Quantified Carbon

Role of Nuclear in Germany’s Decarbonisation

A STUDY BY QUANTIFIED CARBON

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ABOUT THIS PUBLICATION

This report has been prepared by Quantified Carbon (QC) for WePlanet-DACH to simulate the decarbonisation of the German power sector and provide policy recommendations. The objective is to compare two technology scenarios with and without nuclear on their potential to meet Germany's 2045 climate neutrality goals.

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

Germany's energy transition, known as the Energiewende, is centred on deploying renewable energy sources and phasing out fossil fuels and nuclear power to achieve climate neutrality by 2045[1]. While the transition to renewable energy has been progressing, the nuclear phase-out reaching completion in April 2023 has introduced new challenges, especially in maintaining energy security, affordability, and resilience. The exclusion of nuclear energy, once seen as a reliable low-carbon energy source, has raised concerns about the ability to meet Germany's ambitious climate goals while keeping energy costs competitive, especially for industry[2].

Germany's nuclear phase-out has sparked extensive analysis[3,4], with studies emphasising the missed opportunities for deeper emissions reductions and cost savings if the nuclear fleet had remained operational. However, the focus now shifts to the future. While recent reports explore the potential for restarting recently closed reactors by the early 2030s[5], this study takes a long-term perspective, envisioning Germany's power system in 2045 when climate neutrality is targeted.

This report examines two technology pathways—one including nuclear power and one excluding it—against the backdrop of projected developments in the European electricity market. Key factors shaping this future include high CO_2 prices, strong electrification driving growing power demand, enhanced demand-side flexibility, cost reductions for supply technologies, decarbonised power trade, and a maturing European nuclear industry. By leveraging a sophisticated modelling framework that incorporates realistic electricity market dynamics across 33 historical weather years, this analysis highlights the potential role nuclear power could play in fostering a resilient, competitive, and fully decarbonised German economy.

The two scenarios for Germany's power system are defined as "Nuclear," which includes nuclear power, and "VRE100," which excludes nuclear power and relies solely on renewables for clean energy. These scenarios represent power systems with distinct capacity and generation mixes, evaluated using the parameters outlined in Table 1. The findings are unequivocal: incorporating nuclear power, even with rather conservative cost assumptions, into Germany's energy policy yields significant advantages across all metrics. A nuclear-inclusive power mix offers a more balanced, competitive, and stable market, enhanced energy security, and a more feasible pathway to decarbonisation. In contrast, excluding nuclear results in higher costs and complex challenges related to system integration and resource constraints, ultimately jeopardising climate goals.

Based on the analysis, the study proposes four **policy recommendations**:

1. **Adopt a technology-inclusive policy:** Develop a balanced energy strategy incorporating nuclear power alongside renewables, streamline permitting processes, and reduce barriers for all clean energy technologies to ensure climate goals and competitiveness.
2. **Restart recently closed nuclear plants:** Extend the lifetimes of recently shut-down reactors until 2050 to provide reliable firm power, lower costs, and support renewable energy integration.
3. **Prepare for new nuclear construction:** Establish regulatory frameworks, secure financing, and build workforce capacity to accelerate nuclear development in line with Germany's 2045 climate targets.
4. **Advance renewable energy deployment:** Promote onshore wind, solar, and battery storage while addressing local conflicts, improving grid infrastructure, and enhancing flexibility solutions.

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[1] Federal Ministry for Economic Affairs and Climate Action of Germany (BMWK).

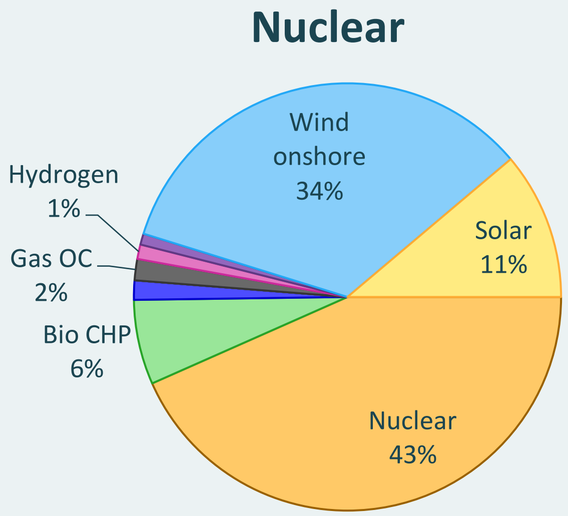
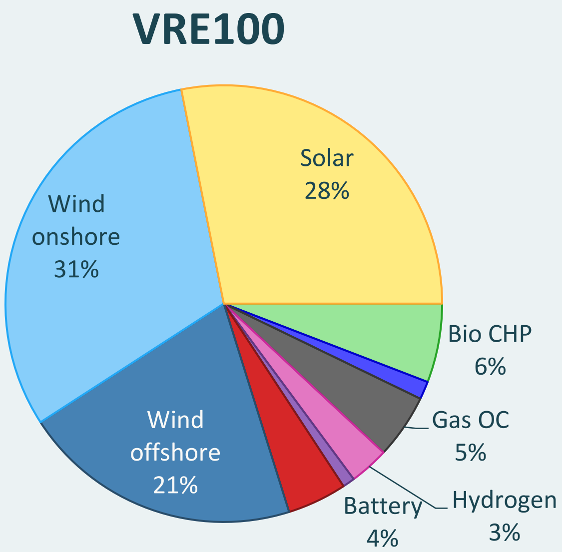
[2] Clean Energy Wire. Public discontent with government risks slowing Germany's climate efforts. August 10, 2023.

[3] Energy Policy (2024), Postponing Germany's nuclear phase-out: A smart move in the European energy crisis?

[4] International Journal of Sustainable Energy (2024), What if Germany had invested in nuclear power?

[5] Radiant Energy Group (2024), Restarting Germany's Reactors: Feasibility and Schedule

Table 1. Relative change in the "Nuclear" vs. the "VRE100" scenario presented for different parameters covering aspects of competitiveness, energy security, reliance on transmission infrastructure and sustainability. The right-most column presents German power system generation mixes for the two scenarios with the share of the primary technologies highlighted.

		Relative change: **“Nuclear” vs “VRE100”**	**Generation mixes**
Total system cost		-20%	
Average electricity price		-22%	
Electricity price volatility		-18%	
Energy security	**Import costs**	-37%	
	Gas consumption	-69%	
Transmission costs		-92%	
Emissions	**Life cycle**	-62%	
	Direct emissions	-67%	
Land use		-7%	
Use of critical materials		-40%	

1 Introduction

The core of the German energy transition (known in Germany as the Energiewende) is the deployment of renewable energy sources in the power sector, accompanied by the phase-out of fossil fuels and nuclear power[6]. The nuclear phase-out, finalised in April 2023 with the shutdown of the country's last reactors, was triggered by the Fukushima disaster in 2011 and reflected deep-rooted public opposition to nuclear technology[7]. The removal of nuclear power as a low-carbon energy source has complicated Germany's journey toward climate neutrality by 2045. Recent news has raised significant concerns about Germany's ability to meet climate goals while maintaining energy security[8,9,10]. Additionally, critics also surged regarding Germany's power system competitiveness[11] and German industry's competitiveness[12]. More and more businesses now even perceive the energy transition as a threat rather than an opportunity due to high energy costs[13].

As pointed out by a counterfactual scenario study, the postponement of the nuclear phaseout from the end of 2022 to the 15th of April 2023, reduced gas-fired power generation by 1.6 TWh in Germany and a decrease of electricity prices by 9 €/MWh[14]. Meanwhile, according to DIW's study, the nuclear phase-out would lead to higher carbon emissions in the interim, as Germany has ramped up the use of lignite (a particularly polluting form of coal) and imports to fill energy gaps, which was estimated to an increase in CO_2 emissions of around 40 million tons yearly[15]. Furthermore, after nuclear phase-out, Germany's Ministry for Economic Affairs and Climate Action (BMWK) has agreed to provide subsidies of €16 billion to build four major natural gas plants (10 GW), which was announced by the governing coalition as "in addition to the consistent expansion of the renewable energies". However, this was criticised for being far away from sufficient to guarantee supply[16]. Additionally, the energy crisis caused by the war in Ukraine further tested Germany's energy resilience, exposing vulnerabilities in its power system after the exit from nuclear. This has sparked a broader debate about whether Germany's stance on nuclear energy has been too rigid, especially given the global push to expand nuclear power as part of a balanced, low-carbon energy mix[17].

The phase-out of nuclear energy places increasing pressure on the expansion of renewables, as well as on the development of energy storage technologies to balance out the intermittency of solar and wind power. Germany is making massive strides in renewable energy deployment, aiming for renewables to provide 80% of electricity by 2030 and nearly 100% by 2035[18]. Despite its significant progress in renewable energies, several challenges still exist that impact the achievement of these targets. Grid infrastructure expansion has not kept pace with the increased capacity from renewables. This lag creates inefficiencies in power distribution, where energy is generated in areas with high renewable output (such as wind-heavy northern regions) but cannot be effectively transferred to

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[6] Federal Ministry for Economic Affairs and Climate Action of Germany (BMWK). National Energy and Climate Plan updated. October 21, 2024.

[7] Federal Office for the Safety of Nuclear Waste Management. The nuclear phase-out in Germany. January 31, 2024.

[8] Clean Energy Wire. Public discontent with government risks slowing Germany's climate efforts. August 10, 2023.

[9] European Commission. Germany's draft updated national energy and climate plan. December 2023.

[10] Clean Energy Wire. Germany set to miss emissions targets, "climate cabinet" could develop strategy – govt advisors. June 03, 2024.

[11] KFW Research. Germany's competitiveness – from 'sick man of Europe' to superstar and back: Where does the economy stand? May 17, 2024.

[12] Clean Energy Wire. Record number of German firms worry about competitiveness due to energy transition – survey. August 08, 2023.

[13] Clean Energy Wire. Energy costs, uncertainty fuel German industry plans to cut or relocate production – survey. August 02, 2024.

[14] Glynos D, Scharf H. Postponing Germany's nuclear phase-out: A smart move in the European energy crisis?. Energy Policy. 2024 Sep 1;192:114208.

[15] DIW. Nuclear turnaround: Shutdown of nuclear power plants opens up prospects for the search for a final storage facility. 2021.

[16] Clean Energy Wire. Germany to hold tenders for new gas power plants "soon", promises capacity mechanism. February 06, 2024.

[17] Politico. Germany leaves door open for extending nuclear power use amid energy crisis. July 18, 2022.

[18] Clean Energy Wire. Germany's greenhouse gas emissions and energy transition targets. September 11, 2024.

demand centres in the south[19]. Delays in the development of both onshore and offshore grid connections are jeopardizing the timely commissioning of new wind farms in Germany, for example, a recent 6 GW offshore wind were delayed up to two years due to grid connection delays[20]. A lack of grid capacity has led to the increase of re-dispatch measures which include curtailing renewable power output. About 19 TWh of electricity were curtailed in 2023, up from 14 TWh in 2022. Due to grid bottlenecks, other non-curtailment regions, such as in western and southern Germany, had to use fossil fuel power plants to cover up[21]. The deployment of renewables also faces regulatory and market-related obstacles. Apart from the lengthy permitting processes and delay of offshore wind projects, supply chain issues and rising raw material costs further hinder progress[22]. Additionally, renewable energy profitability is affected by market volatility, with negative prices during high-output periods limiting returns on investment. These add pressure to the economic sustainability of Germany's renewable energy deployment, as renewables depend on stable grid access and market incentives to remain viable.

Germany has dedicated to reducing greenhouse gas emissions and set binding targets to achieve climate neutrality by 2045 in the Climate Change Act (Klimaschutzgesetz)[23]. Meanwhile, Germany does not adopt a technology-neutral approach, which was examined in this study through the adoption of two different technology scenarios, including a nuclear scenario (denoted "Nuclear") reflecting the technology neutral perspective and a no-nuclear scenario (denoted "VRE100"). The objective is to explore how these technology scenarios can lead to different results in terms of technology choices, electricity generation, system costs, electricity prices and volatility, energy security, infrastructure requirements (including hydrogen and electricity grids), lifecycle greenhouse gas (GHG), and the demand for critical raw materials, on the way to attain a fully decarbonised German power system by 2045.

In contrast to the studies highlighting the role of nuclear power in a retrospective "what-if" approach[24], the current study adopts a long-term perspective, exploring the future landscape of Germany's power system in 2045, when climate neutrality is envisioned. This timeline carries significant uncertainties, making it imperative to incorporate projected developments in the European electricity market. Key factors shaping this market include:

- High CO_2 prices driving decarbonisation efforts,
- Strong electrification reflected in growing power demand,
- Enhanced demand-side flexibility enabled by technologies such as electric vehicles, residential storage systems, and electrolysers paired with hydrogen storage,
- Cost reductions for supply technologies due to technological advancements,
- Decarbonised power trade across a European grid, and
- A maturing European nuclear industry.

Against this backdrop, the report investigates two technology pathways—one with nuclear power and one without—to explore the potential role nuclear energy can play in Germany's transition to a resilient, competitive, and fully decarbonized economy by 2045.

Utilising a dedicated multi-year capacity expansion optimisation framework, the study presents scenarios developed while considering the nuances of German energy policy. With an emphasis on 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.

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[19] Clean Energy Wire. Germany's north-south power line SuedWestLink will extend to Bavaria. February 09, 2024.

[20] WindEurope. Uptake in permitting and investments brings 2030 wind target within reach. Februray 28, 2024.

[21] Clean Energy Wire. Curtailing of renewable power increases in Germany in 2023 as re-dispatch costs recede. April 09, 2024.

[22] Adelphi USA-Germany Climate & Energy Partnership. Onshore wind supply chains in the US and Germany. Janurary 2023.

[23] Federal Ministry of Justice of Germany. Federal Climate Action Act.

[24] Emblemsvåg J. What if Germany had invested in nuclear power? A comparison between the German energy policy the last 20 years and an alternative policy of investing in nuclear power. International Journal of Sustainable Energy. 2024 Dec 31;43(1):2355642.

The report begins with an introduction outlining the context and scope of the study. Section 2 details the study’s design, including the methodology, scenarios, and input assumptions. Section 3 presents the findings, compares the scenarios, and offers insights into decarbonisation pathways. Section 4 examines the key barriers to decarbonisation based on the results. Finally, Section 5 concludes with policy recommendations.

2 Study design

2.1 Overall method

The overarching objective for this work is to answer the following question:

> **QUESTION:**
>
> "Which potential role can nuclear power play in the German transition to a resilient, competitive & fully decarbonised economy until 2045?"

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

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

- The two technology scenarios, i.e. a technology neutral scenario, denoted "Nuclear" and a no-nuclear scenario, denoted "VRE100".
- A single-stage 2045 modelling run is made with essentially no constraints on build-rates, ultimately highlighting the long-term aspects of a future decarbonised German power system in these two technology scenarios.
- Scenarios are built based on best estimates on input assumptions:
    - Investment and operational costs
    - Commodity and CO_2 prices
    - Development of power systems in neighbouring bidding zones along with grid reinforcements
    - Technical land-use constraints
    - Demand growth & flexibility

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 varying weather years.
- Energy security[25], average electricity prices and electricity price volatility are determined which together with total system costs provide key insights on sustainability and competitiveness.
- Lifecycle greenhouse gas emissions, reliance of power and hydrogen transmission infrastructure along with land usage and use of critical materials complement the comparison.

The study design and overall methodology is illustrated in Figure 1.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.

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

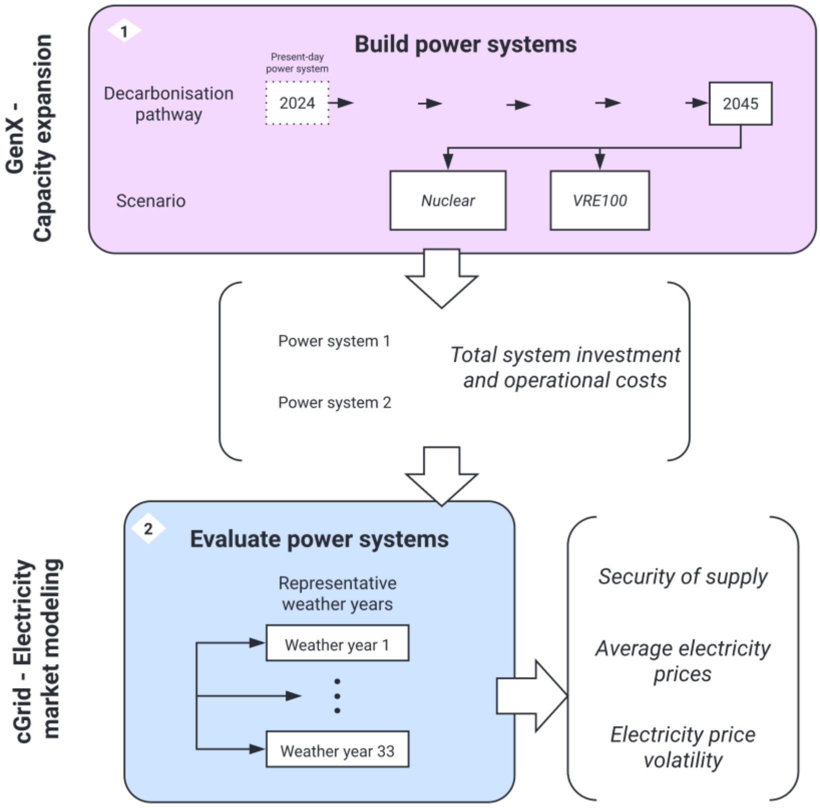

Figure 1. Flow chart illustrating overarching study design and methodology.

The methodology combines the best of different types of modelling tools. GenX builds cost-optimal power systems based on the prerequisites presented earlier forming the initial optimisation step. 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 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. 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 or hydrogen storage utilised to fuel hydrogen gas turbine power plants. cGrid is an in-house developed and maintained tool, which can perform 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. The detailed presentation of the tools and methodologies is outlined in QC's recent scientific paper[26] along with its supplemental materials[27].

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.

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[26] Cox et al. Robust capacity expansion planning in hydro-dominated power systems: a Nordic case study. November 2024. Submitted for scientific publication.

[27] Cox et al. Supplemental material: Robust capacity expansion planning in hydro-dominated power systems: a Nordic case study. November 2024. Submitted for scientific publication.

2.2 Scenarios and input assumptions

2.2.1 Scenarios

The study considers two primary technology scenarios. The first, referred to as the “Nuclear” scenario, assumes a technology-neutral setting. In this scenario, restart of recently shutdown reactors gains political support. Groundwork is being laid for the construction of new nuclear power with the expectation that new plants may come online beyond 2040. The second scenario referred to as “VRE100”, excludes nuclear power from the modelling. This scenario best represents current German energy policy. A third scenario denoted “VRE100 Clean” is also considered specifically in Section 3.8. Here the emission reduction in the VRE100 is forced to meet the same level as the “Nuclear” scenario. In all scenarios, 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 but carbon capture and storage (CCS) is excluded.

2.2.2 Input assumptions

The section below provides an overview of the study’s input assumptions, with further details available in CATF Germany report[28]. “Appendix A Methodology for emission, land use and use of critical minerals & materials” outlines the methodology and assumptions used for lifecycle estimates of emissions, land use, and critical mineral consumption.

CO2 emissions:

- On the background of producing realistic power trade and level of decarbonisation, a set CO2 price drives the decrease in direct emissions. Aligned with levels of advanced economies with net-zero pledges in 2050, the CO2 price in this study is set to be 250 €/tCO2 in 2045[29].

Trade:

- The trade assumptions for the electricity market optimisation consider cross-border electricity trade with Germany’s neighbouring countries. The installed generation capacities for the power system technologies in the regions’ surrounding Germany are fixed in the current simulations. They have been determined through a pre-optimisation accounting for projected decarbonisation pathways which ensures a balanced and realistic representation of power market revenues reflecting the interconnected nature of a future European electricity market.
- The simulations assess the challenges of managing capacity margins, particularly under varying weather conditions across the full set of weather years.

Demand and flexibility:

The demand and flexibility assumptions categorise different energy consumption profiles and their associated flexibility, which reflects the varying behaviours and requirements of each sector.

- Electrolyser: Focused on hydrogen production, it addresses the demand outside the electricity sector, representing a growing share of clean energy solutions.
- Hot water: Has a diurnal (daily) demand profile, growing alongside space heating demand, which suggests energy use concentrated during certain times of the day.
- Space heating: This is temperature-dependent, with electric heating consumption projected to reach 27 W/°C per capita by 2050, comparable to current levels in Sweden, Finland, and France.
- EVs: Also follow a diurnal profile[30], with a projected 85% of passenger transport (i.e., not trains or goods) electrified by 2050, representing a significant demand increase as 16 850 passenger-kilometres (pkm) are expected in Germany alone[31].
- Industry: Covers manufacturing sectors like chemicals, steel, aluminium, and glass, as well as data centres, with a relatively flat energy consumption profile, implying stable, continuous demand.

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[28] Quantified Carbon & CATF. Power System Expansion in Germany. 2024. To be published.

[29] IEA. World energy outlook 2022. November 2022.

[30] ENTSO-E. Demand data.

[31] European Commission. EU reference scenario 2020.

- Losses: Grid distribution losses are estimated at 5%, highlighting energy inefficiencies within transmission systems[32,33].
- Residential & tertiary: These sectors follow both diurnal and weekday profiles, derived from observed load data by country[34]. It is assumed that any increase in demand will be offset by energy efficiency measures, maintaining a balance in overall consumption growth.

The Figure 2 below shows the electricity demand by sector from 2020 and its projection towards 2045 in Germany. The base trajectory has been built from the technology-driven scenario developed in a study by Ember[35] with refinements into further sub-categories as well as the addition of grid losses. Notably, the demand scenario employed in this study reflects a pathway where Germany successfully electrifies a significant portion of its energy usage while retaining energy-intensive industries domestically, avoiding the outsourcing of production abroad.

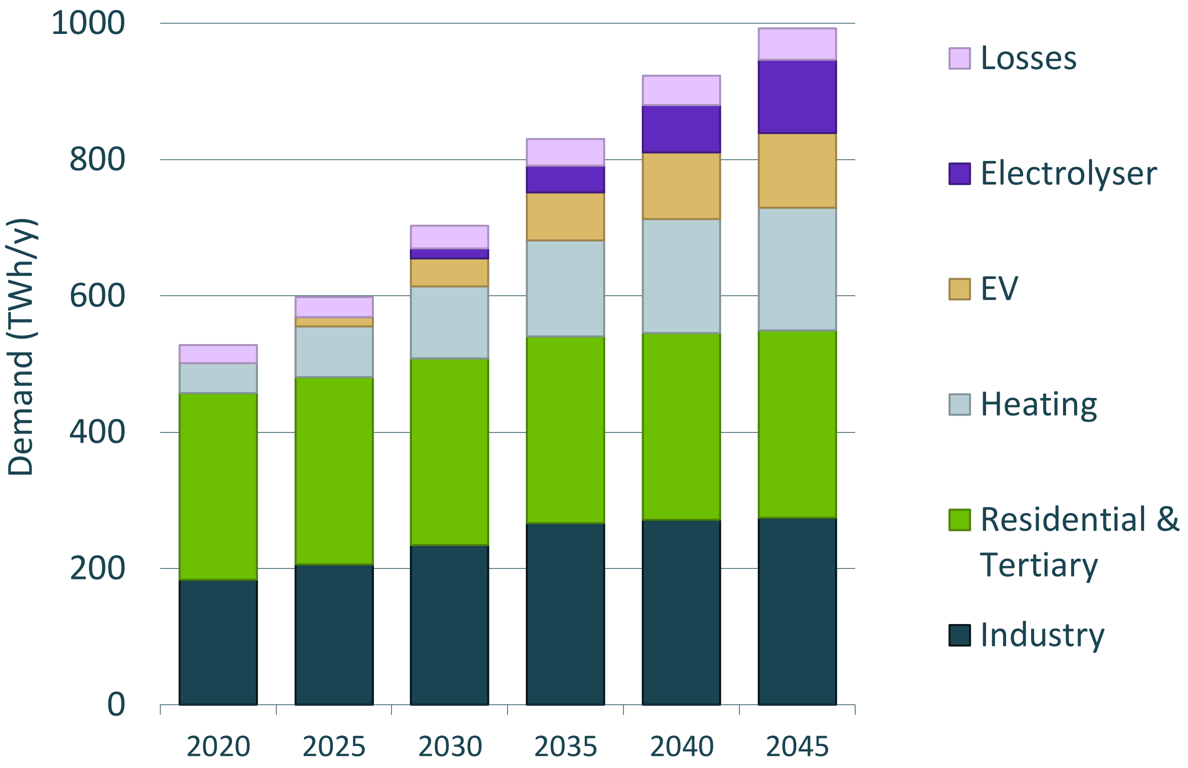

Figure 2. Electricity demand and its projection in different sectors in Germany.

Wind and solar expansion:

- Greenfield expansion is assumed for wind and solar with no existing capacity available for the model year 2045, i.e., existing capacity have retired.
- As identified in the analysis performed for Poland[36], the expansion potential for solar PV is not a constraining factor hence no hard capacity limit on this technology is imposed.
- Maximum land expansion potentials are based on the assumption that 2% of land (7150 km^2) is adopted for wind parks with an estimated 143 GW till 2032, deploying state-of-the-art wind turbines.
- Based on the analysis of 42 weather years and historical data, a capacity factor of 29% is assumed for new onshore wind parks.

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[32] Swedish Transmission System Operator (Svenska Kraftnät). Long-term market analysis. January 26, 2024.
[33] The Federal Statistical Office (Statistisches Bundesamt). Monthly report on electricity supply. June 06, 2024.
[34] ENTSO-E. European resource adequacy assessment – Annex 2 methodology. 2023.
[35] Ember. New generation: Building a clean European electricity system by 2035. June 22, 2023.
[36] Quantified Carbon & CATF (2023), Power System Expansion Poland.

- For offshore wind deployment, the governmental plans provide a guidance setting an upper limit on the expansion of fixed-foundation offshore wind to 70 GW by 2045[37].
- For grid transmission, 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.

Nuclear:

- Nuclear restart 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.
- First projects start off very expensive with long construction durations. Future projects experience the similar challenges as the ongoing projects in Europe with limited learning going forward.

Retirement:

- The retirement of first wind and solar parks in Germany has already started.
- The retirement process in the modelling is based on the installed capacities by the end of historical years assuming 30 years for PV, 25 years lifetime for onshore wind, and 20 years for offshore wind.

Production profiles:

- Wind profiles: The calculation method for the wind power capacity factor time series is conducted with QC's in-house tool Weather2Energy and involves utilising ERA5[38] data for comprehensive climate analysis. 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.
- Solar profiles: Rooftop are simulated with orientation and slope found in existing installation[39]. Solar parks are simulated as oriented to the south with a, for the latitude yield, optimised slope. Gridded population count data[40] is used for spatial weighting, where rooftop and parks are separately curve fitted with actual site data[41].
- The comprehensive insights into the assumptions, tools, and methodologies can be found in QC's recent submission of scientific paper (supplementary material)[42].

Hydrogen:

- 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.
- Hydrogen imports are *not* considered.
- The investment costs have been derived from values of IEA_2023[43]. The operational costs starting point stem from International Council on Clean Transportation (2020)[44] with the value of 50 €/kW and 2045 end points have been inspired from Svenskt Näringsliv (2020)[45].
- 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[46] and TYNDP_2024[47].

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[37] Federal Ministry for Economic Affairs and Climate Action of Germany. New offshore agreement for more wind energy at sea. December 16, 2022.

[38] Climate Data Store. ERA5 Hourly data on single levels from 1940 to present. 2024.

[39] Springer Nature. Metadata record for: a harmonised, high-coverage, open dataset of solar photovoltaic installations in the UK. November 12, 2020.

[40] NASA. Gridded population of the world (GPW, v4). December 31, 2018.

[41] Springer Nature. Metadata record for: a harmonised, high-coverage, open dataset of solar photovoltaic installations in the UK.

[42] Cox et al. Supplemental material: Robust capacity expansion planning in hydro-dominated power systems: a Nordic case study. November 2024. Submitted for scientific publication.

[43] International Energy Agency. World energy outlook 2023.October 2023.

[44] International Council on Clean Transportation. Assessment of hydrogen production costs from electrolysis. June 18, 2020.

[45] The Confederation of Swedish Enterprise (Svenskt Näringsliv). Modelling Swedish electricity supply. 2020.

[46] NREL - National Renewable Energy Laboratory. 2023 Electricity ATB technologies.

[47] ENTSO-G, ENTSO-E. Ten-Year Network Development Plan 2024. 2023.

- The study assumes no upper limit on hydrogen storage energy capacity based on the high potential studies[48], although for computational reasons an upper limit of 3 weeks for the storage capacity (energy to gas turbine power ratio) was introduced.

2.2.3 Cost assumptions

An integral aspect of our analysis revolves around technology cost assumptions, underpinning both investment and operational considerations. Characteristics for the energy technologies under scrutiny have been determined based on a comprehensive review of references as presented as outlined in Appendix B Reference sources and further motivated in CATF report.

All monetary values are denominated in real terms, specifically in Euros (€) for the calendar year 2023. This standardisation of currency ensures the consistency and precision of our cost assessments. Moreover, our financial considerations encompass the Weighted Average Cost of Capital (WACC) with a value of 6%. To account for the financial dynamics inherent in project construction phases, we incorporate an interest rate equivalent to half of the WACC during the construction period as a markup on total capital investment. Capital recovery periods are uniformly set to the technical lifetime for all technologies.

To approximate an average cost weighting for investment and operational expenses, representative of the time span from 2024 to 2045 and accounting for technological advancements, we have derived costs based on the year 2035. Compiled investment and operational cost assumptions for the primary supply technologies are given in Table 2 along with the representative LCOE purely based on input assumptions.

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[48] National Hydrogen Council. Hydrogen storage roadmap 2030 for Germany. November 04, 2022.

Table 2. Input assumptions for new build of main technologies. The presented LCOE values are purely based on input assumptions.

	Solar PV	Wind Onshore	Wind Offshore Fixed	Nuclear	Battery	Hydrogen combined cycle (CC)	Gas open cycle (OC)
WACC (%)	6.0	6.0	6.0	6.0	6.0	6.0	6.0
Interest rate for construction (%)	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Construction duration (yr)	0.5	1.0	1.0	8	1.0	2.0	2.0
Economic lifetime (yr)	30	25	25	60	15	30	30
Overnight cost (€/kW)	570	1330	2500	7000	220	790	650
Overnight cost energy (€/kWh)	-	-	-	-	160	-	-
Fixed OM (€/kW/yr)	11	26	67	65	25	10	10
Variable OM (€/MWh)[1]	-	-	-	4.5	-	2.5	5
Fuel (€/MWh)[49]	-	-	-	4.9	-	300[50]	237
Capacity factor (%)[51]	12	29	41	90	-	10	10
LCOE (€/MWh)	50	53	76	87	-	390	310

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[49] Represents fuel costs per MWh electricity generated. Values include costs for direct and indirect emissions based on the CO_2 price projection.

[50] Based on an estimated cost of hydrogen of around 5 €/kgH2.

[51] 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.

2.2.4 Nuclear assumptions

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[52, 53]. To illustrate, the development of novel nuclear reactor designs in Western Europe has been accompanied by notably high price tags[54], while emerging nuclear power nations such as Türkiye and the United Arab Emirates have realised their initial reactors at relatively lower costs[55, 56].

Table 3 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[57]. 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[58]. Idaho National Laboratory recently published a technical report simulating these potential cost reductions in the US[59] with scenarios largely in congruence with those outlined for the current study below.

The current study employs a conservative assumption on the cost of nuclear to a level of 7000 €/kW overnight. 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 employed conservative assumptions have been constructed such that the average overnight capital cost throughout 2024-2045 is 7000 €/kW, reflecting a scenario where future projects experience the similar challenges as the ongoing projects in Europe today with limited learning. Operational costs have been set to 65 €/kW-yr[60] 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 decommissioning, spent fuel removal, disposal and long-term storage of spent fuel (4.5 €/MWh)[61].

The current study allows for the restart of six recently closed reactors, still holding operating licenses, 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[62], while another source argues 5 reactors may be restarted[63]. To cover for the costs of restarting the reactors an additional cost of 8 €/MWh has been added to the variable operational cost[64] in the simulations. With life-time extension, the restarted reactors are assumed to be operational beyond the model year 2045.

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.

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[52] Energy Policy. Historical Construction Costs of Global Nuclear Power Reactors. 2016.

[53] Energiforsk. El från Nya Anläggningar. 2021.

[54] Institute for Energy Economic and Financial Analysis. European Pressurized Reactors: Nuclear Power’s Latest Costly and Delayed Disappointments. 2023.

[55] WNA. Nuclear Power in the United Arab Emirates. 2023.

[56] WNA. Nuclear Power in Turkey. 2023.

[57] Energiforsk. El från Nya Anläggningar. 2021.

[58] Idaho National Laboratory. Literature Review of Advanced Reactor Cost Estimates. 2023.

[59] Idaho National Laboratory. Meta-Analysis of Advanced Nuclear Reactor Cost Estimations. 2024

[60] International Energy Agency & Nuclear Energy Agency. Projected Costs of Generating Electricity. 2020.

[61] International Energy Agency & Nuclear Energy Agency. Projected Costs of Generating Electricity. 2020.

[62] Radiant Energy Group (2024), Restarting Germany’s Reactors: Feasibility and Schedule

[63] zdfheute. Zurück zur Atomkraft: Ginge das überhaupt? 2023.

[64] Radiant Energy Group. Restart of Germany's Reactors: Can it be Done? 2023.

Table 3. Nuclear costs in perspective based on analysis of nuclear projects in the time period 2000-2020 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[65]
HIGH	Corresponds to the approximate expected cost of a new generation EPR (Sizewell-C in the UK).	5500
VERY HIGH	Olkiluoto unit 3, EPR	6900[66]
THIS STUDY	Assumption in current study	7000

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[65] WNA . Nuclear Power in the United Arab Emirates. September 05, 2024.

[66] Euronews. Finland’s New Nuclear Reactor: What Does It Mean for Climate Goals and Energy Security? April 17, 2023.

3 Results

3.1 Capacity and generation mix

The resulting capacity mix from the modelled capacity expansion optimisation is compared to Germany’s current power system in 2024 is presented in Figure 3. The corresponding generation mix is shown in Figure 4.

Both the “Nuclear” and “VRE” scenarios highlight a dramatic transformation in the power generation landscape and indicates a clear shift towards low-carbon sources and advanced storage technologies. In 2023 and for present-day, the German power system is still heavily dependent on fossil fuels, with coal and gas filling around 35% of the annual generation in 2023. Renewable solar and wind capacity have seen a significant increase to levels approaching 50% of the annual generation in 2023. At this stage, battery storage capacity primarily providing ancillary service and grid support has merely begun its expansion, but the system remains reliant on fossil fuels for stability and meeting energy demand. Excluded from the optimisation, hydro run-of-river, pumped hydro storage and bio-based power carry a similar annual production or installed capacity to what has been observed in recent years.

In the “Nuclear” scenario nuclear power sees a substantial rise, from zero capacity in 2024 to 57 GW in 2045 which includes 8 GW contributed by restarted existing reactors. This growth in nuclear standing for around 40% of the annual generation highlights its competitiveness, despite the conservative cost assumptions, and valuable role as a firm source of baseload power in the German decarbonised power system, complementing variable renewables. Nuclear’s consistent output can help stabilise the grid dominated by renewables and ensure energy availability irrespective of weather conditions reducing the need for flexibility.

In 2024, solar and onshore wind together account for around 143 GW or 46% of the annual generation, making them key renewable contributors. Irrespective of scenario the results show a deployment of new onshore wind and solar capacity is substantial which despite a strong demand growth sees covering around 50% of the annual generation by 2045. Solar capacity sees an increase to 120 GW and 310 GW in the “Nuclear” and “VRE100” scenario, respectively. The large solar capacity in the “VRE100” scenario is coupled to a significant expansion of battery storage at 31 GW with its short-term energy balancing capabilities working in synergy with the solar production. Onshore wind, proving cost-effective, more than doubles to 143 GW in installed capacity in both scenarios reaching its maximum expansion limit covering 2% of Germany’s land area. Overall, this robust growth in onshore wind and solar highlights a heavy investment in renewables to meet the growing energy demand and reduce carbon emissions.

The expansion of offshore wind marks an aspect which strongly differs between the scenarios. While an installed capacity of 66 GW of fixed offshore wind power is observed in the “VRE100” scenario, the “Nuclear” scenario does not build any new offshore wind at all. This result is attributed to offshore wind’s relatively high costs combined with cannibalisation issues with the onshore wind counterpart which makes it challenging to reach levels of profitability.

Fossil fuel-based sources such as combined-cycle gas plants and coal power plants are phased out irrespective of scenario. However, gas open cycle (OC) complemented by hydrogen gas turbines sees a considerable increase in installed capacity to around 21 GW and 12 GW, respectively in the “Nuclear” scenario to about 50 GW and 28 GW, respectively in the “VRE100” scenario. These technologies serve as peaking plants, reflected in their limited share in the generation mix, which can capably respond to the variation in the generation of intermittent solar and wind sources. Their expansion is particularly linked to the build-out of wind power since other means to handle the associated long-duration variation in production are scarce. The increased need for peaking plants in the “VRE100” scenario can be explained by its larger share of wind power. Notably, battery storage and demand-side flexibility technologies primarily provide flexibility on a diurnal time scale and are not able to effectively bridge wind power production gaps. Associated energy security and emissions aspects are described in Section 3.4 and 3.5.

The expansion of hydrogen turbines should be carefully assessed. Its cost-effective expansion relies to a large degree on optimistic cost reductions in electrolysers. Furthermore, the model does not assume any hinderance on the implementation of hydrogen infrastructure required to supply the hydrogen fuel to the power plants. Deeper analysis reveals that hydrogen for power generation should be seen as a last resort[67] [68].

Figure 4 reveals that the total yearly generation is higher in the “VRE100” scenario compared to the “Nuclear” scenario, despite both meeting the same total demand. This discrepancy can be attributed to the larger share of storage resources in the “VRE100” power system mix with their generation output is also included in the figure. Storage systems, particularly hydrogen storage with a roundtrip efficiency of just 35%, incur significant conversion losses. As a result, excess generation is required during periods of high solar and wind production to compensate for these losses and ensure sufficient power is available during periods of low renewable output.

The nuclear expansion until 2045 is significant and would require a very effective European nuclear industry. In scenarios where the nuclear build-out would be constrained to half of the observed 57 GW, the resulting power system from the model optimisation would tend to place itself somewhere between the capacity build-out in the “Nuclear” and the “VRE100” scenarios. This is relevant to keep in mind as the two power system characteristics are compared in the following.

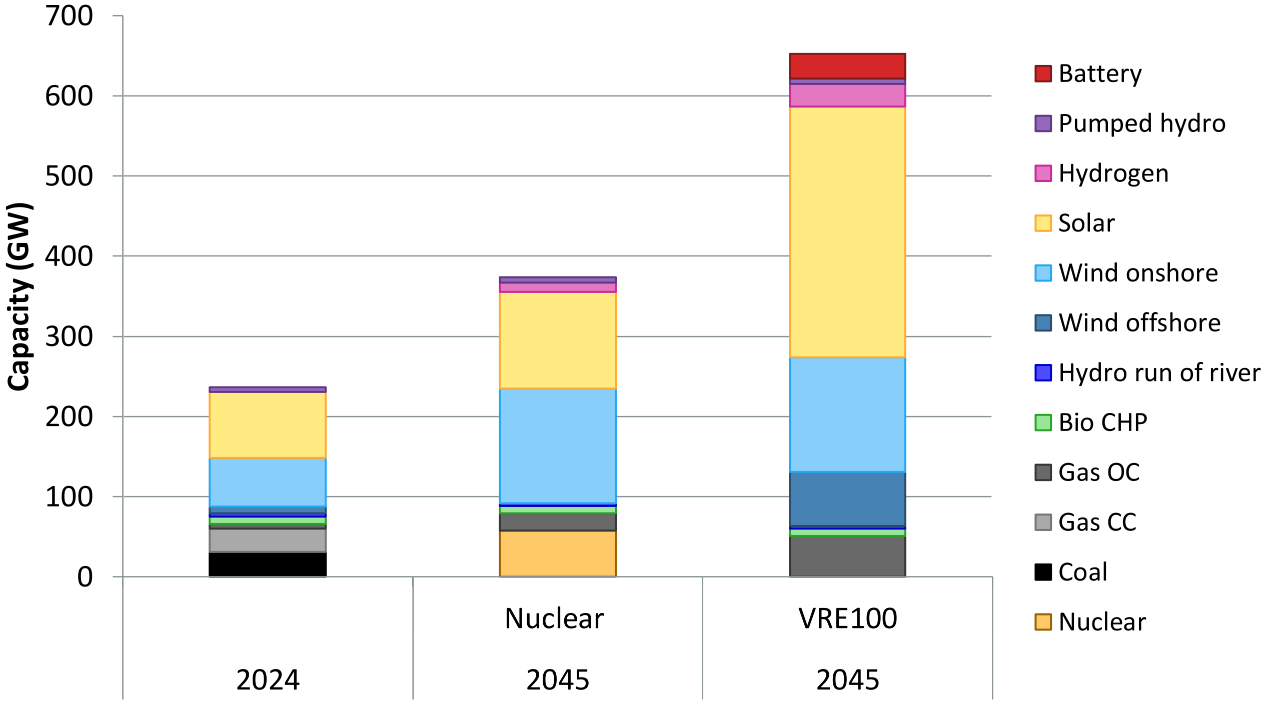

Figure 3. Installed capacity by technology at start of 2024 in first column followed by model results for year 2045 in the “Nuclear” and the “VRE100” scenarios in the last two columns.

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[67] Quantified Carbon & CATF. Power System Expansion in Germany. 2024. To be published.
[68] Quantified Carbon Linkedin. Role of Hydrogen for Power Generation. 2024.

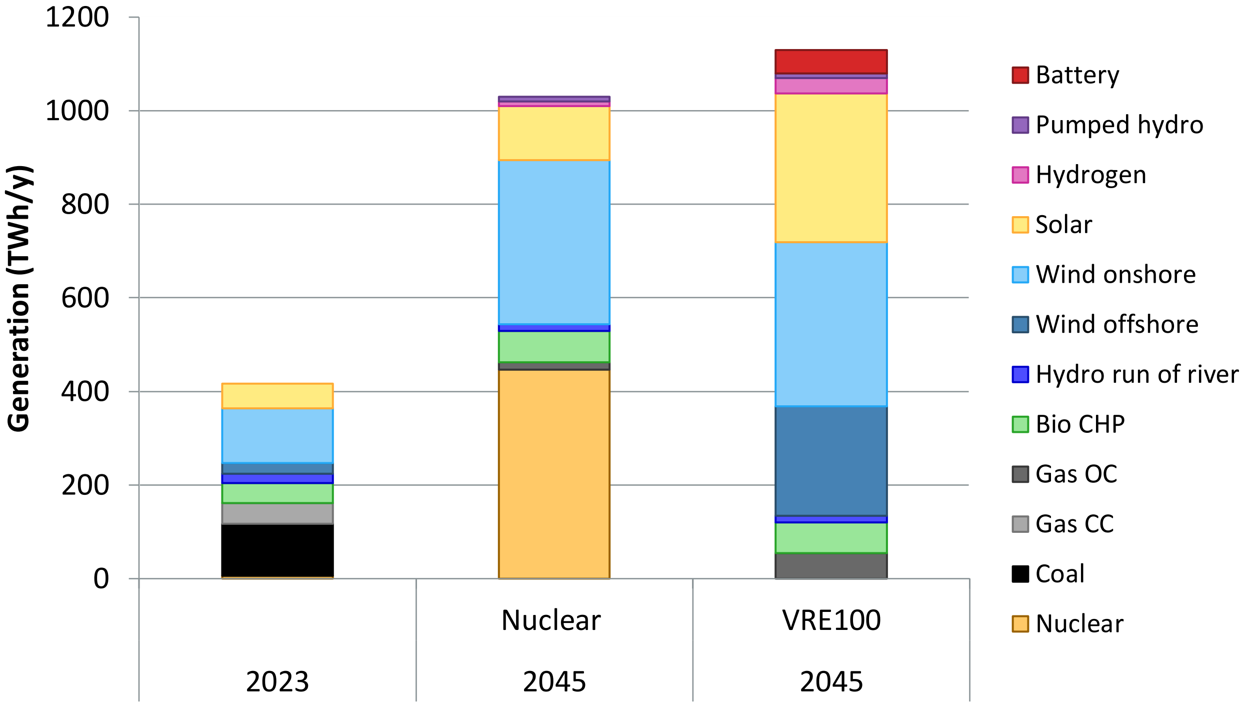

Figure 4. Annual generation by technology for the historical year of 2023[69] in first column followed by model results for year 2045 in the “Nuclear” and the “VRE100” scenarios in the last two columns. Notably, the generation from storage resources is included.

Takeaway on capacity and generation mix:

- Including nuclear in the optimisation results in a considerable expansion of the technology. With an installed capacity of 57 GW in 2045 in the "Nuclear" scenario, which includes 8 GW contributed by restarted existing reactors, nuclear power makes up around 40% of the annual generation in 2045 highlighting its competitiveness, despite conservative cost assumptions, and valuable role as a firm source of baseload power in the German decarbonised power system.

- Both the “Nuclear” and the “VRE100” scenarios showcase a significant deployment of onshore wind and solar highlighting the important role the technologies are set out to play in a decarbonised German power system.

- Gas turbine peaking plants exhibit a role in both scenarios but showing a considerably increasing reliance in the “VRE100” compared to the “Nuclear” scenario. Offshore wind’s role to decarbonise the German power system is merely shown in the “VRE100”.

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[69] Energy-Charts, accessed 2024-11-14.

3.2 System costs

Total system costs for the scenarios have been examined in the current study and are presented normalised to annual demand and by technology contributions or cost categories: fixed costs, variable costs, import costs. These costs are annual "levelised" costs, meaning that investment costs are evenly distributed over the lifespan of the technology. Variable costs include both operational and maintenance (O&M) expenses, charging costs for storage technologies, as well as fuel costs, while fixed costs represent both fixed O&M and capital investment costs. Import costs reflect the net cost of electricity imports due to trade with bidding zones outside Germany. The system costs in Figure 5 and Figure 6 include only the costs associated with generation capacity expansion. Costs related to grid infrastructure has been excluded from optimisation and are addressed separately in Section 3.6.

Figure 5 presents the total system costs split by technology contributions for the two scenarios. In the “Nuclear” scenario, nuclear energy constitutes the largest cost component, at 38 €/MWh. This substantial investment reflects the high initial capital and maintenance costs associated with nuclear power, but also provides a stable, long-term base-load power solution. With nuclear as the backbone of the system, there is less need for additional storage or flexible resources.

In contrast, the “VRE100” scenario completely excludes nuclear with zero nuclear costs. Instead, this scenario incurs high costs in storage and renewable generation, due to its dependence on these technologies to meet demand without nuclear base-load support. The “VRE100” scenario includes a heavy investment in flexibility: energy storage and gas power, particularly in batteries, open-cycle gas turbines and hydrogen storage, which are crucial for balancing renewable variability. Battery costs reach 6 €/MWh, gas turbines 16 €/MWh and hydrogen costs soar to 12 €/MWh. Combined, these storage expenses account for over 36 €/MWh, and highlights the financial commitment required to ensure grid stability when relying solely on variable renewable energy sources.

By comparison, the “Nuclear” scenario requires 9 €/MWh for gas turbines and hydrogen storage, given its reduced reliance on flexibility due to nuclear’s consistent output. This highlights a financial advantage for nuclear in minimising the need for extensive storage infrastructure.

Both scenarios invest significantly in renewable energy, but the allocation varies. In the “Nuclear” scenario, solar costs are 5 €/MWh, while onshore wind costs are 20 €/MWh. The “VRE100” scenario doubles down on renewables, with solar costs rising to 16 €/MWh, a threefold increase compared to the “Nuclear” scenario, due to a higher installed solar capacity. Offshore wind also sees major investment in “VRE100”, costing 19 €/MWh, which supports the scenario’s aim to rely entirely on renewables and maximise generation across diverse sources. Onshore wind costs remain consistent between the scenarios, at 20 €/MWh.

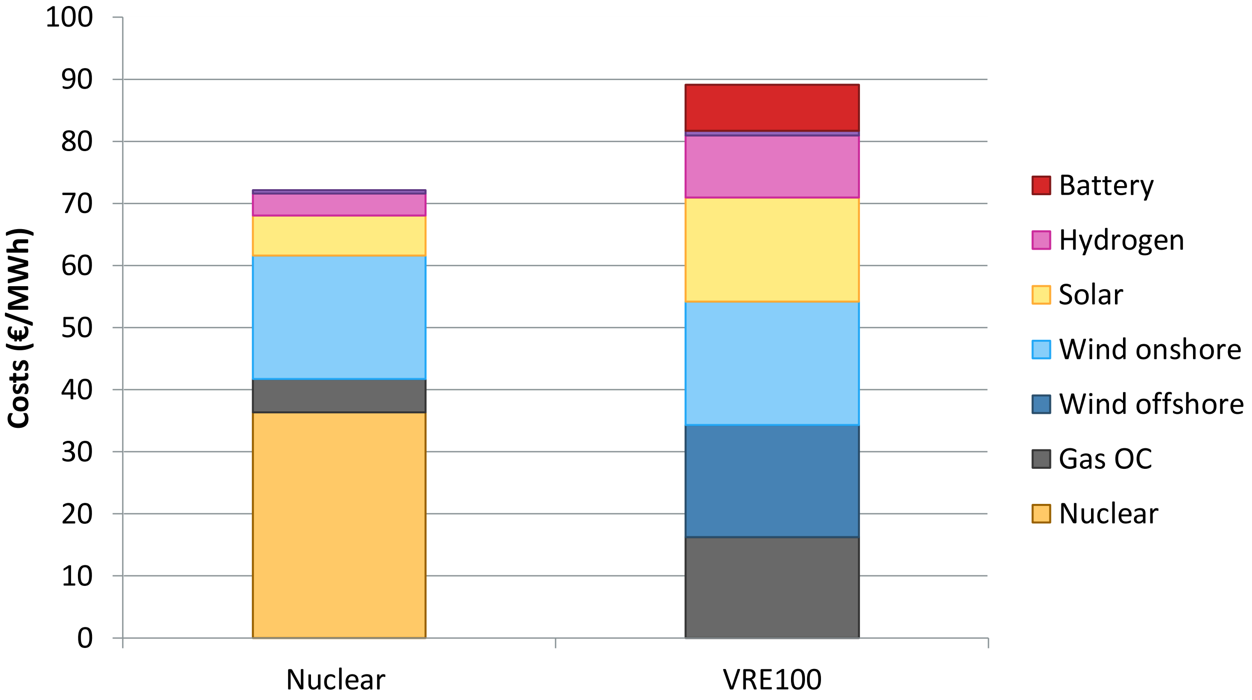

Figure 5. Total system costs normalised to annual consumption split by technology for the “Nuclear” and “VRE100” scenarios.

Figure 6 instead considers the total system costs split by cost category which also add import costs. The “Nuclear” scenario has lower import costs at 7.5 €/MWh compared to 11 €/MWh in the “VRE100” scenario. This difference reflects the “Nuclear” scenario’s stability in generating consistent base-load power domestically, which reduces the reliance on imported electricity to meet demand. With a steady nuclear base, the system can more effectively handle local demand, even as variable sources like wind and solar fluctuate. Conversely, the “VRE100” scenario relies entirely on renewables, which are more variable. This intermittency necessitates higher imports to fill gaps when neither domestic nor neighbour renewable generation can meet demand and contributes to increased import costs. The reliance on imports under “VRE100” indicates the challenges of achieving reliability without nuclear or fossil fuel-based base-load power.

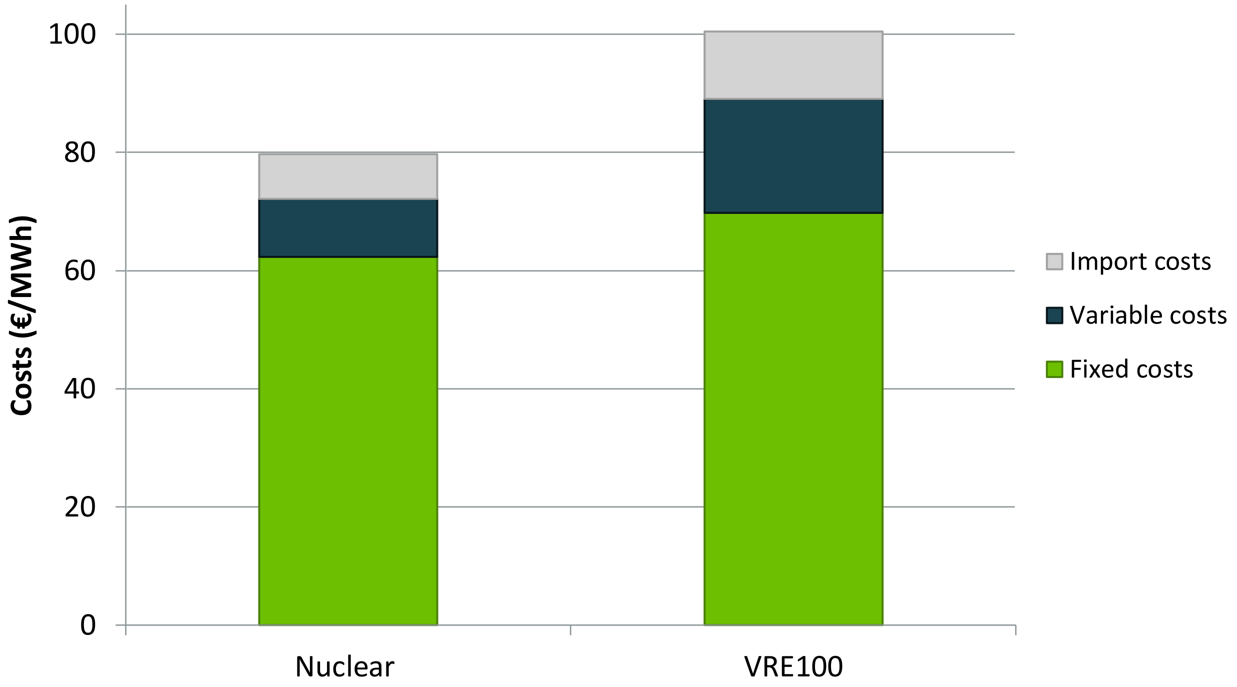

Figure 6. Total system costs normalised to annual consumption split by cost category for the “Nuclear” and “VRE100” scenarios.

Takeaway on system costs:

- The “Nuclear” scenario provides cost benefits due to being able to meet demands with less renewable installation, storage, and flexible generation needs. Although nuclear infrastructure incurs a high cost, the scenario’s lower reliance on flexibility results in a lower overall system cost.

- The “VRE100” scenario, on the other hand, reflects a strong commitment to renewable energy but requires extensive investment in storage and peaking plants. This approach represents a higher-cost pathway.

3.3 Electricity prices and volatility

Similar to the system costs, the simulated yearly average electricity price in the “Nuclear” scenario (left panel of Figure 7) is 82 €/MWh, which is markedly lower than the 105 €/MWh in the “VRE100” scenario. The increased price in the “VRE100” reflects the overarching higher costs that the market needs to provide to ensure profitability for all technologies. Consider offshore wind as an example, offshore wind has its relatively high LCOE of 76 €/MWh (see Table 2). Due to profit cannibalisation—where frequent periods of overproduction during high wind availability suppress market prices—offshore wind producers capture only 75% of the yearly average electricity price (commonly referred to as the *capture rate*). This dynamic requires a higher average electricity price to ensure the economic viability of renewable technologies in the “VRE100” scenario.

The optimisation identifies the lowest system cost for the entire model, including regions outside Germany. Capacity expansion and production optimisation occur for resources within the German power system, while resources in other regions are optimised solely with respect to their operation. This means that only the variable and fuel costs for resources outside the German power system are included in the objective function that is minimised in the power system optimisation.

Compared to the “VRE100” scenario, the “Nuclear” scenario with a higher share of nuclear power results in both lower investment (fixed) costs and lower variable costs. The most significant difference is the import costs as the “Nuclear” scenario shows far less reliance on imports, thus, lowering import costs and allowing for a larger degree of exports to neighbouring countries. These aspects result in a lower electricity price across the entire model for the “Nuclear” scenario. In contrast, the” VRE100” scenario with higher investment and variable costs will turn to importing electricity relying on neighbours dispatchable power supply instead of investing in more production capacity in the German power system as a way to reduce system costs. This highlights the interplay between variable costs (largely influenced by commodity prices) and the investment required for local capacity expansion. Together, they govern the use of trade to achieve a cost-optimal German power system.

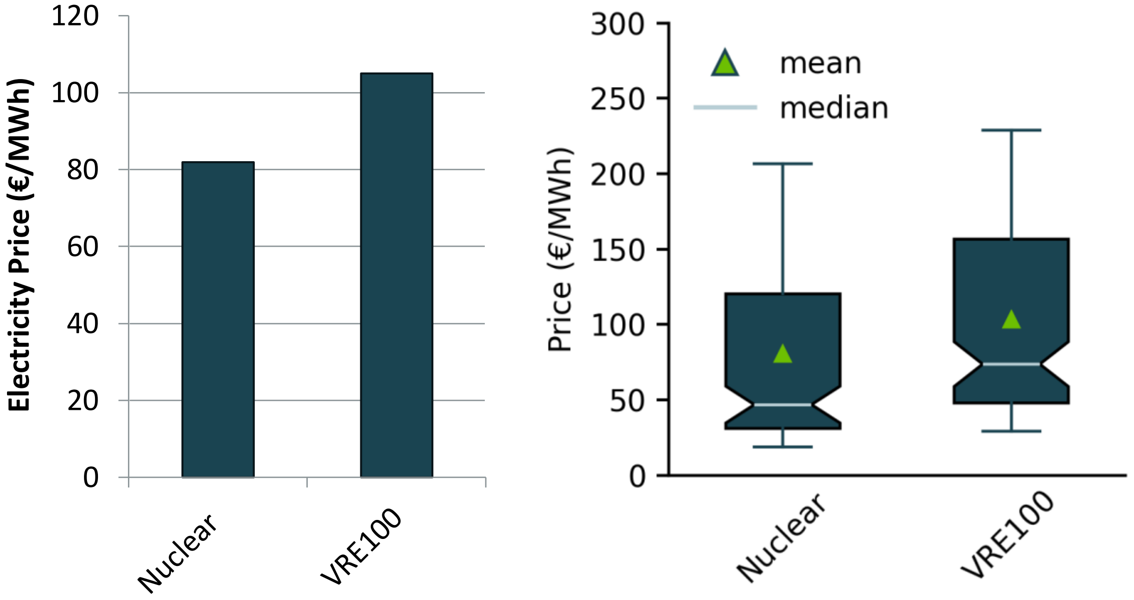

Figure 7. Average electricity price (left panel) and price volatility (right panel) in “Nuclear” and “VRE100” scenarios. The right panel shows yearly average electricity price for the complete set of 33 weather years in 2050 for the different scenarios. The boxplots cover the range of outcomes for the full set of weather years with boxes representing the 25% - 75% quartiles. Median values are shown with grey lines and mean values with green triangles. The whiskers extend to minimum and maximum values excluding extreme outliners.

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.

Electricity price volatility due to weather variability is presented in the right panel of Figure 7 as a distribution of quarterly averaged prices across 33 weather years. Resampling to a quarterly time window has been chosen since it reflects a duration for which it is very challenging to implement flexibility measures able to mitigate price variations. The price volatility as measured by the variation in the 25%-75% quartiles is lower in the “Nuclear” scenario, although the difference is not very large. The similarity in the price volatility despite intrinsically being more weather dependent in the “VRE100” scenario comes from its substantially higher dependence on gas turbine power. Essentially, the natural-gas open-cycle turbines are able to counter-act the increased intermittent generation and saves the “VRE 100” system from becoming more fragile to weather fluctuations. This also means that, if this system replaces the fossil gas power with hydrogen gas turbines charged from the power grid would result in a significantly larger electricity price volatility.

Takeaway on electricity prices and volatility:

- Owing to lower system costs and a reduced reliance on electricity imports, the “Nuclear” scenario achieves lower electricity prices on average.
- Lower electricity price volatility enhances predictability and stability which can reduce financial risks and support investment. It also minimises the need for costly flexibility measures such as energy storage and demand response, which lower the overall system costs and attract energy-intensive industries.
- The “Nuclear” scenario exhibits slightly lower electricity price volatility compared to the “VRE100” scenario of which larger weather dependency is to a large degree saved by dispatchable fossil gas power.

3.4 Energy security

Energy security refers to the availability of energy at all times, in sufficient quantities, and at reasonable prices. This section examines energy availability through two key indicators: import costs and natural gas consumption. Increased import costs indicate a higher dependence on electricity trade, which makes the system reliant on external energy sources and introduces uncertainty. Similarly, natural gas consumption highlights dependence on fossil fuels, tied to emissions and risks such as geopolitical uncertainties (e.g., reliance on authoritarian states), climate concerns (potential political rejection by 2050), and price volatility driven by CO_2 pricing and market dynamics.

In addition to averages, evaluating extreme levels of these indicators is critical. Peaks in demand or supply shortfalls often determine the system's capacity and infrastructure requirements. Managing such extremes is essential for stable operation, placing significant demands on reserves, storage, and infrastructure capacity. Underestimating these peaks poses risks to system reliability, especially as dependence on weather-driven energy sources like wind and solar increases.

Average yearly import costs and gas consumption across 33 weather years are presented in Figure 8. As discussed already, the “Nuclear” scenario exhibits a considerably lower import dependency on average as well as the extreme levels. What stands out is however, the drastic difference in the gas consumption between the two scenarios. The “VRE100” demonstrates a higher average consumption around 140 TWh but also a substantially larger variation. As a point of reference, the natural gas consumption in the power sector for 2023 reached a level around 100 TWh[70]. Thus, the “VRE100” scenario exhibits an increase in natural gas dependency contrasting to the “Nuclear” scenario which shows a decrease to 45 TWh annual consumption on average. These results further indicate that the gas power in the “VRE100” scenario is a mitigator for both import reliance as well as the electricity price volatility. The reliance of gas for power exposes an important vulnerability of the power system in the “VRE100” scenario.

It is generally relevant to evaluate measures that can mitigate the natural gas dependency. It is possible that locally produced biogas and hydrogen can complement to a certain degree but their contributions are highly uncertain especially relating to demand from other sectors. However, the results here clearly demonstrate nuclear’s potential role in reducing dependency on gas for power and its associated risks.

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[70] Estimate based on a 45% thermal conversion efficiency and a natural gas power fleet annual generation of 44 TWh.

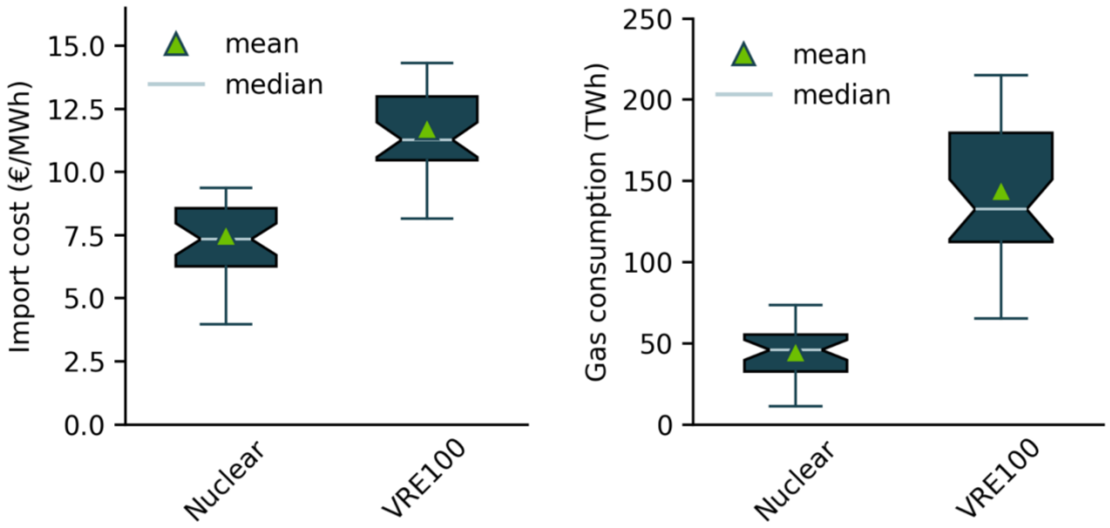

Figure 8. The distribution of yearly imports (left panel) and yearly natural gas generation (right panel) in Germany under “Nuclear” and “VRE100” scenarios. Each boxplot represents the range of outcomes over 33 weather years with boxes showing the 25th and 75th percentiles. Median values are shown with grey lines and mean values with green triangles. The whiskers extend to minimum and maximum values excluding extreme outliners.

Takeaway on energy security:

- The “Nuclear” scenario enhances Germany’s energy security by significantly reducing the reliance on imports and gas generation. This makes Germany less vulnerable to external supply disruptions, price volatility, and geopolitical risks.

3.5 Emissions

The current section evaluates emissions based on lifecycle values and direct mass-based emissions. Starting with the lifecycle emissions, Figure 9 presents consumption-based results split by technology contributions for the two scenarios. Unsurprisingly, open-cycle gas power is responsible for the largest share of the lifecycle emissions for an average weather year and incorporating projected emission reductions[71]. Primarily driven by a larger dependency of natural gas consumption in the “VRE100” scenario, it exhibits 45 kg CO_2-eq./MWh, more than a doubling compared to the “Nuclear” scenario with 17 kg CO_2-eq./MWh. Compared to 381 kg CO_2-eq./MWh for 2023[72] the model results for 2045 showcase a considerable improvement.

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[71] Nature Energy. Understanding future emissions from low-carbon power systems by integration of life-cycle assessment and integrated energy modelling. 2017.

[72] Statista. Carbon intensity of the power sector in Germany 2000-2023. 2024. Accessed 2024-11-15.

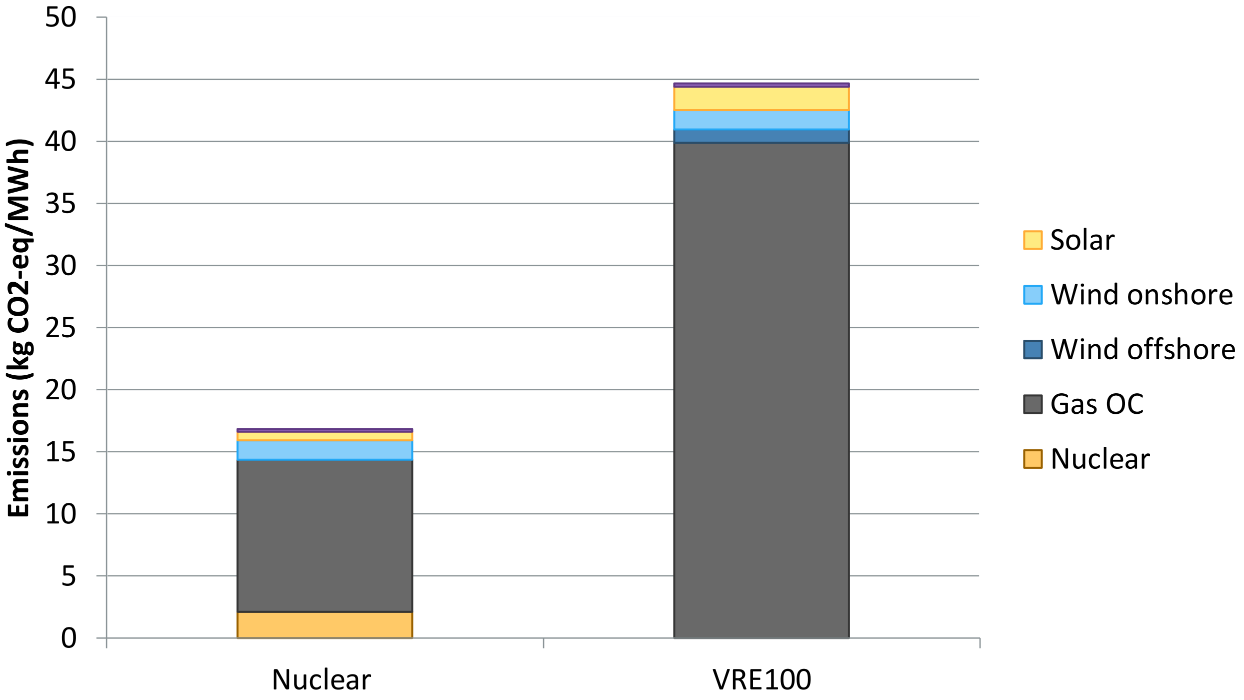

Figure 9. Consumption-based emission intensity split by technology contribution for an average weather year and the ”Nuclear” and ”VRE100” scenarios.

The mass-based direct emission as a result of the modelling for 33 weather years, presented in Figure 10, paints a slightly different picture compared to the consumption-based emission intensity. As a frame of reference, the emission level in 2022 was around 225 Mt[73] and aiming a 99% decrease in emissions compared to 1990 levels means targeting a level just below 4 Mt annually[74]. As the results show, the “Nuclear” scenario exhibits an average level of 10 Mt and correspondingly 31 Mt for the “VRE100” scenario. Achieving a reduction higher than 97% in the “Nuclear” scenario is arguably fulfilling the goal of a decarbonised power system. However, at an average reduction of 91% the “VRE100” scenario could be considered lagging behind targets. It is further interesting to consider how to factor in the weather year variations into climate targets; should the average or the extreme on the high end be used?

The current study assumes a high CO_2 price of 250 €/tCO_2 as the sole driver of emissions mitigation of the German power system. Ultimately these results highlight the tremendous challenge ahead to fully decarbonise the German power system. Consequences from imposing more stringent emission targets on the “VRE100” scenario is investigated in Section 3.8. In the end, the technology pathway represented by the “Nuclear” scenario significantly reduces risks associated with climate achievements.

Power stations equipped with carbon capture and storage (CCS) could be an avenue worth pursuing to enable dispatchable capacity whilst adhering to low carbon emissions, an aspect covered in depth in the CATF report[75].

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[73] Federal Environment Agency (Umwelt Bundesam). Development of the specific greenhouse gas emissions of the German electricity mix in the years 1990 - 2022. 2023.
[74] Bundesregierung. Climate Change Act 2021. June 25, 2021.
[75] Quantified Carbon Linkedin. Role of Hydrogen for Power Generation. 2024.

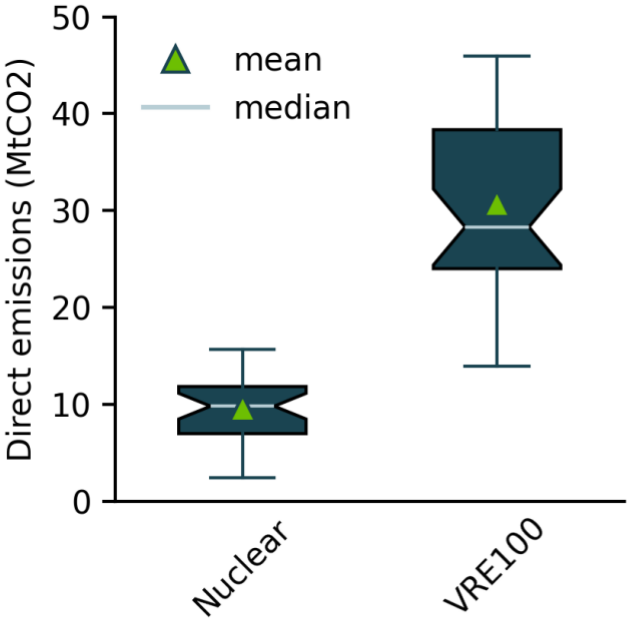

Figure 10. The distribution of yearly direct emissions from German power system under “Nuclear” and “VRE100” scenarios. Each boxplot represents the range of outcomes over 33 weather years with boxes showing the 25th and 75th percentiles. Median values are shown with grey lines and mean values with green triangles. The whiskers extend to minimum and maximum values excluding extreme outliners.

Takeaway on emissions:

- By reducing the need for natural gas peaking plants, the “Nuclear” scenario achieves a considerably larger emission reduction towards climate neutrality compared to the “VRE100” scenario which lags considerably behind.
- An emissions reduction of a mere 91% achieved for the VRE100 scenario despite a very high CO_2 price of 250 €/tCO_2 highlights the magnitude of the challenge to fully decarbonise the German power system without nuclear.

3.6 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 of the CATF report[76]. To compare, the Germany's NGDP - National Grid Development Plan (NGDP)[77] - calls for 25723 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. The "VRE100" scenario requires a substantial grid expansion (totally 21197 km), particularly driven by offshore wind as the largest contributor instead of its onshore alternative. The costs associated with the grid expansions required for offshore wind are comparable in magnitude to those incurred by the electricity producers themselves. Owing to no expansion of offshore wind in the "Nuclear" scenario it shows a negligible need for grid expansion (totally 3304 km). For reference, the current[78] length of the transmission grids is around 37000 km.

Figure 11 compares the transmission line costs for "Nuclear" and "VRE100" scenarios based on contributions from three renewable energy sources: offshore wind, onshore wind, and solar. The cost of integrating offshore wind is significantly higher in the "VRE100" scenario (7.1 €/MWh) compared to no-need of offshore wind in the "Nuclear" scenario (0 €/MWh). This is due to the extensive transmission lines required to connect offshore wind, which are typically located (such as North Sea or Baltic Sea) far from demand centres (such as south and west of the country), to the grid. Notably, incorporating the associated transmission costs to the costs of generation capacity as presented in Figure 5, would mean a 39% increase of cost on a system level or a directed subsidy of 30 €/MWh purely for offshore wind. The sources used for this analysis do not explicitly differentiate costs between onshore grid reinforcement resulting from offshore wind farm deployment and offshore wind farm to onshore grid connections. However, assuming the grid connection costs as presented by the National Renewable Energy Laboratory (2023), Annual Technology Baseline the offshore grid connection cost contribution could represent around one third of the total cost.

The "Nuclear" scenario also requires less transmission line costs for solar (0.5 €/MWh) than the "VRE100" scenario (1.2 €/MWh), while both scenarios have the same transmission costs of onshore wind. The "Nuclear" scenario has clear economic advantage from centralised generation at fewer distributed locations, therefore, it avoids the extensive grid infrastructure expansion and transmission. In contrast, decentralised power system like "VRE100" must invest significantly higher in transmissions to achieve comparable levels of meeting the demand and ensuring system reliability.

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[76] Quantified Carbon & CATF. Power System Expansion in Germany. 2024. To be published.
[77] TenneT. Transmission System Operators Publish First Draft of Grid Development Plan for 2037/2045. 2023.
[78] Federal Ministry for Economic Affairs and Climate Action of Germany (BMWK) . Electricity market of the future. 2023.

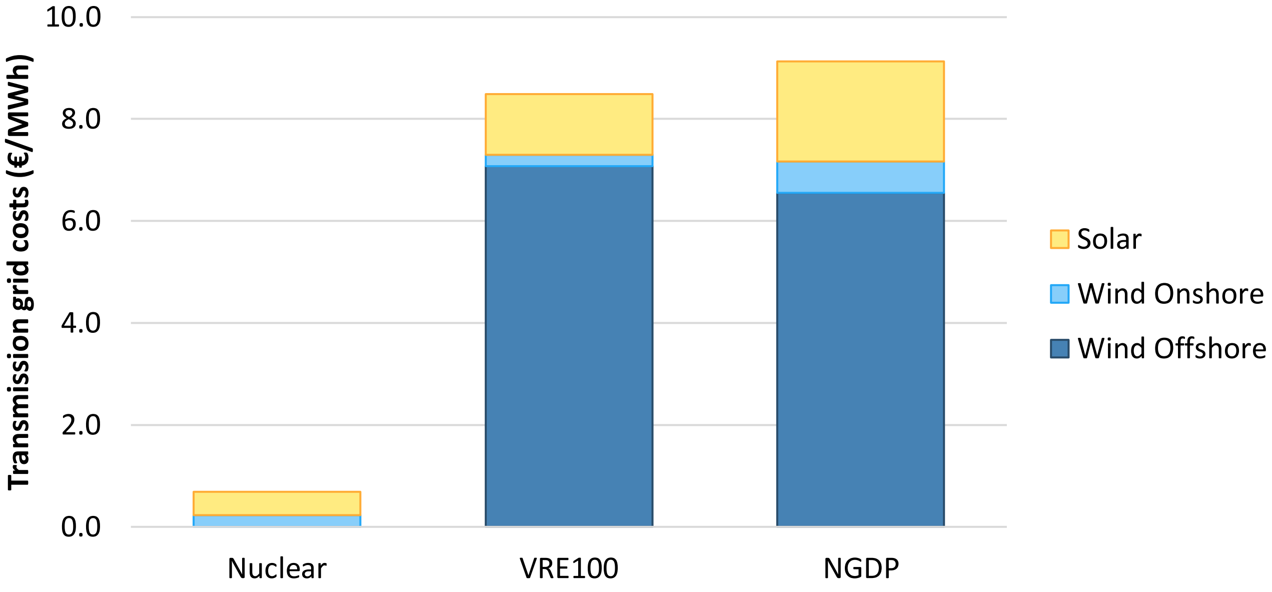

Figure 11. The normalised annual transmission line costs, split by technology, for the ”Nuclear” and ”VRE100” scenarios and National Grid Development Plan (NGDP) as a comparison.

Takeaway on transmission:

- The “Nuclear” scenario requires minimal transmission expansion, demonstrating cost and infrastructure advantages associated with centralised generation.
- A 100% renewable grid (“VRE100” scenario) will require substantially higher investment in transmission infrastructure driven by the expansion of offshore wind.

3.7 Minerals and land usage

Use of minerals and land for the power systems in the two scenarios have been calculated and the resulting values are shown in Figure 12.

Considering use of minerals, the “VRE100” scenario demands substantially higher quantities, particularly for solar panels, wind turbines, and battery storage. This dependency exacerbates concerns about supply chain constraints, geopolitical risks, and environmental degradation from mining and processing. It also intensifies competition for key resources like lithium and rare earth elements, which are vital for renewable energy technologies and battery systems. Owing to a primarily reduced expansion of solar and offshore wind combined with a relatively low use of critical materials for nuclear power, the “Nuclear” scenario requires significantly less minerals usage. This means that nuclear power in the German power system is set to mitigate supply chain vulnerabilities, minimise environmental impacts, whilst enhancing the resilience of the energy system.

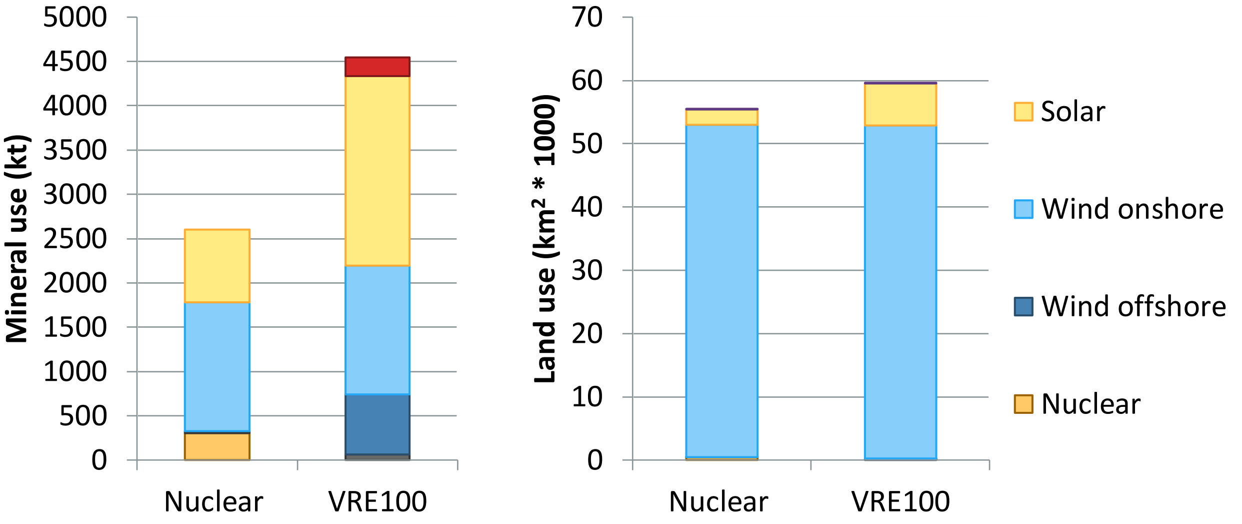

Figure 12. Use of minerals (left panel) and land (right panel) split by technology contributions for the ”Nuclear” and the ”VRE100” scenario.

Turning the attention to the results of the land use calculations, the two scenarios exhibit very similar values. This is due to both the “Nuclear” and the “VRE100” scenarios having the same installed capacity of onshore wind which is the main driver of land use. From a general perspective, considering nuclear’s limited areal footprint, it is reasonable to believe the inclusion of nuclear in the German power system mix would relieve from land use issues such as local opposition to the expansion of onshore wind.

Takeaway on minerals and land use:

- Inclusion of nuclear power in the German power system is set to relieve decarbonisation from issues relating to increased use of critical materials and land with associated risks of supply chain vulnerabilities, environmental impacts and local opposition to expansion of onshore wind.

3.8 Stringent emission targets without nuclear - the “VRE100 Clean” scenario

The current section follows on to the discussion on emissions presented in Section 3.5. To recapitulate, despite employing the high CO_2 price of 250 €/tCO_2 as the sole driver of emissions mitigation in the current study shows an emissions reduction of a mere 91% is achieved for the VRE100 scenario. Whilst these results highlight the magnitude of the challenge to fully decarbonise the German power system, it is relevant to further understand the additional costs and other consequences associated with a “VRE100” system that achieves the same emissions reduction as the “Nuclear” scenario at 97%.

On this background, the scenario “VRE100 Clean” was simulated with the only difference compared to the “VRE100” scenario a constrained natural gas consumption to the same level as the “Nuclear” scenario. Figure 13 presents the main difference in the installed capacity of different technologies between the “VRE100” and the “VRE100 Clean” scenario. As expected, the installed capacity of open-cycle natural gas fuelled turbines (Gas OC) is significantly reduced (-75% or -38 GW) in the “VRE 100 Clean” scenario. The gap in dispatchable capacity is filled by hydrogen power plants (+108% or +30 GW) and a significantly increased offshore wind (+42% or +28 GW) and solar (+28% or +88 GW) generation capacity to produce the hydrogen with electrolysers to fuel the gas turbines. Onshore wind remains at its maximum expansion level while battery storage capacity sees a 10% (-5 GW) reduction.

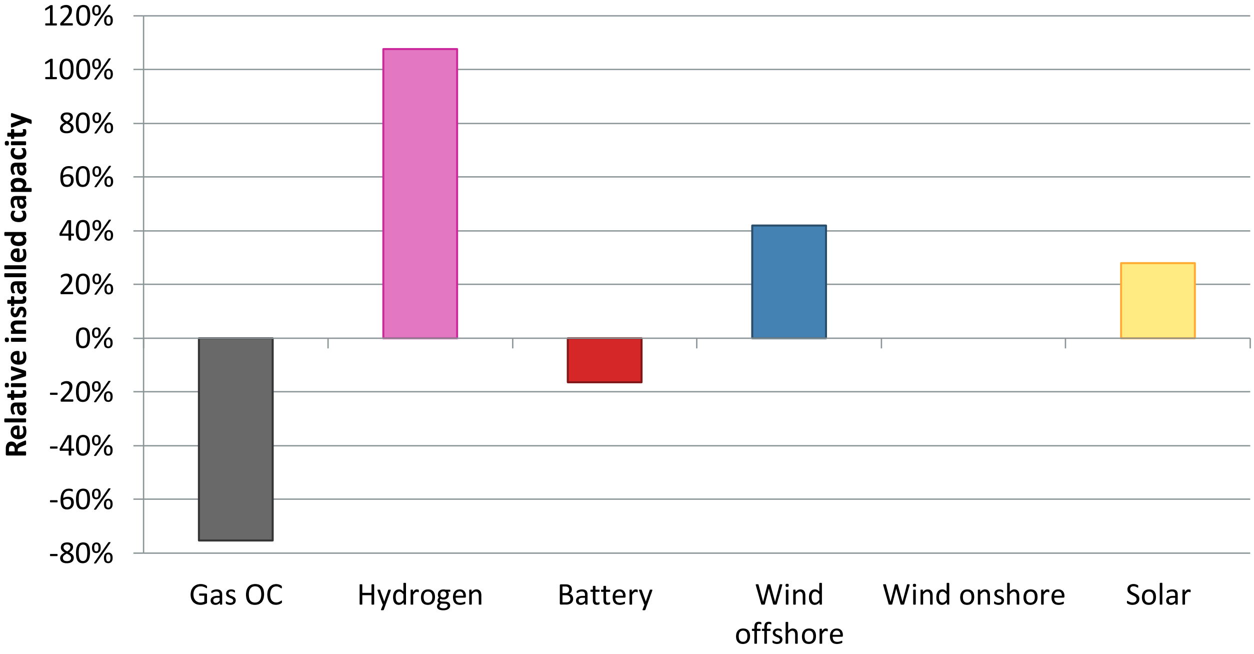

Figure 13. Relative installed generation capacity between the ”VRE100” and the ”VRE100 Clean” scenarios for primary technologies. Negative values indicate a decrease in capacity in the ”VRE100 Clean” scenario.

The “VRE100 Clean” scenario achieves greater emissions reductions compared to the “VRE100” scenario but comes at the cost of significantly reduced system performance. Table 4 highlights the relative changes in system parameters between the two scenarios, with system costs increasing by 18%, severely impacting competitiveness. Although electricity prices and volatility are not explicitly simulated for the “VRE100 Clean” scenario, it is evident that the market would face additional pressures. Sustaining the profitability of a larger generation capacity, combined with increased weather dependency, would likely exacerbate market instability, posing significant risks to energy system investors, including both producers and consumers.

The primary challenge of the “VRE100 Clean” scenario arises from its heavy reliance on locally produced hydrogen for balancing power. This dependency necessitates extensive hydrogen infrastructure development, including pipelines and storage, which introduces substantial uncertainties about its feasibility. These plans face numerous barriers, particularly due to the global inexperience in transporting and storing hydrogen at the scale required. Such infrastructure investments would demand significant coordination, resources, and technological advancements, further complicating their implementation. Furthermore, as shown in Table 4, a heavily increased power transmission grid development represented by an increase in costs of 39% is also required primarily owing to the increased offshore wind in the German power system. As a final note, the current analysis assumes optimistic cost reductions for electrolysers. Should these reductions fail to materialise, the cost-effectiveness of this scenario would be significantly impacted[79] [80].

Although natural gas consumption is significantly reduced in the “VRE100 Clean” scenario, the higher electricity prices drive the German power system to rely more heavily on imports from neighboring regions. This dependency is evident in the increased import costs, underscoring the system’s reliance on, and vulnerability to, developments within the broader European power grid, and posing risks related to energy security. Finally, an increased use of critical materials further highlights risks associated with clean-energy supply chains and environmental impacts.

Table 4. Relative increase for the "VRE100 Clean" vs. the "VRE100" scenario presented for different parameters covering aspects of competitiveness, energy security and reliance on transmission infrastructure.

	System cost	**Import cost**	**Transmission cost**	**Use of critical materials**
Relative change: **“VRE100 Clean” vs “VRE100”**	+18%	+60%	+39%	+18%

Takeaway on stringent emission targets without nuclear:

- Achieving stricter emission targets without nuclear requires a significantly increased dependency on hydrogen for balancing power (+108% or +30 GW), alongside a substantial increase in generation capacity to supply electrolysers to produce the hydrogen to fuel the power plants.
- This reliance on hydrogen introduces significant uncertainties regarding its feasibility for large-scale deployment, while the power system under this scenario faces additional risks related to competitiveness, energy security, transmission infrastructure, and critical material supply chains.

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[79] Quantified Carbon & CATF. Power System Expansion in Germany. 2024. To be published.
[80] Quantified Carbon Linkedin. Role of Hydrogen for Power Generation. 2024.

4 Key barriers to decarbonisation

Table 5 below summarises the results of key parameters between the two technology scenarios “Nuclear” and “VRE100”, the former including nuclear power and the latter excluding it. The results show that the “Nuclear” scenario outperforms the “VRE100” scenario across all evaluated parameters. The inclusion of nuclear in the German power system demonstrates a more economically competitive, secure, sustainable pathway for effectively lowering the barriers to achieve Germany’s goal of climate neutrality by 2045.

The following key barrier discussion draws on the results presented in Table 5 from the perspective laid out by the parameters including competitiveness (system costs, electricity costs, and price volatility), energy security (imports and gas consumption), reliance on infrastructure (transmission lines), sustainability metrics (GHG emission, land use, and critical materials).

The “VRE100” scenario shows a 26% higher **total system cost** compared to the “Nuclear” scenario. This scenario sees significantly higher renewable generation costs than the “Nuclear” scenario (16 vs 5 €/MWh), due to the greater installed capacity required, especially for offshore wind. This scenario, rooting from its renewable-dominant capacity mix, necessitates heavy investments in energy storage and flexible generation (summing to over 36 €/MWh). As a result, the “VRE100” scenario also has a higher average **electricity price** needed to ensure profitability of all technologies in the more costly system. The “Nuclear” scenario results in significantly lower electricity prices which enhances power system competitiveness and affordability critical to sustain Germany’s industrial development as well as social welfare.

The “VRE100” scenario further shows a higher **electricity price volatility** due to its reliance on weather-dependent VRE sources. Although the use of open-cycle natural gas turbines mitigates this volatility by providing the dispatchable backup, this reliance on fossil gas compromises the long-term decarbonisation goals. Furthermore, if these gas turbines are replaced by hydrogen-powered plants reliant on grid electricity, price volatility would increase. The “Nuclear” scenario provides consistent output with much less dependency on weather and minimises the need for flexibility infrastructure. Therefore, it exhibits a lower volatility of the electricity price, which is more attractive for investments for both consumers and producers.

Connecting back to the system costs, the “VRE100” scenario shows higher import costs due to greater reliance on external energy sources from neighbouring countries. This indicates a higher dependence on electricity trade, which makes the system reliant on external energy sources and introduces uncertainty. This **energy security** perspective cannot be overlooked especially when it comes to the geopolitical conflicts, exposure to price fluctuations in neighbouring markets, and adverse weather conditions. The “VRE100” scenario also exhibits both higher average natural gas consumption and greater variability across weather years, as gas turbines are heavily relied upon to mitigate import reliance and electricity price volatility. This dependence poses critical risks. Such dependency not only ties Germany’s energy system to volatile international markets but also increases exposure to price spikes and supply disruptions. The 2022 Russian gas crisis is an example showing the dangers of dependence on authoritarian states for critical energy resources, which may not be avoidable in the “VRE100” scenario. In contrast, the “Nuclear” scenario offers the alternative to mitigate these risks and enhance energy security. This scenario reduces gas consumption and imports with nuclear providing a more self-reliant and geopolitically secure energy system through a possible diverse fuel supply[81].

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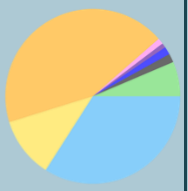
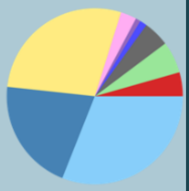
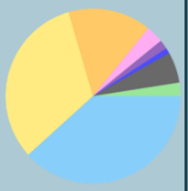
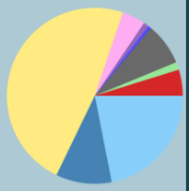
[81] World Nuclear Association (2024), Supply of uranium.

Table 5. Summarised results comparing main parameters of the German power systems in 2045 for the two representative scenarios. Background colours indicate ranking for each parameter.

KEY: RANKING		#1	#2	
Parameters		**Scenarios**		**Legend and explanation of parameters**
		“Nuclear”	**“VRE100”**	
Generation mix				🟨 Solar 🟦 Wind Onshore 🟦 Wind Offshore 🟦 Hydro Run Of River 🟥 Battery 🟪 Pumped Hydro 🟪 Hydrogen ⬛ Gas OC 🟩 Bio CHP 🟧 Nuclear
Capacity mix				
Total system cost (B€)		80	100 (+26%)	Representing annual investment, fixed and variable operational and maintenance costs, as well as import costs, normalised to annual power demand.
Average electricity price (€/MWh)		82	105 (+28%)	Average electricity price seen across full set of 33 weather years.
Electricity price volatility		90	110 (+22%)	Representing absolute spread between 25% and 75% quartiles of yearly averages across full set of 33 weather years.
Energy security	**Import costs (€/MWh)**	7.5	12 (+60%)	Representing the average net import cost across 33 weather years normalised with respect to power demand.
	Gas consumption (TWh)	45	144 (+220%)	Representing the average natural gas consumption (thermal) of open-cycle gas turbines across 33 weather years.
Transmission costs (€/MWh)		0.7	8.5 (+1240%)	The costs of the required new transmission capacity expansion.
Emission	**Life cycle (kg CO$_2$eq /MWh)**	17	45 (+165%)	Consumption-based greenhouse gas emission intensity which include the entire life cycle of the generation type, both for the fuel and the generation plant.
	Direct emissions	3%	9%	Percentage of 1990’s power sector direct emissions level.
Land use (km^2 *10^3)		56	60 (+7%)	Including the land for mining the materials, manufacturing, and installation.
Use of critical materials (kt)		2600	4300 (+66%)	Values include the life-cycle material use (copper, nickel, manganese, cobalt, chromium, molybdenum, zinc, rare earth minerals and silicon), but not the energy infrastructure such as the power grids. Calculated based on the total installed power producing capacity.

In the “VRE100” scenario, the focus on variable renewable energy sources like solar and wind entails overcoming barriers in infrastructure such as **power transmission lines**. Offshore wind accounts for over 83% of the transmission line expansion costs in the “VRE100” scenario. In addition to being costly, this expansion requires extensive construction timelines and lengthy permitting process slowing down connection of clean production and consumption effectively delaying decarbonisation efforts. As a big contrast, the “Nuclear” scenario requires minimal power transmission infrastructure expansion much due to no expansion of offshore wind in this scenario.

The direct **emissions** in the “VRE100” scenario are more than double the “Nuclear” scenario. This is because natural gas fuelled power plants are the most cost-effective measure, despite very high CO_2 price, to meet peak demand and manage the intermittency of a renewables heavy system. The “VRE100 Clean” scenario, investigated in Section 3.8, demonstrates the feasibility of achieving emissions reductions comparable to the “Nuclear” scenario (97%) without nuclear. By replacing natural gas with hydrogen and increasing offshore wind and solar capacities, the scenario reduces emissions but results in an 18% rise in system costs, which significantly impact competitiveness negatively. A heavy reliance on hydrogen for power generation is set to introduce major challenges, including the need for extensive and unproven infrastructure development, while increased power transmission grid requirements further strain resources and logistics. Higher electricity prices also increase the dependence on imports and poses risks to energy security. Additionally, the scenario’s increased demand for critical materials intensifies supply chain vulnerabilities and environmental concerns. Ultimately these results highlight the complex trade-offs and barriers inherent in pursuing a fully decarbonised energy system without nuclear support.

The **land use** results of the “VRE100” scenario and “Nuclear” scenario are rather similar. This is due to both relying on a significant expansion of onshore wind power. A reliance on distributed installations of wind and solar may lead to localised land-use changes and face some social resistance such as growing local opposition associated with NIMBY’s (“not in my backyard”) that needs to be addressed.

Raw critical materials are decisive for Germany’s economy which form a strong industrial base. However, the concern is growing that Germany is falling behind as China establishes the dominant position in critical materials[82]. The “VRE100” scenario demands much higher quantities of **critical materials** especially for solar and wind. This dependency raises concerns about supply chain constraints, geopolitical risks, and environmental impacts from mining and processing. It also intensifies the competition of critical materials such as lithium and rare earth materials, which are essential for renewable technologies and battery storage. In contrast, the “Nuclear” scenario requires much less critical materials which reduces the supply chain vulnerabilities, minimises environmental impacts, and increase energy system resilience.

The comparison outlined here highlights the crucial advantages of a technology inclusive energy policy with nuclear power. The “Nuclear” scenario envisions substantial advances across diverse energy technologies, each presenting specific barriers that must be addressed for successful implementation. Notably, a significant **expansion of nuclear capacity**, corresponding to the construction of approximately 40 conventional large reactors is assumed in the “Nuclear” scenario. While achieving the full scale of deployment outlined in this scenario may be ambitious within the given timeline, building even a smaller number of reactors would yield measurable improvements in key performance metrics. Meeting these goals would require efficient construction processes, minimal delays, and significant regulatory advancements to streamline permitting and safety protocols. Restarting or extending the lifetimes of existing reactors would also demand considerable political commitment and public support—both of which may prove challenging given Germany’s historical phase-out of nuclear power and prevailing public opposition. Addressing these barriers is essential to unlock the full potential of nuclear energy’s positive contribution to the German power system. Furthermore, if serial production of nuclear reactors is achieved, substantial cost reductions could be realised, potentially exceeding the conservative investment cost assumptions used in this study.

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[82] Clean Energy Wire. Germany must use development aid to access raw materials and energy – industry. February 14, 2024.

To conclude, 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 and more.

5 Policy recommendations

This study resulted in a number of actionable policy recommendations that can help in navigating the complex landscape of transforming the Germany power system.

1 Establish technology-inclusive foundational groundwork

- Germany shall take a technology neutral view and a more balanced approach incorporating nuclear to provide stable, low-cost baseload power. Without a technology-inclusive energy policy, Germany risks falling short of its climate goals and compromising its competitiveness.

- Germany shall develop regulatory frameworks and streamline permitting processes to support the expansion of all clean technologies.

- Policies shall 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 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

- Given Germany's climate target in 2045, accelerating nuclear build rates is needed. Even a small addition of nuclear capacity could yield positive impacts, improving energy security, reducing emissions, and enhancing system stability.

- To build new nuclear power, Germany shall prepare to establish a supportive regulatory framework, secure financing, and strengthen the workforce, etc.

4 Continue to promote renewable expansion

- Policies shall continue supporting the strategic deployment of onshore wind, solar, and large-scale battery storage while addressing constraints and conflicts of interest.

- Local generation, flexibility solutions, and grid expansion and enhancement shall be promoted to reduce congestion and enable renewable energy integration.

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

Greenhouse gas emission, land use, and critical materials factors for different power and energy generation sources considered in the current study are presented in Table 6. 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 6 regarding emissions, land use, and use of critical minerals and materials. 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[83]. The lifecycle greenhouse gas emission values for nuclear, solar PV, and wind sources have been taken from Ref. 84 while the background to all the other values is presented in Ref. 85. Notably, contributions from storage technologies battery and hydrogen have not been included into this analysis.

Table 6. Greenhouse gas emission, land use, and critical materials factors for different power and energy generation sources considered in the current study.

	EMISSIONS	LAND USE	CRITICAL MINERALS & MATERIALS
Power generation type	kg CO_2eq/MWh	km^2/TWh	kg/MW
Battery discharge	160*	21	6834
Gas CC	490	0.8	1166
Gas OC	735	0.8	1166
Nuclear	3.5	1	5274
Solar PV	6.0	21	6835
Wind Offshore	4.4	1	10167
Wind Onshore	4.4	1**/150***	10167

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

Appendix B Reference sources

Table 7. Main sources 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

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[83] IEO. Photovoltaics market in Poland. 2023.

[84] Pehl M, Arvesen A, Humpenöder F, Popp A, Hertwich EG, Luderer G. Understanding future emissions from low-carbon power systems by integration of life-cycle assessment and integrated energy modelling. Nature Energy. 2017 Dec;2(12):939-45.

[85] Quantified Carbon & CATF (2024), Power System Expansion Poland.

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

Appendix C Method to calculate transmission costs

To estimate the transmission expansion costs, we combined data from the National Grid Development Plan (NGDP) with cost assumptions sourced from the Institute for Macroeconomics and Business Cycle Research (IMK)[86]. The NGDP provides detailed estimates of grid reinforcement needs for renewable energy technologies, expressed in km/GW of additional capacity: 18.3 km/GW for solar PV, 7.7 km/GW for onshore wind, and 214.7 km/GW for offshore wind. These figures were paired with cost per unit of transmission line construction derived from IMK's assumptions. A reverse engineering analysis of the cost assumptions was conducted for various transmission lines, and the results were cross-referenced with other data sources. The transmission costs are therefore based on the estimated transmission line length and cost per unit of construction.

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[86] IMK. Expansion of electricity grids: investment needs. December 2024.

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