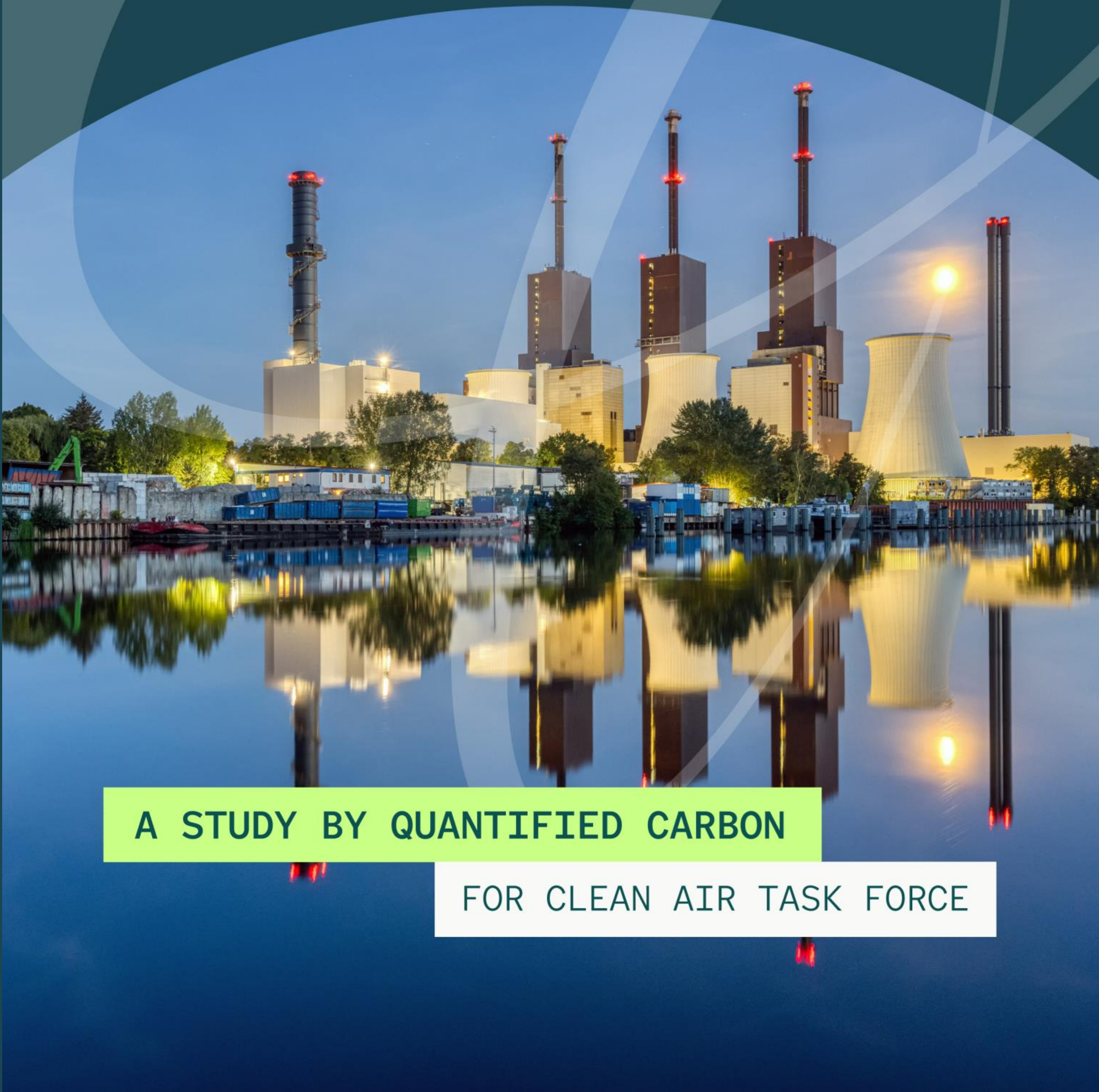
Power System Expansion Germany



A STUDY BY QUANTIFIED CARBON

FOR CLEAN AIR TASK FORCE

ABOUT THIS PUBLICATION

This report has been prepared by Quantified Carbon (QC) for Clean Air Task Force (CATF) to simulate Germany's power sector decarbonisation and inform recommendations for German policymaking.

ABOUT QUANTIFIED CARBON

We are an international consultancy firm providing complex problem solving, modelling, and optimisation to support decarbonisation of energy systems and industries.

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Executive summary

As Germany sets its sights on achieving climate neutrality by 2045, the nation stands at the forefront of global efforts to build a sustainable future. Central to this endeavour is the Energiewende, a bold initiative driving a rapid transition from fossil fuels to renewable energy sources while phasing out nuclear power. To catalyse investment and ensure the resilience of this energy transition whilst maintaining competitiveness, Germany requires a steadfast regulatory framework and energy policy capable of withstanding political shifts. Such stability is essential to inspire investor confidence, underpin sustainable investments, and advance successful decarbonisation initiatives.

This study explores diverse pathways to attain a *fully decarbonised* German power system by 2050. Utilising carefully crafted scenarios, including custom geospatial analysis for wind and solar potential alongside grounded assumptions for demand-side flexibility, the analysis showcases varying projections related to crucial technology developments. These scenarios encompass optimistic and conservative viewpoints on parameters such as investment costs, commodity prices, maximum expansion potential, and build rates[1].

Employing a dedicated multi-year capacity expansion optimisation framework, the study outlines scenarios from 2030 with five-year increments until 2050. With an emphasis on energy resilience, this methodology integrates investment and dispatch optimisation, relying on a comprehensive set of 33 historical weather years to ensure the construction of reliable power systems with realistic dispatch schedules and electricity prices. Ultimately, the current study seeks to enhance the existing body of evidence from previous studies tailored to the German context. Furthermore, the study utilises transparent inputs firmly rooted in German-specific conditions. Notably, the current work is one of the first contemporary studies including nuclear to Germany’s technology portfolio.

The cornerstone of energy system decarbonisation is electrification, leading to an inevitable growth in electricity demand. This study employs a single demand scenario that reflects an increase in electricity consumption aligning with the average of demand projections of other sources. Focusing on the production side, our modelling approach is anchored in Germany's steadfast commitment to transitioning towards a decarbonised economy. Accordingly, the simulated scenarios follow a decarbonisation pathway driven by ambitious CO_2 emission targets defined by a 99% reduction of power system direct emissions compared to 1990 levels, ultimately reflecting a power sector leading the way towards climate neutrality and assuming that negative emissions are used to address the last 1%.

At the heart of the Energiewende is the deployment of renewable energy sources, accompanied by the phase-out of fossil fuels and nuclear power, aimed at transitioning the German power system to climate neutrality as mandated by the Climate Change Act[170]. This energy policy, which does not adopt a technology-neutral approach, was scrutinised in the current study through the adoption of four technology pathways: *All Tech., No CCS, No Nucl.* and *No Nucl. No CCS*, described in TABLE 1.

[1] Note that this modelling does not consider various off-model buildout speed limits, such as development timelines, societal resistance to infrastructure buildout, or supply chain bottlenecks, that may limit the realisation of the simulation results. Instead, it is meant to provide an idealised view of what portfolios are cost-optimal if these barriers were not to exist.

TABLE 1.

Technology pathway scenarios considered in the current study accompanied with their background stories.

SCENARIO NAME	STORYLINE
All Tech.	Scenario embracing all supply technologies with reference input assumptions on simulation parameters. No local opposition and NIMBY are considered. Restart of recently shutdown reactors gains political support. Groundwork is being laid for the construction of new nuclear power with the expectation that the first new plants may come online beyond the year 2040. Infrastructure development is underway such that captured CO_2 from fossil power plants can be transported and stored. Moreover, infrastructure is being developed to draw hydrogen from an established pipeline network and storage, enabling its direct use as well as its use as fuel for power plants.
No CCS	Compared to *All Tech.,* groundwork for CCS is not made reflecting a non-existent infrastructure in this technology pathway.
No Nucl.	Compared to *All Tech.,* restart of recently shutdown reactors gains no political support and building new nuclear power is not part of energy policy in this technology pathway.
No Nucl. No CCS	Compared to *All Tech.,* neither nuclear nor CCS is allowed in this scenario thus representing the combination of *No CCS* and *No Nucl.*. This scenario best represents current German energy policy.

The robustness of the results in the technology pathways were thoroughly evaluated through explorations of around 60 scenario variations. In general, the optimal power system design was observed to not vary much between parameter sensitivity variations within separate technology policy pathways. Accordingly, the different technology pathways are merely highlighted here. Indeed, the unique characteristics of these scenarios make them particularly interesting for comparison, as they represent distinctly different German power systems as illustrated by their installed capacity of variable and firm technologies in FIGURE 1.

First and foremost, it is important to recognise that wind and solar cover at least 50% of the generation mix in all of these scenarios. Moving from left to right, these power systems show an increasing share of wind and solar power combined with stronger reliance of hydrogen as a long-duration energy storage technology for power generation while simultaneously adopting their share of nuclear and Gas CCS according to the technology pathway.

The role of hydrogen power is highly sensitive to other system assumptions about technologies. This is because hydrogen power is very costly, roughly three times the cost of nuclear or double the cost of gas with CCS. Put another way, if the buildout of other technologies is not constrained or other system conditions are relaxed (e.g. near-term emission constraints), represented with the *No Limits* scenario included in FIGURE 1, the role of hydrogen significantly diminishes to reduce system costs.

The study investigated the role of Figure 1, long-duration energy storage (LDES), which was shown to further reduce reliance on hydrogen by facilitating solar expansion, delaying offshore wind installations, and optimising flexibility under stricter decarbonisation targets provided continued innovation accelerates its deployment as demonstrated with the modelling results shown in FIGURE 56. Importantly, the incorporation of LDES also reduces the reliance on unabated gas and reduces gas consumption (see FIGURE 44), likely reducing price volatility (though this scenario was not modelled for price impacts).

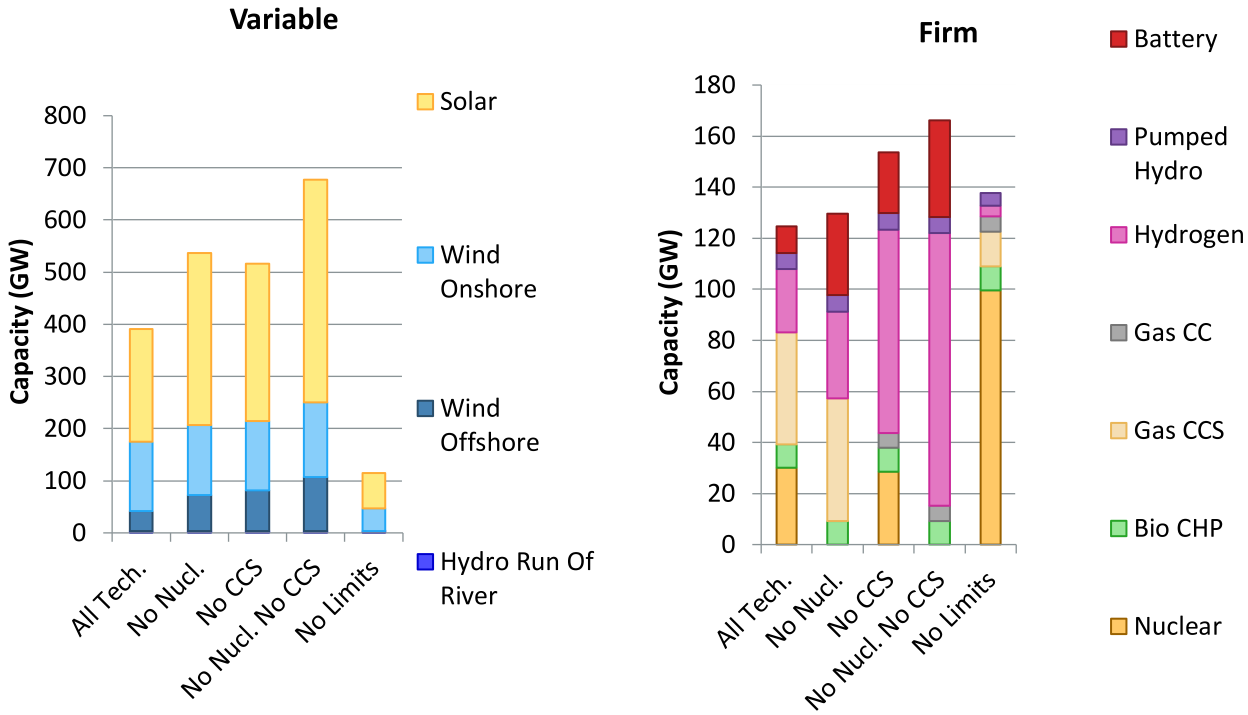


FIGURE 1.

Installed capacity of variable (left panel) and firm (right panel) technologies in the decarbonised German power system in 2050 for the different technology pathways accompanied with the *No Limits* scenario representing relaxed build rate constraints between 2030 and 2050.

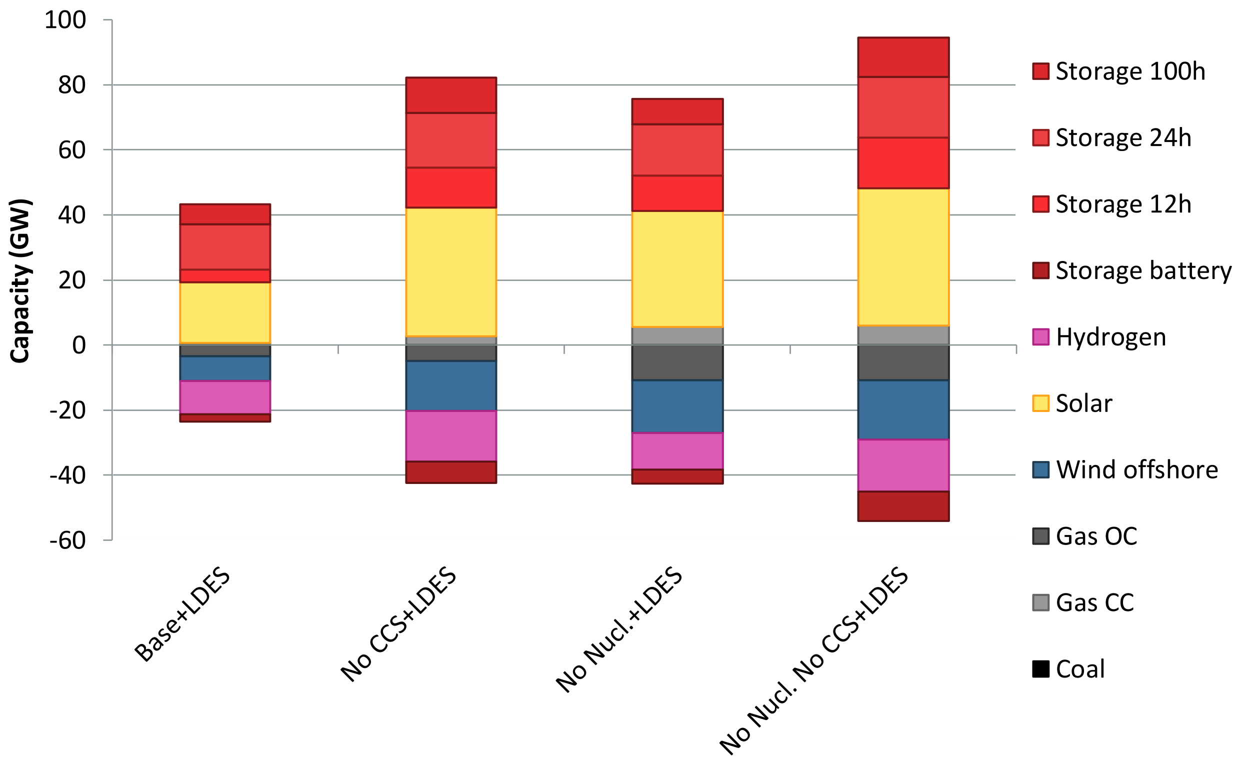


FIGURE 2.

Difference in installed capacity between the *LDES* and their corresponding scenario without LDES for model year 2035 split by technology.

TABLE 2 offers a high-level comparative analysis, showcasing the performance of various power systems in terms of sustainability and competitiveness across different technology-policy pathways. This parameter comparison sets the foundation for the remainder of the executive summary.

Echoing heightened concerns following the Russian invasion of Ukraine[173], the employed methodology in this study emphasises energy resilience, ensuring a capacity reserve margin across 33 weather years in all simulated scenarios.

The comparative analysis of total system costs, electricity prices, and volatility across the four technology pathways reveals the *All Tech.* pathway as the most competitive option for the German power system. In contrast, the *No Nucl. No CCS* pathway lags considerably behind on all metrics, with notably high total system costs and electricity prices nearing 100 €/MWh. Its heavy reliance on wind and solar power exposes it to significantly larger electricity price volatility with varying weather conditions. This volatility, alongside average electricity price and total system costs, are worsened considerably under a conservative parameter outlook defined by stagnating cost reductions, unsuccessful projects for all technologies, high fossil fuel prices, inflexible electricity load, and strong public opposition to onshore wind power. The resulting high electricity prices and substantial volatility are likely unsustainable for both the public and the German industry, posing risks of deindustrialisation lately on the agenda. Additionally, the instability in market conditions, compounded by weather variations, presents challenges for energy system investors, undermining climate achievements.

Similarly, the *No Nucl. No CCS* scenario displays a heavy reliance on power transmission, hydrogen infrastructure and critical materials, driven by its extensive deployment of wind, solar, and hydrogen for power generation. Notably, offshore wind presents itself as the primary driver of increased transmission expansion. Conversely, the *No Nucl.* scenario shows the greatest need for CCS infrastructure, while also indicating higher lifecycle greenhouse gas emissions owing to higher upstream emissions associated with natural gas fuel use.

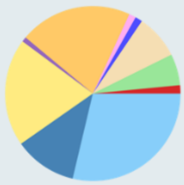
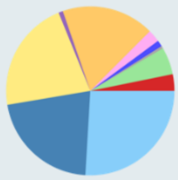
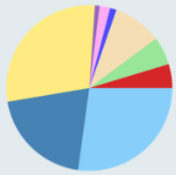
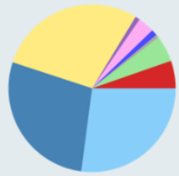
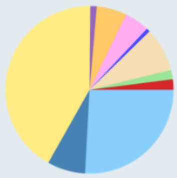
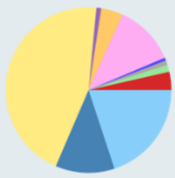
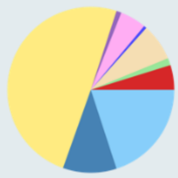
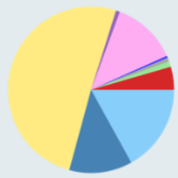
The pivotal role of nuclear power in the technology mix emerges as a common theme across measures of competitiveness, infrastructure reliance, and sustainability for the German power system. It is worth emphasising that in the absence of our assumed build rates constraints, nuclear power shows potential for a considerably larger expansion as exhibited in FIGURE 1. Nuclear power effectively demonstrates its competitiveness as well as its robust role which even manifest in conservative cost projections. Despite inherent uncertainties, this work’s results also underscore the potential advantages of integrating CCS into Germany's energy policy. Embracing a diverse range of technologies enhances resilience against unforeseen obstacles, such as resistance to expanding onshore wind and potential stagnation in cost reductions for renewables and storage. When progress with one technology lags, others can compensate, ensuring continued advancement. Ultimately, adopting a technology-inclusive approach offers a pathway for the German power system to achieve its climate goals while remaining economically competitive.

This study has given rise to the policy recommendations listed below.

TABLE 2.

Summarised results comparing main parameters of the German power systems in 2050 for the four technology pathway scenarios in 2050. Background colours indicate ranking for each parameter.

KEY: RANKING	#1	#2	#3	#4

PARAMETER	Technology Pathway			
	All Tech.	*NO CCS*	*NO NUCL.*	*NO NUCL. NO CCS*
Generation mix: Solar, Wind Onshore, Wind Offshore, Hydro Run Of River, Battery, Pumped Hydro, Hydrogen, Gas CCS, Bio CHP, Nuclear				
Capacity mix:				
Security of supply	✓	✓	✓	✓
Total system cost[2]	Lowest	+10%	+10%	+30%
Average electricity price (€/MWh)	61	78	66	103
Electricity price volatility	Lowest	Moderate	Higher	Highest
Relative dependency on transmission infrastructure – **Power & hydrogen**	Lowest	Higher	Moderate	Highest
Relative dependency on transmission infrastructure – **CO_2 sequestered**	Moderate	0	Highest	0
Relative lifecycle greenhouse gas emissions	Moderate	Lowest	Highest	Moderate
Relative land use and use of critical minerals	Lowest	Moderate	Moderate	Highest

[2] Representing aggregated costs for the time period 2025-2050.

Policy recommendations

Concluding policy recommendations derived from the current study for fostering a competitive and sustainable decarbonisation of the German power system are listed below. The order of these recommendations is first based on the degree to which they deviate from current policy, followed by their presumed level of importance[3] on the background of the modelling results of this study.

FORWARD-LOOKING POLICIES

1 **Establish Technology-Inclusive Foundational Groundwork:**

- Develop regulatory frameworks and permitting processes to support the expansion of *all* clean technologies which means particularly embracing nuclear power. Without a technology-inclusive energy policy, Germany risks falling short of its climate goals and compromising its competitiveness.
- Focus on reducing costs, eliminating barriers, and resolving conflicts of interest to facilitate cost-effective and scalable deployment.

2 **Restart Existing Nuclear Power Plants:**

- The most cost-effective approach to integrate low-carbon energy into the German power system in the very near-term future, while ensuring reliable firm power and freeing up capacity on the power transmission grid and hydrogen network for new variable renewable energy, is to restart and extend the lifetimes of recently shut down reactors until 2050.

3 **Prepare for the Construction of New Nuclear Power:**

- Target the establishment of a nuclear fleet surpassing a total capacity of 30 GW in 2050. Nuclear power reduces reliance on transmission infrastructure, fossil-based generation including power plants equipped with Carbon Capture and Storage (CCS), reserve capacity as well as it provides fossil-free firm capacity to the German grid. In addition, nuclear power generation is a cornerstone for a competitive decarbonised German power system.

4 **Facilitate Natural Gas Power Plants with Carbon Capture:**

- Facilitate the implementation of natural gas power plants equipped with carbon capture capabilities, both from greenfield projects as well as retrofits on existing power plants. Target a deployment of 15 GW installed capacity towards 2045.
- These power plants have the potential to offer cost-effective dispatchable power, playing a crucial role in balancing the high proportion of variable renewable energy in the future German power system. Additionally, they

[3] For instance, level of urgency in implementation, impact on power system competitiveness and share of generation or capacity in the German power system.

- can help reduce the dependence on costly hydrogen fuel for electricity generation.
- Establish infrastructure for the transport and storage of captured Carbon Dioxide (CO_2) targeting storage capabilities of 35 Mt annually towards 2045.

5 **Promote Long-Duration Energy Storage (LDES) to Enhance System Flexibility:**

- Accelerate the deployment of LDES technologies, particularly 24-hour systems, to address diurnal balancing needs. This would enable significant solar expansion while reducing reliance on less cost-effective options such as hydrogen, open-cycle gas peaker plants, and offshore wind.

CONTINUED POLICIES

6 **Swift Transition away from Coal:**

- In the short term, replace coal power with lower-emission natural gas combined-cycle and open-cycle gas turbine power plants, while implementing measures to mitigate indirect emissions, particularly those associated with liquefied natural gas (LNG).
- Mothball the most efficient coal power stations to serve as a capacity reserve until the early 2030s.

7 **Promote Onshore Wind Expansion:**

- Continue prioritising the deployment of onshore wind power to the most suitable sites while respecting constraints and conflicts of interest. A successful onshore wind expansion reduces the need for less cost-effective offshore wind, which also requires more extensive grid reinforcement.
- Maximise the build rate to expedite the phase-out of environmentally detrimental coal power, thereby limiting CO_2 emissions in the near-term future.

8 **Pave the way for Solar and Battery Deployment:**

- Continue supporting the deployment of solar. Solar plays a significant role in all decarbonised German power systems explored in the current study. It also presents the best near-term hedge for a stagnating wind expansion.
- Implement a large-scale deployment of battery storage as outlined in the *Electrical Storage Strategy*.

9 **Focus Development of Offshore Wind Power to best locations:**

- Install offshore wind power in the most cost-effective locations, aiming to lower system costs and electricity prices, or at least minimise the need for subsidies. This approach also has the added benefit of reducing the need for extensive transmission grid expansion.

10 **Reinforce Transmission Grids:**

- Implement targeted policies and regulatory reforms to expedite the planning, permitting, and construction of local, regional, and national transmission grids.
- Accelerating grid reinforcement is essential to support the rapid deployment of wind and solar capacity, addressing current slow buildout rates that risk delaying the energy transition. The inclusion of nuclear power can help alleviate pressure on transmission expansion by providing localized, reliable generation.

1 Introduction

Germany aims to be a climate-neutral industrial country by 2045, positioning itself as a global leader in combating the climate crisis. Key to this ambition is the country's commitment to the energy transition, marked by a swift shift from fossil fuels to renewable energy sources. Germany has already decided to phase out nuclear power[4] and coal power generation[5]. The German nuclear phase-out, initiated by a Bundestag (German federal parliament) decision on June 30, 2011, following the Fukushima nuclear disaster, marked a significant shift towards ending nuclear technology in Germany. The last three nuclear power plants operated until April 15, 2023, under restricted conditions due to a temporary extension during the energy crisis triggered by the war in Ukraine[6].

Germany's climate policy is influenced by the 2015 Paris Agreement, the 2030 Agenda, and the principle of climate justice[7]. The Paris Agreement sets a global goal to limit global warming to well below two degrees Celsius, aiming for 1.5 degrees if possible. environmental and nature conservation has been a major focus in Germany for decades. In 2023, triggered by the war in Ukraine, the federal government further confirmed and intensified its efforts toward the energy transition to quickly reduce dependency on fossil fuel imports[8]. According to the German Ministry for Economic Affairs and Climate Action, the phase-out of nuclear energy primarily led to an increased reliance on coal, rather than gas, thereby making the impact on gas dependency negligible[9]. The transition to renewable energy is seen as key to achieving energy independence. Initiatives include a significant expansion of renewable energy, development of hydrogen infrastructure, and diversifying energy sources beyond Russian imports as part of Germany's broader strategy to ensure a reliable and independent energy supply.

In 2024, the government has published key points of its novel carbon management strategy[10]. Recognising that certain emissions are difficult or impossible to eliminate, the strategy emphasises the necessity of Carbon Capture and Storage (CCS, involves capturing CO_2 emissions and storing them underground) / Carbon Capture and Utilization (CCU, repurposes captured CO_2 into useful products) to meet climate goals, especially in emissions-intensive sectors like cement and waste incineration. The carbon management strategy outlines steps to remove existing barriers to CCS/CCU, enhance renewable energy for electricity production, and avoid fostering fossil fuel dependency. The strategy also plans for the development of a CO_2 transport and storage infrastructure, including adjustments to current laws to facilitate pipeline construction and international cooperation for offshore CO_2 storage, adhering to high safety and environmental standards.

While the details of the future capacity market mechanism are unclear at the time of publication of this study, initial details on the Power Plant Strategy outline the development of a market-based, technology-neutral capacity mechanism scheduled to be operational by 2028, with political agreement anticipated by the summer of 2024[11].

Since May 2021, specific climate protection targets have been enshrined in law[12], which has been amended to intensify CO_2 reduction commitments. By 2030, Germany must reduce its greenhouse gas emissions by at least 65% compared to 1990 levels—a 10-percentage point increase from previous targets. This initiative extends to all sectors including energy industry, industry, transportation, building, and agriculture. The revised law sets an 88% reduction by 2040 and aims for greenhouse gas neutrality by 2045, maintaining a balance between emissions and their mitigation.

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4 Federal Office for the Safety of Nuclear Waste Management (2024), The nuclear phase-out in Germany.
5 Bundesnetzagentur (n.d.), Kohleausstieg.
6 Bundesamt für die Sicherheit der nuklearen Entsorgung (2024), Der Atomausstieg in Deutschland.
7 Auswaertiges Amt, Tatsachen ueber Deutschland (n.d.), Vorreiter in der Klimapolitik.
8 Die Bundesregierung (2024), Ein Plan fürs Klima.
9 BMWK (2022), FAQ Atomkraft
10 BMWK - Bundesministerium für Wirtschaft und Klimaschutz (2024), Eckpunkte der Bundesregierung für eine Carbon Management-Strategie.
11 BMWK - Bundesministerium für Wirtschaft und Klimaschutz (2024), Einigung zur Kraftwerksstrategie.
12 Bundesministerium der Justiz (n.d.), Bundes-Klimaschutzgesetz.

Post-2050, the government aims for negative emissions, seeking to absorb more greenhouse gases through natural sinks than it emits. This roadmap to climate neutrality provides more generational justice and planning security, ensuring Germany's structured and accountable progression towards its environmental commitments.

Germany, like many nations pursuing ambitious climate goals, faces several significant challenges in achieving its target of climate neutrality by 2045. These challenges include:

- **Rapid Expansion of Renewable Energy**: Despite significant progress with renewable energies like photovoltaics, wind, biomass, and hydropower covering nearly half of Germany's electricity demand, the goal is to reach 80% by 2030 and 100% by 2045. To achieve these targets, the pace of renewable energy installation must increase drastically. The annual installation capacity for onshore wind energy must nearly quadruple by 2025 from 2022 levels. Similarly, photovoltaic capacity additions need to triple by 2025. However, a major obstacle is the availability of land, especially for wind energy, compounded by lengthy and complex permitting processes as well as local siting restrictions such as distance regulations, where wind turbines must be set a minimum distance from residential buildings. The government has recently passed several laws to mitigate these challenges.

- **Future-Proofing Power Grids with Urgent Expansion Needs**: Grid congestion, often caused by excessive electricity production, has incurred costs of approximately one billion euros annually in recent years. Despite a rapid increase in renewable energy generation, especially in northern Germany, grid expansion has not kept pace, leading to frequent shutdowns of entire wind parks to prevent overload. The Bundesrechnungshof (Federal Court of Audit) reports that the essential grid expansion is lagging seven years and 6,000 kilometres behind schedule[13].

- **Organising and building the Scale-up of Hydrogen**: The topic of hydrogen scale-up awaits implementation as a critical endeavour. It is essential to prioritise green hydrogen in industrial applications, from steel to chemicals, to foster sustainable development. In 2023, legislators initiated a scalable storage strategy, which still needs to be integrated into a coherent overall concept. The focus for 2024 is on establishing a flexible, system-serving hydrogen strategy to successfully coordinate the ramp-up of the domestic green hydrogen economy with the expansion of renewable energies. Key measures include the Origin Assurance Register Act[14] and a Power Plant Strategy[15]. To meet its ambitious hydrogen demand, Germany plans to import around 50% to 70% of its hydrogen by 2030. This is essential due to limited domestic renewable energy resources. Germany aims to establish partnerships with countries possessing favorable conditions for green hydrogen production, such as those with abundant solar and wind resources. Preferred partners include countries within the EU, such as Spain and Norway, as well as nations in the Middle East and North Africa[16].

- **Developing CCS Storage and Transport Infrastructure**: To achieve climate neutrality, it is crucial to develop a comprehensive CCS infrastructure. This includes establishing new CO_2 storage sites and building the necessary transport networks to move captured CO_2 to these storage locations. The development of this infrastructure is essential for industries with hard-to-abate emissions and will require significant investment and regulatory support to ensure safe and efficient operation. A clear and binding legal framework is crucial for investment decisions. Therefore, a fundamental prerequisite is the adaptation of the legal framework, particularly the Kohlendioxid-Speicherungsgesetz[17].

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[13] Bundesrechnungshof (n.d.), Energiewende nicht auf Kurs.

[14] BMWK - Bundesministerium für Wirtschaft und Klimaschutz (2022), Entwurf eines Gesetzes zur Umsetzung der Vorgaben in Artikel 19 der Richtlinie (EU) 2018/2001 zu Herkunftsnachweisen für Gas, Wasserstoff, Wärme und Kälte aus erneuerbaren Energiequellen.

[15] BMWK - Bundesministerium für Wirtschaft und Klimaschutz (2024), Einigung zur Kraftwerksstrategie.

[16] BMWK (2023), Fortschreibung der nationalen Wasserstoffstrategie

[17] BMWK (2024), FAQ zu CCS und CCU

- **Transitioning to Renewable Heating (Wärmewende)**: A large part of Germany's energy demand comes from the heating needs of industry and households, predominantly fuelled by fossil energy sources, which constitute over 75% of the supply. The share of renewable energy in this sector stands at only about 19% in 2023[18]. Germany’s coalition government has drafted laws aiming to increase the share of renewable energies to 30 percent by 2030 in the district heating sector, with an earlier draft stipulated a share of 50 percent by 2030[19]. However, these efforts have sparked significant public backlash and political infighting, particularly due to concerns over the high costs of heat pump installations and the perceived impracticality of rapid changes mandated by the new heating law[20].

- **Reforming the Electricity Market:** Structural barriers hindering renewable energies in the electricity market need to be removed. While renewables now account for 52 percent (22.3% wind onshore, 12.2% solar PV, 9.8% bio, 4.5% wind offshore, 3.7% hydro) of gross electricity demand[21] and have become system-critical, the current system does not yet cater to their needs. To address the increasing occurrence of hours with negative electricity prices and minimise economic risks for operators of solar and wind facilities, which are penalised during these periods, a shift in the subsidy system is necessary. This shift involves transitioning from fixed feed-in tariffs to market-based mechanisms, incentivising flexibility and storage solutions, and adjusting support to better align with market conditions, thus ensuring economic stability for renewable energy operators and accommodating the increasing share of renewables in the electricity market. The current strength of massive cost degression over recent years is being undermined by penalties in the Renewable Energy Sources Act (EEG).

Given the challenges and opportunities previously outlined, this study utilises a power system optimisation methodology to identify the necessary infrastructure and technologies for establishing a sustainable and competitive power system in Germany by 2050, without addressing the practical challenges of implementation.

This study models the impacts of different policy and input assumptions on the optimal decarbonised German power system by 2050. Through a range of scenarios, it analyses forecasts for essential technological advancements and policy decisions about technology inclusivity. These scenarios include both optimistic and conservative assumptions about investment costs, commodity prices, expansion capabilities, the adoption of various technologies like nuclear and CCS, and construction speeds. Utilising a dedicated multi-year capacity expansion optimisation framework, the study presents scenarios developed while considering the nuances of German energy policy, in five-year increments starting from 2030 up to 2050. With an emphasis of energy resilience, the methodology incorporates both investment and dispatch optimisation, drawing on data from 33 historical weather years to develop reliable power systems with limited import dependency as well as realistic dispatch schedules and electricity prices.

STRUCTURE: the report is organised to deliver a detailed understanding of the study's aims, methods, and results. It begins with an introduction that sets the **context and scope** of the research. Following this, the sections progress through the **study’s framework**, baseline scenario, and the different sensitivities analysed. The third section discusses the **modelling approach**, the tools used, their limitations, and the exogenous assumptions made. The fourth section elaborates on **input assumptions**, covering aspects from CO_2 emissions and demand forecasts to the potential for expanding wind and solar resources and the role of thermal power plants. The fifth section presents the findings, compares scenarios, and outlines the **pathways toward decarbonisation**, providing insights into the evolving dynamics of the power system. The report wraps up with a summary of key conclusions.

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[18] UBA (2024), Energieverbrauch fuer fossile und erneuerbare Waerme.
[19] Clean Energy Wire (2023), German Government Weakens Renewables Targets In Municipal Heating Plans.
[20] DW (2023), German lawmakers pass heating law that divided government
[21] S&P Global (2023), German renewables to cover record 52% share in 2023 power demand: BDEW.

2 Study

2.1 Design

The overarching objective for the current work has been to answer the following question:

QUESTION:

"How do various policy and input scenarios impact the optimal modelled power system decarbonisation of Germany by 2050?"

To provide answers to the question the following method has been applied:

METHOD

1. Build a German power system that meets power demand every hour of the year whilst ensuring profitability for producers based on the following:

- Pathway towards a fully decarbonised economy in 2050 starting from a present-day power system and touching down in 2030 and then in steps of 5 years until 2050.
- A technology neutral scenario, denoted *All Tech.,* is formed from a technology neutral setting and a decarbonisation pathway to 1% of 1990s emissions with best estimates on input assumptions:
  - Investment and operational costs
  - Commodity and CO_2 prices
  - Maximum build rates
  - Development of power systems in neighbouring bidding zones along with grid reinforcements
  - Technical land-use constraints
  - Demand growth & flexibility
- Sensitivities are created based on technology parameter variations with respect to the *All Tech.* scenario investigating optimistic and conservative projections of costs and fossil fuel prices as well as technology restrictions.
- Relaxed build rate constraints and CO_2 targets are explored in the *No Limits* and *CO_2 --* scenarios, respectively. The inclusion of a capacity reserve margin constraint is investigated in the *Capacity Market* scenario.

2. Evaluate the built power systems based on their *total system investment & operational costs* and through comprehensive electricity market modelling:

- Each power system is confronted with a set of 33 different weather years.

- Security of supply[22], average electricity prices and electricity price volatility are determined which together with total system costs provide key insights on sustainability and competitiveness.
- Quantified lifecycle greenhouse gas emissions, reliance on transmission infrastructure along with land usage and use of critical materials complement the comparison.

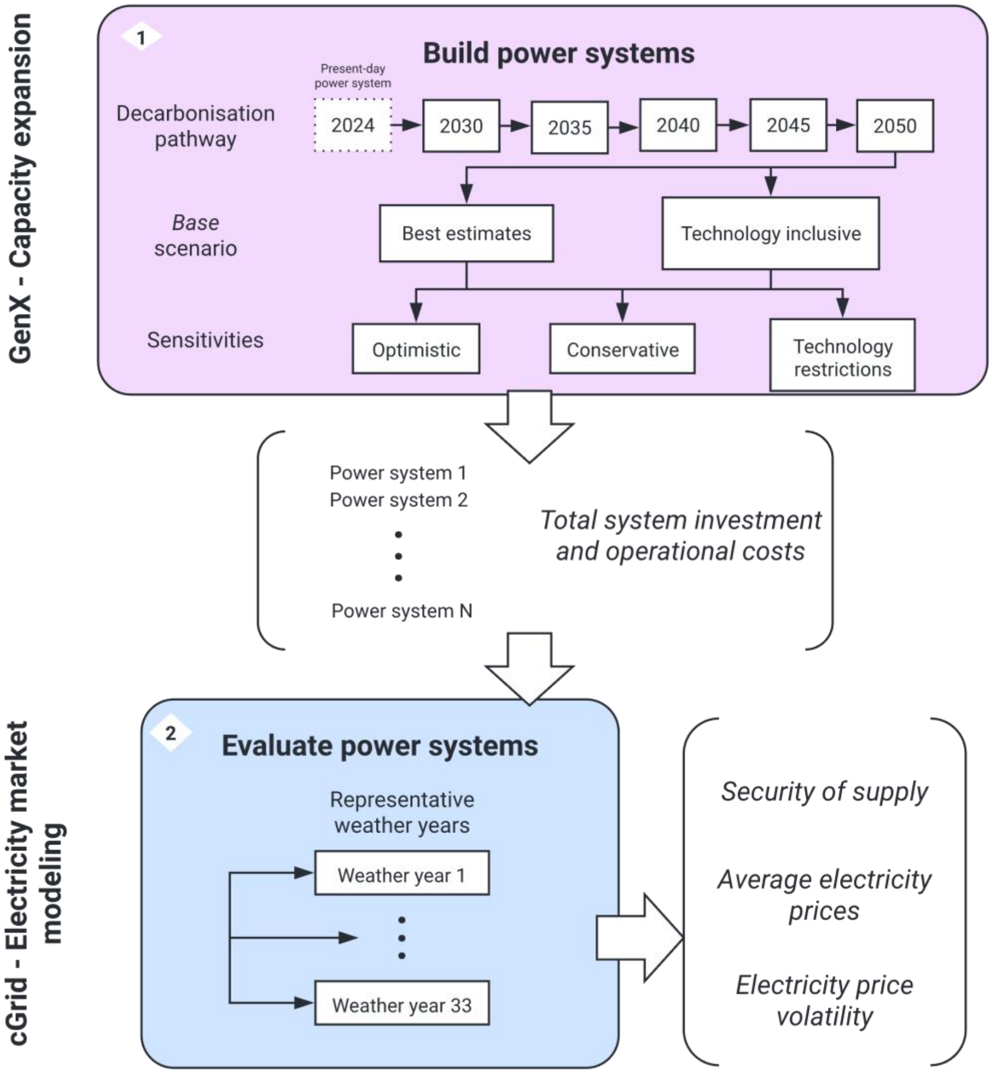

FIGURE 3.

Flow chart illustrating overarching study design and methodology.

The study design and methodology are illustrated in FIGURE 3**ERROR! REFERENCE SOURCE NOT FOUND.**. The foundation of the approach is two modelling steps: (1) Power system optimisation, performed with the open-source tool GenX and (2) Electricity market modelling, performed with the QC-developed tool cGrid, both explained in detail in SECTION 3.13.1.

[22] Probed by means of evaluating capacity margins across the 33 weather years.

The methodology combines the best of different types of modelling tools. The power system optimisation identifies cost-optimal power systems across a multi-year pathway including retirement and retrofitting of resources whilst ensuring that all production resources being profitable and capacity reserve requirements[23] are fulfilled. The electricity market modelling achieves highly detailed dispatch profiles for the power systems obtained in the optimisation step and can determine realistic electricity price series. Valuable is also the feasibility to confront power systems to a comprehensive set of weather years to thoroughly assess how robust they are. Together, the modelling methodology delivers credible values of system costs, security of supply, electricity prices and electricity price volatility, thereby providing firm insights into competitiveness.

Further details on modelling strategy and tools are presented in SECTION 3.

2.2 All Tech. scenario and sensitivities

The *All Tech.* scenario, briefly introduced in the box in SECTION 2.1, is modified parameter-by-parameter to create sensitivities. The sensitivities and the *All Tech.* scenario together create the set of scenarios that the study ultimately investigates. A technology-neutral setting is the fundamental assumption for the *All Tech.* scenario. The *All Tech.* scenario is further based on best estimate input assumptions on parameters including investment and operational costs, commodity and CO_2 prices, maximum build rates, development of power systems in neighbouring bidding zones along with grid reinforcements, land-use constraints, demand growth and demand-side flexibility. Restart of existing nuclear reactors is also permitted in the *All Tech.* scenario. These assumptions are described in more detail in SECTION 4.

Sensitivities are created based on technology parameter variations with respect to the *All Tech.* scenario investigating optimistic and conservative projections of costs and fossil fuel prices as well as technology restrictions. The scenario building process is illustrated in FIGURE 4 while APPENDIX A.1 complements this figure with a table presentation of the sensitivity definitions. The sensitivities aim to probe the potential variations in resulting power systems with respect to the best-estimate assumptions of the *All Tech.* scenario. Additional variations are explored in the *No Limits, CO_2 --* , the *Capacity Market* and the *+LDES* scenarios, where relaxed build rate limits, a slower decarbonisation pace is explored, the inclusion of a capacity reserve margin constraint and long-duration energy storage technologies are investigated, respectively.

[23] Merely in *Capacity Market* scenarios.

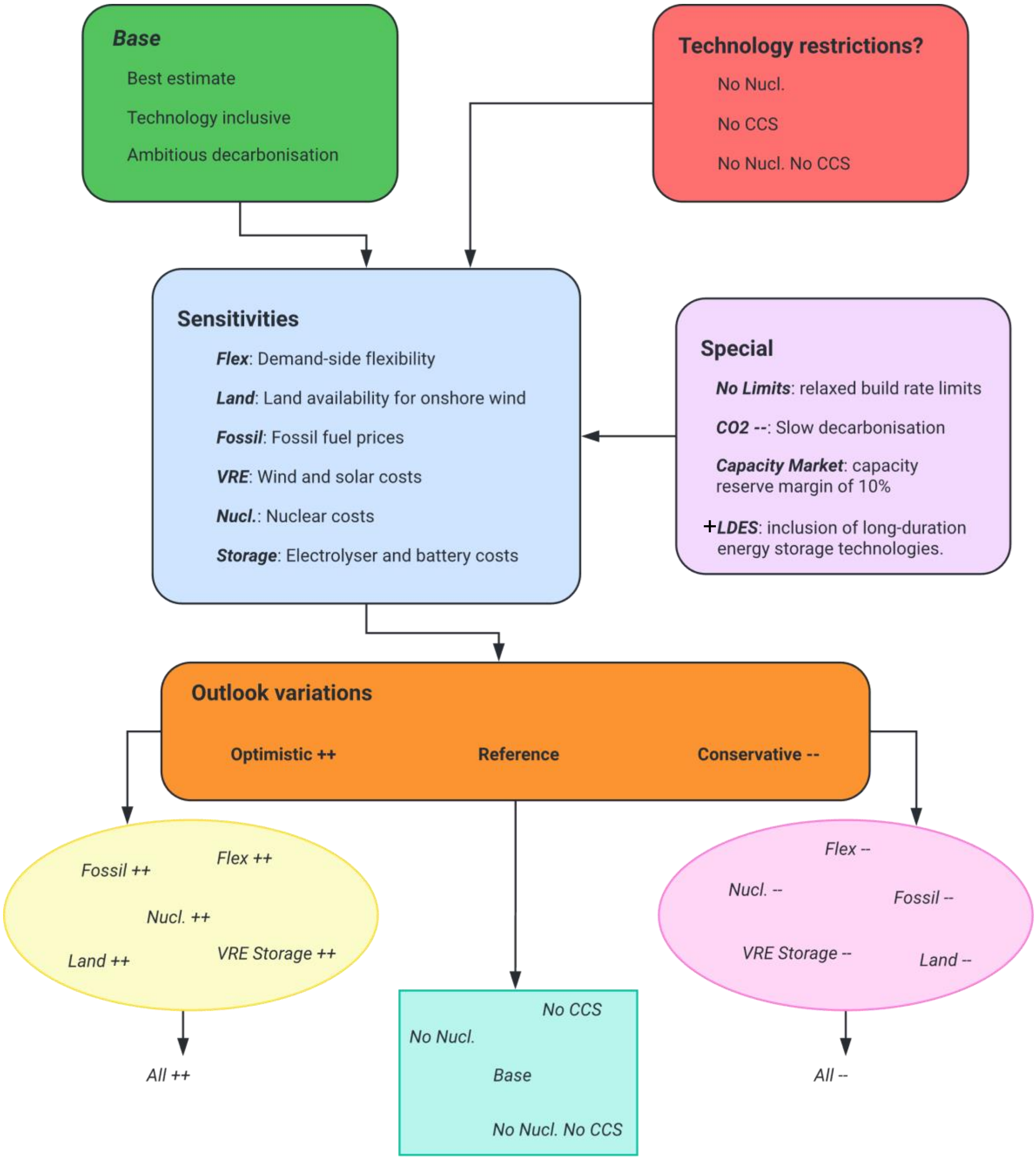

FIGURE 4.

Flowchart illustrating the scenario building process.

Behind each sensitivity lies a potential background story, i.e. a description which lays out a narrative given the scenario materialises. It is of interest to further explore scenarios in which multiple sensitivities materialise simultaneously, and as such merged sensitivities were also investigated. The variations *All* ++ and *All* -- are two examples of merged sensitivities. Further examples include *No Nucl. No CCS, No CCS Flex* ++ and *No Nucl. No CCS All* --. The primary set of simulated scenarios are presented in TABLE 3 along with descriptions, i.e. background stories which lay the foundation for the discussion later in the report. The current study has run more than 70 scenarios in total.

TABLE 3.

Scenario storylines.

SCENARIO NAME	STORYLINE
All Tech.	Scenario embracing all supply technologies with reference input assumptions on simulation parameters. No local opposition and NIMBY are considered. Restart of recently shutdown reactors gains political support. Groundwork is being laid for the construction of new nuclear power with the expectation that the first new plants may come online beyond the year 2040. Infrastructure development is underway such that captured CO_2 from fossil power plants can be transported and stored. Moreover, infrastructure is being developed to draw hydrogen from an established pipeline network and storage, enabling its direct use as well as its use as fuel for power plants.
No Limits	In contrast to the *All Tech.* scenario, no build rate constraints are imposed on thermal power plant expansion and nuclear allowed to be constructed already in the period 2031-2035.
CO_2 --	In contrast to the *All Tech.* scenario, no interim CO_2 targets between 2030 and 2050 are imposed.
Capacity Market	Compared to *All Tech.*, in this scenario a capacity market is established where technologies providing reserve capacity receive revenue such that a 10% margin is always achieved.
LDES	Compared to *All Tech.*, in this scenario long-duration energy storage technologies are included in the simulations as introduced in SECTION 4.10.
No CCS	Compared to *All Tech.*, groundwork for CCS is not made reflecting a non-existent infrastructure in this technology pathway.
No Nucl.	Compared to *All Tech.*, restart of recently shutdown reactors gains no political support and building new nuclear power is not part of energy policy in this technology pathway.
VRE Storage ++	Compared to *All Tech.*, the costs of wind and solar energy development are displaying optimistic trends, experiencing consistent decreases in this scenario. Simultaneously, storage components such as batteries and electrolysers are also witnessing significant cost reductions.
VRE Storage --	Compared to *All Tech.*, development of costs for both wind and solar as well as for battery and electrolyser storage components stagnate.
Fossil ++	Compared to *All Tech.*, fossil fuel prices rebound to EU pre-energy crisis levels by mid 2030s, facilitated by re-established pipeline network in this scenario.
Fossil --	Compared to *All Tech.*, fossil fuel prices don’t fully subside following present-day’s energy crisis and instead relies on liquefied natural gas, LNG, in this scenario.
Nucl. ++	Compared to *All Tech.*, initial nuclear projects gain good governmental support and become successful in this scenario. Following projects sees a learning rate owing to serial construction.
Nucl. --	Compared to *All Tech.*, initial nuclear projects don’t obtain a strong governmental support and starts off expensive in this scenario. Following projects only sees a limited learning rate owing to serial construction.

Land ++	Compared to *All Tech.,* a larger expansion of onshore wind is enabled from a strong local support in this scenario. However, as further land is occupied, onshore wind developers face increasing challenges with finding good sites.
Land --	Compared to *All Tech.,* due to large struggles with negative public opinion, the expansion of onshore wind comes to a full halt at present-day capacity in this scenario.
Flex ++	Compared to *All Tech.,* this scenario represents highly flexible electricity load, reflecting substantial incentives for EV, heating, residential and industry consumers to install necessary components for flexible operations, as well as the realisation of ambitious plans for hydrogen network.
Flex --	Compared to *All Tech.,* this scenario represents, to a large extent, inflexible electricity load, reflecting lack of incentives for EV, heating, residential and industry consumers to install necessary components for flexible operations, as well as a delay in the realisation of ambitious plans for hydrogen network.
All ++	Compared to *All Tech.,* this scenario represents a generally optimistic view on the future outlook with significant cost reductions or successful projects for all technologies, low fossil fuel prices, highly flexible electricity load and strong public acceptance for onshore wind power.
All --	Compared to *All Tech.* and in contrast to *All ++,* this scenario outlines a generally conservative view on future outlook with stagnating cost reductions or unsuccessful projects for all technologies, high fossil fuel prices, rather inflexible electricity load and strong public opposition for onshore wind power.

2.3 Comparison energy system studies in Germany

Power system optimisation studies in Germany reveal a rich tapestry of methodologies and underlying assumptions, leading to a range of outcomes and interpretations. Given the complex and evolving nature of the German energy landscape, this diversity reflects the multifaceted challenges and opportunities inherent in transitioning to a sustainable energy future.

For this purpose, we compare our findings with those of similar studies. These include:

- Agora (2021), Klimaneutrales Deutschland 2045 (Climate-Neutral Germany by 2045)
- BDI (2021), KLIMAPFADE 2.0 (Climate Paths 2.0)
- dena (2021), dena-Leitstudie Aufbruch Klimaneutralität (dena Pilot Study on the Rise of Climate Neutrality)
- BMWK (2021), Langfristszenarien für die Transformation des Energiesystems in Deutschland (Long-Term Scenarios for the Transformation of the Energy System in Germany)
- Ariadne (2021), Auf dem Weg zur Klimaneutralität 2045 (On the Way to Climate Neutrality 2045)
- Ember (2022), New Generation - Building a clean European electricity system by 2035.
- Carbon-Free Europe (2023), Annual Decarbonisation Perspective 2023.

The first five focus specifically on Germany. All those studies are aligned in their overarching goal to drastically reduce greenhouse gas emissions and achieve climate neutrality in Germany by 2045. They emphasise the importance of the 2020s as a critical decade for setting foundational strategies and policies. Each study underscores the necessity of expanding renewable energy capacities and improving energy efficiency across various sectors including industry, transportation, and buildings. The studies acknowledge the role of advanced technologies, such as hydrogen and synthetic fuels, and the development of CO_2 sinks to offset residual emissions.

The methodologies and focal points vary among these studies. Agora's approach is largely technology-driven, emphasising the acceleration of existing technologies without significant behavioural changes. In contrast, BDI's "KLIMAPFADE 2.0" incorporates a broader economic and policy perspective, advocating for a mix of regulatory and fiscal policies to drive the transition. The dena study provides a detailed modelling of sector-specific pathways, particularly focusing on the roles of different energy carriers and the integration challenges associated with them. BMWK's scenarios explore the techno-economic implications of different primary energy carriers, assessing the suitability of electricity, hydrogen, and synthetic hydrocarbons in the energy transformation. Finally, the Ariadne Report integrates multiple systems and sector models to provide a comprehensive view of the transition pathways, emphasising a nearly complete move away from fossil fuels and the critical role of direct and indirect electrification.

While there are overlapping themes of technology scaling and renewable integration, the approaches vary from focusing primarily on technology (Agora), to policy and economic instruments (BDI), detailed sector-specific modelling (dena), techno-economic scenario analysis (BMWK), and integrative modelling approaches (Ariadne). These differences highlight the complexity of the energy transition and the multiple layers of strategy and policy necessary to achieve Germany's ambitious climate goals.

TABLE 4 provides a summary of the strengths and weaknesses compared across different studies. By juxtaposing the strengths and weaknesses of these examples in TABLE 4 the present study seeks to augment existing knowledge. It accomplishes this by combining detailed and comprehensive power system optimization, placing a particular emphasis on realistic electricity market modelling, resilience to diverse weather scenarios as well as pathways to full decarbonisation. Furthermore, the study employs transparent inputs firmly rooted in German-specific conditions. This synthesis aims to complement the approaches of other studies by offering a nuanced set of scenarios, including varying costs for technologies, and robust contributions to the ongoing discourse on optimising the German power system. Notably, the current work is one of the first contemporary studies including nuclear to Germany's technology portfolio.

TABLE 4.

Non-exclusive review of studies relevant for the development of the German power system with their strengths and weaknesses from the perspective of the current study. Primary geographical focus is indicated along with the organising institution in the first column.

STUDY & GEOGRAPHICAL FOCUS	STRENGTHS	WEAKNESSES
QC_CATF **(current study)** **Focus: Germany**	• Technology inclusive multi-year investment optimisation with hourly temporal granularity and bidding-zone trading in long-term model future horizon accounting for retirements and retrofits. • Emphasis on realistic electricity market modelling – prices, volatility & security of supply – through inclusion of capacity reserve market and power systems examined on full set of weather years and commodity price scenarios. • Tailored and transparent technology cost scenarios and inputs well founded in Germany-specific conditions. • Thorough custom Geographic Information System (GIS) analysis for wind and solar expansion potential. • Demand flexibility and sensitivities incorporated. • Covers a diverse range of scenarios	• Limited coupling to other sectors, such as heat and hydrogen. However, includes endogenous optimisation and realistic market modelling of hydrogen production for regeneration of electricity. • Limited accounting for granular grid aspects and considerations for zone-intrinsic network reinforcement. • Limited geographical focus.
dena-Leitstudie **Aufbruch Klimaneutralität**[24] **Focus: Germany**	• Coverage of both sectoral and cross-sectoral aspects. • Combining practical insights from a wide range of experts and scientifically grounded parameters, the methodology ensures that the transformation paths are both realistic and thoroughly validated. • Germany is investigated in the European context.	• No cost-optimisation across all sectors simultaneously, thus potentially missing out on some synergies or cost efficiencies that could be realized with a more integrated modelling approach. • Only limited number of time steps.

Ariadne-Report
Deutschland auf dem Weg zur Klimaneutralität 2045[25]
Focus: Germany
	• Different models employed. They focus here on REMIND (multi-regional integrated assessment model) and REMod (sector-coupled cost optimisation model):
	• REMIND:
		• Neither model includes all technological options.
		• REMIND:
		  ○ No modelling of hourly dispatch solutions
		  ○ Parametrisation of the demands for grid and storage

[24] dena (2021), Leitstudie - Aufbruch Klimaneutralität.
[25] Ariadne Report (2021), Deutschland auf dem Weg zur Klimaneutralität 2045.

	○ Coupling of energy system model with macro-economic model ○ Detailed modelling of developments in different sectors • REMod: • Detailed electricity market model with hourly dispatch	• REMod: ○ Limited geographical scope ○ Relatively limited coverage of diverse weather years
Agora **Klimaneutrales Deutschland 2045**[26] **Focus: Germany**	• Detailed sectoral models of the energy demand. • Electricity exchanges in Europe modelled with hourly resolution. • Methodology also accounts for cross-sectoral dynamics and socio-economic factors, making the scenarios more realistic and aligned with potential future societal and economic conditions.	• Doesn’t include all technological options.
BMWK **Langfristszenarien für die Transformation des Energiesystems in Deutschland**[27] **Focus: Germany**	• Detailed region-specific models of the energy demand • Modelling of renewables in high temporal and spatial resolution • Europe explicitly modelled. • Iterative modelling of grids (gas, distribution, etc.), detailed distribution grid modelling	• Sector-coupling limited to Germany • Doesn’t include all technological options, e.g. nuclear.
BDI **KLIMAPFADE 2.0**[28] **Focus: Germany**	• Results are obtained using an extensive "bottom-up" process involving more than 150 experts from companies, associations, and an advisory board of scientists and labour representatives. • Assesses the effectiveness of existing regulations and identifies gaps to suggest necessary enhancements for achieving emission reduction targets. • The methodology includes examining fiscal impacts, such as changes in government spending and tax revenues due to climate policies.	• No explicit modelling included. • Regulatory-based approach, which may not always follow a cost-optimal path due to possible misjudgements by regulators. • Study's methodology reveals a heavy reliance on CO_2 pricing to drive the adoption of renewable technologies

[26] Agora (2021), Klimaneutrales Deutschland 2045.
[27] Fraunhofer ISI (2021), Langfristszenarien für die Transformation des Energiesystems in Deutschland.
[28] BDI (2021), KLIMAPFADE 2.0.

Ember[29] **Focus: Europe**	• Holistic multi-year European power system dispatch and investment optimisation with country-level spatial and hourly temporal resolution based on three varying weather years. • Well-founded carbon-budget methodology which forms the basis for scenarios all with the long-term 2050 net-zero perspective and main focus least system cost pathways. • Technology inclusive and accounts for different energy demand scenarios. • Strongly connected and based on European electricity infrastructure plans and boundary conditions e.g., on technology build rates, resulting in realistic capacity expansion paths.	• Limited coupling to other sectors, such as heat and hydrogen. However, the hydrogen production for the power sector is endogenously optimised. • Limited accounting for granular grid aspects and consideration for zone-intrinsic network reinforcement. • Limitations imposed by current European plans and the prevailing political landscape entail the risk of an overly restricted infrastructure expansion or the exclusion of certain possibilities. • Limited emphasis on electricity market modelling aspects: electricity prices, volatility, security of supply and capacity reserve.
Carbon-Free Europe[30] **Focus: Europe**	• Advanced multi-year optimisation in a single objective allowing for the development of coherent multi-decadal infrastructure plans including optimised resource retirements, repowers, retrofits, as well as deployment of new infrastructure. • Holistic technology inclusive European energy system optimisation, strongly sector coupled with e.g., advanced flexible nuclear active on both power and heat markets. • Automated day-sampling approach allowing for a representation of characteristic energy system conditions. • Comprehensive set of technology build and demand scenarios including coverage of hydrogen, Carbon Capture, Utilisation and Storage (CCUS), refined liquid fuels and electricity. • Thorough custom GIS analysis for wind and solar expansion potential.	• Limited consideration for technology build rate and network transmission expansion constraints, especially relevant for the near-term. • Limited insights into country-specific conditions. • Limited emphasis on electricity market modelling aspects: electricity prices, volatility, security of supply and capacity reserve. • Limited high-temporal resolution of full continuous years and electricity market bidding zone spatial resolution.

[29] Ember (2022), New Generation - Building a clean European electricity system by 2035.
[30] Carbon-Free Europe (2023), Annual Decarbonisation Perspective 2023.

3 Modelling

This section is initiated with an introduction to the tools employed and continues to describe the details on the modelling framework introduced in SECTION 2.1 as well as the tools employed in ERROR! REFERENCE SOURCE NOT FOUND..

3.1 Tools

3.1.1 GenX

GenX is a highly configurable open-source tool[31] for capacity expansion of generation resources, which includes several state-of-the-art methods for exploring cost-optimised power systems. In this study, an extended version of GenX v. 0.3.3 has been used, which allows for:

- limiting the minimum and/or maximum consumption of each defined fuel type,
- limiting flows between zones at the same time resolution as other input values, thus taking into account a variable transmission capacity as well as asymmetries in the direction
- limiting the maximum instantaneous consumption of flexible loads.

GenX builds cost-optimal power systems based on the prerequisites presented earlier forming the initial optimisation step here. It is worth noting that GenX and cGrid share a common approach in modelling the capacity reserve requirement[32].

In the context of this study, GenX faces limitations with thorough modelling of hydrogen markets and the dispatch of long-duration storage—crucial considerations for modelling future power systems with a substantial penetration of variable renewable energy coupled with storage. Additionally, GenX's computational intensity poses a challenge, making it less suitable for sensitivity analyses that involve a large number of weather years and scenarios.

3.1.2 cGrid

The Quantified Carbon in-house developed and maintained tool cGrid is a dedicated electricity market modelling tool originally designed to simulate a realistic bidding pattern of reservoir hydro power dispatch, especially important for the Nordics. Diverging from GenX's linear optimisation with complete foresight over the entire model year, cGrid shapes its dispatch strategy for flexible demand resources and storage technologies around short-term electricity price forecasts. This distinction becomes particularly important for realistic dispatch as well as electricity prices in power systems with long-duration storage resources, including hydro reservoir power.

cGrid allows for the modelling of the hydrogen market, encompassing both direct demand for hydrogen and its utilisation for electricity regeneration coupled with hydrogen storage energy capacity, shared through a hydrogen network. The approach ensures realistic pricing of hydrogen, for instance, to fuel combined-cycle hydrogen gas turbine power plants.

Finally, cGrid is capable of performing a modified expansion, fine-tuning of capacities, but unlike GenX it cannot perform a greenfield optimisation. This distinction underscores the rationale behind employing both codes simultaneously. Additionally, cGrid's notably faster runtime makes it the preferred choice for handling the extensive set of scenarios analysed in the current study.

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[31] GitHub (n.d.), GenXProject.
[32] https://genxproject.github.io/GenX/dev/policies/#Capacity-Reserve-Margin

3.2 Strategy

The power system optimisation in this study follows a multistep process utilising two primary modelling codes: GenX and cGrid. These codes are instrumental in constructing a comprehensive set of power systems for various scenarios, future model years, and different weather years.

The GenX tool, further described above in SECTION 3.1.1, is used to study the long-term evolution of the German power system across multiple investment stages. Through capacity expansion and dispatch optimisation, this tool aims to minimise total system costs, facilitating the construction of a power system that satisfies demand every hour of a typical weather year. This optimisation process is designed to meet direct emission targets, maintain a capacity reserve margin, and ensure the profitability of each technology. Within this simulation, retirements are contemplated based on the technical and economic life of both pre-existing installed capacity and capacity built within the model's timeframe. Additionally, the concept of retrofitting is considered for the case of combined-cycle gas power plants with the addition of CCS. Retrofitting involves upgrading uncompetitive technologies instead of retiring them, transforming them into cost-effective alternatives.

In power system analysis, perfect-foresight and myopic optimisation represent two contrasting approaches. In our model, "myopic" specifically refers to the multi-year capacity expansion planning, structured in five-year stages from 2026 to 2030 and continuing in similar intervals up to 2050, and does not apply to the dispatch optimisation. Perfect-foresight assumes complete knowledge of future trends, allowing for long-term planning with an ideal perspective on future developments. However, this approach can be overly optimistic, failing to account for real-world uncertainties, evolving policies, and market dynamics. Myopic optimisation, on the other hand, operates within shorter timeframes, focusing on immediate outcomes and incremental decision-making. This approach, also employed in the current study, is more flexible, reflecting the inherent uncertainty and limited information available to decision-makers in the power sector. It also aligns with real-world constraints, like budget cycles and project timelines, and mimics the typical behaviour of investors who prioritize short- to medium-term returns.

The multi-year capacity expansion planning involves five-year stages, with the first stage commencing in 2026 and concluding in 2030. This pattern continues until 2050.

The optimisation approach adopts a myopic strategy, where capacity expansion is individually optimised for each stage, treating investment decisions from previous stages as fixed. This contrasts with a full-model horizon perfect-foresight strategy, where cost and policy assumptions about all stages are known and exploited to determine the least-cost investment trajectory. While long-term perfect-foresight optimisation carries an unrealistic investment logic due to the uncertainties of the distant future, it does require profitability for all technologies across the entire model horizon. Though the current myopic approach has a more reasonable foresight of five years, the long-term profitability of resulting investments needs to be further examined which is part of the analysis.

In an initial optimisation step with GenX, Germany is modelled as an isolated system, functioning as an island without any interconnections to its neighbours. This approach is deemed reasonable since Germany's load exceeds the transmission capacity of its interconnections. However, the validity of this isolation is tested in the second step using cGrid.

In the subsequent phase, a pre-optimisation of installed generation capacities for the power system technologies in the regions' surrounding Germany is conducted with cGrid. This process was merely pursued for year 2050. Installed generation capacities in neighbouring regions are modified from the European Network of System Operators for Electricity (ENTSO-E) and other public data sources, through an expansion procedure with cGrid to ensure realistic electricity prices and credible trade between the German power system and external regions. This step provides two crucial components to the analysis.

First, the expansion is carried out across a full set of 33 weather years to identify and understand the average weather year. This process which is applied to all bidding zones included in the model essentially culminate in the results shown in FIGURE 5. From these results weather year 1991 was identified as having the minimum deviation in modelled electricity prices for each bidding zone compared to the average from the full set of weather years. Importantly, the 1991 weather year is fed into the initial optimisation step with GenX.

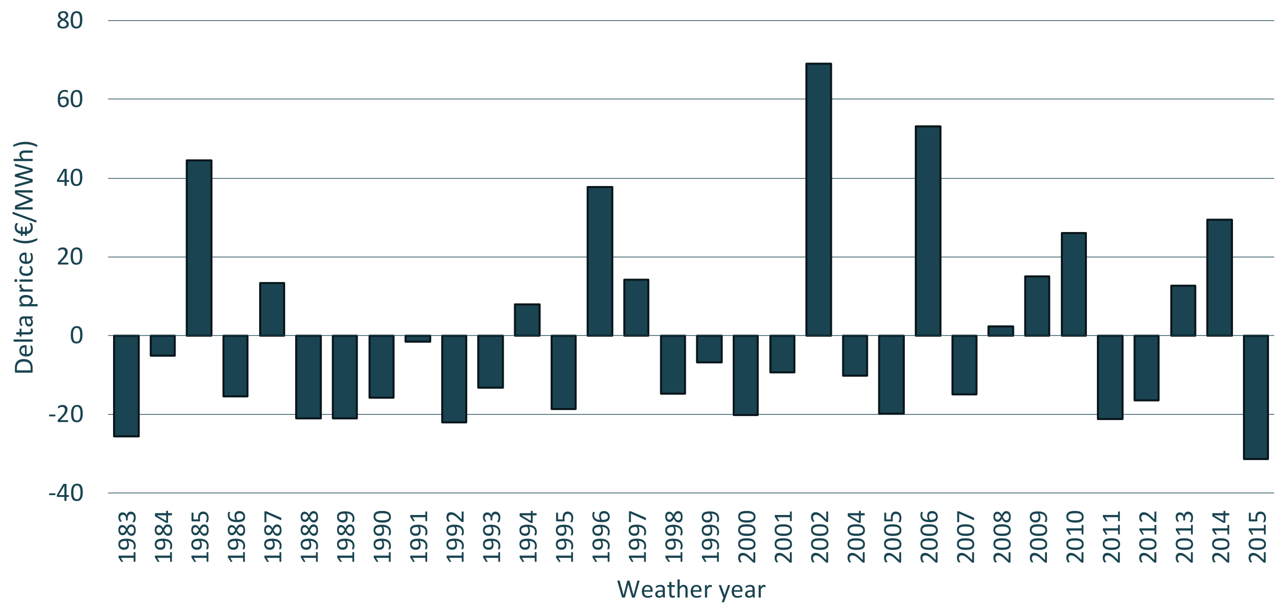

FIGURE 5.

Relative deviation of yearly averaged modelled electricity price from the average electricity price for each bidding zone across the full set of weather years for all bidding zones included in the model.

Secondly, the pre-optimisation step aims to avoid the capacity expansion for Germany subsidising inadequate generation capacities in surrounding regions or being subsidised by artificially low import prices. Given the study's focus on the electricity market, the geographical scope and resolution have been thoroughly examined to replicate historical power market dynamics (see also SECTION 4.7). This is an important benchmark which lay the foundation to also model future power systems. Following the realistic representation of electricity trade established through pre-optimisation, cGrid executes a modified capacity expansion of key clean energy technologies based on the GenX myopic multi-stage investment optimisation for 2045. Subsequently, the expanded system on the average weather year 1991 is tested against for 33 weather years (1983-2015), thus introducing variation for the weather-dependent generators and in the space heating part of the demand profiles, to assess its performance under diverse conditions.

The cGrid electricity market modelling is merely part of the optimisation in 2050 effectively limiting dependency on imports underscoring the value of energy resilience highlighted in the current study. Given Germany's large proportion of demand relative to interconnection transmission capacity, impact from inclusion of trade on the results is considered low. To understand its potential impact, we undertook additional electricity market modelling capacity expansion runs using inputs from 2040 instead of 2045. The main differences observed was a slightly lower wind expansion of around 15 GW in the *All Tech.* technology pathway. Solar capacity increased around 50 GW in the technology pathway *No Nucl. No CCS* thus exhibiting larger deviations. These modest differences can be attributed to a limited solution space, shaped by common initial conditions and restricted build options within the German power system. As mentioned above, the significant size of Germany in the electricity market adds to this understanding.

3.3 Limitations and exogenous assumptions

The current study, with a focus on the power system has its limitations and relies on exogenous assumptions to handle certain limitations in the interaction with other sectors. Limitations and exogenous assumptions include:

1 **Single demand forecast:**

- A fixed demand scenario is established from present day to 2050, with assumptions for heating, hydrogen, Electric Vehicles (EVs), and industry, including associated flexibility (see SECTION 4.2 for details) that are in-line with a fully decarbonised German economy by 2050.

2 **Hydrogen:**

- In case of the cGrid simulations a hydrogen market, including electrolyser demand for both industrial direct use and regeneration of electricity with hydrogen gas turbines, is modelled for Germany without limits to transmission, i.e., the model accommodates potential surplus of hydrogen between demand from industry and power plants.
- Imported hydrogen is not explicitly modelled but exogenous to the German power demand scenario.

3 **CO_2 emissions and prices:**

- The power system optimisation sets CO_2 prices such that the assumed CO_2 target for direct emissions is met (see also SECTION 4.1).
- The model optimisation accounts for direct emissions from the combustion of thermal power plants. Indirect emissions are integrated into the analysis by considering lifecycle emissions (see SECTION 6).
- Direct emissions associated with biopower plant operations are assumed to *not* contribute to the set CO_2 target for Germany in the model. Potential negative emissions with implemented CCS are only factored in during a post-analysis.

4 **Power transmission network:**

- The German power network is not explicitly modelled. Reinvestments to maintain the existing German national grids (220 kV and 400 kV) are assumed to occur.
- A custom analysis of required new transmission capacity expansion for the 2050 German power system based on technology contributions is performed as outlined in APPENDIX B.6. This expansion is not part of the power system optimisation, and associated costs are *not* part of the analysis.
- Transmission expansion for international connections is assumed to occur in all modelling cases according to ENTSO-E plans as described in SECTION 4.7.

5 **Carbon capture and storage (CCS):**

- Carbon Capture and Storage (CCS) is a technology that fossil fuel power plants can employ. Plant operators are assumed to pay a tariff, an additional variable cost, representing the cost for CO_2 transport and storage infrastructure. This infrastructure is not modelled explicitly but assumed to exist from 2030 onwards (as further described in SECTION 4.4.6). The exception is the scenarios in the *No CCS* technology pathway, where infrastructure for CO_2 transport and storage is not in place.

6 **Demand-side flexibility and hydrogen:**

- Costs to achieve demand-side flexibility, described in 0,are not included to the total system costs.
- Infrastructure investments related to the production, transmission, and storage of hydrogen *purely for demand side* are excluded in the optimisation. The investments are primarily to be carried by consumers; however, they provide the power system valuable flexibility. Note that production and storage of hydrogen for *regeneration of electricity* is an endogenous part of the power system optimisation.

7 **Capacity expansion and trade:**

- Near-term expansions of power production capacity, where investments are already made or projects are likely to progress, are *not* prescribed but purely determined by the model optimisation. This also means that capital costs associated with existing power capacity has not been taken into account.
- Unless deemed uncompetitive, existing capacity follows a prescribed retirement according to its technical lifetime. An exception is bio-based combined-heat-and-power plants, Bio Combined Heat and Power (CHP). These are not part of the capacity expansion and instead assumed a fixed installed capacity and annual generation as detailed in SECTION 4.6.3.
- Expansion with trade on the electricity market was merely directly incorporated in the simulations for model year 2050, as discussed in detail in SECTION 3.2.
- Limited consideration for non-technical land-use limitations, such as local opposition to siting large scale projects.
- Limited consideration for development, siting, permitting and other planning or supply chain limitations to annual buildout rates.

8 **Capacity and frequency reserve:**

- While the model incorporates a capacity reserve margin in the *Capacity Market* scenarios, aligned with German regulations as discussed in SECTION 4.8, satisfactory required levels of inertia and spinning reserves have not been included in the modelling.
- The optimisation only accounts for energy arbitrage and as such does not cater to short-duration grid services, potentially underestimating technologies, such as batteries, providing such services.

Finally, it's important to underscore that the present analysis focuses on the power system within the electricity market, serving as an initial phase to inform power system development. Balancing services and short-term markets are not accounted for in the modelling. After the current study, a thorough analysis of the resulting power system is required, taking into account factors like frequency stability, N-1 criteria, black start capability, and more. However, such a detailed analysis is beyond the scope of this study.

4 Input assumptions

This section provides an overview of the study's input assumptions, with further details available in the appendices. 0 includes a comprehensive list of power supply technologies incorporated in the model and assumed pre-existing installed generation capacities. Additionally, background information on investment and operational cost assumptions, along with the calculation of the levelised cost of electricity, is detailed. APPENDIX B offers an in-depth exploration of the GIS analysis methodology employed to determine wind and solar expansion potential. Lastly, APPENDIX E outlines the methodology and assumptions used for lifecycle estimates of emissions, land use, and critical mineral consumption.

4.1 CO_2 emissions

Our modelling approach is anchored in Germany's steadfast commitment to transitioning towards a decarbonised economy. Central to this endeavour is the nation's overarching objective of achieving nationwide net-zero emissions by 2045, as stipulated in the Climate Change Act[33].

We have implemented mass-based emission constraints in line with the CO_2 reduction targets specified for two sensitivity scenarios in TABLE 5 and FIGURE 6. It is often assumed that decarbonising the power sector is relatively easy compared to other sectors. To offset delays in emission reductions in hard-to-abate sectors such as steel, cement, and petrochemicals, it is expected that the power sector will lead the way by decarbonising at a faster pace. This approach also implies that negative emissions achieved through sustainable land use, land-use change, and forestry, LULUCF, measures are allocated to compensate for emissions from other sectors. The emission targets in the reference sensitivity for this study are consistent with this rationale.

The reference sensitivity reflects the ambitious goal of a 65% reduction in emissions by 2030 compared to 1990 levels when it was 366 million tons (Mt)[34]. Subsequent targets for 2035 and 2040 draw inspiration from both recent analyses conducted by Energy4Climate[35] as well as tailored adjustments to obtain a smooth expansion in the modelling results. As we progress towards 2045 and 2050, our modelling assumes a stringent 99% reduction, with the emission target constraint set at 3.7 Mt for the power sector. This equates to an approximate annual generation of 9 TWh for a combined-cycle gas power plant. Importantly, we posit that achieving net negative emissions beyond 2050 will occur outside the confines of the power system boundaries in our current study.

[33] Bundesregierung (2021), Climate Change Act 2021.
[34] Bundesregierung (2021), Climate Change Act 2021.
[35] Energy4Climate (2023), Treibhausgasneutralität in Deutschland bis 2045, Ein Szenario aus dem Projekt SCI4climate.NRW.

TABLE 5.

Annual mass-based power sector emission target for each model year. Corresponding level in 2022 was around 225 Mt[36].

SENSITIVITY	SCENARIO	YEAR	2030	2035	2040	2045	2050
Reference	*Base*	CO_2 emission target (Mt)	128	63	21	3.7	3.7
Conservative	*CO_2 --*		128	128	128	128	3.7

In this study, we examined a conservative sensitivity scenario, denoted *CO_2 --*, which assumes a slower pace of decarbonisation with more relaxed CO_2 targets. As detailed in TABLE 5, this scenario sets CO_2 targets for 2030 and 2050 that are identical to those in the reference sensitivity, but with no interim targets.

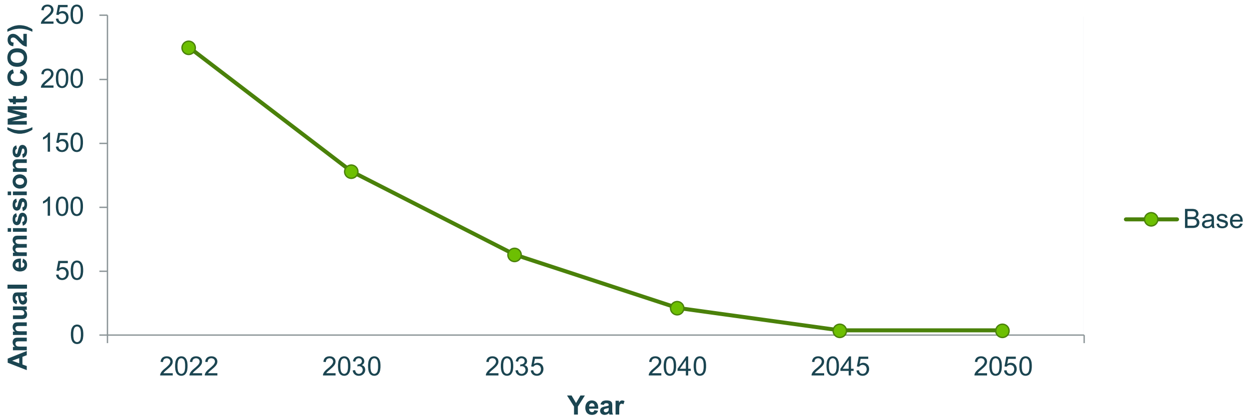

FIGURE 6.

Annual mass-based power sector emission target for each model year and scenario with level in 2022[37] included.

Despite clear directives[38], near-term projections for EU carbon allowance price projections until 2030 are subject to significant uncertainties as been observed in recent months[39]. In our current modelling approach, CO_2 prices are determined entirely by the model to meet the specified CO_2 targets for the German power system.

Upstream emissions, particularly relevant for natural gas supply, were *not* considered in this study, potentially rendering the fuel prices used optimistic. Related uncertainty in development revolves around the European Union's Carbon Border Adjustment Mechanism[40], or CBAM, which came into effect in June 2023. It currently does not encompass fossil fuels, but it is deemed likely to do so in the future[41], which the EU methane strategy further signals[42].

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[36] Umwelt Bundesamt (2023), Entwicklung der spezifischen Treibhausgas-Emissionen des deutschen Strommix in den Jahren 1990 – 2022.
[37] Umwelt Bundesamt (2023), Entwicklung der spezifischen Treibhausgas-Emissionen des deutschen Strommix in den Jahren 1990 – 2022.
[38] European Commission (2023), Our Ambition for 2030.
[39] Reuters (2024), Analysts Cut EU Carbon Price Forecasts on Weak Industry, Power Sector Demand.
[40] European Commission (2023), Carbon Border Adjustment Mechanism.
[41] KAPSARC (2022), Potential implications of the EU Carbon Border Adjustment Mechanism.
[42] European Commission (2020), EU Methane Strategy.

4.2 Demand and flexibility

The current section introduces the demand trajectories and demand-side flexibility relevant for the present analysis. For more details, the reader is referred to 0.

4.2.1 Demand trajectories

FIGURE 7 shows estimated breakdown by demand category for year 2020 and for this study used projection until 2050. The base trajectory has been built from the technology-driven scenario developed in a study by Ember[43] with refinements into further sub-categories as well as the addition of grid losses.

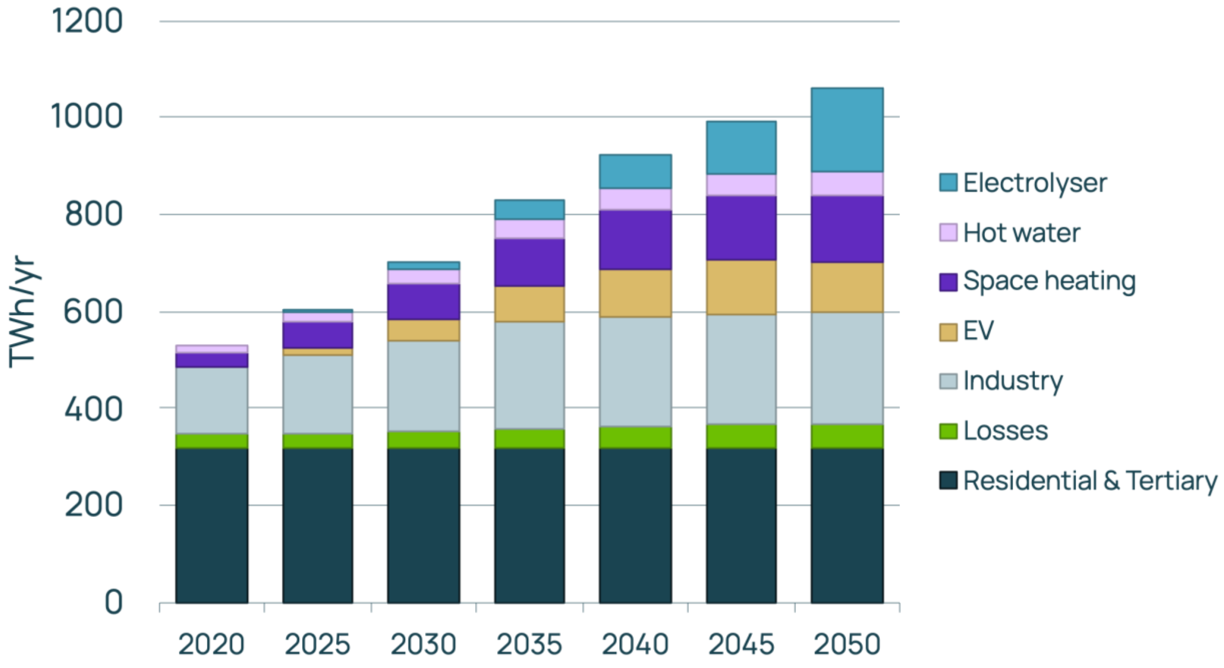

FIGURE 7.

Electricity demand for Germany in the base sensitivity breakdown by demand category for year 2020 and projection for the future until 2050.

We have built two additional demand trajectories, named local and outsource, to highlight a potential variation in the power demand growth for Germany[44]. Let's assume that the *Base* scenario, shown in Figure 7, presumes that German hydrogen demand is met with 50% imports, corresponding to the lower limit of present-day long-term estimates by the German government (50%-70%)[45]. The *Local* and *Outsource* scenarios encompass variations on imports of clean hydrogen, its derivatives (e.g., e-fuels, ammonia), and energy-intensive industrial base products (e.g., steel, aluminium). The *Outsource* case is defined by an increase to 70% hydrogen imports (upper end of governmental estimate[46]), meaning a decrease in German electrolyser demand, combined with a 30% lower industry demand. In contrast, the *Local* case represents a scenario with only 15% hydrogen imports and a 30% higher industry demand. These additional scenarios result in a decrease of 140 TWh in the *Outsource* scenario and an increase of 190 TWh for the *Local* scenario compared to 1060 TWh in the *Base* scenario. Future studies integrating demand scenario variations show the potential to provide insights

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[43] Ember (2023), New Generation: Building A Clean European Electricity System by 2035.
[44] These scenarios have not been simulated.
[45] Hydrogeninsight (2023). Habeck: Germany will have to Import 70% of the Green Hydrogen it Consumes.
[46] Hydrogeninsight (2023). Habeck: Germany will have to Import 70% of the Green Hydrogen it Consumes.

on changing power system characteristics enabling energy-intensive industry continuation in Germany.

FIGURE 8 shows the yearly total electric demand trajectories of this study in comparison with other recent studies. All in all, the trajectories in the present study, QC-CATF, land in the middle of the range.

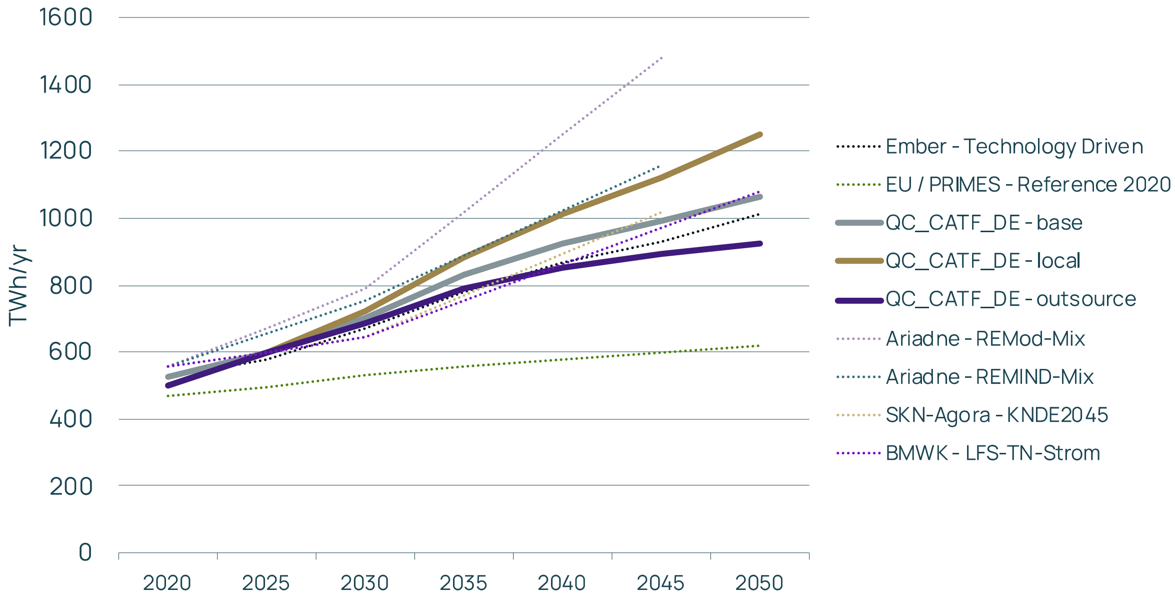

FIGURE 8.

Yearly total electricity demand trajectories for Germany of this study (filled lines) in comparison with other recent study scenarios in dotted lines[47].

4.2.2 Demand flexibility

FIGURE 9 illustrates the share of demand that is considered flexible at average. It's important to note that each demand category exhibits distinct load profiles, leading to varying degrees of available flexibility throughout each hour. For instance, there is minimal space heating demand during the summer months. The share of demand considered flexible varies across future years for all categories, as elaborated in 0.

Demand representing the industry category, i.e., excluding electrolyser demand, is anticipated to make a significant contribution, particularly due to its robust demand projected for 2030, thereby constituting the majority of short-term flexibility for that model year in both the reference and optimistic scenarios. The consistent provision of significant flexibility by electrolyser demand across sensitivities in 2050 is facilitated by the expected development of a robust hydrogen network, transmission infrastructure, and storage capabilities. Notably, electrolyser flexibility emerges as the primary source of flexibility in 2050 for the conservative scenario.

Furthermore, space heating through utility and commercial scale heat pumps as well as thermal storage implementations, and Electric Vehicles (EVs) are forecasted to follow electrolysis in their capacity to provide flexibility. Lastly, in 2050, there appears to be a discernible 1:2:3 relationship among the different sensitivities for total flexibility share.

[47] Ember (2023), New Generation., European Commission (2021), EU Reference Scenario 2020., Dena (2022), Vergleich der "Big 5" -Klimaneutralitätsszenarien.

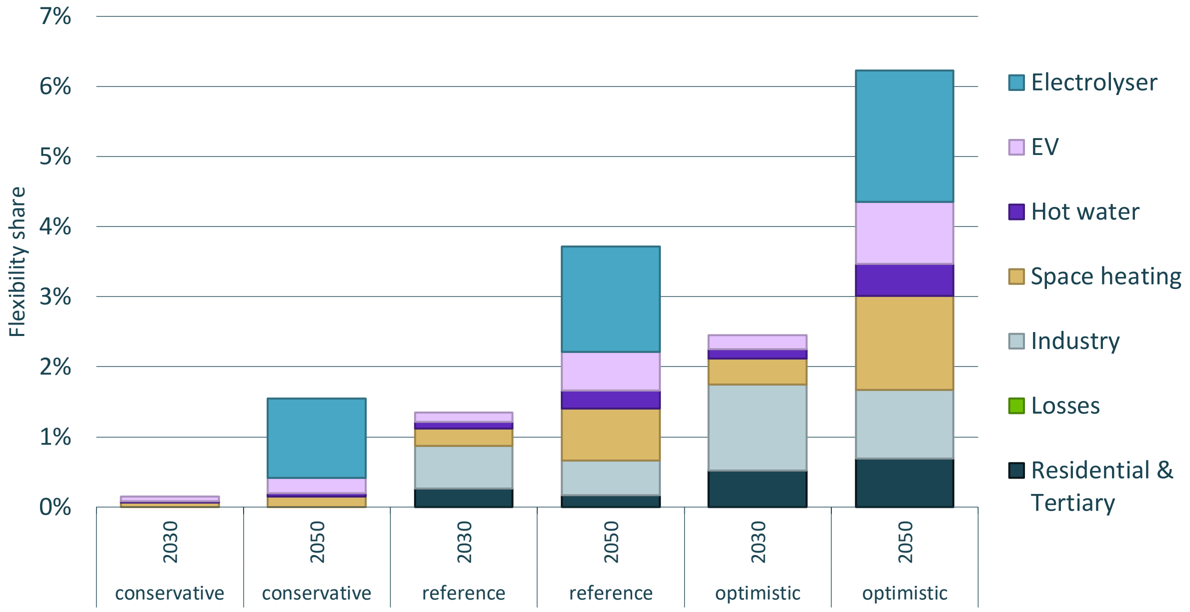

FIGURE 9.

Share of demand that is flexible on average ("flex down") for the different sensitivity as well as model years 2030 and 2050 for Germany.

4.3 Wind and solar expansion

4.3.1 Expansion limits

In the case of onshore wind power, a combination of GIS based calculations and analysis of existing literature was used to derive three potential sensitivities of wind power development. The first sensitivity, land conservative, reflects a constrained expansion to 61 GW where no further investments in new wind parks is allowed and the only option to keep the capacity available is to repower them. In the reference sensitivity (current policy) the calculations were made based on the governmental plans to allocate 2% of country area to wind parks. Taking this number into account and power density of wind parks at 20 MW/km^2 the maximum expansion potential of onshore wind was estimated to 143 GW. In the optimistic scenario (that assumes current legal regulations when it comes to onshore wind placement) the maximal wind capacity was set to 350 GW. This scenario assumes that wind turbine placement is allowed in forests, and as close as 500 meters to the closest residential buildings. Notably, these are technical constraints not capturing potential social oppositional aspect.

The capacity factor (CF) assumptions for the future onshore wind fleet in Germany concludes with a cautious yet optimistic outlook. In contrast to a CF of new onshore wind capacity of around 29% in the conservative and reference sensitivities, a CF of 25% is proposed for the optimistic expansion scenario. This adjustment considers several key factors: Technological Advancements and Repowering: Improvements in technology and the replacement of older turbines with newer, larger models suggest a potential for higher efficiency. However, these advancements are tempered by the recognition of operational losses such as wake effects, which can reduce overall efficiency as capacity increases. Historical Performance Data: The historical CF range for onshore wind in Germany, which has varied significantly over the past decade, provides a basis for cautious optimism. It indicates that while high CFs have been achieved, variability due to environmental and operational factors is a critical consideration. Grid Congestion and Curtailment: Discussions around the impact of grid congestion and the need for curtailment highlight the complexities of integrating large-scale wind energy into the national grid. The anticipation of curtailment due to grid congestion, estimated conservatively at around 5% for onshore wind, underscores the practical challenges of expanding wind energy capacity. Modelling Approaches: whether to use multipliers or cutoffs to adjust for technical curtailment—emphasises the need for accurate, realistic CF projections. The consensus leans towards a conservative approach that can be adjusted based on actual operational data. The collective insight from the above suggests that while optimistic expansion of onshore wind capacity in Germany is feasible, it must be approached with caution. The 25% CF assumption for the optimistic scenario is seen as a balanced figure that acknowledges both the potential for technological and operational improvements and the challenges posed by environmental factors, grid integration, and operational efficiency losses.

4.3.2 Offshore wind

For offshore wind deployment the governmental plans[48] have been followed, which indicate that by 2030 the offshore capacity could reach 30 GW, followed by 40 GW by 2035 and reaching as much as 70 GW by 2045. When it comes to the grid connection capacity Deutsche WindGuard[49] summarises (FIGURE 10) that by 2031 the expected capacity should increase by an additional 22.58 GW in the North Sea region and by 2.5 GW in the Baltic Sea region. North-South transmission corridor in onshore setting requires further strengthening to match the spatial demand-supply mismatches[50]. As indicated in FIGURE 10 in 2030 already 3.8 GW of capacity has been awarded with grid capacity and for 16.8 GW the tenders have been scheduled. The situation seemingly remains less clear for the subsequent years.

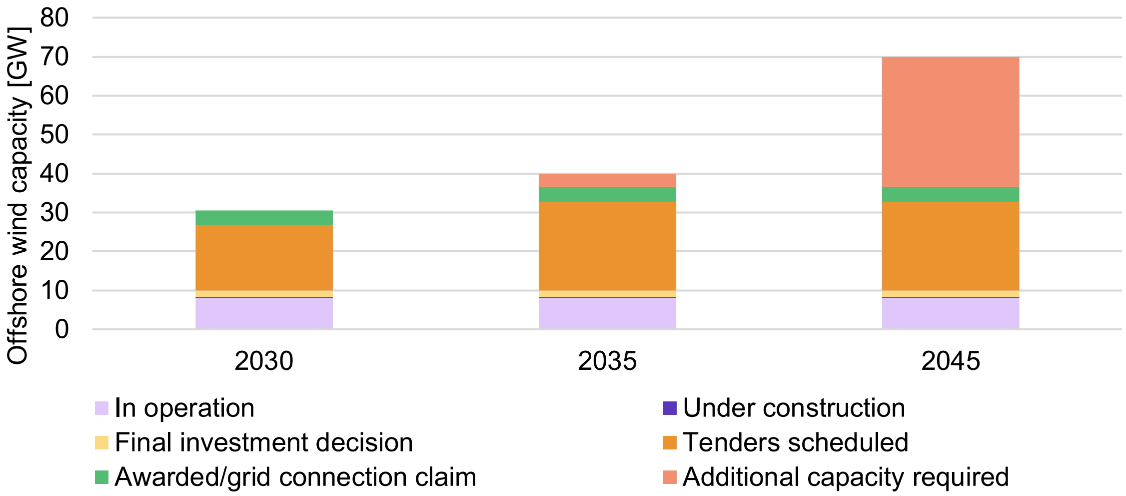

FIGURE 10.

Overview of ongoing situation in offshore wind energy in Germany, source: based on Deutsche WindGuard[51].

4.3.3 Solar Photovoltaic (PV)

As identified in the similar analysis conducted for Poland[52] the expansion of solar PV is not limited by the availability of land/roofs but rather by the value of the solar energy considering the daily and seasonal demand/supply matching. In other words, the PV capacity limit identified within the GIS

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48 Federal Ministry for Economic Affairs and Climate Action (2022), New Offshore Agreement for More Wind Energy at Sea.
49 Deutsche WindGuard (2022), Status of Offshore Wind Energy Development in Germany.
50 Bundesnetzagentur (2024), Präsident Müller: "Schaffen Voraussetzung für eine klimaneutrale Energieversorgung Deutschlands“.
51 Deutsche WindGuard (2022), Status of Offshore Wind Energy Development in Germany.
52 Quantified Carbon (2023), Power System Expansion Poland.

analysis has not been reached – it is so high it is irrelevant from the modelling perspective as a constraint. For this reason, no hard capacity limits on this technology have been implemented in this study.

4.3.4 Comparison other studies

In our analysis we have used the datasets and exclusion criteria (see APPENDIX B for details on GIS modelling) implemented by others as indicated in a very recent review, on renewable energy sources potential in Germany based on GIS analysis, conducted by Risch *et al.*[53]. As noted by the authors of this review various studied completed for Germany indicate the onshore wind potential to range from 68 GW to as much as 1188 GW. Our analysis is more conservative compared to some other studies like for example Lütkehus *et al.*[54] (1188 GW) but matches well in general with the numbers proposed by Risch *et al.* For offshore wind there seems to be a better agreement between various authors as Risch *et al.*, report values ranging from slightly above 25 GW to just above 100 GW. Analysis of Fig. 6 from Risch *et al.*, review indicates two potential scenarios for offshore wind with 50 GW of maximum capacity and roughly 80 GW. In our analysis we have adopted a maximum expansion of fixed foundation offshore wind at 70 GW while floating offshore wind may be expanded on top of this with no limit. When it comes to solar PV, the literature mentioned by Risch *et al.*, suggest the potential to be ranging from 90 GW to 1285 GW for open-field PV with an additional 43 GW to 746 GW that could be obtained from rooftop PV systems.

4.3.5 Historic and near-term development

The deployment of large-scale onshore wind power started in Germany around the year 1990 (FIGURE 11 – includes offshore that constitutes around 11.5% of total installed capacity in wind energy) and preceding the development of solar PV (FIGURE 11).

The largest (FIGURE 11) addition in new wind capacity was observed in 2016 (6 GW), followed by 2014 (5.9 GW). In the case of solar PV (FIGURE 11), in 2023 only roughly 13.2 GW of new capacity was added, which was almost twice the number observed in 2022 (7.4 GW).

The national expansion goals call for 215 GW of solar PV by 2030 (19 GW/year) and 115 GW of onshore wind by 2030 (7.7 GW per year)[55]. Solar technology almost matched this target in 2023 however onshore wind was significantly lagging.

[53] Energies (2022), Potentials of Renewable Energy Sources in Germany and the Influence of Land Use Datasets.

[54] Umweltbundesamt: (2013), Potenzial der Windenergie an Land.

[55] Renewables Now (2024), Germany Installs 17 GW of Renewables in 2023.

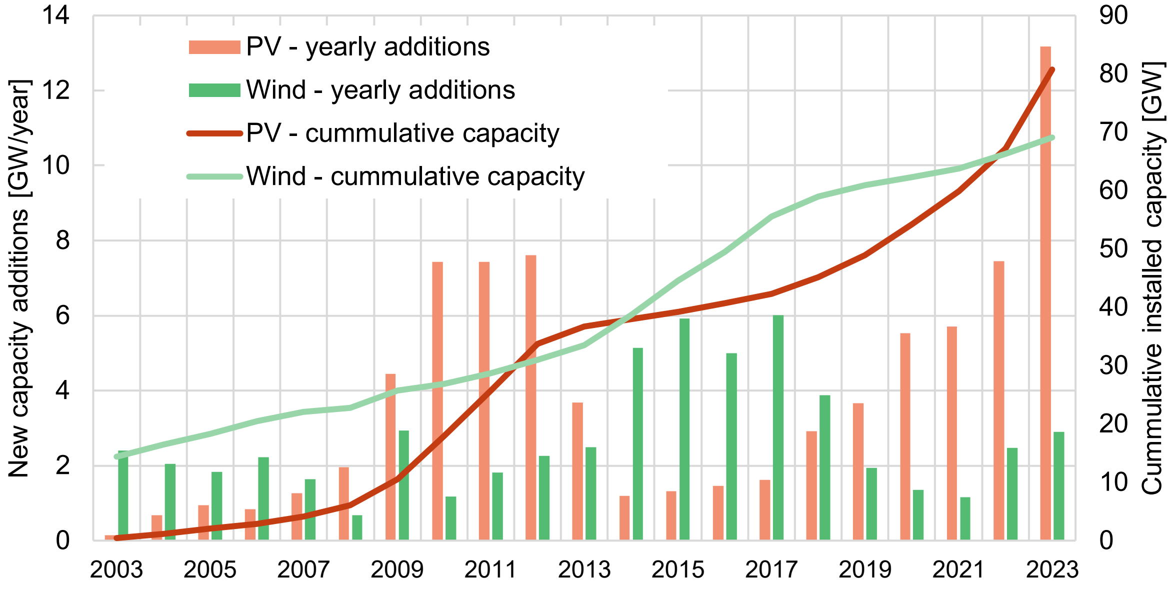

FIGURE 11.

Newly added (per year) solar PV and onshore wind capacities in Germany juxtaposed with the dynamics of cumulative installed capacity of both energy sources (offshore wind included)[56].

First offshore wind power plant in Germany was commissioned in the year 2004 (4.5 MW). The development of offshore wind power is characterised by high variability in terms of new connected capacity where in 2015 as much as 2.3 GW was added and in 2020 only 200 MW, and the next year 0 MW. The total installed capacity in offshore wind oscillates around 8 GW with expansion aimed to reach 30 GW by 2030, 40 GW by 2040 and 70 GW by 2045[57] (FIGURE 12).

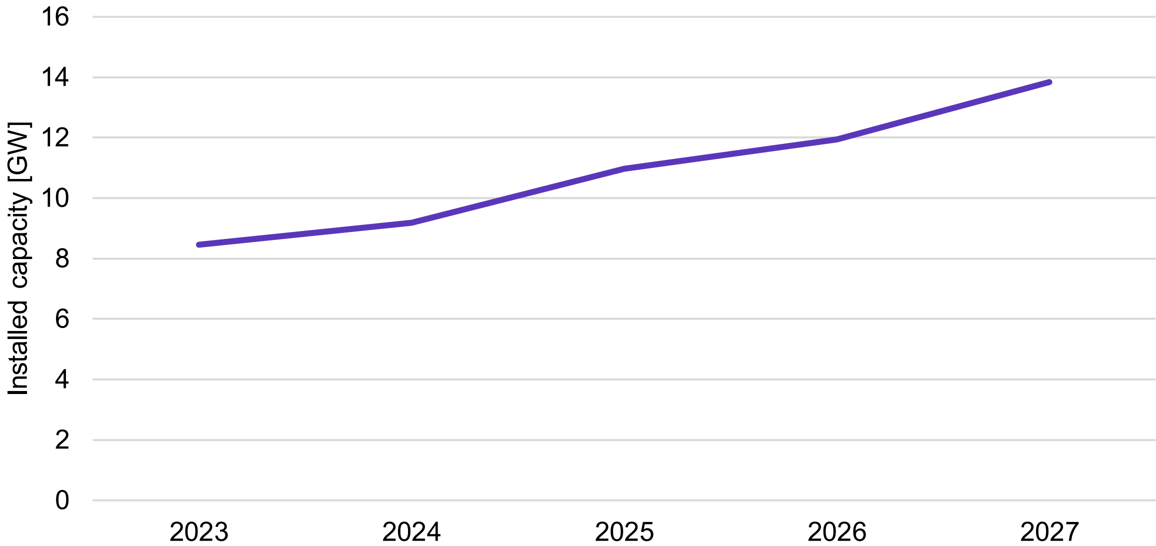

FIGURE 12.

[56] Merged data from IRENA (2023), Renewable Capacity Statistics 2023 (https://www.irena.org/Publications/2023/Mar/Renewable-capacity-statistics-2023); Bundesnetzagentur (n.d.), Marktstammdatenregister (https://www.marktstammdatenregister.de/MaStR); and Bundesministerium für Wirtschaft und Klimaschutz (https://www.bmwk.de/Navigation/EN/Topic/topic.html?cl2Categories_LeadKeyword=erneuerbare-energien).

[57] Clean Energy Wire (2024), German Offshore Wind Expansion Slowly Picking Up In 2023, Must Multiply Soon to Meet Targets.

Projected short term development of offshore wind energy in Germany, source: own elaboration based on Deutsche WindGuard[58].

4.3.6 Retirement

The retirement of existing solar and wind parks is already happening in Germany. From February 2023 to January 2024[59] in total 21 MW of solar PV systems have been decommissioned (6.5k installations). When it comes to onshore wind during that period, 561 MW of capacity was decommissioned totalling to 466 wind turbines. In both cases it is observed that rather small systems are decommissioned. Based on the numbers above (total decommissioned capacity and number of decommissioned systems both per technology) it can be concluded that the mean capacity of retired solar PV was 3.24 kW whereas for onshore wind it was 1.2 MW. The projected retirement of both technologies assuming their respective lifetimes is shown on FIGURE 13 – assuming no new installations in the meantime.

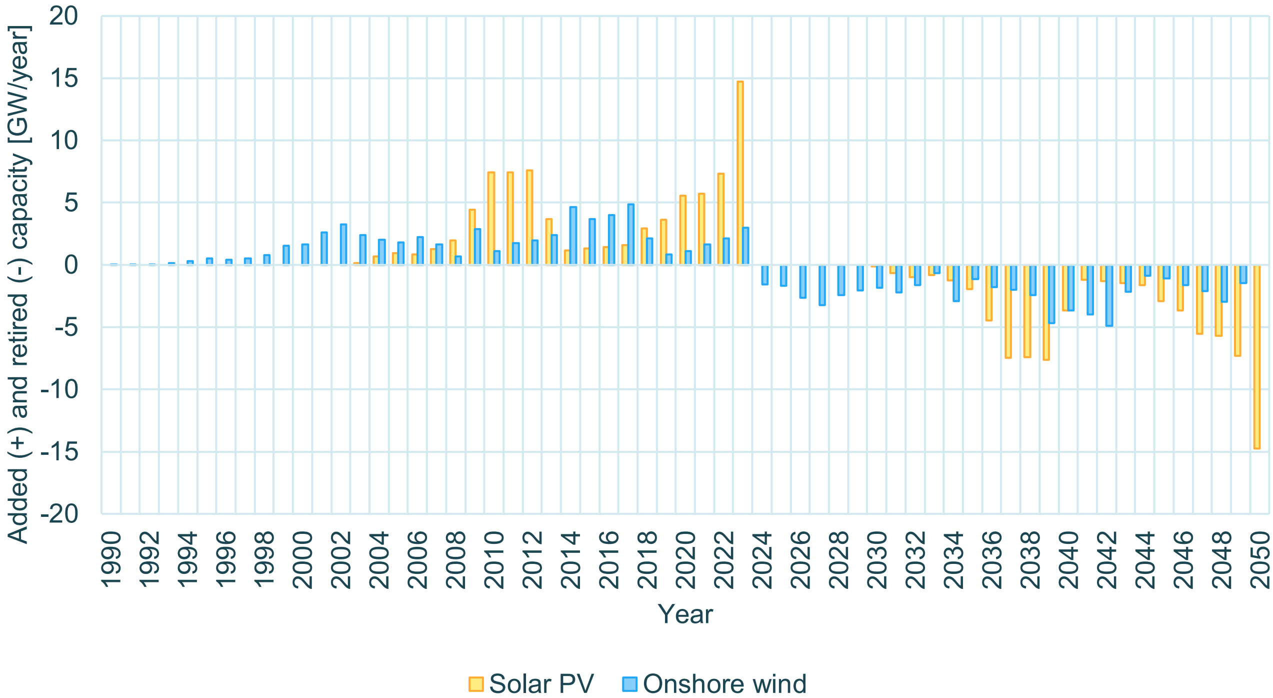

FIGURE 13.

Yearly historic expansion and projected retirement (shown as decreasing installed capacity past year 2023 for onshore wind and past year 2029 for solar PV) of existing solar PV and onshore wind in the model.

4.3.7 Production profiles

The calculation method for the wind power capacity factor time series is conducted with QC's in-house tool *Weather2Energy and* involves utilizing ERA5[60] data for comprehensive climate analysis, downscaling using Global Wind Atlas[61] for enhanced resolution and topographical accuracy, and subsequent steps like forcing factor and shear exponent calculations for precise wind speed

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58 Deutsche WindGuard (2022), Status of Offshore Wind Energy Development in Germany.
59 Bundesnetzagentur (2024), Statistiken erneuerbarer Energieträger.
60 Climate Data Store (2024), ERA5 Hourly Data on Single Levels from 1940 to Present.
61 Global Wind Atlas (2024), Global Wind Atlas.

adjustments at various heights. Hourly wind output per wind park is calculated based on specific turbine power curves and adjusted wind speeds at hub height, and then aggregated to hourly capacity factors per bidding zone. Two profiles are created, one modelling existing wind parks as of 2024 (using actual turbine heights, type etc) and one to model new wind parks based on larger and higher turbines.

Separate solar profiles are created for rooftop and parks. Rooftop are simulated with orientation and slope found in existing installation[62], parks are simulated as oriented to the south for the latitude yield optimised slope. Gridded population count data[63] is used for spatial weighting, where rooftop and parks are separately curve fitted with actual site data[62]. The current study merely employs the park profiles for utility-scale solar PV expansion.

4.4 Investment and operational costs

The current study considers a set of general financial assumptions that form the foundation for our analysis. All financial values are expressed in pre-tax real currency in terms of Euros (€) for the year 2023. These currency adjustments ensure consistency and accuracy in our cost evaluations. Furthermore, the financial assumptions encompass the Weighted Average Cost of Capital (WACC) for which a value of 6% has been employed for all sensitivities. To accommodate the financial dynamics during the construction phase of projects, we employ an interest rate equal to half of the respective scenario's WACC for the construction time as a mark-up on total investment costs[64]. Capital recovery periods have been set equal to the technical lifetime.

Investment and operational costs as well as operational characteristics for the energy technologies included in the current study have been determined based on review of references presented in TABLE 6. The references encompass historical, present-day/near future and future projections.

Investment and operational costs have been made in three sensitivities: optimistic, reference and conservative. Technology cost assumptions is a vital component of our analysis, and it has been conducted by comprehensive investigation of a diverse array of credible sources as outlined in TABLE 6. Cost estimates from these sources were made both prior to and during the transformative landscape of 2022, which was marked by the invasion of Ukraine, the energy crisis, inflationary pressures, and increasing geopolitical tensions. Notably, the costs associated with renewables have exhibited an upward trajectory since 2020, attributed to the evolving global context characterised by escalating prices of commodities and energy[65], inflation, and geopolitical complexities[66]. Costs "are expected to decline by 2024, but not rapidly enough to fall below pre Covid-19 values in most markets outside China."[67] It is further worth mentioning, that while solar PV deployment is set to shatter many records in 2023[68], wind power is facing challenges[69] with a growth more uncertain[70].

Summarised assumptions and calculations of Levelised Cost of Electricity (LCOE) are described at the end of the current section in SECTION 4.4.7.

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62 Springer Nature (2020), Metadata Record for: A Harmonised, High-Coverage, Open Dataset of Solar Photovoltaic Installations in the UK.
63 NASA (n.d.), Gridded Population of the World (GPW), v4.
64 Rephrased, a WACC of 6% was calculated assuming 3% cost of debt which also includes the assumption that construction is financed with 100% debt.
65 IEA (2021), What is the Impact of Increasing Commodity and Energy Prices on Solar PV, Wind And Biofuels?
66 BloombergNEF (2022), Cost of New Renewables Temporarily Rises as Inflation Starts to Bite.
67 IEA (2023), Renewable Energy Market Update – Outlook for 2023 and 2024.
68 Canary Media (2023), Chart: Solar installations set to break global, US records in 2023.
69 Reuters (2023), Siemens Energy's Shares Tumble as Wind Turbine Troubles Deepen.
70 IEA (2023), Renewable Energy Market Update – Outlook for 2023 and 2024.

TABLE 6.

Main source of references building investment and operational cost estimates for power technologies considered.

REFERENCE	ACRONYM	TYPE
National Renewable Energy Laboratory (2023), Annual Technology Baseline.	ATB_2023	Future projections, 2021 - 2050
International Energy Agency & Nuclear Energy Agency (2020), Projected Costs of Generating Electricity.	IEA_NEA_2020	Present-day/near future
International Renewable Energy Agency (2022), Renewable Power Generation Costs in 2021.	IRENA_2022	Historical
International Renewable Energy Agency (2023), Renewable Power Generation Costs in 2022.	IRENA_2023	Historical
Energiforsk (2021), El Från Nya Anläggningar.	Energiforsk_2021	Present-day/near future
Idaho National Laboratory (2023), Literature Review of Advanced Reactor Cost Estimates.	INL_2023	Present-day/near future
European Commission (2021), EU Reference Scenario 2020.	EU_2020	Future projections, 2020 – 2050
Ten-Year Network Development Plan 2024 (2023).	TYNDP_2024	Future projections, 2022 – 2050
International Energy Agency (2023), World Energy Outlook 2023.	IEA_2023	Future projections, 2022 – 2050
Department for Business, Energy & Industrial Strategy UK (2020), Electricity generation costs 2020.	BEIS_2020	Future projections, 2025-2040

4.4.1 Solar PV

The top panel of FIGURE 14 illustrates the projected overnight capital costs for utility-scale solar PV as assumed in the present study. For solar PV, the initial point is derived from the historical average of European countries[71]. Learning trends and endpoints are guided by the IEA_2023[72], with China representing optimistic, the European Union representing reference, and the United States representing conservative sensitivities. Fixed operational costs have been determined based on TYNDP_2024[73]: starting at 14 €/kW/yr in 2023 dropping to 8 €/kW/yr in 2050.

[71] International Renewable Energy Agency (2023), Renewable Power Generation Costs in 2022.
[72] IEA- International Energy Agency (2023), World Energy Outlook 2023.
73 ENTSO-G, ENTSO-E (2023), Ten-Year Network Development Plan 2024.

4.4.2 Onshore and offshore wind

In the case of onshore wind, Germany exhibits relatively high capital costs compared to other European countries, such as Sweden, as illustrated in the middle panel of FIGURE 14.Generally smaller projects, i.e. total power capacity per wind park, for instance due to land constraints could provide an explanation to the difference. Given that the best locations have been taken already, we have deemed it likely that this relationship will continue to hold throughout the modelling horizon. APPENDIX B.5 presents an analysis on this topic. On this background, starting values have therefore been derived from Germany's historical costs as per IRENA_2023[74]. Endpoints for optimistic and conservative scenarios are set to approximate the range of cost projections from other references, with a linear learning trend faster in the 2020s compared to 2030s and 2040s. Fixed operational costs starts at 35 €/kW/yr[75].

For offshore wind, bottom-fixed foundations represent the sole mature technology. The bottom panel in FIGURE 14 compares data from various reference sources, revealing a noticeable scarcity compared to onshore wind. Notably, among European countries with substantial installed capacity, such as the United Kingdom and Germany, IRENA_2023[76] reports similar overnight capital costs as of 2022, values which include the escalating costs observed in recent years[77]. Utilising this data point as the starting reference for our projections, we have implemented linear learning trends segmented into two periods, with the split in 2035. These trends encompass optimistic and conservative scenarios, enveloping the spectrum of values observed in reference studies, with the current study's reference sensitivity positioned between them. Offshore wind on floating platforms have been assumed costs according to ATB_2023, however their costs are not competitive compared to fixed foundations.

General grid connection costs for offshore wind have been set according to ATB_2023. Onshore grid reinforcement required to accommodate both onshore and offshore wind as well as solar are not included in the power system optimisation but instead covered separately as detailed in APPENDIX B.6.

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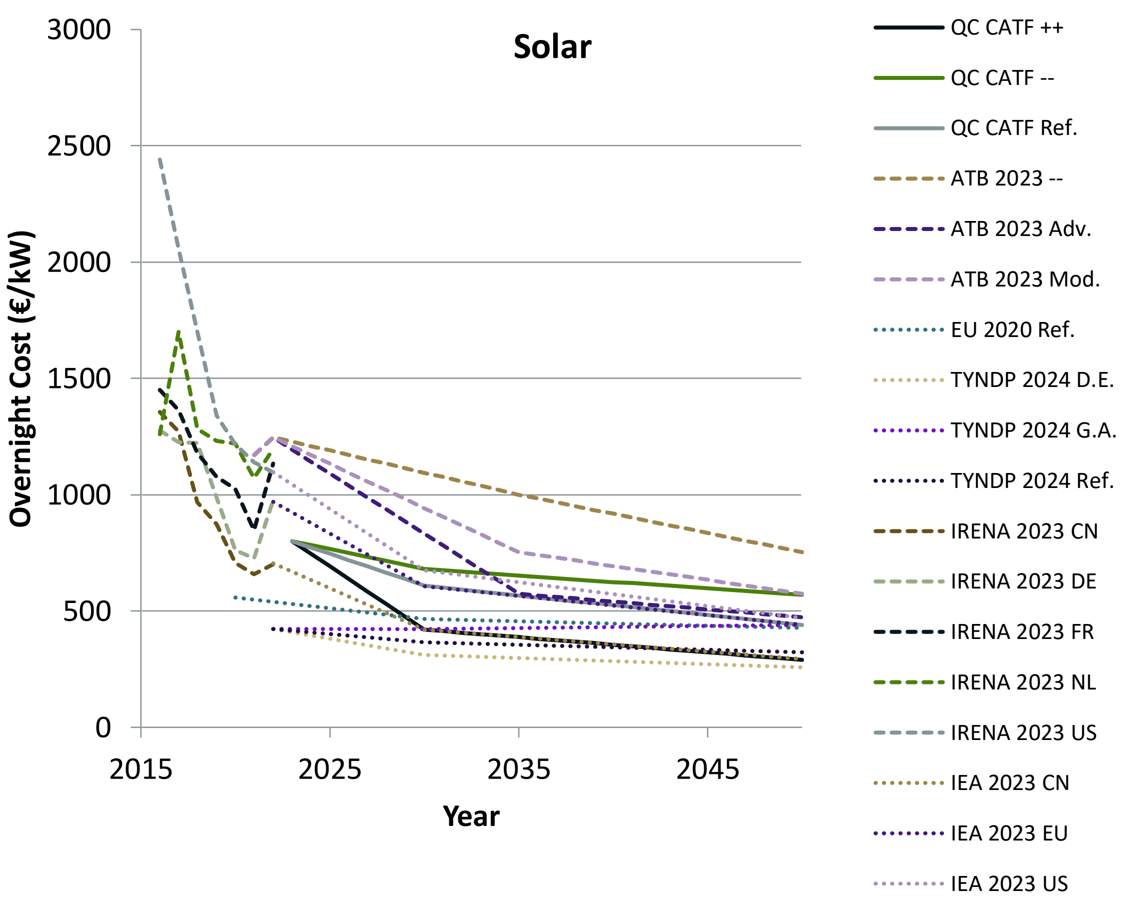
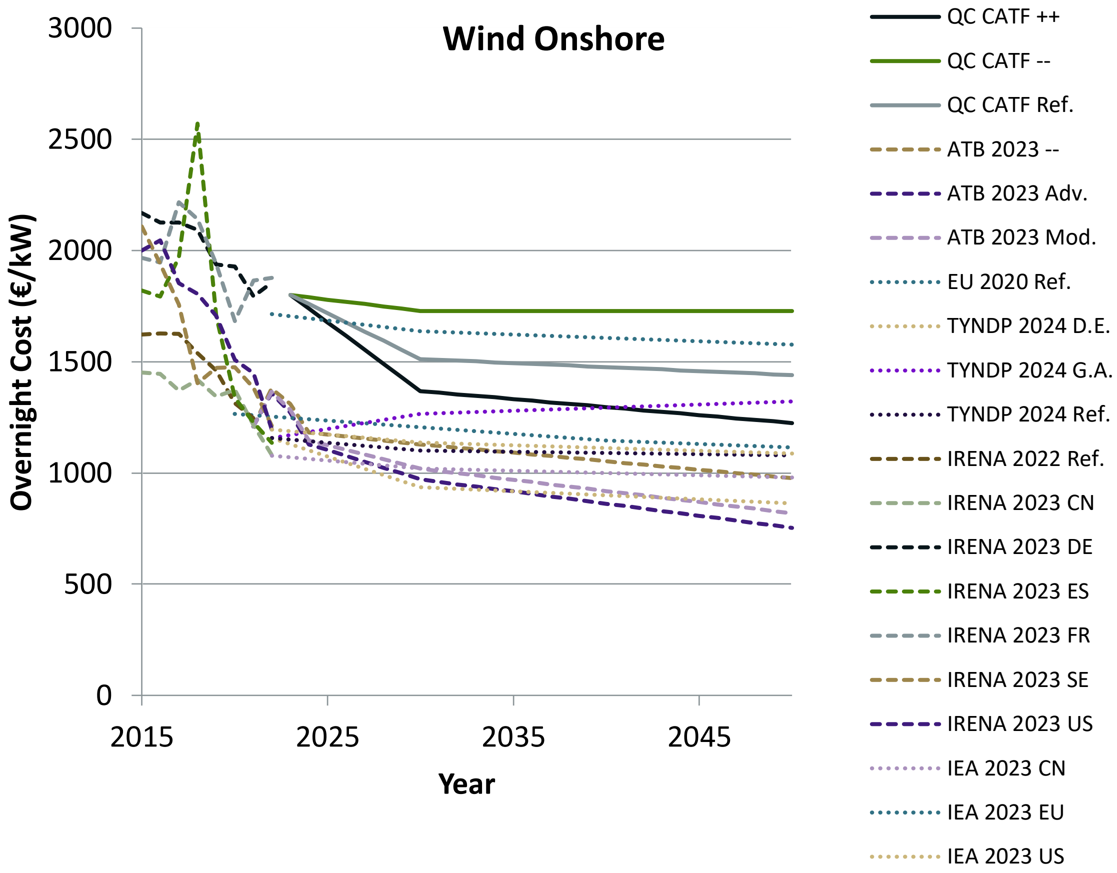
[74] IRENA- International Renewable Energy Agency (2023), Renewable Power Generation Costs in 2022.
[75] IRENA- International Renewable Energy Agency (2023), Renewable Power Generation Costs in 2022.
[76] IRENA- International Renewable Energy Agency (2023), Renewable Power Generation Costs in 2022.
[77] Financial Times (2023), The Struggles of the Offshore Wind Industry.

TABLE 7.

Fixed operational and maintenance costs in €/kW/yr for solar and wind technologies for different sensitivities and model year. For the case of solar PV the there is only a reference sensitivity.

PARAMETER	SENSITIVITY	2030	2040	2050
Solar PV	Reference	12	10	8
Wind onshore	Optimistic	30	22	15
	Reference	32	29	25
	Conservative	34	32	30
Wind offshore fixed	Optimistic	70	55	40
	Reference	72	61	50
	Conservative	75	67	60





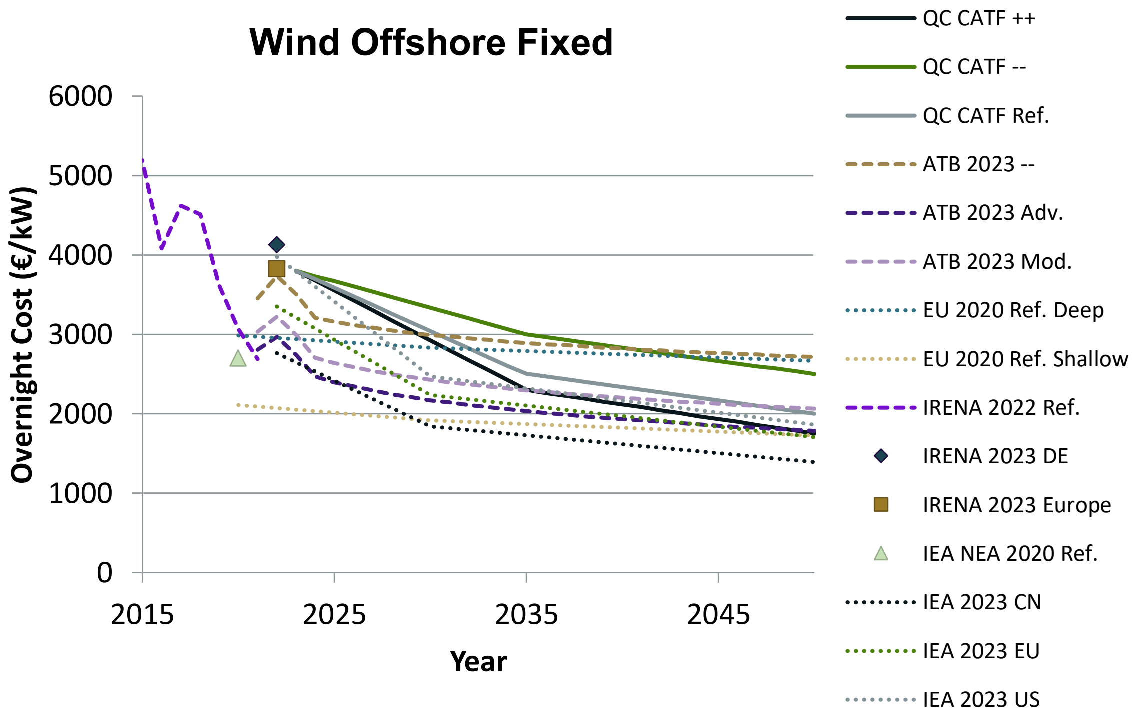


FIGURE 14.

Comparison of overnight capital costs for solar (top panel), wind onshore (middle panel) and wind offshore fixed (bottom panel) in the present study with those from other references, as specified in the legend. The data points are differentiated by markers and line styles: single-point series feature square markers, series with yearly frequent data are represented by dashed lines, and series with multi-year intervals between data points are denoted by dotted lines with circle markers. Grid connection costs are included for offshore wind.

4.4.3 Battery storage

Utility-scale battery storage overnight capital costs, for power and energy separately, and operational costs have been derived from ATB_2023[78]. Two points are worth mentioning. Firstly, IEA_2023[79] and ATB_2023 both use the same underlying source for battery storage costs, though ATB_2023 refers to a more recent version[80] compared to IEA_2023[81]. Secondly, the present study does not separate battery storage technologies by its storage duration. Instead, a generic battery storage technology may be expanded by the model under the constraint that the storage duration is between 2 and 10 hours.

4.4.4 Hydrogen for power generation – electrolysers, storage and gas turbines

The model optimisation includes the possibility to build gas turbine power plants fuelled with hydrogen. The model includes the electrolyser charging of a centralised German hydrogen storage. Cost assumptions of electrolysers are presented in TABLE 8. The investment costs have been derived from values of IEA_2023[82] excluding China, with net-zero representing optimistic and stated policies representing conservative sensitivity, respectively. The reference sensitivity has been set as the average of the optimistic and conservative. The operational costs starting point stem from International Council on Clean Transportation (2020)[83] with the value of 50 €/kW and 2050 end points have been inspired from Svenskt Näringsliv (2020)[84].

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[78] National Renewable Energy Laboratory (2023), Annual Technology Baseline.
[79] International Energy Agency (2023), World Energy Outlook 2023.
[80] NREL- National Renewable Energy Laboratory (2023), Cost Projections for Utility-Scale Battery Storage: 2023 Update.
[81] NREL- National Renewable Energy Laboratory (2023), Cost Projections for Utility-Scale Battery Storage: 2023 Update.
[82] International Energy Agency (2023), World Energy Outlook 2023.
[83] International Council on Clean Transportation (2020), Assessment of Hydrogen Production Costs from Electrolysis.
[84] Svenskt Näringsliv (2020), Modellering av Svensk Elförsörjning.

TABLE 8.

Investment and operational costs for electrolysers for power generation.

PARAMETER	SENSITIVITY	2030	2040	2050
Overnight cost (€/kW)	Optimistic	600	530	460
	Reference	780	680	590
	Conservative	950	840	730
Fixed Operation and maintenance (OM) (€/kW/yr)	Optimistic	29	16	11
	Reference	37	29	26
	Conservative	45	41	39

The model has the option to either build open-cycle or combined-cycle hydrogen gas power plants with investment and operational costs equal to the natural gas counterpart determined based on an average of ATB_2023[85] and TYNDP_2024[86].

Geological storage of hydrogen gas in Germany shows high potential. The German Hydrogen Roadmap 2030[87] estimates 33 TWh of hydrogen storage potential in caverns and saline aquifers could add another 2-20 PWh. With this background, the present study assumes no upper limit on hydrogen storage energy capacity. However, an upper limit of 3 weeks for the storage capacity (energy to gas turbine power ratio) was introduced as a constraint for the expansion of the hydrogen storage energy capacity.

We have for the current study calculated[88] the levelised cost of underground hydrogen storage based on Polish geological data (saline aquifers[89] and salt caverns[90]), representative of German conditions. Values of 3.3 €/kgH2 for saline aquifers and 2.5 €/kgH2 for salt caverns were obtained. The current study assumes the levelised cost of hydrogen *storage* at 2.5 €/kgH2 (63 €/MWh_{th} [HHV]), which is based on a lifetime of 40 years and a capacity factor of 0.8 corresponds to an overnight capital cost of hydrogen storage energy capacity at 920 €/MWh.

4.4.5 Nuclear

Unlike the typical "learn-by-doing" trends observed in solar PV and wind power, the realm of nuclear power plant construction exhibits significant variations, contingent upon the specific project in question[91,92]. To illustrate, the development of novel nuclear reactor designs in Western Europe has

85 NREL - National Renewable Energy Laboratory (2023), Annual Technology Baseline.
86 ENTSO-G, ENTSO-E (2023), Ten-Year Network Development Plan 2024.
87 National Hydrogen Council (2022), Hydrogen storage roadmap 2030 for Germany.
88 International Journal of Hydrogen Energy (2023), Capacity assessment and cost analysis of geologic storage of hydrogen: A case study in Intermountain-West Region USA.
89 Ministry of Environment - Poland (2014), Assessment of Formations and Structures Suitable for Safe CO_2 Geological Storage (in Poland) including the Monitoring plans.
90 International Journal of Hydrogen Energy (2018), Salt Domes in Poland – Potential Sites for Hydrogen Storage in Caverns.
91 Energy Policy (2016), Historical Construction Costs of Global Nuclear Power Reactors.
92 Energiforsk (2021), El från Nya Anläggningar.

been accompanied by notably high price tags[93], while emerging nuclear power nations such as Türkiye and the United Arab Emirates have realized their initial reactors at relatively lower costs[94,95]. TABLE 9 aims to put the investment costs of nuclear power plants, which dominate the total costs of nuclear power generation, further into perspective by listing four scenarios and comparing them to observed costs for nuclear power projects in the 21st century[96]. As a final note, it is important to recognise that the widespread expectation is that serial construction, i.e., building many reactors of the same kind, and manufacturing of advanced reactor designs, will refine practices, ultimately resulting in cost reductions[97]. Idaho National Laboratory recently published a technical report simulating these potential cost reductions in the US[98] with scenarios largely in congruence with those outlined for the current study below.

TABLE 9.

Nuclear costs in perspective based on analysis of nuclear projects in the time period 2000-2020[99] along with two example projects completed in the early 2020s.

SCENARIO	DESCRIPTION	OVERNIGHT CAPITAL COST (€/KW)
Low	Meets a realistic expectation for a very successful project outside Asia today. However, the value is 45% *higher* than the world average of projects between 2000 and 2020.	3300
Medium	Equivalent to what VVER and APR reactors have been built for in recent years in countries that previously lacked nuclear power (e.g., the United Arab Emirates, Turkey), and the average for new nuclear power outside leading nuclear power nations (China, India, Russia and South Korea).	4400
	Barakah units 1-4, APR1400	4600[100]
High	Corresponds to the approximate expected cost of a new generation EPR (Sizewell-C in the UK).	5500
Very high	Representing very expensive single overnight costs for EPR projects in France, UK and Finland.	7100
	Olkiluoto unit 3, EPR	6900[101]

The projection of the nuclear overnight capital cost employed in the present study is presented in FIGURE 15. It is relevant to recognise that the assumed overnight capital cost represents an average cost of several future reactor projects based on a distribution including both successfully and cheaper projects as well as the most extreme outliers on the expensive end. The conservative sensitivity has been constructed such that the average overnight capital cost throughout 2030-2050 is 7000 €/kW,

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93 Institute for Energy Economic and Financial Analysis (2023), European Pressurized Reactors: Nuclear Power's Latest Costly and Delayed Disappointments.
94 WNA (2023), Nuclear Power in the United Arab Emirates.
95 WNA (2023), Nuclear Power in Turkey.
96 Energiforsk (2021), El från Nya Anläggningar.
97 Idaho National Laboratory (2023), Literature Review of Advanced Reactor Cost Estimates.
98 Idaho National Laboratory (2024), Meta-Analysis of Advanced Nuclear Reactor Cost Estimations.
99 Energiforsk (2021), El från Nya Anläggningar.
100 WNA (2023), Nuclear Power in the United Arab Emirates.
101 Euronews (2023), Finland's New Nuclear Reactor: What Does It Mean for Climate Goals and Energy Security?

reflecting a scenario where future projects experience the similar challenges as the ongoing projects in Europe today with limited learning. On the opposite side, the optimistic sensitivity has been set to average 4000 €/kW 2030-2050 mimicking a path with initially more successful projects as well as high learning rate following the successful implementation of dedicated factory serially produced units. The reference sensitivity is placed in between the extremes. Additionally, the construction time for these nuclear units initiates at 5 years for the optimistic sensitivity, 7 years for the reference sensitivity, and 9 years for the conservative sensitivity. Over time, these construction periods decrease linearly, to 3.0, 4.0, and 5.0 years for the optimistic, reference, and conservative sensitivitiy, respectively. Operational costs have been set to 65 €/kW-yr[102] for fixed OM and a total cost for variable OM of 9.4 €/MWh accounting for both cost of fuel (4.9 €/MWh) as well as spent fuel removal, disposal and long-term storage of spent fuel (4.5 €/MWh)[103].

As a final note, the current study only considers revenues within the electricity market (energy-only market and capacity market for a limited set of scenarios). This means that, for instance, nuclear plant potential revenues from selling heat and/or other products are not accounted for.

[102] International Energy Agency & Nuclear Energy Agency (2020), Projected Costs of Generating Electricity.
[103] International Energy Agency & Nuclear Energy Agency (2020), Projected Costs of Generating Electricity.

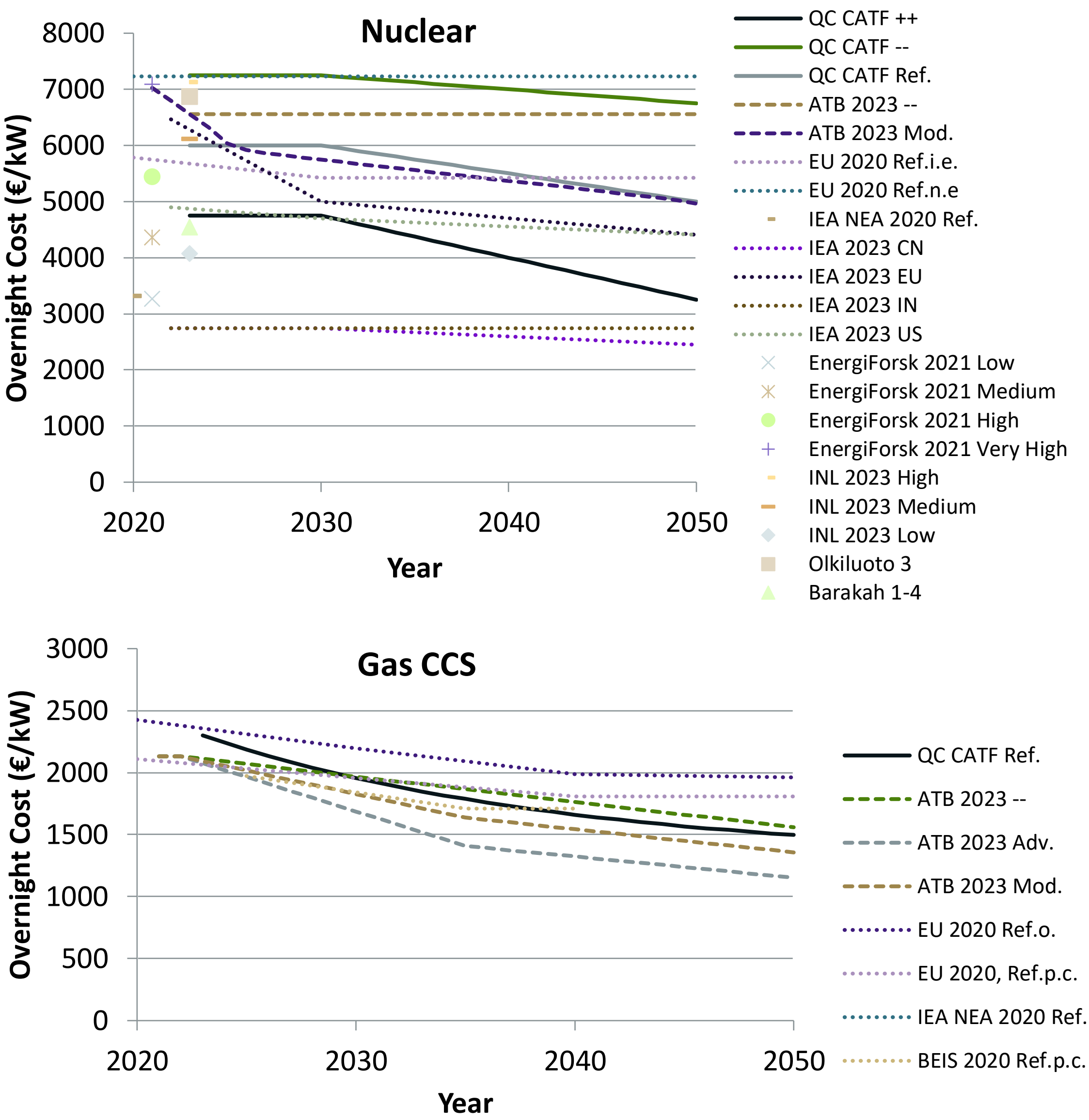

FIGURE 15.

Comparison of Nuclear (top panel) and Gas CCS (bottom panel) overnight capital costs in the present study with those from other references, as specified in the legend. The data points are differentiated by markers and line styles: single-point series feature square markers, series with yearly frequent data are represented by dashed lines, and series with multi-year intervals between data points are denoted by dotted lines with circle markers.

4.4.6 Gas CCS

Recent studies have highlighted the techno-economic feasibility of achieving approximately 100% capture efficiency through post-combustion capture, with manageable increases in investment and operational costs[104,105]. There are few examples where carbon capture technology has been demonstrated today[106,107] but it still needs to be proved commercially and on a larger scale. We have optimistically assumed a steady capture efficiency at 95%. This assumption is balanced by not accounting for learning effects on the operational and maintenance costs.

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[104] IEAGHG (2019), Towards Zero Emissions CCS in Power Plants Using Higher Capture Rates or Biomass.
[105] Energy Reports (2024), On the cost of zero carbon electricity: A techno-economic analysis of combined cycle gas turbines with post-combustion CO_2 capture.
[106] International CCS Knowledge Centre (2018), The Shand CCS Feasibility Study Public Report.
[107] Reuters (2020), Problems plagued U.S. CO_2 capture project before shutdown.

Overnight capital costs for combined-cycle natural gas power plant equipped with carbon capture (Gas CCS) is presented in bottom panel of FIGURE 15. Merely one reference sensitivity has been employed representing the available data and commercially available solvent-based post combustion CO_2 capture (PCCC) designed for 95% capture efficiency[108] but weighing in that the technology has not reached large scale implementation at present day. Based on ATB_2023 and EU_2020, operational costs have been set to 47 €/kW for fixed OM and 3.6 €/MWh for variable OM[109].

The cost of transport and storage for capture CO_2 is estimated as a variable OM cost of 20 €/tCO_2. However, the levelised cost of transport and storage can vary significantly based on factors like infrastructure, transport distance, monitoring, reservoir geology, and transport costs. Studies have suggested a range of estimates, from 12-45[110] to 4–45[111] €/tCO_2. To account for these variations, the sensitivity *Fossil* -- employs a variable OM cost for CCS transport and storage of 45 €/tCO_2.

A final note, process disturbances associated with highly flexible power plant operations, including start-up and shut-down cycles in CCS systems, lead to deviations from optimal conditions[112]. This deviation can result in an increase in residual CO_2 emissions, unless additional investments in equipment such as solvent storage or additional heating are made[113]. Our current modelling does not directly account for these increased emissions which ultimately risks results leading to an overestimated value for CCS technologies in the simulation as well as underestimated costs for the simulated power systems which increasingly rely on the CCS technologies for achieving deep decarbonisation. Aiming to accommodate parts of this problem, higher (+20%) cycling costs as well as minimum power and lower ramping constraints (-20%) have been implemented for Gas CCS plants compared to their unabated counterpart.

4.4.7 Levelised Cost of Electricity (LCOE)

Like for solar, wind and battery storage, a similar methodology has been applied to other technologies, as well as for other costs inputs, such as fixed and variable operational and maintenance costs.

The Levelised Cost of Electricity (LCOE), denoting the average cost of unit electricity generated by a specific technology, exhibits certain limitations in facilitating meaningful comparisons between technologies[114]. A crucial criterion for capacity expansion is the profitability of all technologies, necessitating their capture price—defined as the average electricity price experienced by the technology—to surpass the LCOE. Transparency of the LCOE ensures a full understanding of input assumptions related to investment and operational costs for various technologies, where the Weighted Average Cost of Capital (WACC) plays a pivotal role.

TABLE 10 and TABLE presents *input* LCOE values for primary technologies, serving as a basis for comparison with values employed in other studies to achieve a more comprehensive understanding. The LCOE calculations are purely based on input assumptions and don't account for economic and grid-related technical curtailment. The capacity factors of high marginal-cost thermal power plants represent rough estimates of predicted operational patterns. For the calculations, the cost of hydrogen fuel has been assumed an average value of 5 €/kg and a range investigating [3, 7] €/kg. Finally, the LCOE calculation methodology employed in the current study is presented in APPENDIX D.

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[108] Similar to ATB_2023 assumptions in Figure 14.
[109] International Energy Agency & Nuclear Energy Agency (2020), Projected Costs of Generating Electricity.
[110] Uniper Technologies (2018), BEIS: CCUS TECHNICAL ADVISORY.
[111] International Journal of Greenhouse Gas Control (2021), The cost of CO_2 transport and storage in global integrated assessment modeling.
[112] iScience (2023), The Prospects of Flexible Natural Gas-fired CCGT within a Green Taxonomy.
[113] AECOM for BEIS (2020), Start-up and Shut-Down Times of Power CCUS Facilities.
[114] World Resources Institute (2019), INSIDER: Not All Electricity Is Equal—Uses and Misuses of Levelized Cost of Electricity (LCOE).

TABLE 10.

Compiled input levelised cost of electricity (LCOE) in 2023€/MWh for the main technologies considered in the current study, optimistic, reference and conservative scenarios and years 2030 and 2050. For comparison values in 2024 are also given in the first column. For background on the calculations see TABLE 11 and APPENDIX D.

TECHNOLOGY	REFERENCE	OPTIMISTIC		REFERENCE		CONSERVATIVE	
	2024	2030	2050	2030	2050	2030	2050
Nuclear	76	61	45	75	62	92	79
Gas OC	340	270	240	290	260	310	270
Gas CC	180	130	110	140	120	160	130
Gas CCS	170	100	81	120	95	140	110
Solar	68	41	27	53	38	59	47
Wind Onshore	70	56	45	62	56	69	68
Wind Offshore Fixed	110	86	51	89	56	97	74
Wind Offshore Floating	120	100	72	110	84	130	110

TABLE 11.

Input assumptions for new build of main technologies for the model year 2040 for the reference sensitivity. If applicable, assumptions in the optimistic and conservative sensitivities are given in the brackets.

	SOLAR PV	WIND ONSHORE/ *LAND ++*[115]	WIND OFFSHORE FIXED	NUCLEAR	BATTERY	HYDROGEN CC	GAS CCS	GAS OC
WACC (%)	6.0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
CONSTRUCTION DURATION (YR)	0.5	1.0	1.0	5.5 [4.0, 7.0]	1.0	2.0	2.0	2.0
ECONOMIC LIFETIME (YR)	30	25	25	60	15	30	30	30
OVERNIGHT COST (€/KW)	530 [360,630]	1500 [1300, 1700]	2300 [2100, 2800]	5500 [4000, 7000]	220 [110, 260]	740	1700	640
OVERNIGHT COST ENERGY (€/KWH)	-	-	-	-	160 [140, 260]	-	-	-
FIXED OM (€/KW/YR)	10	29 [22, 32]	61 [55, 67]	65	25	25	47	10
VARIABLE OM (€/MWH)[116]	-	-	-	4.5	-	2.5	12 [12, 20]	5
FUEL (€/MWH)[117]	-	-	-	4.9	-	200 [120, 280]	59 [44, 75]	130 [110, 150]
CARBON CAPTURE EFFICIENCY (%)	-	-	-	-	-	-	95	0
CAPACITY FACTOR (%)[118]	12	29 / 25	41	90	-	10	60	10
LCOE (€/MWH)	46 [34, 53]	59 [51,68] / 68 [59,79]	70 [64, 83]	68 [53, 85]	-	300 [220, 380]	104 [89, 120]	270 [250, 290]

115 If applicable, deviating assumptions in the Land ++ sensitivity given in denominator.
116 Includes variable costs for CO_2 transport and storage if applicable to technology.
117 Represents fuel costs per MWh electricity generated. Values include costs for direct and indirect emissions based on the a CO_2 price projection with values of 120, 160 and 180 €/tCO_2 in 2030, 2040 and 2050, respectively.
118 Values prior to model results as the average of 33 weather years. Does not account for economic and grid-related technical curtailment. For high-marginal cost thermal power plants this represents an estimate.

4.5 Commodity prices

Commodity prices assumed for the current study are presented in FIGURE 16.

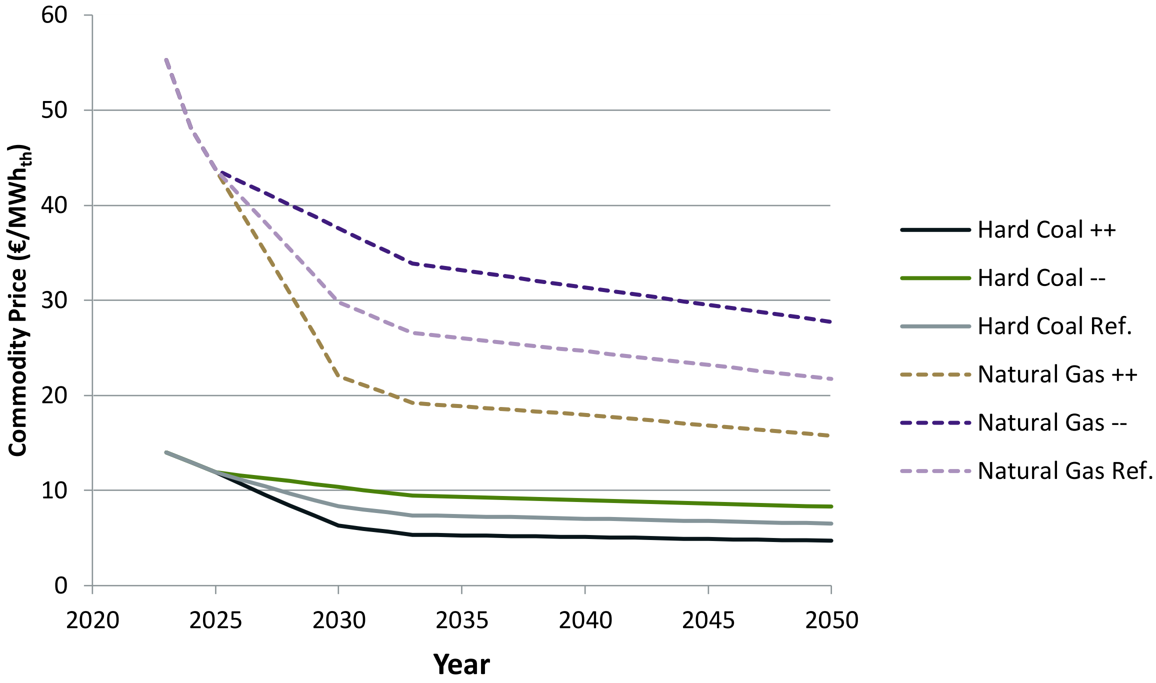

FIGURE 16.

Natural gas and coal commodity prices in €/MWh$_{th}$ for the three sensitivities considered in the current study.

The natural gas price scenarios considered in our study closely follow the fundamental trends of the European Resource Adequacy Assessment (ERAA) 2023 proposal[119]. In the optimistic sensitivity, it is assumed that natural gas prices will approach levels reminiscent of those in the European Union before the energy crisis, indicating a reduction of approximately 10% by the mid-2030s, with a target price of 20 €2021/MWh by 2035. Conversely, the conservative sensitivity anticipates natural gas prices to approach levels akin to those observed in Asia for liquefied natural gas (LNG) before the energy crisis, reflecting an increase of approximately 10% by the mid-2030s, with a projected price of 34 €2021/MWh by 2035. The reference sensitivity, as an average between the optimistic and conservative sensitivity, anticipates natural gas prices to reach 27 €2021/MWh by 2035. Notably, the pricing trends for hard coal have been directly linked to those of natural gas and scaled accordingly.

Other commodity prices used in the current study only assume a base scenario. Lignite coal has been set a value of 1.96 €/GJ[120], biogas 19.7 €/GJ[121], biomass 5.13 €/GJ[122] and uranium 0.51 €/GJ[123].

4.6 Existing thermal power plants

Modelling and input assumptions for existing thermal power plants is covered in this section except for commodity prices handled separately in SECTION 0.

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119 ERAA (2023), Proposal of Commodity Prices for Call for Evidence.
120 ERAA (2023), Proposal of Commodity Prices for Call for Evidence.
121 ERAA (2023), Proposal of Commodity Prices for Call for Evidence.
122 National Renewable Energy Laboratory (2022), Annual Technology Baseline.
123 ERAA (2023), Proposal of Commodity Prices for Call for Evidence.

4.6.1 Coal

Lignite and hard coal fuelled power plants are modelled separately with existing installed capacity of 18 GW and 13 GW, respectively. The retirement of the coal plants is purely determined by the optimisation.

4.6.2 Gas

The model assumes an existing capacity of 5.6 GW for open-cycle gas power plants and 29 GW for combined-cycle gas power plants. With CO_2 prices exceeding 100 €/tCO_2, gas combined-cycle power plants outcompete coal due to their relatively lower CO_2 emission intensity. As CO_2 targets become increasingly stringent, unabated gas power plants also retire. Regardless of model optimisation, existing gas power plants are assumed to retire linearly between 2035 and 2045, or alternatively be retrofitted to Gas CCS if the model deems it cost-effective. New gas power capacity built by the model may only be retired or retrofitted as a result of the model optimisation.

4.6.3 Bio and CHP

A delayed German biomass strategy is under preparation at the time of writing[124]. However, it states it to be likely there will be no increase in bioenergy, instead the share of bioenergy stagnates or declines in the long term until 2045 which is in line with other studies[125]. The aim of the biomass strategy is to optimise the use of biomass in a way that supports climate protection[126]. The focus is on prioritizing the material use of biomass, as this allows for long-term carbon sequestration, for example, by using it as renewable raw materials for durable industrial goods. This approach is preferred over the energy use of biomass, which only temporarily stores carbon before releasing it back into the atmosphere. However, it's acknowledged that the energetic utilisation of biomass, particularly using waste and residues, still plays a role in the energy transition. The preliminary information on the strategy also emphasises the importance of multiple uses and recycling of biomass to promote the permanent binding of carbon and support Germany's long-term energy and raw material supply security, while acknowledging that biomass cannot fully replace fossil fuels and primary raw materials.

The present study assumes the current fleet to be reinforced such that the annual power generation is increased from present-day's 45 TWh[127] to around 66 TWh. This may be compared with estimates for waste biogas potential of 40 TWh p.a. by UBA[128]. Associated necessary investment and reinvestment costs have been excluded in the model.

The majority of the existing units are combined heat and power plants. Their operation is assumed to follow a set profile based on an average of historical years. Finally, the combustion of biomass and biogas is assumed to have a CO_2 emissivity of zero.

4.6.4 Nuclear

The current study explores a nuclear restart scenario. This scenario corresponds to the restart of the six recently closed reactors, still holding operating licenses, before 2030, summing to 8 GW of installed capacity returned to the grid. One recently published study say three reactors could be restarted by 2028 and an additional 6 reactors by 2032[129], while another source argues 5 reactors may be restarted[130].

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[124] Federal Ministry Germany (2022), Key points of a National Biomass Strategy (NABIS).
[125] Dena (2022), Vergleich der "Big 5" -Klimaneutralitätsszenarien.
[126] BMEL - Bundesministerium für Ernährung und Landwirtschaft (2022), Die Nationale Biomassestrategie.
[127] IEA Bioenergy (2021), Country report Germany 2021.
[128] Umweltbundesamt (2010), Energieziel 2050: 100% Strom aus erneuerbaren Quellen.
[129] Radiant Energy Group (2024), Restarting Germany's Reactors: Feasibility and Schedule
[130] zdfheute (2023), Zurück zur Atomkraft: Ginge das überhaupt?

To cover for the costs of restarting the reactors an additional cost of 8 €/MWh has been added to the variable operational cost[131]. Furthermore, the average age of these reactors is around 40 years and for consistency with the assumption that new reactors have an economic lifetime of 60 years, the restarted reactors are assumed to fully retire 2046-2050.

4.7 Modelling regions and transmission capacities

A full market optimised expansion model for Germany is used in this study. This method ensures that crucial factors such as transmission capacities, generation limits, and demand fluctuations are all accounted for, leading to a more accurate representation of the system's behaviour compared to dispatch only analysis. The modelling regions considered in the power modelling are shown in **ERROR! REFERENCE SOURCE NOT FOUND.**. For computational purposes, zones are grouped together in the Nordics and Baltics. This grouping does not affect the overall behaviour of the power market in these regions, which is the most important for the power modelling in Germany.

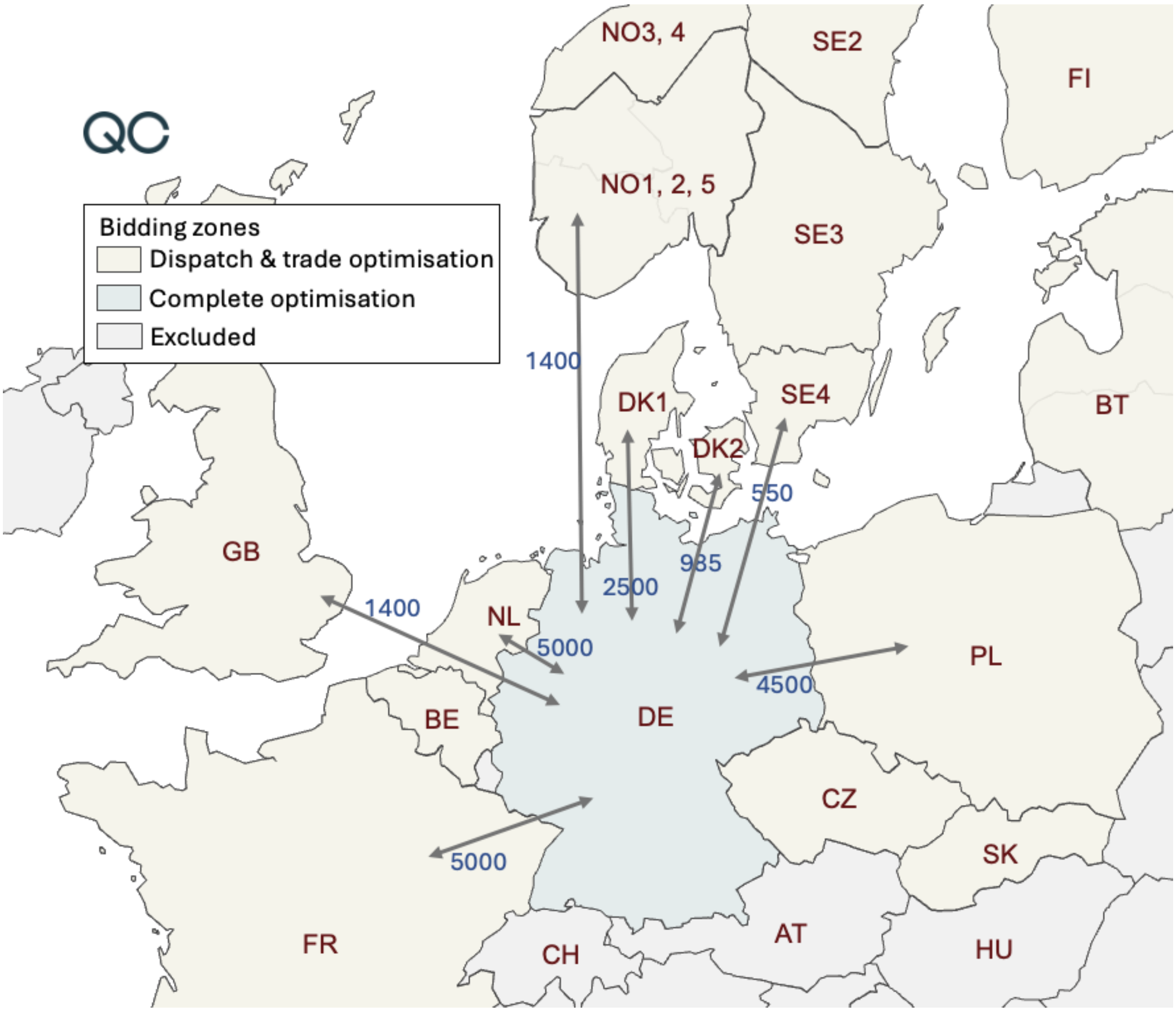

FIGURE 17.

Geographical boundaries with regions included in the modelling and how they are treated in the optimisation. Only transmission lines directly connected with Germany are shown.

Modelled transmission capacities for 2050 between Germany and interconnected regions are shown in **ERROR! REFERENCE SOURCE NOT FOUND.**. Since GenX and cGrid do not directly optimise/simulate

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131 Radiant Energy Group (2023), Restart of Germany's Reactors: Can it be Done?

granular grid infrastructure, we rely on the National Grid Development Plan to estimate this required transmission capacity expansion. The underlying methodology is further described in APPENDIX B.6.

4.8 Capacity market

There are currently three types of energy reserve available in the German electricity system: Netzreserve, Kapazitätsreserve und Sicherheitsbereitschaft:

Network Reserve (Netzreserve): This reserve ensures the stability of the electricity grid, especially during periods of high demand or stress on transmission lines, such as during cold and stormy winters. It involves reducing power generation in areas with excess supply and increasing it in regions with high demand to prevent grid overloads. The network reserve, also known as "winter reserve" or "cold reserve", comprises power plants that are either not operational or scheduled for decommissioning but can be quickly activated if needed. Its utilisation is regulated by the Energy Industry Act (EnWG) and the Network Reserve Ordinance.

Capacity Reserve (Kapazitätsreserve): This reserve is for addressing unforeseen extreme situations where the electricity supply may not be sufficient to meet demand, even with free market pricing. It operates independently of the electricity market and provides additional security for consumers. The capacity reserve includes existing power generation facilities, storage units, or loads held outside the electricity market. Power plants in the capacity reserve cannot actively participate in electricity markets but can increase their output upon request from transmission system operators to address imbalances between electricity consumption and generation.

Security Standby (Sicherheitsbereitschaft): This reserve consists of power plants that have been shut down as part of the planned phase-out of coal-fired power plants. These plants can be temporarily reactivated for up to four years in extreme situations if other measures, including network and capacity reserves, prove insufficient. Activation of the security standby is a last resort and has never been utilised thus far. The reactivated power plants must be ready to operate within ten to eleven days upon request from transmission system operators. The security standby aims to provide an additional layer of security for the electricity grid while minimizing CO_2 emissions, as these temporarily reactivated plants no longer emit harmful greenhouse gases.

However, we envision significant changes for energy flexibility reserves in upcoming years, as outlined by recent policy and planning documents. According to the Grid Development Plan Electricity 2035[132], the necessity for redispatch is diminishing, thanks in part to advancements in grid management and a governmental push towards integrating these reserves into local capacity markets or phasing them out altogether. We therefore envision a phasing out of Sicherheitsbereitschaft (security standby) and Netzreserve (grid reserve). This is in line with prospects of the government to either abolish the grid reserve at some point or let it be part of region-specific capacity markets[133].

The relevance of traditional capacity reserves is expected to diminish as energy storage capabilities, including hydrogen storage, sector coupling, and electrical storage, become more prevalent. These technologies offer promising prospects for enhancing grid flexibility and storing excess renewable energy, thereby reducing the reliance on conventional capacity reserves.

Furthermore, in the recently published Power Plant Strategy, a market-like capacity mechanism was announced, which will likely integrate the capacity reserve. This move indicates a shift from a regulated to a more market-driven approach to ensure grid stability and supply security. Proponents of a comprehensive capacity market emphasise that market mechanisms will be most efficient at the provision of capacity reserves[134].

[132] Netzentwicklungsplan (2022), Netzentwicklungsplan Strom 2035.
[133] BMWi (2014), Ein Strommarkt für die Energiewende.
[134] Agora Energiewende (2013), Kapazitätsmarkt oder strategische Reserve: Was ist der nächste Schritt?

Ancillary services are not the primary focus of the current study, there's a growing consensus that these services will increasingly be provided by decentralised, grid-forming elements. This trend aligns with the broader move towards decentralisation in energy systems, highlighting the potential for local energy resources to contribute to grid stability and flexibility.

A study by Enervis[135] indicates that the tender volume for electricity generation capacity would amount to 55 GW of secured capacity. However, by retaining power plants within various reserve mechanisms, using replacement power plants, and potentially converting coal-fired power plants to biomass or gas, the tender volume could be decreased to 32 GW. It is crucial to note that in this scenario, coal and oil power plants would still be operational. In contrast, a tender volume of 55 GW would enable a full transition away from coal and oil power generation.

Other studies assume activating capacity reserves at a high market price threshold, such as 20,000 €/MWh as assumed in some scenarios by the German Environment Agency[136] (Umweltbundesamt), offers a strategic approach to ensuring grid reliability and preventing supply shortages during peak demand periods or when energy prices spike due to scarcity.

For our analysis, capacity reserve requirements are modelled with a capacity reserve margin of 10%. Except for coal power plants which are not allowed in the capacity reserve beyond the year 2035, the model treats all technologies equal, including flexible shifting demand. This means that all technologies may contribute to the capacity reserve in accordance with their availability during times of scarce power supply.

4.9 Build rates

In our analysis, we consider a phased approach to capacity expansion, acknowledging that various factors influence the rate at which different energy resources can be deployed. These constraints are particularly relevant within the context of short-term and long-term planning, and we aim to strike a balance between technological advancements and practical limitations. A summary of the build rates is presented in TABLE 12.

Historic and near-term future development of wind and solar PV in Germany is described in SECTION 4.3.5. Given the substantial deployment of solar PV observed in Germany, as well as across Europe and globally[137], the model does not impose any build rate limits on new solar capacity. This approach is deemed realistic considering the evolving demand-supply balance.

The model assumes a maximum build rate of 43.7 GW for onshore wind power between 2024 and 2030[138]. This equates to an average of 6.2 GW of new capacity per year, comparable to the maximum yearly expansion observed thus far in Germany but very high in comparison with the most recent five years (see FIGURE 11). It is important to note that the build rates presented here do not include repowering of sites with retired wind power capacity. Consequently, it is merely feasible to reach a capacity of around 89 GW for onshore wind power in 2030 in the current study. This can be compared to Germany's goal of reaching 115 GW by 2030[139].

In the subsequent period, 2031-2035, an additional 50 GW is permitted, averaging 10 GW per year[140], reflecting a European wind power supply chain significantly improved with respect to today[141]. At this juncture, the maximum expansion limit due to land availability in the reference sensitivity of 143 GW is nearly reached. Hence, build rates in the remaining periods only apply to the *Land* ++ sensitivity. To be able to reach the full expansion potential of 350 GW, build rates beyond 2035 are quite optimistic.

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135 Enervis (2022), Marktdesign für einen sicheren, wirtschaftlichen und dekarbonisierten Strommarkt.
136 Umweltbundesamt (2020), Strommarkt und Klimaschutz: Transformation der Stromerzeugung bis 2050
137 IEA (2023), Renewables 2023.
138 Reuters (2024), Germany Sees Jump in Wind Installations as New Laws Hike Activity.
139 Renewables Now (2024), Germany installs 17 GW of renewables in 2023.
140 Reuters (2024), Germany Sees Jump in Wind Installations as New Laws Hike Activity.
141 Wind Europe (2023), The EU Built Only 16 GW New Wind in 2022.

The build rates for offshore wind encompass both fixed and floating technologies. In the initial period (2024-2030), the assumed build rate aligns with the current German goal for 2030, as described in SECTION 4.3.5. Subsequent periods allow for steadily increasing deployment, with build rate expansion limits permitting a pace that surpasses 70 GW in 2040, corresponding to the expansion ceiling for fixed foundation offshore wind. Beyond this threshold, floating foundations may continue the expansion of offshore wind power.

In scenarios involving nuclear power, the model permits the reactivation of existing retired nuclear capacity totalling 8 GW, as further elaborated in SECTION 4.4.5. An expansion of 10 GW and 20 GW of new nuclear power capacity is allowed in the time periods 2041-2045 and 2046-2050, respectively. However, for this expansion to be feasible, it presupposes thorough preparation and groundwork for new construction in Germany beginning in the very near-term future, i.e., before 2030. Furthermore, it assumes the utilisation of multiple parallel projects and varying reactor designs/technologies to prevent overwhelming competence and supply chain capabilities within a revived, efficient, and strong European nuclear industry.

As the impact of escalating CO_2 taxes diminishes the cost-effectiveness of coal power generation, the model transitions towards natural gas power plants. We optimistically allow a build rate of 15 GW for new natural gas capacity, equal for open-cycle and combined-cycle technology types to ensure flexibility in response to market demands. This allocation is applied to the periods 2024-2030, 2031-2035, and 2036-2040. Historical data from UK[142], where an expansion of around 10 GW was observed in the 5-year period from 2008 to 2013, serve as a point of comparison.

The build rates employed for Gas CCS reflect a perfect-foresight perspective. The myopic or short-sighted optimisations fail to appreciate or acknowledge the increasingly stringent CO_2 targets in subsequent stages. Given the cost-effectiveness of Gas CCS technology, this may lead to overbuilding of capacity, resulting in potential significant financial losses as the decarbonised power system is reached in 2045 and beyond. To accommodate a more long-term foresight and achieve more realistic pathways, approximately half of the observed capacity in 2045 from perfect-foresight runs has been allocated to 2040, steadily increasing from 2035 onwards. Build rate limits have been applied such that half of the capacity may be retrofitted Gas CC, while the other half is designated for greenfield Gas CCS.

Finally, to explore the impacts of build rates on the results, a *No Limits* sensitivity analysis was conducted. In this scenario, the build rate limits for thermal power plant technologies, as outlined in TABLE 12, were removed.

[142] Ember (2023), Gas.

TABLE 12.

Limits on maximum capacity addition, denoted build rates, applied in the modelling presented by technology and sensitivity (where reference is the default). The unit is GW per seven years for the 2024-2030 column and then GW per five years for the last columns. Existing capacity by beginning of 2024 in GW is also given.

Technology	Sensitivity	Existing (2024)	2024-2030	2031 - 2035	2036-2040	2041-2045	2046-2050
SOLAR	*Reference*	82	-	-	-	-	-
WIND ONSHORE	*Reference*	61	43.7	50	80[143]	110[144]	-
WIND OFFSHORE[145]	*Reference*	8.5	21.5[146]	25	40	60	-
NUCLEAR	*Reference*	0.0	0.0	0.0	0.0	10.0	20.0
	No Limits	0.0	0.0	-	-	-	-
NUCLEAR EXISTING	*Reference*	0.0	8.0	0.0	0.0	0.0	0.0
GAS OC	*Reference*	5.6	15	15	15	-	-
	No Limits	-	-	-	-	-	-
GAS CC	*Reference*	29	15	15	15	-	-
	No Limits	-	-	-	-	-	-
GAS CCS[147]	*Reference*	0	0	6.3	13	-	-
	No Limits	-	-	-	-	-	-

4.10 Long-duration energy storage

To explore the role of long-duration energy storage (LDES) in the decarbonisation of Germany's power system, this study integrates LDES technology archetypes based on operational and economic parameters adapted from the California Energy Commission report on LDES[148]. The modelled LDES archetypes represent technologies with storage durations ranging from 12 to 100 hours, addressing both inter-day and multi-day storage requirements. These technologies are designed to complement battery and hydrogen storage systems, which are included across all scenarios, by providing extended-duration solutions for grid flexibility and reliability.

Four archetypes were defined, incorporating assumed cost trajectories, round-trip efficiencies, parasitic losses, and reference technologies as presented in TABLE 13. The cost projections are based on the mid-scenario of the California Energy Commission report, with average "all-in" levelised costs

[143] Only applies to scenarios where *Land* ++ sensitivity is applied.
[144] Only applies to scenarios where *Land* ++ sensitivity is applied.
[145] This represents both fixed and floating offshore wind technologies.
[146] Aligned with goal as described in Section 4.3.5.
[147] Representing both greenfield Gas CCS and retrofitted Gas CC.
[148] California Energy Commission (2024), Assessing the Value of Long-Duration Energy Storage in California.

provided for the 2030–2050 period. Lifetime was assumed 15 years for all technologies.

TABLE 13.

Key characteristics of the modelled LDES archetypes, including reference technologies, efficiencies, parasitic losses, and projected costs. These archetypes span durations from 12 to 100 hours, enabling inter-day and multi-day storage solutions.

LDES Archetype	Reference Technology	Round-trip efficiency (%)	Self-Discharge (% per day)	Average cost (€/kW)
Storage 12h	Advanced Flow, Metal-Air	81	Negligible	172
Storage 24h	Adiabatic CAES	60	1.0	140
Storage 48h	Thermo-Photovoltaic	45	1.0	155
Storage 100h	Iron-Air	46	Negligible	183

These archetypes provide a representative framework for assessing the technical and operational trade-offs across different durations of LDES deployment. The assumed cost trajectories indicate relatively stable development over time, without drastic reductions or increases across the modelling horizon.

The assumptions for these LDES technologies were incorporated into the four primary technology-pathway scenarios of this study: *Base*, *No Nucl.*, *No CCS*, and *No Nucl. No CCS*. For scenarios incorporating LDES, an appended “+LDES” notation is used (e.g., *Base+LDES*). Furthermore, the LDES technologies are assumed to be available from 2030 onwards with no build rate constraints. Their impact on the German power system is evaluated in detail in SECTION 5.10.

5 Results

The results section dives into detail on results accompanied by first level interpretations. SECTION 6 makes a summary of the results including overarching conclusions.

5.1 Path to decarbonisation

This section examines the trajectory of decarbonisation in the German power system, extending from 2030 to 2050, as depicted in FIGURE 19 for the *All Tech.* and *No Nucl. No CCS* scenarios. For reference, resulting values are presented in TABLE 14.

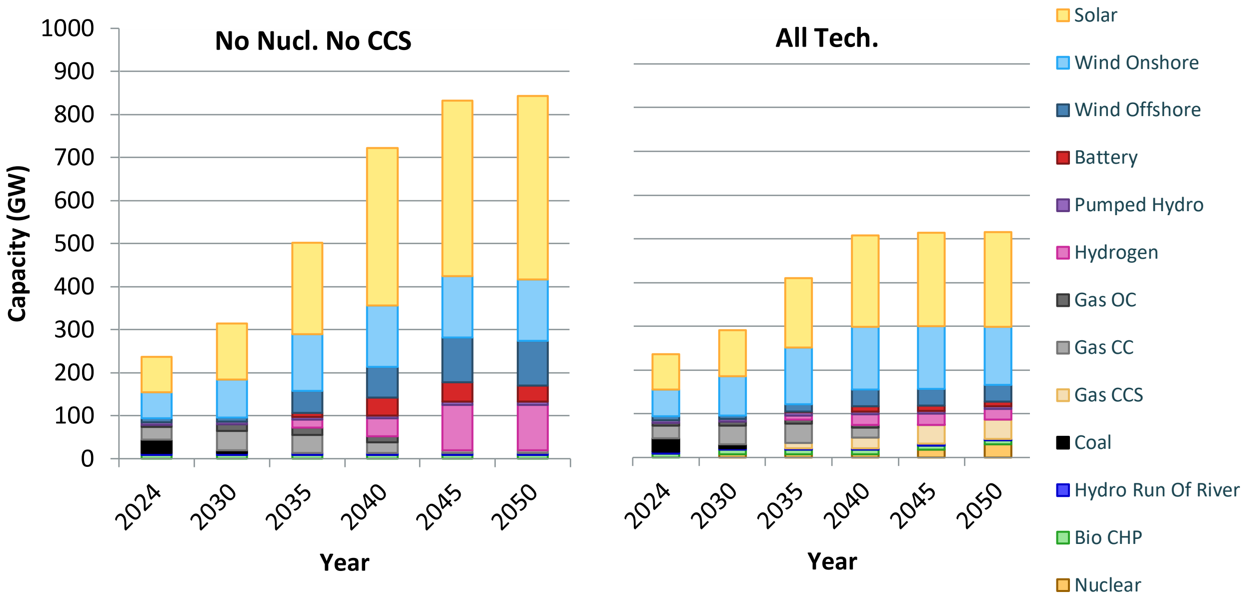


FIGURE 18.

Installed capacity for the German power system across the model horizon for the *No Nucl. No CCS* and the *All Tech.* scenarios.

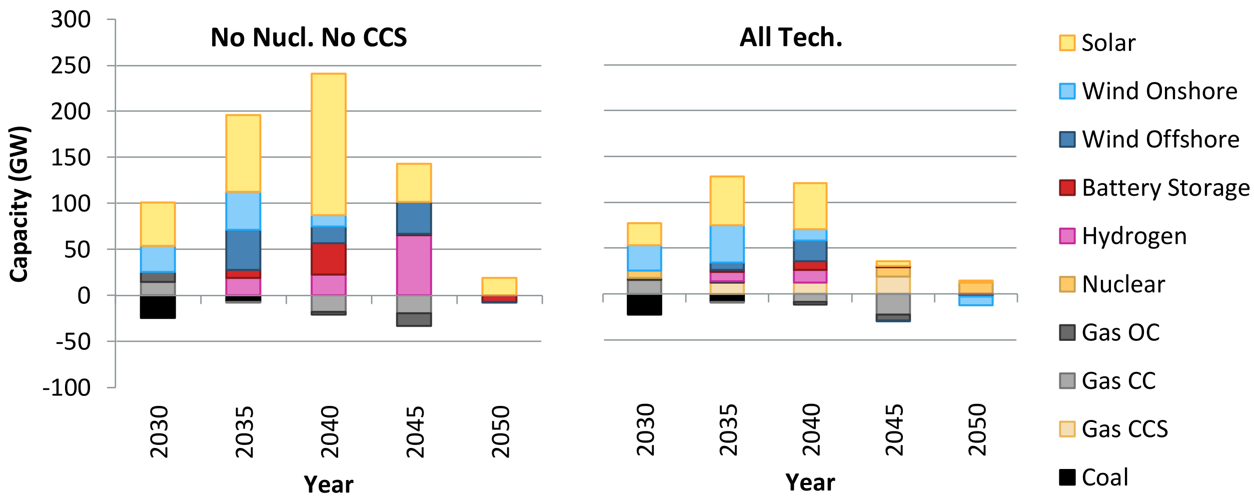


FIGURE 19.

Additions (positive) and retirement (negative) of installed capacity for the German power system across the model horizon for the *No Nucl. No CCS* and the *All Tech.* scenarios.

TABLE 14.

Installed capacity in GW for the German power system across the model horizon , for the *All Tech.* and the *No Nucl., No CCS* scenarios.

Capacity (GW)		Nuclear		Other		Coal		Gas						Storage			Wind Offshore			Wind Onshore		Solar	
		Existing	Nuclear	Bio CHP	Hydro R oR	Hard	Lignite	CC CCS	CC CCS Retrofit	CC Existing	CC	OC Existing	OC	Hydrogen	Battery	Pumped Hydro	Floating	Fixed Existing	Fixed	Existing	Wind Onshore	Existing	Solar
All Tech.	2024			9	4	13	18			29		6				6		8		61		82	
	2030	8		9	4	9				29	15	6	2			6		8		46	44	82	24
	2035	8		9	4			6	6	26	18	6	4	10	2	6		8	8	37	94	76	83
	2040	8		9	4			13	13	11	12	3	4	24	11	6		5	34	23	120	45	163
	2045	8	10	9	4			20	24				0.2	25	13	6		1	38	10	133	37	177
	2050		30	9	4			20	24					25	10	6			38		133		214
No Nucl. No CCS	2024			9	4	13	18			29		6				6		8		61		82	
	2030			9	4	7				29	15	6	11			6		8		46	44	82	47
	2035			9	4					25	17	6	11	19	9	6		8	44	37	94	76	136
	2040			9	4					8	17	3	11	41	43	6		5	65	23	120	45	321
	2045			9	4						6			107	45	6	34	1	69	10	133	37	371
	2050			9	4						6			107	38	6	34		69		143		427

The restart of recently shutdown reactors proves to be a cost-effective low-carbon addition to the German power system across all scenarios where it is permitted. Another observation that is common across all scenarios is a swift phase-out of coal which is driven by steadily more stringent CO_2 targets with the increasing model-determined CO_2 prices. Primarily combined-cycle gas, Gas CC, replaces coal power capacity in the early 2030s, succeeded by both greenfield Gas CCS and CCS retrofitted Gas CC in the later 2030s and early 2040s. Notably, Gas CCS expansion reaches its set build rate limits in 2035 and 2040. Beyond 2040, Gas CCS becomes an important ingredient of the German power system. Its expansion reaching around 44 GW, split roughly half greenfield, half retrofitted, is primarily limited by the set CO_2 targets which restrict the residual emissions (recall the assumed 95% CO_2 capture efficiency of the Gas CCS power plants). This underscores the significance of dispatchable power capacity and highlights the competitiveness of Gas CCS.

Within the ambitious decarbonisation pathway, the German power system's need for dispatchability is further evident as around 10 GW of hydrogen CC power plants come online in 2035. This expansion coincidentally aligns with the recently announced German Power Plant Strategy[149] despite deviating from the current energy policy with the inclusion of nuclear power and Gas CCS. Furthermore, without the inclusion of trade the 10 GW hydrogen power plants consume 1 Mt of hydrogen annually. This means that they would effectively utilise the entire locally produced green hydrogen supply estimated for 2030[150], thus leaving no room for industrial hydrogen demand.

The expansion in 2035 and 2040 of hydrogen power plants is primarily triggered due to build rate limits being reached for more cost-effective Gas CCS which is a topic covered in more detail in SECTION 5.3. Similarly, Gas CCS is limited in 2045 and 2050 due to set CO_2 targets therefore leading the way to hydrogen's potential further expansion. In the absence of nuclear power and CCS in the *No Nucl. No CCS* scenario, 20 GW of hydrogen CC power plants are already constructed in 2035 surpassing the current set goals with a factor 2. Once decarbonisation is reached in 2045, the *All Tech.* and the *No Nucl. No CCS* scenario witness installed capacities of 25 GW and 100 GW of Hydrogen CC, respectively.

Onshore wind reaches its expansion limit across the entire model horizon, proving to be cost-effective. This implies a significant build rate until 2035. Following this attainment, at least two follow-on effects occur: firstly, a considerable amount of solar capacity, settling to around 190 GW in 2050, is deployed to meet increasing electricity demand and fulfil CO_2 targets. Secondly, offshore wind enters the market in 2035, with final installed capacity reaching around 38 GW by 2045 in the *All Tech.* scenario.

Furthermore, in the *No Nucl. No CCS* scenario, a total installed capacity of 104 GW offshore wind is observed in 2050, with 34 GW of floating foundation due to the fixed foundation technology's maximum expansion of 70 GW already reached. Finally, with limits on nuclear and CCS, solar assumes a considerably larger role with an installed capacity around 430 GW in 2050, thus effectively competing with offshore wind. Battery storage installations follow suit, with a capacity of around 40 GW, working symbiotically with solar's diurnal production. It is worth noting that both onshore and offshore wind simultaneously see a significant rate of expansion likely pressuring the supply chains to their limits.

5.2 Sensitivity comparison

Power generation by technology for 2050 for a full suite of sensitivity variations for the *All Tech.* and *No Nucl. No CCS* technology policy alternatives are presented in FIGURE 20. Corresponding total system costs are shown in FIGURE 21.

[149] MWK - Bundesministerium für Wirtschaft und Klimaschutz (2024), Einigung zur Kraftwerksstrategie.
[150] Hydrogen Insight (2023), Germany doubles its green hydrogen production target for 2030 in new update of national strategy.

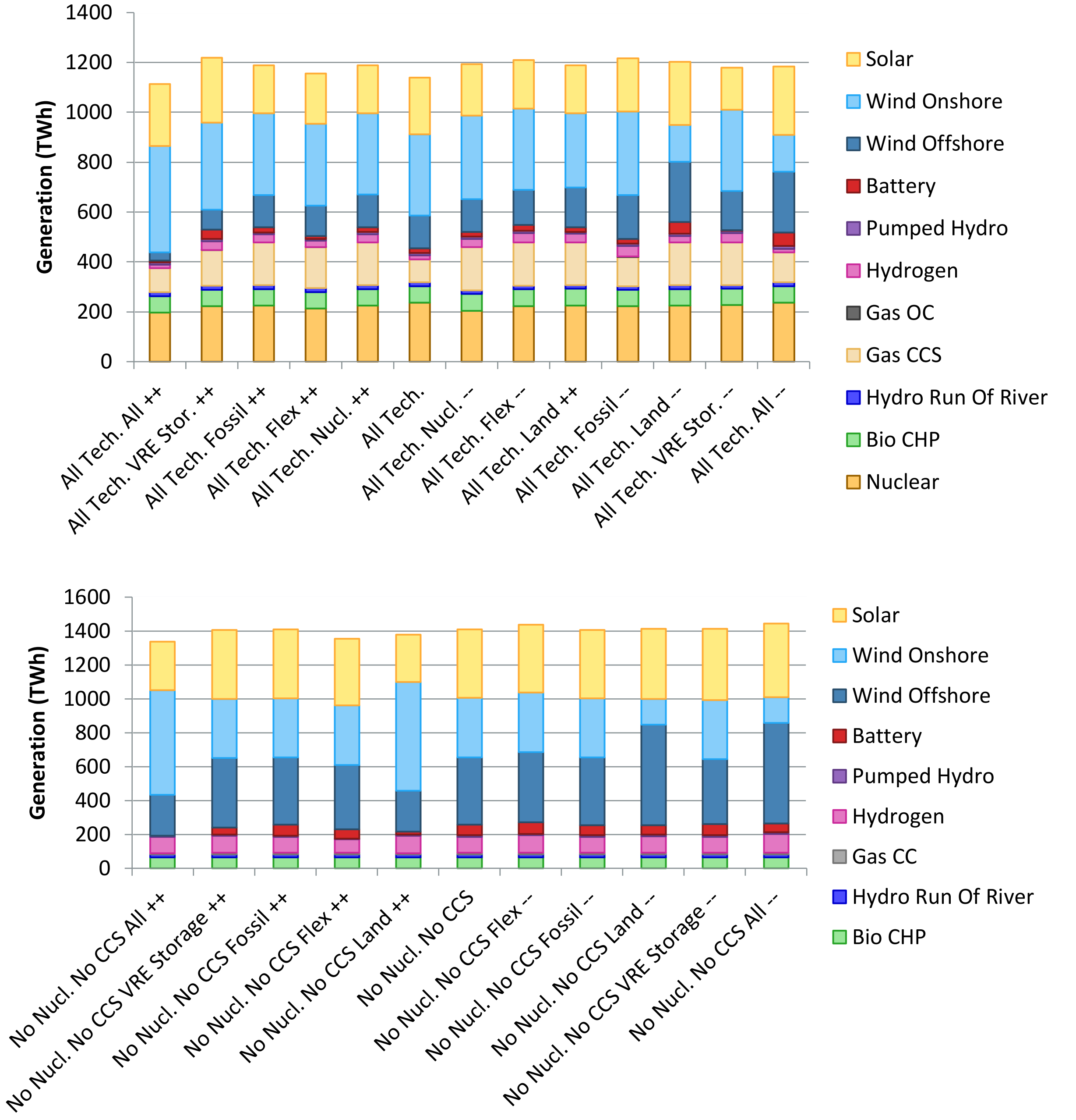
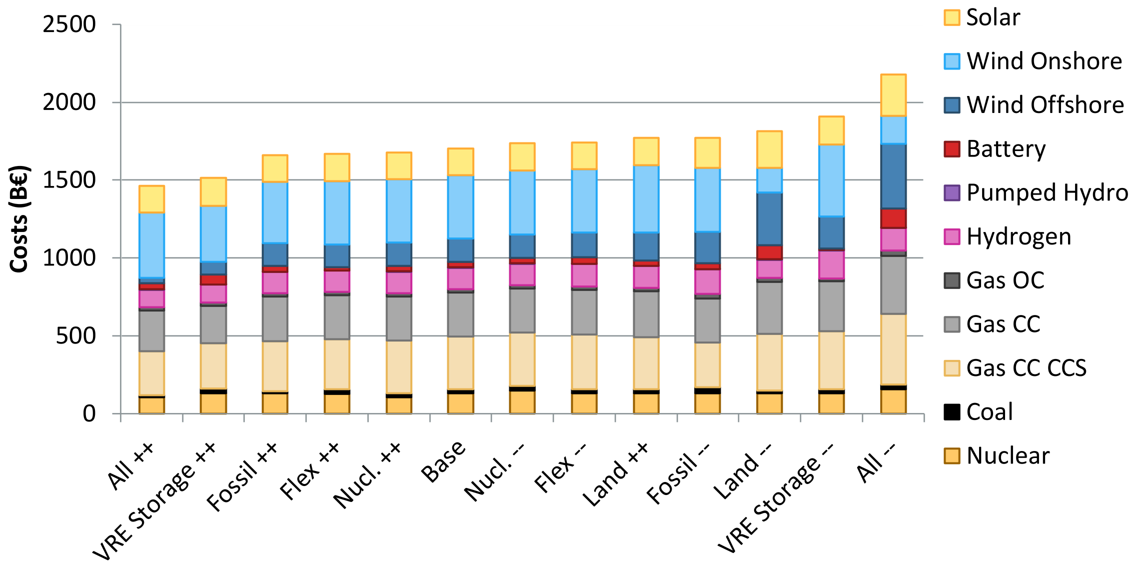


FIGURE 20.

Generation mixes for sensitivity variations of *All Tech.* (top) and *No Nucl. No CCS* (bottom) for model year 2050. Scenarios are sorted based on ascending total cumulated system costs.

At a first glance, it is evident that the German generation mix in 2050 does not vary much between sensitivity within separate technology policy pathways. The initial conditions of the German power system combined with the limited build options, especially apparent in the near-term future, contribute to the limited variations observed within the explored sensitivities for a specific policy pathway. On this background, the report focuses on a set of main scenarios exhibiting the most extreme variations for all policy pathways. These are the *All Tech.* and the All Tech.-derived *No Nuclear, No CCS* and *No Nuclear No CCS,* along with their extremes *All* ++ and *All* --.

It is still of relevance to dive deeper into sensitivity simulation runs as they can provide insights into the relative value of the underlying parameters varied. Therefore, each sensitivity variation, e.g., *Flex* -- and *Flex* ++ but except for *All* ++ and *All* --, are reviewed in the following in descending order of their assumed impact represented by a combination of the total system costs and the change of the generation mix.



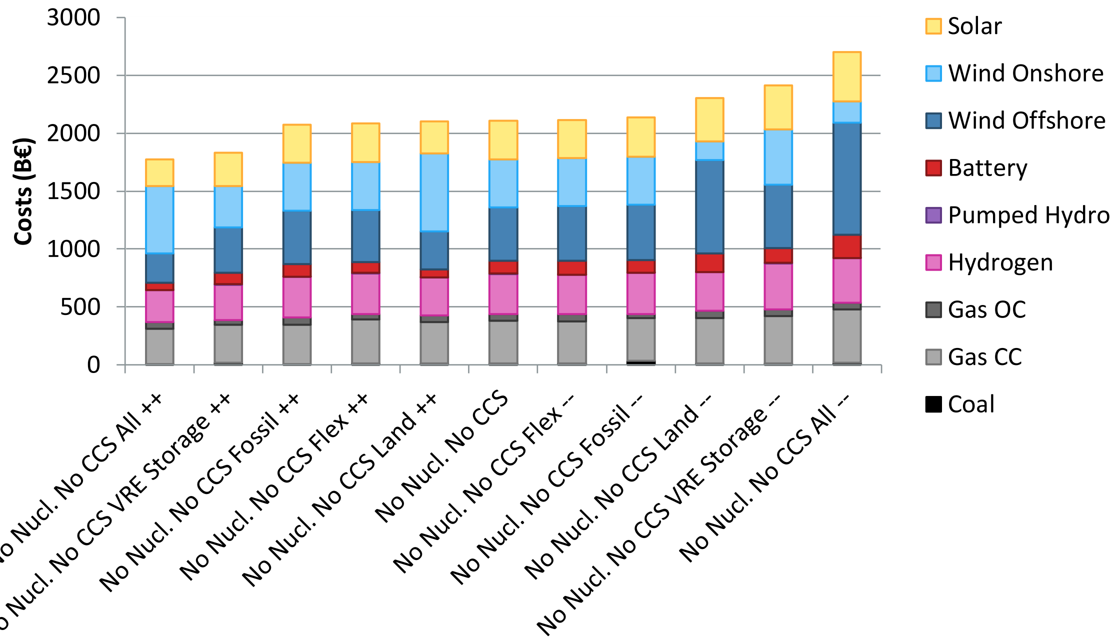


FIGURE 21.

Total cumulated system costs split by technology for sensitivity variations of *All Tech.* (top) and *No Nucl. No CCS* (bottom) for the model horizon 2030-2050.

The *VRE Storage* sensitivities, which explore variations in the cost development of Variable Renewable Energy (VRE) and storage technologies, demonstrate the most significant effects on system costs. This indicates that the development of the German power system is highly sensitive to this parameter, a natural consequence of a VRE-dominated system. Notably, a sensitivity variation focusing solely on storage technologies was also explored but had negligible impact, thus it was coupled with VRE.

Variations in technical land availability for onshore wind expansion exhibit intriguing and perhaps counterintuitive behaviour. For all technology pathways, except for *No Nucl. No CCS,* both *Land* -- and *Land* ++ exhibit larger total system costs compared to the *All Tech.* scenario. This effect is driven by the assumption of a more limited capacity factor in the *Land* ++ scenario, which reduces the cost-effectiveness of onshore wind. However, the policy pathway excluding nuclear and CCS technologies shows the largest potential benefits from greater land availability given its lower system costs compared to the *All Tech.* scenario.

The three remaining sensitivity variations—fossil, nuclear, and demand-side flex—exhibit very limited impact on both the generation mix and total system costs.

Firstly, the power system in 2050 is largely independent of fossil fuels due to stringent CO_2 targets and high CO_2 prices, which define the expansion of Gas CCS power capacity.

Secondly, new nuclear power is highly cost-effective, driving its expansion to allowed build rates. Notably, the nuclear expansion in the *No CCS, No CCS Nucl.* ++ and *No CCS Nucl.* -- was observed to be identical. Costs for restart of nuclear is negligible in the full context.

Thirdly, demand-side flex, explored in the *Flex*++ and *Flex*-- scenarios, shows limited impact on the decarbonised German power system. For instance, in the *All Tech.* sensitivity variations, a 2 GW lower expansion of nuclear is seen for *Flex* ++ and in the *Flex* -- scenario an additional 3 GW hydrogen CC power plants are built along with about 5 GW more offshore wind. The results may be explained by the assumed time constants of the shiftable components of the flexible load categories, which generally range from 4 to 24 hours. The German power system, dominated by wind, exhibits production variations on the order of weeks rather than daily fluctuations. As a result, it caters more to long-duration storage, such as hydrogen storage. The flexibility provided by the demand side, approximately 25 GW of electrolyser charging capacity (see also APPENDIX 0), is insufficient to manage the peaks in wind production, which can reach around 250 GW. This triggers the expansion of hydrogen combined-cycle power plants along with additional hydrogen storage capacity.

5.3 Relaxed limits on build rates and CO_2 targets

Two additional sensitivity variations—relaxed build rate limits (*No Limits*) and more lenient CO_2 targets (*CO_2 --*)—were applied to the *All Tech.* technology pathway. This approach aimed to further investigate potential pathway dependencies and the cost-effectiveness of various technologies.

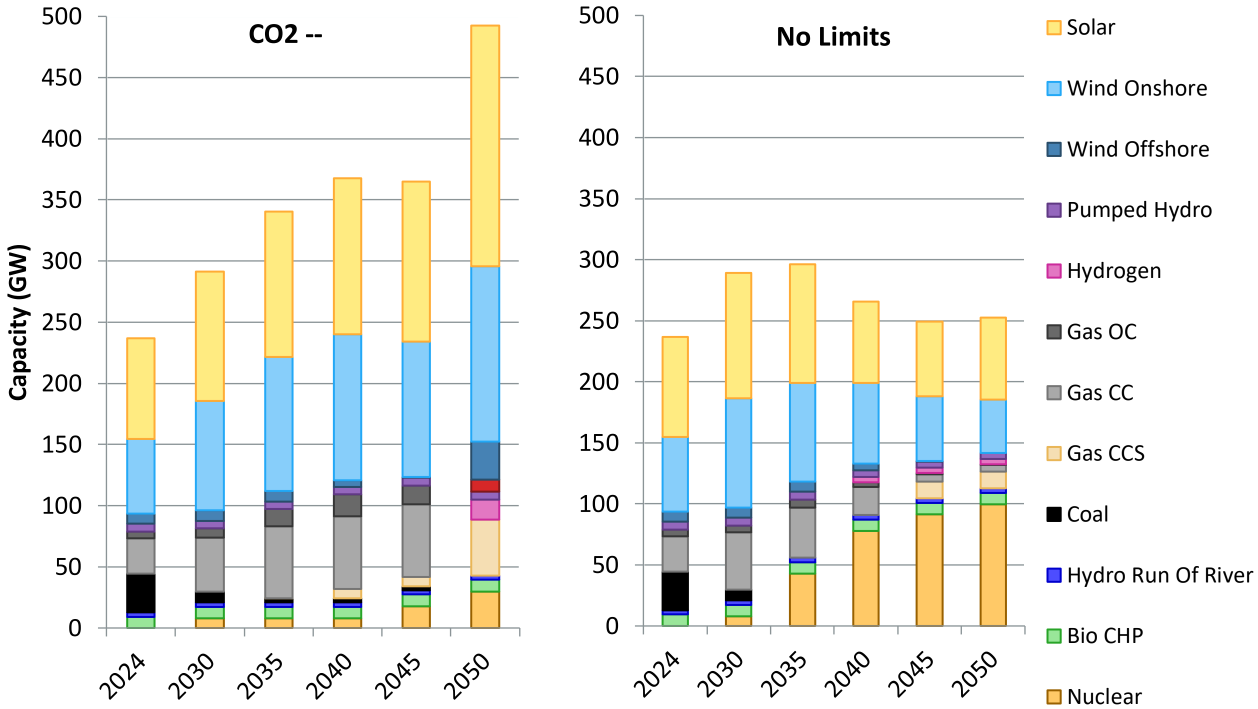


FIGURE 22.

Installed capacity for the German power system across the model horizon for the *CO_2 --* (left) and *No Limits* (right) scenarios.

The time-evolving capacity mix of the *CO_2 --* and *No Limits* scenarios is presented in FIGURE 22. Due to the relaxed CO_2 targets, natural gas power plants maintain significant capacity through to 2050. Offshore wind, Gas CCS, and hydrogen power plants primarily enter the capacity mix in 2050, marking a notable difference from the *All Tech.* scenario results shown in FIGURE 18. These findings indicate that the increasing CO_2 prices imposed by the model to achieve interim targets drive the deployment of these technologies. For example, they promote the replacement of Gas OC with hydrogen for power generation and encourage more wind power, particularly offshore wind.

In the *No Limits* scenario, the most notable difference compared to the *All Tech.* scenario is the significantly larger presence of nuclear power from 2035 onwards, enabled by the removal of build rate limits. FIGURE 23, which displays all related sensitivity variations, clearly shows that the *No Limits* sensitivity has the greatest impact on the model-deduced German power system design in 2050. In contrast, the *All Tech.* and *CO_2 --* scenarios exhibit only marginal differences in 2050. With regards to system costs, the scenarios *CO_2 --*, *No Limits* and *No Limits CO_2 --* assume values of aggregated costs in the time period 2025-2050 of -10%, -15% and -20% compared to the *All Tech.* scenario, respectively[151].

These scenarios underscore the sensitivity of clean energy technology deployment rates and the potential missed opportunities for a more robust, optimised system by 2050 due to fewer stranded assets in pursuit of interim targets. The results strongly emphasise the high competitiveness of nuclear power in decarbonising the German power system, as demonstrated by its significant expansion in the *No Limits* scenarios, where it replaces a substantial portion of wind and solar capacity as well as Gas CCS. Additionally, these findings suggest that offshore wind and hydrogen-fuelled power plants are considered by the model as last resorts to add clean generation and capacity to the German power system to meet ambitious CO_2 targets while accommodating increasing power demand. This discussion raises an important question: are the near-term 'best' actions for decarbonisation, such as significant expansion of offshore wind and hydrogen-fuelled power plants, necessarily optimal for the long term? Future studies could provide more insights by exploring supply-demand coupled modelling analyses.

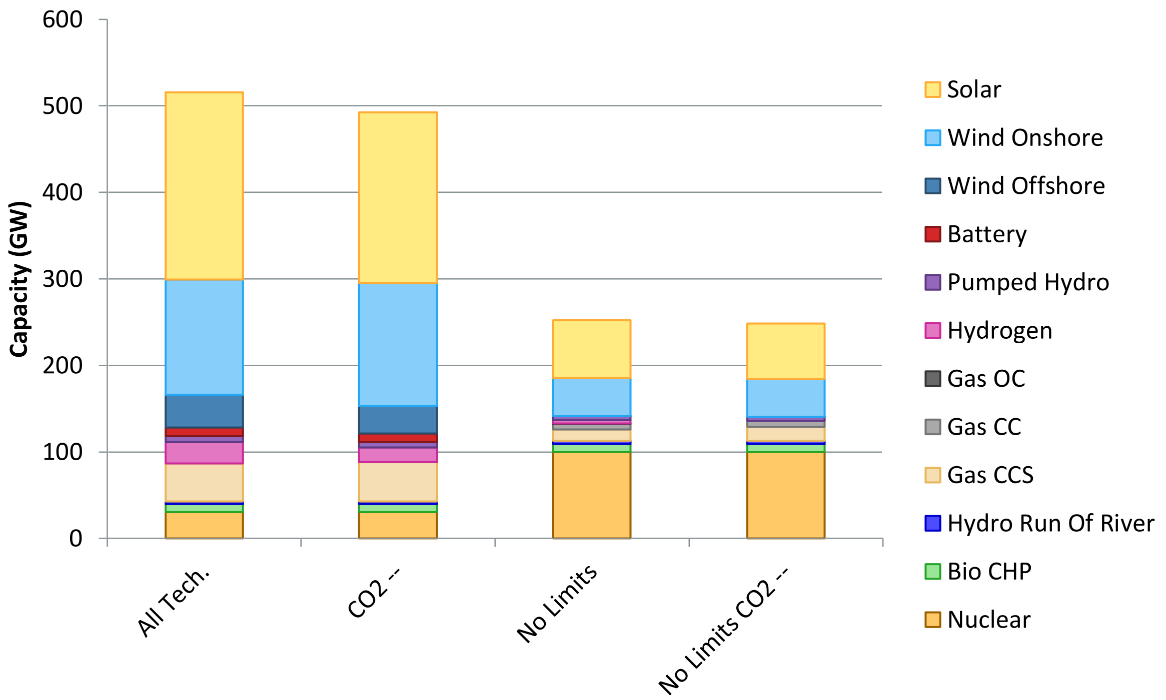


FIGURE 23.

Capacity mixes for model year 2050 for the *All Tech.* scenario accompanied with sensitivity variations thereof with respect to CO_2 targets (*CO_2 --*) and build rate limits (*No Limits*).

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[151] This comparison should also account for increased emissions in the CO_2 – scenarios.

5.4 System costs

Total system costs have been determined for all scenarios explored in the current study and are presented by technology contributions or cost types: investment costs, fixed costs, variable costs, and import costs. These costs are annual levelised costs, meaning investment costs are evenly spread over the technology's lifetime. Variable costs include both operational and maintenance (O&M) expenses and fuel costs, while fixed costs represent fixed O&M. Trade has been simulated only for 2050, with a linear increase from 2025 to 2050 applied to infer net import costs[152] over the entire time horizon. The costs account only for investment in new capacity additions built in the model; existing capacity is only subject to fixed and variable O&M costs and fuel expenses. Costs gathered on year 2030 represents the aggregated costs between 2024-2030, on year 2035 between 2031-2035 etc.

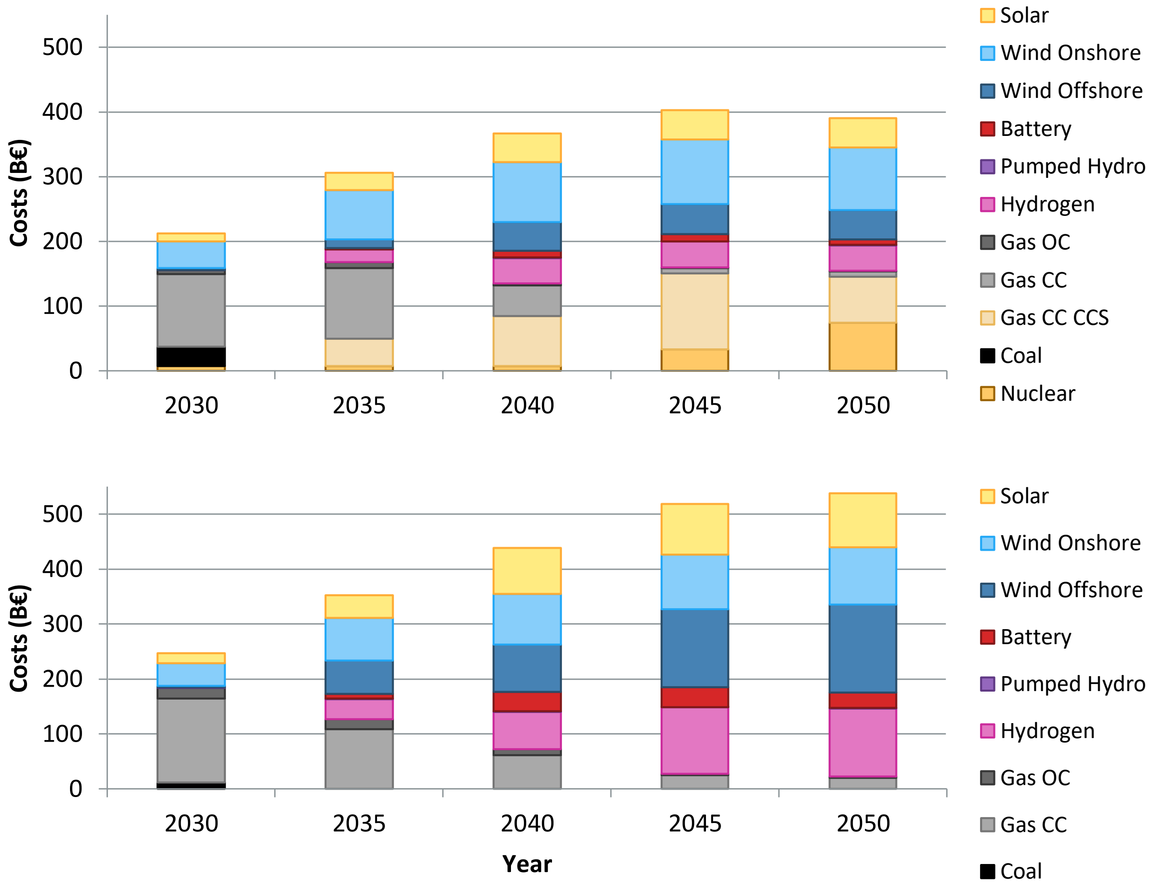

FIGURE 24.

Total system costs as a function of model year for the *All Tech.* (top panel) and *No Nucl. No CCS* (bottom panel) scenarios split by technology. Costs gathered on year 2030 represents the aggregated costs between 2024-2030, on year 2035 between 2031-2035, etc.

In FIGURE 24 the total system cost divided by resource technology and separated by model year is shown for the *All Tech.* scenario and *No Nucl. No CCS* scenario. System costs have been calculated summing yearly investment costs, operational and maintenance costs and fuel costs for each resource. We see that during the initial phase, all costs are dominated by the existing fossil fuel system, mainly consisting of fuel costs and CO_2 emissions prices. By the end of the studied period, the costs in the *All Tech.* scenario are spread rather evenly with around half representing wind and solar costs while the nuclear and Gas CCS technologies contribute roughly similar costs with hydrogen adding a little bit on top. In the *No Nucl. No CCS* scenario offshore wind constitutes the

[152] Net export revenues are displayed as negative costs.

largest share of costs in 2050 with hydrogen coming in second and solar and onshore wind following on similar levels. FIGURE 25 displays the scenarios with costs segmented by cost type instead. From this perspective, the results indicate a trend of high variable costs in 2030, shifting towards a larger share of investment costs by 2050. Furthermore, the *No Nucl. No CCS* scenario exhibits increasing import costs an aspect which is discussed further below.

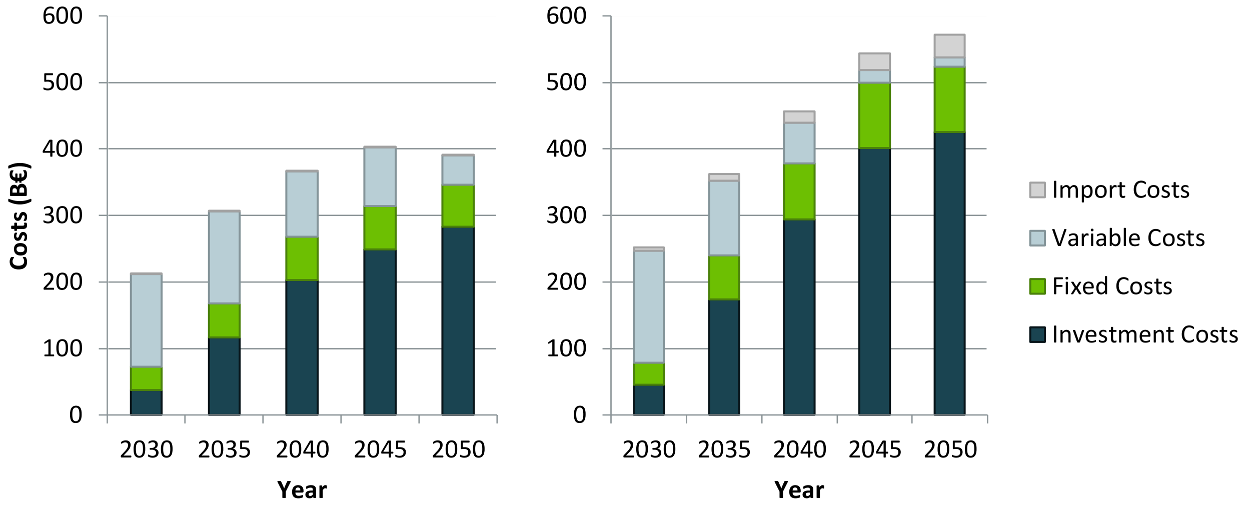

FIGURE 25.

Total system costs as a function of model year for the *All Tech.* (top panel) and *No Nucl. No CCS* (bottom panel) scenarios split cost type.

Owing to a shared starting point as well as similar model boundary conditions in the early stages of the model horizon, the scenarios display differences on system costs which are small in the 2030s but increasing considerably towards 2050. FIGURE 26 compares the aggregated total system costs for *All Tech.* and *No Nucl. No CCS* scenarios on the full horizon with that of the 2041-2050 time period. The relative cost difference between *All Tech.* and *No Nucl. No CCS* increases from +30% to +40%. For reference, the aggregated total system costs are 1680 B€ and 2190 B€ for the *All Tech.* and the *No Nucl. No CCS* scenarios, respectively. These results indicate amplified differences on the total system costs for the German power system in the long-term perspective supported by the comparison of electricity prices in 2050, which in some sense, provides a snapshot of the total system costs, as presented in SECTION 5.6.2.

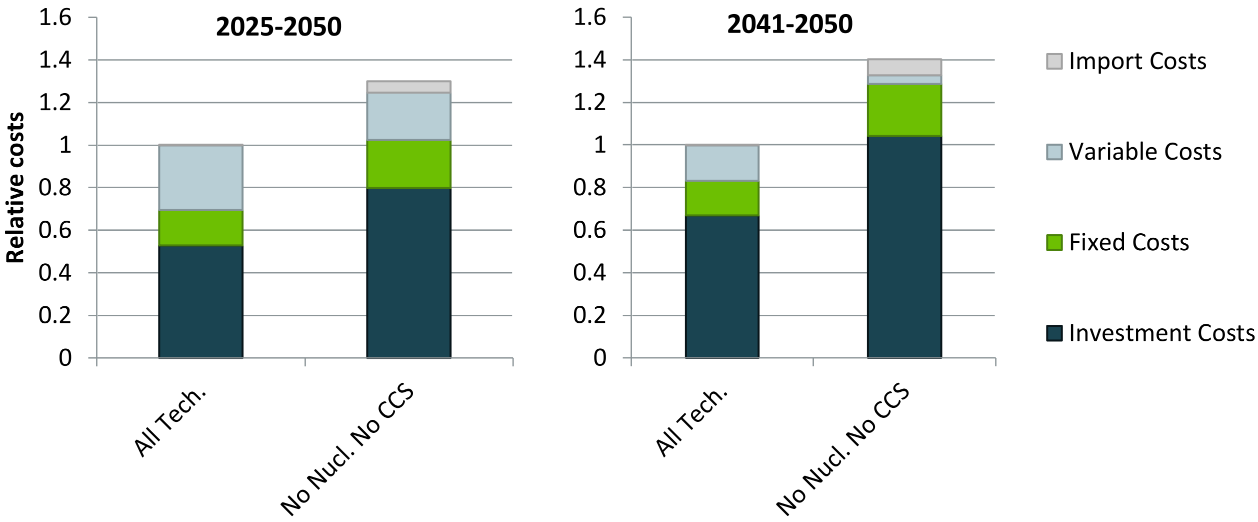

FIGURE 26.

Relative cost difference compared to the *All Tech.* scenario for aggregated costs across the full model horizon (left) and the period 2041-2050 (right).

The German power systems built in the current work display a limited import dependency inherent to the methodology as elaborated in SECTION 3.2. Therefore, unsurprisingly, import costs and export revenues generally display marginal levels compared to the total system costs. In the more technology restricted scenarios, *No Nucl. No CCS*, there is a lack of low marginal cost firm power in Germany which means that the model relies to a larger degree on neighbouring regions for balancing the system. Notably, since the weather correlates significantly over northern Europe, the likelihood that neighbouring regions are experiencing low wind and solar production at the same time as Germany is high. This means that German imports primarily occur at times of high prices which in turn results in import costs overweighing export revenues.

For reference[153], the investment in renewable energy plants in 2023 amounted to 36.6 B€ and was the highest number since 2010 (29.9 B€). These costs amount to over 150 B€ over five years and may therefore be considered high compared to the model results in FIGURE 25. The strong technology cost reductions assumed in the current work could provide an explanation for the difference. Furthermore, the planned investment in high voltage transmission lines from wind-rich northern regions to industrial centres will require over 35 B€[154] but arguably can be considered relatively small in the context of total system costs.

5.5 Main scenarios

The three panels in FIGURE 27, FIGURE 28 and FIGURE 29 show comparisons of capacity and generation mixes as well as total system costs for the four technology pathways *All Tech.*, *No CCS, No Nucl.* and *No Nucl. No CCS* along with their extreme variations *All ++* and *All --*. This set of scenarios denoted main scenarios, exhibit widely varying German power systems and provide the basis for further comparisons.

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[153] Statista (2024), Investments in renewable energy plants in Germany from 2001 to 2023.
[154] Germany Trade and Invest (2024), Energy Infrastructure.

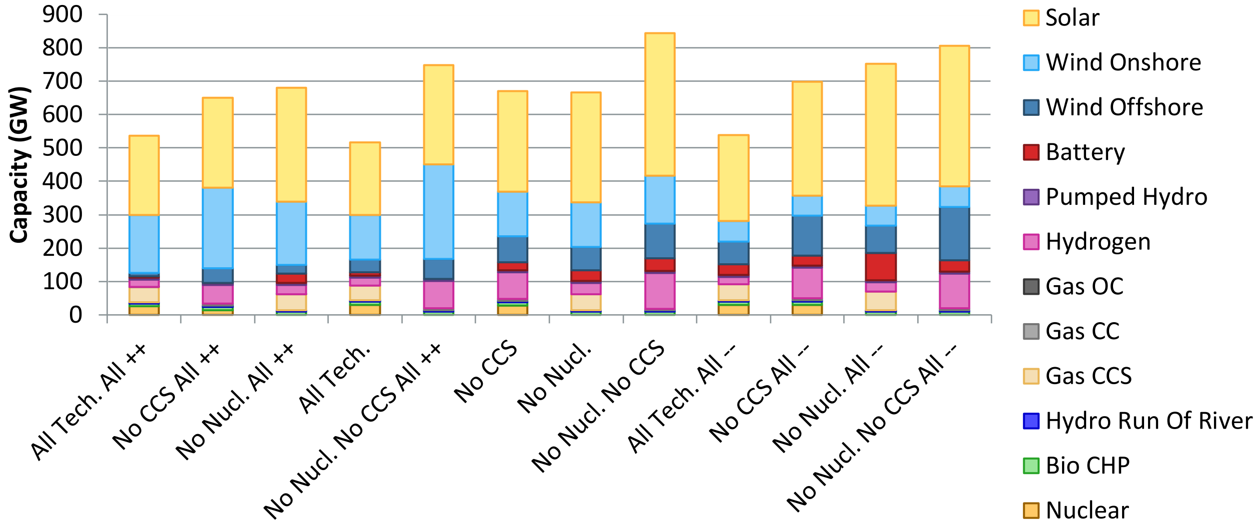

FIGURE 27.

Capacity mixes for model year 2050 and the technology pathways scenarios accompanied by their extreme scenarios.

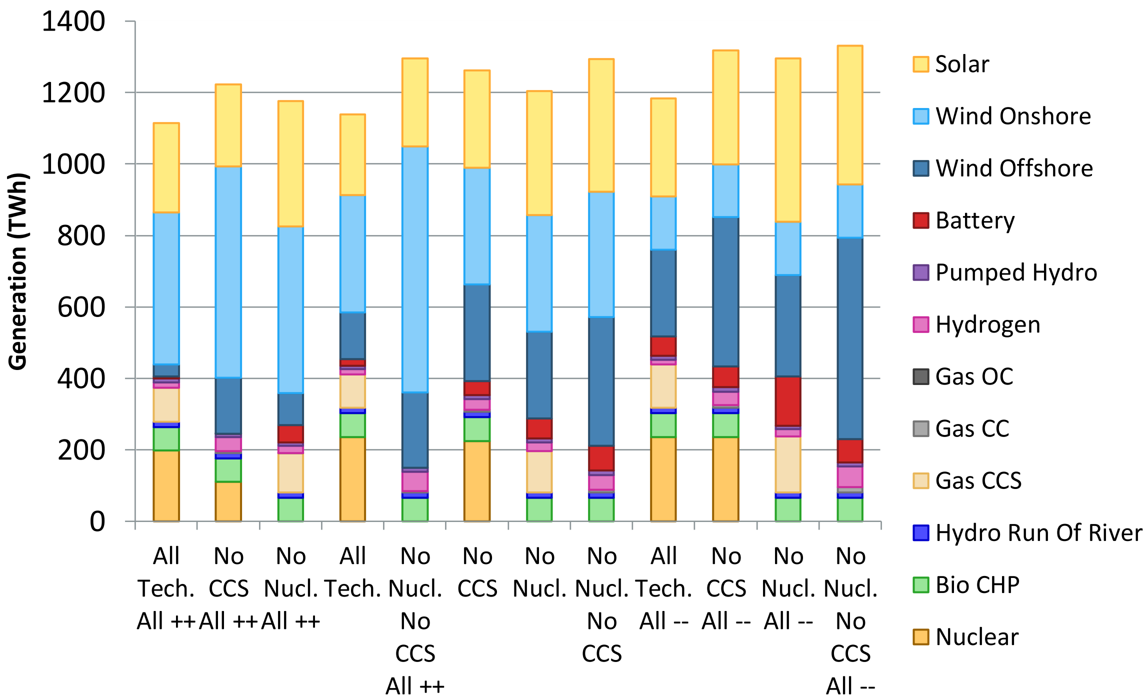

FIGURE 28.

Generation mixes for model year 2050 and the technology pathways scenarios accompanied by their extreme scenarios.

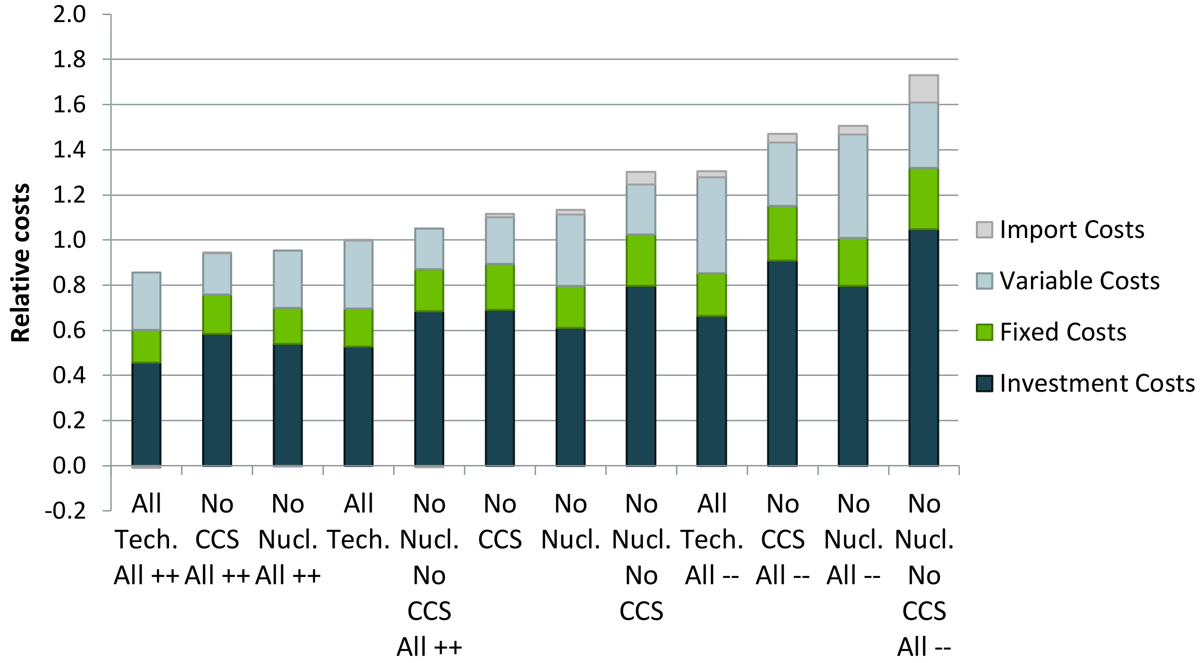

FIGURE 29.

Relative total cumulative system costs for 2030 to 2050 with respect to the *All Tech.* scenario split by cost type for the technology pathways scenarios accompanied by their extreme variations.

FIGURE 29 shows the relative costs to the *All Tech.* scenario. The absolute costs range from 1680 B€ in the *All. Tech*. scenario to 2910 B€ in the *No Nucl. No CCS All --* scenario. Based solely on total system costs, the following ranking can be inferred for different technology policy pathways: 1) *All Tech.*, 2) *No CCS*, 3) *No Nucl.*, and 4) *No Nucl. No CCS*. The total system costs show low sensitivity to technology inclusiveness in the optimistic scenario variations (*All* ++), with all these scenarios falling within 85% to 105% of the relative costs of the *All Tech*. scenario. These optimistic scenarios assume significant cost reductions, successful projects for all technologies, low fossil fuel prices, highly flexible electricity load, and strong public acceptance of onshore wind power, indicating that with overall positive technological development the choice of policy pathway becomes less critical.

Conversely, in the conservative *All* -- scenarios, where stagnating cost reductions, unsuccessful projects for all technologies, high fossil fuel prices, inflexible electricity load, and strong public opposition to onshore wind power are assumed, significant impacts are observed. These effects are further amplified with additional technology restrictions. The *No Nucl. No CCS* scenario incurs an extra 500 B€, or 30% higher total system cost compared to *All Tech.* In relative terms, the conservative *All* -- variations of *All Tech.* and *No Nucl. No CCS* show a difference of 32%, translating to an absolute cost difference of 720 B€.

The German power systems built in the current work display a limited import dependency inherent to the methodology as elaborated in SECTION 3.2. Observed net annual flows range from 70 TWh exports to 50 TWh imports. Generally, import costs and export revenues display marginal levels compared to the total system costs. The *No Nucl. No CCS* scenarios are exceptions with import costs reaching 200 B€ aggregated across the 25-year model horizon.

5.6 Electricity market modelling

5.6.1 System overview

In the full system model, 17 zones are used. An example of the dispatch is given in FIGURE 30 showing daily averages for generation and consumption in all zones. The model year is 2050 and the weather year is 1991. For the surrounding zones, the goal has not been to reach the same level of detail in the analysis as for the German model, but to create a realistic representation of the trade between

Germany and neighbouring zones. The surrounding zones are allowed to optimise the expansion of their resources within boundary conditions given by their national policies. For example, nuclear power is not allowed in countries that currently do not include it in their future energy plans, e.g. Spain and Denmark, and reservoir hydro power not allowed to expand further in the Nordic countries. The resulting capacities obtained from the GenX expansion are used as starting values in cGrid and allowed to adjust further to reflect the different conditions when Germany can trade with the surrounding regions.

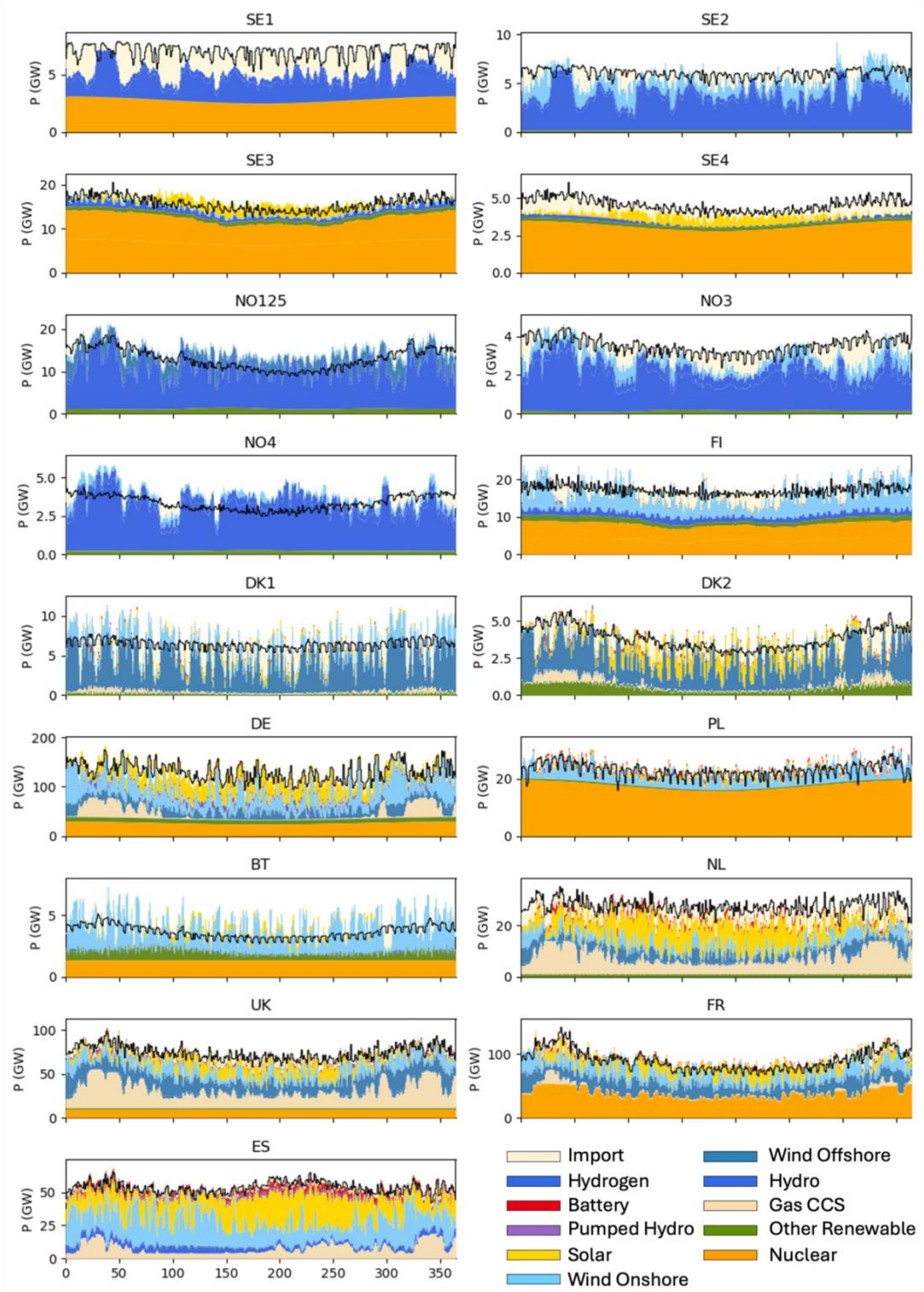

FIGURE 30.

Overview of the full system simulation showing daily averages for each modelled zone. The model year is 2050 and weather year is 1991.

We can see that the countries solve the dispatch in different ways depending on their conditions. Countries with neither nuclear nor significant reservoir hydro tend to rely on a combination of wind and solar power backed up by natural gas plants with CCS. Nordic countries rely mainly on nuclear, hydro and wind power. It can also be noted that Spain, with its favourable solar conditions, sees solar power backed up by storage as its largest contributor.

In FIGURE 31 and FIGURE 32 we illustrate what the dispatch in Germany looks like for the scenarios *All Tech.* and *No Nucl. No CCS* during a demanding two-week winter period. In the *All Tech.* scenario, nuclear power and gas with CCS are covering most of the non-flexible demand while the flexible demand is able to follow the production profile of wind and solar power. Storage technologies in the form of pumped hydro, batteries and hydrogen fuelled gas turbines also help to cover the night-time load during low wind periods. As a contrast, in the *No Nucl. No CCS* scenario a much greater reliance is made on the storage technologies to cover a majority of the demand during night-time when wind power is low. Around hour number 690 the storage constitutes 85% of the total demand. We can also see that during daytime, the flexible demand has to cycle up to 200% of the baseload demand in order to capture the solar generation during daytime.

Finally, in FIGURE 33 an example of the storage dispatch is shown. A boundary condition on the storage level is set, forcing it to end at the same level it started at (50%). During the winter there are a few demanding periods where the storage level drops significantly. These are generally characterised by prolonged periods, up to two weeks, with low wind production in the entire system. During summertime, solar power, which is varying with a shorter time period than wind, is dominating the system, and the storage levels remains more constant around 50% as it is being charged and recharged every day. On average about 25% of the hydrogen produced by the electrolysers and injected into the storage are consumed by the hydrogen turbines. The remaining 75% of the hydrogen is used as a feedstock for non-electricity purposes.

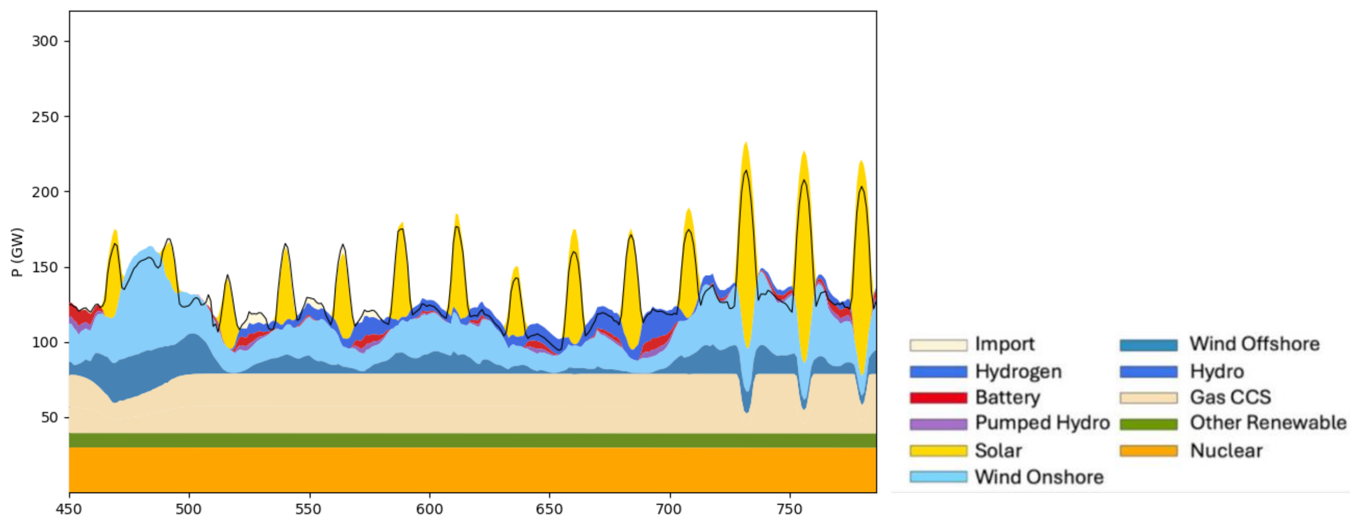

FIGURE 31.

Example of two winter weeks in Germany for the *All Tech.* scenario. The model year is 2050 and the weather year is 1991.

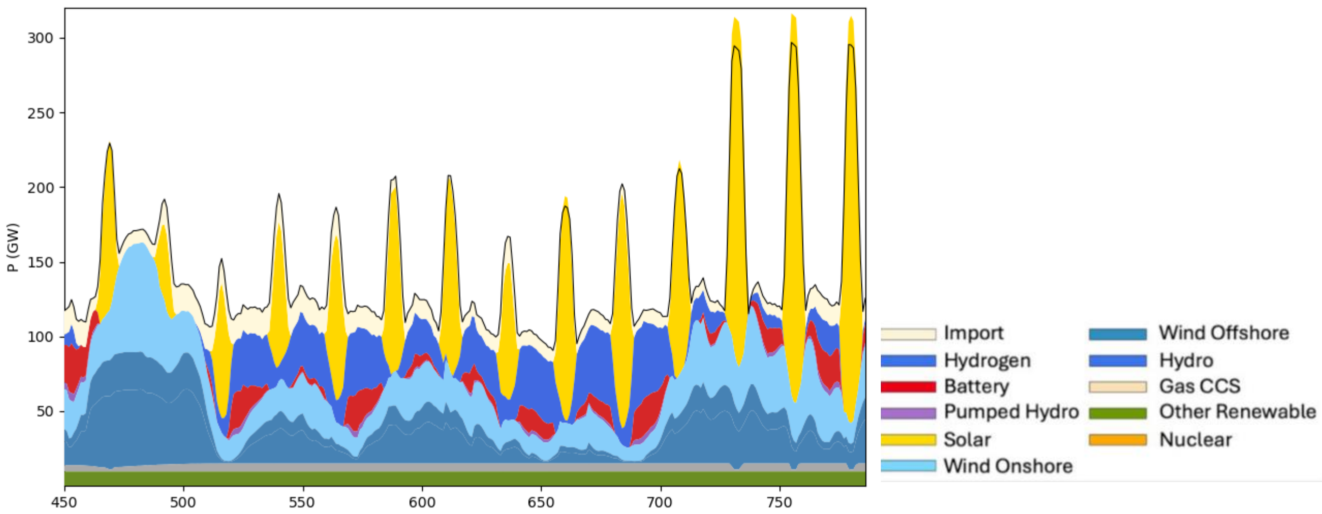

FIGURE 32.

Example of two winter weeks in Germany for the *No Nucl. No CCS* scenario. The model year is 2050 and the weather year is 1991.

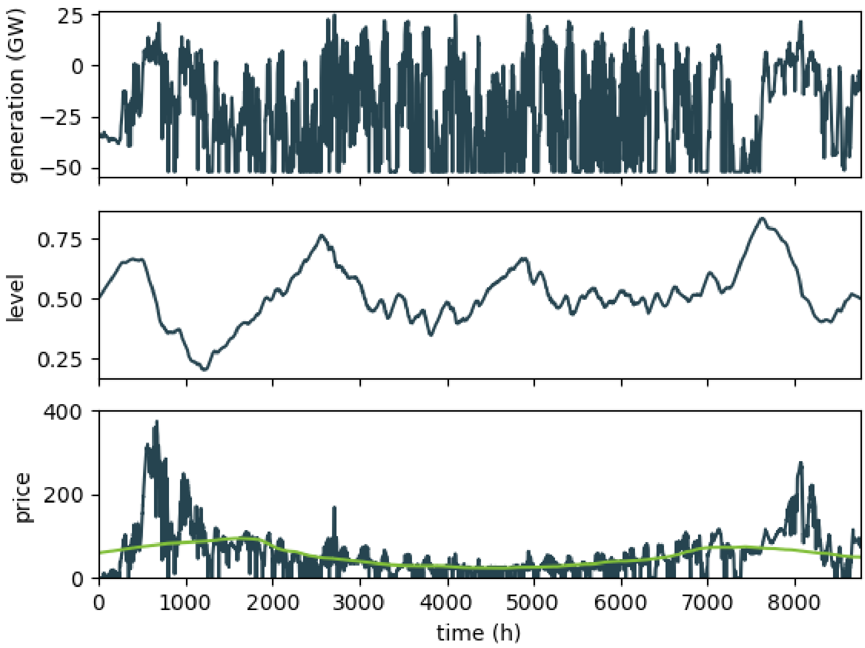

FIGURE 33.

Example of the dispatch of the hydrogen storage in Germany for the *All Tech.* scenario. The model year is 2050 and the weather year is 1991. In the top panel the net generation (positive) and net demand (negative) is shown. In the middle panel the relative storage level is shown, and in the bottom panel the hourly spot price is shown together with the smoothed price.

5.6.2 Prices

The electricity prices, obtained from the full system model, for the main technology pathway scenarios, are shown in FIGURE 34. In all cases the weather year is 1991. The *All Tech.* scenario averages around 60 €/MWh. Some optimistic scenarios (++) reach as low as 40 €/MWh while some conservative scenarios (--) passes 80 €/MWh. The worst-case scenario is unsurprisingly the No *Nucl. No CCS All --* that reaches 120 €/MWh on average with 1991 as weather year.

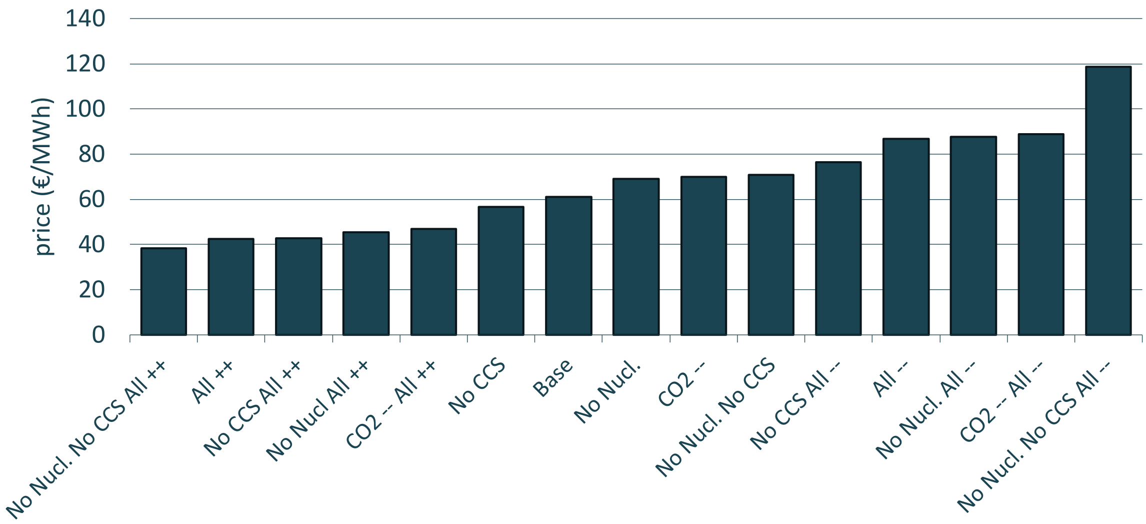

FIGURE 34.

Yearly average prices for model year 2050 and the reference weather year 1991.

Some results in FIGURE 34 might, at first sight, seem somewhat counter intuitive. For example, the more constrained scenario *No Nucl. No CCS All ++* actually has a slightly lower average price than the more open scenario *All ++* that allows for inclusion of all technologies. Even if the difference is small, one would expect the opposite behaviour. However, this is a result of path dependencies leading up to 2050. In order to meet CO_2 targets during the model years 2030, 2035, 2040 and 2045, and stay within all time-dependent constraints, the model must overbuild some technologies that, later, might not be fully profitable during the final model year 2050. Had the model made a Greenfield expansion only for 2050, the results would be different.

In addition to the average prices, the volatility between years is also important to factor in. Low electricity price volatility is valuable for a power system since it provides predictability and stability for both consumers and producers. This stability can reduce financial risk, facilitate investment planning, and ensure more consistent electricity costs, contributing to a reliable and efficient energy market. Low electricity price volatility also reduces the need for flexibility measures, such as energy storage and demand response, that are typically used to manage price fluctuations. This can lead to lower overall costs for maintaining system balance and reliability as well as more attractive market for energy-intensive industries, as it reduces the need for extensive flexibility infrastructure to capitalise on lower electricity prices.

The main technology-pathway scenarios, *All Tech., No Nucl, No CCS*, and *No Nucl. No CCS*, were confronted with a set of 33 different weather years. Box plots of the distribution of yearly electricity prices in 2050 for different weather years is presented in Figure 35. We can see that for scenarios including nuclear power, the average prices (blue triangles) are very close to the median prices (green lines) indicating that the distribution is symmetrical. However, scenarios excluding nuclear power see significantly skewed price distributions where the mean price is significantly above the median price. This is a result of problematic weather years that can drive prices up to very high levels. Further, for this reason, using the median year 1991 is no longer fully representative for the mean value of the price as a few very problematic years can influence this value significantly. For example, the price for the *No Nucl. No CCS* scenario during weather year 1991 in FIGURE 34 above (70 €/MWh) is significantly lower than the mean price including all weather years at 102 €/MWh. This illustrates a risk with more weather-based systems, that many years may exhibit reasonable average prices, but for some years the prices can be very high.

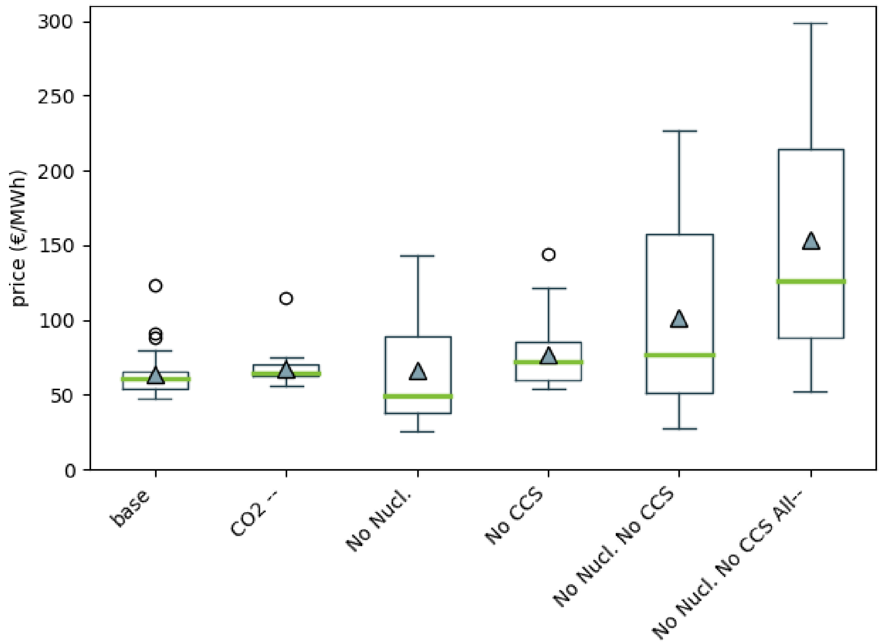

FIGURE 35.

Yearly average electricity price for the complete set of 33 weather years in 2050 for the different technology pathway scenarios, as well as the *CO_2* -- and *No Nucl. No CCS All* -- scenarios. The boxplots cover the range of outcomes for the full set of weather years with boxes representing the 25% - 75% quartiles and dots representing outlier values. Median values are shown with green lines and mean values with blue triangles.

It is worth noting that the electricity price volatility presented here is likely underestimated, particularly for scenarios with a significant proportion of Gas CCS in the generation mix. The use of fixed fossil fuel and CO_2 prices in these simulations does not fully capture the variability of a realistic electricity market. To address this, additional simulations were performed with varying fossil fuel prices, based on the sensitivities outlined in SECTION 0 to assess their impacts. A linear relationship between fossil fuel price fluctuations and Germany's yearly average electricity prices was observed. For a natural gas price increase of approximately +6 €/MWh (LHV) in the *All Tech.* and *No Nucl.* scenarios, the average electricity prices rose by about +10 €/MWh and +12 €/MWh, respectively. This suggests that imposing a variation of around ± 8 €/MWh, or roughly ±30%, in fossil fuel prices would likely bring the volatility of the *All Tech.* scenarios to a level similar to that of the *No CCS* scenario. As a level of reference, average natural gas prices exceeded 100 €/MWh in the extremes of 2022 then to settle at around 40 €/MWh in 2023 compared to the assumed price of 22 €/MWh in 2050 in the reference sensitivity of the current study.

Finally, it was observed that all scenarios avoid hours of power deficits across the 33 weather years. This is ultimately a consequence of the employed methodology emphasising limited trade dependency. Section 4.8 demonstrates that imposing a capacity reserve margin requirement through a capacity market involves minimal additional costs, suggesting that this approach could improve supply security.

5.7 Transmission infrastructure

5.7.1 Power transmission

The calculations concerning new required capacity for power transmission lines for each scenario have been conducted based on the method presented in detail in Appendix B.6. The range of determined values, as shown in FIGURE 36, goes from 3,952 km of required transmission expansion for scenario denoted *All* ++ to as much as 39,023 km for scenario marked *No Nuclear No CCS All* --. Apart from the all-out optimistic scenario, *All* ++, the majority of the new required transmission expansion is being driven by offshore wind with fixed foundations (Wind Offshore Fixed) with an exception to scenario *No Nucl. No CCS All* -- where more than half of expected grid expansion (19,620 km) is required by a massive expansion of floating offshore wind (Wind Offshore Floating). To compare, the Germany's GDP - Grid Development Plan[155] - calls for 25,723 km of new transmission lines in 2045 which is driven by a massive development of solar PV (in the range of 400-445 GW), 70 GW of offshore wind power followed by 160-180 GW of onshore wind. In the analysis presented in this report, the *No Nucl. No CCS* is the closest (in terms of required grid expansion) to the German GDP. However, we report in our scenario 427 GW capacity installed in solar PV, 34 GW more in offshore wind (floating) and 40 GW less in onshore wind. Overall, the higher required expansion of transmission infrastructure in the scenarios of the current study is driven by a larger offshore wind expansion instead of its onshore alternative - that roughly translates into doubling the existing transmission capacity. For reference, the current[156] length of the transmission grids is around 37, 000 km.

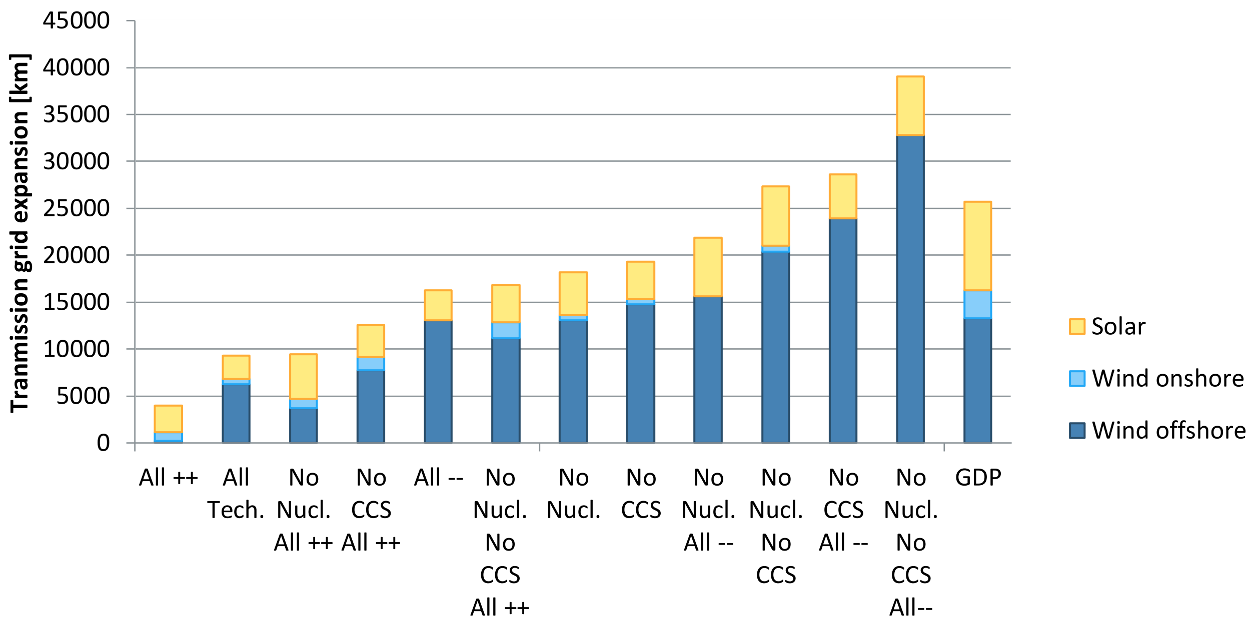

FIGURE 36.

Required new transmission capacity expansion for the 2050 German power system split by technology contributions under various scenarios as well as compared to the German Grid Development Plan (GDP).

5.7.2 Hydrogen infrastructure

Installed hydrogen storage infrastructure in 2050 for the German power system are shown measured in annual hydrogen production in FIGURE 37, hydrogen thermal energy capacity in FIGURE 38 and electrolyser charge capacity FIGURE 39 for main scenarios. These figures show results from the power system optimisation without trade. Hence, the results solely present the expansion needed for production and storage of hydrogen for the purpose of regeneration of electricity through combined-cycle hydrogen gas turbine power plants. The model includes exogenous assumptions of hydrogen infrastructure capacity for demand-side consumption which is further described in APPENDIX 0. Notably, hydrogen consumption for power generation and industrial demand are integrated into the same hydrogen market in the cGrid model results not highlighted here.

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[155] TenneT (2023), Transmission System Operators Publish First Draft of Grid Development Plan for 2037/2045.
[156] Bundesministerium für Wirtschaft und Klimaschutz der Bundesrepublik Deutschland (2023).

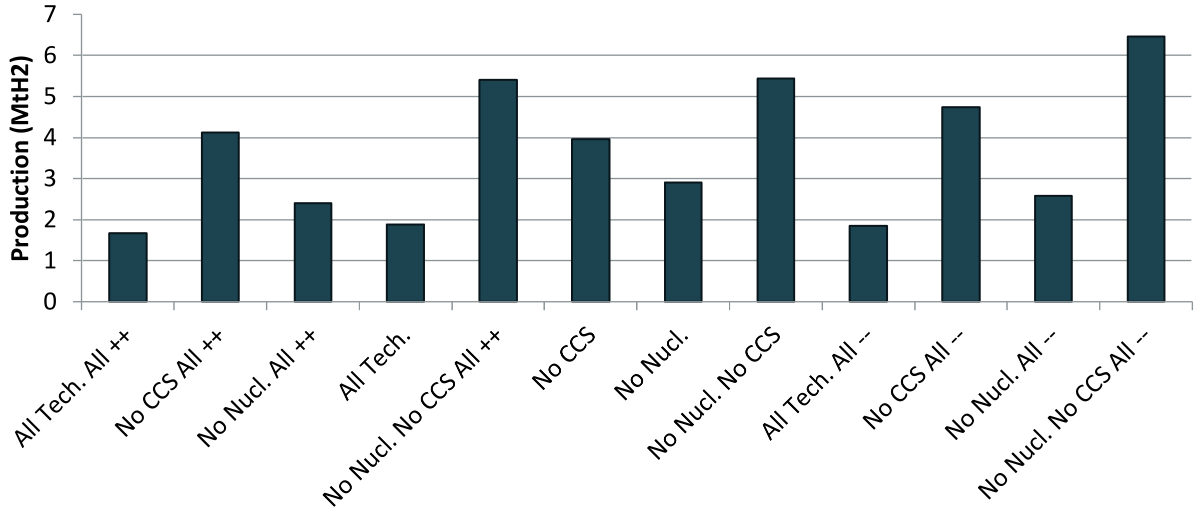

FIGURE 37.

Annual hydrogen production solely for power generation for main scenarios.

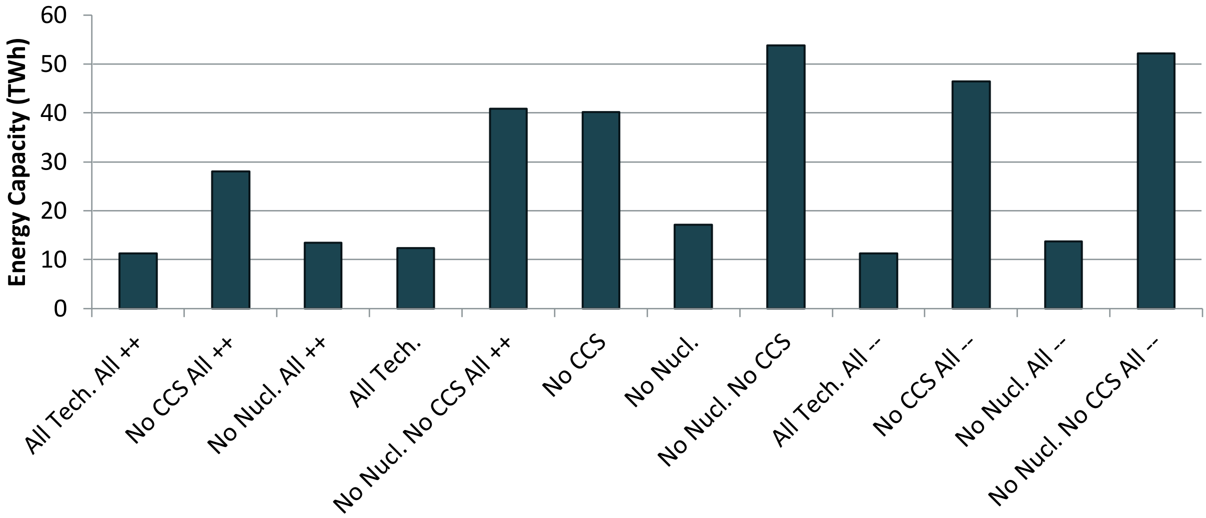

FIGURE 38.

Installed hydrogen thermal energy capacity solely for power generation for main scenarios.

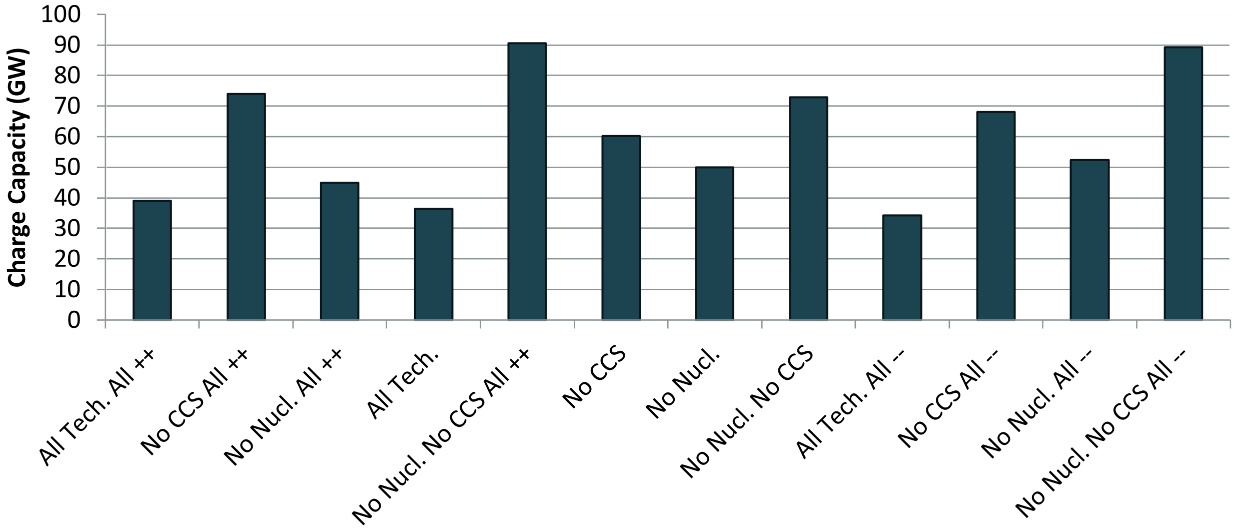

FIGURE 39.

Installed electrolyser capacity solely for power generation for main scenarios.

It is evident that scenarios excluding CCS, i.e., *No CCS* and *No Nucl. No CCS*, show a greater dependency on hydrogen infrastructure. Annual hydrogen production in these scenarios range from 4.0 to 6.5 Mt, while storage capacity cover the range 30 TWh to beyond 50 TWh and electrolyser charging capacity spans the interval 80 to 120 GW. Corresponding power plant capacities are presented in SECTION 5.5. Given the considerably larger expansion of storage capacity for power compared to the assumptions for industrial demand at around 3 TWh, it appears that the assumed 12 days of storage for demand-side consumption is inadequate. In the *No CCS* scenario, the system installs 80 GW of hydrogen power capacity and 40 TWh of storage energy capacity. This results in an estimated 21 days, or three weeks, of storage, indicating that additional storage capacity is necessary. These findings suggest that the demand-side flexibility assumptions used in this study may not be extensive enough to significantly impact the wind-dominated German power system (see also SECTION 5.2).

The significant hydrogen power capacity observed in the modelling results of the current study may be realised from brownfield investments or directly replacing existing gas power stations, i.e. a site repurposing. This to an extent enables them to exploit the existing transmission infrastructure if such will be modernised to transport hydrogen. Apart from hydrogen peaking power stations it is likely that the development of the hydrogen infrastructure will be mostly driven by large infrastructure projects (e.g., steel industry, fertilizers) of which optimal location within the German power system is outside the scope of this study. Note that hydrogen pipeline infrastructure has neither been included in the optimisation nor the total system costs.

5.7.3 CO_2 infrastructure

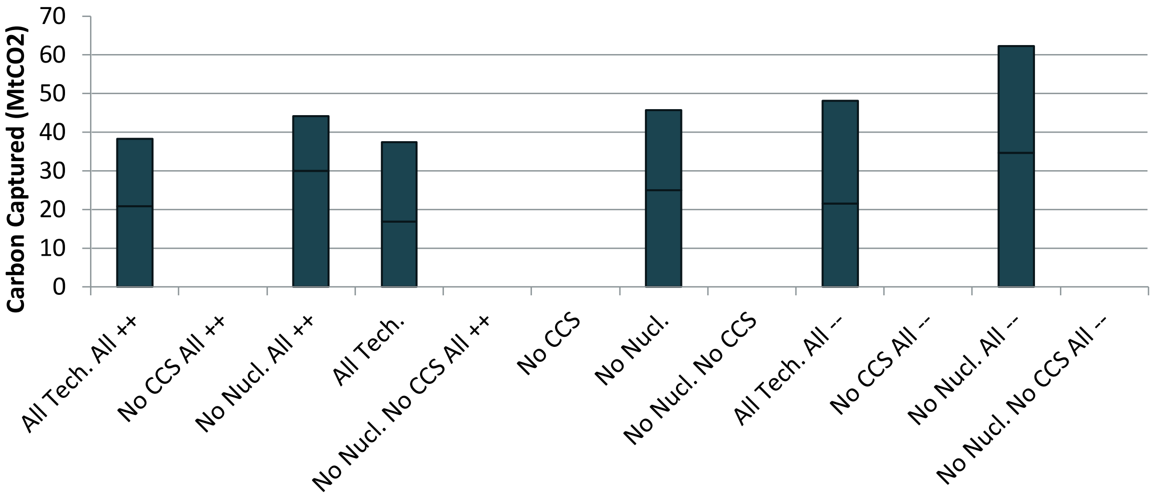

FIGURE 40.

Annual CO_2 captured and sequestered for the German power system in 2050 and main scenarios.

The model expands both greenfield combined-cycle gas CCS and retrofitted Gas CC with CCS which rely on infrastructure for transmission and storage of CO_2. FIGURE 40 depicts the annual CO_2 captured and sequestered of these Gas CCS power plants in the model for 2050 and weather year 1991. With the inclusion of trade, we arguably see a limited variation of the CCS utilisation in the scenarios where it is allowed. Most scenarios arrive at a level of annual CO_2 captured of 40 Mt which is slightly below 68 Mt feasible within the CO_2 targets (captured carbon is directly linked to direct emissions) in the *All Tech.* scenario. The largest deviation is seen for *No Nucl. All --* reaching beyond 60 Mt carbon captured and sequestered per year. Note that CO_2 pipeline and storage infrastructure has been included as a variable cost to the German power system.

5.8 Capacity market

FIGURE 41 illustrates the difference in the resulting German power system with the inclusion of a 10% capacity reserve margin constraint for the technology-inclusive pathway in the *All Tech.* scenario. Three key observations should be highlighted. First, in 2030 and 2035, when permitted, coal power plants are used as a capacity reserve, providing significant standby capacity. Second, an additional 20 GW of firm or dispatchable capacity is constructed compared to the *All Tech.* scenario. Thirdly, the capacity reserve drives up the system costs across the model horizon with around 25 B€. This additional cost is negligible in the context of the total system costs hovering at 1500 B€ and above. These findings are consistent across other technology pathways, such as *No Nucl, No CCS*, and *No Nucl. No CCS*.

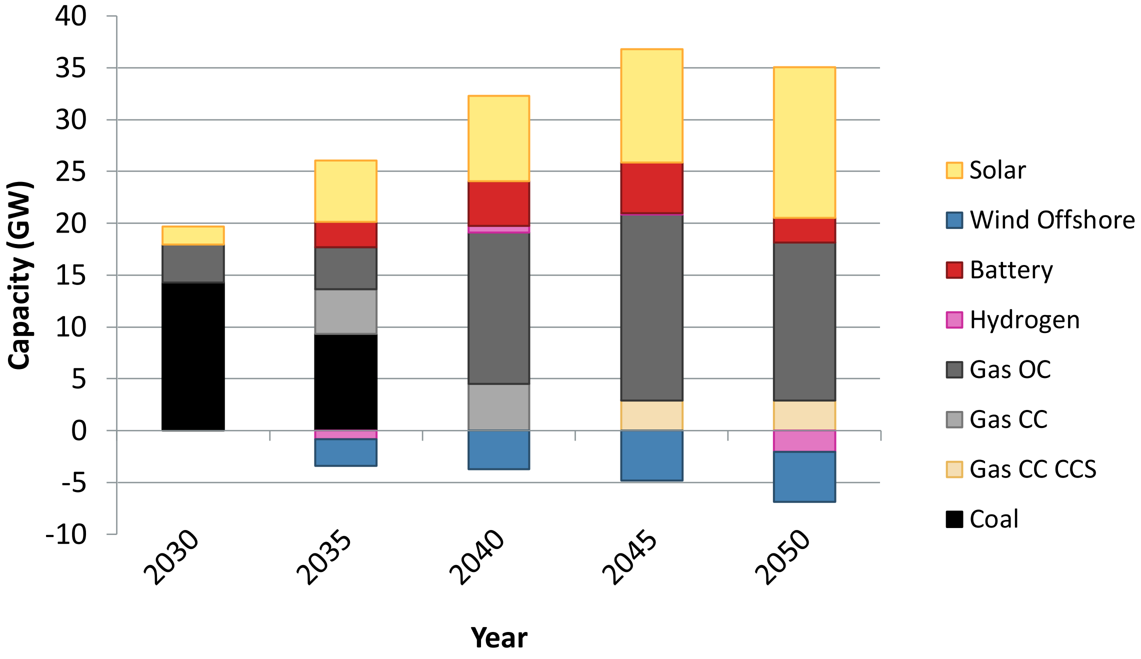

FIGURE 41.

Difference in installed capacity by technology for the German power system across the model time horizon with the inclusion of a capacity market, i.e., the difference between scenarios *Capacity Market* and *All Tech.*. Negative numbers thus represent an exceeding capacity for a certain technology in the *All Tech.* vs the *Capacity Market* scenario.

In 2050 the additional capacity in the *All Tech.* scenario is primarily comprising Gas OC, contributing approximately +15 GW, followed by Gas CCS with +3 GW. A few GW of Wind Offshore and Hydrogen power plants are removed which may be explained by their limited value to the system at the most extreme hours of scarce supply.

This study does not explore the expansion of open-cycle biogas power plants. However, it is evident that Biogas OC could potentially replace the reserve capacity of Gas OC, as long as its generation stays within sustainable consumption limits for biogas fuel. In the scenario where fossil fuel power plants with significant CO_2 emissions not being allowed in the capacity reserve, bio-based power plants—using biomass and biogas—become a likely combination to replace open-cycle gas turbines.

In conclusion, a 10% capacity margin has several effects: In the short term, particularly in 2030 and 2035, coal power plants can serve as significant standby capacity under certain conditions. To meet the requirements of the capacity market compared to the All Tech. scenario, an increase of 20 GW in firm or dispatchable capacity is necessary. Although this capacity reserve increases system costs by 25 billion euros, this amount is a small fraction of the total system costs, which are significantly higher. By 2050, the energy system shifts towards more Gas OC and Gas CCS capacities, with a reduction in Wind Offshore and Hydrogen plants. Biogas OC presents a sustainable alternative for reserve capacity, aligning with future scenarios that limit CO_2 emissions from fossil fuels. Incorporating biogas OC plants into Germany's Power Plant Strategy for reserve capacities will likely necessitate changes to the biomass strategy. These changes would include providing financial incentives and support, promoting integration with other renewables, and developing certification programs. Such adjustments would ensure that biogas OC plants can effectively contribute to a sustainable and reliable energy future for Germany. Additionally, maintaining a 10% capacity margin, particularly during years with unfavourable weather conditions, is essential to ensure a stable and resilient German power system.

5.9 Firm power

The simulation results from this study demonstrate that mature technologies like wind and solar are projected to surpass 50% of the generation mix in the 2050 German power system. While firm power is expected to complement variable renewable energy, its implementation varies depending on the technology pathway considered and may be influenced by uncertainties and factors such as technology readiness and required infrastructure implementation. This section delves into a discussion to further elucidate the role of firm power technologies in a decarbonised German power system.

5.9.1 Nuclear

Nuclear power, like wind and solar, is a proven technology. Our study's numerous scenarios demonstrate a robust role for nuclear power, with an installed capacity of 30 GW limited only by our assumed build rate. If constraints on build rates are removed, nuclear expansion could approach 100 GW as shown with relaxed limits in SECTION 5.3, effectively demonstrating its competitiveness based on our reference cost projections. Even with conservative cost projections, nuclear is still expanded until its allowed maximum. This indicates that nuclear remains competitive and valuable to the German power system, even when assuming investment costs not benefiting from serial production, suggesting that the European nuclear industry has not fully exploited the learning opportunities faced with recent challenges.

Notably, nuclear power maintains a high and steady utilisation, with simulated capacity factors around 80% across various scenarios and future model years, both with and without trade. This consistency further underscores the robustness of investments in nuclear power.

5.9.2 Hydrogen for power generation

Hydrogen production and storage for power generation, referred to simply as Hydrogen in the figures, features in most of the scenarios modelled in this study. This is somewhat unexpected given its low round-trip efficiency and very high LCOE among potential firm technologies, as shown in TABLE 11. Understanding what assumptions result in hydrogen being built in the model is crucial to understanding about whether it may have real-world applicability.

From a systemic perspective, storage technologies like hydrogen are complementary to the expansion of variable renewable energy sources. They provide the capability to absorb excess electricity when it's cheap and discharge electricity when renewable generation is low. Given hydrogen's substantial potential for long-term energy storage capacity, assuming the related infrastructure to transport and store hydrogen is built, it is particularly well-suited to accommodate the large-scale expansion of wind energy in the German power system, which typically varies with weather patterns over weeks.

Despite this capability to help balance renewables, the costs of deploying hydrogen are high. The cost of hydrogen production from excess power generation is presented in FIGURE 42 along with derived LCOE for the hydrogen power plants excluding trade with neighbouring regions. It is calculated by summing all annual costs and normalising them with the annual production of hydrogen. These costs align with the range of 3-7 €/kgH2 shown in Table 11, corresponding to LCOE values between 200 and 360 €/MWh as can be observed in the figure. Considering the capacity factors of the hydrogen turbines, for instance, the *All Tech.* scenario operates at 15%, while the *No Nucl. No CCS* scenario runs at 10%. A utilisation of the electrolysers generally between 30% and 40% is seen. This low utilisation of infrastructure is one important driver for the high costs exhibited. The observed LCOE values are competitive with Gas OC, hydrogen's primary competitor, given a considerable CO_2 price, as evidenced in TABLE 11 (here 160 €/tCO_2).

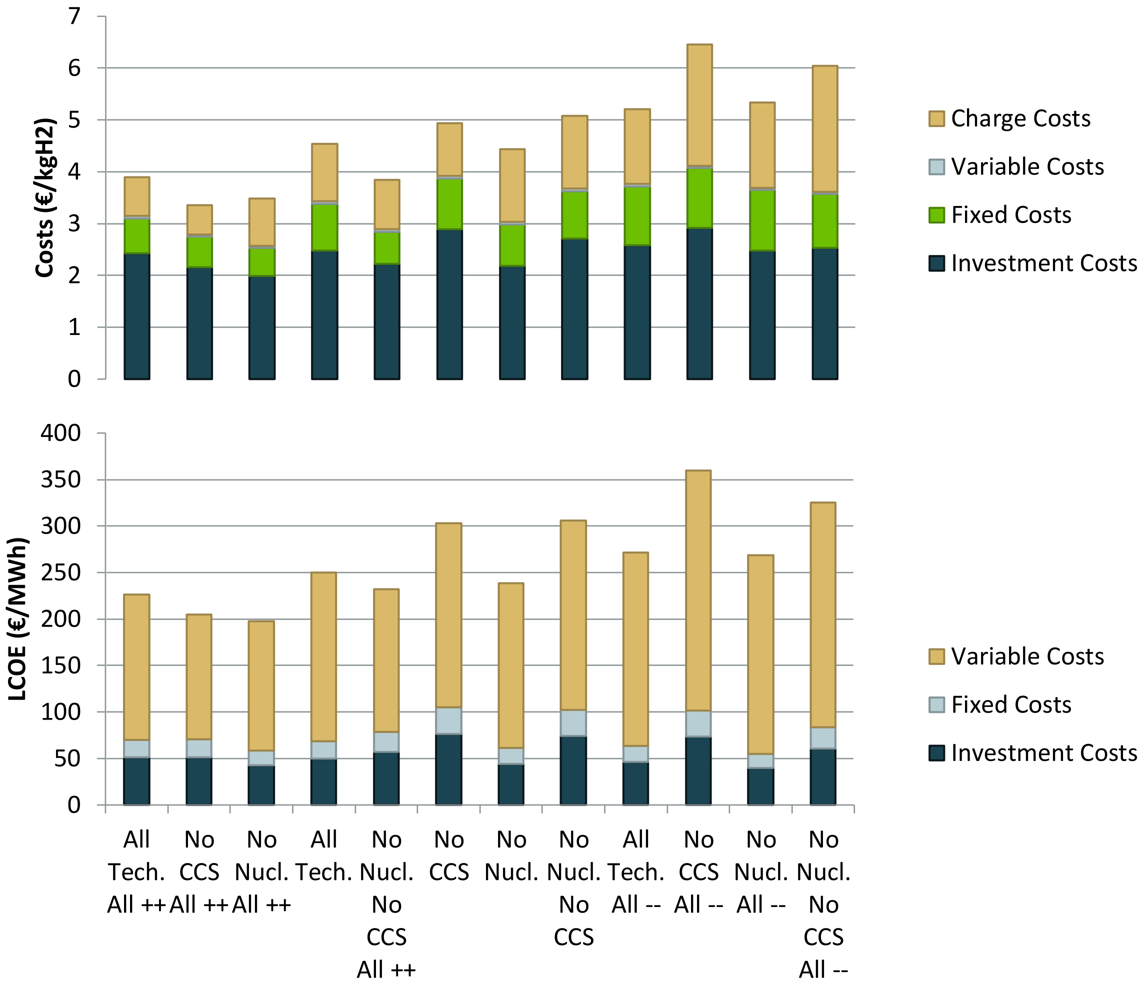

FIGURE 42.

Cost of hydrogen purely for power generation (top panel) and calculated LCOE for hydrogen combined-cycle power plants (bottom panel) in 2050 without trade with neighbouring regions.

In comparison to hydrogen power generation cost, the LCOE for both Gas CCS and nuclear power at 95 €/MWh and 62 €/MWh in 2050, respectively, are significantly lower. Therefore, the major factor driving hydrogen capacity expansion in the model is the assumed limited availability of cheaper firm capacity from nuclear and both abated and unabated gas. These limitations are assumed based on a reasonable attempt to estimate the future build rates of alternative firm technologies and stringent CO_2 emission targets that force significant amounts of renewables in the model. When the model is constrained from building nuclear and Gas CCS in the near-term, the model's only option is to maximise renewable build and resorts to hydrogen storage and generation as the last option to ensure sufficient power supply to meet demand. The sensitivity runs with relaxed build rates and CO_2 targets in SECTION 5.3 further corroborate this reasoning.

As such, the amount of hydrogen built in this model is an artifact of the assumptions and the methods. The modelling approach prioritises energy resilience and minimises import dependence in the power system design. If greater electricity trade were permitted, firm capacity could be imported outside Germany during periods of power system stress as a likely cheaper alternative to expanding hydrogen for power generation in Germany. Under the current modelling constraints, however, hydrogen for power must be included to maintain system reliability and energy adequacy. With the inclusion of trade, the capacity factors of the hydrogen gas turbines are roughly halved in the *All Tech.* and *No Nucl. No CCS* scenarios. This suggests a potential lack of synergy between hydrogen for power generation and energy resilience.

For the current context, no hydrogen fuel imports were considered but merely locally produced *green hydrogen* were allowed in the modelling. Current estimated costs of *blue hydrogen* lie in the range 2.9-

3.7 €/kgH2[157] ending up at the low end of the model-determined costs in FIGURE 42. These cost levels, though potentially lower, arguably carry similar conclusions due to expected LCOE for gas turbines running on the hydrogen to come out considerably larger than the competition. It is furthermore questionable that strong emission benefits can be considered when incorporating upstream emissions. In the end, nuclear and Gas CCS provides more competitive options still.

Germany presents a promising geographic region for establishing a robust hydrogen infrastructure for transmission and storage, bolstered by its ambitious plan for a hydrogen core network to be "fully operational by 2032." However, significant uncertainties accompany its potential implementation. These plans face numerous barriers and challenges, particularly due to the world's relatively low experience in transporting and storing hydrogen at the necessary scale. Additionally, using existing infrastructure poses challenges due to hydrogen's different properties compared to natural gas, such as its considerably lower heating point, lower density (both gaseous and liquid), and lower energy density.

In summary, although the modelling results indicate a role for hydrogen-fuelled power plants, they should be considered a last resort for providing additional firm power to the German power system due to their high costs and significant infrastructure requirements. If implemented, it should be done on a limited scale and preferably in synergy with industrial demand for hydrogen and associated demand-side flexibility.

5.9.3 Gas CCS

The results from this study, focusing on the *All Tech.* decarbonisation pathway underscore a considerable role for Gas CCS in the future German power system. This is attributed to the technology's ability to provide valuable dispatchable capacity while remaining competitive in terms of costs. However, the model's increasing CO_2 prices, designed to meet specific targets, raise the levelised cost of electricity (LCOE) for Gas CCS, effectively limiting its expansion to a maximum annual generation of around 170 TWh. For instance, in the *All Tech.* scenario in 2050 the model determines a CO_2 price of 350 €/tCO_2.

Notably, the electricity market capture price[158] for Gas CCS in 2045 settle at approximately to 140 €/MWh in the *All Tech.* scenario compared to 104 €/MWh LCOE as presented in TABLE 10. A higher CO_2 price in the *All Tech.* scenario contributes to this discrepancy but a different average capacity factors of actual operations serve as another key explanation. The simulated average capacity factor for Gas CCS is around 40% in the *All Tech.* scenario.

This relatively low capacity factor of about 40% for Gas CCS deserves additional attention. It suggests that these power plants operate quite flexibly, potentially leading to higher emissions unless additional mitigation measures, like those described in SECTION 4.4.6, are implemented. To assess the impact on the German power system, a simulation was conducted where the capture efficiency of Gas CCS plants was reduced from 95% to 90%. This reduction in efficiency caused Gas CCS to become uncompetitive in the 2040s largely due to the set CO_2 emission targets, with expansion ceasing by 2040 and capacity factors dropping below 40% for existing plants. This outcome underscores the importance of achieving a 95% capture efficiency or higher for Gas CCS to best support deep decarbonisation. Further research could explore the impact of start-up and shut-down cycles on the flexible operation of these power plants, potentially using v0.4 of the GenX tool, which models their operations with increased detail[159].

There are uncertainties that must be considered regarding the development and potential role of Gas CCS. Firstly, it is relevant to acknowledge that Gas CCS has not yet reached commercial utility-scale implementation. As previously mentioned, capture efficiency will be a key determinant in whether this

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[157] GEP (2023), Outlook for Green and Blue Hydrogen Market.
[158] Capture price is defined as the revenue captured by the indicated technology per unit of energy generation. It is calculated by dividing the overall income of the technology by the total generation in the specified time period.
[159] GitHub (n.d.), GenXProject.

technology can play a major role in deep decarbonisation. While there are measures to reduce indirect emissions associated with natural gas, these need to be rigorously applied to ensure the technology's sustainability. Considerable uncertainty surrounds future natural gas prices, which are intricately linked to both the expenses associated with fees for CO_2 transport and storage and the finite supply of fossil fuels. These factors collectively have the potential to exert a substantial influence on the competitiveness of Gas CCS.

Considering the clear role of Gas CCS across range of scenarios explored in this study, it is realistic to target the deployment of new Gas CCS power plants with an installed capacity of at least 15 GW in the long term. Even assuming a 90% capture efficiency, this would leave 3.6 Mt of annual uncaptured emissions - still aligning with the 2050 emissions target - and requiring the capture sequestration of 35 Mt of CO_2 annually[160]. In the near term, maximising the deployment of Gas CCS within the capacity of implemented CO_2 transmission and storage infrastructure presents a significant opportunity to mitigate emissions while maintaining firm capacity on the German grid. Leveraging the advantages of retrofitting existing brownfield gas power plant sites should be prioritised.

5.9.4 Biopower and BECCS

Given the potential challenges, it is reasonable to consider alternative clean energy technologies. Although the current study does not explore the expansion potential of biopower, with an LCOE of around 130 €/MWh, based on QC analysis, the results suggest that biomass thermal power plants may provide valuable additional dispatchable power within the limits of sustainable biomass fuel consumption.

Furthermore, BECCS is a technology that was not included in the current modelling study. The potential advantages that come with negative emissions would allow for more direct emissions (e.g., larger deployment of firm Gas CCS capacity) which could be countered with BECCS. As such, calculations were pursued to evaluate their potential role in the decarbonisation of the German power system.

With a CO_2 capture rate of -551 $kgCO_2$/MWh[161], 20 TWh of electricity from 4 GW of BECCS capacity operating at an average capacity factor of 60% could offset 11 Mt of CO_2 annually. The effect of CCS on the efficiency of the power plants have not been accounted for in these calculations. From a pure electricity market perspective, BECCS could see a competitive LCOE of around 100 €/MWh given a price of negative emissions at 100 €/tCO_2 otherwise potentially struggling at levels around 160 €/MWh.

It is relevant to recognise that there are uncertainties regarding the extent to which BECCS can contribute to negative emissions. First of all, the assumed capture rate of -551 $kgCO_2$/MWh[162] is intended to represent Europe-wide conditions, but it may not accurately reflect German-specific conditions in the 2040s or the actual capture efficiency achieved for the plants. In general, a comprehensive lifecycle assessment is necessary for bio-based resources to ensure that the supply of biomass fuel is sustainable[163]. Finally, BECCS faces similar challenges with CCS infrastructure and technology readiness as Gas CCS.

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160 Capacity factor of 60% assumed.
161 Applied Energy (2021), Tightening EU ETS targets in line with the European Green Deal.
162 Applied Energy (2021), Tightening EU ETS targets in line with the European Green Deal.
163 Potsdam Institute for Climate Impact Research (2023), Worse than Diesel and Gasoline? Bioenergy as Bad as Fossils if There is No Pricing of CO_2 Emissions from Land-use Change.

5.10 Long-duration energy storage

The current section presents the results of the additional scenarios run including the option for the model to expand capacity of four archetype long-duration energy storage (LDES) technologies as introduced in SECTION 4.10. Starting with FIGURE 43 the result of the capacity expansion is shown for the *Base+LDES* scenario compared to the *Base* scenario.

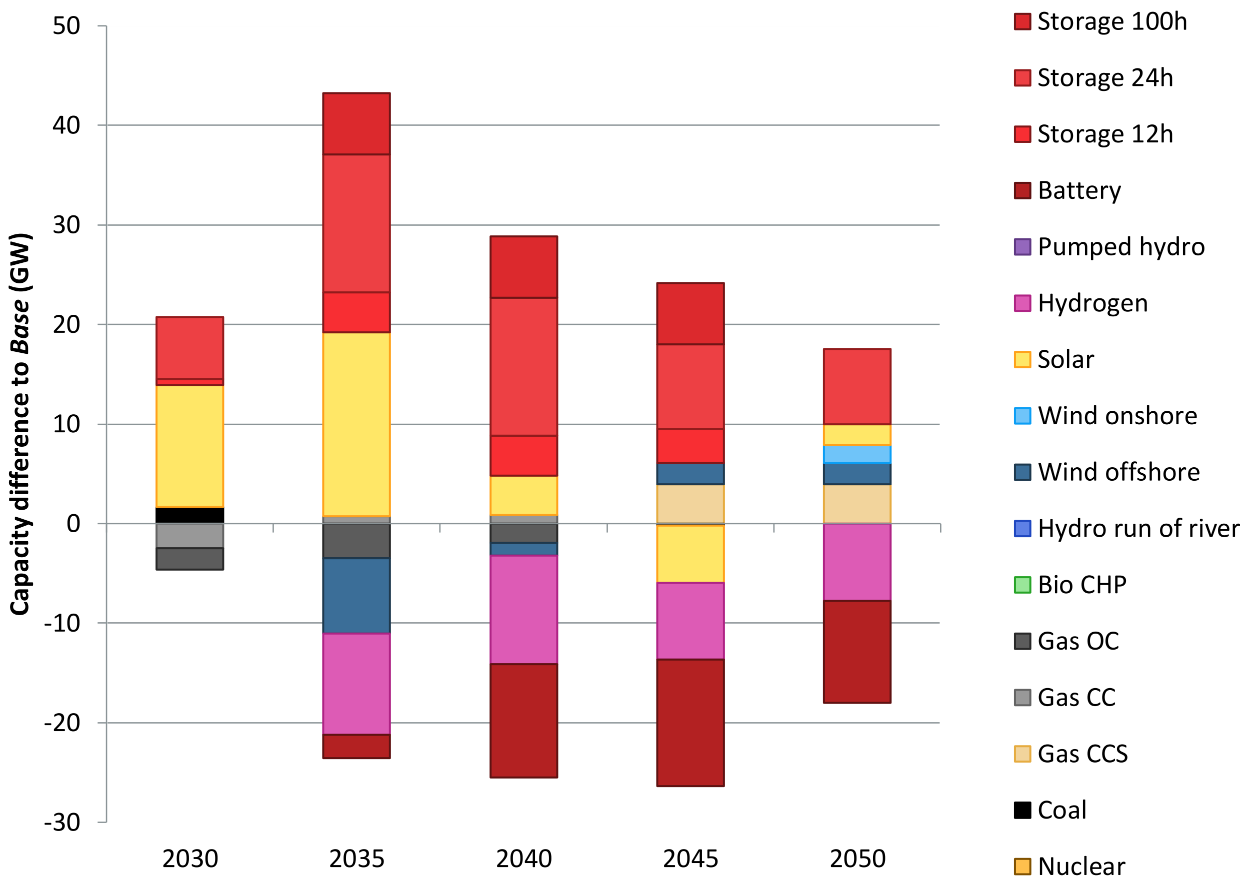

FIGURE 43.

Difference in installed capacity between the *Base+LDES* and the *Base* scenario by model year and split by technology.

The results demonstrate a role for LDES technologies, particularly in 2035, where the model indicates an aggregated installed capacity of 24 GW. FIGURE 43 reveals that this expansion in 2035 is accompanied by an additional 19 GW of solar capacity. However, this increase is offset by reductions in other technologies, notably offshore wind (-8 GW) and hydrogen power plants (-10 GW). Moreover, a considerable installed capacity of open-cycle natural gas fuelled power plants (Gas OC) is replaced (3 GW in 2035) with the flexibility provided by the combination of low-emission LDES and solar technologies.

By 2045, under climate neutrality conditions, the installed capacity of LDES technologies declines. End-of-life (15 years assumed) is the primary reason for retirement. Purely based on the scenarios run in the current study, these results reflect a potentially diminished role for these systems as the energy system transitions toward deep decarbonisation. This shift suggests that other technologies are increasingly able to fulfil balancing and flexibility needs more cost-effectively. Among these, Gas CCS emerges as a key competitor to LDES, particularly as constraints on build rates in 2035 create opportunities for LDES expansion. Most notably, even in the long term, there is a shift from battery storage, which typically provides a duration of around 5 hours, to 24-hour LDES being the only cost effective LDES technology in 2050. The latter proves more valuable to the system due to its ability to more effectively address diurnal variations and capitalise on price volatility through energy arbitrage.

This advantage is particularly pronounced because the current modelling does not account for the balancing services provided by battery storage in shorter-term markets.

Additionally, the steadily increasing flexibility of demand-side resources, particularly on diurnal timescales, further reduces the reliance on LDES technologies. Similar trends are observed across other scenarios, including *No Nucl. LDES*, *No CCS+LDES*, and *No Nucl., No CCS+LDES*. It is worth noting that hydrogen storage and hydrogen-based power generation remain a necessary ingredient in the simulated decarbonised German power system, serving as the primary solution for balancing week-long variations in wind energy production.

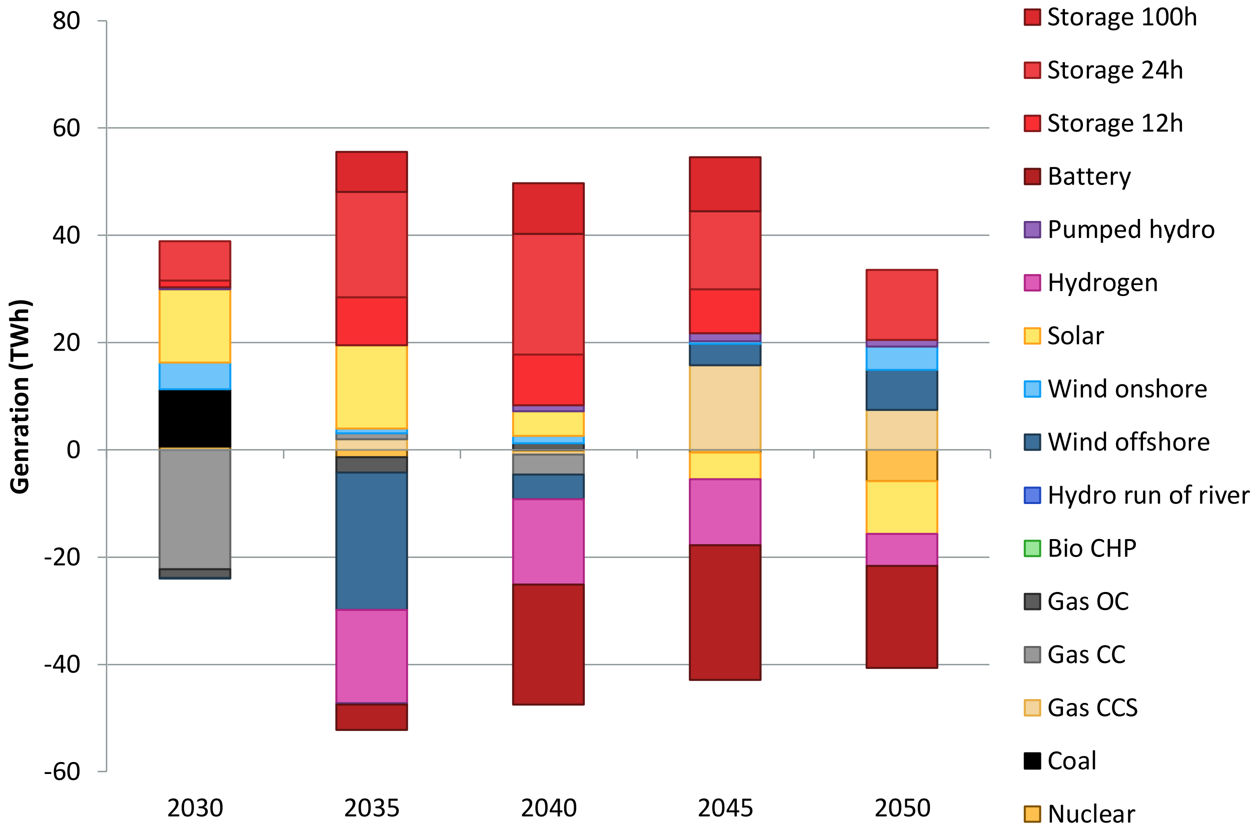

FIGURE 44.

Difference in annual generation between the *Base+LDES* and the *Base* scenario by model year and split by technology.

FIGURE 44 complements FIGURE 43 with a view of the annual generation instead of the installed capacity for the *Base+LDES* scenario. While many aspects are consistent with the capacity results, two notable differences emerge.

First, a significant reduction in natural gas generation is observed in 2030. While this reduction offers potential emissions benefits, it is offset by the continued reliance on coal power plants in the German power system. However, coal power plants are less flexible compared to Gas CC, underscoring the role of LDES technologies in reducing dependence on natural gas while mitigating exposure to price volatility and enhancing energy security. Moreover, LDES technologies provide critical clean and flexible capabilities needed to support the energy transition. From 2035 onwards, as CO2 targets become more stringent, the role of LDES technologies shifts. Rather than offsetting natural gas, they increasingly replace a less cost-effective combination of offshore wind and hydrogen power plants, further optimising system flexibility and cost-effectiveness under tighter decarbonisation constraints.

Second, a significant difference may be seen in 2045 and 2050, where higher levels of generation are observed, particularly from Gas CCS, as well as from onshore and offshore wind. As discussed in other parts of the results section, the expansion of Gas CCS is constrained by emissions targets. These same targets apply here; however, Gas CCS power plants in this scenario benefit from reduced start-up and shut-down cycling. This operational stability minimises the additional emissions associated with the start-up process, where extra fuel is burned. By enabling smoother and more continuous operation of Gas CCS power plants, LDES technologies play a role in limiting emissions—an aspect also discussed in SECTION 5.9.3. Moreover, the enhanced role of the Gas CCS combined with the LDES in the *Base+LDES* scenario facilitates a symbiotic relationship with onshore and offshore wind with a greater expansion as a result.

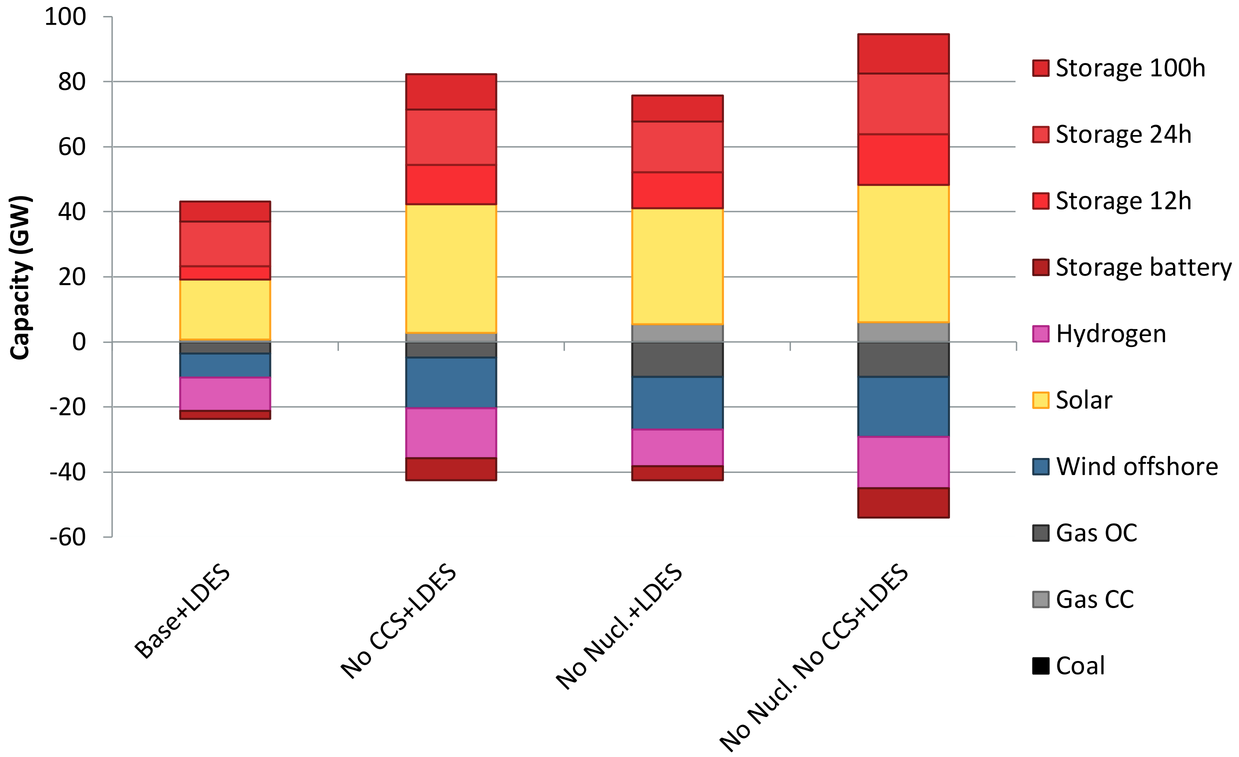

FIGURE 45.

Difference in installed capacity between the *LDES* and their corresponding scenario without LDES for model year 2035 split by technology.

To further explore the role of LDES technologies, FIGURE 46 illustrates their impact across all scenarios. In the *Base+LDES* scenario, the restart of existing nuclear reactors adds 8 GW of nuclear capacity, alongside 12 GW of Gas CCS. These additions result in a relatively smaller but still significant expansion of LDES technologies, totaling 24 GW in the *Base+LDES* scenario. However, when nuclear and/or CCS technologies are restricted, the cost-effectiveness of LDES deployment increases substantially, with capacity rising to 35–46 GW. This expansion is symbiotic with a significant growth in solar capacity, ranging from 19 GW to 42 GW, and is accompanied by a stronger reduction in peaking plants, including both open-cycle natural gas plants and hydrogen power plants, as well as offshore wind capacity.
In a short-term perspective, these results highlight the following impact of LDES technologies to the German power system aiding its transition to climate neutrality:

- **Enabling Larger Solar Expansion:** LDES facilitates substantial growth in solar capacity, ranging from an additional 19 GW in the *Base+LDES* scenario to as much as 42 GW in the *No Nucl. No CCS+LDES* scenario.

- **Delaying Offshore Wind Deployment:** In the *Base+LDES* scenario, the deployment of LDES postpones new offshore wind farm installations from 2035 to 2040. In other scenarios, LDES offsets approximately 10 GW of offshore wind capacity in 2035. This delay aligns more effectively with offshore wind issues related to cost increases and supply chain constraints experienced in present day, providing a more practical and achievable timeline for scaling up installations.

- **Reducing Hydrogen Dependence:** In synergy with the reduction in offshore wind deployment, LDES significantly reduces reliance on hydrogen for power generation. This is a relevant outcome, given the large challenges associated with hydrogen power as highlighted in SECTION 5.9.2. Rather than offsetting natural gas, they increasingly replace a less cost-effective combination of offshore wind and hydrogen power plants as well as high-cost open-cycle gas power plants, further optimising system flexibility and cost-effectiveness under tighter decarbonisation constraints
- **Hedging Against Demand-Side Uncertainty:** Investing in LDES technologies provides a hedge against the risk of demand-side flexibility not materialising. The 24-hour LDES duration is particularly well-suited to address the flexibility requirements of electric vehicles, space heating, and residential and tertiary energy demands.

In conclusion, while uncertainties remain regarding the technology readiness and scalability of LDES technologies, the results of this study underscore their potential value in enabling flexibility in the decarbonisation of the German power system. The demonstrated benefits—ranging from supporting larger solar expansions to reducing reliance on offshore wind, hydrogen, and natural gas power plants—highlight the strategic importance of pursuing investments in LDES. By addressing both diurnal and multi-day balancing needs, LDES technologies could play a role in achieving climate neutrality, provided continued innovation and targeted support accelerate their development and deployment.

5.11 Comparison with other studies

We compare the results of our study in the scenarios *All Tech.* and *No Nucl. No CCS* with the findings of related studies, which were introduced in SECTION 2.3.

The scenarios and included models of the comparison studies are:

- Ariadne, Auf dem Weg zur Klimaneutralität 2045 (On the Way to Climate Neutrality 2045), Models REMIND-EU v1.1 & REMod v1.0, scenario 8Gt_Bal_v3[164]
- Agora, Klimaneutrales Deutschland 2045 (Climate-Neutral Germany by 2045)[165]
- BDI (2021), KLIMAPFADE 2.0 (Climate Paths 2.0)[166]
- dena (2021), dena-Leitstudie Aufbruch Klimaneutralität (dena Pilot Study on the Rise of Climate Neutrality), scenario KN100[167]
- BMWK (2021), Langfristzenarien für die Transformation des Energiesystems in Deutschland (Long-Term Scenarios for the Transformation of the Energy System in Germany), scenario T45[168]
- Ember (2022), New Generation - Building a clean European electricity system by 2035, scenario stated policy[169]
- Carbon-Free Europe (2023), Annual Decarbonisation Perspective 2023, scenario core[170]

There are significant differences between the installed capacities in the year 2045 between the studies as depicted in the following figures. FIGURE 46 shows installed renewable capacities by 2030 and 2045. All studies show a strong expansion of renewables solar PV and wind onshore as well as offshore between 2030 and 2045. Overall, renewable generation capacities are projected to range from approximately 400 to 800 GW. This variance can be attributed to differences in projected demand by then. However, our *All Tech.* scenario exhibits the smallest growth of solar PV and offshore wind capacities among all investigated scenarios. This may be attributed to the inclusion of nuclear power, which provides considerable baseload capabilities. The scenario excluding nuclear power and CCS aligns closely with most studies we reviewed, likely due to similar policy choices. However, this scenario might diverge from recent changes in German legislation, where CCS was previously prohibited, but the government intends to allow it under new regulations[171]. Therefore, it is useful to compare one scenario with CCS and one without.

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164 Ariadne (2024), Scenario File v1.3.
165 Agora (2021), Klimaneutrales Deutschland 2045, Data Appendix
166 BDI (2021), KLIMAPFADE 2.0, Figure 8
167 dena (2021), Aufbruch Klimaneutralität, Table 2
168 Fraunhofer ISI (2021), Enertile Scenario Explorer
169 Ember (2022), New Generation, Raw Data File
170 Carbon-Free Europe (2023), Country Specific Results – Germany
171 BMWK - Bundesministerium für Wirtschaft und Klimaschutz (2024), Entwurf eines Ersten Gesetzes zur Änderung des Kohlendioxid Speicherungsgesetzes.

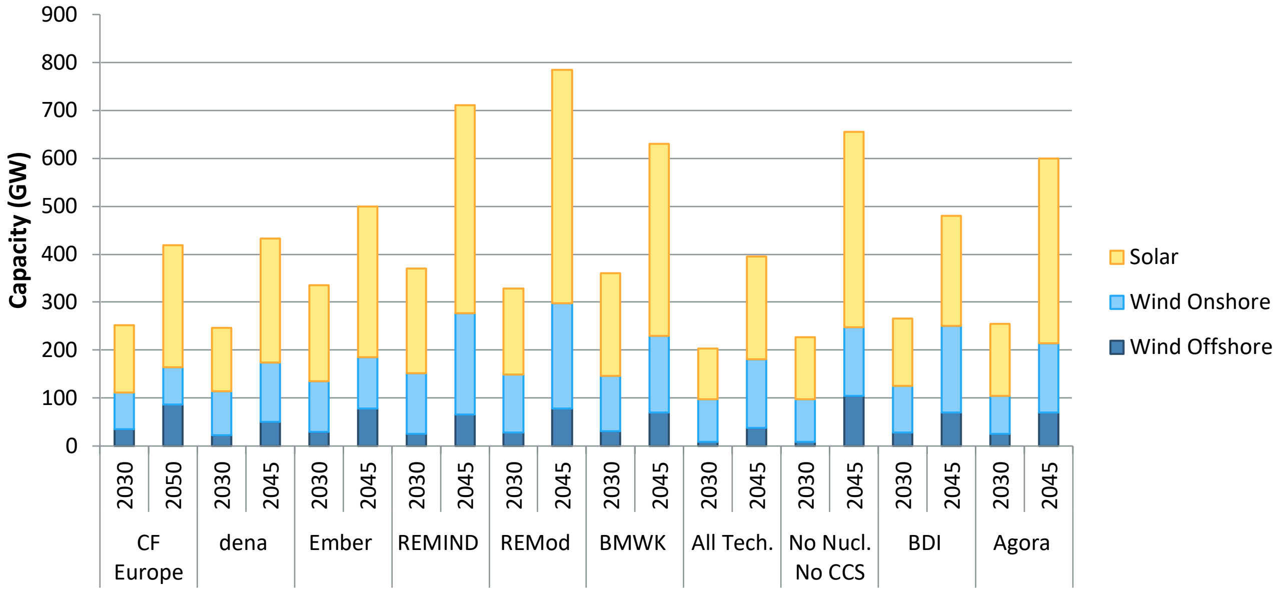

FIGURE 46.

Installed renewable generation capacities in the compared studies by 2030 and 2045 in ascending order of electricity demand in 2045.

The availability of dispatchable generation capacities is shown in FIGURE 47. Roughly half of the scenarios have already phased out coal by 2030, while gas is anticipated to form the backbone of flexible generation by 2045. By 2045, dispatchable generation capacities comprise around one sixth to one quarter of renewable generation capacities. It should be noted that *not* every scenario distinguishes between gas and hydrogen-based generation in its categorisation, although most generation capacity by 2050 is either gas with CCS or hydrogen. Furthermore, in all scenarios, bioenergy plays a negligible role, with the REMIND scenario being the only one approaching to 20 GW of bioenergy capacity. This aligns with the German government's energy policy, which emphasises the material utilisation of biomass over its use for energy production. The policy advocates for the carbon in biomass to be sequestered in long-lasting products rather than being quickly released back into the atmosphere through combustion for heat or electricity. Therefore, the limited capacity for bioenergy in the scenarios reflects a strategic decision to favour long-term carbon storage and prioritize other forms of renewable energy that are consistent with national climate protection goals.

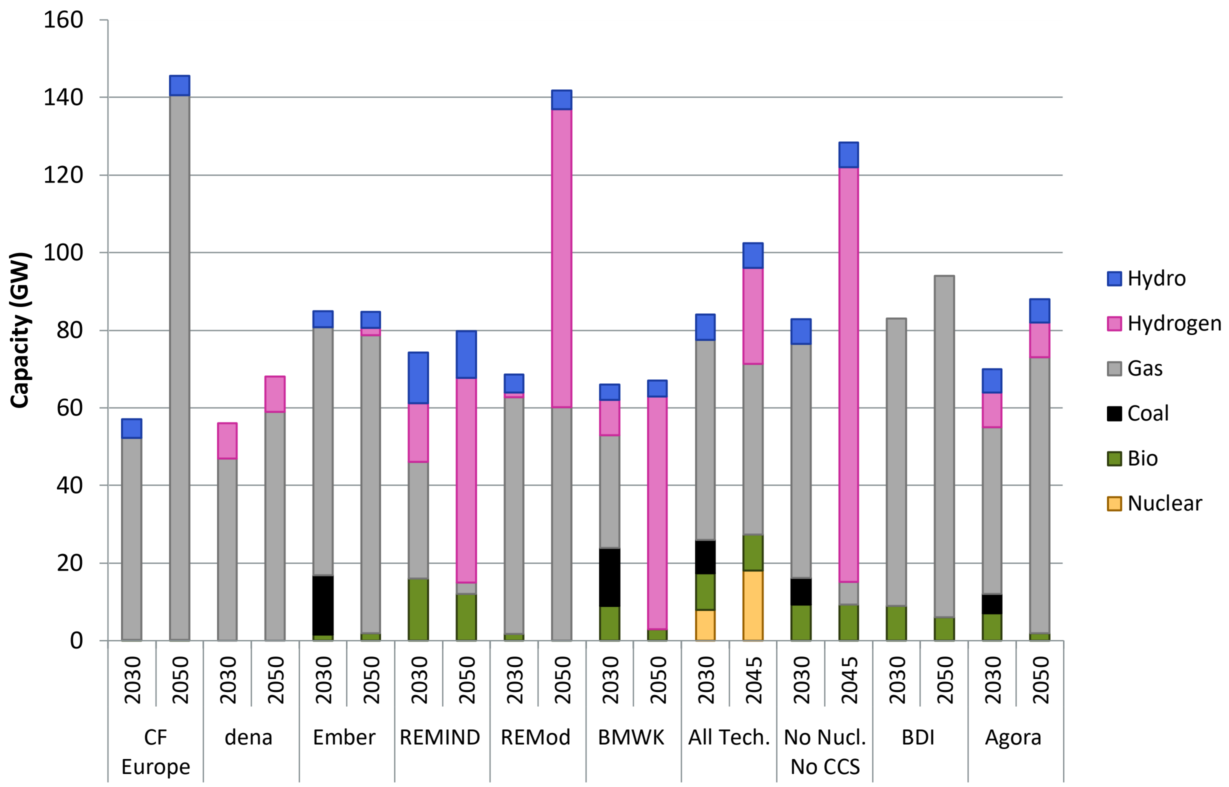

FIGURE 47.

Installed dispatchable generation capacities in the compared studies by 2030 & 2045 in ascending order of electricity demand in 2045.

Differences in renewable generation capacities are linked to differences in the modelling chain. The capacity factor, which measures the actual electricity output relative to the potential output of a technology, plays a crucial role in determining the necessity and cost-effectiveness of renewable energy capacities. When the capacity factor of wind turbines is high, meaning that wind conditions are consistently favourable, fewer turbines are needed to generate a set amount of electricity. This directly impacts the total installed capacity: the less reliable the wind resource, the more installed capacity is needed. However, the assumed investment and operational costs also play a role.

There are significant differences in capacity factors between the studies with offshore capacity factors varying by more than 10 percentage points, indicating meaningful impacts on the deployed generation capacities. For example, Agora, has relatively small onshore wind capacity factors, resulting in a relatively small ratio of onshore wind to solar PV. FIGURE 48 presents the projected capacity factors for onshore and offshore wind in 2030 and 2045 across different models. While the capacity factors for onshore wind are relatively consistent across models and exhibit an upward trend, increasing by up to 5 percentage points due to taller hub heights, offshore wind experiences more variability.

Our model predicts that the capacity factors for offshore wind are 5 to over 10 percentage points lower than those predicted by other models. This discrepancy in capacity factors results in other models predicting a significantly larger share of offshore wind within the wind category, especially when compared to our All Tech. scenario. It is important to note that these output capacity factors may vary significantly from input capacity factors due to factors such as curtailment in the dispatch model. For our study, input capacity factors for offshore wind are 41% (see Table 11).

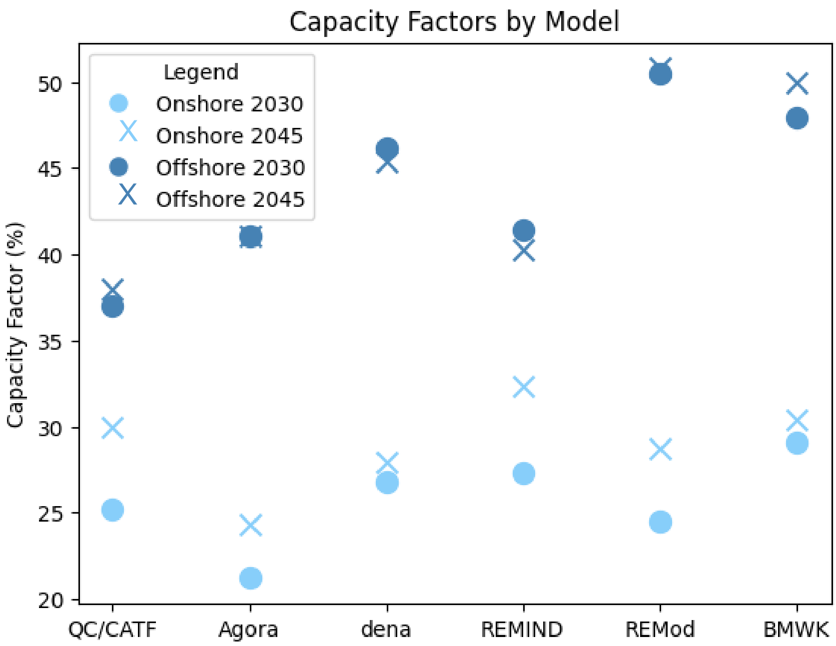

FIGURE 48.

Capacity factors by model for wind onshore and offshore in the years 2030 and 2045.

6 Summary

This study delves into various technology pathways aimed at achieving a decarbonised German energy system by the year 2050 defined by a 99% reduction of power system emissions compared to 1990 levels. Using a meticulously crafted set of scenarios, which encompass custom GIS analysis for wind and solar expansion potential alongside grounded assumptions for demand-side flexibility, this analysis scrutinizes over 60 scenarios in total. These scenarios variances in projections concerning technology-relevant advancements, ranging from optimistic outlooks to more conservative perspectives on factors like investment and operational costs, commodity prices, maximum expansion potential for onshore wind, and the pace of decarbonisation.

The study employs a dedicated multi-year capacity expansion optimisation framework with first stop in 2030 and then with five-year increments until 2050. The methodology emphasises a robust integration of investment and dispatch optimisation. Notably, the expansion is interrogated on a comprehensive set of 33 historical weather years. With an emphasis on energy resilience, this approach ensures both the construction of reliable power systems with limited import dependency but also realistic dispatch schedules and electricity prices. Ultimately, the current study aims to lay the groundwork for determining the most sustainable and competitive type of power system to guide the future of the German power landscape.

The cornerstone of energy system decarbonisation is electrification, leading to an inevitable growth in electricity demand. This study employs a single demand scenario that reflects an average increase in electricity consumption compared to other sources[172]. Focusing on the production side, our modelling approach is anchored in Germany's steadfast commitment to transitioning towards a decarbonised economy. Accordingly, the simulated scenarios follow a decarbonisation pathway driven by ambitious CO_2 emission targets[173] reflecting a power sector leading the way to climate neutrality.

6.1 Technology pathways

At the heart of the Energiewende is the deployment of renewable energy sources, accompanied by the phase-out of fossil fuels and nuclear power, aimed at transitioning the German power system to climate neutrality as mandated by the Climate Change Act[174]. This energy policy, which does not adopt a technology-neutral approach, was scrutinized in the current study through the adoption of four technology pathways: *All Tech., No CCS, No Nucl.* and *No Nucl. No CCS* as described in TABLE 15.

[172] Outlined in Section 4.2.1
[173] Detailed in Section 4.1.
[174] Die Bundesregierung (2021), Intergenerational Contract for the Climate.

TABLE 15.

Technology pathway scenarios considered in the current study accompanied with their background stories.

SCENARIO NAME	STORYLINE
All Tech.	Pathway embracing all supply technologies with reference input assumptions on simulation parameters. No local opposition and NIMBY are considered. Restart of recently shutdown reactors gains political support. Groundwork is being laid for the construction of new nuclear power with the expectation that the first new plants may come online beyond the year 2040. Infrastructure development is underway such that captured CO_2 from fossil power plants can be transported and stored. Moreover, infrastructure is being developed to draw hydrogen from an established pipeline network and storage, enabling its direct use as well as its use as fuel for power plants.
No CCS	Compared to *All Tech.,* groundwork for CCS is not made reflecting a non-existent infrastructure in this technology pathway.
No Nucl.	Compared to *All Tech.,* restart of recently shutdown reactors gains no political support and building new nuclear power is not part of energy policy in this technology pathway.
No Nucl. No CCS	Compared to *All Tech.,* neither nuclear nor CCS is allowed in this scenario thus representing the combination of *No CCS* and *No Nucl.*. This scenario best represents current German energy policy.

TABLE 16 provides a comparative analysis, aiming to highlight the power systems' performance concerning sustainability and competitiveness for all technology-policy pathways. The unique characteristics of these scenarios make them particularly interesting for comparison, as they represent distinctly different German power systems as illustrated by their firm and variable capacity mixes and generation mixes in 2050 in FIGURE 49 and FIGURE 50, respectively. Moving from left to right, these power systems show an increasing share of wind and solar power combined with stronger reliance of hydrogen for power while simultaneously adopting their share of nuclear and Gas CCS according to the technology pathway.

TABLE 16.

Summarised results comparing parameters, measuring security of supply, competitiveness, reliance on transmission infrastructure and sustainability, of the German power systems in main scenarios. Power system state in 2050 is assumed, except for total system costs which represents aggregate costs from 2030 to 2050. Presented ranges in brackets represent optimistic and conservative variations of the respective technology pathways *[All ++, All--]*.

KEY: RANKING	#1	#2	#3	#4

PARAMETER	TECHNOLOGY PATHWAY			
	ALL TECH.	NO CCS	NO NUCL.	NO NUCL. NO CCS
Security of supply	✓	✓	✓	✓
Total system cost (T€)[175]	1.7 [1.4,2.2]	1.9 [1.6,2.5]	1.9, [1.6,2.5]	2.2 [1.6,2.9]
Electricity price level 2050 (mean €/MWh)	61	78	66	103
Electricity price volatility (€/MWh)[176]	12	25	50	107
Power transmission (km $\cdot 10^3$)[177]	8.7 [3.7,16]	19 [13,29]	18 [14,23]	32 [20,45]
Hydrogen storage capacity (TWh)[178]	12 [11,11]	40 [28,46]	17 [13,14]	54 [41,52]
Annual CO_2 captured & sequestered (Mt)[179]	37 [38,48]	0	46 [44,62]	0
Life-cycle greenhouse gas emissions (g CO_2eq/kWh)	34 [32,45]	26 [19,31]	44 [41,61]	33 [19,36]
Land use (km$^2 \cdot 10^3$)	55 [70,30]	59 [84,32]	62 [69,37]	64 [100,35]
Use of critical materials (kt) [180]	3300 [3600,3500]	4500 [4800,4500]	4600 [4800, 5000]	5700 [5500, 5400]

[175] Represents aggregated total system costs from 2030 to 2050 in trillion €.
[176] Representing absolute spread between 25% and 75% quartiles of yearly averages. This volatility assessment solely encompasses fluctuations attributed to weather dependence and does not factor in variations stemming from fuel prices.
[177] See Appendix B.6 for calculation methodology.
[178] In hydrogen thermal energy capacity. Representing expansion needed for regeneration of electricity through combined-cycle hydrogen gas turbine power plants.
[179] Only representing needs from power sector and value in mega tons.
[180] Calculated based on the total installed power producing capacity.

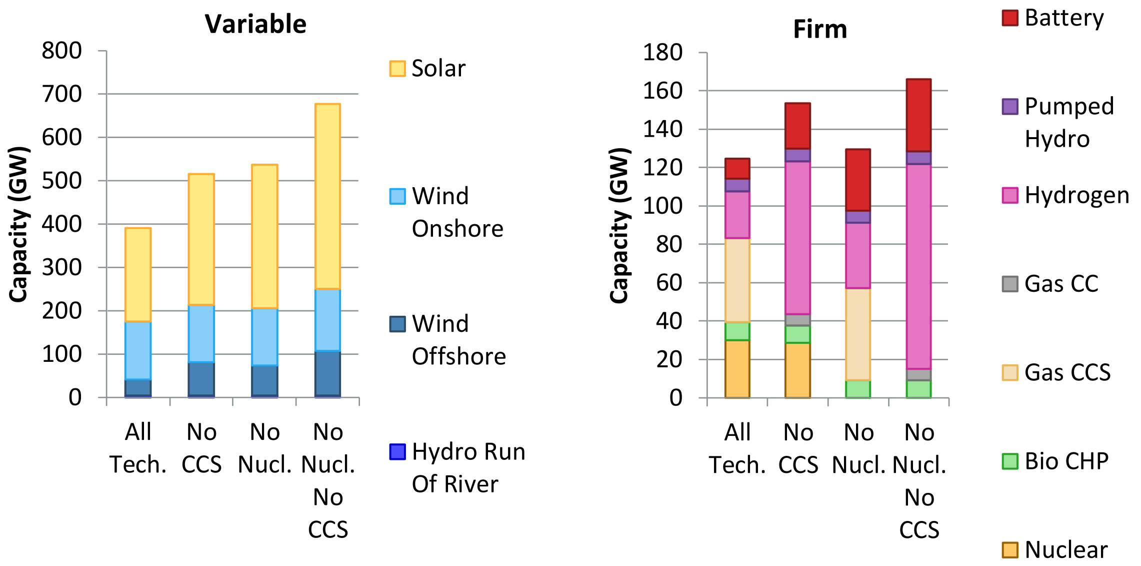

FIGURE 49.

Installed capacity of variable (left panel) and firm (right panel) technologies in the decarbonised German power system in 2050 for the different technology pathways.

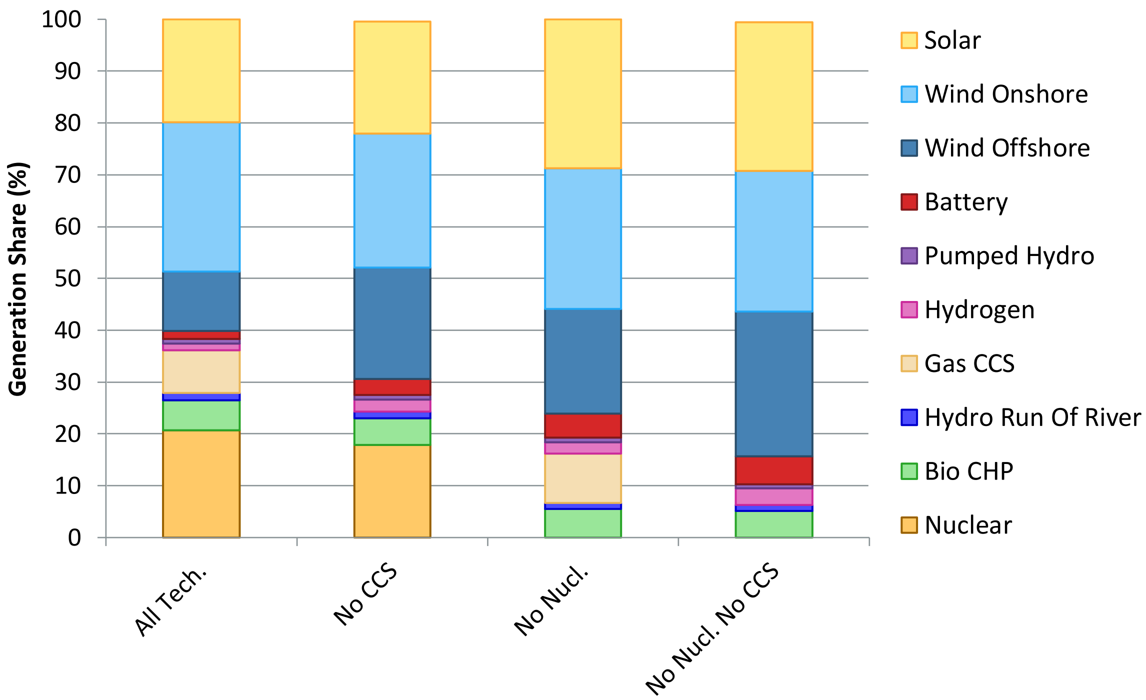

FIGURE 50.

Generation share split with respect to technology for the different technology pathways in the decarbonised German power system in 2050.

The reinforced resilience and reliability of the power systems created in this study demonstrate adequate capacity reserve margin for the 33 weather years evaluated. This methodology prioritises energy independence and supply security, echoing heightened concerns following the Russian invasion of Ukraine[181]. Consequently, these scenarios meet the defined *security of supply* criteria outlined in TABLE 16. In practice, this ensures that the German power systems are well-equipped to handle challenging conditions, including adverse weather years, e.g., characterised by prolonged periods of low wind production. Moreover, the inclusion of capacity reserve requirements, investigated in the *Capacity Market* scenario, demonstrate potential additional capacity to address unforeseen contingencies.

Recent debates have raised concerns about whether Germany is experiencing a creeping deindustrialisation[182], potentially leading to the loss of entire value chains of production or the preference of investments abroad over domestic expansion due to high energy costs. TABLE 16 provides key metrics such as total system costs, electricity prices, and electricity price volatility, which collectively gauge the competitiveness of the German power system. Across these metrics, the technology-inclusive German power systems in the *All Tech.* scenario emerge as the most competitive. Following closely are the *No Nucl.* and *No CCS* scenarios, while the most technology-restricted scenario, *No Nucl. No CCS*, lags considerably behind. The assessment of electricity price volatility shows advantages with nuclear in the generation mix with the *No CCS* scenario displaying lower spread than *No Nucl*. The difference in volatility originates purely from the degree of weather dependent generation in the system. Introducing a ±30% variation in natural gas fuel prices, not accounted for in this assessment, brings the volatility of the *All Tech.* scenario to a level comparable to that of *No CCS*. However, the observed volatility in the *No Nucl. No CCS* scenario surpasses the others due to its heavy reliance on wind and solar generation for power.

These scenarios, based on input assumptions from the reference sensitivity, represent significant advancements across all technologies, particularly in investment and operational costs, demand-side flexibility capabilities, land availability for onshore wind expansion, and fossil fuel prices. To explore extremes, optimistic and conservative outlooks, scenario variations *All* ++ and *All* -- were implemented, respectively. Overall, positive technological developments reduce the criticality of technology pathway policies, as evidenced by minimal variations in total system costs.

Conversely, conservative *All* -- scenarios exhibit more pronounced impacts, amplifying with further technology restrictions. The competitiveness of the *No Nucl. No CCS* scenario is contingent upon an overly optimistic outlook. The high electricity prices and significant price volatility in the *No Nucl. No CCS All* -- scenario are likely unacceptable to the public, rendering the German industry non-competitive. Moreover, the instability in market conditions, exacerbated by different weather conditions, poses negative consequences for energy system investors, whether consumers or producers. Ultimately, this technology pathway jeopardises climate achievements.

Additional parameters in TABLE 16 shed light on the power systems' dependence on transmission infrastructure—a crucial facilitator of new production and consumption, yet a potential obstacle in decarbonisation. These parameters include the length of additional power transmission needed, the size of hydrogen storage required for generating backup electricity, and the annual amount of CO_2 captured and sequestered into geological storage by the power system.

Owing to the strong expansion of offshore wind and hydrogen power plants, the *No Nucl. No CCS* scenario exhibits the largest reliance on power transmission and hydrogen infrastructure, respectively, followed by *No CCS* and *No Nucl.* Conversely, *No Nucl.* demonstrates largest needs for CCS infrastructure, with the other scenario allowing CCS, *All Tech.,* following. Altogether, these results demonstrate that nuclear power in the German power system has the potential to generally reduce reliance on an expanded transmission infrastructure while CCS offers additional advantages for both power and hydrogen infrastructure needs, specifically.

[181] Energiepartnerschaft (n.d.), Germany Remains Committed to its Existing Climate and Power Sector Decarbonisation Targets.
[182] Financial Times (2023), Germany Faces Threat of Creeping Deindustrialisation, Warns Steel Boss.

Quantified Carbon lifecycle greenhouse gas emissions, land use and use of critical minerals, as further presented in TABLE 16. aim to probe how the power systems perform with respect to sustainability.

It's important to acknowledge that the lifecycle greenhouse gas emission values encompass upstream emissions, unlike the power system optimisation, which only considers direct emissions. Consequently, power systems excluding CCS generally demonstrate better performance in this regard, largely due to their reduced reliance on fossil natural gas. Actually, the *No Nucl. No CCS* scenario shows similar lifecycle emission values as the *All Tech.* scenario. The considerable emissions in the *No Nucl. No CCS* scenario is primarily driven by the significant expansion of solar capacity.

Small differences in land use are observed among the compared scenarios, primarily due to the limited variation in onshore wind and solar deployment. However, more significant disparities emerge regarding the utilisation of critical materials, driven by the extensive reliance on wind power, particularly in scenarios where certain technologies are not available, such as *No CCS, No Nucl.*, and *No Nucl. No CCS*. This highlights the potential of a technology-inclusive policy to mitigate risks associated with the security of critical mineral supplies, especially considering the current concentrations limited to a small number of quasi-monopolistic countries.

6.2 Sensitivities

The robustness of the results in the technology pathways were thoroughly evaluated through explorations of around 60 scenario variations. In sensitivity comparisons, the impact of specific parameter variations was investigated to understand what drives the design of the optimal decarbonised German power system. This evaluation showed that sensitivity variations of fossil and nuclear costs, as well as demand-side flexibility exhibit very limited impact on both the generation mix and total system costs. Variations in the costs of wind, solar, and storage technologies, along with land availability for onshore wind expansion, had a greater impact. The total system cost was primarily influenced by costs for VRE and storage technologies, a natural consequence of a VRE-dominated system. Conversely, restricted land availability purely limited by technical constraints had a significant effect on the generation mix in the way of onshore wind capacity being replaced by solar and offshore wind compared to the *All Tech.* scenario.

In general, the German capacity and generation mix was observed to not vary much between parameter sensitivity variations within separate technology policy pathways. On this background, additional sensitivity variations were explored as relaxed build rate limits (*No Limits*) and more lenient CO_2 targets (*CO_2 --*) were applied to the *All Tech.* technology pathway. These scenarios aimed to reveal how sensitive the final German power system was to clean energy technology deployment rates whilst spotlighting potential missed opportunities for a more robust, optimised system by 2050, resulting in fewer stranded assets while fulfilling interim targets.

FIGURE 51 compares the variable and firm installed capacity between the *All Tech.* and the *No Limits CO_2 --* scenarios in a fully decarbonised 2050 German power system. A striking decrease in wind and solar deployment as well as reduced reliance on Gas CCS may be observed in lieu of a considerably larger expansion of nuclear power strongly underscoring the high competitiveness of nuclear power in decarbonising the German power system. Additionally, with the full removal of offshore wind and hydrogen-fuelled power plants these findings suggest that these technologies are seen by the model as last resorts for adding clean generation and capacity to meet ambitious CO_2 targets while accommodating increasing power demand.

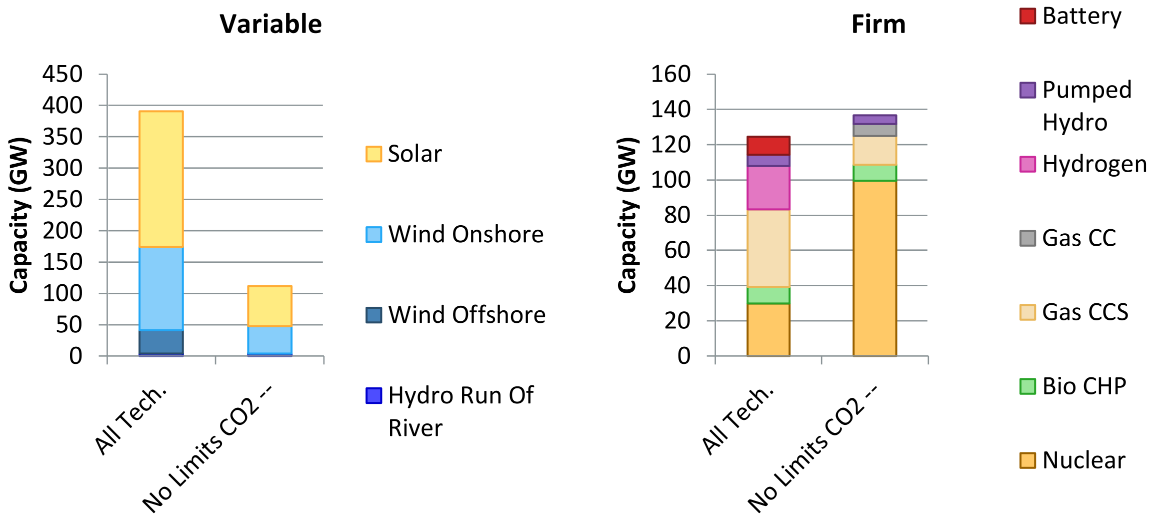

FIGURE 51.

Installed capacity of variable (left panel) and firm (right panel) technologies in the decarbonised German power system in 2050 for the *All Tech.* and the *No Limits CO_2 --* scenarios.

6.3 Decarbonisation pathway

The central scenario of this study, termed *All Tech.,* adopts a technology-inclusive approach that incorporates both nuclear power and gas power plants with CCS. Using best-estimate input assumptions, this scenario maps out a pathway for the German power system's transition to decarbonisation, as illustrated by the evolving capacity and generation mixes from the present day to 2050 in FIGURE 52. While the *All Tech.* scenario does *not* predict the future of the German power system; it serves as a valuable discussion tool. Supported by the range of scenarios and sensitivities explored in this study, it may serve as discussion basis to highlight a potential pathway to decarbonisation emphasised by the integration of diverse technologies.

First and foremost, it is important to recognise that wind and solar cover at least 50% of the generation mix in the majority of scenarios considered in the current work. Onshore wind, proving to be cost-effective, is expanding at a pace consistent with national targets[183], indicating a revitalised and strengthened European wind power industry. Onshore wind reaches its maximum expansion limit of 143 GW in 2035, a limit based on the governmental plans to allocate 2% of country area to wind parks. Following on, solar and offshore wind continue to add more clean power to the German power system, addressing both growing demand and CO_2 reduction targets. Notably, near-term expansion goals of solar with 210 GW in 2030[184] and offshore wind with 30 GW in 2030[185] are not reached. In 2050, 190 GW and 38 GW of solar and offshore wind along with around 20 GW of battery storage capacity[186] are established parts of the German power system. As a point of comparison, the renewable energy[187] expansion proceeds such that the share reaches around 50% in 2030 in line with the EU's renewable energy directive target at 42.5%[188]. This echoes the ongoing commitment to wind

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[183] Renewables Now (2024), Germany installs 17 GW of renewables in 2023.
[184] Energy Monitor (2023), Signal: Germany's Solar Plans are Powering Up, Energising the Job Market.
[185] Clean Energy Wire (2024), German Offshore Wind Expansion Slowly Picking Up in 2023, Must Multiply Soon to Meet Targets.
[186] As supported in the recently published Electrical Storage Strategy:
BMWK - Bundesministerium für Wirtschaft und Klimaschutz (2023), Stromspeicher-Strategie -Handlungsfelder und Maßnahmen für eine anhaltende Ausbaudynamik und optimale Systemintegration von Stromspeichern – barrierefrei.
[187] Calculated as the sum of generation from wind, solar, hydro and bio-power sources.
[188] EU – European Commission (n.d.), Renewable Energy Directive.

and solar power, driven by Germany's Energiewende policy. However, the results fall short of recently announced potential levels achievable in 2030 by the German government, an example being an 80% renewable energy share[189]. A key factor contributing to this large deviation is the significant increase in projected electricity consumption assumed in the current analysis.

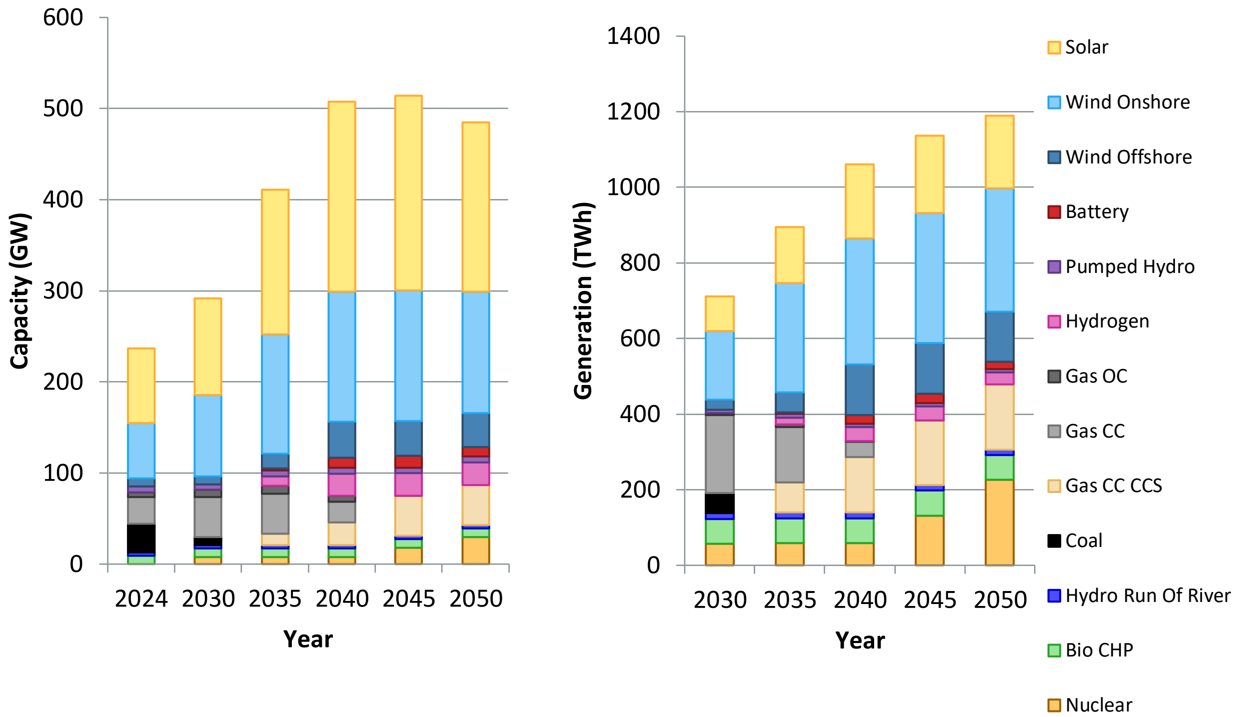

FIGURE 52.

Installed capacity (left panel) and annual generation (right panel) as a function of year split by technology for the *All Tech.* scenario.

The results highlight a rapid and comprehensive phase-out of coal power before 2035. This shift is driven by coal's high emissions, which conflict with decarbonisation goals, and aligns with announced plans[190] to fully phase out coal “no later than 2038”. With an inclusion of a capacity market, the results further show a potential role of mothballing a share of coal power plants until 2035.

In the early 2030s, combined-cycle gas (Gas CC) primarily replaces coal power capacity, with both greenfield Gas CCS and CCS retrofitted Gas CC following in the later 2030s and early 2040s as CO_2 targets become increasingly stringent. Abated gas power, with a total installed capacity of 44 GW (including 24 GW from retrofitted plants), proves competitive and plays a considerable role in the decarbonised German power system, contributing to 15% of the generation mix by 2050. Gas CCS introduces uncertainties, ranging from the achieved capture efficiency to the volatility of fuel prices and the expenses associated with CO_2 transport and storage. These factors, coupled with the finite supply of fossil fuels, necessitate consideration when evaluating the potential role of Gas CCS in the decarbonisation journey of the German power system. It is worth mentioning that the upcoming carbon management strategy[191] at its current state does not accommodate a role for CCS in the future

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[189] Clean Energy Wire (2024), Germany’s aim for 80 Percent Renewables in Electricity by 2030 Well Within Reach – Minister.
[190]
[191] Clean Energy Wire (2024), Germany to Support CCS for Industry, Allow Offshore Carbon Storage with Upcoming Strategy.

German power system. This also underscores the importance of starting CCS infrastructure development as soon as possible.

A capacity of 10 GW combined-cycle hydrogen power plants come online in 2035, coincidentally aligning with the recently announced German *Power Plant Strategy*[192] despite being a scenario deviating from the current energy policy with the inclusion of nuclear power and Gas CCS. Hydrogen's role is enhanced with 25 GW installed power generation capacity in 2050. However, as investigated in detail in the current work, hydrogen for power generation is considered by the model as last resorts to add clean generation and capacity to the German power system to meet ambitious CO_2 targets due to build rate limits on nuclear and Gas CCS. Though Germany presents a promising geographic region for establishing a robust hydrogen infrastructure for transmission and storage, it is important to recognise the numerous barriers and challenges in the way for implementation at scale. Finally, it is crucial to emphasise that the current analysis presupposes a self-sufficient supply of hydrogen which contrasts to current policy narratives suggesting: "Germany will have to import 70% of the green hydrogen it consumes[193]. The modelling results ultimately echo the challenge that lie ahead for decarbonising Germany's power system while maintaining competitiveness.

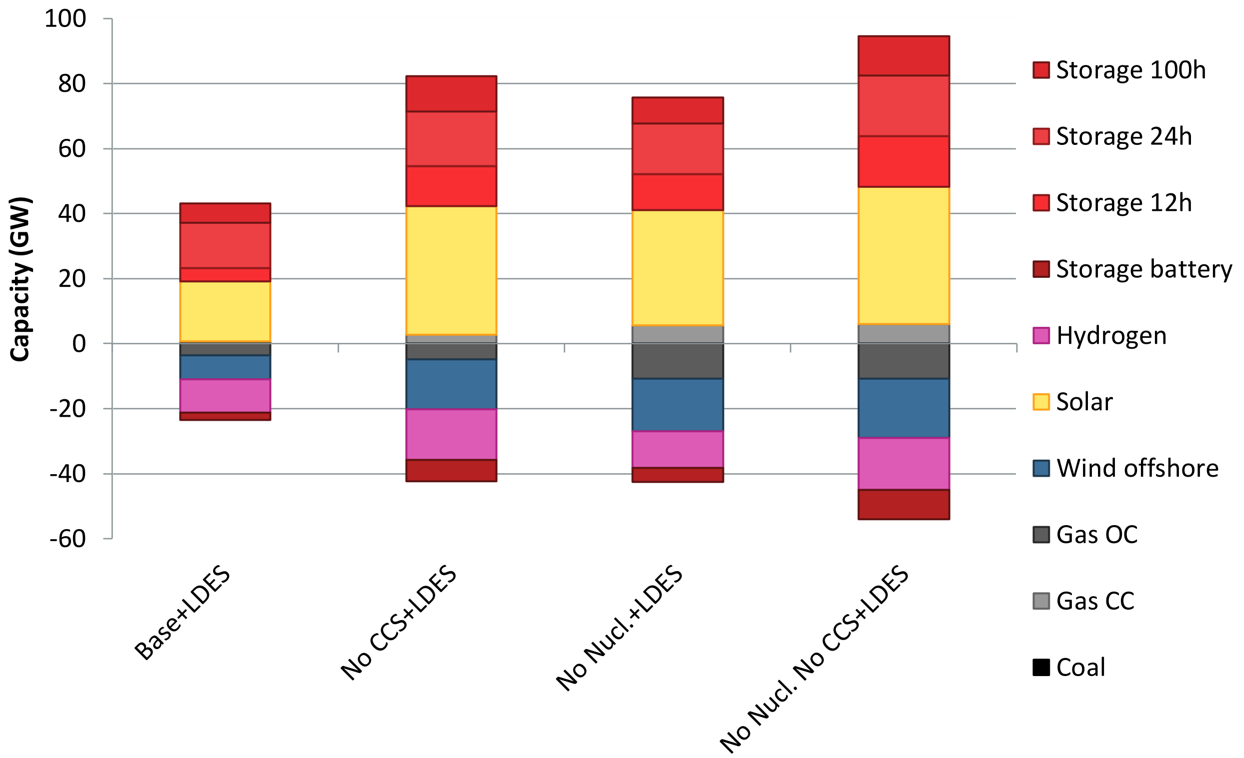

FIGURE 53.

Difference in installed capacity between the *LDES* and their corresponding scenario without LDES for model year 2035 split by technology.

The value of hydrogen power for balancing underscores the importance of flexibility from clean energy sources in decarbonising the German power system, with long-duration energy storage (LDES) technologies potentially playing a key role. Demonstrated in SECTION 4.10, LDES facilitates substantial solar expansion, delays the need for offshore wind installations, and reduces reliance on hydrogen and high-cost peaking plants like open-cycle gas turbines, optimising system flexibility under stricter decarbonisation targets. Furthermore, LDES could act as a hedge against demand-side flexibility

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[192] MWK - Bundesministerium für Wirtschaft und Klimaschutz (2024). Einigung zur Kraftwerksstrategie.
[193] Hydrogeninsight (2023). Habeck: Germany will have to Import 70% of the Green Hydrogen it Consumes.

uncertainties, addressing the needs of electric vehicles, space heating, and residential energy demands primarily through its 24-hour duration. While uncertainties remain regarding the scalability and readiness of LDES technologies, their ability to address diurnal and multi-day balancing needs underscores their strategic importance for achieving climate neutrality, provided continued innovation and support to accelerate their deployment.

Restarting six recently shut down reactors, representing 8 GW of installed capacity, proves to be a cost-effective, low-carbon addition to the German power system from 2030 onwards. As these older reactors are retired before 2050, a new wave of nuclear power plants comes online in the 2040s, eventually contributing 30 GW of installed capacity and providing 20% of the generation mix by 2050. This expansion, purely limited by our assumed build rate, indicates nuclear power’s competitiveness further demonstrated by its robust role also in scenarios with conservative cost projections. The simulated expansion requires a swift shift in German energy policy and rapid commencement of preparatory work, ideally well before 2030. Successfully executed nuclear projects with relatively low costs can set the stage for a more competitive German power system in the long run.

6.4 Conclusions

We conducted an in-depth comparison of our results with eight other studies. Notably, our study is among the first to include nuclear power in the German power system's technology portfolio. Naturally, the inclusion of nuclear power reduces the need for extensive wind and solar deployment in the decarbonisation of the German power system. All power systems in this comparison rely significantly on gas for firm capacity, although the specific fuel used is not always specified. On the background of the high costs of hydrogen for power generation, moving forward it is relevant to scrutinise all energy system studies regarding their associated assumptions. Additionally, our study emphasises energy resilience by limiting electricity imports and not allowing for hydrogen imports, key boundary conditions that may distinguish it from other studies.

In conclusion, the common thread among the examined measures regarding the technology pathways of the German power system's competitiveness, reliance on transmission infrastructure, and sustainability, is the significant added value of including nuclear power in the technology mix. While uncertainties remain, these findings also highlight the potential benefits of integrating CCS into German energy policy.

A policy that embraces and supports the development of a diverse range of technologies is better prepared to navigate uncertainties. This includes unforeseen obstacles in development, resistance to expanding onshore wind, potential stagnation in cost reductions for wind, solar, and storage technologies, as well as challenges associated with larger and more complex nuclear and CCS projects. In practice, when progress with one technology is slower than anticipated, others can step in to fill the gap. The findings of the current study highlight the advantages of embracing a technology-inclusive approach, laying the groundwork for the German power system to attain its climate objectives while maintaining economic competitiveness. Concluding policy recommendations derived from the current study for fostering a competitive and sustainable decarbonisation of the German power system are presented in SECTION POLICY RECOMMENDATIONS.

Finally, the current study highlights the potential value of conducting integrated supply-demand modelling analyses to gain deeper insights into the dynamics between producers and consumers. This approach would help to better understand the impacts on the pace of decarbonisation in the German power system. The present analysis focuses on the power system within the electricity market, serving as an initial phase to inform power system development. Subsequently, a thorough analysis of the resulting power system is required, taking into account factors like frequency stability, N-1 criteria, black start capability, multi-node optimisation and more.

Appendix A Input assumptions

A.1 Sensitivity definitions

TABLE 17.

Definition of each sensitivity explored in the current study along with their display name.

SENSITIVITY		DISPLAY NAME	DEFINITION
ALL TECH.		*All Tech.*	WACC=0.06, reference cost forecast, land availability, commodity and CO_2 prices, maximum build rates, demand growth and flexibility.
CO_2 CONSERVATIVE		*CO_2 --*	No interim CO_2 targets between 2030 and 2050 are imposed, as detailed in SECTION 4.1.
CAPACITY MARKET		*Capacity Market*	The inclusion of a capacity market in the modelling ensures that a capacity reserve margin of at least 10% is met (see also SECTION 4.8).
RENEWABLES	**OPTIMISTIC**	*VRE ++*	Optimistic cost forecasts for onshore and offshore wind, and solar
	CONSERVATIVE	*VRE --*	Conservative cost forecasts for onshore and offshore wind, and solar.
STORAGE	**OPTIMISTIC**	*Storage ++*	Optimistic cost forecasts for batteries and electrolysers.
	CONSERVATIVE	*Storage --*	Conservative cost forecasts for batteries and electrolysers.
FOSSIL	**OPTIMISTIC**	*Fossil ++*	Prices for natural gas approaching EU pre-energy crisis levels by mid 2030s. Coal price development coupled to natural gas.
	CONSERVATIVE	*Fossil --*	Prices for natural gas approaching Asia-LNG pre-energy crisis levels by mid 2030s. Coal price development coupled to natural gas.
NUCLEAR	**OPTIMISTIC**	*Nucl. ++*	Nuclear with optimistic cost forecast.
	CONSERVATIVE	*Nucl. --*	Nuclear with conservative cost forecast.
LAND	**OPTIMISTIC**	*Land ++*	A larger expansion of onshore wind is allowed, albeit with a lower capacity factor.
	CONSERVATIVE	*Land --*	Expansion of onshore wind halts to present-day level.

FLEX	OPTIMISTIC	*Flex ++*	Represents highly flexible electricity load as detailed in 0.
	CONSERVATIVE	*Flex --*	Represents, to a large extent, inflexible electricity load as detailed in 0.
ALL	OPTIMISTIC	*All ++*	Combines all the optimistic sensitivities, i.e., *VRE ++, Storage ++, Fossil --, Nucl. ++, Land ++* and *Flex ++*.
	CONSERVATIVE	*All --*	Combines all the conservative sensitivities, i.e., *VRE --, Storage --, Fossil --, Nucl. --, Land --* and *Flex --*.

*Weighted Average Cost of Capital

A.2 Technologies in model

TABLE 18.

Power supply technologies included in the model along with a brief description. Technology category also indicated where 'Thermal' represents thermal power plant, 'Must run' power plant forced to follow dispatch profile, 'VRE' variable renewable energy subject to production profile and curtailment and 'Storage' systems.

TECHNOLOGY	CATEGORY	DESCRIPTION
NUCLEAR	Thermal	General representation of greenfield nuclear power.
HYDRO RUN OF RIVER	Must run	Profile based on average of historical years.
BIO CHP	Must run	Biomass and biogas-fuelled CHP with profile based on average of historical years.
COAL HARD	Thermal	Hard coal-fuelled thermal power plant.
COAL LIGNITE	Thermal	Lignite coal-fuelled thermal power plant.
GAS OC	Thermal	Natural gas fuelled open-cycle turbine power plant.
GAS CC	Thermal	Natural gas fuelled combined-cycle turbine power plant.
GAS CCS	Thermal	Natural gas fuelled combined-cycle turbine power plant with CCS.
GAS CCS RETROFIT	Thermal	Natural gas fuelled combined-cycle turbine power plant retrofitted with CCS.
WIND OFFSHORE FLOATING	VRE	Offshore wind power, floating foundation.
WIND OFFSHORE FIXED	VRE	Offshore wind power, fixed foundation.
WIND ONSHORE	VRE	Utility-scale onshore wind power.
SOLAR	VRE	Utility-scale solar PV.
HYDROGEN OC STORAGE	Storage	Hydrogen-fuelled open-cycle turbine power plant with electrolyser charging station and hydrogen energy storage.

HYDROGEN CC STORAGE	Storage	Hydrogen-fuelled combined-cycle turbine power plant with electrolyser charging station and hydrogen energy storage.
BATTERY STORAGE	Storage	Utility-scale lithium-ion battery storage.
HYDRO PUMPED STORAGE	Storage	Closed-loop pumped storage hydropower.

A.2.1 Existing installed generation capacities

TABLE 19.

Existing dispatch capacity before expansion in 2030 for the different power generating technologies in Germany based on indicated references ENTSO-E[194], Open Power System Data[195], IEA Bioenergy196, and Energy-Charts[197].

TECHNOLOGY	EXISTING CAPACITY (MW)
NUCLEAR	0
HYDRO RUN OF RIVER[198]	3700
BIO CHP	9300
COAL HARD	13000
COAL LIGNITE	18000
GAS OC	5600
GAS CC	29000
GAS CCS	0
GAS CCS RETROFIT	0
WIND OFFSHORE FLOATING	0
WIND OFFSHORE FIXED	8500
WIND ONSHORE	61000
SOLAR	82000
HYDROGEN OC STORAGE	0
HYDROGEN CC STORAGE	0
BATTERY STORAGE[199]	0

194 ENTSO-E (2024), Map of Day-ahead Prices.
195 Open Power System Data (2020), Data Platform.
196 IEA (2021), IEA Bioenergy Task 37: Country Report Germany 2021.
197 Energy-Charts (2024), Electricity generation in Germany in 2023.
198 The hydro run-of-river fleet is assumed to continue to be in operation with reinvestments such that the current installed production capacity is conserved throughout all modelling cases.
199 It is assumed that the current installed capacity is primarily residential and enters the model through demand-side flexibility as discussed in 0.

TABLE 20.

Existing discharge, energy storage and charge capacity for pumped hydro storage in Germany based on International Hydropower Association[200].

TECHNOLOGY	DISCHARGE CAPACITY (GW)	ENERGY STORAGE CAPACITY (MWH)	CHARGE CAPACITY (GW)
HYDRO PUMPED STORAGE	6.4	37000	6.1

[200] IHA (2024), Pumped Storage Tracking Tool.

Appendix B GIS analysis for wind and solar expansion potential

GIS (Geographic Information System) is a work environment that uses spatial analysis tools, cartographic methods and databases of spatial objects or spatial distributions of variables. Significant developments in the availability of GIS for research and analysis are related not only to technological advances but also to broader access to ever larger geospatial databases, including open-access data. Renewable energy systems research uses vector and raster data, reflecting the shape and structure of building roofs or representing the terrain.

Numerous scientific studies in individual countries, continents, and on a global scale show the possibilities of using GIS data and tools to analyse energy supply. Most scientific research does not differ in terms of the adopted methodology, which is based on basic tools and analyses, but the differentiating parameter are the type and resolution of the spatial data, as well as the conditions and assumptions adopted for the analyses. The adopted GIS approach in this report is illustrated in FIGURE 54.

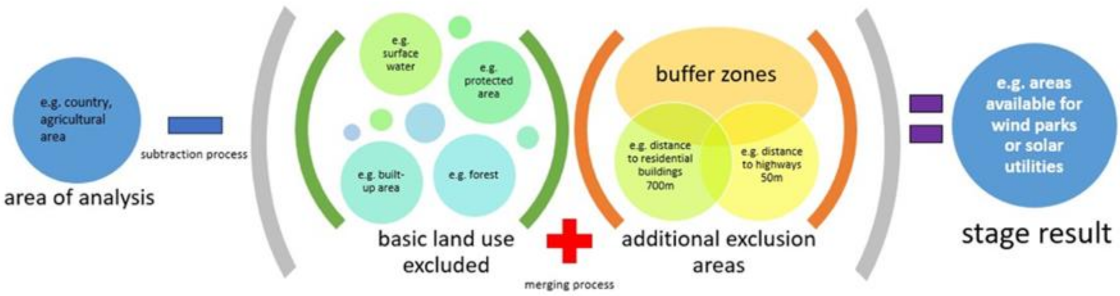

FIGURE 54.

Illustration of the adopted GIS approach.

B.1 Core input data

In terms of input data, the analysis was based on three crucial databases, namely:

- ESA WorldCover 2021[201]

It is a set of spatial data covering the entire world, with uniform structure, resolution, accuracy and symbology. The ESA WorldCover dataset describes a type of land cover. The study distinguishes 11 land cover classes, including: "Tree cover", "Shrubland", "Grassland", "Cropland", "Built-up", "Bare / sparse vegetation", "Snow and Ice", "Permanent water bodies", "Herbaceous Wetland", "Mangrove" and "Moss and lichen". The data set has a spatial resolution of 10 m. The data was created based on the classification of data from the ESA Sentinel-1 and Sentinel-2 satellite missions. The use of ESA WorldCover data allows for the unification of analysis parameters for the entire world, while maintaining high data accuracy and resolution. The data were used to estimate the potential for wind energy development, in particular taking into account current land cover/land use. It excluded built-up areas, forest areas, and areas under water.

[201] ESA WorldCover 2021 (n.d.), Download.

- **OpenStreetMap (OSM)**[202]

OSM is a global open access data collection for spatial data. The resource contains information about point, line and polygon objects, as well as relations. OSM is a wide resource of topographic and infrastructure information, constantly updated and expanded. The disadvantage of using OSM is the issue of supplementing the database with new objects that are added by users and do not require greater control. The study used OSM to define residential from built-up areas with ESA Worldcover, and protected areas such as national parks, landscape parks, reserves, Natura2000. Used in the location of existing wind turbines and solar farms.

- **Flood hazard map of the World - 500-year return period**[203]

It is a global flood risk database. It indicates areas at risk of flooding with the characteristics of a once-in-500-year flood (low risk, high risk when the phenomenon occurs). The data is prepared using a uniform methodology for the entire study area. The spatial resolution is 100 m. It is used to exclude areas at risk of flooding from the potential for the construction of technical facilities.

B.2 Onshore wind

The analysis of areas available in Germany for the installation of wind parks was made based on ESA WorldCover 2021 data, supplemented with OSM data, and current Land legal regulations regarding the required location conditions. Legal issues regarding the location of wind turbines in Germany are well described and defined in legal acts but are different between each Lands. The range of the distance difference between residential buildings and the possibility of locating wind turbines is in the range of 0 to 2000 m.

The following raster data were obtained from the ESA WorldCover database: land use/land cover data (built-up areas, forests, surface waters) protected areas (Natura2000 areas, national parks, landscape parks, nature reserves) and location of residential buildings in the country were obtained from OSM data. Areas at risk of flooding were exported from the European Commission data.

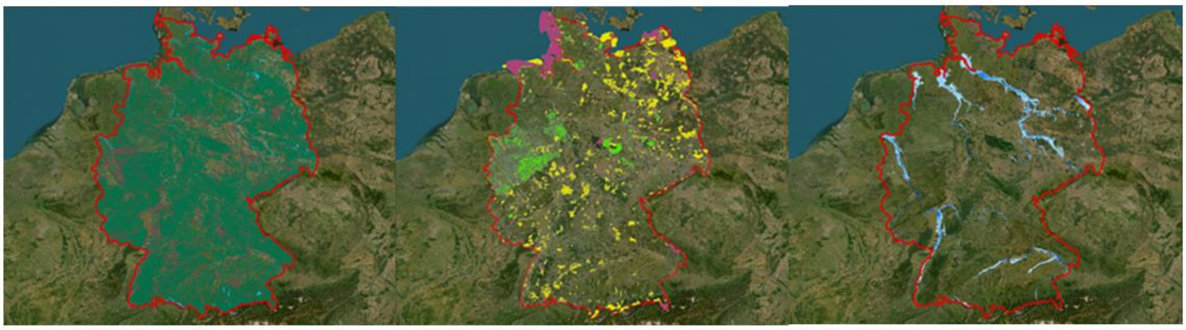

FIGURE 55.

Visualisation of land use and land cover in Germany based on BDOT10k data from 2023.

The analysis was performed in the GIS environment as an analysis of polygon vector data. Using available tools, areas excluded from the accepted permitted areas were subtracted (masked). Buffering tools were used to determine exclusion areas around residential buildings.

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202 OpenStreetMap (n.d.), OpenStreetMap.
203 EU Joint Research Centre Data Catalogue (2024), River Flood Hazard Maps at European and Global Scale.

Buffer zones were created for residential areas (developed areas with ESA verified by OSM): 500 m, 700 m, 1000 m, and according to regulations in individual Lands (0-2000 m). These areas were excluded from the possibility of locating elevator parks.

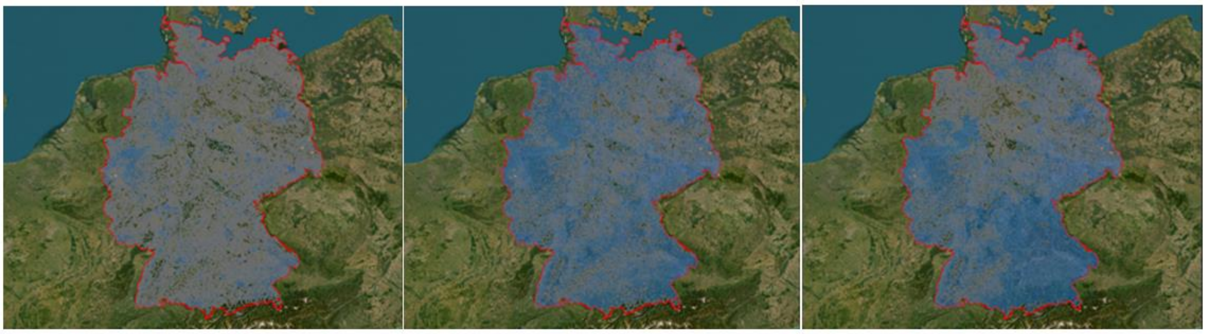


FIGURE 56.

Buffer zones to residential areas, 500m, 1000m, lands regulation.

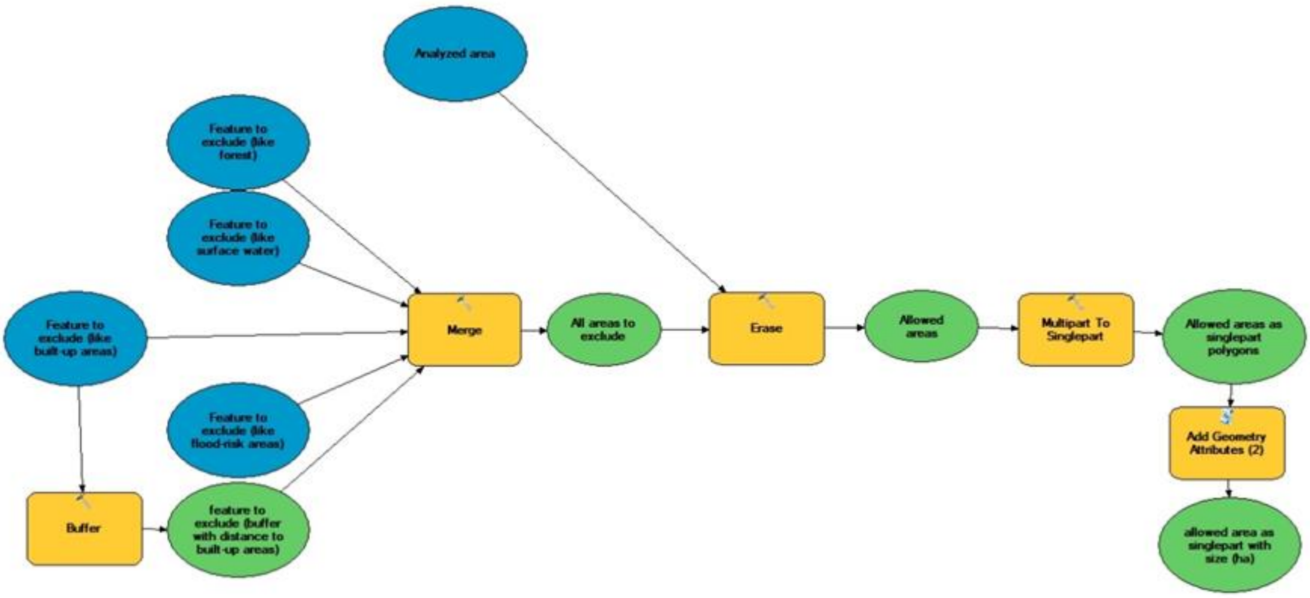


FIGURE 57.

GIS related methods flowchart.

B.3 Criteria for wind parks

Using available global databases on land cover/land use, flood risk, protected areas, built-up areas and building locations, a total of 16 versions of areas potentially available for the location of wind turbines were developed.

The 4 main scenarios are based on the exclusion of areas generally considered off-limits for locating wind turbines in Germany:

a) excluded surface waters, flood areas, built-up areas, national parks, natura2000 (Scenario 0)

b) the same as in a) and excluded forests (Scenario 1)

c) the same as in a) and excluded landscape parks (Scenario 2)

d) the same as in a) and excluded both forests and landscape parks (Scenario 3)

Each of the scenarios a) b) c) d) was counted in 4 variants:

*) excluded 500 m from buildings for the entire country,

**) excluded 700 m from buildings for the entire country,

***) excluded 1000 m from buildings for the entire country,

****) excluded distance zone from buildings, individual for each Land.

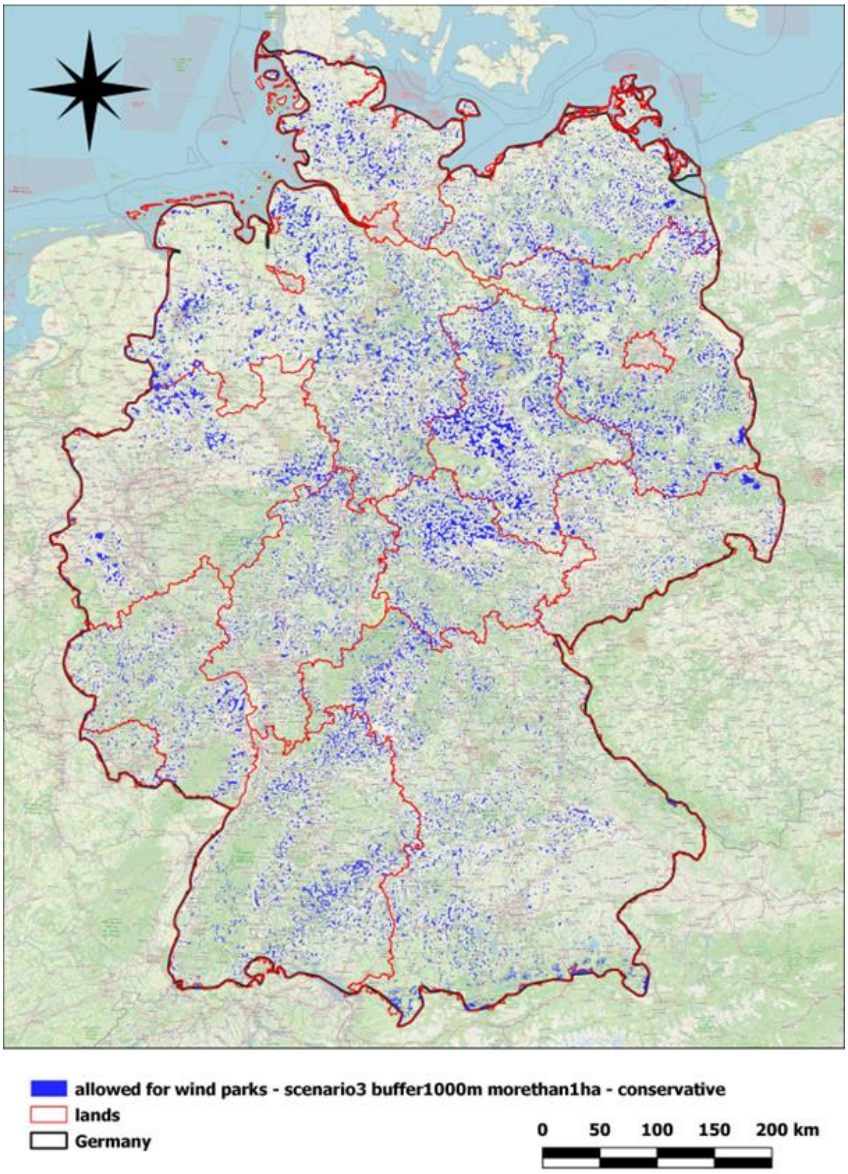


FIGURE 58.

Areas allowed for wind parks in Scenario 3 with buffer 1000 m to residential buildings.

B.4 Calculations for existing wind parks

Information on the location of approximately 30.5 thousand wind turbines in Germany was obtained from the OSM database. For some, the attribute information also included data on the power or height of the turbines, or the manufacturer or current owner. However, more than half of the facilities did not have complete information. No area of wind parks was found in the OSM database, so it was decided to develop its own area database of wind parks.

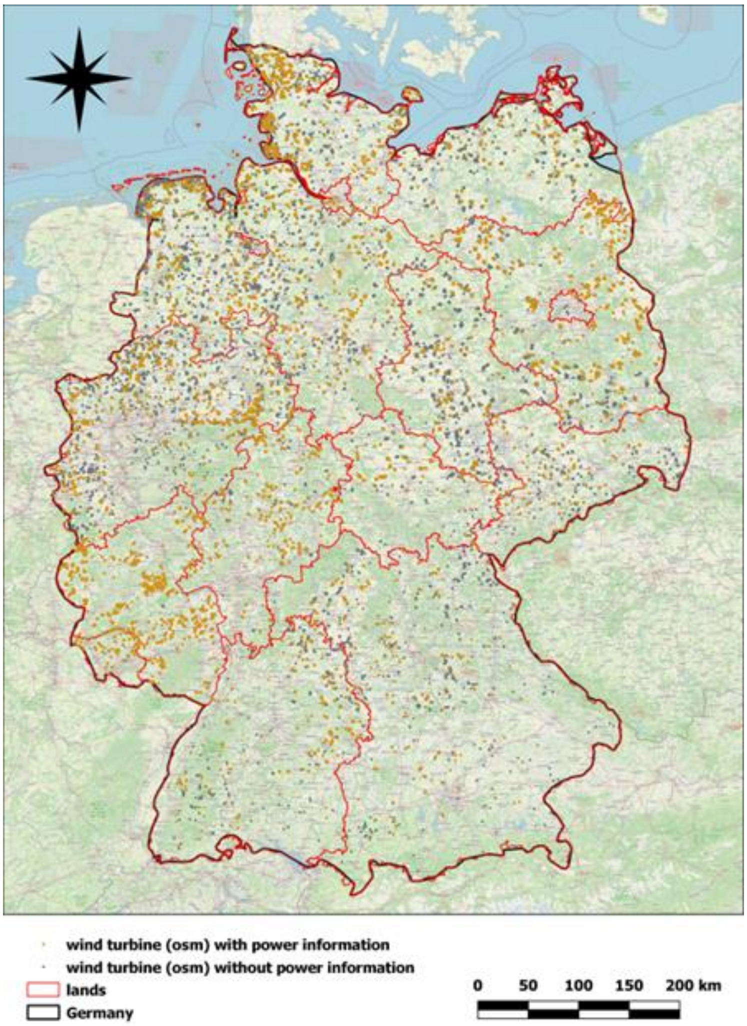


FIGURE 59.

Location of existing wind turbine according to OSM data.

For this purpose, dedicated tools in GIS software were used to classify turbines belonging to the area of one wind park using the clustering method. The only criterion was a minimum number of 3 turbines for one park. The tool did not have the ability to set a minimum distance between objects.

The next step was to calculate the average distance between neighbouring turbines in the area of one cluster, which enabled the development of buffer zones, increasing the area of wind parks, with individual conditions for each facility.

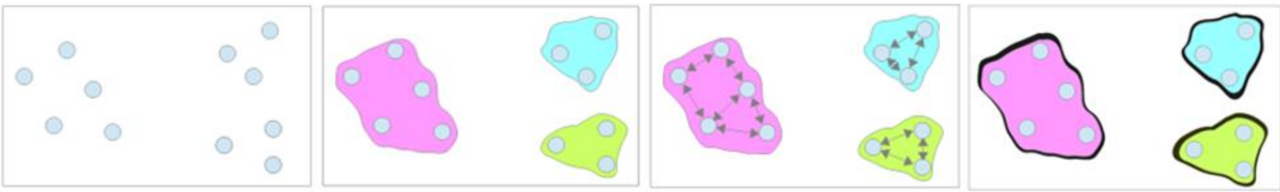


FIGURE 60.

Flowchart for wind park analysis.

B.5 Wind parks-investment cost correlations

To verify our approach stating that in general smaller parks are being commissioned in Germany what in consequence makes their investment costs higher, we have compared the spatial distribution of wind parks in Sweden and Germany. For that purpose, Open Street Map database was used along with spatial clustering performed in GIS. In the first step the database has been cleaned by removing wind turbines for which capacity (kW or MW) was not available. Next remaining turbines have been clustered into wind parks assuming that a wind park must constitute of at least three wind turbines. In the final step the cumulative capacity (MW), spatial distribution of wind turbines and average wind park size (number of wind turbines) have been juxtaposed. The first and last parameter were calculated every 1° of latitude starting from 47.5 °N. The results are shown in FIGURE 61.

Clearly Germany exhibits a much higher total capacity of installed wind turbines compared to Sweden – in the analysis conducted we have used 27 GW (43% of total capacity) and 9 GW (64%) for respectively Germany and Sweden – as this was the data available through OSM. As can be observed in FIGURE 61 (right panel) the wind parks in Sweden (latitude +55°N) have on average 31.7 turbines whereas those in Germany 7.3 turbines. In particular the wind parks in northern Sweden tends to be much larger and actually a similar trend (to a lesser extent) is observed in Germany where wind parks in the north (54.5°N) tend to have on average 10.2 turbines. Considering above we claim that our assumption regarding higher investment costs for typical wind park in Germany holds due to the sheer *effect of scale/size* of the wind park.

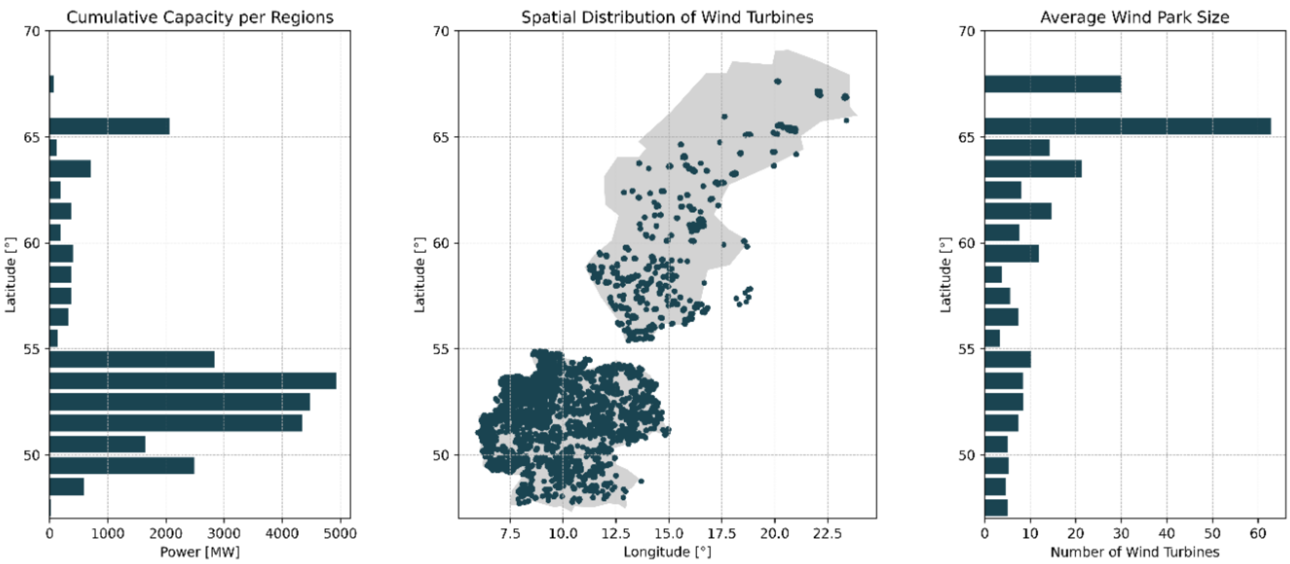


FIGURE 61.

Spatial distribution of wind turbines in Sweden and Germany based on Open Street Map (OSM).

B.6 Transmission expansion modelling approach

To estimate the required new capacity expansion in our modelling we have relied on the National Grid Development Plan[204]. This is required as implemented power system modelling frameworks in GenX and cGrid do not optimise/simulate granular grid infrastructure. Use of the chosen reference (National Grid Development Plan) is justified as it also simulates a highly decarbonised (net-zero) future energy system with high shares of solar and wind generation with a distinction made for onshore and offshore wind power. The major assumptions in the National Grid Development Plan are as follows: electrolysers are located in Northern Germany; onshore wind power concentrates mostly in north and north-east of Germany; due to the increased investment in PV in the south the power flow during midday solar PV generation peaks is from south to north to power for electrolysers located there. FIGURE 62 schematically illustrates the adopted approach where for each technology (solar PV, onshore and offshore wind) the required grid reinforcement given in km/GW has been estimated. Considering the numbers provided in the National Grid Development Plan and the approach presented in FIGURE 62, it was found that solar PV requires 18.3 km of additional grid per 1 GW of capacity, onshore wind 7.7 km/GW and offshore wind as much as 214.7 km/GW. It could be expected that in the initial grid expansion phase a large share of additional capacity could be minimised by the use of cable pooling in the case of solar-wind hybrid parks.

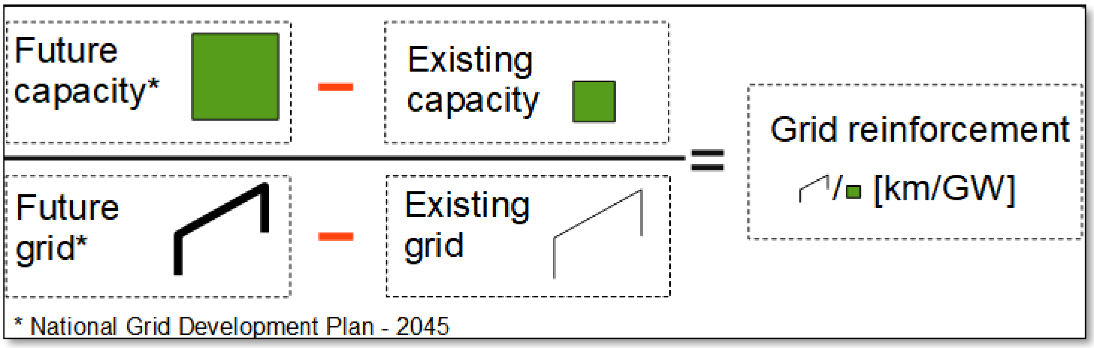


FIGURE 62.

Approach used to estimate required grid reinforcement considering new additions of solar and wind capacity.

Summarising, the calculations conducted were based on linear regression that can be expressed by means of the following formula:

$$TGE = \sum_{i=1}^{n} \max\left(Cap_i^{2050} - Cap_i^{Ex}; 0\right) * \alpha_i$$

where: TGE – grid expansion [km]; Cap_i^{2050} – projected capacity of technology i in year 2050 [GW]; Cap_i^{Ex} – existing capacity of technology i in year reference year [GW]; α_i – technology i specific grid expansion demand [km/GW]; n – set of technologies, including solar PV, onshore wind and offshore wind.

[204] TenneT (2023), Transmission System Operators Publish First Draft of Grid Development Plan for 2037/2045.

Appendix C Demand flexibility

C.1 Demand categories and profiles

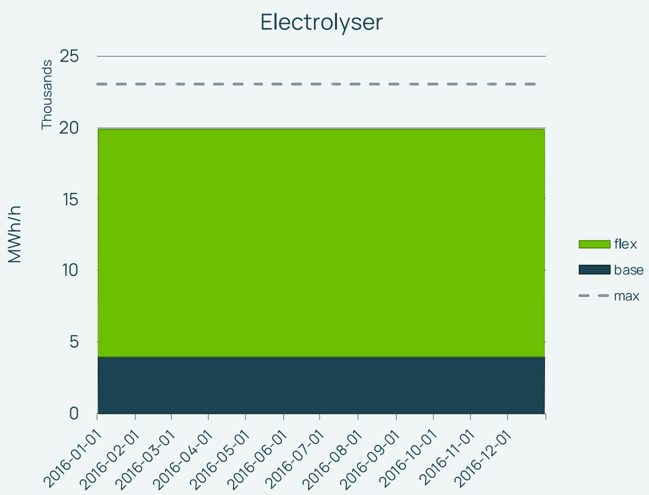
Definitions of demand categories and their granularity have been informed by four aspects:

1. Availability of data
2. Demand growth potential and associated uncertainty
3. Divergent profiles
4. Flexibility behaviour and potential

We have concluded seven different categories, as presented in FIGURE 7. First there is a category denoted "Losses". This category represents grid distribution losses with the assumption of 5%[205,206] of the demand, The remaining categories along with their demand profiles are introduced in TABLE 21.

TABLE 21.

Demand categories and associated demand profiles described in left column. The right column figures illustrate actual demand profile in 2050 along with its flexibility components for the reference sensitivity. 'flex', 'base' and 'max' represent flex_share, inflexible share and max_fraction, respectively, which are further described below.

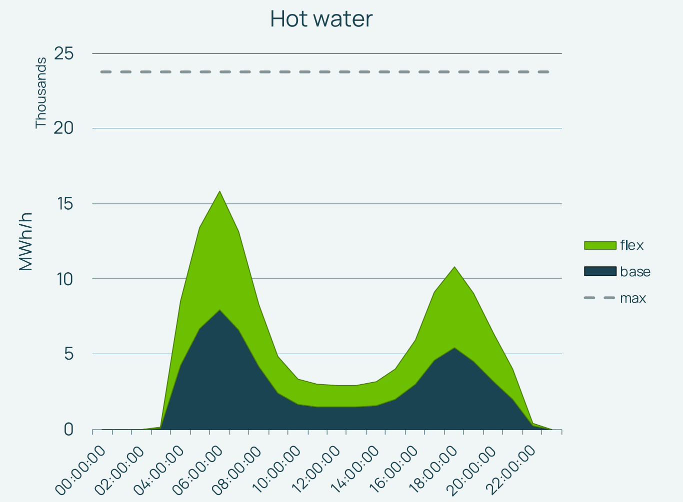
CATEGORY AND PROFILE DESCRIPTIONS	PROFILE
Electrolyser **Representing hydrogen production fulfilling demand outside electricity sector, i.e., excluding demand for regeneration of electricity with hydrogen gas turbines.** **Profile: flat**	

205 Svenska Kraftnät (2024), Långsiktig Marknadsanalys.
206 DEStatis (2023), Monatsbericht über die Elektrizitätsversorgung.

Hot water

Representing demand for sanitary heating with growth coupled to space heating.

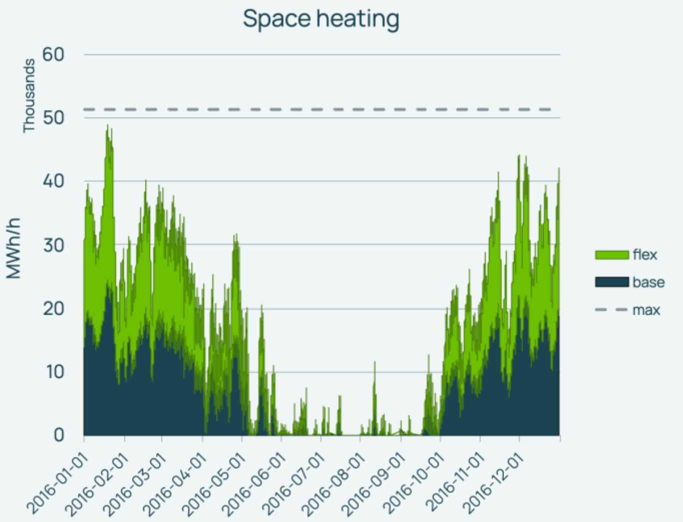
Profile: diurnal[207]



Space heating

Representing demand for heat pumps and electric heating. Electric heating consumption assumed to be 27 W/℃, capita in 2050, bit lower to what can be observed in Sweden, Finland and France today.

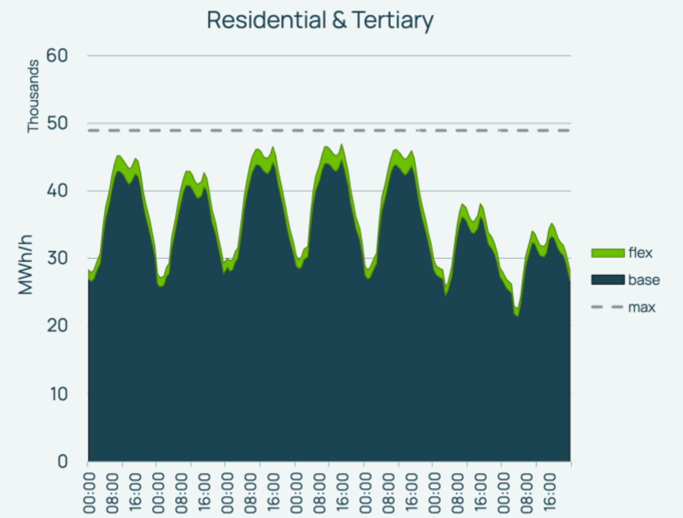
Profile: weather-dependent profile[208].



Residential & Tertiary

Representing households and tertiary activities (administration, shops, offices, education), but potentially further sectors such as farming and construction. Demand growth assumed to equal energy efficiency measures.

Profile: diurnal and weekday profile, based on observed load data per country from TRAPUNTA/ERAA209, heating and EV demand removed. Figure shows one week 8th to 14th January in weather year 2016.

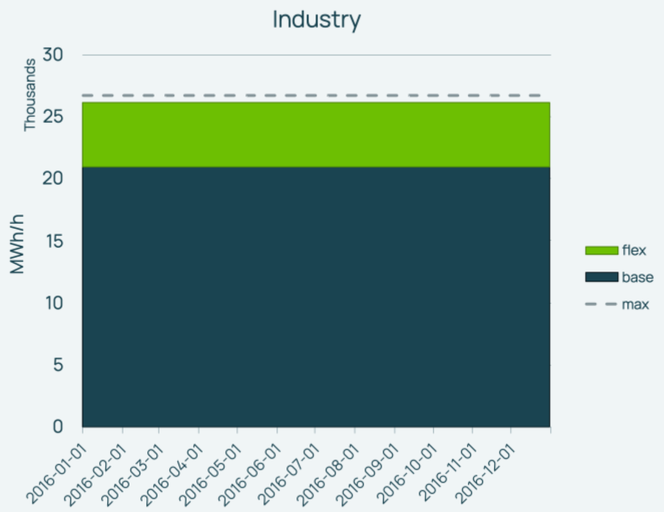


[207] ENTSO-E (2022), ERAA 2022 - Demand Forecasting. (Figure 16)
[208] International Conference on European Electricity Market, EEM (2023), Empirical Weather Dependency of Heat Pump Load: Disentangling the Effects of Heat Demand and Efficiency.
[209] ENTSO-E (2023), European Resource Adequacy Assessment 2023 Edition, Annex 2: Methodology.

Industry

Representing demand for manufacturing, chemicals, steel, aluminium, glass, etc. Data centres also included here.

Profile: flat

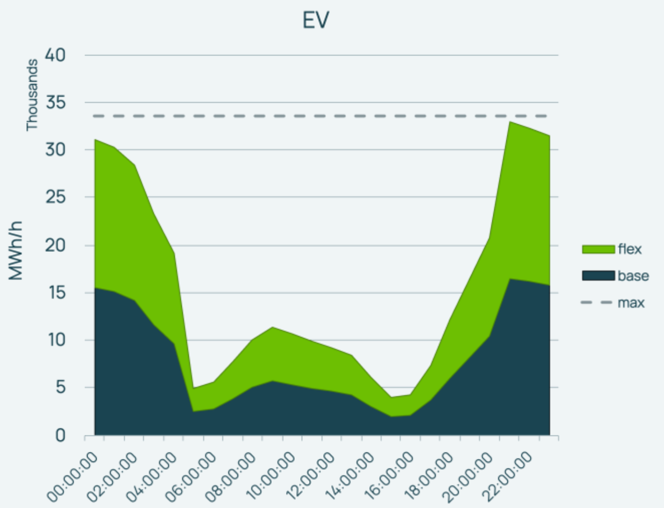


EV

Representing demand for EVs (neither trains nor goods). A share of 85% in 2050 of the passenger transport part (i.e., not trains or goods) assumed electrified. 16 850 pkm in DE in 2050[210].

Profile: diurnal. The used EV demand profile[211] combines a diverse mix of EV user groups with different types of potential flexibility.

- **Light-duty: charging ~1/week**
- **Medium-duty: ~1/day**
- **Heavy-duty: ~several/day and limited flexibility**



The scheduled demand time series for a given category *c* is calculated as the product of the demand profile time series and the average hourly demand:

$$demand^c(t) = profile^c(t) \cdot \frac{{demand_{tot}}^c}{\sum profile^c(t)}$$

Where ${demand_{tot}}^c$ is the total yearly demand (MWh) for category *c* and $profile^c(t)$ is the demand profile for category *c.*

The following two sections describe in more detail the two different forms of demand-side flexibility. Sections following motivate the input assumptions applied to each demand category, while values used in the model are compiled in TABLE 23 and APPENDIX C.9.

[210] European Commission (2020), EU Reference Scenario 2020.
[211] ENTSO-E (2022), ERAA 2022, Demand Data.

C.2 Shifting flexibility

The modelling incorporates two distinct forms of demand-side flexibility: shifting and cutting. The shifting demand response for a demand category is represented through three key parameters and input values:

1. A time series of the demand deemed flexible, defined by the product of the *flex_share* and demand profile of the category, denoted ‘flex’ in TABLE 21.

$$demand_{flex}{}^{c}(t) = flex\_share^{c} \cdot demand^{c}(t)$$
$$demand_{base}{}^{c}(t) = (1 - flex\_share^{c}) \cdot demand^{c}(t)$$

2. A maximum capacity measured in MW for the flexible load which represents to the maximum possible instantaneous consumption (“flex up”).

$$demand_{max}{}^{c}(t) = \max\left(demand_{base}{}^{c}(t)\right) + \max\left(demand_{flex}{}^{c}(t)\right) \cdot max\_fraction^{c}$$

3. A maximum time duration*, tau,* within which this flexible load can be shifted both forward and backward.

It is relevant to note that the energy of the flexible shifting load is always conserved, ensuring no energy is lost during the shifting process. The entire demand side flexibility implementation can be interpreted as a virtual storage with time-dependent energy and power capacities. For instance, consider the demand profile of electrolysers in TABLE 21. The flexible demand is 16 GWh/h. A time duration of $tau = 12d = 288h$, may then be interpreted as a virtual hydrogen energy storage with capacity $= 16 \cdot 288 = 4608$ GWh (~3.2 TWh H2).

Notably, the shifting demand-side flexibility comes at *no cost* to the German power system.

C.3 Cutting

The demand denoted *base*, is subject to cutting demand-side response, representing consumers cutting their demand when electricity prices are too high, i.e., a type of non-permanent demand destruction. The demand-side response of the cutting flexibility is defined by:

1. An electricity price interval $[p1, p2]$ in which demand is cut. Demand cut increases linearly with price as illustrated in FIGURE 63.
2. A share of demand that is allowed to be cut, cut_share. The minimum capacity following cut demand for category *c* is determined by:

$$demand\_min^{c} = (1 - cut\_share^{c}) \cdot demand_{base}{}^{c}$$

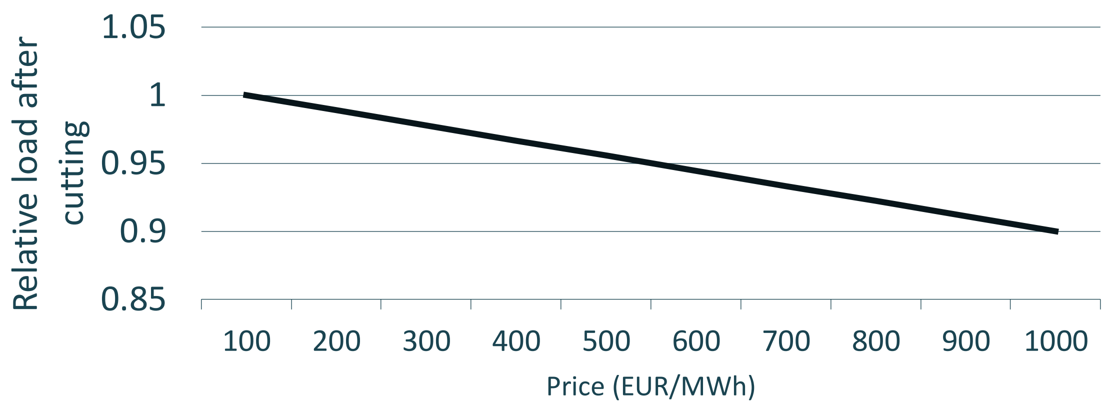


FIGURE 63.

Relative load after cutting demand side response as a function of the electricity price where $[p1, p2] = [100, 1000]$ €/MWh and $cut\_share = 10\%$.

The current analysis is predicated on the assumption that up to 10% of the baseload demand can be curtailed at a price of 1000 €/MWh. The cost structure is modelled to increase linearly from 100 to 1000 €/MWh for lower cuts, as depicted in FIGURE 63. These assumptions are inspired from the findings of the Swedish Transmission System Operator (TSO), which observed a reduction in demand ranging from 5-10% within the price range of [0, 700] €/MWh in a recent analysis examining the effects of the energy crisis[212].

Moreover, the model assumptions incorporate model definitions of the Swedish TSO, where approximately 3% of the demand was permitted to be curtailed within the price bracket of [50, 500] €/MWh[213]. Additionally, a recent study conducted by the ENTSO-E suggested that around 7% of the German demand could be eligible for curtailment within the price range of [100, 760] €/MWh for the model year 2030[214].

Finally, Value of Lost Load (VOLL) which applies to cutting demand in excess of 10% has been set to 5000 €/MWh.

C.4 Electric Vehicles

The overarching premise is that the total EV load should not exceed the grid's capacity estimated as the maximum demand allowed by the demand profile (*max_fraction* = 1). This assumption refers to the prediction that distribution grid capacities will be planned to meet maximum demand. The scenario considers a heterogeneous mix of EV user behaviours, each contributing differently to the grid's load. For light-duty EVs, it is assumed they will charge roughly once a week, whereas medium-duty EVs are expected to charge daily. Heavy-duty EVs, with their more frequent charging requirements, are assumed to provide limited flexibility due to their operational demands. A daily time flexibility window of 24 hours is allowed, optimistically[215] representing an aggregate view of the different user groups' charging needs. On this background, the flexibility share has been set to 50% (reference), 80% (optimistic) and 20% (conservative) for the different sensitivities in 2050. These levels of flexibility represent well the range presented in references[216,217,218,219,220,221], capturing a realistic spectrum of potential EV integration scenarios. It's important to note that while Vehicle-to-Grid (V2G) interactions are not modelled directly, their potential impact may be inferred through the optimistic scenario's assumption of high flexibility, pointing to a future where EVs could play a dynamic role in balancing the grid.

C.5 Heating

The parameters for flexibility in space and sanitary heating sectors were derived as follows. For space heating, the demand profile considers the passive thermal mass effect of the building stock, which

[212] Svenska Kraftnät (2023), Report on Reduction of Gross Electricity Consumption During Peak Hours in Sweden for December 2022.
[213] Svenska Kraftnät (2023), Kortsiktig marknadsanalys 2022.
[214] ENTSO-E (2023), European Resource Adequacy Assessment 2023 Edition, Annex 2: Methodology.
[215] A recent German vehicle-to-grid field trial indicates that vehicles are connected 12 hours per day during the week.
[216] BEIS (2020), Electricity System Flexibility Modelling.
[217] Electrification Futures Study: Scenarios of Power System Evolution and Infrastructure Development for the United States (2021).
[218] Agora Energiewende (2023): Haushaltsnahe Flexibilitäten nutzen.
[219] DNV GL Energy Sweden (2021), Socioeconomic Costs and Benefits of Smart Electricity Grids.
[220] Svenska Kraftnät (2024), Långsiktig Marknadsanalys.
[221] Bundesministerium für Bildung und Forschung (2016), Ergebnisse und Empfehlungen des BMBF-Forschungsprojektes Regenerative Stromversorgung & Speicherbedarf in 2050.

dictates the maximum flexibility fraction. A *max_fraction* of 1.1 has been determined based on a reasonable maximum value observed for extreme cold weather events. Notably, cold conditions provide little flexibility, whereas warm conditions allow for significant upward flexibility, even though the demand might be low. A four-hour time window (*tau*=4h) has been determined as most suitable. This is a relatively conservative estimate compared to studies deriving values of estimating heat pump demand flexibility via the thermal storage capacity of the building stock such as by the Bundesverband Waermepumpe[222], who conclude a flexibility value of around 20 hours. In Germany, current regulations allow for a two-hour shift in heat pump demand if a specific heat pump tariff is applied[223]. The flexibility share may be compared to the range of 0-90%[224] used in another modelling study as well as to the 85% share of heat pumps expected to be on dynamic tariffs by 2035[225].

Sanitary heating, on the other hand, allows for up-flexibility approximately two times the maximum observed demand. A twelve-hour time window (*tau*=12h) is considered feasible, provided there is significant storage capacity to manage diurnal electricity price variations. This is a more generous allowance compared to references, where in the USA by 2050, the time window and flexibility share are expected to be 4 hours and 25%, respectively[226].

C.6 Residential and Tertiary

The assumptions for the flexibility within the residential and tertiary sectors are primarily centred around the integration of home storage solutions and the utilisation of smart appliances. These technologies provide the foundation for flexible energy use, allowing for both demand-side management and response to varying energy prices or supply conditions. Two key sensitivities have been defined to encapsulate the range of potential scenarios: a conservative sensitivity that assumes no incentives or low incentives for the adoption of such technologies, and an optimistic sensitivity that assumes substantial incentives are in place, thereby reducing installation costs and encouraging widespread adoption. When benchmarked against existing literature, the flexible share for smart appliances is anticipated to fall between 0-3%[227]. Meanwhile, a recent study by Agora EnergieWende[228] suggests that by 2035 in Germany, 65% of home storage systems and 52% of households could be engaged with dynamic tariffs. These figures provide indications on the potential for increased flexibility through consumer-level technology adoption and the critical role of economic incentives in realizing this potential.

C.7 Industry sector

For the industry sector, demand flexibility was estimated based on a study by FfE[229] which quantified existing and future demand flexibility potentials in the German industry. The study provides estimates on various parameters such as reduceable, shiftable or destructible share, operational and investment costs for demand flexibility, overall demand, as well as shift durations for various technologies for various sectors such as industry, cross-over technologies in industry and trade and services. An excerpt of the summarised values is presented in the TABLE 22.

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[222] Ecofys (2011), Potenziale der Wärmepumpe zum Lastmanagement im Strom und zur Netzintegration erneuerbarer Energien
[223] Bundesministerium der Justiz (2024), § 14a Netzorientierte Steuerung von steuerbaren Verbrauchseinrichtungen und steuerbaren Netzanschlüssen; Festlegungskompetenzen.
[224] BEIS (2020), Electricity System Flexibility Modelling.
[225] Agora Energiewende (2023): Haushaltsnahe Flexibilitäten nutzen.
[226] U.S. Department of Energy Office of Scientific and Technical Information(2018), Electrification Futures Study: Scenarios of Electric Technology Adoption and Power Consumption for the United States.
[227] BEIS (2020), Electricity System Flexibility Modelling.
[228] Bundesministerium der Justiz (2024), § 14a Netzorientierte Steuerung von steuerbaren Verbrauchseinrichtungen und steuerbaren Netzanschlüssen; Festlegungskompetenzen.
[229] FfE (2021), Regionale Lastmanagementpotenziale.

TABLE 22.

Estimates on various parameters such as reduceable, shiftable or destructible share, operational and investment costs for demand flexibility, overall demand, as well as shift durations for various technologies and various sectors[230].

NAME	INSTALLED POWER	TOTAL CONSUMPTION [TWH]	REDUCABLE SHARE	SHIFTABLE SHARE	SHEDDABLE SHARE	MAX SHIFT DURATION [H]	COST REDUCE	COST SHIFT	COST SHED
Paper production 1	336	2.5	0.51	0.2	0.73	5	461	200	1470
Paper production 2	1400	12.1	0	0,1	0.9	2	0	200	710
Chlor Alkali Electrolysis	338	11.1	0.01	0.06	0.86	0.25	820	0	1100
Glas production	78	3.5	0.33	0	0.8	0	487	200	1110
Steel production 1	2050	6.6	0.11	0	0.95	0	564	0	620
Aluminium	1080	8.8	0	0.02	0.93	48	0	115	620
Data Centers	3800	14.9	0	0.35	0.45	5	0	0	8550
Waste Water	800	4.4	0	0.2	0.65	2	0	0	8550
Drinkable Water	1000	4.5	0	0.9	0.5	2	0	0	8550
Food Cooling	2800	14.2	0	0.41	0.57	2	0	0	2000

[230] FfE (2021), Regionale Lastmanagementpotenziale.

The methodology requires parameters for the shares that are flexible, the maximum demand at a given time as well as the value a scheduled demand can be shifted in time. To derive these parameters, several steps were taken:

I. Aggregate Installed Power: The first step involves summing up the installed power capacity across all industries. This total installed power provides a baseline for understanding the potential maximum demand.
II. Total Energy Consumption: Next, we add up the annual energy consumption figures from all sectors. This aggregation gives us a picture of the total energy demand over a year.
III. The demand flexibility of the different categories contains three values:
    a. Reducible: This is the portion of the energy consumption that can be reduced without significant disruption to the industrial processes or consumer activities. It is calculated as a product of the total consumption and the reducible share.
    b. Shiftable: This refers to the energy demand that can be shifted in time without affecting the overall energy consumption. To quantify it, we multiply the total consumption by the shiftable share.
    c. Destructible: This part of the demand can be temporarily turned off during peak times or when the energy system is under stress. It is found by multiplying the total consumption by the destructible share.
IV. Weighted Average Shift Duration: For the shiftable load, it is important to know the duration for which the load can be shifted. This is determined by calculating a weighted average of the maximum shift duration across all industries. We do this by multiplying the max shift duration by the shiftable consumption for each industry, summing these products, and then dividing by the total shiftable consumption.

Applying this methodology leads to the following results:

- Total Installed Power: The system's aggregate installed power is 13,682 MW.
- Total Consumption: The total energy consumption across the analysed sectors is 82.6 TWh.
- Reducible Load: 4% of the energy consumption is reducible, implying that this portion can be minimised without significant operational disruption.
- Shiftable Load: 22.4% represents the shiftable load, which can be deferred to different times of the day or night.
- Destructible Load: Independent of electricity prices a majority of 72% is destructible which can be completely turned off for short periods during peak demand or emergencies without compromising the processes. Below 1000 €/MWh this amounts to around 30%.
- Weighted Max Shift Duration: The average maximum duration for shifting loads is calculated to be 3.3 hours.

By consolidating the results of the analysis, we have set *tau* =4h, a cutting share to 30% and a flexible share to 20% in the reference scenario, see also APPENDIX C.9.

C.8 Electrolyser

The electrolyser category represents hydrogen production in the power sector. Electrolysis is inherently power-intensive, rendering hydrogen consumers heavily reliant on the electricity market. Consequently, these industrial consumers are acutely sensitive to fluctuations in electricity prices. Exploring diverse flexibility options has emerged as a crucial endeavour, with significant progress achieved through dual fuel operation. Notably, projects such as Salzgitter's dual fuel Direct Reduced Iron (DRI) initiative exemplify this approach[231], where electrolysers are operated during periods of low electricity prices while seamlessly transitioning to natural gas utilisation in industrial processes during periods of elevated electricity prices. Looking towards the future, the establishment of a mature hydrogen network and storage infrastructure holds the promise of fostering fossil-free flexibility in the long term.

TABLE 23.

Flexibility model definitions for the electrolyser demand category.

CATEGORY	SENSITIVITY	YEAR	SHIFTING			CUTTING	
			FLEX_SHARE	MAX_FRACTION	TAU	CUT_SHARE	[P1,P2]
Electrolyser	Optimistic	2030	0%	-	-	30%	[80,200]
		2035	70%	1.1	1d	20%	
		2040	80%	1.2	3d	10%	
		2045	90%	1.3	6d	5%	
		2050	100%	1.4	12d	0%	
	Reference	2030	0%	-	-	30%	
		2035	50%	1.1	1d	30%	
		2040	60%	1.1	3d	20%	
		2045	70%	1.2	6d	10%	
		2050	80%	1.2	12d	5%	
	Conservative	2030	0%	-	-	30%	
		2035	30%	1.1	1d	30%	
		2040	40%	1.1	3d	30%	
		2045	50%	1.1	6d	20%	
		2050	60%	1.1	12d	20%	

The assumptions governing electrolyser flexibility are presented in TABLE 23. The optimistic sensitivity aligns closely with the ambitious targets outlined in the hydrogen strategy, envisioning a comprehensive hydrogen network — encompassing pipelines and storage infrastructure — to be fully operational by 2035[232]. This sensitivity presupposes a progressive increase in electrolyser

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[231] Salzgitter AG (2024), Project mydral.
[232] FNB Gas (2024), Wasserstoff-Kernnetz.

overcapacity and storage capabilities, with flexibility expanding in tandem with the scale of *flex_share* and overall electrolyser demand. This is propelled by the availability of affordable electrolysers and efficient infrastructure deployment. For hydrogen consumers with limited access to hydrogen storage, flexibility is modelled to entail a reduction in demand within the price range of [80, 200] €/MWh, corresponding to approximately ~[2, 5] €/kgH2. However, as connections to the hydrogen network proliferate, the necessity for demand reduction is anticipated to diminish.

Conversely, the reference and conservative sensitivities present a more restrained outlook, characterised by a gradual rollout of the hydrogen network and storage infrastructure, alongside higher electrolyser costs resulting in limited overcapacity. Consumers within these sensitivities are expected to possess a prolonged capacity to curtail their demand as a safeguard against high electricity prices. The resulting input assumptions for the demand-side electrolyser charging capacity, derived based on the total electrolyser demand as well as the share flexible and the *max_fraction,* in the different sensitivities is presented in TABLE 24.

TABLE 24.

Total installed electrolyser capacity from electrolyser demand-side flexibility in the different sensitivities.

	SENSITIVITY	2030	2035	2040	2045	2050
Electrolyser charging capacity (GW)	Optimistic	1.8	4.7	9.2	16	28
	Reference	1.8	4.6	8.4	14	23
	Conservative	1.8	4.5	8.3	13	21

From a modelling perspective, a representative estimation of hydrogen energy storage capacity can be derived by multiplying the average hourly electrolyser consumption by the flexibility duration (*tau*). Consequently, the hydrogen storage capacity scales proportionally with the total electrolysis demand. The corresponding energy storage capacity for hydrogen is detailed in TABLE 25 and is assumed to incur no additional cost within the model.

TABLE 25.

Representative hydrogen thermal energy storage capacity translated from electrolyser demand-side flexibility in the different sensitivities.

	SENSITIVITY	2030	2035	2040	2045	2050
Storage energy capacity (GWh) [H2]	Optimistic	0	52	320	1100	4000
	Reference	0	37	240	860	3200
	Conservative	0	22	160	610	2400

C.9 Summary

Tables below compile the flexibility parameter assumptions for all categories except electrolyser, which is given separately in TABLE 23, and losses which is assumed inflexible.

TABLE 26.

Model shifting and cutting parameter definitions by demand categories. Parameters are fixed with regards to sensitivity and model year.

CATEGORY	SHIFTING		CUTTING	
	MAX_FRACTION	TAU	CUT_SHARE	[P1,P2]
Residential & Tertiary	1.0	4h	10%	[100, 1000]
EV	1.0	24h	0%	-
Space Heating	1.1	4h	10%	[100, 1000]
Sanitary Heating	2.0	12h	10%	[100, 1000]
Industry	1.1	4h	30%	[100, 1000]

TABLE 27.

Definition of flexible share for shifting demand by demand category, sensitivity and model year. A potential linear growth is assumed between 2030 and 2050.

CATEGORY	SENSITIVITY	FLEX_SHARE	
		2030	2050
Residential & Tertiary	Optimistic	10%	20%
	Reference	5%	5%
	Conservative	0%	0%
EV	Optimistic	30%	80%
	Reference	20%	50%
	Conservative	10%	20%
Space heating	Optimistic	40%	90%
	Reference	20%	50%
	Conservative	5%	10%
Sanitary heating	Optimistic	40%	90%
	Reference	20%	50%
	Conservative	5%	10%
Industry	Optimistic	20%	40%
	Reference	20%	20%
	Conservative	0%	0%

Appendix D Description of LCOE calculations

The Levelised Cost of Electricity (LCOE) is a metric used to determine the average cost of producing one MWh of electricity over the lifetime of a power generation project. It combines the initial construction cost, annual fixed and variable operating costs, and the electrical output to provide a standardised measure of the cost of electricity. Here is how LCOE is calculated, broken down into its key components:

1. Construction Cost (€/MW):

Represents the upfront cost of building the power generation facility, accounting for construction duration and interest rate. The interest rate has been assumed to be half of the WACC.

$$construction\_interest\_rate = WACC/2$$

$$\begin{aligned} construction\_cost \\ &= overnight\_capital\_cost * (1 + construction\_interest\_rate)^{construction\_duration} \\ &- overnight\_capital\_cost \end{aligned}$$

2. Investment Cost (€/MW):

The total investment required for the project, combining the construction cost, overnight capital cost, and grid connection cost.

$$investment\_cost = construction\_cost + overnight\_capital\_cost + grid\_cost$$

3. Annuity Factor:

Factor used to calculate annualized costs, incorporating the Weighted Average Cost of Capital (WACC) and the project's capital recovery period.

$$annuity\_factor = \frac{WACC * (1 + WACC)^{capital\_recovery\_period}}{(1 + WACC)^{capital\_recovery\_period} - 1}$$

4. Annual Costs (€/MW/yr):

Annual costs are relevant for investment as well as fixed costs for operating and maintaining the facility, which may involve reinvestment.

$$annual\_investment\_cost = investment\_cost * annuity\_factor$$

$$annual\_fixed\_OM = fixed\_OM + reinvestment$$

5. Marginal Cost of Electricity (€/MWh):

Additional cost associated with producing one extra MWh of electricity, incorporating variable operating costs and fuel expenses.

$$\begin{aligned} marginal\_cost\_of\_electricity \\ &= total\_variable\_cost + fuel\_price\_per\_MWh\_with\_upstream\_emissions \end{aligned}$$

Here the total variable cost comprises variable OM as well as potential tariffs for transport and storage of CO_2 ($variable\_cost\_CCS$). Fuel price per MWh (fuel cost per MWh of generated electricity) with upstream emissions (€/MWh) is calculated according to:

$$fuel\_price\_per\_MWh\_with\_upstream\_emissions = fuel\_price\_per\_MWh + (CO2\_price * CO2\_emission\_coefficient\_upstream * heat\_rate)$$

Where $CO2\_emission\_coefficient\_upstream$ represents indirect emissions associated with the combustion of the fuel. For thermal power plants with direct emissions cost of emitting CO_2 is added to the marginal cost of electricity in the following way:

$$marginal\_cost\_of\_electricity += CO2\_price * CO2\_emission\_coefficient * heat\_rate * (1 - carbon\_capture\_efficiency)$$

6. Full Load Hours (hours):

Number of hours in a year that the power plant operates at full capacity, determined by the capacity factor.

$$full\_load\_hours = 8760 * capacity\_factor$$

7. LCOE (€/MWh):

Primary metric indicating the cost of generating electricity per MWh over the project's lifetime.

$$LCOE = \frac{annual\_\_investment + annual\_fixed\_OM}{full\_load\_hours} + marginal\_cost\_of\_electricity$$

Appendix E Methodology for emission, land use and use of critical minerals & materials

TABLE 28 presents general assumptions on aspects of sustainability for the technologies considered in the current report. These are further introduced and motivated in the sections below.

TABLE 28.

Greenhouse gas emission, land use and critical minerals factors for different power and energy generation sources. Open cycle, combined cycle, carbon capture & storage and photovoltaic abbreviated as OC, CC, CCS and PV respectively.

Power generation type	Emissions (kg CO_2eq/MWh)	Land use (km^2/TWh)	Critical minerals & materials (kg/MW)
Battery discharge	**160***	**21**	**6834**
Biomass	230	580	0
Hard coal	820	17	2485
Hard coal CCS	220	24	2485
Gas OC	735	0.8	1166
Gas CC	490	0.8	1166
Gas CCS	170	1.3	1166
Hydropower	24	11	0
Nuclear	12	1	5274
Solar PV	48	21	6835
Wind Offshore	12	1	10167
Wind Onshore	11	1**/150***	10167

*Storage emissions are calculated via installed capacity
**Direct land use
***Project site area land use

E.1 Assumptions for the current study

For this study, the project site area was used for wind power (i.e., the area of the entire farm), but direct impact is also shown in TABLE 28. Using direct land use value instead would reduce the total land use results to ~20% of the stated value, but project area was chosen since the entire site area is affected at some level. For PV, it was assumed that 30% of existing and new PV was ground mounted and 70% was roof mounted[233]. Bioenergy in European countries is generally mainly generated using

[233] IEO (2023), Rynek fotowoltaiki w Polsce.

forest biomass, where some is direct use, and some are by-products [234]. Biomass was therefore assumed to use 70% of the emission and land use allocation of a purpose grown, dedicated energy biomass [235].

E.2 Energy use and installed generation capacity

The energy use and installed capacity used in calculations are a result from the simulations of this report. The normalized yearly energy consumption was used for emission calculations and land use whereas the installed capacity was used for critical material use.

E.3 Greenhouse gas emissions

Greenhouse gas emissions quantify the increase in atmospheric greenhouse gases, measured in kg CO_2eq/MWh. The data used was taken from IPCC[236] and Electricity Maps[237] and includes the entire life cycle of the generation type, both for the fuel and the generation plant. The global median life cycle emissions were used. Battery discharge emissions were calculated using 160 kg CO_2eq/MW installed capacity[238], and then adding the emissions of the local electricity mix for the energy discharged by batteries for that year. CCS was assumed to have a capture efficiency of 75-90 %[239]. Electricity generation from biomass by-products and waste can be assumed to have a lower emission impact then dedicated biomass. In several methodologies, waste and by-products are not assigned any allocation and have a zero-emission value for greenhouse gases[240]. In this way, some of the bioenergy was assumed to have a lower emission than the listed values, as seen in the specific assumptions for this study.

E.4 Land use

All land use values are taken from UNECE[241] and include the land for mining the materials, manufacturing, and installation. In addition, the value for wind power is validated with the median project site land use from National Renewable Energy Laboratory (NREL)[242].

Land use for biomass, wind power and use are all varies depending on the method used for calculation. Wind power either use directly impacted land use or project site land use, where the former is the immediate area around the wind turbine and the latter includes the spacing between turbines as well. For PV, roof mounting was assumed to have zero direct land use while ground mounted PV have both the direct land use and the land use from mining and such. Biomass grown for dedicated energy usage have a higher land use area than biomass from waste or by-products, where the land use is allocated on the primary product and can be considered less for the by-product[243]. To accommodate for this, and the lack of accurate source data for biomass, an assumption of 70% of the listed land use value were used as an aggregate.

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234 European Commission (2024), Bioenergy report outline.
235 Assumption based on Polish biomass composition.
236 IPCC (2018), Annex III Technology-specific Cost and Performance Parameters.
237 Electricity maps (2023), Methodology.
238 IVL (2019), Lithium-ion Vehicle Battery Production.
239 IPCC (2018), Annex III Technology-specific Cost and Performance Parameters.
240 Frontiers (2022), RED, PEF, and EPD: Conflicting Rules for Determining The Carbon Footprint Of Biofuels Give Unclear Signals To Fuel Producers and Customers.
241 UNECE (2022), Carbon neutrality in the UNECE region.
242 NREL - National Renewable Energy Laboratory (2009), Land-Use Requirement of Modern Wind Power in the United States.
243 How much is less is intensively discussed in the LCA community. As an example, Brandao et al (2022) suggest 50% for HVO and a variable amount for biogas from waste.

E.5 Critical metals & minerals

The use of critical materials per installed capacity is taken from IEA[244], and includes the use of the critical minerals copper, nickel, manganese, cobalt, chromium, molybdenum, zinc, rare earth minerals and silicon, as well as minor critical minerals. All values include the life-cycle material use, but not the energy infrastructure such as the power grids.

[244] IEA (2022), The Role of Critical Minerals in Clean Energy Transitions.

Appendix F List of abbreviations

ABBREVIATION	DEFINITION
APR	The Advanced Power Reactor
BECCS	Bioenergy with Carbon Capture and Storage
CCS	Carbon Capture and Storage
CCUS	Carbon Capture, Utilisation and Storage
CF	Capacity Factor
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CHP	Combined Heat and Power
DRI	Direct Reduced Iron
EEG	Germany's Renewable Energy Sources Act
ENTSO-E	European Network of System Operators for Electricity
ENWG	Germany's Energy Industry Act
ERAA	European Resource Adequacy Assessment
€	Euros
EV	Electric Vehicles
GAS CC	Gas combined-cycle gas
GAS CCS	Gas combined-cycle natural gas power plant equipped with carbon capture
GDP	German Grid Development Plan
GHG	Greenhouse gas emissions
GIS	Geographic Information System
HYDROGEN OC	Hydrogen-fuelled open-cycle turbine power plant
LCOE	Levelised Cost of Electricity
LNG	Liquefied Natural Gas
LULUCF	Land Use, Land-Use Change, and Forestry
MT	Million tons
MW	Megawatts
NREL	National Renewable Energy Laboratory
OM	Operation and Maintenance

OSM	OpenStreetMap
PCCC	Post combustion CO_2 capture
SOLAR PHOTOVOLTAIC	Solar PV
TSO	Transmission System Operator
VOLL	Value of Lost Load
VRE	Viable Renewable Energy
VVER	The water-water energetic reactor
V2G	Vehicle-to-Grid
WACC	Weighted Average Cost of Capital

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