate change**, while questioning key assumptions about **flexibility** (like shares of market-oriented prosumers in the residential and services sector).

/ **Approach:** hourly-based analyses based on a model chain (Energy System Model > Market Model > Grid Model) indicate cost-optimal system designs in 2050 under various "Scenario Clusters", including in particular:

- **Extreme meteorological years** (low annual renewable generation, heat waves, cold spells)
- **Flexibility technologies and operation** (decentral / central, national / international)

KEY FINDINGS

/ The current NEP may **underestimate infrastructure and flexibility needs** due to simplified weather assumptions and idealised prosumer behaviour.

/ **Additional investments** (e.g. hydrogen power plants, large-scale batteries, interconnectors) are essential to maintain security of supply at all times under stress scenarios.

/ **Prosumer participation and their market orientation** have a significant impact on affordability and system stability.

/ **European interconnectivity** is a key enabler of flexibility and resilience.

REASONS WHY YOU SHOULD READ THE STUDY

/ Why this study matters: It shows how cost-optimal security of supply can be achieved to support a competitive Germany and EU by closing a gap in long-term adequacy planning, and challenges optimistic assumptions in official planning.

/ It is not purely technical: The findings are highly relevant for policy makers, grid planners, investors, and society.

/ It quantifies risk: Showing concrete numbers for cost increases as well as adequacy metrics such as Energy Not Served, and Loss of Load hours helps understanding of the problem and of actions needed.

CONCLUSION

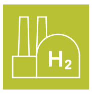
If we want a climate-neutral, reliable and affordable energy system in Europe and in Germany, we need comprehensive and robust planning against uncertainties. Adequacy 2050 shows that long-term energy security depends on resilience, flexibility, realistic assumptions, and strong European energy infrastructure.

2.0

OUR MAIN FINDINGS

1. Planning of climate-neutral systems must include weather variability and climate change impact, not just historical averages.
Planning with average weather is no longer enough. Our study shows that wind and solar output can vary by up to 15 % year on year – a critical factor for a climate-neutral energy system that relies heavily on renewables.

2. European interconnectivity lays the groundwork for a more efficient energy system.
Stronger interconnections across borders reduce costs and risks for everyone. Our findings show potential annual savings of up to 18 billion € for Europe in 2050.



3. Hydrogen power plants are essential – especially when flexibility falls short.
In stress scenarios with lower prosumer participation, Germany could need at least 9 GW of additional hydrogen capacity in 2050 in comparison to the NEP reference scenario to maintain balance. These plants are a lifeline during weather extremes and low renewable output.

4. Unlocking smart decentral flexibility potentials is essential for the affordability of the energy transition.
If prosumers don't act in line with the market, additional balancing measures are needed, and costs rise sharply: up to 11 billion € more per year across Europe in 2050. Smart meters, dynamic pricing, and consumer engagement are not "nice to have" – they are essential and efficient.

5. Flexibility technologies are key – and they must be both central and decentral.
The secure operation of a climate-neutral energy system in Europe and in Germany requires a mix of flexibility technologies: prosumers who respond to market signals, as well as large-scale solutions like hydrogen power plants, batteries and interconnectors. Adequacy needs robustness and resilience, not over-reliance on any single approach.

3.0

DEFINITIONS

SYSTEM ADEQUACY

Under System Adequacy we understand the combination of Ressource and Transmission Adequacy.

/ From a market perspective, **Resource Adequacy** is ensured when the available supply in the electricity market is sufficient to meet demand at all times in an economically efficient manner. This requires that – under predictable and manageable risks such as changes in electricity demand or carbon dioxide (CO_2) prices – the market provide adequate generation capacity within the given political and economic framework. The main metrics in this context are Energy Not Served (ENS, expressed in TWh/y) and Loss of Load (LoL, expressed in hours – i.e. hours during which full supply is not reached).

/ **Transmission Adequacy** is ensured when the electricity supply can also be physically transmitted via the grid – meaning that generation can be delivered to consumers, either without congestion or with congestion management measures in place.

FLEXIBILITY

Within our study we define **flexibility technologies** as follows:

/ Under **decentral flexibility** technologies we understand household-proximate devices such as rooftop PV, small-scale batteries, heat pumps and e-mobility.

/ Under **central flexibility** technologies we understand climate-neutral thermal power plants such as hydrogen turbines as well as large-scale batteries, electrolysers and interconnectors (in order to enable access to additional, geographically distant balancing options). Due to the limited additional available potential, hydropower is, however, only considered with existing capacity.

The flexibility aspect that we focus on consists **of the ability to change the dispatch of a unit, whether this involves load or generation.** The signal for controlling such flexibility-providing technologies might be a market signal or a direct dispatch signal ordered by an operator. We do not further elaborate on whether communication is directly with the unit or via an aggregator, as this would not influence the systemic effect of flexibility dispatch.

4.0

EXECUTIVE SUMMARY

1. PLANNING OF CLIMATE-NEUTRAL SYSTEMS MUST INCLUDE WEATHER VARIABILITY AND CLIMATE CHANGE IMPACT, NOT JUST HISTORICAL AVERAGES.

The results reveal the urgent need for robust energy system planning, taking into account the variability of renewables from year to year. This requires consideration of weather variability on different time scales. In particular, consideration of both short-term weather variability and "Dunkelflaute" ("dark doldrums") events as well as year-to-year variability in yield from both photovoltaics and wind power will be of key importance in climate-neutral energy systems. Taking around-average renewables yields into account – as is the case for 2012 – may lead to an underestimation of actual system requirements. Analysis of historical weather data for Germany shows that both wind power and PV are prone to relevant year-to-year yield variability. Such **generation variability is in the range of ± 15 % for wind power and ± 5 % for PV**, taking the long-term average as a base. Annual variability comparable to that seen in the past decades is also expected for future years and decades. As wind power and PV will represent the pillars of energy supply in climate-neutral energy systems, the impact of this yield variability will become larger in absolute numbers than today (i.e. in Germany **up to approx. 150 TWh/y, or about 12 % of annual demand**).

In order to take these elements into account and at the same time make the analysis less complex, we focus on the evaluation of a set of challenging meteorological years by considering a pessimistic Shared Socioeconomic Pathway (SSP) according to the Intergovernmental Panel on Climate Change (IPCC), i.e. a pathway characterised by fossil-fuelled development and energy-intensive lifestyles worldwide, leading to extremely high greenhouse gas emissions and projecting an additional radiative forcing of 8.5 W/m² by the year 2100[1]. Our selection of **extreme meteorological years** includes three cases: 1) an annual shortfall of renewables throughout Europe, 2) an exceptionally cold winter with a high number of hours below 0°C (42 days), 3) **a particularly high number of heat wave days** (37 days with temperatures reaching at least 28°C), **also characterised by low renewable yields**. We thus provide a series of what-if analyses as we do not aim to assess the probability of such scenarios occurring.

1 – Although the radiative forcing is the same in all simulations of the SSP5-8.5 scenario, the temperature response can vary across different climate models. According to the IPCC report, this results in a projected temperature increase of 3.3°C to 5.7°C by 2100 compared to pre-industrial levels.

Under reference weather conditions, underlying capacity projections of the NEP potentially lead to 39 GWh/y[2] of energy not served in Germany (which can, however, be solved with additional relief measures). In extreme weather case 3, the effect is even amplified if we assume an energy system as expected in the NEP. In this case, the power system experiences 508 GWh of energy not supplied. The number of Loss of Load Hours thereby increases by 40 hours per year. This means that during an additional 40 hours per year the load supply may be lower than 100 %. **Yearly average wholesale prices for electricity are expected to double in Germany from 69 €/MWh (reference scenario, i.e. NEPv23, Scenario B) to 136 €/MWh in extreme weather case 3**. On average across Europe, prices will rise from 33 €/MWh to 99 €/MWh. This deterioration signals a pressing need for additional investments in comparison to the NEP reference.

2 – This value corresponds to approx. 0.003 % of the assumed annual load in Germany, 2050 (1,106 TWh/y)

The consecutive grid modelling analyses for **extreme weather case 3** indicate for Germany a reduction in transport demands in comparison with the 2012 weather case, which is mirrored in a decrease in annual grid overload situations by one third in comparison to the reference, totalling a reduction of 3 TWh. Remaining overload energy can be relieved by redispatch measures. These figures highlight that overall trends do not uniformly apply to single grid elements, necessitating focused attention on interconnectivity enhancements. **A complementary n-1 analysis for this scenario for Germany shows that the reference transmission grid (NEP 23) is robust despite the change in the meteorological year investigated.** No significant need for further network expansion measures is recognisable from this analysis for the TransnetBW control area for these particular weather conditions.

With regard to overall cost for the European energy supply, the system design analysis showed that years characterised by low renewable energy yields and cold spells significantly raise overall system costs. More specifically, **lower renewable energy yields require more energy imports, primarily of hydrogen, for an additional 26 billion € annually in Europe**, while years characterised by pronounced cold spells cause the highest cost increase in the heating sector of up to 20 billion € annually.

2. EUROPEAN INTERCONNECTIVITY LAYS THE GROUNDWORK FOR A MORE EFFICIENT ENERGY SYSTEM.

The importance of interconnector capacity planning highlights the crucial role of international cooperation in reducing costs for society (by up to 18 billion € yearly for Europe) when allowing investments in interconnector capacities even beyond NEP targets. This international cooperation thereby forms the cornerstone of a competitive Europe. Optimal cost planning frequently leads to stronger interconnectedness among European countries, with **Net Transfer Capacity (NTC) levels between 76 GW and 81 GW for Germany**, aligning with those suggested by the German Langfristszenarien (Long-term Scenarios) study (Fraunhofer ISI, 2025). A prerequisite for this development is cost efficiency in the implementation of such projects which includes, for example, the preference for overhead lines instead of underground cables (whenever feasible). This enhanced interconnection leverages the diverse weather conditions across Europe, reducing the demand for national flexibility in energy systems. However, the impact on national grids has not been fully analysed, and additional cost for certain grid investments might remain unaccounted for.

We found that year-to-year variability of electricity generation from renewables in Europe impacts the need for green hydrogen imports from outside Europe. Among the selected meteorological years and based on the given boundary conditions, the share of **European hydrogen imports may vary between approx. 22% (384 TWh) for an around-average weather scenario and approx. 50% (823 TWh) for a renewable shortfall scenario**. This calls for robust, sector-coupled energy system planning which can integrate strategies to handle both year-to-year variability of renewable energy generation and changing climate conditions.

3. HYDROGEN POWER PLANTS ARE ESSENTIAL – ESPECIALLY WHEN FLEXIBILITY FALLS SHORT.

Despite the higher costs in comparison to the reference case, investments in additional central capacities such as hydrogen-fuelled power plants are crucial for maintaining system stability during periods of stress and avoiding extensive supply gaps. Our study analyses the resilience of systems designed to withstand reduced market participation by prosumers. In a worst-case „stress test" scenario with **prosumer market participation down from 100 % to 50 %** and a future meteorological year characterised by low annual renewable energy source yields (extreme weather case 1), an energy system designed according to the reference case with no additional investments proves to be inadequate unless additional relief measures are in place. Specifically, **Germany could encounter 168 hours during which load cannot be fully served under such stress**. The driver of such situations is the simultaneous combination of high power demand and low yields from renewables. High heating demand, coupled with lower heat pump efficiencies and calm wind conditions, has the potential to create critical situations in the mornings and evenings. While investing in additional central balancing capacities is more expensive (see also next key message), it is necessary not only to ensure reliability when prosumer participation rates and market orientation are lower than assumed in the NEP but also to provide robust protection against challenging meteorological situations. These centralised capacities provide the robustness necessary to effectively overcome these periods and reduce the Loss of Load Hours by 97 % to 5 hours per year.

4. UNLOCKING SMART DECENTRAL FLEXIBILITY POTENTIALS IS ESSENTIAL FOR THE AFFORDABILITY OF THE ENERGY TRANSITION.

The active, market-oriented participation of prosumers in the energy market is an important factor in handling the variability of renewable energy sources. It significantly enhances the affordability of the energy transition, **potentially avoiding costs of 11 billion € annually in total in Europe and 1.5 billion € in Germany**. This conclusion arises from analysing the needs of the energy system when the availability of decentralised market-oriented flexibility technologies falls short of planned targets. By reducing prosumer participation in e-mobility, decentral heating and home-battery application from 100 % (as assumed in the NEP23 process) to 50 %[3] on the spot market and permitting additional investments in hydrogen power plants, we found that at least **9 GW of additional hydrogen power plants (in comparison to the NEP reference scenario)** are essential in Germany to maintain market balance during average meteorological years.

Enhancing affordability necessitates dynamic pricing, widespread adoption of smart meters, new flexibility services and overall consumer acceptance of market participation. A cold period in February can exemplify the importance of

3 – The installed capacity of home battery storage systems is reduced by approx. 49 GW. The reduction in the availability of BEVs results in 14 GW that is no longer market-friendly. The reduction in storage tank size (50% of the reference scenario) for the decentralized electricity-driven heat supply (heat pump water tanks) results in a reduced capacity of 1.5 GW. The total reduction therefore amounts to approx. 64 GW.

prosumer market orientation. In such a situation, heat pumps offer no flexibility due to extremely cold conditions, and the criticality of the situation is driven mainly by the non-flexibility of e-mobility users, as 50 % of their load patterns are not flexible. Additional power supply is therefore needed in the scenario where only 50 % of prosumers react to market signals, which is provided by additional storage and hydrogen power plant dispatch in comparison to the reference case. **With fully market-oriented prosumers**, e-mobility users shift loads within a 12-hour timeframe from evening to night hours to achieve more efficient market conditions, **lowering spot market price levels by at least 50 €/MWh in such situations.**

5. FLEXIBILITY TECHNOLOGIES ARE KEY – AND THEY MUST BE BOTH CENTRAL AND DECENTRAL.

The overall scenario-based and model-based approach has shown that European decarbonisation efforts are best implemented using a diverse mix of technologies and strong cooperation. A broad mix of technologies helps to overcome long-term (seasonal) and short-term (hourly) flexibility demands, and offers resilience in dealing with year-to-year weather variations and security against behavioural unpredictability in an energy system with high consumer participation rates. By analysing flexibility trade-offs between centralised and decentralised technologies, we identified high cost-saving potentials if consumers offer their decentral flexibility to the markets. However, while being cost-effective, this cost relief applies only to short-term flexibility use cases, which are in the range of several hours. The naturally occurring year-to-year weather variations at a national level create an additional need for seasonal flexibility, which can be provided by a combination of hydrogen power plants and electrolysers.

We must deal with a high degree of complexity driven by the interdependencies of those technology groups. While decentral flexibility usually operates only in the short-term horizon of a few to several hours, hydrogen power plants offer both short-term flexibility and seasonal flexibility, but at much higher cost compared to prosumers. While being less competitive against prosumer flexibility in the short term, they are characterised by increased technical availability and planning security. Centralised technologies such as hydrogen power plants are typically operated by companies, which can be legally bound to comply with certain standards and put under individual contracts to ensure grid-friendly operation of the assets in question.

In contrast to this, the existence of smart and flexible prosumers alone is not sufficient to ensure that the energy system operates appropriately. Market ignorance among prosumers, which only optimise their rate of self-consumption and do not take account of hourly market prices in their dispatch decisions, leads to a **significant increase (approx. 60 %) in the demand for large-scale battery storage compared to the planned reference system**. In critical situations, granular control over those units might not be possible. The magnitude of this impact emphasises the importance of the predictability of prosumer behaviour, which favours the option of having costlier but more predictable central capacities in the system. This also calls for the setting of a clear and forward-looking regulation of both central and decentral flexibility.

European interconnection for electricity and hydrogen is the last point in the complex of interdependencies in the system. In the context of short-term and seasonal flexibility needs, countries with stronger electrical interconnection are able to share their regionally diverse weather conditions and thus reduce seasonal flexibility demand. We identified that **German seasonal flexibility needs of 9 GW can be managed with 9.5 GW of technologies providing short-term flexibility, if coupled with an additional 32 GW of interconnection capacity**. At a European level, the cost analysis has shown that this trade-off is economically favourable, as it reduces the overall system cost by 7 billion € per year. This is because having a more interconnected electrical system would reduce Europe's needs for hydrogen.

5.0

INTRODUCTION

5.1 MOTIVATION

The transition to a sustainable and carbon-neutral energy system remains one of the most pressing challenges of our time. The previous Energy Systems 2050 study provided a comprehensive vision of what the future European energy landscape might look like, and demonstrated how the energy system can be expanded and optimised across all sectors.

Meanwhile in Germany, the Network Development Plan (NEP) – Electricity, 2023 version, marked a significant milestone by presenting, for the first time, network development measures aimed at achieving a fully carbon-neutral energy system by 2045. This ambitious plan outlines the steps needed to transform the German electricity grid, ensuring it can support a carbon-neutral future while maintaining reliability and efficiency. Over the past few years, the discourse on energy policy has been strongly influenced by the topic of security of energy supply. Ensuring a stable, economically affordable and secure energy supply is paramount in guaranteeing future European development. This focus on energy security highlights the need for robust and resilient energy systems that can withstand various challenges and uncertainties.

Despite the progress made in understanding and planning for carbon-neutral energy systems, there remains a significant gap in the literature regarding adequacy aspects of these systems in Europe. No known study has comprehensively addressed the adequacy of carbon-neutral energy systems, which is critical for ensuring that energy supply meets demand at all times.

To address this gap, the study at hand (Adequacy 2050, or AQ2050 for short) aims to provide valuable insights and contribute to the ongoing discourse on energy adequacy with a focus on carbon-neutral systems. This report will examine the findings of the study and explore the methodologies used, the scenarios analysed and the implications for the future of energy systems in Europe. Through this comprehensive analysis, we aim to provide a clearer understanding of the challenges and opportunities associated with achieving a carbon-neutral energy system in Europe by 2045 / 2050.

5.2 DEFINITIONS

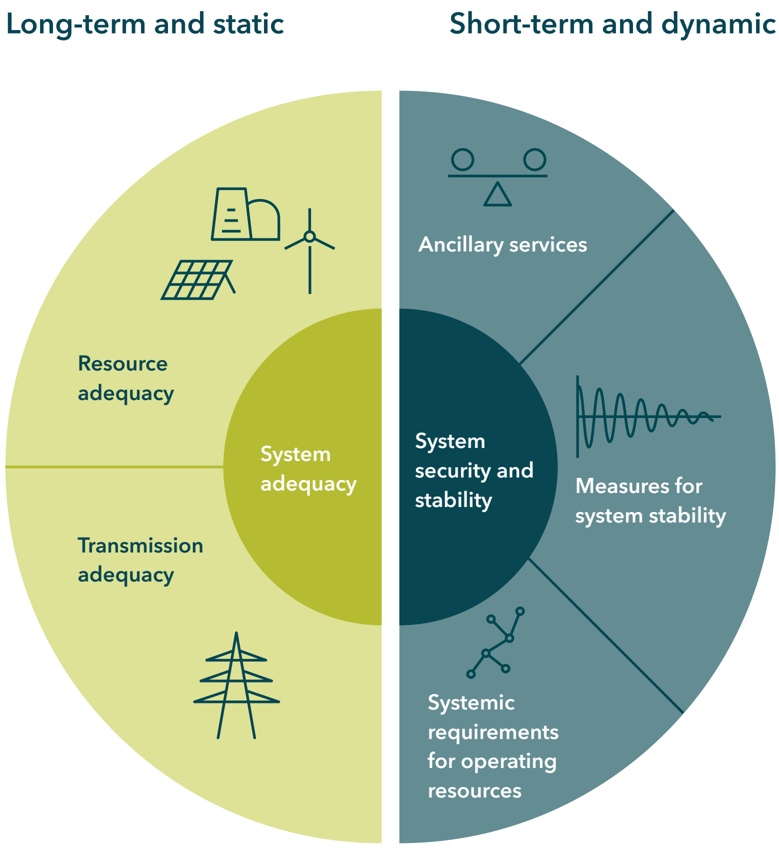
Ensuring a secure electricity supply – referred to as adequacy or "AQ" in the title of the study – is a key objective set at both the European level, under Regulation (EU) 2019/943 on the internal market for electricity, and at the German national level, through the Energy Industry Act (Energiewirtschaftsgesetz, EnWG). This objective is particularly significant in view of the expansion of renewables, the expected increase in electricity consumption from the electrification of other sectors and the phase-out of fossil fuels (and of nuclear energy in Germany).

5.2.1 DEFINITION OF ADEQUACY

Before evaluating the adequacy of the future carbon-neutral energy system, it is essential to define what adequacy means. Rather than one universal definition, several different concepts exist – for example, those offered by the Federal Ministry for Economic Affairs and Climate Protection (Bundesministerium für Wirtschaft und Klimaschutz; BMWK, 2019; p. 2) and the European Commission (2016; p. 25). The BMWK defines "security of supply" as the adequate coverage of electricity demand, which is primarily influenced by available power generation, transmission capacity and the availability of energy sources for electricity production. The European Commission considers system adequacy to be the sum of generation and transmission adequacy. Generation adequacy, in this context, refers not only to having sufficient generation capacity to meet demand but also to maintaining reserves that enable the system to withstand extreme dry periods or potential fuel shortages. However, we classify fuel shortages and extreme dry periods under a separate process called „Risk Preparedness" (see 3.3.4). For these reasons, and because the definitions provided by the Federal Network Agency (Bundesnetzagentur, BNetzA) and German Transmission System Operators are more detailed and specific to the German context, we adopt their definitions as outlined below.

Figure 1 illustrates the classification of the various elements of security of supply. Accordingly, security of supply can be divided into two key areas: (1) the planning aspect of security and reliability, known as system adequacy, and (2) system security and stability, which involves dynamic operational effects.

FIGURE 1:
Dimensions of security of supply based on dena (2020)



(1) System Adequacy
In a static analysis, System Adequacy consists of the following two components, market-based Resource Adequacy and grid-based Transmission Adequacy:

(1a) Resource Adequacy
From a market perspective, security of supply is ensured when the available supply in the electricity market is sufficient to meet demand in an economically efficient manner. This requires that, under predictable and manageable risks – such as changes in electricity demand or carbon dioxide (CO_2) prices – the market provides adequate generation capacity within the given political and economic framework (German Federal Network Agency (Bundesnetzagentur, BNetzA), 2023; p. 21).

This means having sufficient secured capacity from thermal and renewable generation technologies to meet electricity demand. These capacities may be located domestically or abroad; in the latter case, limitations due to interconnector capacities and broader political considerations (e.g. national self-sufficiency policies, fuel shortages due to crises or wars) should also be considered. Additionally – and even more importantly – future considerations must include flexibility options, such as demand-side management, which can shift consumption in response to system needs.

In this context it is important to distinguish between grid reserve and capacity reserve:

Grid reserve focuses on the grid and ensures the safety and reliability of the electricity system – specifically regarding network shortfalls, maintaining voltage, and enabling potential supply restoration. Transmission system operators therefore maintain backup plants, including facilities that are currently non-operational but must be made operational on request due to their system relevance, system-critical facilities scheduled for provisional or permanent decommissioning, and facilities located in other European countries (see section 13d EnWG). In contrast, capacity reserve focuses on the market and compensates for power balance deficits resulting from an incomplete match of supply and demand during threats or disturbances to system safety or reliability. The capacity reserve is designed to safeguard against unforeseen extreme events that the electricity market itself does not account for. Transmission system operators maintain reserve capacity for this purpose. Since the 2020/2021 winter half-year, capacity reserve has been formed outside the electricity markets, and its facilities feed in exclusively on request by the transmission system operators (see section 13e EnWG). Since it is not part of market operations, its existence must not influence investment decisions within the electricity market.
Note that grid reserve and capacity reserve may be used by system operators to cover demand.

(1b) Transmission Adequacy
Grid-related security of supply is ensured when the electricity supply can also be physically transmitted via the grid – meaning that generation can be delivered to consumers without congestion (or with congestion management measures in place) (BNetzA, 2023; p. 71). The German Network Development Plan also takes limited transmission capacity and potential equipment failures into account (German Transmission System Operators, 2024b).
Measures to ensure transmission adequacy include not only traditional grid expansion and reinforcement but also grid-optimising technologies, such as phase-shifting transformers and high-voltage direct current (HVDC) systems, redispatch mechanisms including grid reserve power plants and special network operation resources, and flexibility solutions such as battery storage (grid boosters) (BNetzA, 2023; p. 10-11).

(2) System security and stability
Even though AQ2050 will only focus on system adequacy, i.e. the long-term/static aspects described above, it is also worth mentioning the short-term/dynamic aspects of security of supply, i.e. system security and stability:

/ (2a) Ancillary services: To comply with technical limits during operation, ancillary services are of essential importance. These include (i) frequency control, to offset imbalances between supply and demand and maintain grid frequency at its target value of 50 Hertz; (ii) voltage control, to keep the voltage within a predefined range at all times; (iii) system operation, where grid operators monitor correct grid operation and intervene if necessary; and (iv) supply restoration, to restart the power supply as quickly as possible after the unlikely event of a large-scale power outage (BMWK, 2025).

/ (2b) Measures for system stability: To prevent power outages, the power system must be stabilised after a disturbance event. The measures aim to prevent outages or the spread of outages or a complete blackout. One example is the network operators' system protection plan.

/ (2c) System requirements for operating resources: If all measures to prevent severe system disruptions fail, it must be ensured that these do not affect the functionality of individual operating resources.

5.2.2 DEFINITION OF INDICATORS

The market-side assessment of security of supply (i.e. Resource Adequacy) is based on indicators. In the national context, the German Federal Network Agency uses both Loss of Load Expectation (LOLE) and Expected Energy Not Served (EENS) to measure security of supply in European electricity markets, considering their impact on Germany as part of the internal electricity market. The term „expected" in LOLE and EENS comes from probability and statistical analysis, specifically in the context of power system reliability. It refers to the statistical mean or probabilistic average of an event occurring over a given period (for mathematical relationships regarding both indicators, see Chapter 11.2 ENTSO-E (2023b)). Note that there is a difference between EENS and Energy Not Served (ENS), as well as between LOLE and Loss of Load Hours (LOLH). The first metric in each pair represents a mean (not a median) over multiple yearly simulations (e.g. meteorological years and/or power plant availabilities), while the second refers to the value of a single yearly simulation. The LOLE indicator is compared with a threshold value (see below), and if the threshold is exceeded or not met, an assessment is conducted and, if necessary, appropriate measures are implemented to ensure security of supply (see section 51 (4a) EnWG as well as the biennial report by BNetzA on the status of and changes in security of electricity supply).

At the European level, which is also relevant for AQ2050, the same indicators are used in the European monitoring process (European Resource Adequacy Assessment, ERAA) by the European Network of Transmission System Operators for Electricity (ENTSO-E) and submitted for approval to the European Union Agency for the Cooperation of Energy Regulators (ACER) (see Article 23 (5) of Regulation (EU) 2019/943 on the internal market for electricity). However, while AQ2050 focuses on long-term and optimal investment assessment for carbon-neutral energy systems, ERAA analyses resource adequacy in the medium term (i.e. approx.10 years ahead).

The indicators specifically describe (see also BNetzA, 2023; p. 35-36):

/ Loss of Load Expectation – LOLE (h/a): Expected number of hours per year in which demand cannot be fully met on the electricity market. These hours do not indicate a blackout but may lead to the use of instruments beyond the market, such as capacity reserve.

/ (Expected) Energy Not Served – (E)ENS (GWh/a): (Expected) amount of energy per year that cannot be fully covered on the electricity market.

The LOLE target (i.e. the national reliability standard) for Germany is 2.77 h/a. The determination of the national reliability standard must follow the method established in Article 23 (6) of Regulation (EU) 2019/943, which is based on the calculation of various indicators, such as the Cost of New Entry (CONE) for reference technologies or the Value of Lost Load (VOLL). Article 25 (1) stipulates that member states must have a national reliability standard in place when applying capacity mechanisms. Because Germany and Luxembourg share a bidding zone, the Institut Luxembourgeois de Régulation and the Bundesnetzagentur, as the competent regulatory authorities, must jointly propose a national reliability standard. The BMWK (together with the Luxembourg Ministry of Energy) followed this proposal and established the LOLE value described above (see BMWK, 2021). For EU Member States the targets are typically in the range of 3-9 h/a (ENTSO-E, 2023a).

5.2.3 IMPORTANCE OF A MULTI-METRIC APPROACH

It is important to recognise that resource adequacy assessments should not rely exclusively on the LOLE metric (without incorporating the ENS metric) as it has several drawbacks. For example, LOLE uses an arbitrary threshold that fails to consider the balance between reliability and cost. Ideally, the optimal reliability level is achieved when the combined expenses – those of acquiring additional capacity (including both capital and operating costs) and the losses incurred from load curtailment – are minimised. Moreover, LOLE does not distinguish between the magnitude, frequency, duration and timing of shortfalls. This omission is significant because the damage from outages does not increase in a linear manner; longer or more severe disruptions incur disproportionately higher costs.

To overcome these limitations, the Energy Systems Integration Group (2024; ESIG) Resource Adequacy Task Force, in their report "New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements", recommends a multi-metric approach that incorporates both LOLE and ENS. The ENS metric calculates the average amount of unserved energy per year over all simulations, offering key advantages. First, it emphasises larger, more disruptive events, which is crucial for distinguishing among different types of shortfalls. Second, ENS explicitly accounts for energy constraints within the power system – an increasingly important factor as systems shift toward greater storage and load flexibility. Additionally, according to the ESIG report, ENS aligns well with economic assessments, since cost metrics such as Value of Lost Load (VoLL) are typically expressed in dollars per MWh, thereby providing a clearer link between reliability and cost objectives. For example, if a model provides two ENS values [in GWh/a] along with their corresponding system costs [in €/a] for different energy system configurations, these can be directly compared with metrics of the same unit, such as VoLL (e.g. defined as value added divided by electricity consumption, in €/GWh). Similarly, ENS can be measured by season, month, or hour of the day, enabling a more precise cost assessment if a seasonal VoLL is determined.

AQ2050 incorporates key ESIG recommendations. First, since only limited data is available to determine the probability of extreme weather events, stress testing is preferred over statistical measures (see ESIG, 2024; p. 29). AQ2050 applies this by using the NEP (v2023, scenario B*) as a reference and conducting stress tests based on identified clusters, such as the climate cluster. Second, AQ2050 follows ESIG's guidance on balancing reliability and cost in resource adequacy (see ESIG, 2024; p. 38). It examines how lower willingness to pay on the part of inflexible consumers affects market security of supply and how expanding marginal technologies impacts overall system costs.

5.3 LITERATURE AND ADEQUACY ASSESSMENTS REVIEW

This section provides a brief review of the status quo of adequacy assessments, first focusing on Resource Adequacy, then on Transmission Adequacy. This section does not claim to be exhaustive but rather places the study within the subject area.

5.3.1 RESOURCE ADEQUACY

Historically, security of supply was assessed comparing annual peak load with secured generation capacity (i.e. production capacity that is always available) at the time of highest demand – typically a winter evening. This deterministic approach is unsuitable for renewables-based systems, as renewables are not considered secured due to weather-dependent fluctuations. Additionally, demand is assumed to be inflexible, with no consideration of balancing effects from neighbouring countries (see, as an example, ENTSO-E RG BS, 2021).

To better capture security of supply, the EU has shifted to a probabilistic approach. In a deterministic approach, all parameters are fixed, including climate factors affecting supply and demand, as well as the technically or economically constrained availability of generation, storage and transmission resources. Probabilistic assessments embrace the fact that these parameters cannot be precisely determined but instead follow probabilistic rules. The following selected studies, BNetzA (2023), ENTSO-E (2023a, 2023b) and TenneT (2023), all follow probabilistic methodologies.

It is worth noting that probabilistic adequacy analyses can be combined with prior investment modelling. Investment and decommissioning decisions for power plants, storage, and flexible loads are determined by assuming operators will seek to maximise profits, considering plant cost structures and typically assuming perfect competition, so that the total cost of load coverage is minimised while meeting an adequacy standard. The analysis normally begins with the current system and then projects a best-guess future system (see Article 6 in ENTSO-E (2020) as a guideline and chapter 10 in ENTSO-E (2023b) for its implementation). Examples include the ERAA from ENTSO-E and the BNetzA report on the status of and changes in security of supply, which both project up to approx. 10 years ahead. In addition to their probabilistic analyses, their approach to investment modelling is also described in more detail in the following section.

5.3.2 SELECTED RELEVANT STUDIES

Only a few multi-model studies analyse security of supply in Germany and Europe. Three such studies are described below, highlighting their key characteristics and differences compared to AQ2050. These are the "Bericht zu Stand und Entwicklung der Versorgungssicherheit im Bereich der Versorgung mit Elektrizität" (report on the status of and changes in security of supply in the electricity supply area) by BNetzA (2023), the ERAA by ENTSO-E (2023a, 2023b), and the "Adequacy Outlook" by TenneT (2023). Table 1 provides an overview of their scope.

BNetzA (2023): The German Federal Network Agency continuously monitors security of supply in Germany, publishing a report every two years. Unlike ERAA, it places greater emphasis on national conditions, political frameworks, and specific grid and market factors. The study consists of two main analytical frameworks:

/ Future power plant development: Investment modelling (economic analysis using representative and complementary meteorological years, 2012 and 2019) + actor analysis (business analysis). The meteorological year 2012 is considered „average," with typical solar and wind energy yields. Despite containing a cold week, it serves as a good reference year for analysis. A warm year, 2019, was chosen as a second year for sensitivity analysis, with higher wind power generation (396 TWh vs. 360 TWh in 2012) and possible climate change effects. Comparing both years helps to assess weather impacts on power plant development (BNetzA, 2023; pp. 48-49).

/ Security of supply assessment: Market-based security: Variations using nine meteorological years (2011-2019) and power plant availability. Grid-based security: Representative and complementary meteorological years (2012 and 2019).

TABLE 1:
Scope of relevant Resource Adequacy studies

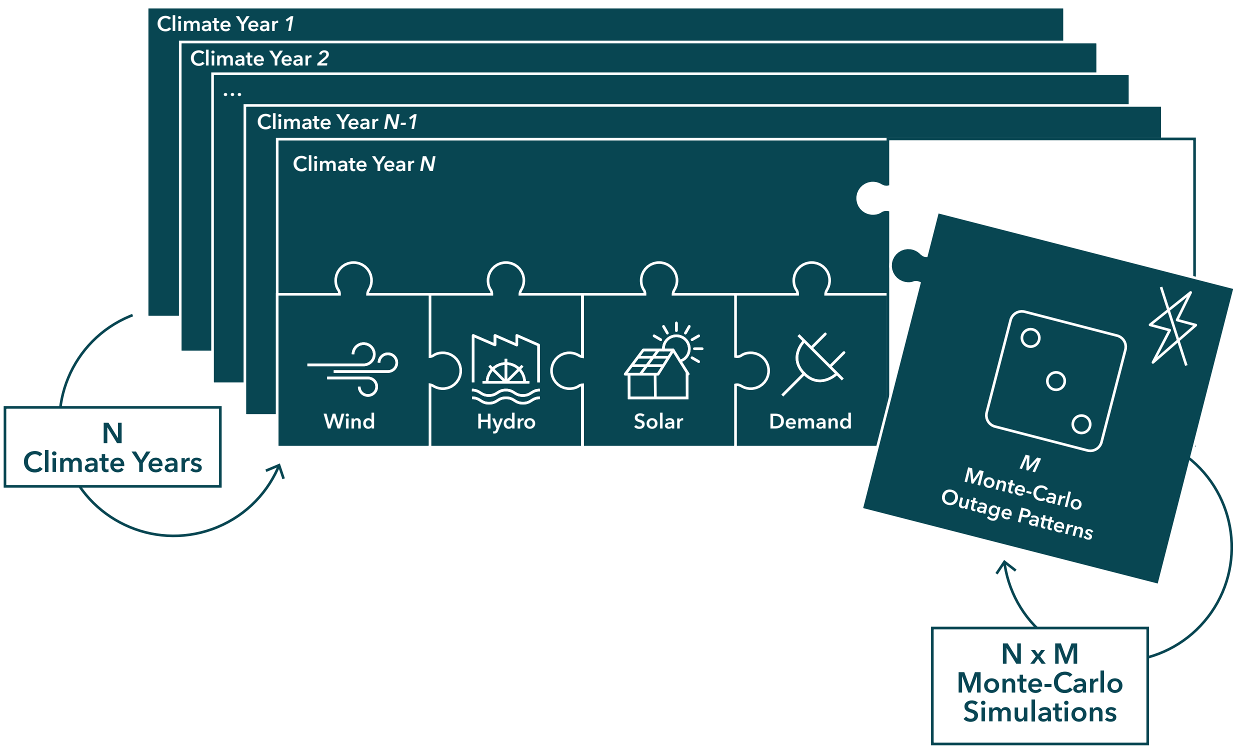
Study	BNetzA (2023)	ENTSO-E (2023a, 2023b)	TenneT (2023)
Objective	Determining security of supply in Germany's electricity market and grid for the period 2025-2031.	Determining security of supply in Europe's electricity market for the period 2025-2033.	Determining the supply-side and demand-side resources required to ensure resource adequacy in a climate-neutral energy system in the Netherlands and Germany.
Region	Germany, Luxembourg (focus region), Europe divided into regions of closer and more distant neighbours.	ENTSO-E countries (including all EU member states).	Germany, Netherlands (other European regions are not analysed in detail).
Base Year	2023	2024	2021
Target Year	2025, 2026, 2028, 2031	2025, 2028, 2030, 2033 (non-target years are duplicates of the most recently available target year, e.g. 2026 and 2027 have the same demand, generation capacity and network constraints as 2025)	≥2045 (The study deliberately does not specify a target year but examines a scenario in which the energy transition is complete.)
Energy system model	Yes	No	Yes
Electricity market model	Yes	Yes	Yes
Grid model	Yes	Yes	No

ENTSO-E (2023a, 2023b): Since 2021, ENTSO-E has published ERAA annually under Regulation (EU) 2019/943. This regulation ensures that current investments and regulatory decisions align with future needs. ERAA also serves as the basis for approving national capacity mechanisms. The study consists of two main analytical frameworks:

/ Economic Viability Assessment (EVA): Determines capacity adjustments for future years based on economic feasibility. The EVA technology scope covers "gas" and "lignite/hard coal/oil" for decommissioning, (de-)mothballing, and life extension decisions. New entry decisions are permitted for "gas", "demand-side response", and "battery" (see Section 10.3 in ENTSO-E (2023a)). In contrast, the AQ2050 technology scope and investment options are significantly broader, with a strong emphasis on flexibility solutions. These include both centralised options (such as thermal power plants, electrolysers, and industrial demand-side response) and decentralised solutions (such as "smart home" technologies, including e-mobility).

/ Adequacy assessment: The objective of the ERAA adequacy study is to calculate the risk of security of supply of the post-EVA scenarios by calculating LOLE and EENS metrics. It uses Monte Carlo Simulation to combine asset-specific forced-outage events with distinct climate years for each target year (see Figure 2). Forced outages impact on thermal generation and transmission assets (HVDC and high-voltage alternating current (HVAC) interconnections). By combining random outage patterns with climate years, the simulation captures a wide range of potential system states for each target year. The process begins by selecting climate years (e.g. historical climate years 1982-2016 in ERAA 2021-2023 or forward-looking projections as provided for in ERAA 2024). Each year provides detailed time series data for temperature-dependent demand, wind and solar load factors, hydro generation (including inflows and capacity limits), and other climate-sensitive renewable and non-renewable generation. For every climate year, multiple hourly outage patterns are generated (the number being determined after model convergence), with each Monte Carlo year – one climate year paired with one outage pattern – optimised individually, resulting in a total of NxM model runs (ENTSO-E, 2023b; p. 45).

FIGURE 2:
Monte Carlo Simulation based on ENTSO-E (2023b)



TenneT (2023): The Adequacy Outlook was conducted to assess the supply-side and demand-side resources needed to ensure resource adequacy in a climate-neutral energy system in the Netherlands and Germany. It is an ad-hoc study rather than a regular monitoring process. The study framework includes:

/ Energy system scenario quantification (35 meteorological years, 1982-2016).

/ Power market simulations (35 meteorological years, 1982-2016, with variations in power plant availability).

/ Analyses, including resource adequacy and economic feasibility (business analysis).

5.3.3 TRANSMISSION ADEQUACY

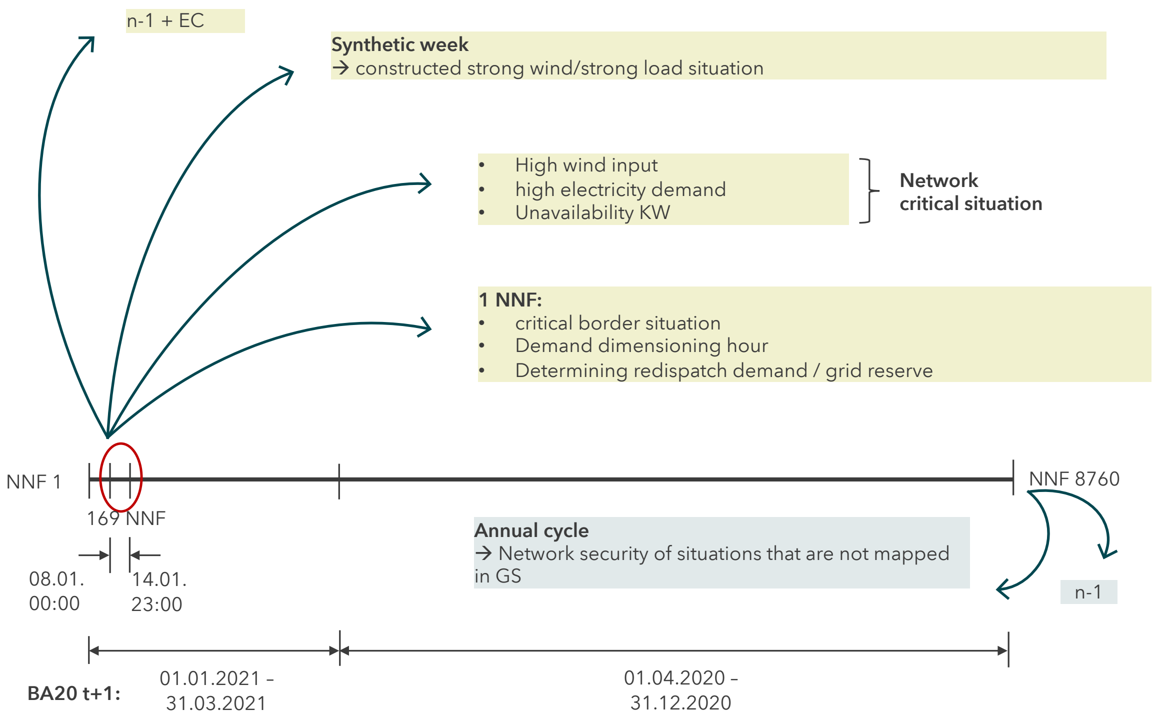
Transmission adequacy examines whether the existing grid can reliably balance supply and demand, even under critical conditions, to deliver energy from producers to consumers.

(1) Short- to Medium-Term Processes: Focus on Reserve Power Plants
Both Demand Analysis and Long-Term Analysis rely on a single meteorological year and model a synthetic critical situation to assess viable congestion relief measures.

Demand Analysis ("Bedarfsanalyse"; "BA"): TSOs perform an annual system analysis in accordance with section 3 (2) of the German regulation on reserve power plants (Netzreserveverordnung). This analysis determines the need for reserve power plants by evaluating available secured generation capacities and their development for the coming winter and at least one of the following four years. Long-Term Analysis ("Langfristanalyse"; "LA"): Under the Coal Phase-Out Act (2020), transmission system operators (TSOs) analysed the grid in connection with plans to phase out coal by 2038. With the accelerated target of 2030 (as per the 2021 coalition agreement), the BMWK has requested an update using the same method as the BA to assess conditions for secure grid operation under a faster phase-out.

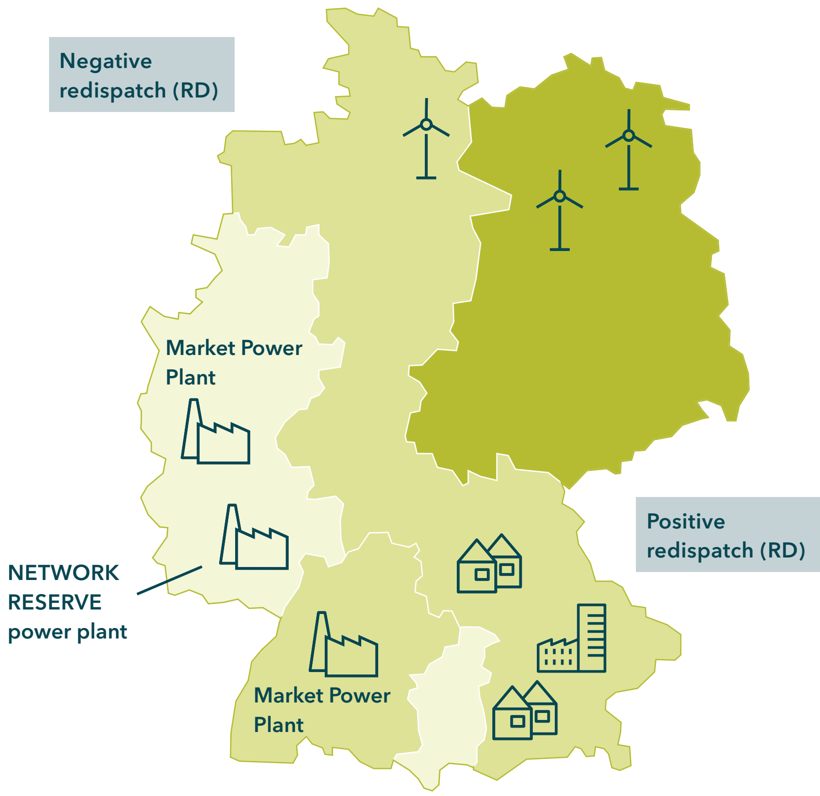
Critical Situation Identification: A synthetic winter week is simulated to find which hour shows the highest need for additional redispatch abroad in a high wind/high demand scenario coupled with plant outages. This hour defines the grid's critical limit for redispatch or reserve requirements (see Figure 3)

FIGURE 3:
Critical Situation Identification (own elaboration)



Congestion Relief (Figure 4): Solutions include negative redispatch (reducing generation in the north/east) or positive redispatch (boosting generation in the south/west via market and reserve power plants, plus additional plants abroad if necessary)

FIGURE 4:
Congestion Relief mechanism (own elaboration based on German Transmission System Operators, 2022)



(2) Long-Term Processes: Network Development Requirements
Network Development Plan ("Netzentwicklungsplan"; "NEP"): In accordance with Section 12 EnWG, German TSOs must develop a joint Network Development Plan every two years. This begins with a scenario framework, submitted to the Federal Network Agency, which outlines likely developments over the next 10 to 15 years (with additional scenarios for 2045 required since the 2022 amendment). Scenarios developed in the NEP have to consider the overall system development strategy (Systementwicklungsstrategie, SES). The SES is renewed every four years and evaluates the energy system under consideration of system costs, the current legal framework and the optimal utilisation of available energy carriers.

Federal Requirements Plan ("Bundesbedarfsplan"; "BBP"): Based on the scenario framework, TSOs identify where transmission demand will exceed capacity and propose remedial measures following the NOVA principle: Prioritise grid optimisation over reinforcement, and reinforcement over expansion.

5.3.4 RISK PREPAREDNESS

For the sake of completeness, we also mention here the Risk Preparedness process, which is separate from the resource and transmission adequacy assessments mentioned above. Traditional security-of-supply analyses focus only on standard states of the electricity market, in the sense that electricity supply crises triggered by extreme events are not included. Instead, they are addressed through a dedicated procedure known as risk preparedness. The BMWK published the associated Risk Prevention Plan "*Risikovorsorgeplan nach Art. 10 der Verordnung (EU) 2019/941 des Europäischen Parlaments und des Rates vom 5. Juni 2019 über die Risikovorsorge im Elektrizitätssektor und zur Aufhebung der Richtlinie 2005/89/EG*" (Risk Prevention Plan in accordance with Article 10 of Regulation (EU) 2019/941 of the European Parliament and of the Council of 5 June 2019 on risk-preparedness in the electricity sector and repealing Directive 2005/89/EC).

Electricity supply crises can stem from very different causes, involve distinct causal chains, and vary significantly in their impact. In this context, Article 5(2) of Regulation (EU) 2019/941 requires regional scenarios for electricity supply crises to be determined based on at least the following risks: a) natural hazards, b) accidental hazards going beyond the (n-1) security criterion and exceptional contingencies, and c) consequential hazards including the consequences of malicious attacks and of fuel shortages.

These guidelines establish which risks must be examined in any case. Only after identifying these regional scenarios do the relevant authorities in each Member State determine the most important national scenarios for electricity supply crises.

Drawing on the regional crisis scenarios developed by ENTSO-E and considering the probability and severity of potential impacts, the BNetzA identified the nine most critical crisis scenarios for Germany: 1) cyber-attack on entities connected to the electricity grid, 2) dry period, 3) physical attack on critical assets, 4) physical attack on control centres, 5) insider attack, 6) heat wave, 7) fossil fuel shortage, 8) pandemic, 9) forest fire (BMWK, 2023).

5.3.5 LONG-TERM SYSTEM ADEQUACY

Weather variability significantly affects resource adequacy and is considered in several adequacy assessment studies, as mentioned earlier. Gøtske et al. (2024) take a systematic approach to designing a sector-coupled European energy system that remains robust across 60 years of historical weather data. Using the open energy system model Python for Power System Analysis – Europe (PyPSA-Eur; Brown et al., 2018; Hörsch et al., 2018), the authors optimise capacity layouts for a European energy system under net-zero CO_2 emissions across 62 different meteorological years. These layouts are then fixed, and their operation is optimised under each meteorological year to assess resource adequacy.

The results show that capacity layouts designed for different meteorological years exhibit varying levels of resource adequacy (ranging from 90 % to 99.9 %) and a ± 10 % variation in total system costs. This underscores the importance of considering multiple meteorological years in analyses for European and national policies rather than relying on a single year. While AQ2050 incorporates fewer meteorological years, each with distinct weather conditions, it extends the analysis further by integrating multiple linked models, including an energy system model, a market model and a grid model.

5.4 HIGH-LEVEL OBJECTIVES

Chapter 5.3 above shows that the topic of adequacy is multi-faceted, and several aspects contribute to the fulfilment of security of supply standards.

The literature review described in 5.3 makes it clear that, despite its being a relevant topic, a comprehensive assessment of long-term security of supply is currently not adequately covered within energy and grid planning processes. "Comprehensive" as used here refers to the integrated, comparative evaluation of several factors contributing to adequacy such as optimal investment decisions regarding energy system needs as well as optimal energy system operation, impact of the availability of renewables (also including climate change), operation of decentral (households and e-mobility) and central flexibility options (mainly thermal power plants, electrolysers and large-scale batteries) as well as energy sovereignty issues. This multiplicity of factors is also represented in the logo of the study by the hexagons (see Figure 5), each of which represents a specific element. More details on the underlying research questions are discussed in 6.2.

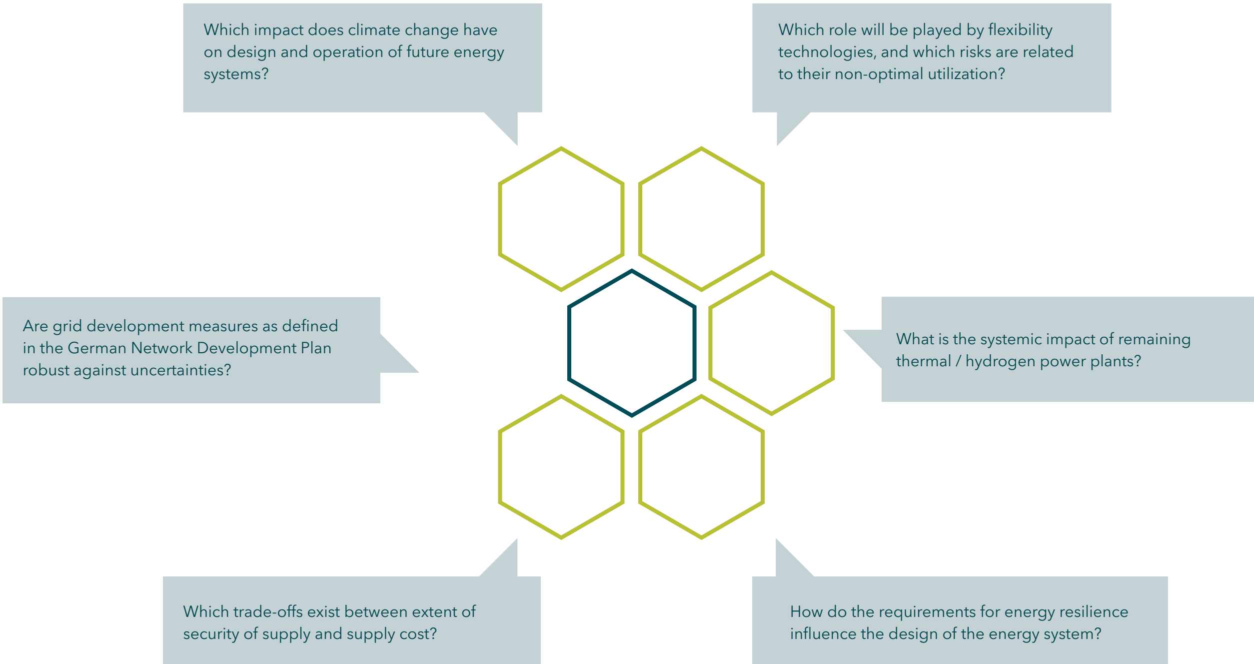


FIGURE 5:
Overview of key research questions of the AQ2050 project

At least four aspects should be highlighted in this regard:

1 The evaluation of **cost-optimal investment decisions** proposed in AQ2050 goes far beyond the economic evaluation assessment used in the ERAA process, since investment options in the latter are limited to thermal plants and large-scale batteries. In addition to conventional indicators such as LOL(E) and (E)ENS, AQ2050 also considers system costs in its assessments (see also next sub-section).

2 In addition, this study provides extra added value in the form of the wide spectrum of analyses regarding different assumed capacities and **behaviour of decentral and central flexibility technologies**.

3 Hydrogen imports as well as **energy sovereignty levels** aimed at by the European countries, together with their potential impact on overall supply cost for European citizens

4 The development and establishment of a **comprehensive methodology and model chain** is essential, **from scenario building to grid analysis**. This included creating detailed scenarios that account for various factors affecting energy supply and demand and using advanced modelling tools to analyse grid performance under different conditions. The model chain thus developed is robust, flexible, and capable of providing actionable insights for policymakers and industry stakeholders. This dedicated, novel model chain is described in 5.5, while the functionalities of each tool are presented in 7.1.

To make the implemented methodology usable beyond the end of the project and the project results directly comparable with those of existing processes, we decided to reproduce the German Network Development Plan (Netzentwicklungsplan, NEP) as a first step of our activities. Indeed, for the first time, the 2023 version of the NEP outlines network development measures for a fully carbon-neutral energy system in Germany by 2045. In AQ2050, system adequacy is evaluated by using the current NEP (version 2023, Scenario B) as a reference. As a second and main step, we aim to prove the robustness of the NEP results through a series of stress tests, which include the factors mentioned above and which will be explained in detail in the Cluster section of Chapter 6.0.

Accordingly, one of the key objectives of the AQ2050 study is to derive statements on future demand for flexible and controllable capacities under different scenarios and boundary conditions. This involves assessing the need for technologies and infrastructure that can provide the necessary flexibility to balance supply and demand, ensuring a stable and reliable energy system. By identifying the future demand for these capacities, the study aims to inform policymakers and industry stakeholders about the investments and developments needed to achieve the defined level of security of supply.

Finally, the study aims to help make network development planning more robust by integrating security of supply into the analysis methodology.

5.5 PROCEDURE AND METHODOLOGY

This section briefly describes the internal project structure and its relation to this report. The description of the model chain as developed, as well as the key functionalities of each model, will be presented in Chapters 6.1 and 7.1, respectively. The structure of the project is summarised in Table 2.The first work package (WP1), which also corresponds to the content of Chapter 5.0 of this report, introduces the topic of adequacy (5.2) together with a brief literature review (5.3). This helps to identify gaps in and the limitations of the methodologies currently applied and to define high-level objectives of this study (5.4).

WP2 is a pivotal work package, as this is where scenarios and needed input data for the subsequent model activities have been set. In this report, these items have been split between Chapter 6.0 and Chapter 7.0. Chapters 7.1 and 7.2 describe in detail the toolchain that has been developed, consisting of three models, and the way these have been linked.

Chapter 8.0 then exposes the main results. To enhance readability and to highlight the implications of results on the key messages, all model results are presented in a single chapter. The presentation of results reflects the choice of the different clusters, i.e. the exposition starts with the reproduced NEP and continues with the clusters of climate, flexibility, hydrogen turbines, energy sovereignty and service target. Only high-relevance results are presented, while details of additional results can be found in the Appendix.

The last WP, covering evaluation and synthesis, evaluates the results of the models and formulates the key messages. The key messages are presented in the executive summary at the beginning of the report.

The AQ2050 toolchain consists of three linked models, each focusing on specific aspects of the energy system. These models are arranged in a chain that begins with overall energy system planning, continues with detailed electricity market operation, and concludes with an evaluation of network performance:

/ Energy System Model: The energy system model is the starting point of the analysis. It assesses the impact of AQ2050-clusters on outcomes, primarily the necessary capacities and investment decisions in renewable energy, flexible generation (including thermal power plants), storage systems, and grid infrastructure in the European market, as well as the optimal dispatch of technologies. This model establishes the level of sector coupling by integrating the electricity, heating, transportation, and industry sectors into a comprehensive view of the European energy system. Moreover, it produces optimised electricity time series for the operation of sector-coupled technologies. The model operates in an aggregated and simplified manner, with an extended time horizon focused on investment decisions and dispatch.

/ Market Model: Building on the outputs of the energy system model, the market model focuses exclusively on the electricity sector. It provides detailed dispatch calculations by simulating the dispatch of generation assets at a resolution that is compatible with subsequent network analysis. In doing so, the model determines electricity market prices based on these dispatch outcomes and calculates the ENS distributions and patterns through simulations. Designed for the power sector only, the market model uses a disaggregated

#	INTERNAL WORK PACKAGE	OBJECTIVES	RELATED REPORT CHAPTER
1	Initial situation	Description of security of supply today, including key figures on security of supply. Description of the limitations of current methods regarding the energy transition.	Chapter 5.0
2	Scenario design and data mining	Definition of scenarios to be examined: Key parameters and provision of input data. Validation of scenarios (quantitative and qualitative aspects) with the involvement of a panel of experts.	Chapter 6.0 and 7.0
3	Energy system modelling	Optimisation of EU energy transition from an economic perspective. Upgrade evaluation of flexibility options, especially prosumers, industry. Establish the toolchain. ESM – market model – grid model.	
4	Market modelling	Determination of feed-in and consumption situations in the EU. Cost-optimised dispatch for different weather (climate) years. Generation of regional input data for grid analyses.	Chapter 8.0
5	Power grid modelling	Checking compliance with grid security with regard to the shortfalls that occur. Analysis of grid weakening as a result of equipment failure. Proof that grid security is guaranteed, absence of permanent limit violations.	
6	Evaluation & synthesis	Overall assessment of long-term security of supply. Determination of quantitative key indicators, including costs and risks as well as qualitative assessments and conclusions within the scenario framework.	Chapter 8.0 and Executive Summary

TABLE 2:
Brief description of the AQ2050 work packages and relation to the report structure

and detailed representation of technologies, operating under a dispatch-only optimisation mode over a single-year time horizon. This allows for a focused analysis of system operation and power market dynamics.

/ Grid Model: The final step in the chain is the grid model, which performs calculations for selected scenarios. It takes the market model results as input to evaluate the physical transmission network. It assesses network capacity and identifies potential overloads or shortfalls, examines the necessary network development measures to address these constraints, and performs redispatch calculations to determine the adjustments required to relieve network stresses. The grid model is a detailed mathematical representation of the network's topology and physical transmission properties in a stationary time range. It offers a high level of detail for Germany and its neighbouring countries, while applying a reduced level of detail for other EU countries.

Together, these three AQ2050 models form a comprehensive chain: The energy system model establishes long-term investments and capacities; the electricity market model refines these insights; and the grid model ensures that physical network constraints are adequately addressed.

5.6 LIMITATIONS AND DISCLAIMERS

Once the high-level objectives of AQ2050 have been exposed, it is worth clarifying which goals will expressly not form part of this study. We also want to make potential limitations of the selected approach – with regard to the statements which can be generated from it – as transparent as possible.

Table 3 summarises what is outside the scope of AQ2050. While the path towards climate neutrality in Europe will be addressed by means of energy system modelling, the focus of the analysis remains 2050. Intermediate years are calculated and analysed, but 2030 is not the focus of this study, as other dedicated projects and processes such as ERAA and others already cover this medium-term time frame.

In addition, we set the focus of the analyses in the market and grid model on the possible impact of climate change (i.e. higher temperatures) and we opted not to calculate a wide range of meteorological years as in the ERAA process. On the other hand, we set a major focus on system needs and calculate results for five selected climate years.

Further, the identification of a target network, power dynamics and a bidding zone review are not part of the study objectives.

TABLE 3:
Summary of elements which are out-of-scope in AQ2050

WHAT IS OUTSIDE THE SCOPE OF AQ2050?

/ A detailed analysis of intermediate years (e.g. 2030) – we focus on the 2050 timeframe
/ Calculating a wide range of meteorological years (as performed in ERAA) – we focus on the possible impact of climate change
/ Identification of a target network, power dynamics, and a bidding zone review
/ An exact location of new power plants or other energy system components
/ Detailed technological characterisation of power plants (e.g. future PV or wind power yields may differ)
/ Real-world battery dispatch operations (since the model optimises dispatch over the whole year)
/ A detailed consideration of different individual country targets and sector-specific targets
/ A consideration of optimal investment strategies for single stakeholders and individual technologies
/ Real-world hourly electricity prices (due to characteristics of energy system and market models)
/ Consideration of dynamic system stability in network modelling
/ Assessment of potential changes and limitations on planned assets due to altered climatic conditions

As with all models, those used in the context of this project use simplifying assumptions. These assumptions mainly serve to reduce complexity and keep the task of computation manageable.

As an example, in the energy system model geographical regions are aggregated to sub-country or country level. This means that this category of model is not suitable for identifying the exact location of new power plants or other energy system components. Further, the technological detail of power plants, whether thermal power plants or renewables, is quite limited, which means that future PV or wind power yields, for example, may differ significantly from the calculated values. Another simplifying assumption of the energy system model is the linearisation of power flows. Exact grid calculations are therefore performed using the grid model. Moreover, model years in the energy system are optimised as a whole. This means, for example, that battery dispatch is more efficient than in reality since the optimiser knows the dispatch of all technologies for the whole year and can ensure the ideal dispatch of battery capacities, which does not happen in reality.

Additionally, AQ2050 does not provide a detailed analysis of individual country targets or sector-specific targets within a single country, such as carbon emissions or renewable energy goals. Nor do we assess optimal investment strategies for individual stakeholders or technologies.

In both energy market models (energy system model, market model) hourly prices can be extracted from the results. These prices should be treated with caution. On the one hand, energy system models including expansion runs typically show very high price spikes during critical hours. This behaviour reflects the need for the system to install additional or new technologies to cover the load. Those high prices include annualised investment needed for the additional or new technology. On the other hand, it must be noted that because modelled markets assume perfect foresight, these typically contain flatter price patterns than real markets. Despite these limitations, the resulting prices are excellent indicators for energy scarcity or critical situations.

In the context of network modelling, the focus is on the analysis of transmission security. There is no consideration of dynamic system stability. Potential changes and limitations due to altered climatic conditions affecting the planned assets are not addressed in this study. For example, significantly increased temperatures at a local level could lead to a reduction in the transmission capacity of converter stations.

For a more detailed methodological list of limitations, see PyPSA-Eur (2025) for the energy system model, and German Transmission System Operators (2023, pp. 62 ff.) for the market model.

5.7 ADVISORY BOARD

As it was the case in the previous TransnetBW 2050 studies, AQ2050 benefits from the expertise of an advisory board consisting of distinguished European scientists and institutional representatives, as well as industry experts.

The involvement of the advisory board can be summarised as follows:

/ First, bilateral interviews with the members of the board helped the project team to both broaden and deepen the understanding of such a multi-faced topic as power adequacy. In addition, the members provided differentiated feedback on the major proposed project streams. An anonymised version of the collected feedback is presented in the Appendix.

/ In the following phases of the project, our methodologies and results have been critically challenged within the framework of a series of in-depth and fruitful meetings. The discussions and the feedback provided by the advisory board decisively helped us to improve the quality of the final product.

/ Finally, the advisory board supported us in the review and fine-tuning of the report at hand.

The advisory board was constituted as follows:
/ Dr. Philipp Ostrowicz (Copenhagen Business School)
/ Dr. Hans Wolf von Koeller (Steag)
/ Prof. Wolf Fichtner (KIT)
/ Dr. Markus Doll (BNetzA)
/ Prof. Dogan Keles (DTU)
/ Dr. Martin Konermann (NetzeBW)
/ Torsten Maus (EWE Netz)
/ Dr. Francisco Boshell and Adrian Gonzalez (IRENA)
/ Dr. Marion Schroedter-Homscheidt (DLR)

We would like to take the opportunity to thank the members of the advisory board for their valuable input and interesting discussions, as well as their expert advice at all stages of the study. Responsibility for the results as presented, however, lies entirely with TransnetBW.

6.0

SCENARIO BUILDING

In the following chapter, we describe the scenario-building process and the underlying motivation for each analysis. First, we will describe the overall structure of the scenarios and related activities. This will be followed by a detailed description of the scenario background and the methodology used. And lastly, we will explain the priorities that were applied as the scenarios were developed.

6.1 INTRODUCTION: CLUSTERS AND SCENARIOS

The 2023 German National Network Development Plan (NEP23) looked for the first time at the year 2045, the target year for the German energy transition to climate neutrality. Scenarios targeting 20 to 30 years in the future are classed as long-term, and their assumptions naturally involve a high degree of uncertainty. Some examples of such uncertainty are the future role of domestic hydrogen production versus imported hydrogen, the role of central and decentral flexibility technologies and the impact of PV and wind yield variability in the short and long term on the design and operability of the energy system. Despite these challenges, grid planning must be as robust as possible on account of the lengthy implementation times for large grid expansion projects.

Accordingly, NEP23 addresses some of these uncertainties and proposes three different scenarios which cover different aspects of the framework conditions for a decarbonised Europe. Based on these assumptions, model-based analyses comprising an electricity market model and a grid model were performed within the framework of the official NEP23 process to identify the grid investments needed to ensure a carbon-neutral system.

In AQ2050 we aim to extend the analysis of the potential impact of further uncertainties on system adequacy and on robust energy system planning. The first step towards achieving this objective is therefore to develop a suitable methodology capable of both reproducing the NEP23 scenarios and being flexibly adapted to implement differing scenarios (more details provided below). For reasons of simplicity, we focus only on reproducing the B scenario (which also can be understood as the reference scenario within the NEP process). In principle, however, A and C scenarios may also be selected.

With this methodology, we want to shed light on the possible impacts on grid and system planning if one or more framework assumptions differ from the reference scenario. This study is therefore centred around the NEP scenarios. This allows us to identify the uncertainties relating to the framework condition assumptions involved in the official scenarios. It is important to distinguish the goal of the scenarios presented in this study compared to already existing scenarios in studies such as the European Resource Adequacy Assessment (ERAA), which analyses mid-term security of supply. The scenario and modelling approach differ significantly from each other. As mentioned previously in Chapter 5.3, ERAA and similar studies try to grasp the current trends with the goal of measuring estimated security of supply in great technological detail, while the focus of this study lies in identifying the impact of framework assumptions on security of supply.

We identified several fields / dimensions in which we can group these changes to the framework conditions. Throughout the study, we will refer to these thematic groups as "clusters" or "scenario clusters". Through several iterations with internal and external stakeholders, we identified six relevant clusters, which are listed in Table 4.

TABLE 4:
Scenario Clusters

Cluster	Topic
NEP	Are grid development measures as defined in the German Network Development Plan robust against uncertainties?
FLEXIBILITY	Which role will be played by flexibility technologies, and which risks are related to their non-optimal utilisation?
CLIMATE	Which impact does climate change have on design and operation of future energy systems?
H_2 POWER PLANTS	What is the systemic impact of remaining thermal / hydrogen power plants?
ENERGY SOVEREIGNTY	How do the requirements for energy resilience influence the design of the energy system?
SERVICE TARGET	Which trade-offs exist between extent of security of supply and supply cost?

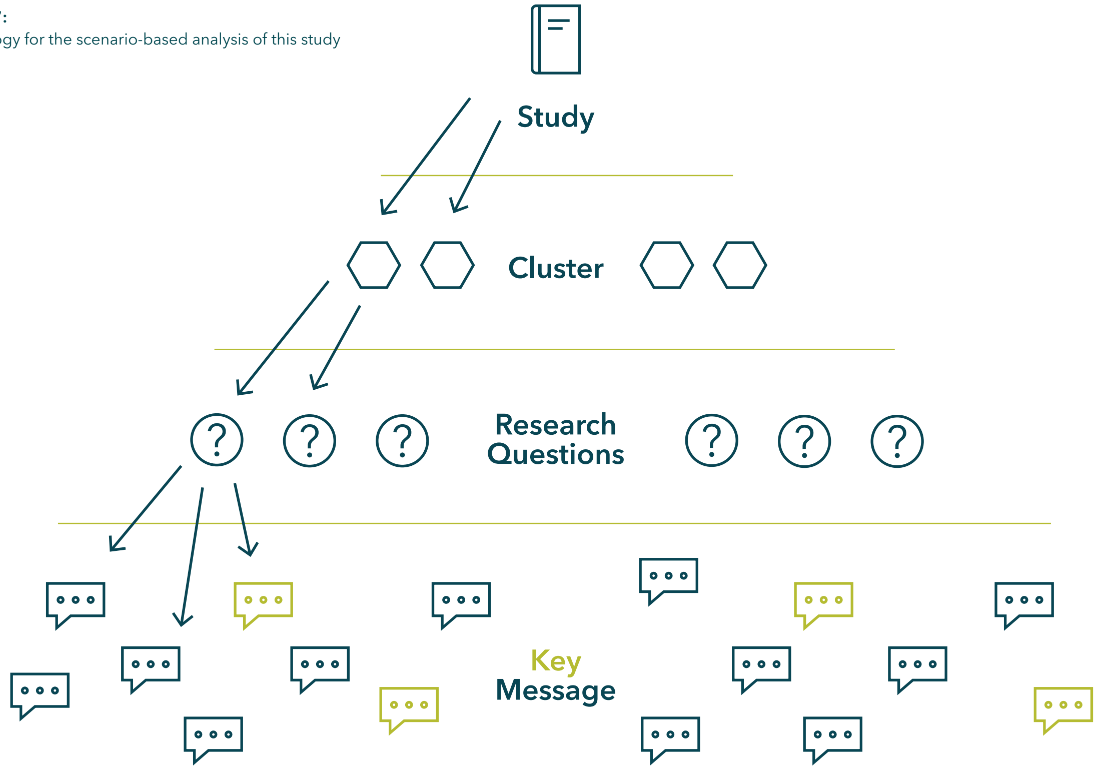
As presented in Chapter 6.2, each cluster in turn contains multiple research questions which address more detailed topics. Multiple scenarios are also assigned to each cluster, and these help to provide answers to the research questions. The scenarios used in this study are quantitative in nature, calculated using a newly introduced model chain (also referred to as "toolchain"). The in-house energy system model (ESM) based on the open-source energy system model PyPSA-Eur-Sec represents the most upstream model. Its horizon includes all sectors of the European energy system, such as electricity, heat, transport and industry. The electricity market model BID3 is placed in the toolchain further downstream. Its strength lies in the detailed calculation of power plant dispatch on a per-plant level in the European context. Even further downstream is the Integral grid model. Its specialty lies in calculating physical power flows in the transmission grid. Because the uncertainties of framework conditions around the NEP scenarios are the focus of the study, we use the NEP23 target grid to parameterise the Integral model. The toolchain with its model-specific contributions to the study is shown in Figure 6.

FIGURE 6:
Toolchain used for this study and the role of each model

Energy System Model	Market Model	Grid Model
Determines capacities and investments in renewable energy and flexibilities (including thermal power plants)	Detailed dispatch in the electricity sector (in a resolution compatible with the network model)	Overload energy in the network
Determines the level of sector coupling	Determines electricity market prices	Evaluation of NEP measures
Produces optimised electricity time series for sector-coupled technologies	Determines ENS and ENS-sharing among bidding zones	Redispatch calculations

It is worth highlighting that not all models are essential to answer each research question. The strengths of each of the models are combined to derive comprehensive quantitative answers to the research questions without submitting to the limitations of individual model classes. We then synthesise the available data to elaborate key messages, which we regard as the answer / result for the research questions. Figure 7 illustrates the relationship between the clusters, research questions and key messages. The following chapter will cover the details of each cluster and present the related research questions.

FIGURE 7:
Terminology for the scenario-based analysis of this study



6.2 DEFINITION OF SCENARIOS AND RELATED RESEARCH QUESTIONS

This chapter will cover the details of all clusters, their respective research questions and the proposed model configurations.

6.2.1 NEP CLUSTER

The NEP cluster, also referred to as "reference", focuses on technical aspects relating to the models used in this study. NEP23 was originally implemented using the electricity market model PLEXOS and Integral as the grid model. Scenario building includes different aspects. First of all, basic scenario assumptions are taken from the previous Ten-Year Net Development Plan 2022[4] (TYNDP22), which contains three scenarios, of which "Distributed Energy" was chosen as being most compatible with the German energy transition pathway. Detailed data on the German energy transition is determined in collaboration with the regulator and is debated in a public consultation process.

This original NEP toolchain can deliver highly detailed input data for the core PLEXOS and Integral models but is rather inflexible in representing fundamentally different framework assumptions. A novel, complementary toolchain has therefore been used for this study. It is illustrated in Figure 6 and will be described in detail in Chapter 7.0. One of the major advantages of the novel toolchain is the endogenous representation of multiple sectors, which are exogenous to the NEP toolchain. The data pre-processing workload that is required is reduced by the sector coupling and processing of weather data processing in the ESM shown in the endogenous representation.

The following research questions tackle all the methodological and data-driven aspects of this cluster:

/ NEP/RQ1: Can we recreate the NEP23 B-scenario within a novel, flexible approach to comprehensively assess system adequacy?

/ NEP/RQ2: What are the blind spots in the original scenario and how do our models fill the gap?

4 – Although TYNDP24 scenarios and data were available, the European context of NEP23 is originally derived from the TYNDP22 dataset. Optimal consistency for analysing the uncertainties associated with clusters is provided by sticking to the original dataset. We therefore did not update model data on the basis of TYNDP24.

To adequately recreate the NEP scenarios, we must transfer the overarching assumptions into our toolchain. This is straightforward in some cases, such as installed capacities, as the technology depiction is quite similar. Other aspects, such as weather data, need more attention. The NEP scenarios use 2012 as the default meteorological year because it is a good proxy for a typical meteorological year, since the renewable energy sources (RES) provide average yields. In addition, 2012 was characterised by a cold week in February, which typically leads to power flows especially relevant for system design. We reproduced all data transformation steps in the technical framework provided by the ESM, which diverges in some aspects of the processing steps. The model configuration for the NEP recreation task can be found in Table 5.

TABLE 5:
Model configurations related to NEP/RQ1

NEP/RQ1
Can we recreate the NEP23 B-scenario within a novel, flexible approach to comprehensively assess system adequacy?

ESM: ☑ MM ☑ GM: ☑

ID	Scenario Name	Input Parameter	Toolchain Part
N0	Reference 1	NEP	ESM – MM
N0b	Reference 2	NEP	MM – GM

One of the benefits of recreating the NEP scenarios in our broader sectoral operating toolchain is the ability to take a deeper look at the blind spots in the original NEP. For example, insights into the hydrogen sector, such as demand structure, import needs and storage utilisation can be assessed. The results provide the answer to NEP/RQ2.

6.2.2 CLIMATE CLUSTER

Within the framework of the Climate Cluster, we aim to assess the impact of weather variability on various adequacy levels. The NEP process takes only the meteorological data for 2012 as a basis. While this choice is motivated by the fact that 2012 represents a rather average year for Germany in terms of PV and wind power yield (with the addition of a cold week in February), the impact of year-to-year weather variability on optimal system design remains largely unconsidered. It should be highlighted that such variability, which in Germany amounts on annual basis to around ± 15 % for wind power and around ± 5 % for PV (see Chapter 7.3.1 for more details), will likely have a much greater impact on power system operation in 2045.

In this regard, one topic which is currently controversially debated among climate scientists is the future of the Gulf Stream. Some studies suggest that the Gulf Stream could weaken or even collapse due to climate change, potentially leading to drastic cooling in Europe, altered weather patterns, and increased frequency of extreme weather events (DKK, 2017). However, other researchers argue that such predictions are based on models with considerable uncertainties, that the Gulf Stream is more resilient than these scenarios suggest, or even that no decline has been observed so far (Atlantic overturning inferred from air-sea heat fluxes indicates no decline since the 1960s | Nature Communications).
Selecting climate projections is a significant challenge due to the multitude of existing climate models, each yielding different results. These models are based on various assumptions and parameterisations, leading to uncertainties and systematic biases. For instance, models may have different sensitivities to

greenhouse gases or varying representations of cloud formation and precipitation. Additionally, some models use similar parameterisations, meaning that frequent results do not necessarily indicate higher likelihood but rather reflect the parameterisation of the model itself. Climate projections are not designed for hourly analysis but rather to generate long-term trends over extended periods, such as 30 years (mainly due to simplified model parameterisation as well as rather coarse resolution, which climate models often rely on). Additionally, all climate simulations face the same challenge of estimating probable pathways as they depend on changes in socio-economic factors, and current activities in the economy and politics are challenging to project. The result is a significant spread between the projections.

Despite the challenges, there are ongoing efforts to utilise climate projection data for the energy sector. For instance, the German Weather Service (Deutscher Wetterdienst, DWD) is working on projects aimed at making climate projection data more applicable in the energy sector (see DWD, 2025, and Pechlivanidis et al., 2020). However, this data is currently not fully usable as it is largely limited to Germany and has, at best, a daily resolution instead of the hourly resolution that is needed.

The Pan-European Climatic Database (PECD) offers comprehensive information on climatic and renewable energy variables for both historical and future periods. The PECD data is based on the latest IPCC climate simulations. Uncertainty is represented through an ensemble of climate projections from different climate models. Although they provide time series in adequate temporal resolution, the spatial resolution of the climate models is still comparatively low (for additional details, see 7.3.1).

The Destination Earth project (DestinE) is an initiative by the European Commission to create a high-precision digital twin of Earth. This digital twin provides high-resolution climate projections and impact-sector information on multi-decadal timescales. Through an extensive co-design with end users of the data, output of the digital twin will be tailored to the needs of the energy sector, e.g. by providing time series with an hourly resolution. In combination with this high resolution, DestinE can be considered a valuable extension of the existing databases (Hoffmann et al. 2023).

However, all initiatives mentioned are still in their early stages. Data has not yet undergone extensive validation, which impacts on its reliability. Demonstration and validation projects are currently being implemented to address this.

In order to take these different levels of variability and uncertainty into account, we base our analysis on both climate change scenarios and historical years. To achieve a trade-off between computational efforts and wide coverage of possible cases, we perform a pre-selection of meteorological years based on the methodology explained in 7.3.1.

The main research questions within the Climate Cluster are:

/ CLIMATE/RQ1: What influence do year-to-year weather patterns / climate change have on investments for energy system planning? And how do those two impacts compare?

/ CLIMATE/RQ2: How do security of supply and overload patterns in the power grid change in particularly hot years?

Table 6 and Table 7 show the model configuration for the research questions in this cluster.

TABLE 6:
Model configurations for scenarios relating to CLM/RQ1

CLM/RQ1
What influence do year-to-year weather patterns / climate change have on investments for energy system planning? And how do those two impacts compare?

ESM: ☑ MM: ☐ GM: ☐

ID	Scenario Name	Meteorological Year	Installed Capacities
C0	Reference	2012 (NEP)	NEP
C1-8	(Various years)	Extreme historical years or extreme projection data	Investments in Renewables, Batteries, Power Plants and Interconnectors allowed

TABLE 7:
Model configurations for scenarios relating to CLM/RQ2

CLM/RQ2
How do security of supply and overload patterns in the power grid change in particularly hot years?

ESM: ☐ MM: ☑ GM: ☑

ID	Scenario Name	Meteorological Year	Installed Capacities
C0	Reference	2012 (NEP)	NEP
C9	Extreme Weather 3	Extreme Weather 3 (see Chapter 7.3)	NEP

6.2.3 FLEXIBILITY CLUSTER

Flexibility is currently a focus for multiple stakeholders in the energy sector, and its future role is controversially debated among academia, politics and industry. However, multiple contexts exist for this term, which can lead to different interpretations of results or messages.

References to "flexibility" in this study relate to technologies. Units, plants or actors in the energy system which are able to react to dispatch signals are defined as flexibilities. An exception is the curtailment of RES, which we do not include in the category of flexibilities. Dispatching signals may come from existing markets, such as the day-ahead market, from possible future markets such as local flexibility markets at a distribution grid level, or take the form of interventions by the TSO or other entities, for example. An additional criterion is the voltage level of the grid connection ("central vs. decentral") to group technologies and actors of flexibility, because these are subject to different restrictions.

The FLEXIBILITY cluster, or FLEX Cluster in short, contains multiple research questions relating to central and decentral flexibility technologies. NEP scenario B, which forms the basis of our study, assumes that 100 % of private households will be fully market-oriented by 2050. While this seems to be a well suited planning goal for the optimal use of resources in the future, it may be argued that this amount of decentral flexibility might not be available, either because of slower diffusion of related technologies and services, or as a consequence of technical non-availabilities. In this study, we count hydrogen power plants, Net Transfer Capacities (NTC) and large-scale battery electric storage systems (BESS) among the central technologies[5]. In contrast, the technologies of home batteries, electric vehicles (EV) and heat pumps (HP), which are typically allocated in the private household and service sectors at lower voltage levels in the distribution grid, are counted as decentral technologies. Electrolysers sit somewhere in between, because their expected characteristics are neither fully central nor fully decentral. Variations of renewable energy sources (RES) such as wind, solar and biomass are not the focus of this cluster.

5 – Due to the limited additional available potential, hydropower is only considered on the basis of existing capacity.

To assess flexibilities in the context of this study, two fundamentally different approaches can be depicted in our model toolchain. If research questions are formulated on the basis of "system need" (see RQ 1-2 and 5), the expected results take the form of additional necessary capacities to ensure a secure system under the modelled conditions. But if research questions are targeted towards the aspect of security of supply (RQ 2-3), then a different modelling approach is necessary, which puts a given system under stress and measures the supply gap in the form of either Loss of Load Hours or Energy Not Served. Both question elements might target similar fields, but they are fundamentally different and cannot be answered with the same set of model calculations. We chose the research question in such a way that both aspects of adequacy are present in this cluster. The research questions are:

/ FLX/RQ1: What are the additional energy system needs in terms of new capacities if the availability of decentral flexibility does not meet the planned targets?

/ FLX/RQ2: How robust is a system with a stronger focus on central flexibilities in response to challenging weather conditions?

/ FLX/RQ3: What security of supply standard do we have if efficient flexibility utilisation is assumed, but not available?

/ FLX/RQ4: What are the differences between different central flexibility technologies such as hydrogen turbines, large scale BESS and NTCs? Are their capacities interchangeable?

In the first research question, the use of a model with investment optimisation capability is necessary because of the "system needs" aspect of the question. In addition, different availabilities of decentral flexibility technologies must be distinguishable from central flexibilities in the modelling methodology. For this, we developed dedicated model-based functionalities, which allow different availability constraints to be analysed.

The default approach of an energy system model is the assumption of a "central planner" who is acting in a fully transparent environment with perfect foresight. This assumption might be feasible for an optimal electricity market containing power plant operators with trading departments running state-of-the-art market and weather modelling tools, but does not apply to private households or the services sector, especially with abundant dynamic pricing, which could include the possibility of forwarding real-time market and grid feedback to the consumer. The available options for reducing the availability of flexibility are listed in the table below (Table 8):

TABLE 8:
Decentral flexibility availability variation methods

Availability Aspect	Description
Partly Inelastic Prosumer	**Target:** reduce the amount of shiftable load. **Method:** charging of EVs is set to the profile complementary to the driving profile ("charging as soon as not driving"), heat pumps have reduced hot water storage ("pre-heating storage as flexibility not possible"), no home battery ("a consumer with no flexibility ambitions has no need for battery storage")
Self-Sufficiency Priority	**Target:** flexibility is used for self-sufficiency "at any cost". Market orientation is followed only as a secondary objective. **Method:** electricity flow towards the prosumer has added penalty cost –> rooftop PV, household batteries, heat pumps and EVs are affected

The topic of system needs can be addressed by configuring the ESM in investment mode. We used two different investment settings:

/ Hydrogen power plants only: Hydrogen plants are available for investments. They are a representative technology for measuring flexibility needs.

/ Multiple central investment options: hydrogen power plants, large BESS and interconnection capacities are available for investments.

For research questions 2 and 3, security of supply KPIs play a major role. These are typically assessed by Monte Carlo simulations, which have a demand for highly detailed data and resources. We therefore chose a more practical approach: We neglect the stochastic nature of the classic resource adequacy KPIs and try to measure an overall order of magnitude of the security of supply. We thus compare the performance of two different systems with fixed capacities under stress. We chose the following stress situations:

/ Security of Supply Stress 1: Reduced flexibility provision by prosumer (demand is partly inelastic)

/ Security of Supply Stress 2: Future meteorological year with overall low RES yields across all seasons (Extreme Weather 1, see Chapter 7.3)

The fixed capacities of the systems can lead to supply gaps in the dispatch calculations. Although the ESM could quantify these supply gaps, we chose to use the electricity market model in addition, which ensures an estimation of security of supply with state-of-the-art methods and a sophisticated level of technological detail (see Chapter 7.1.2).

The NEP reference scenario assumes all prosumers to be fully market-oriented. We therefore chose three variations of reduction in decentral flexibility availabilities to analyse the first research question. These are listed in Table 9. The analysis is performed in pairs: F0 – F1c, F0 – F4, F0 – F6. A complete list covering all model settings and scenarios can be found in the Appendix.

TABLE 9:
Model configurations for scenarios relating to FLX/RQ1

FLX/RQ1
What are the additional energy system needs in terms of new capacities if the availability of decentral flexibility does not meet the planned targets?

ESM: ☑ MM: ☐ GM: ☐

ID	Scenario Name	Central Flexibility	Decentral Flexibility
F1c	Less Flexible Consumers	Additional H2 power plant investment possible	-50 % of households and services respond flexibly to market prices
F4	Self-Sufficiency Consumers	Additional H2 power plant investment possible	Self-consumption by consumers as first priority (market as secondary priority)

The scenarios relating to FLX/RQ1 allow only one central flexibility technology to be traded against the decentral one with lower availability. While this is beneficial for a general understanding of system needs, it neglects the advantages of different technologies. FLX/RQ4 targets exactly this field, i.e. understanding the different areas where various central flexibility options can make a contribution. Table 10 below lists the scenarios used to measure the different impacts of the possible central flexibility options.

TABLE 10:
Model configurations for scenarios relating to FLX/RQ4

FLX/RQ4
What are the differences between different central flexibility technologies such as hydrogen turbines, large scale BESS and NTCs? Are their capacities interchangeable?

ESM: ☑ MM: ☐ GM: ☐

ID	Scenario Name	Central Flexibility	Decentral Flexibility
F0	Reference	NEP	NEP (100 % market oriented)
F1c	Hydrogen power plants only	Additional H2 turbine investment possible	-50 % of households and services respond flexibly to market prices
F1a	Multiple central investment options	Additional H2 turbine, large scale BESS and NTC investment possible	-50 % of households and services respond flexibly to market prices

The key idea is to generate the need for an investment by reducing decentral flexibility and to allow different investment options as a countermeasure. Like in the previous research question, scenario analysis is done in pairs: F0 – F1c and F0 – F1a.

To answer research question 3, two models need to be used (Table 11). The ESM is necessary for the calculation of cross-sectoral optimal dispatch and then MM is used to quantify the resulting security of supply KPIs. We reduce flexibility by assuming a 50 % reduction in market-oriented consumers (as previously also analysed in the less flexible consumers scenario) and we also choose a challenging meteorological year to induce stress in the system for the security of supply index. This represents a worst-case scenario and should demonstrate the severity of inadequate system planning.

TABLE 11:
Model configurations for scenarios relating to FLX/RQ3

FLX/RQ3
What security of supply standard do we have, if efficient flexibility utilisation is assumed, but not available?

ESM: ☑ MM: ☑ GM: ☐

ID	Scenario Name	System stress	Flexibility
F0	Reference	Normal – meteorological year 2012	NEP (100 % market oriented)
F2	Worst-Case	Challenging meteorological year (Extreme Weather 1, see also Chapter 7.3)	-50 % of households and services respond flexibly to market prices

The focus of research question 2 is the resilience analysis of a system designed specifically with lower decentral flexibility in mind. We want to test how much additional resilience against weather anomalies is present in a system if the system design already takes account of unavailable consumer flexibility. We therefore need three scenarios for the comparison: The reference scenario (NEP), a scenario which has additional central capacities to cope with reduced decentral flexibility and a stress scenario in which capacities are fixed and weather stress is induced. As in the previous research question, both ESM and MM are used for this scenario comparison. Table 12 shows an overview of the model configuration for this scenario set.

TABLE 12:
Model configurations for scenarios relating to FLX/RQ2

FLX/RQ3
What security of supply standard do we have, if efficient flexibility utilisation is assumed, but not available?

ESM: ☑ MM: ☑ GM: ☐

ID	Scenario Name	System stress	Flexibility
F0	Reference	Investment Run – normal weather	Decentral Focus (100 % market-oriented prosumer)
F1a	Multiple Central Investment Options	Investment Run – normal weather	Stronger Central Focus (50 % market-oriented prosumer)
F1b	Partly Decentral – Stress test	Stress test with challenging meteorological year (projection)	Stronger Central Focus (50 % market-oriented prosumer)

6.2.4 HYDROGEN POWER PLANT CLUSTER

Hydrogen power plants represent a key technology in a carbon neutral energy system because they can dispatch independently of any weather condition. They provide short-term and long-term flexibility and are a source for spinning and non-spinning reserve. The research questions in this cluster directly target the capacity of H2 power plants:

/ H2P/RQ1: How much alternative capacity is necessary if the constructed hydrogen plant capacity is less than planned?

The model configuration for this research question is listed below in Table 13.

TABLE 13:
Model configurations for scenarios relating to H2P/RQ1

FLX/RQ3
What security of supply standard do we have, if efficient flexibility utilisation is assumed, but not available?

ESM: ☑ MM: ☐ GM: ☐

ID	Scenario Name	System stress	Flexibility
F0	Reference	Normal – meteorological year 2012	NEP (100 % market oriented)
F2	Worst-Case	Challenging meteorological year (Extreme Weather 1, see also Chapter 7.3)	-50 % of households and services respond flexibly to market prices

6.2.5 ENERGY SOVEREIGNTY CLUSTER

Transforming the energy sector towards a decarbonised future also brings about changes in energy trading at a global and a European level. The decline in demand for fossil fuels and the strong increase in demand for green energy carriers such as hydrogen and its derivatives will also create a shift in the sources of these energy carriers. There is a major difference in the sourcing of green hydrogen compared to fossil fuels: It is not bound to resources buried in the earth, but to infrastructure and renewable energy, which can also be harvested locally in Europe.

While it transitions towards carbon neutrality, the European Union might strive towards stronger independence with regard to energy imports. Taking control of energy carrier production may reduce uncertainties affecting their availability. However, the cost of local production might be higher than elsewhere in the world. EU member states may also debate among themselves regarding cooperation vs. self-sufficiency. There may be a reduction in willingness to cooperate among member states, depending on the view of the political parties in charge. Both dimensions of self-sufficiency, i.e. at a national or a European level, might have significant impacts on the necessary infrastructure and therefore also on security of supply. We formulated the following two research questions which will drive our analysis in this field:

/ SOV/RQ1: How are the national energy systems impacted by different ambitions in terms of hydrogen autarky?

/ SOV/RQ2: What additional efforts are necessary if the European Union is to strive for higher energy resilience?

The analysis of these research questions is based on the model configurations in Table 14 and Table 15.

TABLE 14:
Model configurations for scenarios relating to SOV/RQ1

SOV/RQ1 How are the national energy systems impacted by different ambitions in terms of hydrogen autarky?			
ESM: ☑	MM: ☐	GM: ☐	
ID	**Scenario Name**	**Autarky Constraint**	**Capacities**
N0	Reference	NEP (50 % local H2 production)	NEP
E1	Low Hydrogen Self-Sufficiency	30 % local H2 production	Additional investment in RES, H2 power plants and large BESS
E2	High Hydrogen Self-Sufficiency	70 % local H2 production	Additional investment in RES, H2 power plants and large BESS

TABLE 15:
Model configurations for scenarios relating to SOV/RQ2

SOV/RQ2 What additional efforts are necessary if the European Union is to strive for higher energy resilience?			
ESM: ☑	MM: ☐	GM: ☐	
ID	**Scenario Name**	**Autarky Constraint**	**Capacities**
N0	Reference	NEP (H2 national constraints)	NEP
E3	Higher European Energy Sovereignty	Higher overall self-sufficiency, all energy carriers	Investments possible in RES, H2 power plants, large BESS and electrolysers

6.2.6 SERVICE TARGET CLUSTER

Conventional security of supply assumes the same value of lost load for all load components. However, security of supply in a system relying heavily on fluctuating renewables might become expensive if backup capacities for the “last MWh” are built but are then not used due to stochastic weather effects. One approach in the future could be to actively market a lower level of security of supply, to avoid some investments in infrastructure that may possibly be used for only a few hours every few years (Table 16).

The exact market form is not debated in this study, as there would be multiple possible designs. However, for the sake of modelling, we assume that a product exists which provides a monetary bonus to consumers for accepting lower levels of security of supply. In detail, this means that the electricity supply for these consumers can be cut off for a maximum of one hour per year, on condition that they are informed several days ahead. The amount of curtailable energy per market zone can be assessed for the modelling purposes. The model configuration to the research question shown below can be found in the Appendix:

/ . STA/RQ1: Can a variable ENS target have an economic impact?

TABLE 16:
Model configurations for scenarios relating to STA/RQ1

STA/RQ1
Can a variable ENS target have an economic impact?

ESM: ☑ MM: ☐ GM: ☐

ID	Scenario Name	H2 Power Plants	Curtailable Load
N0	Reference	NEP	No
S3	Variable ENS	Lesser capacities allowed if system is still secure	20 % of private households allowed to be curtailed for 1 hour for a price of 2.5 T€/MWh

6.2.7 CONCEPT OF "BASE" SCENARIOS

All scenario-based analyses have a common aspect: A reference scenario which serves as a benchmark for the scenario comparisons. For technical reasons, comparison with the "original" reproduction run of the NEP scenario is not always possible. The reason behind this lies in the nature of the recreation process itself. Using different models leads to different results, even if the context stays the same. In order to meet the NEP KPIs, the models, especially the ESM, are forced into an equilibrium (in terms of installed capacities) which might deviate from the global optimum. Most scenario variations allow some kind of investment, which the model might identify as cost-optimal even without further changes. But for the purposes of the recreation, these investment options are deactivated.

The scenario comparison design needs to account for this methodological offset. We therefore relax the constraints relating to the key component of the scenario variation to identify the "natural" equilibrium of the model with regard to this specific component. **We call this scenario the "base" scenario of the cluster in question. In the tables above, we refer to this mainly as a "reference",** because it still represents the NEP. In the variation scenario, we then change one of the framework assumptions, e.g. the availability of decentral flexibility. The resulting reaction from the model is then measured against the base scenario, and not against the original NEP scenario, which would also include the methodological offset of our toolchain.

7.0

SCENARIO DEVELOPMENT/ MODELLING APPROACH

7.1 MODELS

In this study we developed and used a novel toolchain of models to generate new insights, as briefly mentioned in 5.5.

After defining relevant scenarios, we analysed them using an energy system model (described in 7.1.1). An energy system model can generate insights into a sector-coupled energy system that also takes account of investment decisions with a low spatial resolution. These results were then transferred to a market model (described in 7.1.2). The market model works fundamentally like the energy system model but reduces the technical scope to the electricity sector. In addition, the market model assumes that the energy infrastructure (power plants, storage systems, interconnectors) is fixed, i.e. no investment options are allowed. This initially reduces complexity, which allows for a higher spatial and technological resolution. The market model delivers detailed information on dispatch and cross-border flows. This data can then be used in the grid model (described in 7.1.3). This model analyses the effects of the calculated dispatch on the power grid and can evaluate network overloads and requirements for redispatch.

The main aspects of the different models are compared in Table 17. Additional details can be found in the Appendix.

TABLE 17:
Overview of scope and type of models used

	Energy System Model	Market Model	Grid Model
Considered energy sectors	Sector-coupled (includes electricity, heat, gas, transport)	Power sector with exogenous information on electricity-related sector-coupling technologies	Power sector only
Model type	Optimisation: Minimise overall energy supply cost. Investment decisions (myopic approach) and dispatch optimisation per target year	Optimisation: Minimise electricity supply cost. Dispatch optimisation per week per target year	Simulation: Simulate load flows for all hours in a target year
Level of technological aggregation	Highly aggregated (representation on technology type level)	Detailed: Depiction of individual units	Detailed: Depiction of individual units and grid assets
Main tasks	Energy system planning (capacities, sector integration level, dispatch)	Power system operation, adequacy Key Performance Indicators (KPIs)	Transmission grid utilisation, redispatch needs

7.1.1 ENERGY SYSTEM MODEL

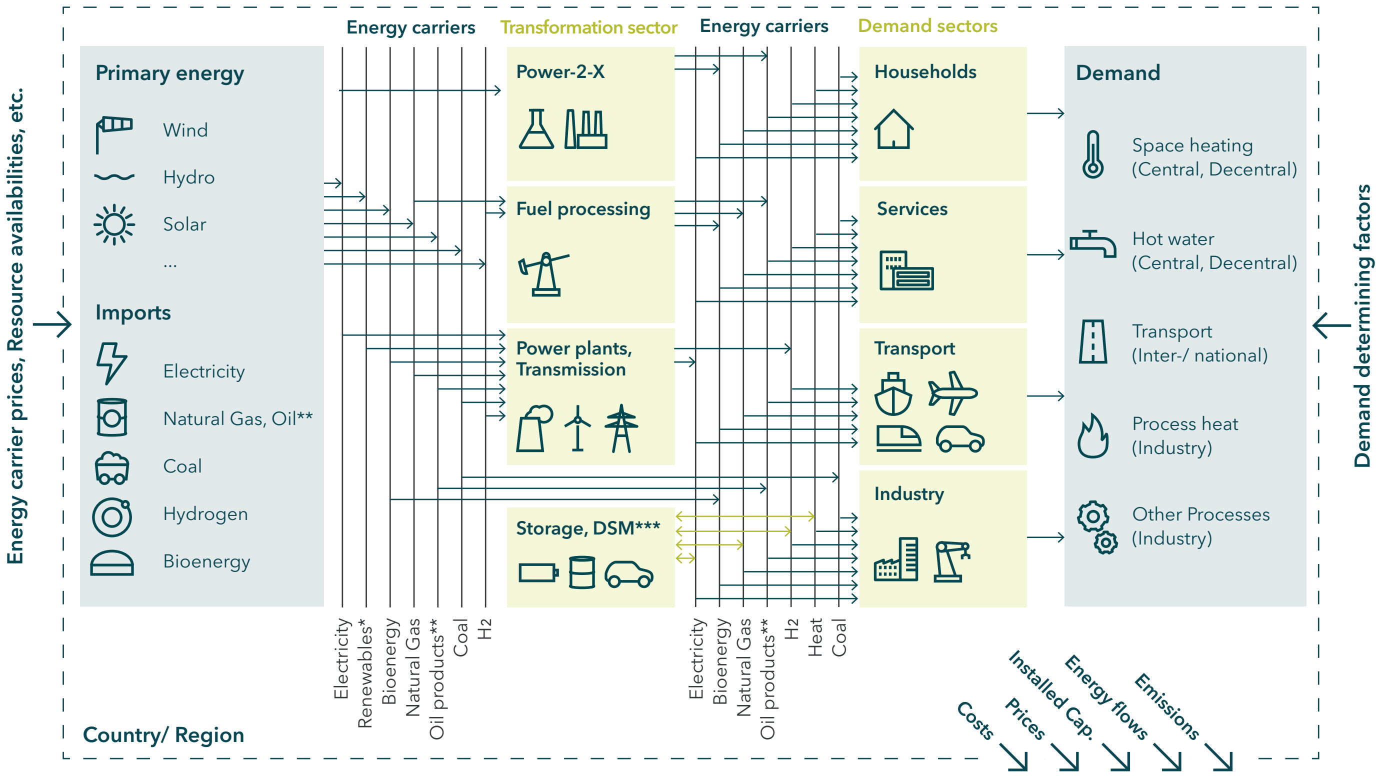
The Energy System Model (ESM) is a version of the open-source model Python for Power System Analysis – Europe – Sector Coupling (PyPSA-Eur-Sec) which was forked in 2020 and has since developed independently. Several new features of PyPSA-Eur-Sec and PyPSA-Eur have, however, been implemented in the model.

Fundamentally the model is an optimisation model of the sector-coupled European energy system, with the objective of ensuring minimal system costs. This broad view enables us to work out a cost-efficient electricity system in Europe embedded in a comprehensive energy system. In an electricity-only model the dispatch of electrolysers, for example, is not optimised in terms of the needs of the hydrogen system but is simply an exogenously defined demand curve. Looking at the entire energy system, sector-coupled assets such as electrolysers and heat pumps can be modelled more realistically, and the model has more flexibility regarding ways of meeting energy needs. This approach means, on the other hand, that the spatial resolution needs to be quite low to reduce computational efforts. How we achieve a higher granularity for our results will be explained in the following chapters.

In this study the years analysed were modelled based on a total of 8,784 hours for Germany and its neighbours and 2,928 hours for the other modelled regions. This means that all the time steps in a subject year are optimised together. Investment decisions are made for the whole year, and demand must be met in every time step. Availabilities of renewable power plants are parameterised for each modelled region.

The model covers the whole energy system as seen in Figure 8. Energy carriers can be converted, and different sectors are connected to one another as well as different levels of the production chain. Inputs are availabilities of technologies, techno-economic parameters, demands, grid restrictions and the installed capacities, as well as the political framework. In the end the model returns installed capacities, grid expansions, energy flows, CO_2 emissions and costs for each year analysed.

FIGURE 8:
Coverage of the ESM



*Renewables include energy sources such as wind, photovoltaic (PV), and others
** Oil products ecompass petroleum (crude oil) als weelll as naphtha (used in the chemical industry) and kerosene (used i aviation) derived from the Fischer-Tropsch synthesis
*** Demand-Side Management (DSM) covers the residential, industrial, and transportation sectors, including Vehicle-to-Grid (V2G) applications in the transportation sector

Several new features were developed for the model when this study was conducted. The development process was structured in releases that took place every few weeks and enabled new features for the model. This workflow always ensured a functioning model and the ability to calibrate new features while additional features were under development. Some of the most important are explained in the following.

Autarky constraints
To assess the effects of a higher energy resilience in the European energy system with regard to import dependency, constraints were implemented to deal with minimum and maximum energy imports for each list of regions for different energy carriers. Autarky levels can be set for electricity, hydrogen and all energy carriers in total. It is important to note that the constraints cover only balance sheet autarky and do not enforce total energy independence.

Energy Not Served
Typically, energy system models cannot consider energy not served since that would be an infeasibility. For this study we implemented a new "technology" in the sense of Energy Not Served which can generate the needed energy at a very high marginal cost. This marginal cost represents the value of lost load which would occur if the demand could not be covered.

Different meteorological years
For most optimisations for different consecutive years, the assumed meteorological input data does not change. This means that in every optimised year (2020 / 2030 / 2040 / 2050) the normalised production potentials for renewable energies and the heat demand curve are the same. To investigate the effects of climate change, we implemented a functionality that allows us to define different meteorological input data for either a specific or all optimised years.

Weather-dependent heat demand
In this study we also analyse projected meteorological years for different climate pathways, for which no corresponding demand curve was available. Using the 2012-based demand curve would have led to a mismatch between generation and demand, especially for heat demand which is relatively sensitive to temperature. To tackle this problem, we implemented a weather-dependent heat demand curve calculation in our model.

Distribution grids
The implementation of distribution grids is a major development of this study and is described in detail in 7.3.3.

7.1.2 MARKET MODEL

The electricity market model simulates the generation and consumption of electrical energy in the European electricity system to achieve economic optimisation of the use of electricity generation technologies and flexible loads. The aim is to minimise variable costs by considering various input variables such as electricity consumption, renewable energies, conventional power plants and storage. Optimisation is carried out step by step and takes seasonal effects and technical restrictions of the power plants into account. Flexible loads are also optimised to minimise costs in order to reduce electricity consumption at high prices and lower the overall costs of the system. A more detailed description can be found in German Transmission System Operators (2023).

Curtailment sharing has a special role to play. The main aim here is to achieve a fair distribution of unmet demand (Energy Not Served, ENS) and not to achieve a random allocation to individual or multiple market areas and time steps. A detailed description can be found at doi.org/10.1016/j.apenergy.2024.124679

This is ensured by the following formulations in the dispatch model:

/ Local matching constraint: It must not be exported when there is a shortage.

/ Linearised quadratic minimisation of the curtailment ratio: This method ensures a fair distribution across zones and time segments. The curtailment ratio is a ratio of ENS to demanded load and available generation.

7.1.3 GRID MODEL

In this analysis, we used INTEGRAL (FGH, 2025) for tasks such as load-flow calculation, outage simulation, and load-flow optimisation. We determined the voltage values for the nodes based on their magnitude and phase. For branches and transformers, we analysed electricity flows and losses in terms of active and reactive power, as well as the levels of current and percentage loads. We also calculated the power balance and transmission losses. Automatic transformer tap adjustments and balancing of secondary control power were carried out. Outage simulation helped us to analyse the grid for equipment overloads in case of failures of grid components or changes in feed-in and load values, transformer tap positions, nominal voltages, and switching positions. The linear load-flow optimisation module was used to reduce or eliminate grid congestions by changing the set point of high-voltage direct current transmission lines and phase-shifting transformer tap positions. All relevant branches in Germany are considered as part of the overall optimisation question. Overloads often remain in the electricity grid when load flow optimisation has been performed. Redispatch is therefore used to solve the remaining problems in the power grid.

Based on the market simulations carried out in the study, the robustness of the existing plans is examined as part of the grid modelling. The starting point for this is the confirmed grid for NEP2037/2045 in the 2023 version (NEP23). Foreign countries are mapped analogously to NEP23 using the TYNDP22. Load flow calculations are carried out for the investigation using the methods described above, and resulting violations are examined with a focus on projects in the NDP23 in the TransnetBW control area, both confirmed and unconfirmed. The projects are examined in respect of several meteorological years to be able to consider the robustness of the projects comprehensively.

7.2 MODEL COUPLING

7.2.1 MODEL INTERFACES

ESM – Electricity Market Model Interface
The ESM-MS-Toolbox is a Python package designed to facilitate the interface between the Energy System Model (ESM) and the electricity market model. Combining ESM output data, formatted as PyPSA networks, with the electricity market model input data from the 2023 Network Development Plan(NEP23) ensures consistent and comprehensive integration of energy system and market data. The resulting datasets serve as input files for the electricity market model, bridging the gap between energy system modelling and electricity market simulations.

ESM Output Data and Integration
The ESM output networks provide both master data and time series data. Master data includes installed capacity and storage size per energy carrier, while time series data covers generation, demand, and availability profiles for different energy carriers. To enhance the usability of this data, the electricity market model input from NEP23 extends the dataset by incorporating additional parameters such as regionalisation, CO2 and fuel prices, storage inflow parameters, cross-border transmission parameters (NTC) and controlling power requirements. These additions help to fill potential data gaps, ensuring a more robust market model representation.

/ **Demand Representation:** Demand data is processed regionally. Outside Germany, demand is aggregated per market area as a conventional load. Within Germany, it is disaggregated into categories such as conventional demand, industrial consumers, electromobility, home battery storage and heat pumps. The ESM differentiates between energy carriers with a finer granularity, so classifications are re-aggregated to align with the electricity market model.

/ **Generation Data Integration:** Generation data comes mainly from ESM, supplemented by NEP23 where needed. Conventional plants are mapped by installed capacity and availability per market area. Renewable sources (biomass, wind, solar, hydro) are mapped based on installed capacity, availability and generation time series from ESM.

/ **Storage Representation:** Storage technologies are modelled using a hybrid approach that draws from both ESM and NEP23 data. Storage levels from NEP23 are used, while storage size is sourced from ESM. Hydro storage inflow is taken from ESM and distributed among technologies (pumped storage and storage water) according to NEP23 inflow allocations.

/ **Demand Side Management (DSM):** DSM integration uses ESM and NEP23 data. Industrial DSM and non-German DSM availability are from NEP23. ESM data is used to model large heat pumps, electrode heating boilers, and electrolysers function as switchable loads, with electrolysers also included for non-German market areas.

/ **Other Key Input Data:** CO2 and fuel prices are sourced from NEP23. Network Transmission Capacity (NTC) is derived from NEP23 connection data, while the ESM provides time series for cross-border electricity flows. Germany's control power requirements are integrated as per NEP23.

Technology Depiction Mapping
The ESM-MS-Toolbox facilitates the transfer of electricity demand data from the ESM to the electricity market model in multiple ways, depending on the technological category. This flexible integration allows for differentiated modelling of DSM processes and enables the assessment of system flexibility. The following sections outline the specific data transfer and representation approaches for key technology classes:

Home Battery Storage Systems
The electricity demand from home battery storage systems in the ESM can be transferred to the electricity market model in three distinct ways:

/ As a fixed time series, ensuring that demand follows a predefined pattern.

/ As installed capacity without a fixed load profile, allowing the market model to determine utilisation.

/ As a hybrid approach, where a portion of the demand (e.g. 60 %) is fixed, while the remaining share (e.g. 40 %) is flexible.

This flexibility enables precise control over how much of the home battery storage demand is optimised dynamically in the electricity market model.

Electromobility
The electricity demand from electromobility can be transferred in different configurations:

/ As a fixed time series, where demand follows a predetermined schedule.

/ As a shiftable DSM process, allowing demand to be rescheduled within a defined time window.

/ As a hybrid model, where part of the demand follows a fixed schedule, while the rest can be shifted dynamically.

When modelled as a DSM process, the electricity market model can shift the demand by up to 12 hours, providing enhanced flexibility for system operation.

Household Heat Pumps
The demand from household heat pumps follows a similar integration approach to electromobility:

/ As a fixed time series, reflecting a predetermined consumption pattern.

/ As a shiftable DSM process, allowing demand adjustments within a flexible time window.

/ As a combination of both, distributing demand between fixed and flexible shares.

For DSM modelling, the demand can be shifted by up to six hours, ensuring additional flexibility in system operation.

Large Heat Pumps and Electrode Heating Boilers
Unlike the previous technologies, large heat pumps and electrode heating boilers are exclusively modelled as switchable DSM processes in the electricity market model. Their operation depends on an activation price, which is derived from the average heat demand recorded in the ESM. If the activation price is reached, activation follows these principles:

/ If the heat demand exceeds the combined installed capacity of both technologies, the technologies are considered fully available.

/ If the heat demand is lower than the combined installed capacity, the availability is computed as heat demand divided by installed capacity

This modelling approach ensures that these heating technologies are dispatched only when economically viable within the electricity market framework.

Electrolysers
Electrolysers are also modelled as switchable DSM processes, operating based on a dynamically determined activation price. This price is calculated using the average hydrogen price, derived from the ESM, with high price outliers removed to improve stability.

By incorporating electrolysers into the electricity market model as demand-side flexibility assets, their operation can be optimised based on prevailing market conditions.

7.2.2 REGIONALISATION

Regionalisation of the Electricity Market Model
The regionalisation process for the electricity market model follows a multi-step approach to ensure consistency between the ESM and the market areas defined in the 2023 Network Development Plan (NEP23). This methodology ensures that market-specific data, including installed capacities, electricity generation, and demand, are accurately allocated across different geographical regions. A coherent representation of regional electricity system dynamics within the electricity market model is achieved through structured processes of aggregation, disaggregation and targeted allocation.

As a subsequent step, the adjusted ESM data undergoes further regionalisation using different methodologies tailored to electricity demand, electricity generation, and demand-side management.

Market Area Alignment
In the initial step of regionalisation, data from the ESM is processed by aligning the market areas between the ESM and NEP23. In most cases, a one-to-one correspondence exists between these areas. However, there are exceptions in the following cases:

/ Germany: For the sake of local effects, the ESM distinguishes five market areas which are aggregated in post-processing to one market area, whereas NEP23 defines a single market area.

/ Spain: The ESM differentiates between two market areas, while NEP23 considers only one.

/ Italy: The ESM includes seven market areas, whereas NEP23 consolidates them into two, with one of these being a direct one-to-one match with an ESM market area.

/ Norway: The ESM defines a single market area, while NEP23 differentiates three.

/ Sweden: The ESM aggregates Sweden into one market area, whereas NEP23 identifies four separate regions.

Adjustment Methodology
To harmonise the datasets, adjustments are made to redistribute installed capacities, electricity generation, electricity demand, and hydro power plant inflows:

/ Disaggregation: For Italy, Norway and Sweden, where ESM market areas have a lower resolution than NEP23, demand, installed capacities, electricity generation and hydro power plant inflows per energy carrier are allocated following the NEP23 distribution for respective market areas.

/ Aggregation: For Germany and Spain, where ESM defines more granular market areas than NEP23, data is aggregated to match the NEP23 structure.

/ No Adjustments: Regions with identical market area resolutions require no modifications.

Regionalisation at power plant level
For energy carriers modelled on a plant-specific basis within the electricity market model, installed capacities as well as storage capacities and inflows (if relevant for the energy carrier) are regionalised at the individual power plant level to align with the regionalisation structure defined in NEP23.

The installed capacity of individual power plants is determined by calculating their proportional share of total installed capacity for each energy carrier within a given NEP23 market area. This relative share is then applied to the total installed capacity per energy carrier and market area as provided by the ESM, resulting in the absolute installed capacity of each power plant.

Storage capacities and inflows, if relevant for a specific energy carrier, are calculated using the same approach.

Regionalisation at Network Node Level
For Germany, further regionalisation of electricity demand, grid losses and generation data, for energy carriers that are not regionalised at the power plant level, is carried out at network node level.

Regionalisation of Electricity Demand and Grid Losses
For each demand category, including:

/ Conventional demand
/ Large industrial consumers
/ Electromobility
/ Home battery storage
/ Heat pumps

the contribution of individual consumers to the total demand is determined based on their share within NEP23. These shares are then applied to the total demand from the ESM, ensuring an accurate allocation. The same methodology is used for the regionalisation of grid losses.

Additionally, demand-side management (DSM) data for large heat pumps, electrode boilers, and electrolysers is further regionalised within the German market area. This is achieved by applying the NEP23 regionalisation methodology for each energy carrier, ensuring consistency with the overall framework.

Regionalisation of Generation Data
Generation data for biomass, photovoltaic and wind energy (onshore and offshore) is further refined to align with the regionalisation defined in NEP23. The installed capacity at individual network nodes is determined by calculating their proportional share of the total installed capacity for each energy carrier within the German market area. This relative share is then applied to the total installed capacity per energy carrier and market area, as provided by the ESM, to derive the absolute installed capacity at each network node.

A similar approach is used to determine electricity generation at individual network nodes, utilising total electricity generation for each carrier from ESM and NEP23, along with specific generation data from NEP23 at the network node level.

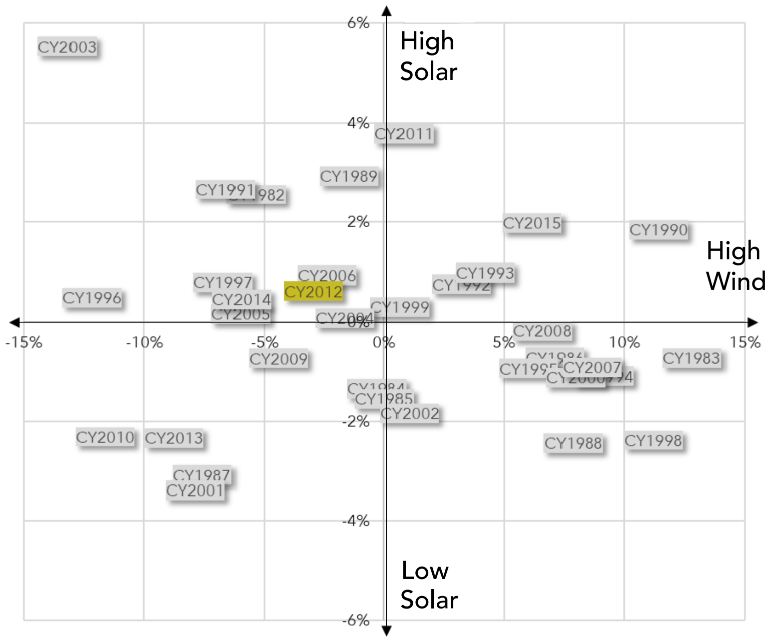
7.3 PREPARATION OF INPUT DATA

7.3.1 METEOROLOGICAL DATA SELECTION METHODOLOGY

In the regulatory processes for planning electrical infrastructure, meteorological effects have so far been taken into account on the basis of situations that have occurred historically. Determination of the volatile generation profiles from renewables and the temperature-dependent components of the electrical load therefore follows a specific meteorological year. In certain cases, temperature and wind speed also increase the potential transmission capacity of overhead lines (dynamic line rating: DLR).

While the planning process for electricity grid infrastructure at European level (TYNDP) uses several meteorological years, the German Network Development Plan up to the 2023 version uses only meteorological year 2012. This is characterised by comparatively lower wind feed-in with slightly higher PV yields in the annual total (Figure 9). To date, cases relevant to grid design in the context of the NEP have been characterised primarily by high wind feed-in (reference scenario framework NEP 2025 consideration of climate impact effects).

FIGURE 9:
Classification of meteorological years from 1982 to 2015 based on wind and PV feed-in relative to long-term average. The data basis is the TYNDP 2017. Shown are the normalised yields from wind and PV generation in Germany. For future scenarios, figures may differ to a certain extent due to regionalisation effects.



The relevant meteorological parameters may change in the future due to anthropogenic climate change. This applies both to the development of mean values and to the frequency and intensity of extreme values.

The aim of this study is to examine the impact of several projected meteorological years on the energy system, and particularly the current plans for the electricity grid infrastructure. The focus here is on examining the robustness of existing measures and projects to changes.

Identification of projected meteorological years for robust planning of the electricity grid infrastructure

The stakeholder survey conducted in the preparatory phase of this study (see Appendix) calls for appropriate consideration of expected future meteorological years in planning studies.

Due to the high level of uncertainty, several climate models using different socioeconomic developments and also developments in greenhouse gas concentrations were used to select suitable meteorological years.

Climate models are essential tools in climate research, contributing to the estimation of potential future climate changes and the understanding of the impacts of human activities on the climate. A significant source for climate model runs in this field is the Coupled Model Intercomparison Project Phase 6 (CMIP6). CMIP6 provides a variety of global climate models developed by various institutions worldwide. These models simulate the spatial distribution of various meteorological variables in three dimensions, considering the interactions between the atmosphere, ocean, cryosphere and land. Climate change is primarily caused by greenhouse gas emissions, which trap solar energy in the atmosphere and increase temperatures.

Shared Socioeconomic Pathways (SSPs) describe possible future socioeconomic developments. There are five main scenarios defined by the IPCC (2018, especially Table 2.3; 2025a; International Panel on Climate Change): SSP1 (sustainable/ green), SSP2 (moderate/middle of the road), SSP3 (regional rivalry, high population growth and large regional differences), SSP4 (inequality, large social and economic disparities) and SSP5 (fossil-fuelled development).

Representative Concentration Pathways (RCPs) represent different possible concentrations of greenhouse gases. There are four main scenarios: RCP2.6 (very low emissions), RCP4.5 (medium emissions), RCP6.0 (medium to high emissions) and RCP8.5 (very high emissions, 'business-as-usual' scenario).

Within CMIP6, these scenarios are merged to project future climate changes and to investigate the effects of different emission pathways and socioeconomic conditions on the climate. For example, the extreme scenario SSP5-8.5 arises from the combination of SSP5 and RCP8.5. By incorporating this scenario, the study aims to provide a robust and comprehensive assessment of future energy generation under ‚worst case' conditions, considering extreme weather events and their potential impact.

In climate change studies, ensemble means are often used, which tend to average out extreme situations. However, it is important to consider extreme events as well. Analysing a complete ensemble is computationally intensive and impractical for this study, so the selection process focuses on extracting a few key, relevant scenarios from the ensemble.

Due to the strong inter-annual fluctuations in the model results, the results of several climate models for one decade (2045-2054) were compared with each other for the target year 2050. In this study, future meteorological years projected by climate models and showing typical weather characteristics were used. These typical characteristics are chosen as they had already led to critical situations in the electricity sector in the past:

/ New Average (NA): A new expected average for Germany to determine a robust portfolio:

  In order to determine a new expected normal meteorological year, the projected irradiation, temperature and wind speed for the period in question were compared with each other. A mean value was calculated for all distributions. The climate model run with the smallest statistical deviations from the mean distribution (equally weighted across all variables) was used as the average meteorological year.

/ Extreme Weather 1 (EW1): A meteorological year with **annual far below-average RE generation in the whole area of EU27+3**. Due to the reduced feed-in across Europe, the maximum required capacity and storage reserve can be determined.

/ Extreme Weather 2 (EW2): A meteorological year with a **pronounced cold phase in Germany** – the primary objective is to investigate the necessary generation structure in the heat and electricity sectors. The selection was based on the largest negative deviation of the distribution curves of the temperature from the mean value distribution in the temperature range below 0°C.

/ Extreme Weather 3 (EW3): A meteorological year with an extended summer heat wave in Germany. Increased temperatures, particularly in summer, reduce PV yields as well as the transmission capacity of the electricity grid and are often coupled with reduced hydropower yields. As climate change progresses, years with extended heat waves are likely to occur more frequently, which is why it is particularly important to analyse this characteristic. Two different metrics were used to identify a meteorological year with an extended heat wave. Firstly, consecutive days with at least one hour with an average temperature in Germany of> 28°C were counted. In addition, the "Standardised Runoff Index" was calculated as an indicator of "dryness". The model result with the highest combined values in both metrics was selected as EW3.

An overview of the selected models and year combinations as well as additional details about all climate models evaluated can be found in the Appendix.

The expected energy yields were estimated by combining country-specific and technology-specific averaged performance curves with the respective meteorological climate model results and the projected capacities for renewable generators of the TYNDP22 Distributed Energy Scenario. The climate model-year combination with the expected lowest annual energy yields was used.

Methodology of Downscaling to Improve Spatial Resolution in Climate Projections

Applying different climate projections helps to avoid specific biases in the results from a single model, but it poses a significant challenge for the comparability and merging of the data. For example, climate projections differ greatly in terms of their spatial resolution. The model CCCma__CanESM5__r1i1p2f1 has a spatial resolution of about 310 x 130 km, while the model MOHC__HadGEM3-GC31-MM has a resolution of about 60 x 40 km. The models used in this study are provided with a resolution of 30 x 30 km. The climate projection data was therefore downscaled to this resolution using statistical methods.

Downscaling is a technique used in climate research to transfer information from large-scale climate models to smaller spatial and temporal scales. This is important for better assessing local and regional climate impacts, vulnerabilities, risks, and resilience. There are two main methods of downscaling: Dynamical and statistical downscaling. Dynamical downscaling uses regional climate models to create detailed projections, while statistical downscaling is based on statistical relationships between large-scale climate models and local climate data.

In this study, Principal Component Analysis (PCA) was used as a statistical downscaling method to derive seasonal (monthly) typical spatial patterns from high-resolution ERA5 data (1992-2021). These patterns are applied to coarse-resolution climate data to reconstruct fine spatial structures that are missing in the coarse data. Figure 10 exemplifies the temperature distribution of the climate projection data before and after the PCA transformation. After the transformation, detailed features such as coastlines and orographic structures, including the Rhine Rift Valley, are clearly visible.

The methodology includes the following steps:

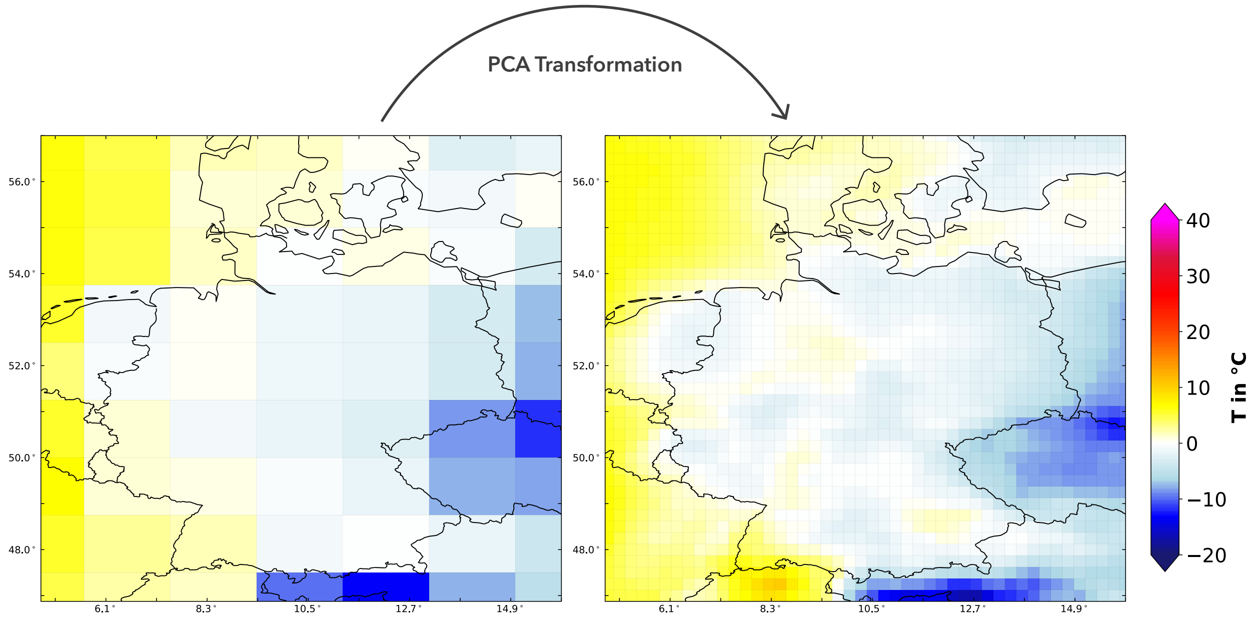
/ Data Preparation: ERA5 data is divided by months and scaled to create a uniform basis for analysis.

/ Conducting PCA: Monthly PCAs are performed, with the data being scaled and transformed to transfer spatial variance.

/ Creating Background Fields: The transformed climate data is interpolated onto the high-resolution ERA5 grid to create background fields.

/ Adding Residual Fields: The difference between the original climate data and the background fields is calculated as the residual field and interpolated. The sum of the background and residual fields results in the final, higher-resolution climate data.

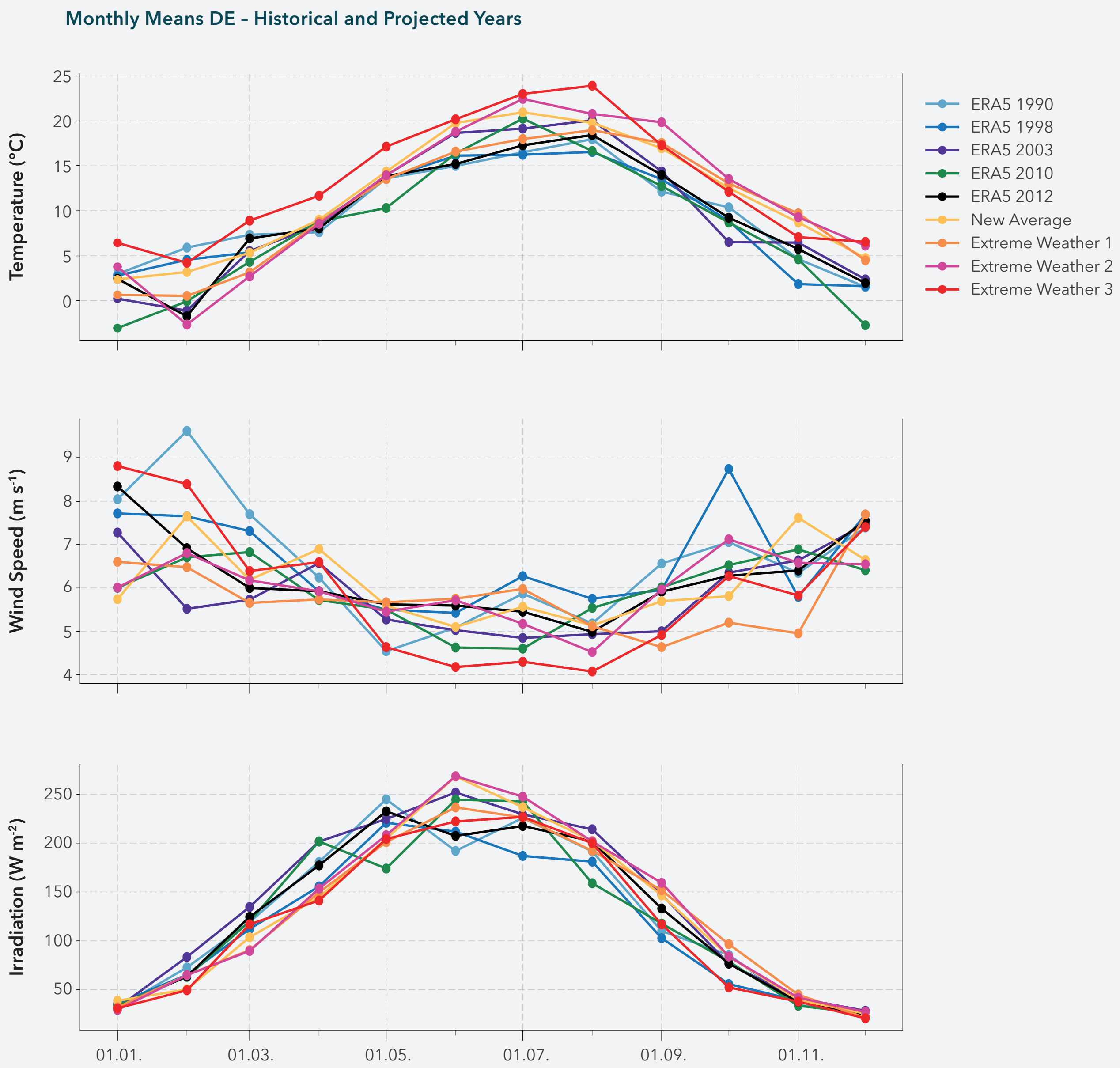
FIGURE 10:
Examples of spatial distribution of the temperature (T) of a climate projection. Left: Coarse resolution. Right: After PCA transformation with high-resolution patterns



7.3.2 METEOROLOGICAL DATA COMPARISON

Figure 11 and Figure 12 show the monthly averages of meteorological variables of the climate projections compared to the historical years 1990, 1998, 2003, 2010 and the reference year 2012, for Germany and Europe. The historical years were identified as extreme years of the four quadrants of Figure 9, representing the maximum inter-annual variability. These years are used as a basis for comparison with the projected extreme meteorological years. Table 18 lists the differences in spatially and annually averaged values in the climate projections and the historical extreme years compared to the reference year 2012. It is evident that climate change results in an increase in temperature in all four climate projections. On an annual average, the temperature in Germany rises between 1.1°C in the EW1 scenario and 3.9°C in the EW3 scenario. The EW2 scenario in February reveals a cold wave, similar to the one observed in 2012.

FIGURE 11:
Mean monthly values for temperature, 100 m wind speed, and solar irradiation averaged over Germany in the climate projections for the scenarios NA, EW1, EW2, EW3, and the historical years 1990, 1998, 2003, 2010, 2012



The wind speed in the climate projections remains slightly below the values of the historical reference year, with the EW1 scenario showing the largest decrease of -0.5 m/s in the annual average for Germany. A decline is projected for the autumn and winter months in particular. The EW3 scenario exhibits greater seasonal variability compared to the other meteorological years. On an annual average, the difference in Germany compared to the reference year 2012 is -0.3 m/s. Figure 11 and Figure 12 show that in the EW3 scenario, wind speed is particularly high in the winter months, while it is significantly lower than the values for the other weather scenarios in the summer months.

FIGURE 12:
Mean monthly values for temperature, 100 m wind speed, and solar irradiation averaged over Europe in the climate projections for the scenarios NA, EW1, EW2, EW3, and the historical years.

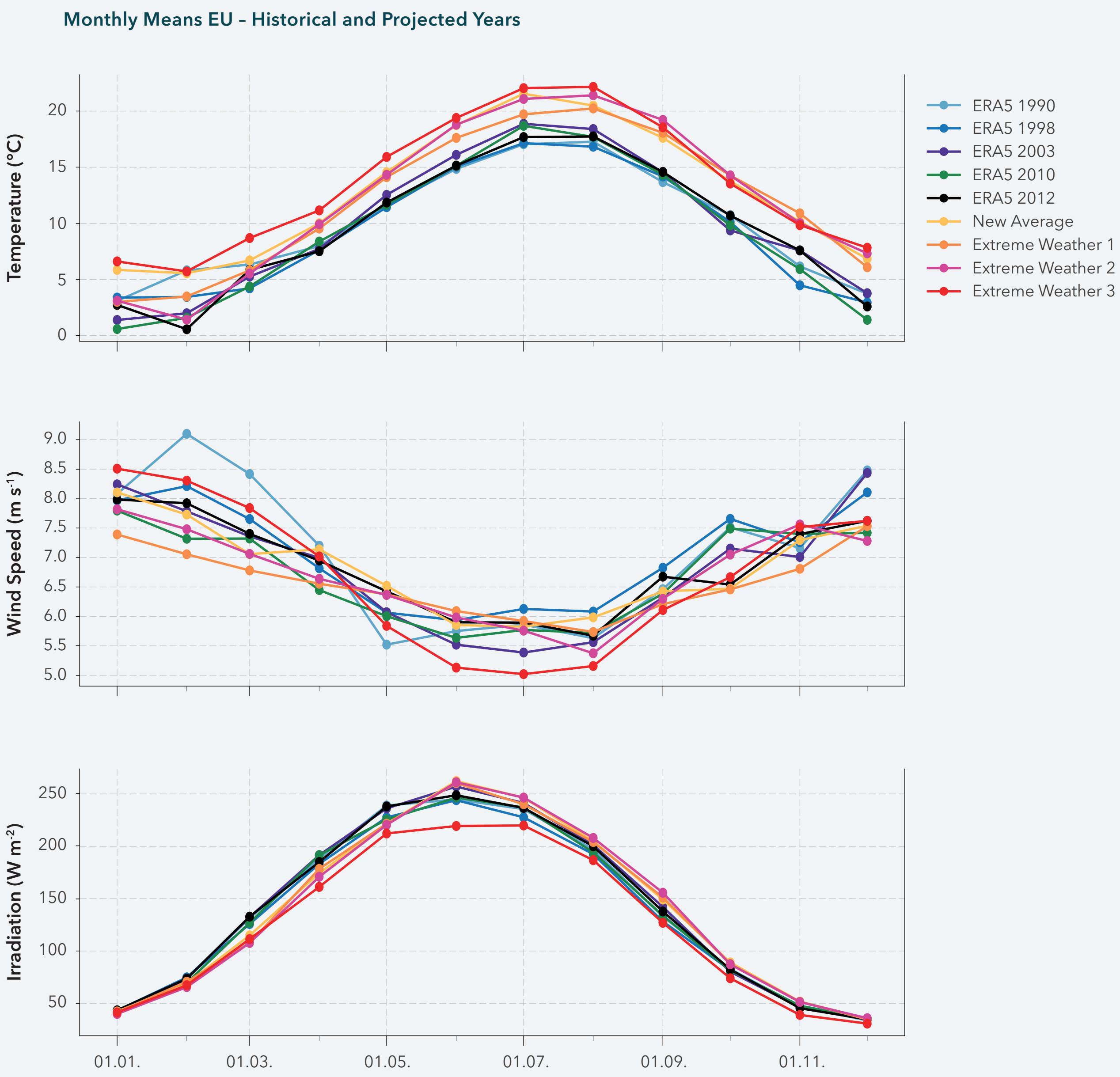


TABLE 18:
Differences in spatially and annually averaged values for temperature (T), wind speed at 100 m height (v), and global horizontal irradiance (GHI) over Germany and Europe between the climate projections and the historical extreme years compared to the reference year 2012.

Wind shadowing, also known as wind wake effect, occurs when offshore wind turbines disrupt the wind flow, leading to reduced wind speed and increased turbulence behind the turbines. This phenomenon can negatively impact the efficiency of downstream turbines, resulting in lower energy production. In the study, this effect is accounted for by scaling the energy production of the offshore turbines to ensure that the full load hours of the NEP are met.

	GERMANY			EUROPE		
	T K	v m/s	GHI kWh/m²/a	T K	v m/s	GHI kWh/m²/a
NA	+2.2	-0.1	+0.4	+3.1	0.0	+1.2
EW1	+1.1	-0.5	0.6	+2.3	-0.3	-7.3
EW2	+3.9	-0.3	-2.8	+3.9	-0.1	-122.9
EW3	+2.2	-0.2	+1.2-	+2.6	-0.1	-6.8
1990	+0.3	+0.4	-0.3	+0.3	+0.2	-7.4
1998	-0.2	+0.4	-3.4	-0.3	+0.2	-33.9
2003	+0.3	-0.4	3.4	+0.2	0.0	+13.6
2010	-1.2	-0.3	-0.9	-0.4	-0.1	-20.7

7.3.3 DISTRIBUTION GRIDS

An individual feature was developed to endogenously consider the grid expansion costs at the low-voltage grid level in the sector-coupling energy system model used in this study. The focus of this development was the model-based consideration of residual loads (in cases where electricity consumption exceeds generation) and residual feed-ins (in cases where electricity generation exceeds consumption) at all relevant nodes in the distribution grid on an individual basis, and their connection to an investment process, which represents the expansion of transmission grid capacity within the distribution grid in MW. This functionality is implemented indirectly into the model using mathematical constraints, which makes it versatile to configure.

The approach follows the basic idea of mapping electricity flows in the distribution grid in relation to costs, whereby the capacity of the distribution grid is considered to be the decisive factor. The aim was to determine and identify the corresponding residual loads and residual feed-ins which arise at each point in time (called snapshot or time slice) in the model as an endogenous result of the optimisation process.

The residual loads and residual feed-ins at each grid node are influenced by the specific dispatch of electricity-generating and consuming technologies and by the available transport capacity through the corresponding grid. At the low-voltage grid level this relates, for example, to generation from PV or small CHP plants or the general household load, the demand for electricity for charging battery electric vehicles (BEV) or the use of heat pumps to meet heating demands. The dispatch of decentralised, stationary battery storage systems also has a significant impact on the residual load/feed-ins. Eq. 1-3 describe the mathematical approach implemented in the model. All power flows are considered to be positive; their direction of flow is already respected via the algebraic sign in the equations. The exact parameterisation is described in the Appendix.

$$\sum_{Tech \in DS^-} P_{Tech}(t) - \sum_{Tech \in DS^+} P_{Tech}(t) - P^{DS}_{VirtualGen.Load}(t) \leq 0 \forall t \qquad \text{Eq. 1}$$

with:

$P^{DS}_{VirtualGen.Load}$ – power of virtual generator for peak load in distribution system (DS)

$P_{Tech}(t)$ – power of technology in time segment t

DS^+– set of electricity generating technologies in DS

DS^-– set of electricity consuming technologies in DS

t– considered snapshot / time slice

The approach is implemented by introducing new virtual processes (generators in the model) $P^{DS}_{VirtualGen.Load}$, $P^{DS}_{VirtualGen.Feed-in}$ for the residual load and residual feed-in respectively, which act as auxiliary components and are connected to virtual auxiliary buses. The distribution grid can be expanded by optimising the capacity allocation (p_nom_opt) of these virtual generators, which is associated with investment costs (CAPEX). It is also possible to take into account ongoing operating costs (OPEX) by allocating marginal costs to the activity of the virtual generators. Depending on the parameterisation, the latter could be interpreted as operating grid charges. In the objective function of the energy system model, therefore, both the costs of process activity (OPEX) of the virtual generators and the costs relating to the expansion or maintenance of the installed capacity (CAPEX) are considered. The values for the specific investment costs of the distribution grid level stored in the model were calculated on the basis of a dedicated study. For all time slices Eq.2 is therefore true and implicitly incorporated in the model.

$$P^{DS}_{VirtualGen.Load}(t) \leq p\_nom\_opt^{DS}_{VirtualGen.Load} \; \forall \; t \qquad \text{Eq. 2}$$

with: $P^{DS}_{VirtualGen.Load}$ – power of virtual generator for peak load in distribution system (DS)

$p\_nom\_opt^{DS}_{VirtualGen.Load}$ – installed capacity of virtual generator for peak load in DS

t– considered time slice / time segment

Formeln prüfen

Since the energy system model differentiates between exogenously parameterised electric loads (DS_{Load}) and endogenously optimised dispatch of electric appliances such as BEV charging processes or heat pump dispatch, the equation can be written out as shown in Eq. 3. In addition, to emphasise the bivalent role of battery storage systems, which can serve both the consumption and supply side, the corresponding storage variables DS^+_{Bat} and DS^-_{Bat} - are also extracted and listed separately. To relax the model from a mathematical perspective, the equation is reformulated into an inequality. Under cost-optimal utilisation of the available capacities, the optimal solution in a linear optimisation problem, as in this case, will lie at the solution space limit (=0).

$$\sum_{Load \in DS_{Load}} P_{Load}(t) + \sum_{Tech \in DS^-} P_{Tech}(t) - \sum_{Tech \in DS^+} P_{Tech}(t) + \sum_{Tech \in DS^-_{Bat}} P_{Tech}(t) - \sum_{Tech \in DS^+_{Bat}} P_{Tech}(t) - P^{DS}_{VirtualGen.Load}(t) \leq 0 \; \forall \; t \qquad \text{Eq. 3}$$

with: $P^{DS}_{VirtualGen.Load}$ – power of virtual generator for peak load in distribution system (DS)

$P_{Load}(t)$– power of exogenously defined electric load in time segment t

$P_{Tech}(t)$–power of technology in time segment t

DS^+– set of electricity generating technologies in DS

DS^-– set of electric consuming technologies in DS

DS_{Load}–set of electric load technologies in DS

DS^+_{Bat}– set of discharging processes of stationary electric batteries in DS

DS^-_{Bat}–set of charging processes of stationary electric batteries in DS

t–considered snapshot / time slice

The equations shown in Eq. 1 to Eq. 3 apply to the peak load case, in which electricity consumption exceeds the electricity supply within the balance area in question and therefore electricity equal to the amount of the virtual load generator dispatch ($P^{DS}_{VirtualGen.Load}$) is drawn from the distribution grid. Conversely, at certain times, local electricity generation can exceed the local electricity demand at the node in question. This is referred to as the peak feed-in case. At these times, the distribution grid is loaded through feed-ins into the grid. The equations formulated in Eq. 2 can therefore also be formulated for all time segments to cover the feed-in case. Eq. 4 represents the mathematical relationship for the residual feed-in ($P^{DS}_{VirtualGen.Feed-in}$) while Eq.5 represents the implicitly considered capacity equation for the virtual generator for the feed-in case.

$$\begin{aligned}\sum_{Load\in DS_{Load}} \boldsymbol{P_{Load}(t)} + \sum_{Tech\in DS^-} \boldsymbol{P_{Tech}(t)} - \sum_{Tech\in DS^+} \boldsymbol{P_{Tech}(t)} \\ + \sum_{Tech\in DS^-_{Bat}} \boldsymbol{P_{Tech}(t)} - \sum_{Tech\in DS^+_{Bat}} \boldsymbol{P_{Tech}(t)} \\ - \boldsymbol{P^{DS}_{VirtualGen.Feed-in}(t)} \geq \boldsymbol{0}\ \forall\ \boldsymbol{t}\end{aligned} \qquad \text{Eq. 4}$$

with:
- $P^{DS}_{VirtualGen.Feed-in}$ – power of virtual generator for feed-in in distribution system (DS)
- $P_{Load}(t)$– power of exogenously defined electric load in time segment *t*
- $P_{Tech}(t)$ – power of technology in time segment *t*
- DS^+–set of electricity generating technologies in DS
- DS^-–set of electric consuming technologies in DS
- DS_{Load}–set of electric load technologies in DS
- DS^+_{Bat}–set of discharging processes of stationary electric batteries in DS
- DS^-_{Bat}–set of charging processes of stationary electric batteries in DS
- *t*–considered time slice / time segment

$$\boldsymbol{P^{DS}_{VirtualGen.Feed-in}(t)} \leq \boldsymbol{p\_nom\_opt^{DS}_{VirtualGen.Feed-in}}\ \forall\ \boldsymbol{t} \qquad \text{Eq. 5}$$

with:
- $P^{DS}_{VirtualGen.Feed-in}$ – power of virtual generator for feed-in in distribution system (DS)
- $p\_nom\_opt^{DS}_{VirtualGen.Feed-in}$ – installed capacity of virtual generator for peak feed-in in DS
- *t*–considered time slice / time segment

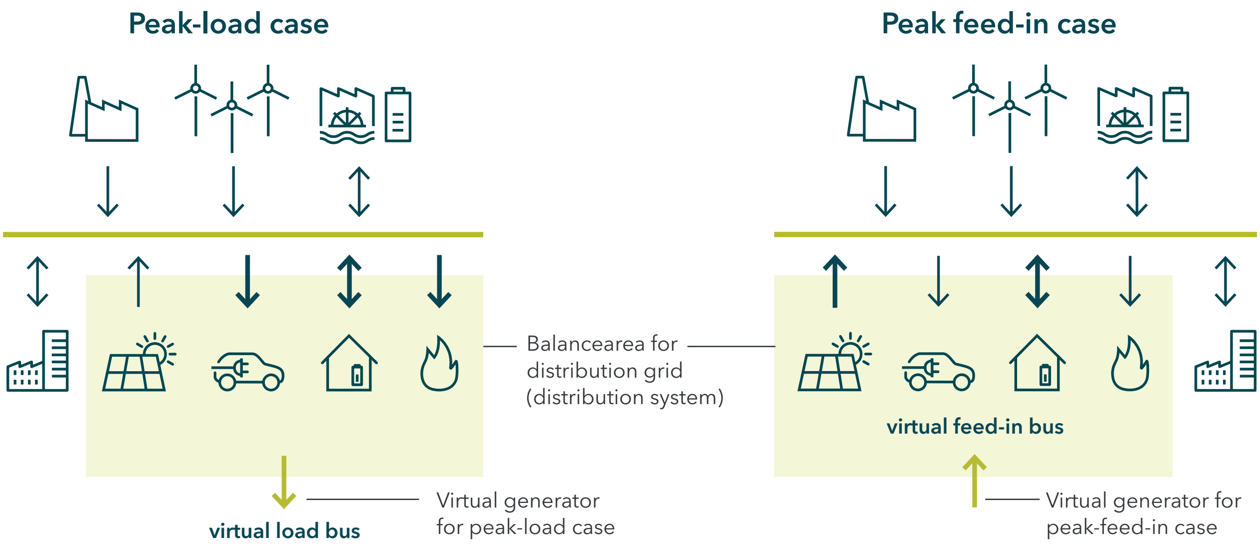
In order to take account of the fact that the capacity of the distribution grid for the load case and feed-in case are not independent of each other, the relationship shown in Eq. 6 was also implemented as a constraint in the model. Both processes modelled as generators represent the same optimised capacity of the distribution grid at the node in question, and their capacity must therefore be set at an identical value. From a physical point of view the direction of the current flow is only a change in the algebraic sign. The optimised capacity is therefore influenced by the maximum absolute value of the dispatch of the virtual load generator and the virtual feed-in generator.

$$\boldsymbol{p\_nom\_opt^{DS}_{VirtualGen.Load}} = \boldsymbol{p\_nom\_opt^{DS}_{VirtualGen.Feed-in}} \qquad \text{Eq. 6}$$

with:
- $p\_nom\_opt^{DS}_{VirtualGen.Load}$ – installed capacity of virtual generator for peak load in distribution system (DS)
- $p\_nom\_opt^{DS}_{VirtualGen.Feed-in}$ – installed capacity of virtual generator for peak feed-in in DS

Figure 13 illustrates the mathematical relationship for the peak-load case (left) and peak feed-in case (right). The area within the dashed lines represents all electricity flows within the distribution grid in question under explicit exclusion of all processes connected to the medium or high-voltage grid as industrial loads, large utilities and commercial-sized battery storage systems. Arrow size represents the amplitude of the respective electricity flow in each of the two cases.

FIGURE 13:
Illustration of the modelled approach for considering distribution grid cost using virtual generators.



The approach enables a realistic representation of the distribution grid infrastructure, which can be individually parameterised and supports the model in the decision-making process for sustainable and economically efficient energy grid planning in the decentral sector.

7.3.4 INITIAL VALUES AND BOUNDARIES

The initial state of the parameterised generation capacities for the base year in the model is mainly based on data from the Global Energy Monitor and the Joint Research Centre Data Catalogue of the European Commission. These databases contain details of plant capacities, their type and geographical location, which are assigned to the modelled regions and specific technologies. The information is updated regularly and is available under an open licence. The data for the base year was additionally supplemented by information from the Network Development Plan in Germany (NEP 23) and TYNDP22 at the European level. The latter two also represent the source for the parameterisation of processes, which are of central relevance for this study. This concerns aspects such as battery storage capacities, the dimensioning of other flexibility options and the composition of heat and transport technologies in the individual model regions and subsectors. With regard to infrastructure dimensioning, the cross-border interconnection capacities defined in NEP 23 are used as the basis for electricity grid parameterisation. For gas network modelling, the transparency data of the European Network of Transmission System Operators for Gas (ENTSOG) is processed in the model. No hydrogen networks are assumed in the initial state.

Upper Boundaries
Renewable Energy Potentials
The expansion of additional renewable energies is guided by the policy targets of various processes at both the national and European levels. The upper limit is determined by the maximum value from the scenario framework of NEP23 Scenario B, TYNDP22, and TYNDP24. The specific values are given in the Appendix. The lower limit remains at the level of NEP23 Scenario B, as in the reference scenario.

CO_2 Constraint

In the ESM a CO_2 constraint is defined for each modelled region and year. The CO_2 emission reduction goals correspond to the EU Effort Sharing Regulation, which sets specific goals for 2030 for each member state. In 2050 each modelled region must be carbon neutral. In-between values are interpolated. An exception is Germany where there is the specific goal to reach an 88 % emission reduction compared to 1990 in accordance with national legislation. The model only covers CO_2 emissions and no other greenhouse gas (GHG) emissions. This is due to the dominance of CO_2 as a GHG in the modelled sectors. Other GHG mainly originate in other sectors such as Land Use, Land Use Change and Forestry (LULUCF) and industrial processes. The historical CO_2 emissions in these sectors are therefore being subtracted from the total to achieve a matching CO_2 limit for the modelled sectors. The reduction plan is then applied as a relative reduction of these historic values.

Mobility

The vehicle fleet mix is based on market shares as per TYNDP22. The vehicle technologies modelled in the energy system model include Fuel Cell Electric Vehicle (FCEV), Internal Combustion Engine (ICE), Plug-in Hybrid Electric Vehicle (PHEV), and BEV. The share of flexible and inflexible BEVs is determined by the scenario. In addition, 75 % of the flexibly charged BEVs must be fully charged by 7 a.m. daily.

8.0

KEY RESULTS

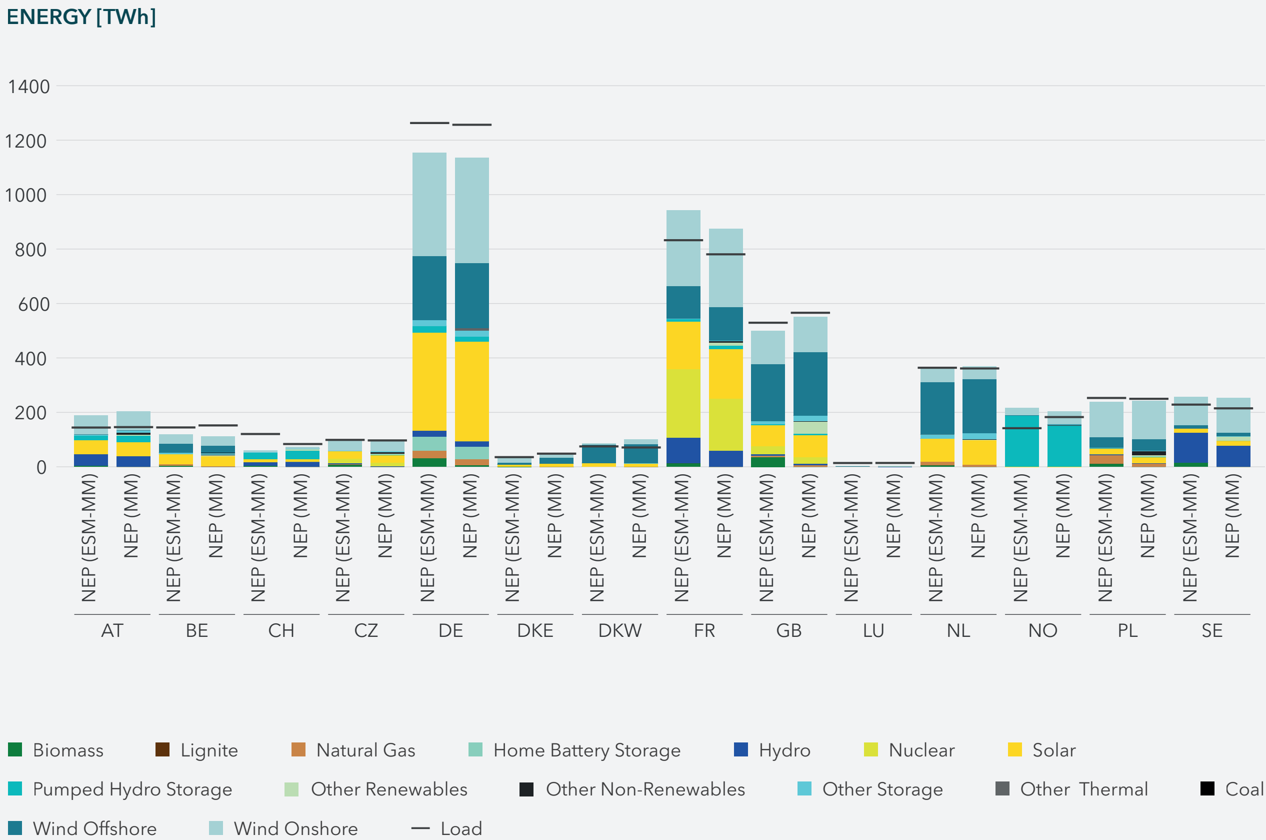
8.1 REFERENCE SCENARIO

In this cluster, the main goal was to reproduce Scenario B (2045) of NEP23, using the tools presented in Chapter 7.1. This scenario then serves as a benchmark for the other clusters and scenarios.

The results of the market model coupled with the ESM (labelled as NEP (ESM-MM) in Figure 14, corresponding to scenario N0 in Table 5, Chapter 6.2.1), are compared with the results of the BID3 recalculation of Scenario B (2045) in NEP23 (labelled as NEP (MM) in Figure 14, corresponding to scenario N0b in Table 5), with the latter serving as a benchmark.

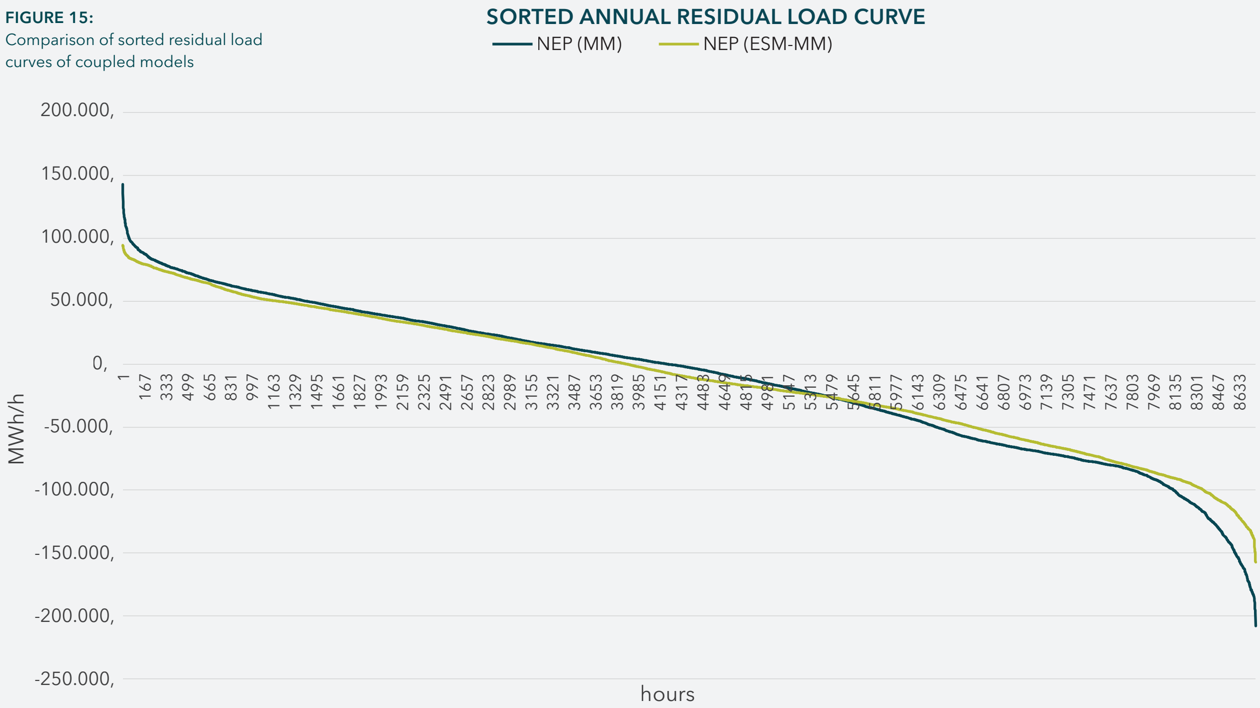
Generation in Germany and its neighbouring countries varies slightly (see Figure 14). The modelling in the NEP (ESM-MM) run reveals shifts in renewable energies (-22 TWh for wind and PV) and loads. As a result, these shifts influence the flexible use of gas-fired CHP and storage systems. Differences in methodology for generating the RE time series in the ESM and NEP23 lead to slight differences in the annual energy volumes of RE generation.

FIGURE 14:
Comparison of electricity generation of coupled models (NEP (ESM-MM): Market model results after ESM run; NEP (MM): NEP23 recalculation with market model BID3)



The amount of Energy Not Served in Germany is reduced from 39 GWh to 0.9 GWh, as the residual load is lower in the high hours (Figure 15). This effect derives from the comprehensive optimisation approach applied in the ESM. Sector-coupled technologies and decentral flexibilities are optimised with perfect foresight and therefore provide the system with greater flexibility and reduce critical situations. This high level of flexibility is consistent with the scenario storyline, i.e. that flexibilities will be utilised as efficiently as possible in the future decarbonised energy system.

FIGURE 15:
Comparison of sorted residual load curves of coupled models



Average electricity prices are 69 €/MWh in the NEP (MM) scenario and 85 €/MWh in the NEP (ESM-MM) run. Although the number of hours with a maximum price (5,000 €/MWh) is lower in the NEP (ESM-MM) run, the average price is higher (Figure 16). This is mainly due to slightly different yields from photovoltaics (-8.6 TWh/y) and wind power (-13 TWh/y).

FIGURE 16:
Comparison of price duration curves between coupled models.

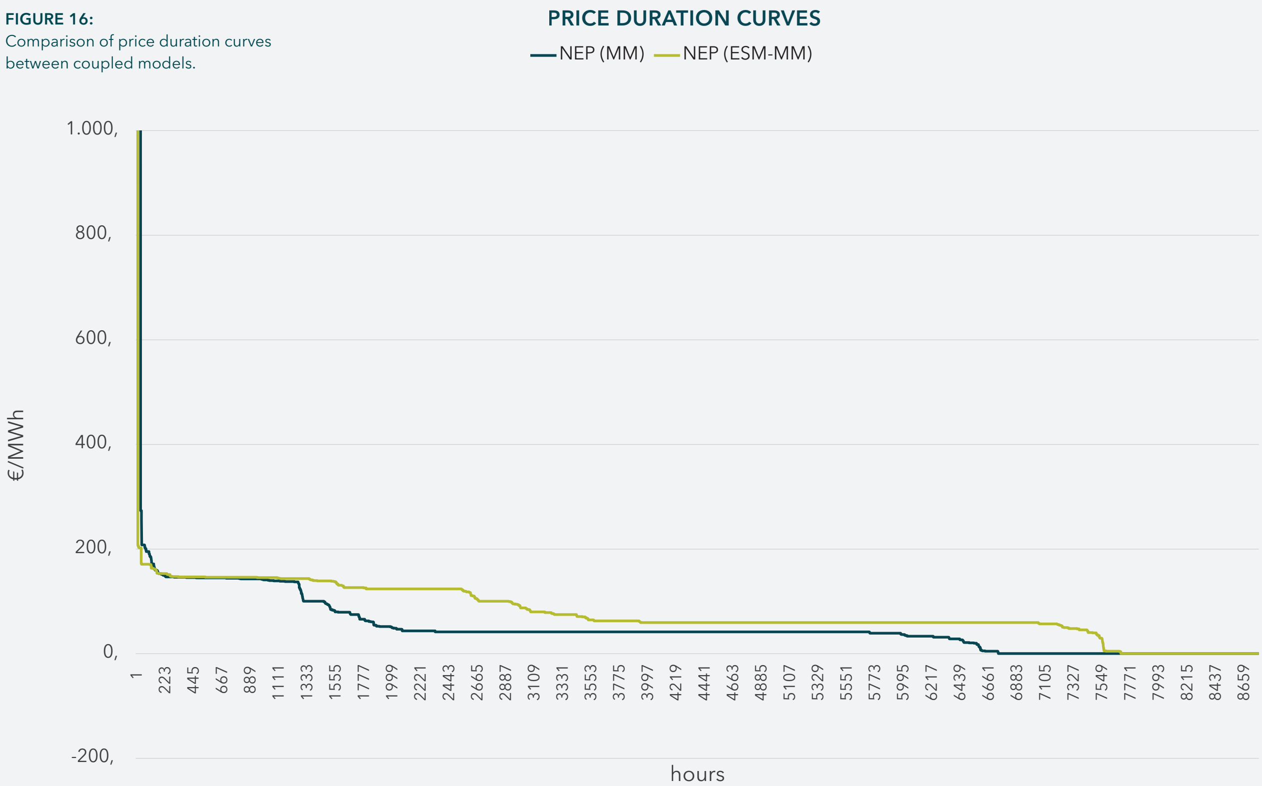
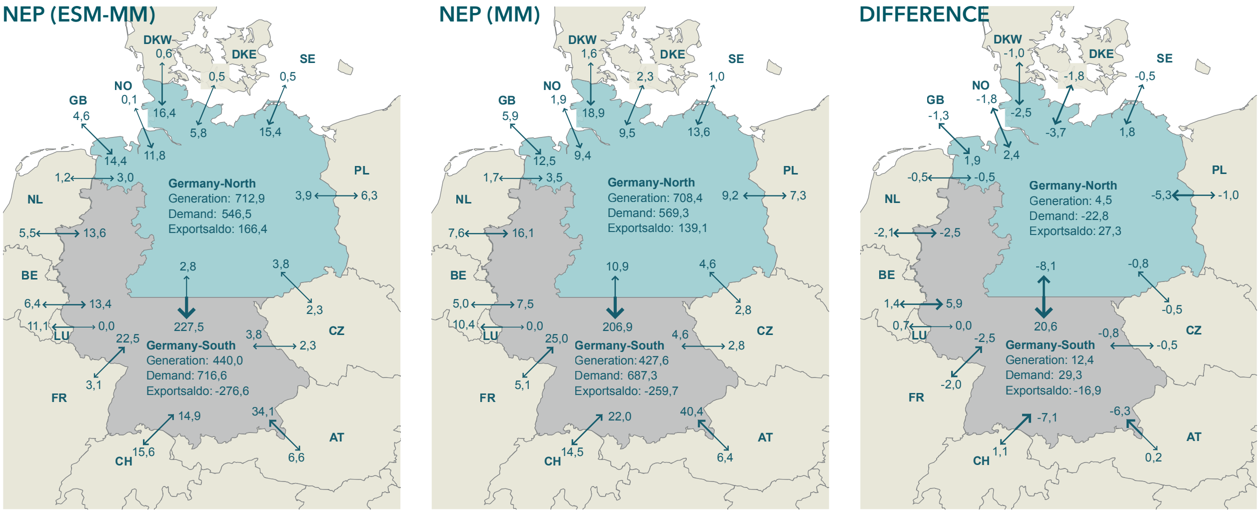


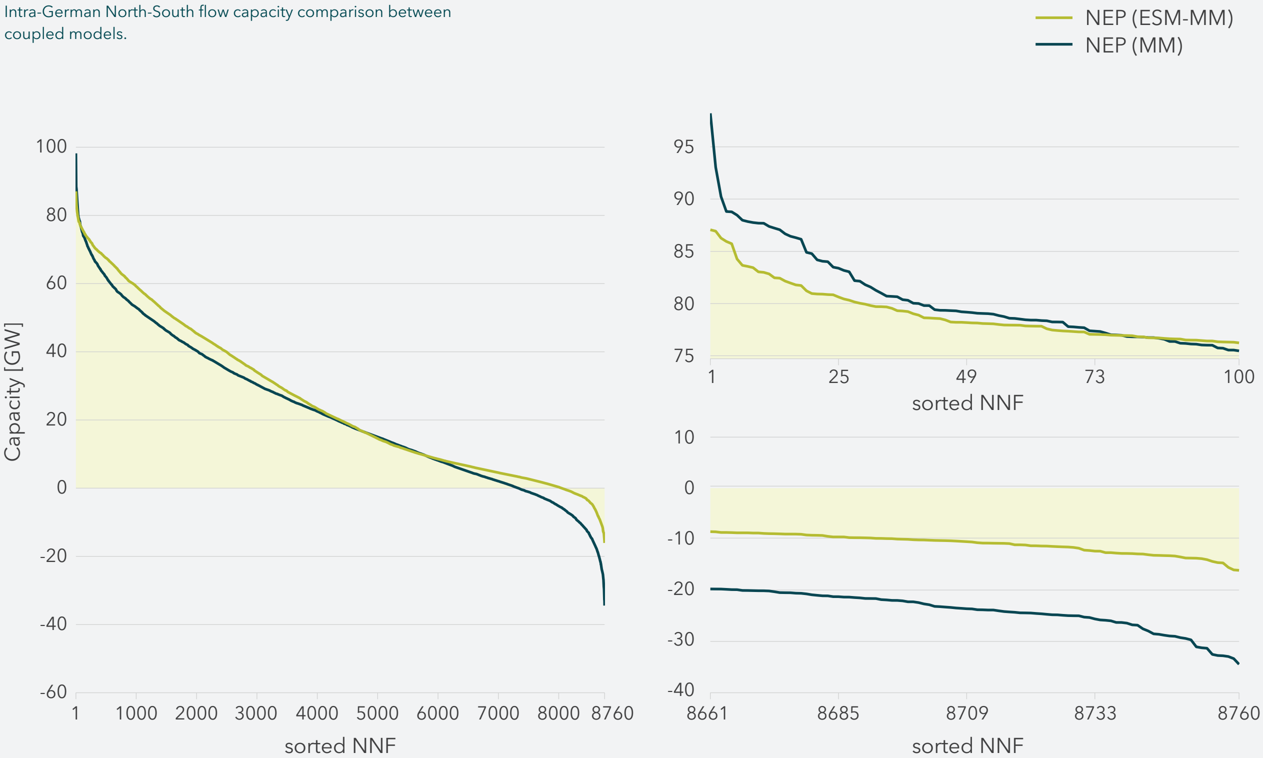
FIGURE 17:
comparison of North -South German power flow.

North-South electricity transport within Germany increases by 21 TWh per year in the NEP (ESM-MM) recalculation, which is approx. 10 % higher than in the NEP (MM) scenario (Figure 17). This difference is due not to trading, but mainly to differences in the use of power plants and loads within Germany. Above all, the electricity load (driven in particular by price-sensitive loads such as electrolysers) decreases in the NEP (ESM-MM) in the north and increases in the south, which leads to a higher annual North-South flow.



At its maximum, however, intra-German North-South transport is 6.7 GW lower within the NEP (ESM-MM) run. Intra-German North-South transport is also approximately 1.0 GW lower on average over the 100 highest hours. This is primarily due to the fact that less is imported from the north (-5 GW) and less is exported to the south (-8 GW). This effect can be seen in Figure 18.

FIGURE 18:
Intra-German North-South flow capacity comparison between coupled models.

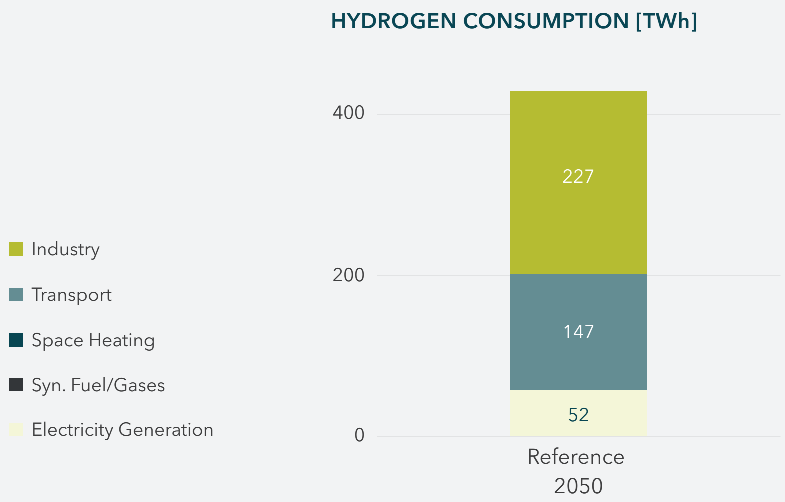


The recalculations have shown that the tools used can almost fully reproduce the results of NEP23 Scenario B (2045). This establishes a toolchain that enables blind spots in the original scenario to be identified and analysed. The focus is primarily on the hydrogen sector, which will be examined in more detail below.

The original scenario only provides information on the amount of hydrogen produced domestically and the additional imports required to meet demand. In contrast, the results reproduced with our tools offer additional insights into the demand structure.

The energy system model that was applied accounts for hydrogen demand in the industrial and transportation sectors. Some hydrogen is also required to fuel hydrogen-based gas power plants for electricity generation. In the selected reference scenario, the heating sector requires no additional hydrogen supply, compared to Figure 19.

FIGURE 19:
Hydrogen consumption of the reference scenario in 2050.

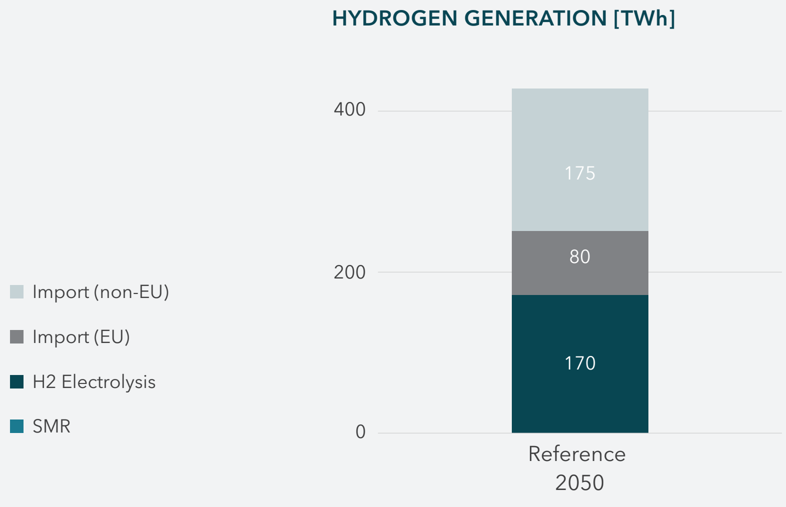


Hydrogen demand in the industrial sector amounts to 227 TWh. In the transport sector, an additional 147 TWh is required, primarily for aviation, shipping and freight transport. Gas power plants also require 52 TWh of hydrogen to provide additional capacity for the electricity sector.

To meet the resulting hydrogen demand, Germany's energy system requires more hydrogen than assumed in the reference scenario (approx. 320 TWh[6]). Domestic hydrogen production through electrolysis accounts for 170 TWh (Figure 20). In addition, 175 TWh is imported from outside Europe, while another 80 TWh is imported from Germany's neighbouring countries.

6 – According to the ESM calculation, Germany's energy system requires more hydrogen than assumed in the official results of NEP23 Scenario B (approx. 320 TWh) to meet the hydrogen demand

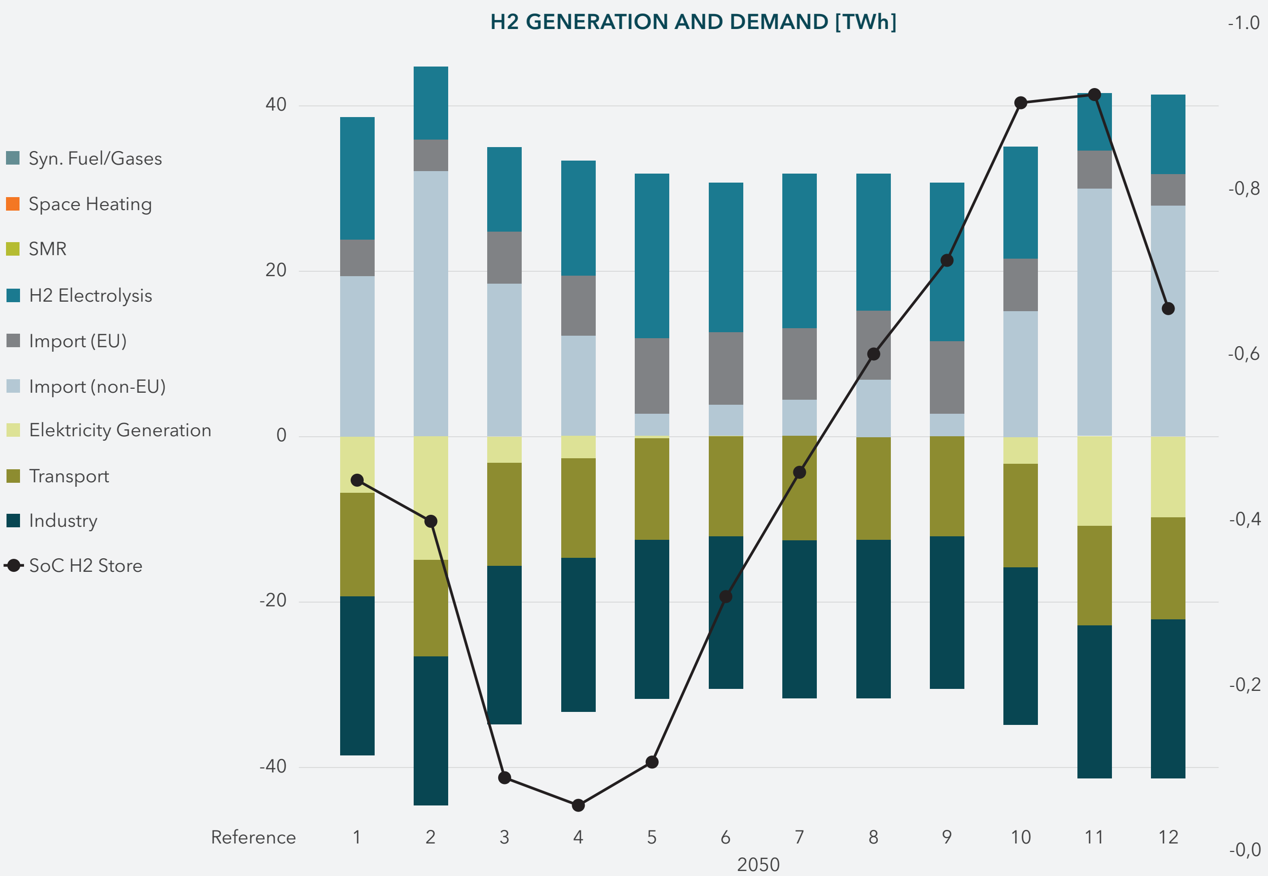
FIGURE 20:
Hydrogen generation of the reference scenario in 2050



During the winter months, hydrogen imports from outside Europe increase significantly due to a decline in domestic and European production. The energy system also requires more electricity for the heating sector to meet increased heat demand.

The operation of hydrogen-powered gas power plants supports the system during these critical winter months. Combined with the reduction in solar power generation, this creates a situation where hydrogen electrolysis is not economically viable, making imports the more cost-effective option, as shown in Figure 21.

FIGURE 21:
Monthly hydrogen balance, including the SoC (first hour of each month) of the hydrogen storage systems under the reference scenario in 2050.



With increasing output from variable renewable energy sources during the summer months, domestic hydrogen electrolysis rises, leading to a reduction in hydrogen imports.

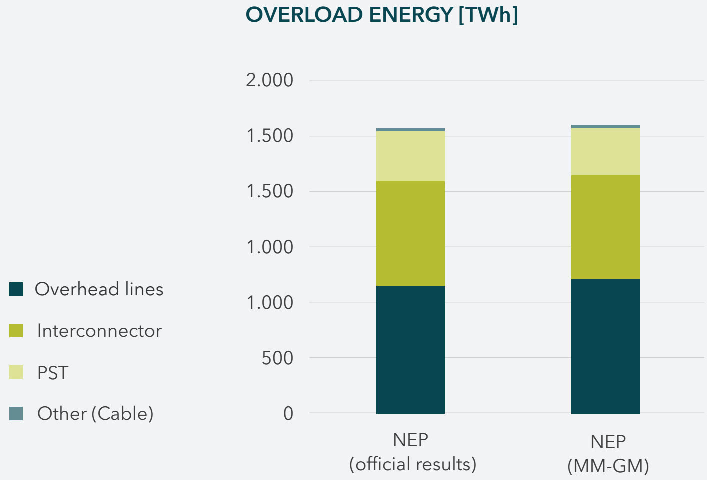
In conclusion, we highlight the fact that the toolchain that was implemented and applied can almost fully reproduce the results of the reference scenario, and is thus suitable for assessing further scenarios and robustness analyses in the context of this study and potentially beyond. We also stress that the uncertainty regarding the future development of the hydrogen sector will definitely impact on the optimal design and operation of future energy systems. The authors of the NEP also acknowledge this high degree of uncertainty. The final NEP report also mentions the "Big 5" energy system studies, in which annual hydrogen demand in a climate-neutral Germany varies from 250 TWh to 650 TWh, including demand for hydrogen derivatives.

8.1.1 ROBUSTNESS CHECK

A robustness test of the approved grid of NEP23 is performed as part of the AQ2050 project. To assess the difference between the approved results of NEP23 and the recalculation carried out as part of the adequacy study, an evaluation of the resulting overload energy for plant types of relevance to interregional electricity transport within Germany and on interconnectors prior to redispatch is carried out. This comparison is based on the grid results from scenario calculation N0b (Table 5, Chapter 6.2.1), also referred to below as NEP (MM-GM).

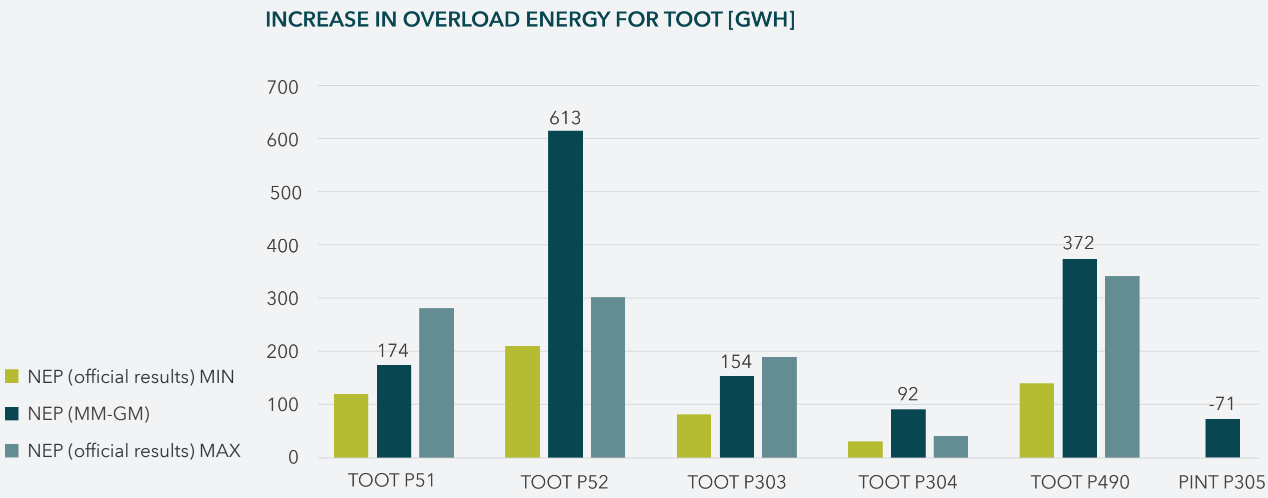
Figure 22 shows the resulting overload energy in the confirmed grid in the NEP23 process, Scenario B (2045), and also the recalculation as part of the adequacy study. The differences between the official version and the recalculation carried out as part of the project are very small. The increased north-south trade flows observed in the previous chapter therefore hardly lead to any increase in grid load. A not insignificant proportion of the remaining congestion in the grid is attributable to interconnectors. In total, Germany-wide overload energy increases slightly from 10.3 to 10.4 TWh before redispatch.

FIGURE 22:
Overload energy before redispatch, by asset type, scenario and grid



The study also includes an assessment of selected AC line measures in the TransnetBW control area that were identified for the first time as part of NEP23. Figure 23 below describes the change in overload energy when projects that have already been approved are specifically removed ("take one out at a time", TOOT) or when projects that have not been approved are specifically added ("put one in at a time", PINT). For all projects presented, both the range of overload energy specified in the NEP23 by the BNetzA in the approval notice and the respective impact of the project in the variants calculated here are shown. In particular, project P304 (grid reinforcement East Württemberg), which is just above the approval threshold, leads to a significant increase in overload energy if it is not taken into account (+92 GWh). In addition, if the non-confirmed project P305 (grid reinforcement Ostalb) is also considered, this leads to significant savings in overload energy (-71 GWh) and is thus well above the confirmation threshold set by the BNetzA (30 GWh for new construction measures; BNetzA, 2024; p. 37). All other projects listed are at least significantly above the minimum value shown in NEP23.

FIGURE 23:
Increase in overload energy for TOOT and reduction in overload energy for PINT calculation runs for selected projects in the TransnetBW control area. (PINT 305 reduces the overload energy and is shown here with the wrong sign for reasons of readability)

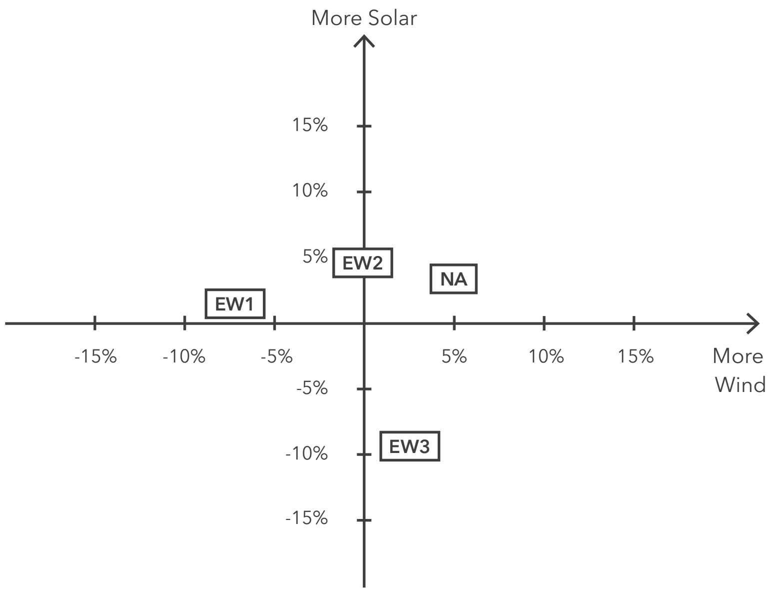


To validate the implemented toolchain, model-specific NEP23 input and official result data were used to accurately reflect the characteristics of the models presented in Chapter 7. In the following chapters, the Reference Scenario describes the results validated in this chapter.

8.2 CLIMATE CLUSTER

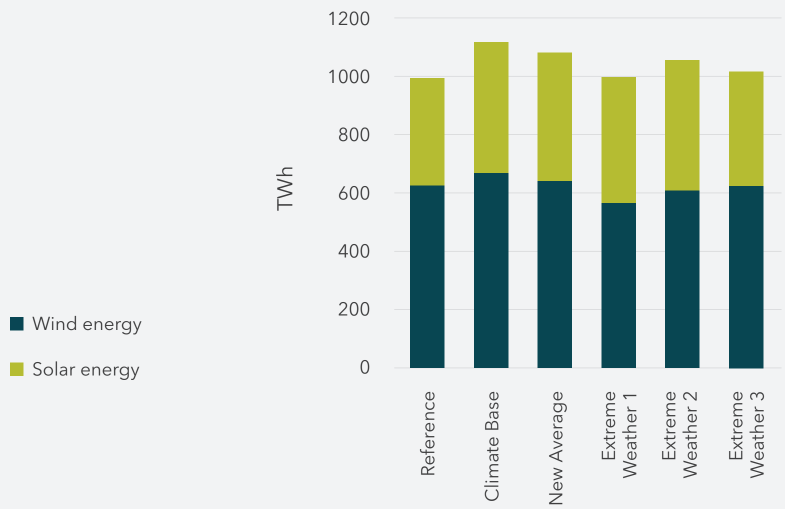
As described in Chapter 6.2.2, the design of the climate cluster scenarios supports the analysis of year-to-year weather variations and climate change on the energy system. The historical data for the year 2012 serves as the Climate Base scenario. For the assessment of climate change, the four scenarios Extreme Weather 1, 2 and 3 and New Average use projections as weather input data. This weather data features aspects such as differing availability of renewable energy. Figure 24 shows the solar and wind energy available in the different climate scenarios compared to the average of either the historic weather data scenarios or the scenarios with projected data.

FIGURE 24:
Deviation of yield in solar and wind energy in projected extreme meteorological years (New Average and Extreme Weather 1-3) compared to their average.



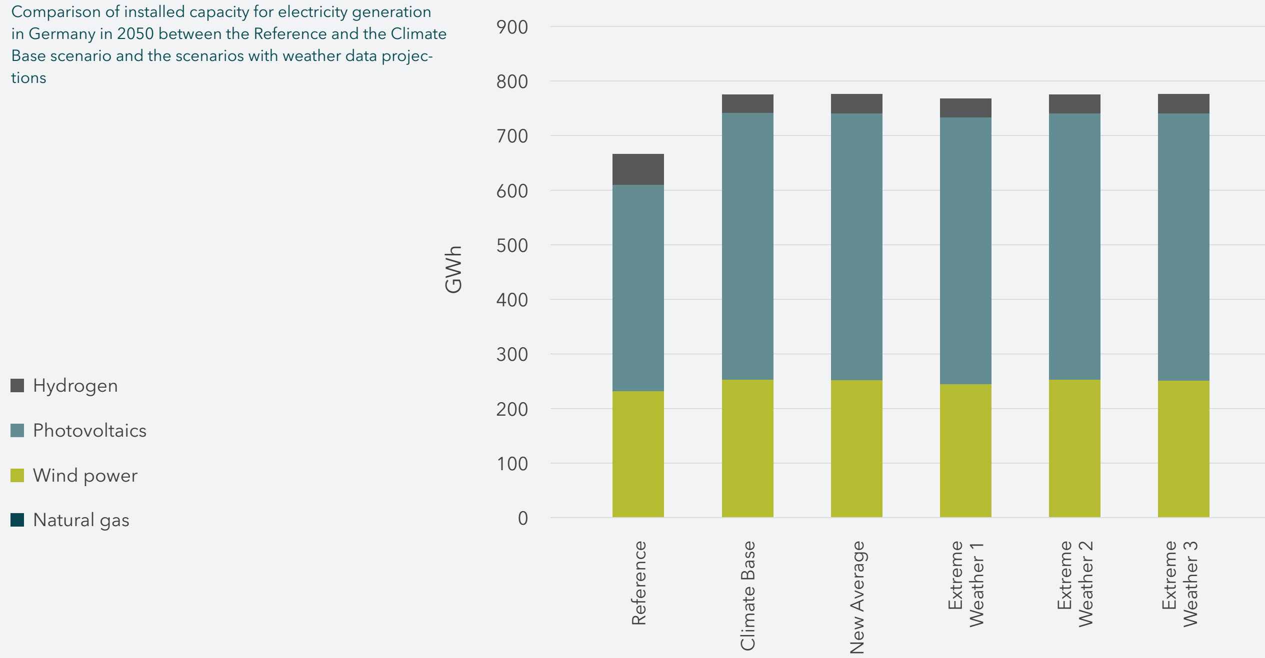
In absolute terms, Figure 25 shows the renewable energy yield of wind and solar power in Germany in 2050 as a comparison of different scenarios. Comparing the Reference and the Climate Base scenario, a higher yield of renewable energy occurs as more renewable capacity can also be built endogenously. The meteorological year projections New Average and Extreme Weather 1, 2, and 3 are designed to put stress on the energy system. As a result, comparing them to the Base scenario, the renewable energy yield varies by 118 TWh, mainly as a result of the variation in wind energy generation.

FIGURE 25:
German solar and wind energy yield in 2050 comparing the Reference scenario with the Climate Base scenario and the scenarios with weather data projections.



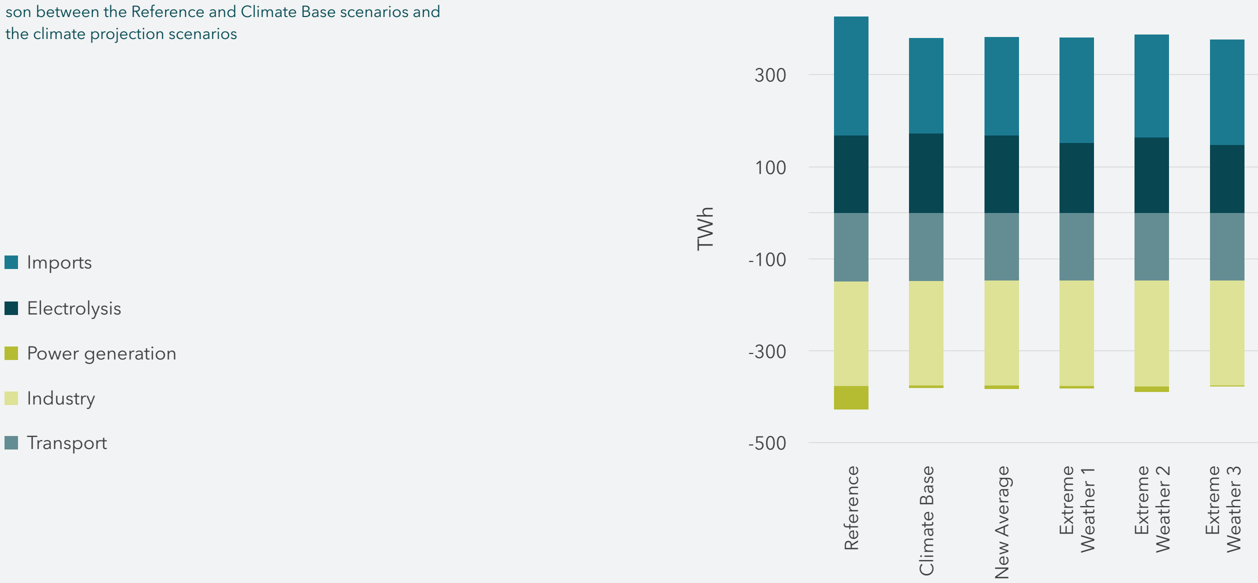
Despite the variation in the renewable energy yield, the installed capacities for photovoltaics and wind power vary only slightly between the scenarios of the climate cluster. The main differences in installed capacities in Germany in 2050 shown in Figure 26 can be observed between the Reference scenario and the climate projection scenarios as the model is allowed to optimise renewable capacities within a certain corridor. Since the scenarios with different meteorological years feature different renewable energy generation, the full-load hours also vary. As a result, there are different needs for flexibility technologies. Figure 26 also shows the capacity for backup power plants such as gas turbines and hydrogen turbines. While natural gas no longer plays a significant role in Germany in 2050 to supply energy in times of low renewable generation, hydrogen power plant capacity of 34.6 GW is installed based on exogenous lower boundaries, reflecting the setting of the reference scenario. However, no additional hydrogen power plants are installed beyond this level.

FIGURE 26:
Comparison of installed capacity for electricity generation in Germany in 2050 between the Reference and the Climate Base scenario and the scenarios with weather data projections



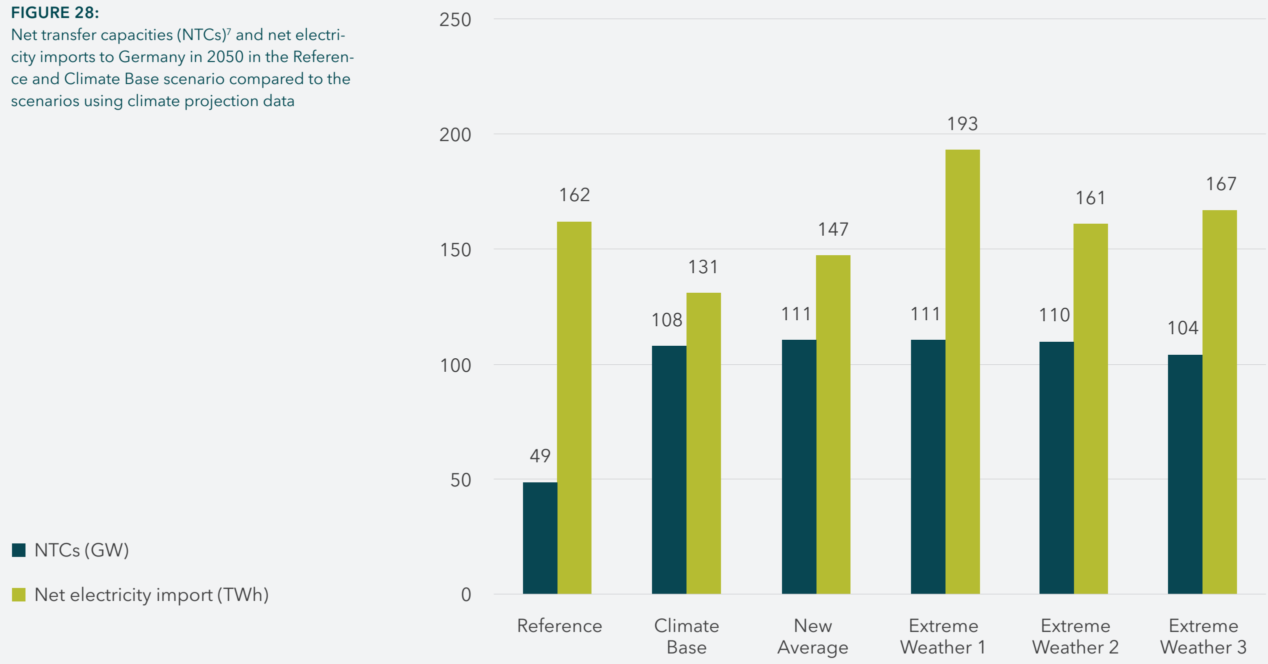
The hydrogen used by these backup hydrogen power plants is shown in Figure 27, along with other hydrogen demand and supply for Germany in 2050. Figure 27 shows the comparison between the Reference scenario, the Climate Base scenario and the scenarios based on weather projections. It clearly shows the largest need for electricity generation from hydrogen in the Reference scenario, whereas the Extreme Weather 2 scenario can suffice even with no re-electrification. In contrast to the demand for hydrogen in power generation, industry and transport remain constant, resulting in comparable total demand and supply between the scenarios with projected weather data. This shows that the low renewable energy generation in this scenario is accompanied by an increased need for flexibility.

FIGURE 27:
Hydrogen demand in supply in Germany in 2050 as comparison between the Reference and Climate Base scenarios and the climate projection scenarios



All scenarios discussed do not extend their stationary battery storage capacity beyond the exogenous minimum, which corresponds to the capacity assumptions of NEP23. Their utilisation increases, however, changing from 24 TWh provided by battery discharging in the Reference scenario to 51 TWh in the New Average scenario. More flexibility is thus provided in the electricity sector itself instead of coupling with hydrogen in the climate cluster scenarios. Further, in periods with low renewable energy generation, the German power system relies heavily on electricity imports. Figure 28 illustrates the net electricity imports along with the Net Transfer Capacities (NTCs) existing between Germany and its neighbour states in the Reference scenario in comparison to the Climate Base scenario and the climate projection scenarios. Since these scenarios in the model are allowed to optimise transmission line capacities in the climate scenarios as opposed to the Reference scenario, the resulting NTCs are more than twice those of the Reference scenario. This result is in line with the findings of the long-term scenarios (BMWK, 2024). In contrast, the net electricity imports in the Reference scenario are within the range covered by the climate cluster scenarios. Therefore, while not necessarily importing more electricity than in the Reference scenario on an annual basis, the climate projection scenarios import or export larger peak flows, resulting in higher NTCs.

FIGURE 28:
Net transfer capacities (NTCs)[7] and net electricity imports to Germany in 2050 in the Reference and Climate Base scenario compared to the scenarios using climate projection data

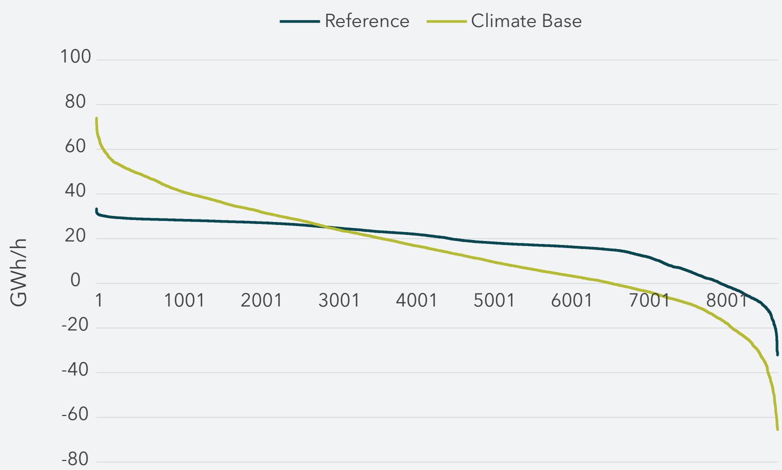


7 – The AC transmission line capacity of the NTCs must be adjusted by a factor of 0.7 to align with actual electrical transmission capability

When comparing the need for electricity imports between the Reference and the Climate Base scenario, we see a decrease in the Climate Base scenario in Figure 28. This can be attributed to the higher renewable capacities which in turn lead to a greater national electricity supply. When comparing the scenarios in Figure 23, it becomes apparent that those with the least renewable energy available locally place the heaviest reliance on electricity imports. The NTCs therefore make a major contribution to the flexibility of the energy system.

The shift in the role of NTCs is further illustrated by Figure 29, which shows the utilisation of German NTCs in 2050 as a comparison between the Reference scenario and the Climate Base scenario as an example for the climate cluster scenarios. It becomes apparent that in the Reference scenario, the overall lower capacities are operated at a relatively constant level of 20 GW. In contrast, the interconnector capacity in the Climate Base scenario is designed to allow the supply of peaks in residual load using imported electricity. The lines are therefore run at lower utilisation levels in the climate cluster scenarios than in the Reference scenario, but provide higher flexibility to the electricity supply in Germany.

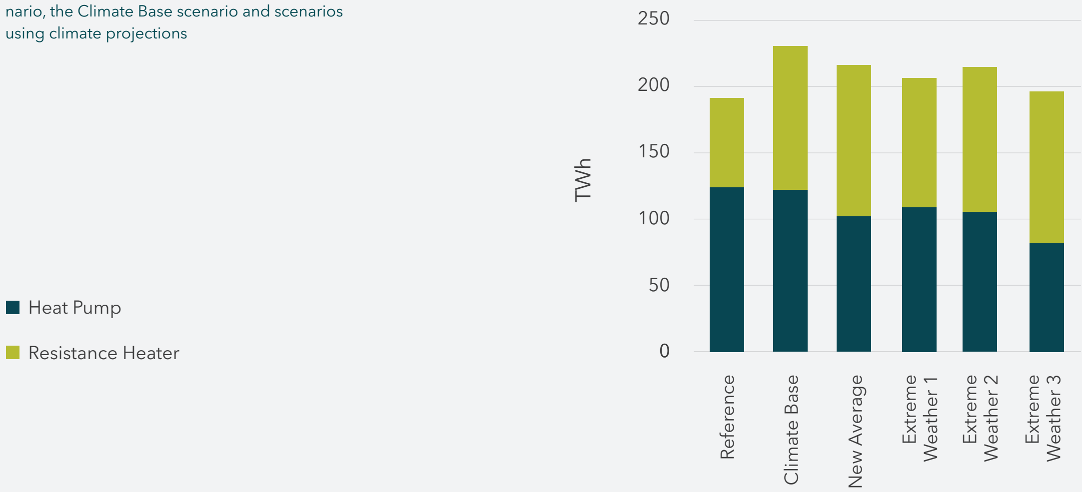
FIGURE 29:
Annual duration curve of German Net Transfer Capacity (NTC) utilisation in 2050 in the Reference scenario compared to the Climate Base scenario.



Besides the influence on renewable energy and the necessary flexibilities, the weather data is also significant in the heating sector due to the variation in ambient temperature.

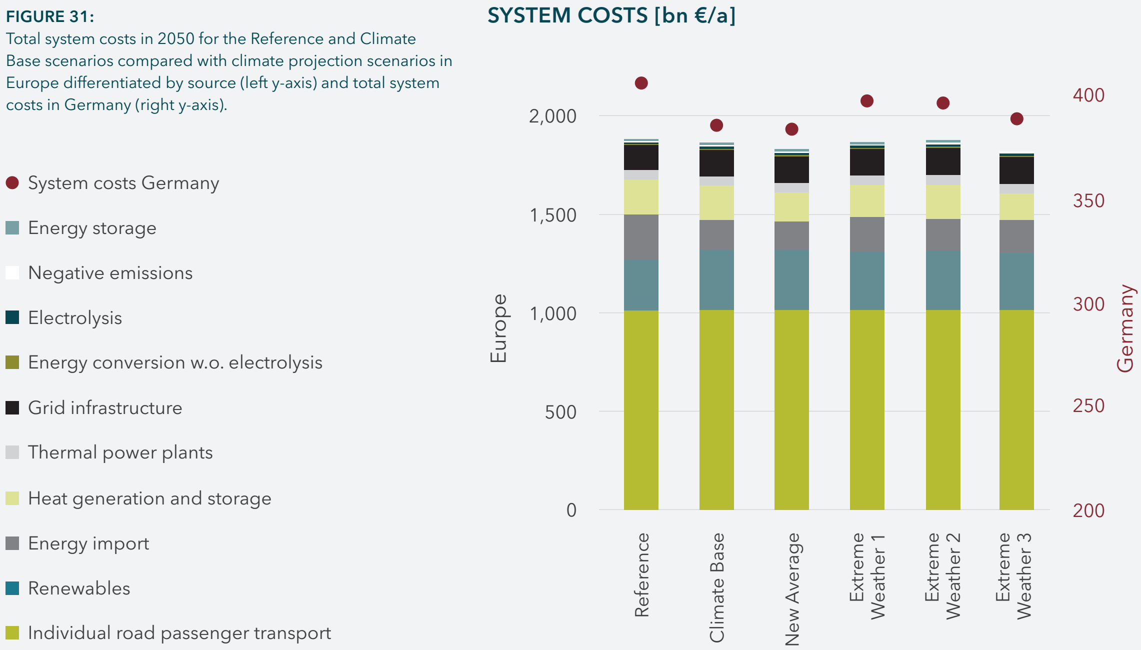
Figure 30 shows power demand due to usage of power-consuming heating technologies (heat pumps and resistance heaters) in Germany in 2050 for the different climate scenarios. The figure first compares the Reference scenario with the Base scenario and the scenarios using climate projection data. As we were seeking to reproduce the NEP, the optimisation constraints in the Reference run were deliberately set at a narrow level. For other scenarios, the constraints of the development trajectories were much broader, allowing the optimiser more leeway. This can be seen in the difference between the results of the Reference scenario and the Climate Base scenario: Both use the same weather data (2012 ERA5), but the base scenario uses roughly 10 % more power for power-to-heat technologies. This indicates that, given similar circumstances, higher usage of power-to-heat technologies seems to be more cost-effective. Besides the Reference scenario, the Extreme Weather 2 scenario also features low power-to-heat demand. On the one hand, heat demand is a function of temperature, and in higher temperatures, heat demand for homes and services is lower. On the other hand, heat pumps can deliver more heat using less electric power when ambient temperature is high. This makes heat pumps more cost-effective and therefore more optimal in heat scenarios.

FIGURE 30:
Electricity demand for Power-to-Heat applications in Germany in 2050 in the Reference scenario, the Climate Base scenario and scenarios using climate projections



All the factors discussed above contribute to differences in the total costs for the energy system. For the Reference, the Climate Base and the climate projection scenarios, Figure 31 shows the system costs both for Germany (red) and for the entire European modelling region (bars) in 2050. In both cases, the differences between these scenarios need to be treated with caution, since the model does not sufficiently reflect costs for the national grids. The German system costs for the various scenarios follow a similar pattern to the European system costs. The costs for the Climate Base scenario are lower than in the Reference scenario because the increase in costs from additional renewable capacities does not outweigh the savings in energy imports. Amongst the scenarios using climate projection data, cost differences mainly arise in the heating sector and energy imports. Scenarios with low renewable generation such as Extreme Weather 1 and low ambient temperature such as Extreme Weather 3 thus turn out to be more costly than the Climate Base scenario. Total system costs in 2050 in Germany therefore vary by 13.5 billion € when different projections of the impact of climate change are compared.

FIGURE 31:
Total system costs in 2050 for the Reference and Climate Base scenarios compared with climate projection scenarios in Europe differentiated by source (left y-axis) and total system costs in Germany (right y-axis).

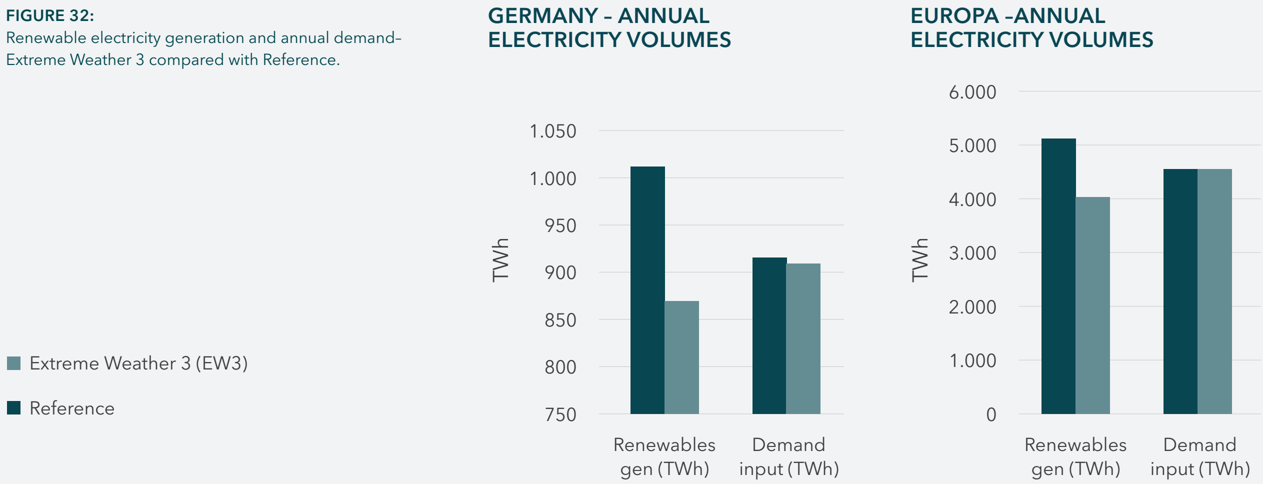


Analysis of the NEP23 electricity system with regard to future weather extremes
For this purpose, we used the Extreme Weather 3 (EW3) projected weather data instead of the meteorological year 2012 as the input dataset.

The modification of the input data leads not only to higher temperatures but also – as a side-effect of the meteorological data selection – to lower electricity production from wind and photovoltaic generation in Germany and Europe. The higher ambient temperatures also imply a slightly lower demand input, mainly due to the lower demand for heat pumps (see Figure 32). Additional loads due to air-conditioning are neglected in this analysis and will be the subject of future evaluations.

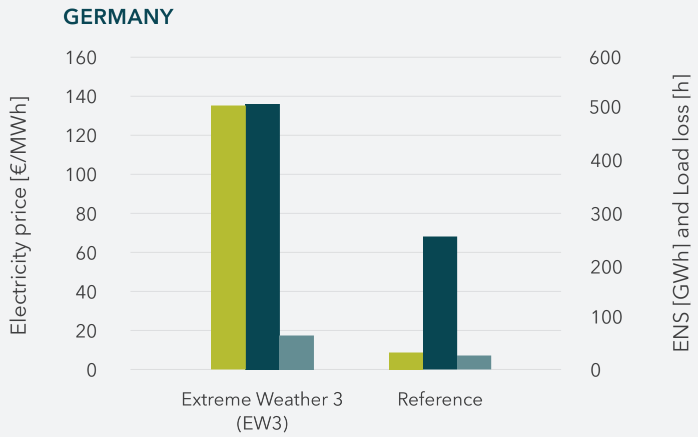
We stress here that particularly hot years do not necessarily present lower renewables yields, although this is the case for this selection. Accordingly, this analysis can also be understood as a stress test for an existing power system under low-renewables conditions.

FIGURE 32:
Renewable electricity generation and annual demand– Extreme Weather 3 compared with Reference.



The Extreme Weather 3 (EW3) scenario shows more hours in the market with scarcity situations in Germany. The ENS volume increases from ~40 GWh to ~500 GWh and the number of Loss of Load hours increases from ~30 to ~70 hours (see Figure 33). The change in electricity generation from renewables results in other scarcity situations. Figure 33 shows that in EW3 scarcity situations, the feed-in of renewable energies is lower than in the Reference scenario.

FIGURE 33:
wholesale price, ENS, Loss of Load hours – Extreme Weather 3 and Reference



	Extreme Weather 3 (EW3)	Reference
Wholesale price (€/MWh)	136	69
Load loss (GWh)	508	39
Load loss (hours)	71	31

In addition, other countries have higher scarcity values, especially Poland (Figure 34). There, the residual load in EW3 is higher than in the Reference – even in the 100 hours with the highest residual load (see Figure 35).

FIGURE 34:
ENS in the EU – Extreme Weather 3 and Reference

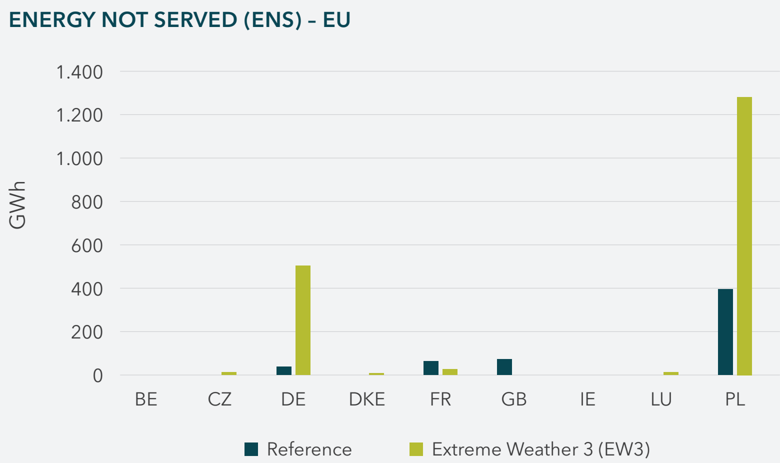


FIGURE 35:
Excerpt showing residual load in Poland - Extreme Weather 3 and Reference

PL: THE 100 HOURS WITH THE HIGHEST RESIDUAL LOAD

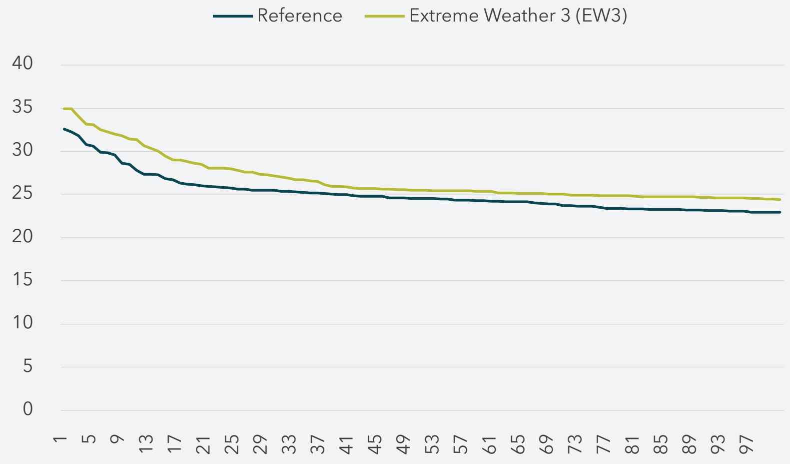
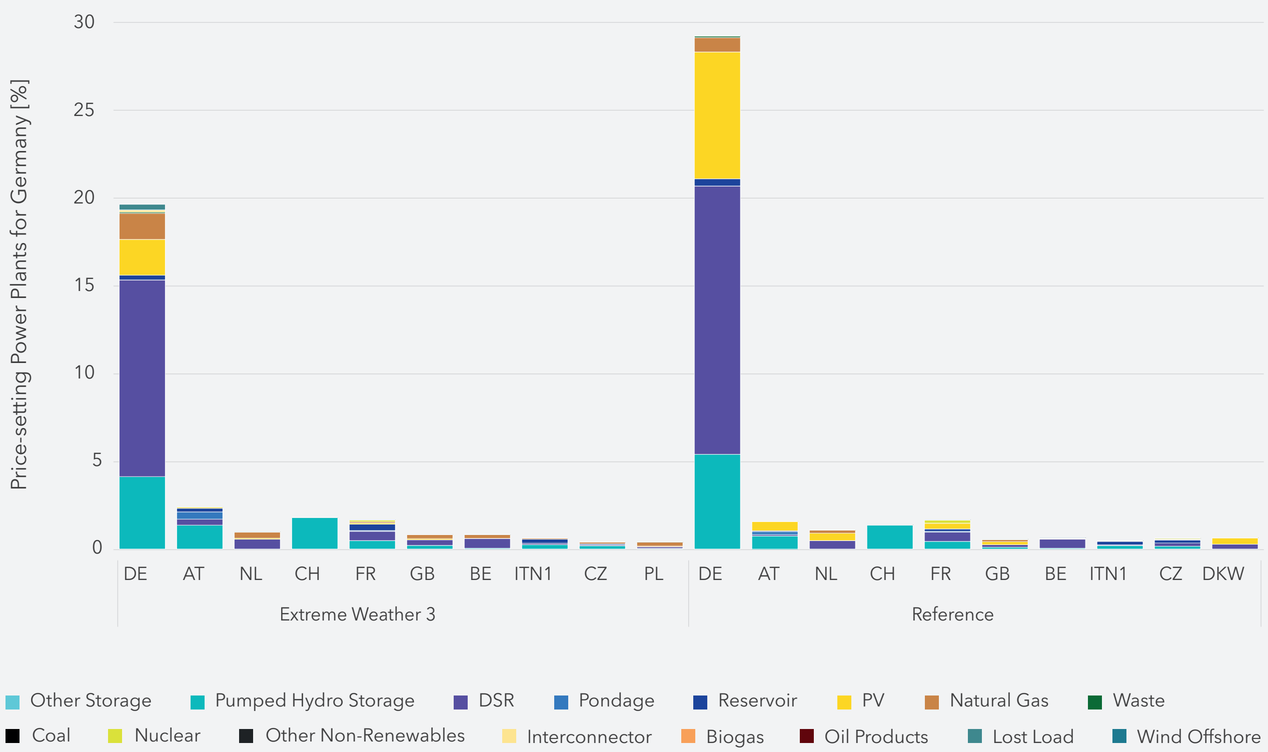


FIGURE 36:
Price-setting power plants – Extreme Weather 3 and Reference - The 10 most influential market areas are shown

Accordingly, prices are also higher in EW3. This is due to several factors: The ENS means there are more hours with maximum electricity prices. In addition, there are fewer hours in which photovoltaics (PV) set the price, but more hours in which gas sets the price (Figure 36). In addition, storage could involve higher opportunity costs.



The trade flows change in the scenarios examined. In the Extreme Weather 3 scenario, less electricity is imported, and more is exported than in the current status quo (Figure 37). Although the trade balance remains negative, the amount is significantly lower than in the Reference. This is due to the fact that although the residual load in Germany is increasing, it is increasing more strongly across the EU (Figure 38). There is less net import from the south (AT & CH) and the north (NO, DK & SE), as well as net export to Poland and the Czech Republic instead of net import as in the meteorological year 2012 (Reference).

FIGURE 37:
Electricity exchange – Extreme Weather 3 and Reference

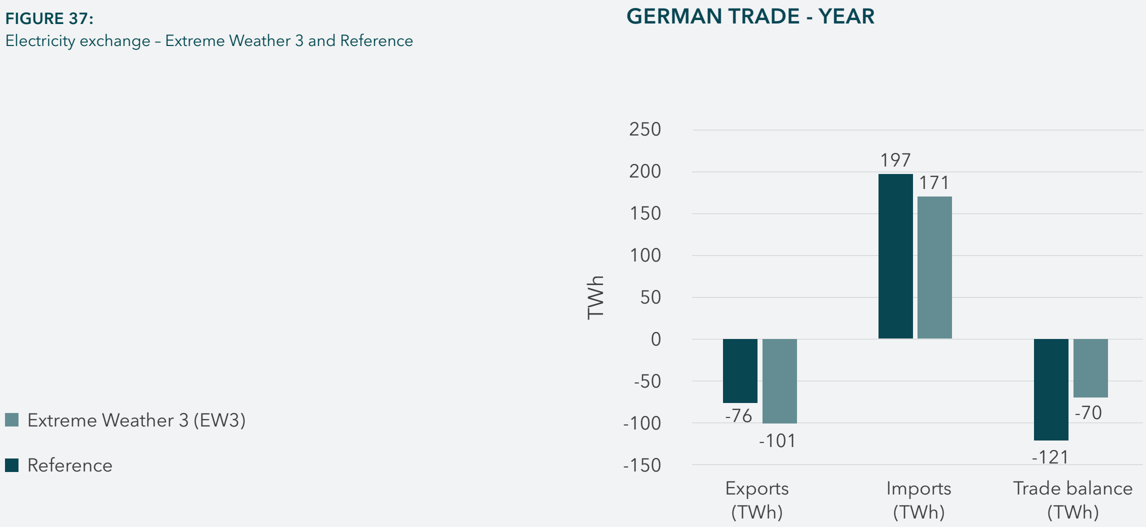
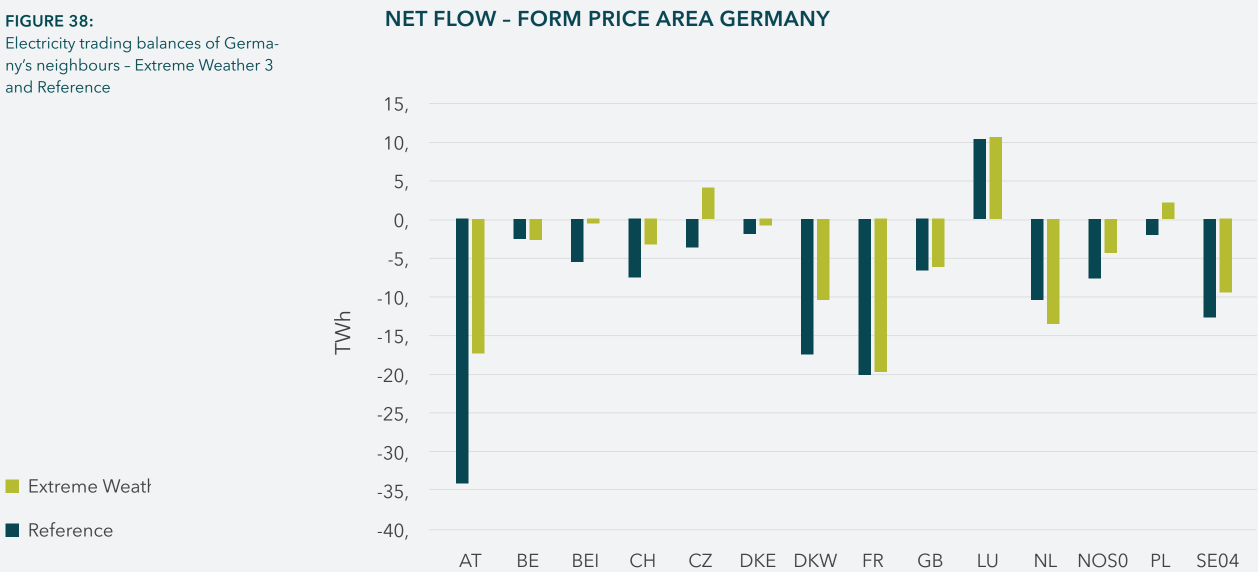


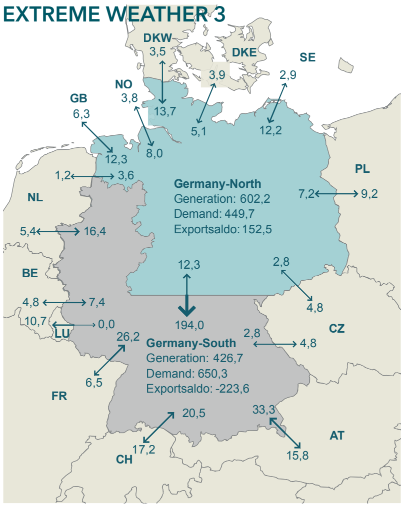
FIGURE 38:
Electricity trading balances of Germany's neighbours – Extreme Weather 3 and Reference



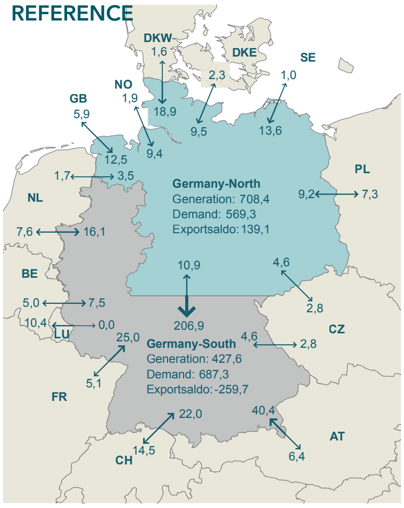
8 – Amprion-Cut

The annual north-south flows within Germany[8] decrease by approx. 13 TWh in EW3 compared to the meteorological year 2012 (see Figure 39).

EXTREME WEATHER 3



REFERENCE



DIFFERENCE

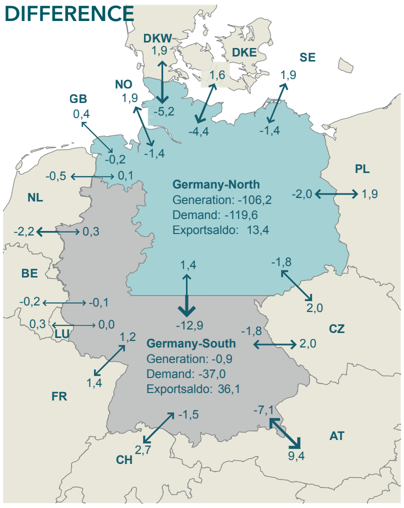


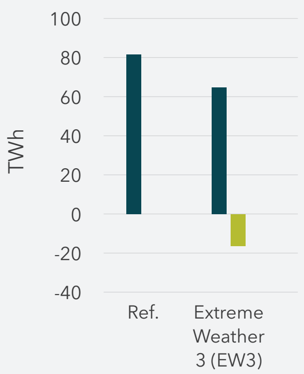
FIGURE 39:
Annual north-south transport activity. Extreme Weather 3 in comparison with the Reference

There are several reasons for this. Firstly, trade reduces annual north-south transport activity (see Figure 40). Figure 40 also shows that almost the entire reduction in this scenario is due to the lower trade transit. Another reason is the reduced amount of electricity production from wind power plants, which primarily feed less into the grid in the north. At the same time, switchable loads are also reduced in the north, but more in the south in relation to wind. Production from H2 power plants is also increasing, primarily in southern Germany.

In the EW3 scenario, the maximum north-south transit hardly changes (Reference 94 GWh/h, EW3 95.5 GWh/h).

FIGURE 40:
North-South transit through trade– Extreme Weather 3
("North" = NL, GB, NO, DK, SE, PL, CZ;
"South" = NL, BE, LU, FR, CH, AT, CZ)

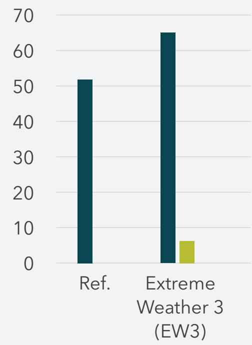
ELECTRICITY IMPORT FROM THE NORTH TO GERMANY



■ Import from the North

■ Difference to Reference

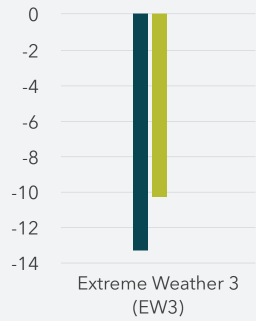
ELECTRICITY EXPORT TO THE SOUTH FROM GERMANY



■ Export to the South

■ Difference to Reference

DIFFERENCE OF THE NORTH-SOUTH POWER FLOW COMPARED TO REFERENCE



■ Difference North-South Power Flow
■ Difference North-South Power Flow (Trade)

Hydrogen production and consumption for the electricity sector
Due to the lower feed-in from renewables, there is less production of hydrogen (H2) from electrolysers and increased use of H2 gas-fired power plants (see Figure 41). In contrast with the Reference, the amount of hydrogen produced from electrolysers in the German electricity market is not sufficient to meet the demand for hydrogen in the electricity sector. 66 TWh would have to be imported. Other H2 demands exist and are not included in the diagrams and the analysis. There is also a "gap" of 147 TWh in Europe (incl. Germany) (see Figure 42). While electrolysers are used most in summer in the Reference, there is no such increase in the Extreme Weather 3 scenario, which shows less electricity from renewables.

FIGURE 41:
Hydrogen production and consumption in electricity-equivalents – Germany

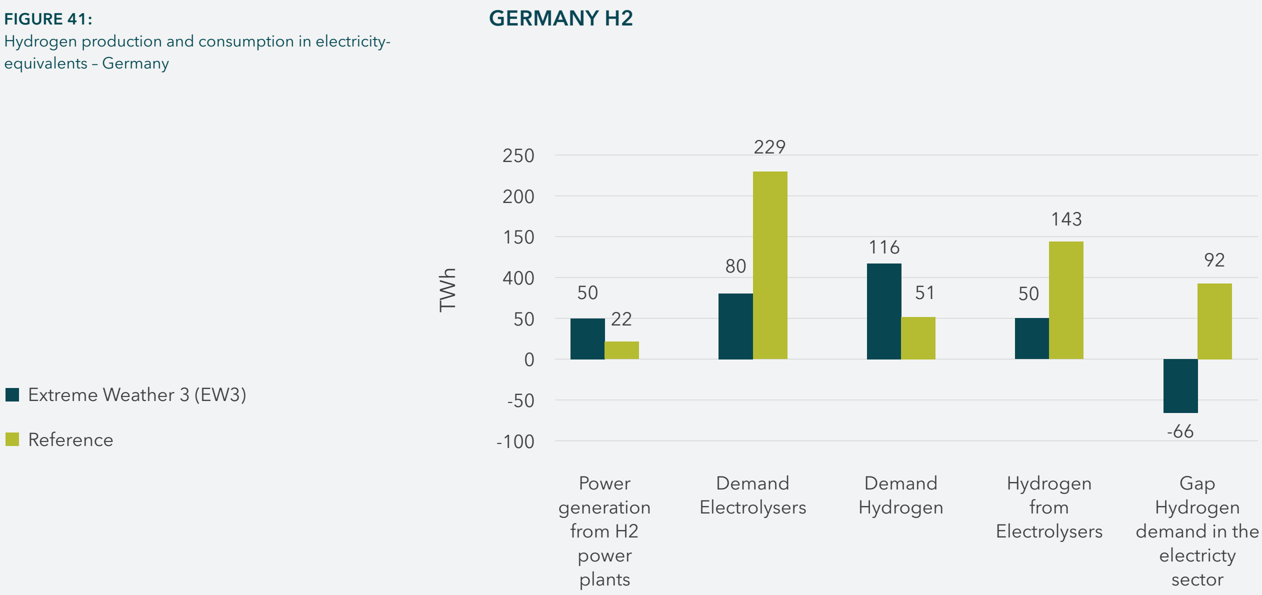
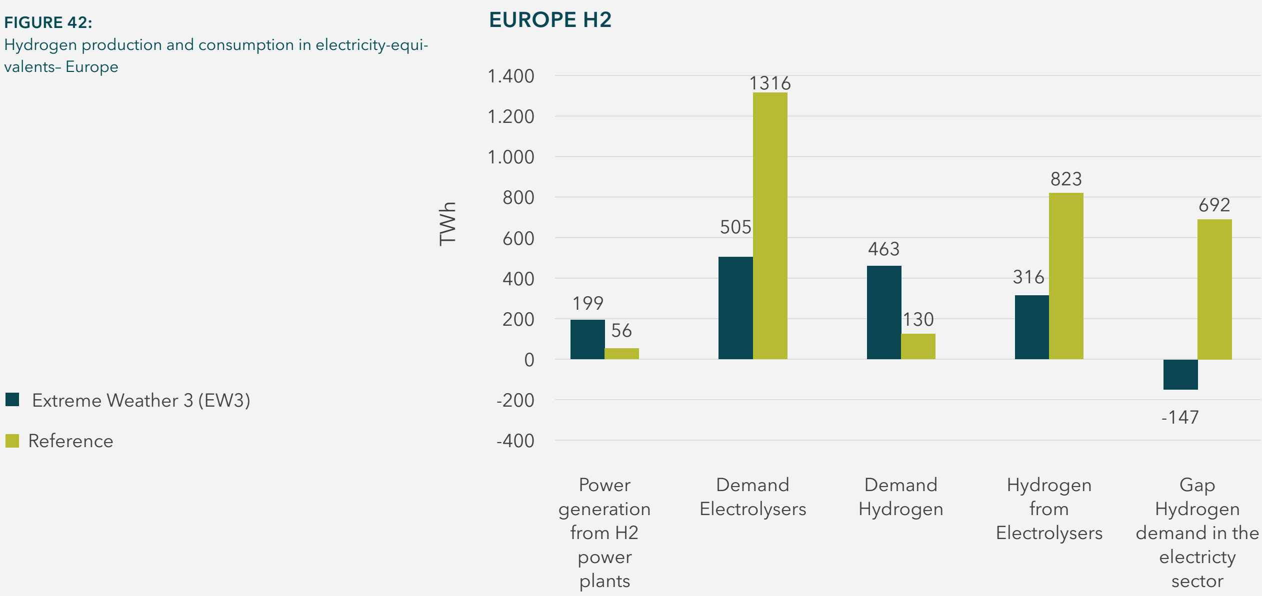


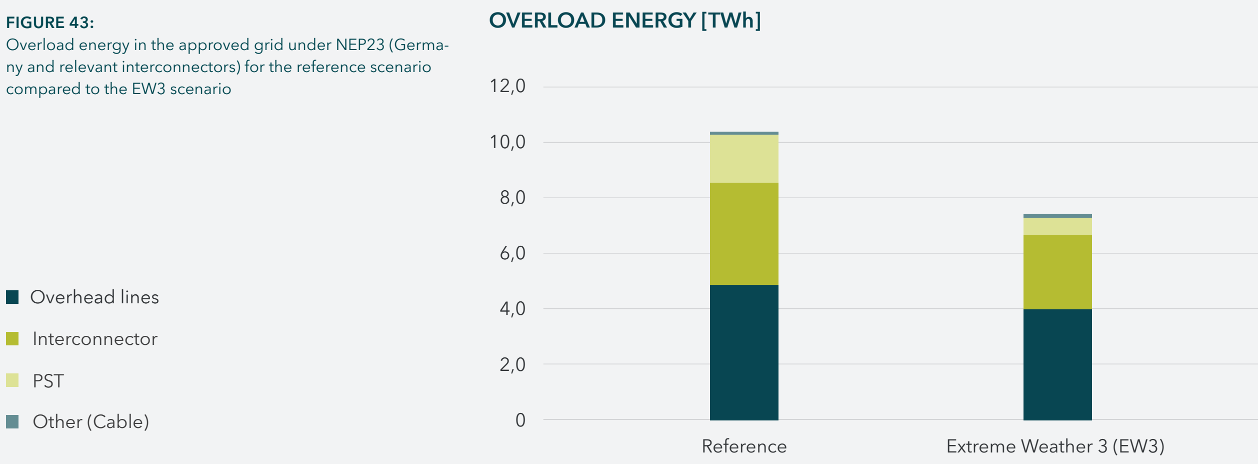
FIGURE 42:
Hydrogen production and consumption in electricity-equivalents- Europe



8.2.1 ROBUSTNESS CHECK

The resulting overloads for the changed meteorological year (EW3) are shown in Figure 43. The overloads in the transmission grid decrease significantly (-3 TWh). In particular, interconnectors and PSTs close to the border are significantly less heavily utilised (-2.1 TWh). At the same time, overloads within Germany decrease only to a very small extent (-0.8 TWh).

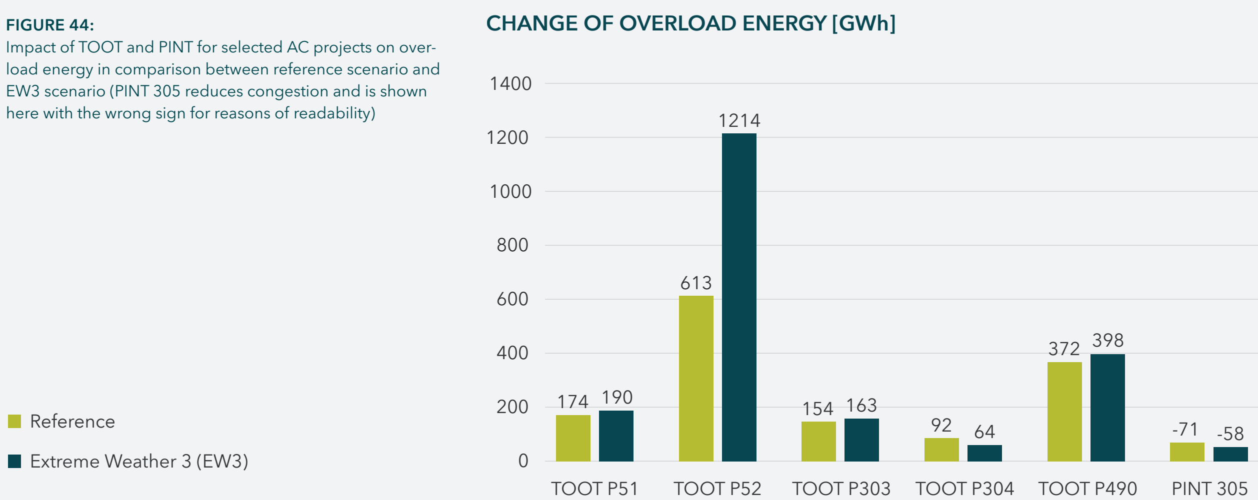
FIGURE 43:
Overload energy in the approved grid under NEP23 (Germany and relevant interconnectors) for the reference scenario compared to the EW3 scenario



In terms of situation, the critical grid usage cases under EW3 and Reference are similar. On the one hand, there is still the "classic" north-south transport activity: This is characterised by strong wind feed-in, high exports to neighbouring countries to the south and a high load in southern Germany. On the other hand, there are also increasing numbers of hours with high PV feed-in peaks, low to moderate wind levels, electricity imports from the south-western neighbouring countries and electricity transport to the north of Germany.

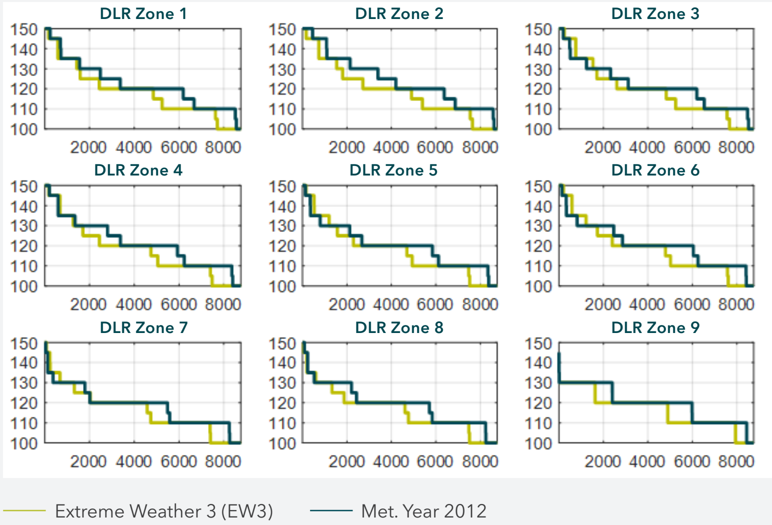
The AC projects presented prove to be consistently relevant and robust in the Extreme Weather 3 scenario (Figure 44). Despite the overall decline in congestion values in this scenario, the non-consideration (TOOT) or consideration (PINT) of individual projects leads to an increase (TOOT) or decrease (PINT) in overload energy above the approval threshold of the Federal Network Agency.

FIGURE 44:
Impact of TOOT and PINT for selected AC projects on overload energy in comparison between reference scenario and EW3 scenario (PINT 305 reduces congestion and is shown here with the wrong sign for reasons of readability)



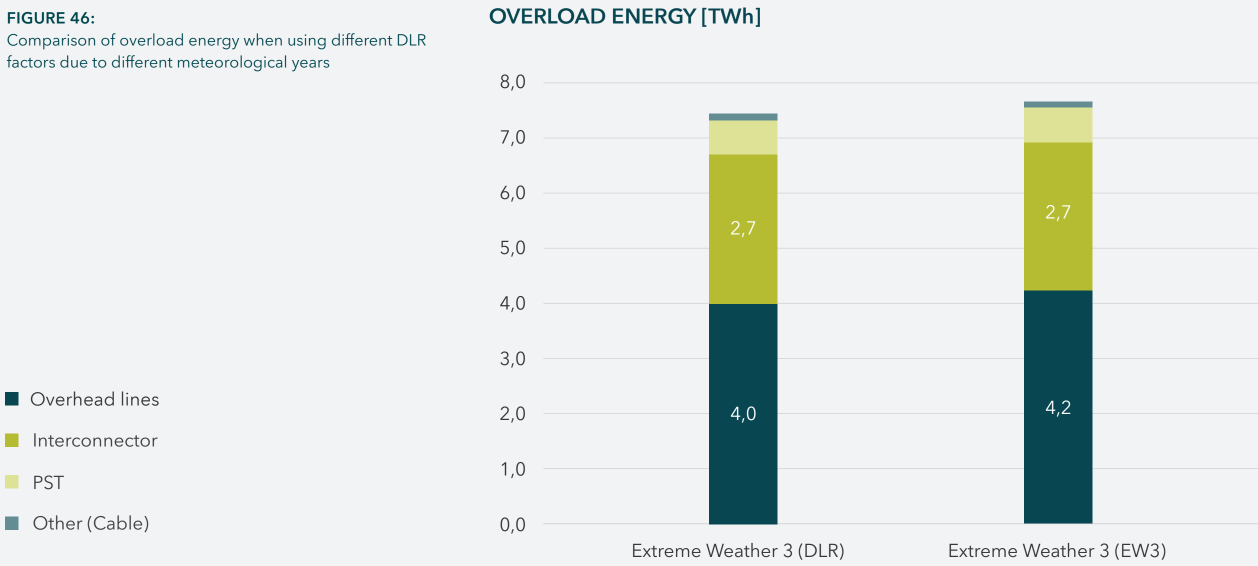
In addition to the robustness tests of the individual projects, sensitivity was calculated with adjusted transmission capabilities due to weather-dependent overhead line operation. Figure 45 shows the congestion possibilities by scenario and DLR zone in accordance with the planning principles of the four transmission system operators (referencing the planning principles of the four TSOs). An overview of the different zones can be found in the Annex. It can be clearly seen that the Extreme Weather 3 scenario reduces the possible overload possibilities in all zones compared to the meteorological year 2012.

FIGURE 45:
Overload possibilities of the scenarios by DLR zone as a percentage for all 8,760 h of the meteorological year (Comparison Reference with meteorological year 2012 and EW3).



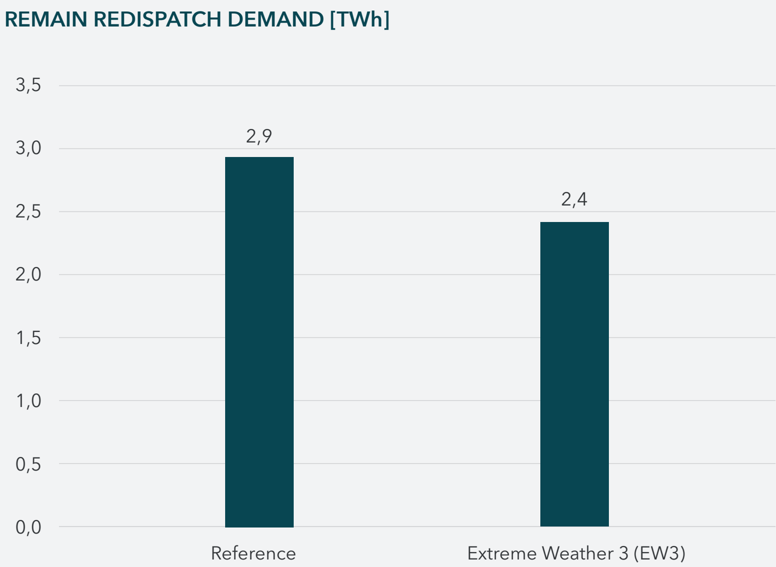
Taking the changed DLR factors into account increases the resulting overload energy – see Figure 46, which shows a direct comparison based on EW3 from the AQ project: once with the DLR factors of the meteorological year 2012 and once with the correct factors of the Extreme Weather 3 scenario. The overload energy increases by 234 GWh. This leads to fewer capacity utilisation options through innovative operating concepts; on the other hand, the expected increase is not too high. Individual AC projects have a similarly high or in some cases significantly higher impact.

FIGURE 46:
Comparison of overload energy when using different DLR factors due to different meteorological years



As with the Reference procedure, no new measures were identified as part of the adequacy process, only a robustness assessment of existing projects. As with the Reference, there are still overloads in the "climate neutrality grid" under consideration, which must be remedied by redispatch measures. As can already be seen from the overload energy values, the redispatch requirement of EW3 is also reduced compared to the reference calculation. See Figure 47.

FIGURE 47:
Comparison of remaining redispatch demand between reference scenario and EW3 scenario (Germany, 2050)



As a conclusion we may state that the NEP objective grid is robust against future heat wave scenarios. Nevertheless, we must not underestimate future weather extremes as they can change asset behaviour (as shown exemplarily in DLR sensitivity) and also some of the scenario assumptions (more electrical load through air-conditioning especially in hours with low feed-in of renewables).

8.3 FLEXIBILITY CLUSTER

The FLEXIBILITY cluster focuses on insights into the role of flexible technologies in a fully decarbonised and sector-integrated energy system. We used two of three models from the toolchain to create a comprehensive understanding of the challenges of a system which is based on fluctuating renewable energy.

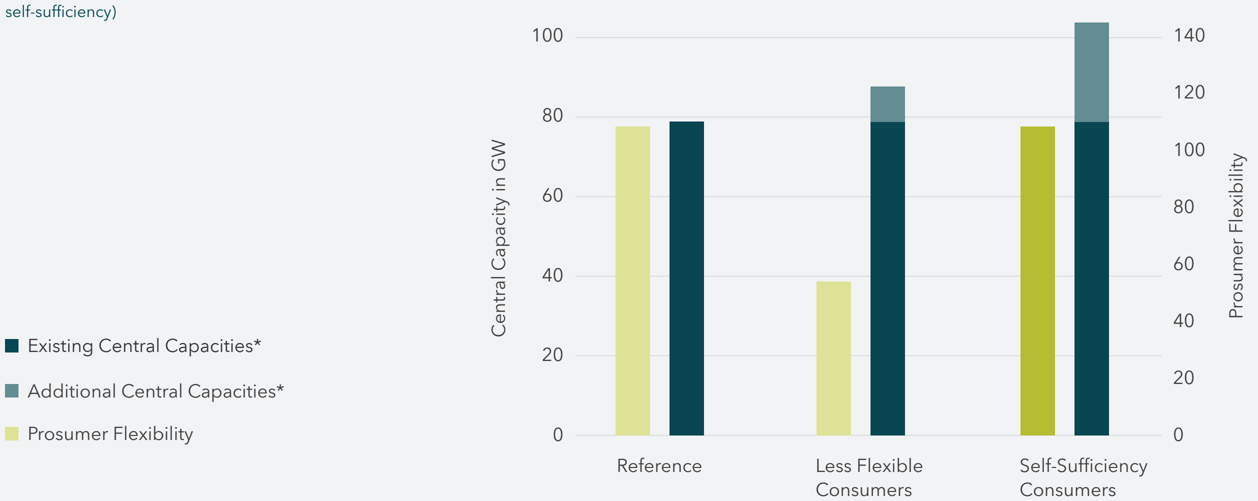
8.3.1 TRADE-OFF CENTRAL VS. DECENTRAL

One pillar of Germany's energy transition plan is the efficient utilisation of decentral flexibility. As already described in the scenario design in Chapter 6.2.3, we define decentral flexibility as a group of technologies located at lower voltage levels and typically operated by private households or by the service sector. What they have in common is that they do not actively participate in any market but are typically supplied by a power supplier via fixed electricity tariffs.

In the scenario directed towards a decarbonised energy system, 100 % market participation by those consumers is assumed. If those stakeholders were not fully market-oriented, additional system needs would arise in the form of central generation capacities. We modelled three different availability reduction types (see Table 8) and analysed the impact on the energy system. We then continued downstream on the toolchain to assess the electricity wholesale prices.

Figure 48 shows the different reactions of central generation capacity, when the availability of flexibility is reduced. Under "Less Flexible Consumers", 50 % instead of 100 % of consumers are assumed to follow market signals. As a result, 9 GW of additional hydrogen power plants need to be built in order to balance generation and demand. In the other variant, consumers are still regarded as fully flexible but have different additional constraints. The "Self-Sufficiency Priority" consumers optimise their dispatch consisting of solar PV, vehicle charging, heat pump and storage operation to use self-generated electricity first. Due to the nature of the self-sufficiency modelling approach, the model uses slack variables to keep it mathematically feasible. This is an expected result, as the scenario design does not consider all consumers as having enough generation capacity to be independent of the electricity market.

FIGURE 48:
Flexibility capacity trade-off for methods of reducing decentral availability . (light blue: 100 % flexible but with priority for self-sufficiency)



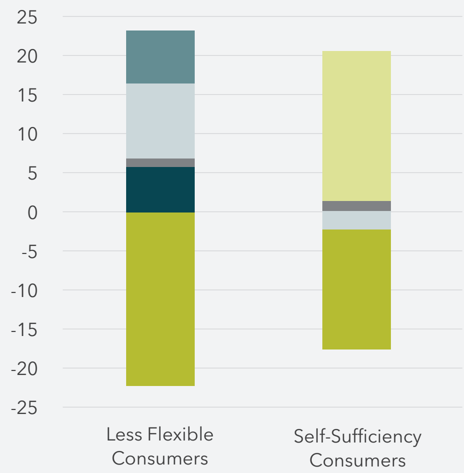
We highlighted the consumer column in light red in the Self-Sufficiency Consumers scenario to represent the imbalance in the system due to the slack variable usage. Consumers are not fully supplied with electricity, which is not a scenario result as it is only a model effect necessary for self-sufficiency parameterisation. The dashed line represents the additional need for flexibility in form of BESS, which is not endogenously determined by the model, but is calculated ex post. Other technologies might also fill this gap, most potentially involving lower additional capacities similar to the "Less Flexible Consumer" case. Possible options could be higher electricity imports, higher utilisation of existing central capacities, or investments in additional storage or power plant capacities.

Figure 49 offers a closer look into the dispatch differences compared to the Reference. For "Less Flexible Consumers" we can see that prosumer storage systems process 22 TWh less electricity, which is compensated for by electrolysis, additional imports, large-scale BESS and hydrogen power plants. Electrolysis serves as a form of "one-way" flexibility, converting surplus renewable energy to additional hydrogen. This energy would otherwise be managed by storage systems to retain it within the electricity sector. Under Self-Sufficiency Priority, storage capacities which could be utilised for arbitrage on the spot-market are not activated because of the consumer's priority on self-optimisation, which would correspond to 15 TWh of electricity. In other words, consumers use their batteries only to match their own consumption with their own PV generation. This leaves a major part of their flexibility unused, which would otherwise support balancing generation and demand.

FIGURE 49:
Dispatch difference compared to the Reference scenario of a selection of technologies in Germany in 2050

	Less Flexible Consumers	Self-Sufficiency Consumers
Slack Variable	0	19
Home BESS	-22	-15
Electrolysis	7	0
Import-Balance	9	-2
Large-Scale BESS	1	1
H2 Power Plants	6	0

DISPATCH DIFFERENCE IN TWh



In the analysis we showed that results differ depending on the reason underlying the reduced decentral flexibility. The biggest impact on the system needs is driven by "Less Flexible Consumers" which assumes 50 % market participation instead of 100 % (Reference case). Consumers not reacting to any signal put "capacity stress" on the system, which could, for example, be tackled with an additional investment of 9 GW of hydrogen power plants. Of course, other centrally acting flexibility options such as large-scale BESS and even additional interconnectors could be part of the solution. But for better comparability of the variations in availability of decentral flexibility, only hydrogen power plants are utilised as investment options.

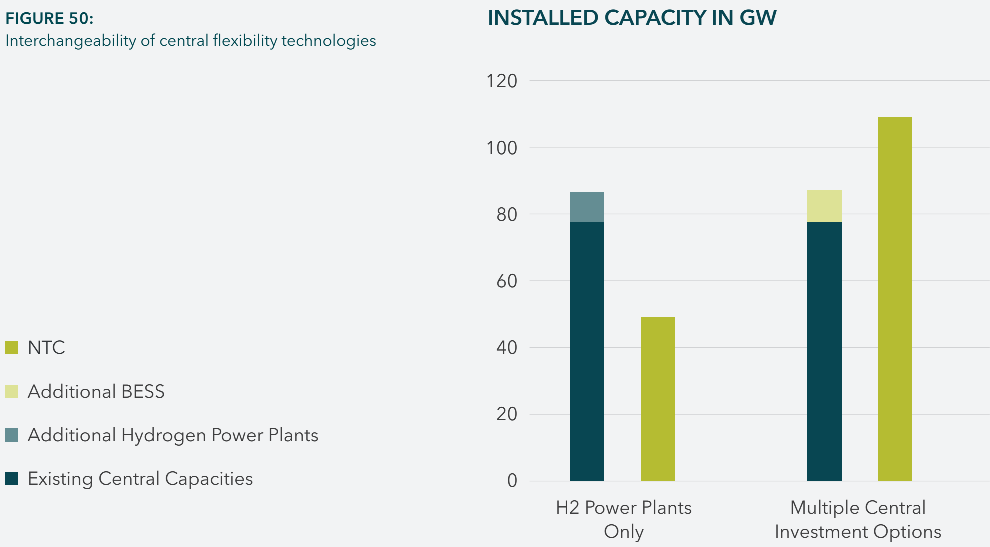
We also showed that being flexible alone is not sufficient for efficient system operation. Flexible consumers which do not follow market signals but optimise only their self-consumption rate do not efficiently utilise their flexibility potential. Integration of other renewable energy sources such as wind energy then relies on other flexibility technologies. In comparison to Less Flexible Consumers, measures taken there to account for missing market-orientation could also be sufficient to cover the additional flexibility needs of prosumers which optimise their self-consumption rate.

8.3.2 INTERCHANGEABILITY OF FLEXIBILITY TECHNOLIGIES

An analysis of possible investment options has been conducted for the case of Less Decentral Flexibility. The case presented above has only one investment option: hydrogen power plants. This case will be labelled in this section as "H2 Power Plant Investment Only". We define a second, opposing, scenario, in which multiple technologies are allowed simultaneously: Hydrogen power plants, large-scale BESS and interconnection capacities. The stress case, which triggers the investments, is the unavailability of decentral flexibility (50 % market-orientation instead of 100 %).

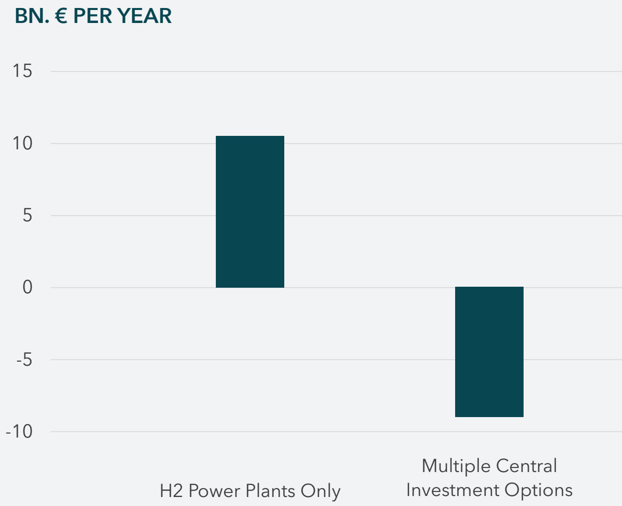
Figure 50 shows the result of this comparison. The lesser available decentral flexibilities trigger either 9 GW of hydrogen power plant investments in Germany, or 9.5 GW of battery storage systems. However, the battery storage systems are accompanied by an additional 60 GW of interconnection capacities to neighbouring countries. This result emphasises the role of battery storage systems: Europe offers a diverse set of weather profiles, which can be accessed by neighbouring countries through stronger interconnection. The short-term flexibility provision of battery storage systems then allows supply of the national load.

FIGURE 50:
Interchangeability of central flexibility technologies



In terms of affordability, our calculations presented in Figure 51 show that higher interconnection targets in comparison with higher storage capacities could result in 9 billion € per year in reduced energy system costs. This is true, although in this case, decentral flexibility potential is not fully utilised. In contrast, additional hydrogen power plant capacities increase European energy system costs by 10.6 billion € per year. The assessment performed in this section refers only to the cost relating to the generation of energy to satisfy demand in a standard meteorological year. Hydrogen power plants and storage systems might add significantly different value to grid operation services such as balancing power, spinning reserves, etc., or to resource adequacy.

FIGURE 51:
System cost differences between multiple central investment options and hydrogen power plants only.



	H2 Power Plants Only	Multiple Central Investment Options
system costs	10,66	-8,99

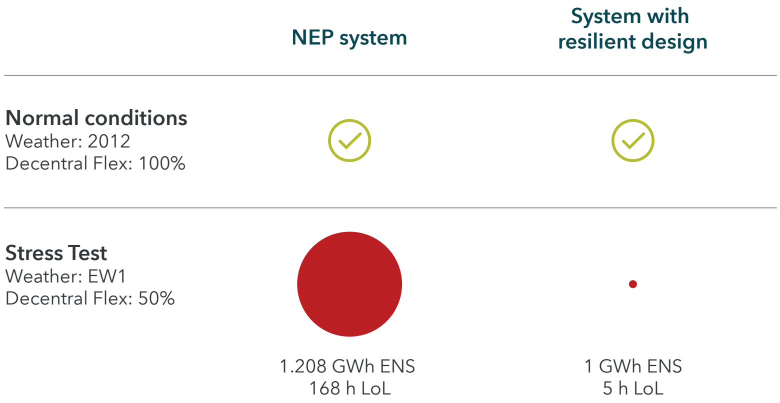
8.3.3 CENTRAL TECHNOLOGIES AND RESOURCE ADEQUACY

We also want to analyse how robust a system is, if lesser decentral flexibilities are taken into account in system design. The linear optimisation models used for this study assume perfect foresight and actors behaving in line with the "homo economicus" characterisation. But decentral flexibility, with diverse households and different levels of market awareness, should be not regarded as fully reliable. Internet outages, unawareness or personal preferences might lead to less than 100 % market orientation in the critical hours.

For this, we define a stress test and test two different systems to deal with it. The first is the original NEP system, which is known to work well with the assumption of 100 % market-oriented prosumers and with climatic conditions comparable to the meteorological year 2012. We will benchmark this against the preferable system of "Multiple Central Investment Options", as it has resilience against non-participating prosumers and is economically attractive. The stress situation involves reducing prosumer market participation from 100 % to 50 % and simulating an SSP5-8.5 meteorological year with overall low RES yields for Europe (Extreme Weather 1, see Chapter 7.3.2). We then used our model coupling approach to measure the adequacy KPIs in the market model.

Figure 52 shows the results of this comparison. We can observe that the combined stress of non-participating prosumers and European weather challenges lead to a severe situation. 1,208 GWh of Energy Not Served with nearly 170 hours of Loss of Load. Clearly, under these conditions, the NEP system does not perform in acceptable ranges. In contrast, the system designed with 9.5 GW of higher storage capacities, in combination with much stronger interconnection of European nations, performs rather well under these conditions, with 1 GWh ENS and 5 hours of Loss of Load.

FIGURE 52:
Resilience of different system designs.



The main thing we learn from this is that considering multiple different situations is crucial to assessing the feasibility of a system. While we identified in 8.3.1 that utilising 100 % of prosumer flexibility might avoid an additional 9 GW of hydrogen turbines, we have now identified that hedging against prosumer non-participation also increases resilience against challenging European weather conditions.

For better readability, the results of the remaining clusters can be found in the Appendix.

9.0

OUTLOOK

In the final chapter we briefly summarise possible streams for future activities:

/ **Combination of climate and flexibility analyses**
Five meteorological years are analysed within the framework of the study. This makes it difficult to quantify statistical risk (e.g. LOLE and EENS distributions), as the frequency of occurrence of extreme weather years is not clear. While the report acknowledges this, an analysis using a Monte Carlo approach (e.g. with 30 or more years as in ERAA) would provide additional statistical rigour for further work. In addition, the Monte Carlo approach could be extended to take into account different combinations of weather conditions and availability of flexibility technologies, as these two elements turned out to be of primary importance for long-term security of supply in the power sector.

/ **Climate impact on grids and optimal placement of new power plants and loads**
Analysis of the impact of several weather and climate patterns on grid usage would help to round out the picture regarding the expected range of variability for the operation of climate-neutral power grids. A further element for consideration is an evaluation of the possible significant reduction in transmission potential at converter locations due to high ambient temperatures. Further, the optimal placement of new thermal power plants as well as large new industrial applications such as electrolysers and data centres still has to be fully investigated in terms of network-friendliness and other criteria.

/ **Policy integration and governance**
While the policy level has deliberately not formed part of the study, a forward-looking, adequate regulatory setting will be of paramount importance in achieving an affordable energy transition – for implementing suitable cross-border solutions, for example. Technical feasibility does not mean political deliverability. Further assessment could include an evaluation of how governance, permit processes, or regulatory alignment may impact the interconnection buildout.

/ **Long-term grid stability**
Calculations of the dynamic behaviour of the transmission grid would be of great benefit in providing insights and checking whether the stability criteria are met. This task is not entirely connected to the question of security of supply, but is nevertheless important for ensuring stable grid operation in 100 % decarbonised energy systems. The aim of the dynamic investigations is to determine how the system will behave in 2050, i.e. what is necessary for stable grid operation from a grid perspective, and what additional costs are associated with this (e.g. statcoms). This step requires the detailed parameterisation of each system including technical limits (reactive power behaviour, controller behaviour or system behaviour in the event of a fault).

/ **End-user cost impacts and adapted scenario setting**
The study reports the cost for Europe and Germany as a whole, but retail price implications for consumers were not the object of the analysis. Affordability is a central public and political concern in the current energy policy discussion. An extension of the cost evaluations should therefore include an estimation of impact for consumers / prosumers (e.g. €/MWh or €/household/year) under different scenarios. Finally, both the rapidly evolving political situation and current trends call for an ongoing update of scenarios to enable future developments in the energy sector to be accurately covered and to facilitate the design of robust solutions. In the last few months, a few studies have appeared which questioned key assumptions regarding long-term power demand trends and the European hydrogen supply. While it is important to consider a wide spectrum of scenarios in order to deliver robust energy system planning, scenario evaluation should take account of the entire energy sector and its overall cost. Finally, to provide better comparability, evaluations of energy transition pathways should span a timeframe that will cover the achievement of climate neutrality.

GLOSSARY

TERM	DEFINITION
(N-1) CRITERION	Generally accepted rule of grid planning principles. It states that a grid is (n-1) securely planned if grid security is guaranteed for all predicted horizontal and vertical transmission tasks that are relevant to planning and dimensioning (grid use cases),both in the event of an (n-1) outage (case of outage of one grid element) and if operational clearance for equipment is given, i.e. if no equipment is outside its operating limits. (German Transmission System Operators, 2024a)
CLUSTER	In this study, a cluster (or scenario cluster) refers to a thematic group in which changes are made to the framework condition assumptions used in the NEP scenarios. Clusters help to identify the impact of (changing) framework assumptions on security of supply. The relevant clusters were determined through several iterations with internal and external Stakeholders, namely NEP, FLEXIBILITY, CLIMATE, H2 POWER PLANTS, ENERGY SOVEREIGNTY and SERVICE TARGET.
COMBINED HEAT AND POWER (CHP)	Combined heat and power (CHP) is the simultaneous conversion of primary energy into mechanical or electrical energy and usable heat within a thermodynamic process. The heat produced in parallel with electricity generation is used for heating and hot water supply or for industrial processes. The use of cogeneration reduces the energy input and carbon dioxide emissions. (Federal Environment Agency, 2025)
CONVERTER STATION	A converter transforms alternating current into direct current and vice versa. The necessary structures are called converter stations. Without converters, HVDC transmission lines cannot be integrated into the interconnected AC grid. A converter must therefore be installed at the beginning and end of an HVDC transmission line.
DECARBONISATION	In the energy system, decarbonisation refers to the reduction of use of energy sources based on hydrocarbons such as oil, coal or gas.
DETERMINISTIC APPROACH	Today, Resource Adequacy assessments generally rely on a probabilistic approach, whereas in the past, they were conducted using a deterministic methodology. In a deterministic approach, all parameters are fixed, including climate factors affecting supply and demand, as well as the technically or economically constrained availability of generation, storage, and transmission resources (Diels and Müsgens, 2023; p. 20). However, in reality, these parameters cannot be precisely determined; as a solution, these can instead be modelled using probabilistic methods.
ENERGY SYSTEM MODEL (ESM)	In this study, the energy system model assesses the impact of AQ2050-clusters on capacities and investment decisions in renewable energy, flexible generation, storage, and grid infrastructure. It integrates electricity, heating, transportation, and industry sectors into a comprehensive European system view, producing optimised electricity time series for sector-coupled technologies. The model operates in an aggregated, simplified way with a long-term focus on investment and dispatch.
(EXPECTED) ENERGY NOT SERVED((E)ENS)	Energy Not Served (ENS [GWh]) is the sum of the electricity demand which cannot be supplied due to insufficient resources. A null ENS suggests that there are no adequacy concerns. Expected Energy Not Served (EENS [GWh]) is the electricity demand which is "expected" not to be supplied due to insufficient resources. The term "expected" comes from probability and statistical analysis. It refers to the statistical mean or probabilistic average. EENS represents a mean (not a median) over multiple yearly simulations (e.g. meteorological years and/or power plant availabilities). (ENTSO-E, 2023b)

ENTSO-E

European Network of Transmission System Operators for Electricity (ENTSO-E), based in Brussels, is the association of European Transmission System Operators for Electricity. The association comprises 40 transmission system operators (TSOs) from 36 countries and has existed since December 2008. ENTSO-E fulfils legally defined tasks and prepares the TYNDP, which contains European scenarios for the years 2030 to 2050. (ENTSO-E, 2025; ENTSOG/ENTSO-E, 2025)

ENTSOG

European Network of Transmission System Operators for Gas (ENTSOG), based in Brussels, is the association of European Transmission System Operators for Gas. The association comprises 43 TSO Members, 1 Associated Partner, and 9 Observers from across Europe and has existed since December 2009. ENTSOG fulfils legally defined tasks. The TYNDP provides a picture of European gas infrastructure and future developments and includes modelling of the integrated gas network based on a range of development scenarios. (ENTSOG, 2025a, 2025b)

ERA5

ERA5 is the fifth generation of atmospheric reanalysis produced by the European Centre for Medium-Range Weather Forecasts (ECMWF). It provides hourly estimates of various atmospheric, land, and oceanic variables from 1940 to the present. ERA5 combines historical observations with advanced modelling and data assimilation techniques to create a comprehensive and consistent dataset.

FLEXIBILITY TECHNOLOGIES

In this study, flexibility technologies are categorized into decentral and central flexibility technologies. Under decentral flexibility technologies we understand household-proximate devices such as rooftop PV, small-scale batteries, heat pumps and e-mobility. Under central flexibility technologies we understand climate-neutral thermal power plants such as hydrogen turbines as well as large-scale batteries, electrolysers and interconnectors (in order to enable access to additional, geographically distant balancing options). Due to the limited additional available potential, hydropower is, however, only considered with existing capacity. The flexibility aspect that we focus on consists of the ability to change the dispatch of a unit, whether this involves load or generation. The signal for controlling such flexibility-providing technologies might be a market signal or a direct dispatch signal ordered by an operator.

Fork (Software)

In software engineering, a project fork occurs when developers duplicate the source code from an existing software package and begin developing it independently, resulting in a new and separate software product.

GRID CONGESTION

Grid congestion is defined as exceeding the capacity of electrical grid equipment or violating technical parameters in the electricity supply. In general, grid congestion is caused by exceeding the active power capacity of electrical equipment (current-related) or by failing to keep the voltage quality for an item of electrical equipment or entire grid area within operational limits (voltage-related). (BNetzA, 2024)

GRID LOSSES

The term grid losses refers to the total energy which is lost during the transmission or transformation of electricity. Network losses are the difference between the metered energy feed-in and consumption over all grid access points. (Zebisch, 1959)

GRID MODEL

In this study, the final step in the model chain is the grid model which evaluates the physical transmission network based on market model results. It assesses network capacity, identifies overloads, determines necessary development measures, and calculates redispatch needs. Representing network topology and transmission properties in a stationary time range, it offers high detail for Germany and neighbouring countries, with reduced detail for the rest of the EU.

HEAT PUMPS

A heat pump is a heat generator which, by supplying energy (usually electricity), can absorb additional environmental energy at low temperature and use it for heating purposes. (Baunetz Wissen, 2025)

INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE (IPCC)

Intergovernmental Panel on Climate Change (IPCC), based in Geneva, Switzerland, is the United Nations body for assessing the science related to climate change. The Panel comprises 195 Member countries and has existed since 1988. Through multi-stage drafting and review, the IPCC provides policymakers with policy-relevant scientific assessments of climate change, its impacts, future risks, and adaptation and mitigation options, informing international climate negotiations. (IPCC, 2025b)

LOSS OF LOAD EXPECTATION (LOLE)

Loss of Load Expectation (LOLE [h]) is the "expected" number of hours during which resources are insufficient to meet demand. The term „expected" in LOLE and EENS comes from probability and statistical analysis. It refers to the statistical mean or probabilistic average. It refers to the statistical mean or probabilistic average. LOLE represents a mean (not a median) over multiple yearly simulations (e.g. meteorological years and/or power plant availabilities). (ENTSO-E, 2023b)

MARKET MODEL

In this study, the market model builds on the energy system model outputs and focuses on the electricity sector. It simulates detailed asset dispatch at a resolution fit for network analysis, determining electricity prices and ENS distributions. Using a disaggregated technology representation, it operates in dispatch-only mode over a single-year horizon to analyse system operation and market dynamics.

METEOROLOGICAL YEAR

A meteorological year is a set of hourly meteorological data. It can be obtained from historical datasets or projected in a climate scenario for a specific year and scenario.

NOVA PRINCIPLE

The term NOVA is a German acronym for network optimisation before enhancement before expansion ("Netz-Optimierung vor Verstärkung vor Ausbau"). The principle describes a principle of grid planning to minimise the need for grid expansions. Existing infrastructure is first optimised, then enhanced and as a last option expanded. (German Transmission System Operators, 2024b)

OUTAGE SIMULATION

Outage simulation is the simulation of the outage of grid elements in electricity grids to determine possible overloads and consequential failures. (Schaefer, 2013)

OVERLOAD ENERGY

Overload energy is calculated for each individual circuit from the sum of the hourly power that cannot be transmitted in the (n-1) case due to an overload.

PHASE-SHIFTING TRANSFORMER (PST)

Grid equipment which is a specific type of transformer. The phase-shifting transformer enables control of load flows in the alternating current grid.

PRINCIPAL COMPONENT ANALYSIS (PCA)

Principal Component Analysis (PCA) is a statistical technique used to reduce the dimensionality of large datasets while preserving as much variability as possible. In the context of climate data, PCA is utilised to identify and extract typical spatial patterns from high-resolution time series data, thereby enhancing the resolution of coarse climate projections.

PROBABILISTIC APPROACH

Based on or adapted to a theory of probability. Resource Adequacy assessment (generally) uses a probabilistic methodology to reflect the behaviour of parameters that cannot be determined precisely but instead follows probabilistic rules. This involves climate parameters affecting supply and demand as well as the unexpected technically or economically constrained availability of generation, storage and transmission resources. (ENTSO-E, 2020; p. 11)

PROSUMER

A prosumer is an individual or entity that both produces and consumes electricity. Prosumers generate their own electricity, often through small-scale installations such as rooftop solar panels, and use this energy for their own needs. Any excess energy can be fed back into the grid.

REPRESENTATIVE CONCENTRATION PATHWAYS(RCPs)

Representative Concentration Pathways (RCPs) are scenarios used to project future greenhouse gas concentrations and their impact on climate change. They describe different potential futures based on varying levels of greenhouse gas emissions and were developed by the Intergovernmental Panel on Climate Change (IPCC, 2025a).

REDISPATCH

Redispatch is the term used to describe measures that avoid grid congestion events (preventive) or eliminate them (curative). If congestion occurs, generation by the power plants on one side of the congestion is reduced, while generation by the power plants on the other side is increased. This reduces the power flows over the overloaded network element. (BNetzA, 2024)

REFERENCE (TRANSMISSION) GRID

The reference grid is the assumed expansion status of the electricity grid as the starting point for the grid calculations.

REGIONALISATION

Regionalisation is the assignment of generation plants and load to certain regions or to specific grid nodes. This assignment is required to carry out market simulations and grid calculations. (BNetzA, 2023)

RESIDUAL LOAD

The residual load corresponds to the demanded electrical power after deducting the volatile feed-in of renewable energy sources such as wind and solar energy (RP Energie Lexikon, 2025). It must be covered by controllable generation, such as CCGT plants, in order to ensure a balance between electricity generation and electricity demand at all times.

RESOURCE ADEQUACY

From a market perspective, security of supply is ensured when the available supply in the electricity market is sufficient to meet demand in an economically efficient manner. This requires that, under predictable and manageable risks – such as changes in electricity demand or carbon dioxide (CO_2) prices – the market provides adequate generation capacity within the given political and economic framework.(BNetzA, 2023; p. 21)

SCENARIO

A scenario is a possible combination of constraints used to analyse and evaluate potential future states or developments. In this study, scenarios model possible energy system developments and their impacts on grid planning and operation.

STORAGE CAPACITY

Storage capacity is the total amount of electrical energy that can be stored in or discharged from the storage system and is measured in units of watt hours (e.g., megawatt hours [MWh], or gigawatt hours [GWh]). (EIA, 2025)

SHARED SOCIOECONOMIC PATHWAYS (SSP)

Shared Socioeconomic Pathways are scenarios developed by the Intergovernmental Panel on Climate Change (IPCC). They describe possible future development pathways for human society, particularly in relation to the use of fossil fuels and the socioeconomic factors driving fossil fuel consumption (IPCC, 2025a).

SYSTEM ADEQUACY

In a static analysis, System Adequacy consists of the following two components, market-based Resource Adequacy and grid-based Transmission Adequacy.

TARGET GRID

The target grid is the theoretical state of expansion of the electrical grid after all identified grid expansion measures have been implemented.

TRANSIT (FLOW)

Transit flows are the transmission of electricity through a dedicated grid area. Transits are the balance of imports and exports of this grid area.

TRANSMISSION ADEQUACY

Grid-related security of supply is ensured when the electricity supply can also be physically transmitted via the grid – meaning that generation can be delivered to consumers without congestion (or with congestion management measures in place) (BNetzA, 2023; p. 71). In the German Network Development Plan, this concept is also referred to as Demand Adequacy ("Bedarfsgerechtigkeit"), taking into account both limited transmission capacity and potential equipment failures. (German Transmission System Operators, 2024b)

(WEATHER-DEPENDENT) DYNAMIC LINE RATING (DLR)

The transmission capacity of the power grid varies depending on the season and weather. With colder temperatures and cooling by wind, more power can be transmitted than on hot summer days. With the help of weather-dependent DLR it is possible to increase the load of the electrical grid significantly. On the basis of current measurement data, it is possible to calculate exactly the maximum load flows that may be acceptable under the current weather conditions, so that the sag of the transmission lines remains within the technical specifications.

LIST OF ABBREVIATIONS

ABBREVIATIONS	INFORMATION
AC	Alternating Current
ACER	European Union Agency for the Cooperation of Energy Regulators
AQ	Adequacy
AT	Austria
BA	Bedarfsanalyse (Demand Analysis)
BBP	Bundesbedarfsplan (Federal Requirements Plan)
Benelux	Union of Belgium, the Netherlands and Luxembourg
BESS	Battery electric storage systems
BE	Belgium
(B)EV	(Battery) Electric Vehicle
BMWK	Federal Ministry for Economic Affairs and Climate Action (Germany)
BNetzA	Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway (Germany)
BW	Baden-Wuerttemberg (German Federal State)
CAPEX	Capital Expenditures.
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CH	Switzerland
CHP	Combined heat and power
CLM	Climate Cluster
CONE	Cost of New Entry
CO2	Carbon dioxide
CMIP6	Coupled Model Intercomparison Project Phase 6
DE	Germany
DestinE	Destination Earth Project
DK	Denmark
DKE	Denmark East
DKK	Deutsches Klima Konsortium
DKW	Denmark West
DLR	Dynamic line rating
DS	Distribution System

DSM	Demand Side Management
EC	European Commission
EIA	U.S. Energy Information Administration
EG	Europäische Gemeinschaft
DWD	Deutscher Wetterdienst (German Weather Service)
ECMWF	European Centre for Medium-Range Weather Forecasts
EEG	Renewable Energy Act
EENS	Expected Energy Not Served
ENS	Energy Not Served
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
EnWG	Law on electricity and gas supply (Energy Industry Act)
ERAA	European Resource Adequacy Assessment
ERA5	ECMWF Reanalysis v5
ESIG	Energy Systems Integration Group
ESM	Energy System Model
EU	European Union
EU27+3	27 member states of the European Union (EU) plus the three non-EU countries that belong to EFTA (European Free Trade Association)
EU-ETS	EU Emissions Trading System
EVA	Economic Viability Assessment
EW 1-3	Extreme Weather 1-3
FCEV	Fuel Cell Electric Vehicle
FGH	Forschungsgemeinschaft für Elektrische Anlagen und Stromwirtschaft e.V.
FLX	Flexibility Cluster
FR	France
W, Wh	Watt, Watt hour
GB	United Kingdom
GHG	Greenhouse Gas
GHI	Global Horizontal Irradiance
GM	Grid Model
H2	Hydrogen gas (or Dihydrogen)
H2P	Hydrogen Power Plant Cluster

H2 GT	H2 gas turbine
HT	High Temperature
HTLS	High Temperature Low Sag
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
ICE	Internal Combustion Engine
ID	Identifier
IPCC	Intergovernmental Panel on Climate Change
IT	Italy
km	Kilometre
KPI	Key Performance Indicator
LA	Langfristanalyse (Long-Term Analysis)
LOL(E)	Loss of Load (Expectation)
LOLH	Loss of Load Hours
LU	Luxembourg
LULUCF	Land Use, Land Use Change and Forestry
MM	Market Model
NA	New Average
NEP	German Netzentwicklungsplan (Network Development Plan)
NL	Netherlands
NO	Norway
NTC	Net Transfer Capacity
OPEX	Operational Expenditures.
PCA	Principal Component Analysis
PECD	Pan-European Climate Database
PHEV	Plug-in Hybrid Electric Vehicle
PINT	„Put one in at a time"
PL	Poland
Pmax	Maximum Power
PST	Phase-Shifting Transformer
PV	Photovoltaic
PyPSA-Eur	Python for Power System Analysis – Europe

PyPSA-Eur-Sec	Python for Power System Analysis – Europe – Sector Coupling
SSP	Shared Socioeconomic Pathways
RCP	Representative Concentration Pathways
RE(S)	Renewable Energy (Source)
SE	Sweden
T	Temperature
TOOT	„Take one out at a time“
TSO	Transmission System Operator
TYNDP	Ten Year Network Development Plan
v	Wind Speed
VoLL	Value of Lost Load

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APPENDIX

1.1 MODEL DETAILS

1.1.1 ENERGY SYSTEM MODEL (ESM)

Conversion Sectors in the ESM	Depiction	
	Invest	Dispatch
Renewable Energies **Offshore & Onshore Wind, Rooftop & Utility Scale PV, Run of River, Hydro Storages**	/ Endogenously modelled and expandable / Endogenously determined area and output potentials / Exogenous expansion paths possible / Aggregated and not location-specific / Local grid connections not depicted	/ Standardised hourly generation profiles after selecting the weather scenario / Consideration of any extreme weather scenarios possible / Endogenous market-driven curtailment possible
Thermal Power Plants **Coal, Nuclear, Natural Gas, Oil, Hydrogen, Biomass, Waste, etc.** **Electr. & Combined Heat and Power**	/ Endogenously modelled and expandable / Exogenous expansion paths possible / Aggregated and nit location-specific / Local grid connections not depicted	/ Flexible / Restriction of full-load hours possible / Consideration of must-run profiles possible
Heating Plants **Incl. Large Heat Pumps**	/ Endogenously modelled and expandable / Exogenous expansion paths possible / Aggregated and not location-specific	/ Flexible / Restriction of full-load hours possible / Consideration of must-run profiles possible
Flexibility **Electrolyzers, Pumped Storages, Large Scale Batteries**	/ Endogenously modelled and expandable / Exogenous expansion paths possible / Aggregated and nit location-specific / Local grid connections not depicted	/ Flexible / Restriction of full-load hours possible / Consideration of must-run profiles possible

Infrastructure	Invest
Transmission Grid **Incl. HVDC**	/ Cross-border transmission grid: aggregated per border and referred to as NTC (Net Transfer Capacity). Cross-border capacities can be expanded endogenously in the model for a cost. Germany can be divided into several zones in the ESM. / Intra-zonal transmission network: This is not taken into account.
Distribution Grid	/ Distribution grids are greatly simplified and aggregated for each market area. / The aim of the highly simplified depiction of the distribution grids is a more realistic consideration of the distribution grid expansion costs in line with the degree of utilization and spatial distribution of electricity demand.
Gas Pipelines **Incl. Hydrogen Pipelines**	/ Cross-border gas pipelines: These are aggregated for each border. Cross-border capacities can currently only be expanded with exogenous expansion paths. Germany can be divided into several zones in the ESM. / Intra-zonal gas pipelines: These are not taken into account.
Gas Distribution Network **Incl. Hydrogen Pipelines**	/ This is not taken into account in the ESM.
Heating Network **District and Local Heating**	/ Expansion and operating costs of heating networks are not taken into account in the ESM. / It is possible to determine exogenously what proportion of the heat for buildings must be covered by heating networks.

Sector	ESM Depiction
Heating Sector	/ **Central heating sector (heating via heating networks):** The proportion of the heat demand of the buildings that must be covered by heating networks is specified exogenously in the ESM. The technologies that generate this heat in CHP plants heating plants are considered endogenously in the conversion sector. Cost optimization prevails on the basis of the so-called „merit order" effect. / **Decentral heating sector:** The rest of the heat demand in the building sector is explicitly and endogenously defined in the ESM based on different technologies (e. g. decentral heat pumps, gas and oil boilers, biomass, etc.), each of which has to meet its own demand profiles independently. There must be no „merit order" effect. In the decentral heating sector, the ESM distinguishes between residential and non-residential buildings. / **Flexibility in the heating sector:** Flexibility in the heating sector, especially in the case of heat pumps, is explicitly and endogenously modelled in the ESM / **Weather dependency:** Both, the total annual heat demand and the demand profile during the year are flexibly oriented to the selected weather scenario, which allows extreme weather events, such as long cold waves, to be analysed.
Other Electricity Demand **Opt. Incl. Air Conditioning**	/ Other electricity demand from the appliances, lighting, etc. from building sectors is modelled in the ESM exogenously and with an hourly profile. / Air conditioning is currently not taken into account endogenously in the ESM and can only be considered exogenously with a fixed demand profile under other electricity demand.
Other Demands	/ Other energy source demand in the building sector (e. g. gas for cooking) is currently not taken into account.

Sector	ESM Depiction
Passenger Cars	/ The passenger car sector is explicitly and endogenously modelled in the ESM on the basis of different technologies (e. g. electric vehicles, fuel cell vehicles, combustion engines incl. Gasoline, diesel, gas, etc.) including their emissions. / **Flexibility** of electric vehicles (both shifting charging and vehicle-to-grid) is explicitly and endogenously modelled in the ESM by modelling the vehicle batteries.
Rest of Transport Sector	/ Final energy demand (including oil products, electricity, synthetic fuels) and their emissions from the rest of the transport sector are modelled exogenously and static the ESM. / Rest of the transport sector includes: / Public transport buses / Rail transport including long-distance traffic, trams, regional trains, etc. / Freight traffic / National shipping and air transport / International shipping and air transport

Sector	ESM Depiction
Industry Sector	Final energy demand (including electricity, methane, hydrogen, oil products, synthetic fuels, biomass, etc.) and their emissions are modelled exogenously and static in the ESM. There is the possibility of meeting methane demand in industry with either natural gas or biogas or electricity-based methane. The model decides endogenously on this. As part of the RESILIENT funding project and in cooperation with TU Berlin, part of the energy-intensive industry, such as cement and steel production, including the connected CO2 network, will be endogenously integrated into the open-source model PyPSA-Eur (basis of our ESM). TransnetBW is involved in this and will be able to introduce this new modelling system into the ESM after completion of the project. Thus, the model can decide endogenously on: / Expand power grids and operate electrolysers on site at industrial sites, OR / Locate electrolysers close to renewable sources and transport hydrogen to industrial sites, OR / To continue to use fossil gas in industry in some cases and to capture emissions and transport them via CO2 network for storage or usage in other industrial sectors (such as chemicals).
Agriculture & Waste Management	Agriculture is not depicted separately and can only be considered exogenously and integrated in the industrial sector.

1.1.2 LIST OF TECHNOLOGIES

TABLE 19:
Overview of model components, part 1.

This table presents the complete list of the technologies included in ESM.

Buses	Generators	Links	
[EU-Level]	**[EU-Level]**	**[EU-Level]**	Air-Source Heat Pumps[2),3)]
Atmosphere CO2	EU-Natural Gas	CO2 Ventilation	Air-Source Heat Pumps[1)]
CO2 Storage	EU Oil	Direct-Air-Capture	Heat Storage[1),2),3)]
Coal	Green Gas Imports	**[Regional-Level]**	Resistance Heater[1),2),3)]
Natural Gas	[Regional-Level]	Gas Turbine	Gas Boiler[1),2),3)]
Biogas / Biomass	Nuclear	H_2-Electrolysis	Micro-CHP[1),3)]
Synthetic Oil	Hydro	H_2-Fuel Cell	CHP[2)]
[Regional-Level]	Solar Thermal1),2),3)	H_2-Pipeline	Gas-to-Urban
Electric Power	Wind Offshore AC/DC	Batteries	Sold Biomass to Urban
Hydrogen	Wind Onshore 1 - 4	Sabatier-Process	Fischer-Tropsch-Synthesis
Batteries	PV Utility and Rooftop	High Temp. P2G (Helmeth)	Coal Power Plant (w CCS)
E-Mobility	Coal	Steam Methane Reforming	Coal –CHP (w CCS)
Heat[1),2),3)]	Energy Not Served	E-Mobility	Oil- und Coal Boiler
Heat Storage[1),2),3)]	DSM	Vehicle-2-Grid	Biomass-Boiler
CHP[2)]		H_2 Pipelines	

TABLE 20:
Overview of model components, part 2.

Stores/Storages	Demand/Load
[EU-Level]	Electricity
Atmosphere CO2	Heat[1),2),3)]
EU Natural Gas	E-Mobility
EU Biomass	Fuel Cells Mobility
Fischer-Tropsch Synthesis	H_2 Mobility[4)]
[Regional-Level]	Oils
Battery Storages	Biomass
E-Mobility-Batteries	Gas
Heat Storages[1),2),3)]	Coal
Pumped Hydro Storage	
Reservoirs	

NOTE
[1)]Rural
[2)]Urban & Central
[3)]Urban & Decentral
[4)]In Industry

1.1.3 IMPACT OF AMBIENT TEMPERATURE ON PV YIELD

PV Modules Lose Efficiency at High Temperatures:

- Increased Recombination: Higher temperatures increase the recombination of electrons and holes, reducing the number of electrons available for electricity generation.
- Reduced Voltage: The voltage produced by a PV module decreases with rising temperature, leading to lower power output. Increase in current is offset by the reduction in voltage
- Material Properties: The physical properties of the materials in PV modules change with temperature, affecting the efficiency of converting sunlight into electricity.

Ideal Operating Temperature: 25°C

Typical temperature coefficients for various PV technologies:

- PolySi: -0.41%/°C
- CdTe: -0.25%/°C
- CIGS: -0.31%/°C
- aSi: -0.3%/°C

PyPSA: -0.4681%/°C at a reference module temperature of 25°C
Example with 400 GW installed PV capacity, 1000 W/m² irradiation

- Summer (40°C): Efficiency loss of -6.00%
- Winter (0°C): Efficiency gain of +10.00%

1.1.4 MARKET MODEL (MM)

The **Market Mode**l represents the core of electricity market simulations. It provides detailed dispatch calculations using a disaggregated and detailed representation of technologies over a single-year time horizon.

How Market Model Fits into the Model Chain?

- Receives input from the Energy System Model (e.g., capacities of the power plants, investment costs and optimized electricity time series for the operation of sector-coupled technologies.).
- Focuses exclusively on the electricity sector and optimizes market dispatch and operation to ensure cost-effective electricity generation.
- Send results to the Grid Analysis Model, which checks grid stability and expansion needs.
- Supports economic evaluation of energy system components.

Table 21:
List of Technologies from the Market Model

Generation	
Biogas	PV (rooftop,ground-mounted)
Biomass	Reservoir Water
Hard Coal	Run-of-river Water
Lignite	Storage (electromobility, home battery, heat pumps, others)
Mineral Oil Product	Waste
Natural gas	Wind Onshore
Nuclear	Wind Offshore
Oil Shale	
Other Non-Renewables	
Other Renewables	
Poundage Water	
Pumped Hydro Storage	

Demand
Conventional
Electromobility
Grid losses
Heatpumps
Home Battery Storage
Large consumers
Demand side management technologies / Shiftable load (service sector and industry), such as food, data center, water and wastewater, aluminium, chlorine, wood, climate cooling, ... / Interruptible load (industry), such as aluminium, lighting and ventilation, chlorine, glass, wood pulp, paper, steel, ... / Power-to-X-technologies: electrode boiler, large heat pump, power-to-hydrogen (onsite, offsite)

1.1.5 GRID MODEL (GM)

The **Grid Analysis Model** in the graphic represents the final step in the model chain. It ensures that the results from the **Market Model** are technically feasible within the electricity grid.

How Grid Model Fits into the Model Chain?

- Receives input from the Market Model: INTEGRAL takes optimized generation dispatch and market-clearing results from Market Model.
- Checks technical feasibility: It runs load flow and stability analyses to determine if the grid can handle the power flows.
- Provides feedback on grid expansion needs: If bottlenecks are detected, it suggests reinforcements and sends recommendations for grid expansion.
- Supports assessment of supply security: The final step ensures that all planned market operations comply with physical grid constraints.

1.1.6 MODEL COUPLING

The model toolchain has been split into two model streams. First model pair consists of ESM and electricity market simulation (MM), which we will call scenario building track (SDT). The second model pair consists of MM and grid model (NeMo), which we will call the grid planning track (GPT). The models could theoretical also operate "in line", but for the sake of better handling of model iterations for bug-fixing, having two parallelizable streams offers significant time benefits. However, the GPT, although not conducted with the PLEXOS-Integral pair but with the BID3-Integral pair, is nearly plug-and-play, because model interfaces are already compatible to each other. Hence, the rest of the descriptions in this section will cover the much more complex coupling task of ESM to BID3.

A detailed list of all scenarios used for the study is given in Table 22

1.2 SCENARIOS

Table 22:
List of all scenarios

Scenarios			Framework Conditions					Model Chain		
Cluster	ID	Short Description	WY	RES	Central Flex	Decentral Flex	Other Constraints	ESM	MM	GM
NEP	N0	Reference	2012	NEP	NEP	NEP	-	yes	yes	no
NEP	N0b	Reference	2012	NEP	NEP	NEP		no	yes	yes
FLX	F0	Reference	2012	NEP	H2 Power Plants investment possible	NEP	-	yes	yes	no
FLX	F1a	Multiple Central Investment Options	2012	NEP	H2 Power Plants, Large-Scale BESS, Interconnection investments possible	reduced flexibility availability	-	yes	yes	no
FLX	F1b	Partly Decentral Stresstest	2050-EW1	NEP	fixed @F1a	reduced flexibility availability	-	yes	yes	no
FLX	F1c	Less Flexible Consumers/ H2 Power Plants Only	2012	NEP	H2 Power Plants investment possible	reduced flexibility availability	-	yes	yes	no
FLX	F2	Worst-Case	2050-EW1	NEP	NEP	less flexible	-	yes	yes	no
FLX	F3	Non-Flexible Electrolyzers	2012	NEP	H2 Power Plants investment possible	NEP	Electrolyzer are not flexible	yes	no	no
FLX	F4	Self-Sufficiency Consumers	2012	NEP	H2 Power Plants investment possible	self consumption		yes	yes	no
FLX	F6	Distribution Grid Optimized Consumers		NEP	H2 Power Plants investment possible	Distribution Grid Constraints		yes	yes	no
CLM	C0	Reference	2012	Investments in "Political Corridor" possible	H2 Power Plants, Large-Scale BESS, Interconnection investments possible	NEP	Electrolyzer Invest possible	yes	no	no
CLM	C1	New Average	2050-TMY	Investments in "Political Corridor" possible	H2 Power Plants, Large-Scale BESS, Interconnection investments possible	NEP	Electrolyzer Invest possible	yes	no	no
CLM	C2	Extreme Weather 1	2050-EW1	Investments in "Political Corridor" possible	H2 Power Plants, Large-Scale BESS, Interconnection investments possible	NEP	Electrolyzer Invest possible	yes	no	no
CLM	C3	Extreme Weather 3	2050-EW3	Investments in "Political Corridor" possible	H2 Power Plants, Large-Scale BESS, Interconnection investments possible	NEP	Electrolyzer Invest possible	yes	no	no

Scenarios			Framework Conditions					Model Chain		
Cluster	**ID**	**Short Description**	**WY**	**RES**	**Central Flex**	**Decentral Flex**	**Other Constraints**	**ESM**	**MM**	**GM**
CLM	C4	Extreme Weather 2	2050-EW2	Investments in "Political Corridor" possible	H2 Power Plants, Large-Scale BESS, Interconnection investments possible	NEP	Electrolyzer Invest possible	yes	no	no
CLM	C5	Historic 2010	2010	Investments in "Political Corridor" possible	H2 Power Plants, Large-Scale BESS, Interconnection investments possible	NEP	Electrolyzer Invest possible	yes	no	no
CLM	C6	Historic 2003	2003	Investments in "Political Corridor" possible	H2 Power Plants, Large-Scale BESS, Interconnection investments possible	NEP	Electrolyzer Invest possible	yes	no	no
CLM	C7	Historic 1990	1990	Investments in "Political Corridor" possible	H2 Power Plants, Large-Scale BESS, Interconnection investments possible	NEP	Electrolyzer Invest possible	yes	no	no
CLM	C8	Historic 1998	1998	Investments in "Political Corridor" possible	H2 Power Plants, Large-Scale BESS, Interconnection investments possible	NEP	Electrolyzer Invest possible	yes	no	no
CLM	C9	Extreme Weather 3	2050-EW3					no	yes	yes
ESO	E1	Less German H2 Autarky	2012	Investments in "Political Corridor" possible	add. Invest	NEP	less H2 autarky, Electrolyzer investments possible	yes	no	no
ESO	E2	Higher German H2 Autarky	2012	Investments in "Political Corridor" possible	add. Invest	NEP	more H2 autarky, Electrolyzer investments possible	yes	no	no
ESO	E3	Higher EU Energy Sovereignty	2012	Investments in "Political Corridor" possible	add. Invest	NEP	more En autarky, Electrolyzer investments possible	yes	no	no
H2P	H1	Reduced H2 Power Plants	2012	corridor	add. Invest	NEP	H2 Power Plants and Electrolyzers reduced	yes	no	no
STA	S3	Variable ENS	2012	NEP	H2 Power Plant capacities below NEP allowed	NEP	ENS 2.5k, 20%HH	yes	no	no

1.3 INPUT-DATA FOR THE MODELS

1.3.1 METEODATA

Scenario	Trajectory	Model	Year
NA	SSP5-8.5	MOHC__HadGEM3-GC31-MM__r1i1p1f3__3hr	2046
EW1	SSP5-8.5	MOHC__HadGEM3-GC31-MM__r1i1p1f3__3hr	2049
EW2	SSP5-8.5	MOHC__HadGEM3-GC31-LL__r1i1p1f3__3hr	2048
EW3	SSP5-8.5	CCCma__CanESM5__r1i1p2f1__3hr	2046

Table 23:
Overview of the climate models used, the respective model year, the trajectory and the assignment to the climate scenario identifiers used in the context of this study

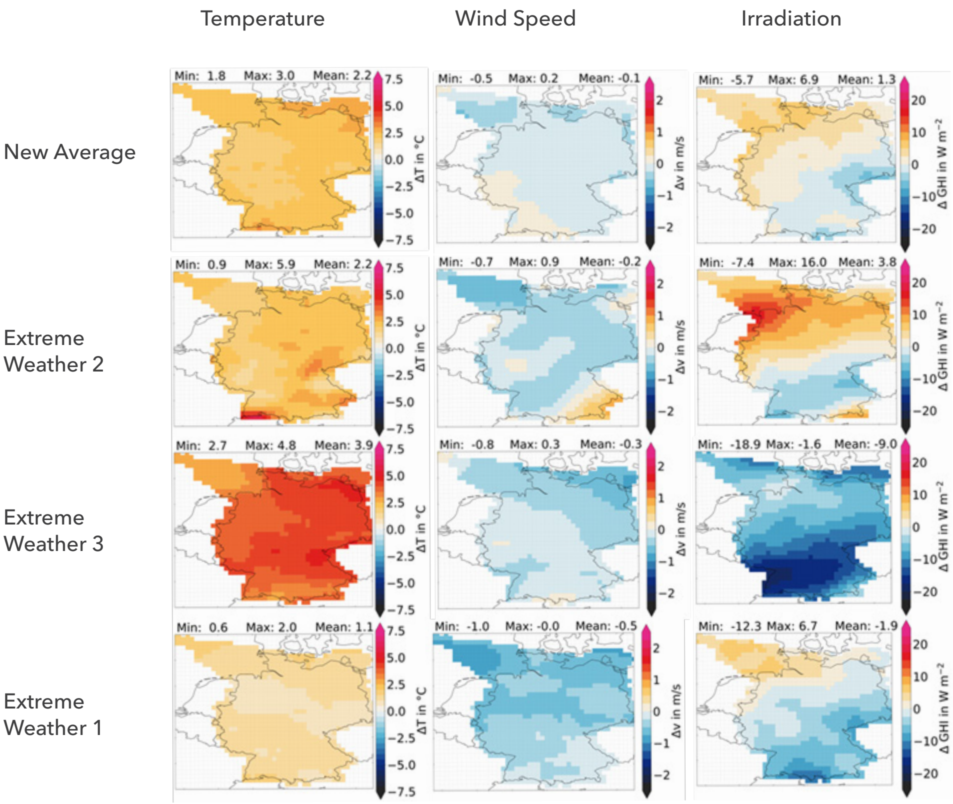


Figure 53:
Mean difference in the annual distribution of temperature, 100 m wind speed, and solar irradiation over Germany in the climate projections of the scenarios Extreme Cold, Extreme Heat, Normal, and Renewable Drought compared to the historical reference year 2012, based on the ERA5 dataset.

1.3.2 TECHNOLOGIES AND TECHNO-ECONOMIC ASSUMPTIONS

Table 24:
Main techno-economic assumptions, 2030 to 2050.

Technology	Unit	Parameter	2030	2040	2050
battery inverter	per unit	efficiency	0.91	0.92	0.92
battery inverter	%/year	FOM	0.49	0.70	0.90
battery inverter	EUR/kWel	investment	160	80	63
battery inverter	years	lifetime	21	26	30
battery storage	EUR/kWh	investment	153	76	60
battery storage	years	lifetime	21	26	30
home battery inverter	per unit	efficiency	0.91	0.92	0.92
home battery inverter	%/year	FOM	0.49	0.70	0.9
home battery inverter	EUR/MWh	VOM	0	0	0
home battery inverter	EUR/kWel	investment	344.6	172	135.5
home battery inverter	years	lifetime	11.1	13.7	15.8
home battery storage	EUR/kWh	investment	344.6	172	135.5
home battery storage	years	lifetime	11.1	13.7	15.8
home battery storage	per unit	standing losses	0	0	0
biomass	per unit	efficiency	0.30	0.30	0.30
biomass	%/year	FOM	5.01	5.01	5.02
biomass	EUR/kWel	investment	3,230	3,227	3,224
biomass	years	lifetime	30	30	30
H2 pipeline	per unit	efficiency	0.99	0.99	0.99
H2 pipeline	%/year	FOM	0.8	0.8	0.8
H2 pipeline	EUR/kWel	investment	659	659	659
H2 pipeline	years	lifetime	55	55	55
biomass	years	lifetime	30	30	30
CCGT	per unit	efficiency	0.6	0.6	0.6
CCGT	%/year	FOM	3.43	3.43	3.43
CCGT	EUR/kWel	investment	691	691	691
CCGT	years	lifetime	31	31	31
CCGT	EUR/MWhel	VOM	4	4	4
CCGT_H2_retrofit	per unit	efficiency	0.6	0.6	0.6
CCGT_H2_retrofit	per unit	FOM	3.16	3.16	3.16
CCGT_H2_retrofit	%/year	investment	774.38	774.38	774.38
CCGT_H2_retrofit	EUR/kWel	lifetime	31	31	31
CCGT_H2_retrofit	years	VOM	4	4	4
DAC	%/year	FOM	4.95	3.91	4.95
DAC	EUR/(tCO2/h)	investment	5714,286	4857,143	4000,000
DAC	years	lifetime	20.00	20.00	20.00
electrolysis	per unit	efficiency	0.66	0.69	0.72
electrolysis	%/year	FOM	4.36	3.61	2.85
electrolysis	EUR/kWel	investment	500	400	275
electrolysis	years	lifetime	19	21	23
Fischer-Tropsch	per unit	efficiency	0.59	0.63	0.66
Fischer-Tropsch	%/year	FOM	7.16	8.45	9.74
Fischer-Tropsch	EUR/kWH2	investment	1,141	994	846
Fischer-Tropsch	years	lifetime	19	22	25

Technology	Unit	Parameter	2030	2040	2050
HVAC overhead	%/year	FOM	2	2	2
HVAC overhead	EUR/MW/km	investment	500	500	500
HVAC overhead	years	lifetime	40	40	40
HVDC inverter pair	%/year	FOM	2	2	2
HVDC inverter pair	EUR/MW	investment	600,000	600,000	600,000
HVDC inverter pair	years	lifetime	40	40	40
HVDC overhead	%/year	FOM	2	2	2
HVDC overhead	EUR/MW/km	investment	2000	2000	2000
HVDC overhead	years	lifetime	40	40	40
HVDC submarine	%/year	FOM	2	2	2
HVDC submarine	EUR/MW/km	investment	2,000	2,000	2,000
HVDC submarine	years	lifetime	40	40	40
hydrogen storage	EUR/kWh	investment	41.57	31.29	21
hydrogen storage	years	lifetime	30	30	30
hydrogen underground storage	EUR/kWh	investment	0.03	0.03	0.03
hydrogen underground storage	years	lifetime	33	33	33
methanation	per unit	efficiency	0.86	0.88	0.90
methanation	%/year	FOM	2.13	2.21	2.30
methanation	EUR/kWMethan	investment	369.36	289.46	249.78
methanation	years	lifetime	20	22	25
nuclear	per unit	efficiency	0.33	0.33	0.33
nuclear	%/year	FOM	3.07	3.07	3.07
nuclear	EUR/MWhth	fuel	1.69	1.69	1.69
nuclear	EUR/kWel	investment	7,619.66	6,676.53	6,268.04
nuclear	years	lifetime	60	60	60
nuclear	EUR/MWhel	VOM	2.10	2.10	2.10
OCGT	per unit	efficiency	0.40	0.40	0.40
OCGT	%/year	FOM	3.25	3.25	3.25
OCGT	EUR/kWel	investment	413.32	413.32	392.31
OCGT	years	lifetime	31	31	31
OCGT	EUR/MWhel	VOM	3	3	3
OCGT_H2_retrofit	per unit	efficiency	0.4	0.4	0.4
OCGT_H2_retrofit	%/year	FOM	3	3	3
OCGT_H2_retrofit	EUR/kWel	investment	475.87	475.87	475.87
OCGT_H2_retrofit	years	lifetime	31	31	31
OCGT_H2_retrofit	EUR/MWhel	VOM	3	3	3
offwind	%/year	FOM	3.5	3.5	3.5
offwind	EUR/kWel	investment	1,684	1,516	1,415
offwind	years	lifetime	25	25	25
offwind	EUR/MWhel	VOM	0.01	0.01	0.01
onwind	%/year	FOM	1.26	1.33	1.41
onwind	EUR/kWel	investment	1,023.17	979.32	946.19
onwind	years	lifetime	25	25	25
onwind	EUR/MWhel	VOM	0.01	0.01	0.01

Technology	Unit	Parameter	2030	2040	2050
SMR	per unit	efficiency	0.74	0.74	0.74
SMR	%/year	FOM	7.03	7.03	7.03
SMR	EUR/kWCH4	investment	416.74	356.62	296.50
SMR	years	lifetime	25	25	25
SMR CCS	per unit	efficiency	0.67	0.67	0.67
SMR CCS	%/year	FOM	5.15	5.84	6.54
SMR CCS	EUR/kWCH4	investment	596.50	596.50	596.50
SMR CCS	years	lifetime	25	25	25
solar-rooftop	%/year	FOM	2.26	2.68	3.11
solar-rooftop	EUR/kWel	investment	784.95	660.72	536.48
solar-rooftop	years	lifetime	25	25	25
solar-utility	%/year	FOM	2.32	2.71	3.11
solar-utility	EUR/kWel	investment	462	357	335
solar-utility	years	lifetime	25	25	25
Hard Coal	€/MWhth	-	13.55	6.86	6.68
Natural Gas	€/MWhth	-	25.07	14.24	14.73
Oil	€/MWhth	-	29.13	28.47	26.86

1.3.3 ENERGY INFRASTRUCTURE

Table 25:
RE Potentials (Maximum of NEP23B, TYNDP 22 & TYNDP 24)

Country	Technology	2030	2040	2050	Unit
AL	Wind Onshore	595	1420	1650	MW
AT	Wind Onshore	11096	32939	41145	MW
BA	Wind Onshore	3557	5853	13221	MW
BE	Wind Onshore	5300	9450	10440	MW
BG	Wind Onshore	2505	8077	12644	MW
CH	Wind Onshore	1163	2921	3026	MW
CZ	Wind Onshore	5389	11587	15150	MW
DE	Wind Onshore	115001	168500	191500	MW
DK	Wind Onshore	12500	12500	12500	MW
EE	Wind Onshore	1867	2500	4694	MW
ES	Wind Onshore	60403	92900	113786	MW
FI	Wind Onshore	26000	66000	106000	MW
FR	Wind Onshore	44581	88811	119440	MW
GB	Wind Onshore	39038	42040	64783	MW

Country	Technology	2030	2040	2050	Unit
GR	Wind Onshore	16344	22773	27992	MW
HR	Wind Onshore	4437	8123	10308	MW
HU	Wind Onshore	4949	12654	15737	MW
IE	Wind Onshore	8975	10765	16826	MW
IT	Wind Onshore	26872	37569	44554	MW
LT	Wind Onshore	5000	5430	5650	MW
LU	Wind Onshore	400	500	600	MW
LV	Wind Onshore	896	1862	2280	MW
ME	Wind Onshore	618	1040	1212	MW
MK	Wind Onshore	1100	1500	1500	MW
NL	Wind Onshore	10300	15601	20000	MW
NO	Wind Onshore	11192	14548	16816	MW
PL	Wind Onshore	22121	45069	63189	MW
PT	Wind Onshore	12520	22544	27948	MW
RO	Wind Onshore	14892	31456	40633	MW
RS	Wind Onshore	4812	4812	4841	MW
SE	Wind Onshore	23333	36083	49100	MW
SI	Wind Onshore	200	448	525	MW
SK	Wind Onshore	715	1355	2000	MW
AL	Wind Offshore	0	0	0	MW
AT	Wind Offshore	0	0	0	MW
BA	Wind Offshore	0	0	0	MW
BE	Wind Offshore	5760	7960	8266	MW
BG	Wind Offshore	0	299	597	MW
CH	Wind Offshore	0	0	0	MW
CZ	Wind Offshore	0	0	0	MW
DE	Wind Offshore	30521	65059	74584	MW
DK	Wind Offshore	119162	129162	129162	MW
EE	Wind Offshore	1000	7000	10000	MW
ES	Wind Offshore	3400	9400	17400	MW
FI	Wind Offshore	7000	35000	65000	MW

Country	Technology	2030	2040	2050	Unit
FR	Wind Offshore	8980	33209	60000	MW
GB	Wind Offshore	31613	58519	107445	MW
GR	Wind Offshore	3410	16700	22200	MW
HR	Wind Offshore	510	1200	3000	MW
HU	Wind Offshore	0	0	0	MW
IE	Wind Offshore	5174	20000	35000	MW
IT	Wind Offshore	8925	20350	35350	MW
LT	Wind Offshore	1569	4200	7600	MW
LU	Wind Offshore	0	0	0	MW
LV	Wind Offshore	1000	2000	14000	MW
ME	Wind Offshore	0	0	0	MW
MK	Wind Offshore	0	0	0	MW
NL	Wind Offshore	23471	50543	72543	MW
NO	Wind Offshore	3004	14500	18500	MW
PL	Wind Offshore	10900	21800	35000	MW
PT	Wind Offshore	182	396	667	MW
RO	Wind Offshore	0	0	114	MW
RS	Wind Offshore	0	0	0	MW
SE	Wind Offshore	699	3750	10585	MW
SI	Wind Offshore	0	0	60	MW
SK	Wind Offshore	0	0	0	MW
AL	Solar	795	1620	1650	MW
AT	Solar	30000	52000	102000	MW
BA	Solar	1172	2791	3239	MW
BE	Solar	17063	35000	55000	MW
BG	Solar	9629	17806	26957	MW
CH	Solar	12210	30090	44567	MW
CZ	Solar	15218	21821	33983	MW
DE	Solar	215002	400000	507250	MW
DK	Solar	62271	62271	62271	MW
EE	Solar	1500	3300	4000	MW

Country	Technology	2030	2040	2050	Unit
ES	Solar	96050	161848	212041	MW
FI	Solar	20000	45000	80000	MW
FR	Solar	85037	164289	250000	MW
GB	Solar	72824	86436	118021	MW
GR	Solar	18396	34189	47489	MW
HR	Solar	1691	3950	7797	MW
HU	Solar	14329	22407	31811	MW
IE	Solar	7987	13162	21298	MW
IT	Solar	101077	175673	249731	MW
LT	Solar	5000	5600	5900	MW
LU	Solar	984	1800	2175	MW
LV	Solar	500	1101	2079	MW
ME	Solar	1885	2765	5514	MW
MK	Solar	4214	8477	11623	MW
NL	Solar	76104	126139	183098	MW
NO	Solar	5150	20600	24050	MW
PL	Solar	33000	65000	96000	MW
PT	Solar	15000	29000	37266	MW
RO	Solar	12831	22916	43045	MW
RS	Solar	795	795	808	MW
SE	Solar	17000	38850	49500	MW
SI	Solar	3455	7955	11555	MW
SK	Solar	1500	3250	5000	MW

1.4 ADVISORY BOARD QUESTIONNAIRE

In the initial phase of the project, the expertise of the advisory board members has been enquired in order to screen the perception of a number of energy-policy relevant topics within the context of long-term adequacy in the energy – and in particular in the power – sector. The collected feedback, which is reported in Table , has been used as a basis for the fine-tuning of the scenario design. The feedback has been completed by two additional internal experts within TransnetBW.

	Self-Sufficiency	Weather / Climate	Dec. Flex	Central Flex	Service Target	Market Design
AB1	6	5	4	2	1	3
AB2	2	4	3	1	6	5
AB3	5	4	3	1	6	2
AB4	5	6	2	4	3	1
AB5	5	1	2	3	6	4
AB6	3	4	1	1	5	-
AB7	6	4	2	1	5	3
TBW1	5	6	1	2	4	3
TBW2	5	6	2	1	4	3

Table 26:
overview of feedback on relevance of topics within the context of adequacy. AB = advisory board member; TBW = internal TransnetBW expert. Ranking from 1 (=most relevant) to 6 (=less relevant)

As expected, the collection shows a clear prominence of the flexibility topics, both at decentral as well as central level. Somehow surprisingly, the topic of weather/climate is ranked as less relevant within this context. After asking the advisory board about the reasons for the relatively low ranking of the weather / climate topic, is becomes clear that the low raking is mainly due to the fact that weather and climate have been perceived as non-influenceble parameters, while the importance of weather and climate for the assessment of adequacy has been fully confirmed.

For this reason, weather/climate and flexibility has been selected as focuses of the quantitative analyses for this project. This choice partially differs from the approach currently in use e.g. within the ERAA process, in which weather variations as well as non-availability patterns of thermal power represents the focus of the evaluation.

The following list represents a synthesized collection of the additional feedback provided by the advisory board:

- For items other than flexibility, large discrepancies among the experts
- Potentially missing points: variation of operation mode of electrolyzers (e.g., market-friendly vs. base-load) à this gap has been addressed in the following steps of the project
- Suggestion for Self-sufficiency parameters in the energy system model: H2-imports: ca. 50 % - 70 % Germany, ca. 50 % EU
- Consideration of weather extremes for system adequacy / energy system design: no consensus among AB members. Exception: reserve dimensioning à should consider extremes
- Dystopian scenarios: rather no. Eventually: show importance of EU cooperation via inverse scenario, e.g. breakdown of energy system cost
- Capacity market: generally assessed as beneficial. “Kraftwerksstrategie”: technically feasible but perceived as expensive
- Flexibility: Actual potentials unequal theoretical potentials. As soon as an individual is affected in consumption behaviour, societal acceptance is lacking
- Current metrics for AQ-measurements are considered to be ok / sufficient (ENS, LOLE)

1.5 RESULTS OF OTHER CLUSTERS

1.5.1 ENERGY SOVEREIGNTY CLUSTER

This section discusses the impact of different targeted levels of hydrogen self-sufficiency on the national energy system. In a further step, an analysis will be carried out to identify the changes that need to be made to the European energy system in order to achieve a high level of energy sovereignty.

To address the first question, two hydrogen self-sufficiency levels are considered, deviating by ± 20 % from the 50 % target set in the Reference. Regardless of whether a lower or higher hydrogen self-sufficiency target is pursued, the system prefers an expansion of renewable energy capacity. The total installed capacity in Europe (2050) increases by 110 GW, reaching 740 GW in total.

Additional system flexibility is provided through large-scale battery storage and electrolysis. In the case of a lower hydrogen self-sufficiency target, the system requires an additional 11.3 GW of large-scale battery storage, whereas a higher hydrogen self-sufficiency target requires approximately 1.7 GW. The installed capacity increases by 10.8 GW to a total of 60.8 GW for a lower hydrogen self-sufficiency target. For a higher hydrogen self-sufficiency target, the installed capacity rises to 102.6 GW, an increase of 50.6 GW compared to the NEP.

The results indicate that with lower hydrogen self-sufficiency, the required flexibility is provided by the electricity side, which uses large-scale battery storage. Figure 54 shows the monthly flexibility of electrical storage systems. In the low scenario, the large-scale battery storage systems are used more compared to the high scenario.
If the system aims for a higher level of hydrogen self-sufficiency, the required flexibility shifts increasingly to the hydrogen sector,

MONTHLY FLEXIBILITY ANALYSIS 2050 [GWh]

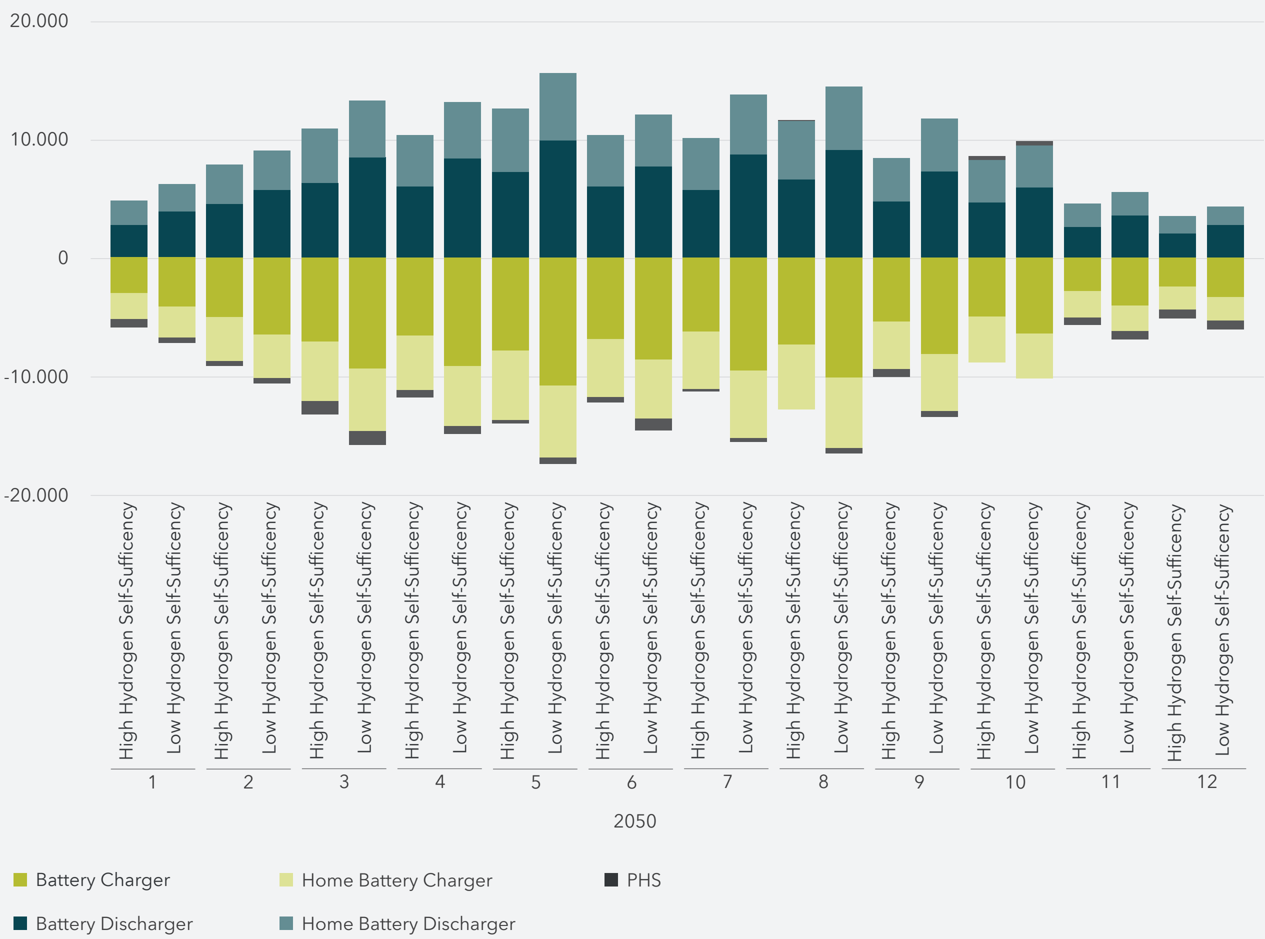


Figure 54:
Monthly flexibility analysis of batteries and pumped hydro storage power plants

which is provided through additional electrolysis capacity. With the additional capacity, the generation of H2 also increases.

With lower hydrogen self-sufficiency, domestic electricity demand decreases by 60 TWh, as less hydrogen needs to be produced using energy-intensive electrolysers. The surplus electricity from renewable energy sources is therefore exported to neighbouring countries, which produce hydrogen and export it back to Germany via pipelines to meet their own self-sufficiency targets. As a result, hydrogen imports from abroad increase from 80 TWh (reference scenario) to 125 TWh. This shift in hydrogen production to neighbouring countries turns Germany into a net electricity exporter.

With higher hydrogen self-sufficiency, the additional electricity from renewable energy sources is not exported but instead used for domestic hydrogen production to achieve the target self-sufficiency level. Domestic electricity demand increases by 70 TWh to a total of 1,330 TWh compared to the Reference. Additionally, reliance on hydrogen power plants to meet this target decreases. As a result, Germany becomes a net electricity importer to meet the energy-intensive demand for domestic hydrogen production. Additional renewable energy capacities are regarded as economically attractive regardless of whether the surplus energy is used for exporting to neighbouring states (low hydrogen self-sufficiency) or for local H2 production (high hydrogen self-sufficiency). But how does this trend evolve if not only Germany but also the entire EU strives for higher independence from energy imports? Additional efforts are needed if the European Union is to achieve greater energy resilience, and these are discussed below.

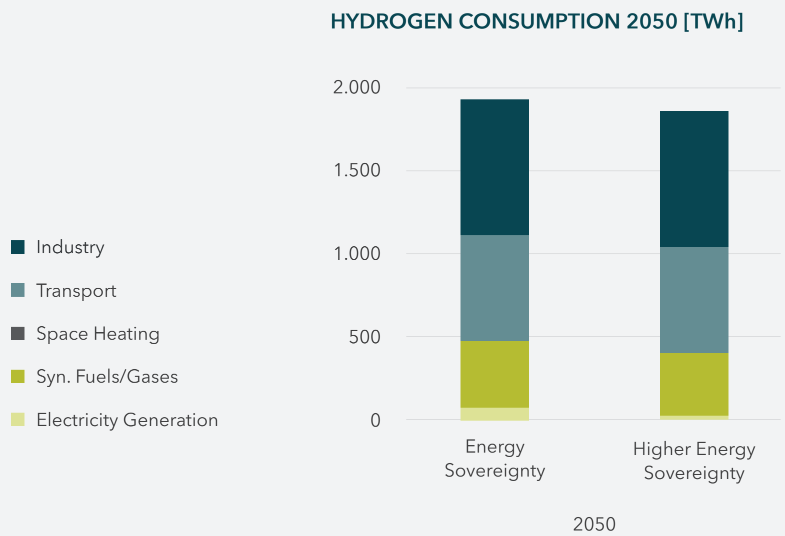
With the increasing pursuit of energy sovereignty in Europe, overall system costs continue to rise. Achieving 85 % energy sovereignty results in an additional system costs of approximately 80 billion €/y in EU27+3.

This increase is mainly driven by investments in local generation units, which require the expansion of additional renewable energy capacity. This is essential to reduce dependence on fossil fuels and increase energy security. While European policy targets remain sufficient, national targets such as the NEP23 are reaching their limits.

To compensate for the loss of flexibility previously provided by intermittent imports, significant investments are being made in large-scale battery storage and hydrogen electrolysis. In addition, as mentioned before, further expansion of production capacity is needed to make efficient use of favourable weather conditions for renewable energy production. Achieving the self-sufficiency targets requires approximately 3,640 GW of renewable energy capacity in the energy system. To efficiently capitalise on EU-wide favourable weather conditions for renewable energy generation, hydrogen production capacities must be expanded further. With the increasing pursuit of energy sovereignty, the demand for electrolysis capacity rises. Achieving 80 % sovereignty requires approximately 640 GW, which increases to 700 GW when sovereignty is raised to 85 %.

Furthermore, the system requires additional capacities to produce synthetic gases and fuels, which is another key driver of rising overall system costs. The additional capacities use hydrogen to produce synthetic gases and fuels, as shown in Figure 55.

Figure 55:
Comparison of hydrogen consumption for the 80 % and 85 % energy sovereignty scenarios



Hydrogen is generated locally and distributed through intra-European pipelines. In contrast, the costs of energy imports are decreasing as expected. The import of hydrogen and synthetic biogas is significantly reduced, while fossil oil continues to be imported in stable quantities.

Increasing European energy self-sufficiency can only be achieved by increasing the cost of the energy system, which requires a strong focus on the

1.5.2 SERVICE TARGET CLUSTER

The willingness to pay of inflexible electricity consumers plays a crucial role in shaping both security of supply and overall system costs.

This section discusses whether there is an economic benefit to the German energy system from electricity consumers forgoing electricity supply for a few hours per year in order to reduce peak loads and potentially limit the expansion of central flexibility resources. To address this question, two calculations were performed, differing in the assumed price for Energy Not Supplied (ENS). One calculation was conducted with a price of 5,000 €/MWh, while the other used 2,500 €/MWh with a limited available ENS volume. The selected values are well below the 10,000 €/MWh mentioned by (BNetzA 2023) as the upper intraday-market limit.

The results indicate that, from a system planning perspective, offering this flexibility as a service and reducing system capacity is not economically preferable . At a compensation rate of 2.50 € per unconsumed kilowatt-hour, it is more cost-effective to invest in central flexibility resources to cover peak loads.

HOURLY ELECTRICITY ANALYSIS [GWh/h]

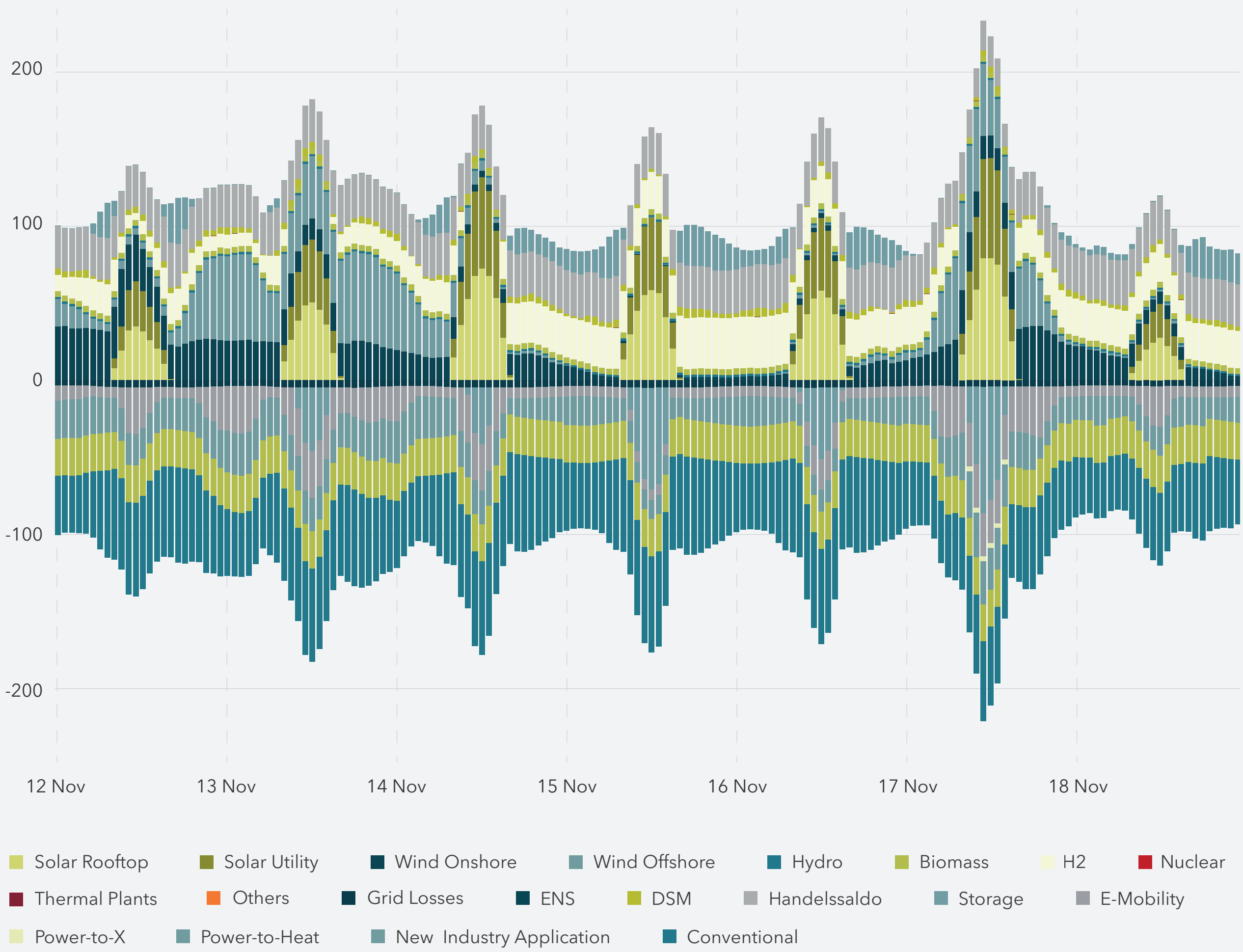


Figure 56:
Hourly electricity balance on 15 November

Maximum residual load occurs during the evening of 15 November, triggering the dispatch of battery dischargers and hydrogen power plants, while the ENS generator remains inactive (see Figure 56). During this critical hour, it is more cost-effective to use existing power plants rather than utilising ENS.

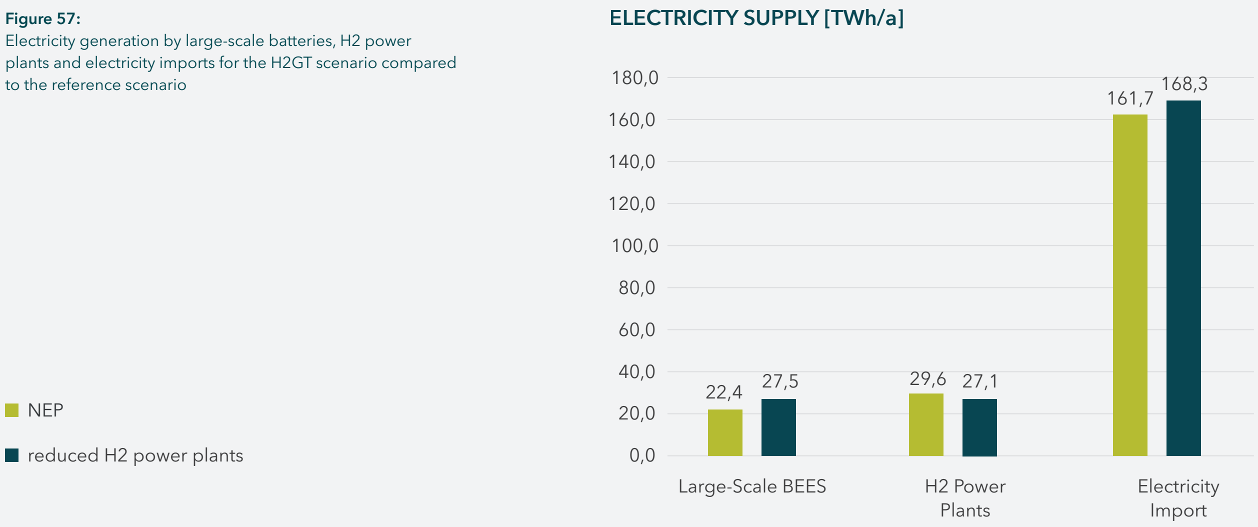
1.5.3 HYDROGEN POWER PLANT CLUSTER

This section aims to quantify the necessary alternative capacities to compensate for the capacity of fewer hydrogen power plants.

The H2 power plant cluster contains one scenario in which about 10 % less hydrogen power plant capacity is built in Germany in 2050 than planned in the reference scenario (NEP). The analysis examines the extent of alternative central flexibility capacities, large-scale batteries in particular, that such a change would render necessary in the German energy system. Additionally, the installed electrolysis capacity is reduced by 10 GW (-20 %) to offset the unused hydrogen resulting from the downsizing of H2 power plants. The installed capacities of renewable energy sources are set to the values used in the reference scenario.

The results show that no additional investments in the large-scale batteries are needed as the existing central flexibility capacities are utilised more frequently and more electricity (+ 6 TWh) is imported.

Figure 57:
Electricity generation by large-scale batteries, H2 power plants and electricity imports for the H2GT scenario compared to the reference scenario



Higher cycle rates of large-scale batteries lead to around 5 TWh more dispatch compared to the reference scenario, as shown in Figure 57. The full-load hours of hydrogen power plants increase by 16, resulting, in combination with -3 GW installed capacity, in 2.5 TWh less electricity production in 2050.

As a result of this reduced capacity, electrolysis will achieve around 750 more full-load hours to meet the unchanged demand for hydrogen in the industrial and transport sectors. 5 TWh/a less hydrogen is imported from Europe. Simultaneously, imports from outside Europe increase by 3 TWh/a, resulting in higher system costs from hydrogen importation.

The total system costs rise further due to additional investments in heat storage (+300 million €) as well as higher electricity imports (+2.7 billion €). Overall, system costs are expected to increase by 3 billion €.

Reducing the number of gas power plants results in an energy system that is more dependent on power imports and incurs additional costs to compensate for the flexibility previously provided by gas power plants.

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