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Postponing Germany's Nuclear Phase-Out: A Smart Move in the European Energy Crisis?

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Abstract

In response to the 2022-2023 energy crisis, the German government postponed the phase-out of the last three nuclear plants from the end of 2022 to the 15th of April 2023. Using the ELMOD and ELTRAMOD model cluster, we compare this decision with a counterfactual scenario without German nuclear capacity and derive its implications for the integrated European electricity market. The postponement of the nuclear phase-out reduced gas-fired power generation in Europe by 2.9 TWh, with a reduction of 1.6 TWh in Germany. The substitution of expensive power plants across nations led to a decrease of almost €9 per MWh in average electricity prices in Germany. Furthermore, carbon dioxide emissions in Germany fell by 3.3 Mt. By extending our analysis to scenarios with increased nuclear capacity and different weather years, we illustrate the limitations of large capacity blocks for managing congestion in a decentralized energy system with multiple regional grid bottlenecks.

Keywords: Power system modeling, Nuclear phase-out, Streckbetrieb, European energy crisis, electricity market

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Introduction

The nuclear phase-out, a cornerstone of Germany's energy transition strategy, faced a pivotal moment during the energy crisis in 2022. Concerns over natural gas shortage prompted the German government to postpone the phase-out by three and a half months. As a result, the last three nuclear power plants in Germany were not phased out at the end of 2022 but instead continued to operate in a so-called "Streckbetrieb" (limited stretched-out operation) until the 15th of April 2023, using the remaining of their fuel elements. In this study, we examine the multifaceted impacts of the nuclear phase-out postponement in Germany on various aspects of the energy landscape in 2023. In particular, the following key research questions are being pursued:

1. *Security of supply and grid congestion*: To what extent have nuclear power plants contributed to securing energy supply by reducing gas-fired generation, given the risk of natural gas shortages? How has this decision reduced grid congestion, ensuring higher transmission security?
2. *Economic implications*: How did the postponement of the nuclear phase-out influence electricity prices in 2023? What trade-offs emerged for consumers, producers, and overall welfare in Germany and Europe? How does the available capacity of nuclear power affect the profitability of other technologies?
3. *Systemic perspective*: How has the postponement of the nuclear phase-out in Germany shaped the generation mix in the integrated European market? What conclusions can be drawn from the analysis of this extraordinary period of energy crisis for the central role of Germany in the European electricity market and the impact of its nuclear capacity in a system with a high share of renewable energy sources (RES)?

To answer these research questions, we explore four scenarios with different assumptions regarding the available German nuclear capacity from 1st of January to 15th of April 2023 utilizing the ELTRAMOD electricity market model and the ELMOD European power system model. We assess variations in generation mix, congestion management, power prices, welfare, and technology profitability across scenarios. We extend our analysis to all weather years from 2012 to 2022 by considering the respective demand and RES generation profile. The nuclear capacity scenarios are outlined below:

1. *REF*: Replicating the actual market clearing and grid situation using historical data and the reported available capacity for German nuclear plants, this factual scenario serves as the baseline for comparisons with the other scenarios.
2. *Nuc_0*: This counterfactual scenario assumes the phase-out proceeding as initially planned by the end of 2022. Hence, Germany's nuclear power capacity is set to zero.
3. *Nuc_3*: In this counterfactual scenario, we investigate the potential outcome of postponing the nuclear phase-out, assuming that the last three power plants in Germany could operate without technical and fuel procurement constraints related to the impending phase-out. We refer to the conditions of 2021 as the last year without such restrictions.
4. *Nuc_6*: This counterfactual scenario explores a situation where Germany would have also postponed the previous phase of nuclear power plant shutdowns from 2021. In this scenario, all six nuclear power plants in Germany would have been operational, with assumed availability factors based on the period from 1st of January to 15th April 2021, the last year in which all six plants were active.

Table 1 provides an overview of the scenario set, depicting how the availability of nuclear plants in Germany varies across the scenarios.

Table 1: Deployability of nuclear plants in the different scenarios analyzed. The REF scenario considers the actual availability of 2023, while the other counterfactual scenarios that allow nuclear power generation assume the availability from 2021. The period is from January 1st to April 15th, respectively. Data sources: [1, 2]

Plant name	Installed net capacity[1]	Mean availability [%] REF	Nuc_0	Nuc_3	Nuc_6
Gemeinschaftskernkraftwerk Neckar	1,310	53.7	0.0	98.3	98.3
Kernkraftwerk Emsland	1,336	60.4	0.0	99.7	99.7
Kernkraftwerk Isar 2	1,410	87.9	0.0	99.0	99.0
Kernkraftwerk Brokdorf	1,410	0.0	0.0	0.0	99.9
Kernkraftwerk Grohnde	1,360	0.0	0.0	0.0	98.0
Kernkraftwerk Gundremmingen	1,288	0.0	0.0	0.0	98.7

The three last active nuclear plants reported average availability between 53.7% and 87.9% between 1st of January and 15th of April 2023. In contrast, in 2021, all German nuclear power plants in operation had an average availability of more than 98.3% in this same period.

In the remainder of this paper, we present the analysis results, focusing on the security of supply and the economic impact of the decision to postpone the nuclear phase-out in Germany during the energy crisis. We then contextualize these findings and draw conclusions for the German and

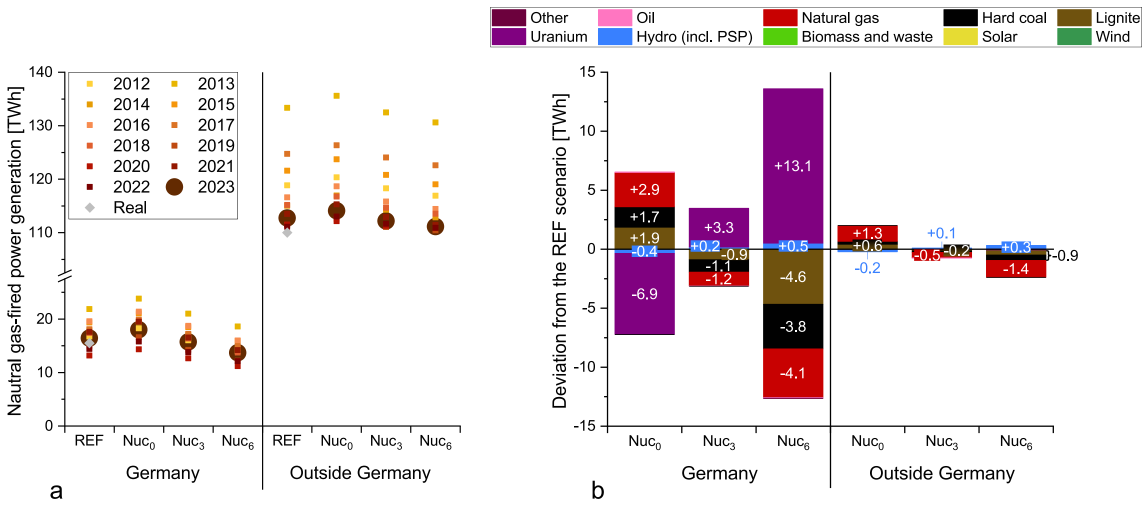

Figure 1: Deviations in gas-fired generation of the counterfactual scenarios from the REF scenario for different weather years (a) and generation volumes for all technologies based on actual 2023 demand and weather profile (b).

European power system. The Appendix briefly outlines the models and the data used, along with the validation of both models.

German nuclear power in 2023 substituted 2.9 TWh of natural gas-fired power generation in Europe

The postponed nuclear phase-out reduced natural gas-fired power generation by 1.6 TWh (-9.6%) in Germany and 1.4 TWh (-1.2%) in the other countries modeled. This outcome is derived from comparing the counterfactual scenario Nuc_0 with the REF scenario. Figure 1 illustrates gas-fired power generation in Germany and Europe for all scenarios and weather years, providing insights into the potential for further gas savings and the effects of the available nuclear capacity in Germany.

The data point distribution of previous weather years suggests that the weather conditions in 2023 were a positive factor for natural gas savings, although the previous three years had been more favorable in this regard. Under less favorable conditions, such as those in 2013 with lower weather-dependent RES generation, increased demand, and higher residual load, the impact of postponing the nuclear phase-out in Germany on gas savings would have been substantially higher. For this weather year, the total gas-fired generation in the REF scenario would have risen, ceteris paribus, by approximately 5.4 TWh in Germany and 20.6 TWh abroad. Against this background, gas savings in Europe between the Nuc_0 scenario and the REF reach their maximum at 4.2 TWh. At the same time, the particularly high additional gas generation would have increased the marginal risk of

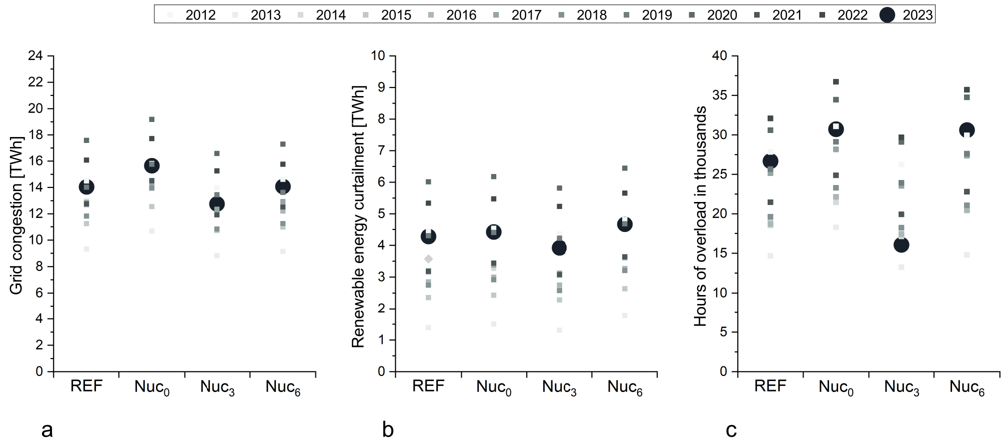

Figure 2: Grid congestion (a), curtailment of RES as part of congestion management (b) and hours of overload (c) in the REF scenario and the counterfactual scenarios analyzed for the different weather years.

gas supply shortages. Therefore, every terawatt-hour saved by postponing the nuclear phase-out would have been even more crucial for the EU's efforts to ensure a stable gas supply.

Ensuring a more balanced distribution of capacity between north and south, the delayed phase-out reduced grid congestion by 1.6 TWh

The postponed nuclear phase-out in Germany also had a positive impact on limiting grid congestion. The comparison of REF and the counterfactual scenario Nuc_0 in Figure 2 reveals that without the nuclear plants, total congestion would have increased by 1.6 TWh (11.5%). Moreover, when compared to the REF scenario, the Nuc_0 scenario results show a total rise in overload hours of 15.2%, resulting in additional positive redispatch of 1.2 TWh (+18.9%) to correct the original market dispatch and ensure transmission viability.

The contribution of nuclear power plants in reducing grid congestion can be attributed to more evenly distributed capacities in market dispatch through higher capacity in western and southern Germany. When operating at full capacity as assumed in the Nuc_3, the last three nuclear power plants could have further relieved the main congestion points. In this scenario, grid congestion is reduced by an additional 1.3 TWh (-9.2%). In contrast, with all six nuclear power plants operational as in the Nuc_6 scenario, the grid congestion volume would be comparable to or slightly higher than in the REF scenario, depending on the weather year.

Contrary to the capacity adequacy on the European electricity market, weather years with more favorable conditions for renewable energy generation and lower residual load would have posed a

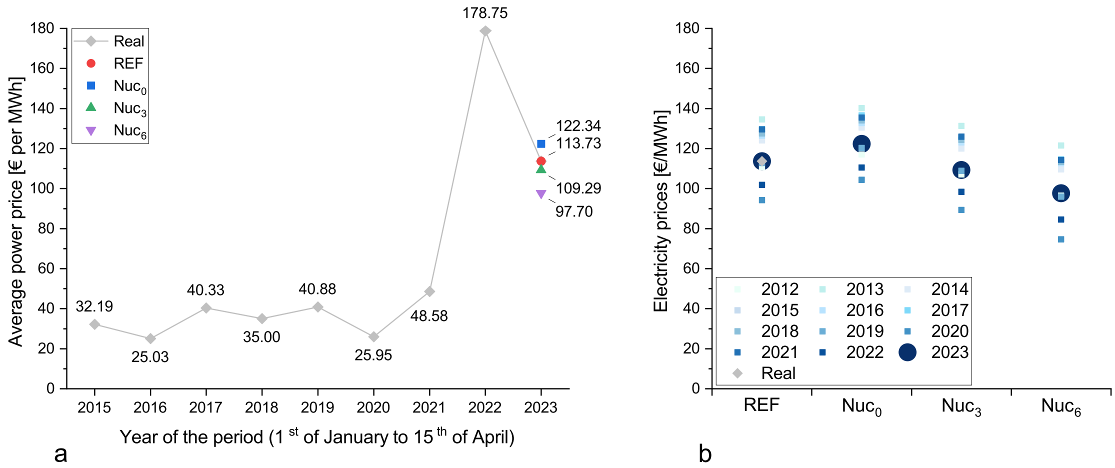

Figure 3: Average power prices of the REF scenario and the counterfactual scenarios compared to historical day-ahead power prices (a) and the price spread for the other weather years (b).

greater challenge for transmission adequacy. Regarding security of supply, in terms of transmission adequacy, the realized configuration of nuclear power plant capacity in Germany had a positive effect on reducing grid congestion compared to a 2022 phase-out (Nuc_0 scenario), and this would have been the case for any weather year over the past decade as Figure 2 highlights.

Average German power prices would have been almost €9 per MWh higher without the postponement of the nuclear phase-out

The model results reveal that the decision to postpone the nuclear phase-out had a noticeable impact on power prices. Figure 3 plots the average power prices of the different scenarios and contextualizes them with the average prices for the same period in the past, i.e., from 1st of January to 15th of April. Moreover, 3 depicts the results for the model runs using the demand time series and renewable availability profiles of the other weather years.

The historical average power price in Germany in the analysis period, as well as the price in the calibrated REF scenario of the model, was €113.73 per MWh. In the counterfactual scenario Nuc_0, the average power prices in Germany would have been approximately €8.61 per MWh higher at €122.34 per MWh, i.e., the postponement of the phase-out led to a price drop of 7.0 %. The maximum potential price reduction from postponing the nuclear phase-out could have been €4.44 per MWh higher, reaching €13.05 per MWh between the scenarios Nuc_0 and Nuc_3, if the last nuclear power plants could operate with the historical capacity.

As Figure 3 shows, larger deviations in average power prices could have been realized in weather years characterized by high renewable energy generation and low residual load, such as 2020 or 2022. The residual load in 2023 was relatively low, meaning that the impact of the decision to extend the operation of the last three nuclear power plants on the reduction of the average electricity price was comparatively large.

In contrast, in less favorable weather years the price level would generally have been higher, as more generation from expensive thermal power plants would have been required. The relatively small capacity of the nuclear power plants would not have been sufficient to displace expensive technologies from the merit order in many hours, narrowing the potential for price reduction through the postponement of the nuclear phase-out.

The postponement of the phase-out increased welfare in Germany by €236 Mio. in a redistribution of welfare at the expense of the European neighbors

Figure 4 shows the variation in producer surplus, consumer surplus, and welfare of the counterfactual scenarios and the reference scenario for Germany and the rest of Europe. In Germany, the delayed phase-out raised electricity consumers' surplus by €576 Mio. (+0.2%), while decreasing producers' surplus by €339 Mio. (-2.4%), resulting in a total welfare gain of €237 Mio. (+0.1%).

The impact on European welfare tends to be marginal. The decision of the German government to postpone the phase-out increased consumer surplus in all modeled European countries, notably in Luxembourg, which shares a market area with Germany, and in the neighboring Czech Republic and Austria. However, the overall welfare effect remained limited as gains on the consumer side were offset by losses on the producer side.

This dynamic is especially pronounced in countries like Czech Republic and Denmark. In the hypothetical Nuc_0, these nations expected to compensate for Germany's missing nuclear capacity by boosting revenues through exports. Nevertheless, as Germany reduced its import needs by postponing the nuclear phase-out, these additional revenues were not realized, leading to slight overall welfare losses for these countries.

Given the limited capacity of the three nuclear power plants, the postponement of the nuclear phase-out in Germany did not have a tangible impact on the merit order of its European neighbors by exporting cheap electricity from which more countries could profit. Instead, its contribution

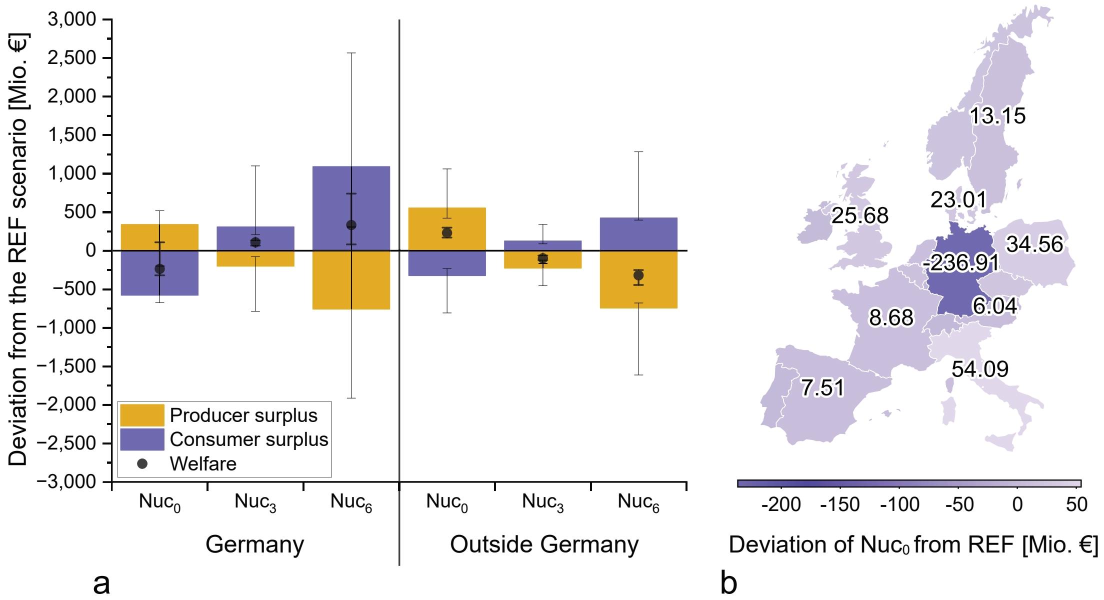

Figure 4: Deviation of consumer surplus, producer surplus, and welfare, of the Nuc_0, the Nuc_3, and the Nuc_6 scenarios from the REF scenario in 2023 with the whiskers indicating the variations deduced from the model runs of the other weather years in Germany and the other regions modeled (a) and absolute deviation in welfare in Nuc_0 by country (b).

was to reduce expensive exports to Germany, with the common market zone of Luxembourg and Germany benefiting the most. In sum, the delayed phase-out reduced welfare by €231 Mio. in the rest of Europe, with the system-wide welfare gain being €6 Mio. only when also considering Germany.

Analyzing the various price paths in our scenarios, we evaluate the possibility of windfall profits and whether the energy-only market can genuinely incentivize capacity investment with these increased energy-crisis price levels. Investment decisions are made based on capital budgeting. Therefore, using the methodology described in [3], we quantify the effects of the different scenarios on the internal rates of return (IRR) for candidate technologies. The techno-economic data of the technologies are derived from reference indications for existing plants from [4]. Figure 5 shows the rates determined for each scenario and the distribution reflecting the impact of the weather year.

The nuclear phase-out policy significantly impacts the profitability of the exemplary plants in Germany. Assuming a capital cost rate of 10.0%, all reference plants are in the red in all scenarios. Consequently, the market conditions in the period analyzed do not seem to incite investments into new plants with market-based revenues only, even with the initially planned nuclear phase-out. The low return rates also rule out windfall profits for the technologies shown in Figure 5 during

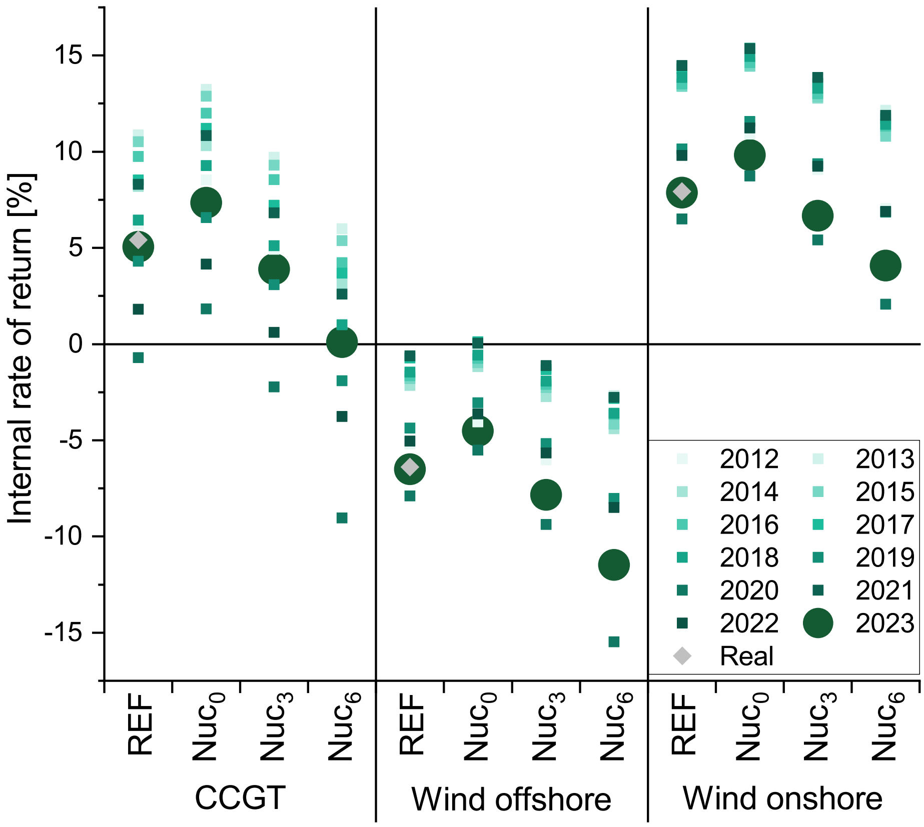

Figure 5: Internal rate of return of candidate power generation technologies by scenario and weather year.

the analyzed period. Onshore wind, however, could be an exception, especially under different weather conditions. The reference CCGT plant could have had IRR clearly above 10.0% as well, but only in the earlier nuclear phase-out scenario and for the specific weather years 2013, 2015 or 2016.

Adding German nuclear capacity primarily reduces domestic coal-based generation and natural gas-based generation abroad

Figure 1 also breaks down the generation shifts in Germany and the rest of the model area and displays the variation in power generation by technology compared to the REF scenario.

In the Nuc_0 scenario, Germany's domestic power plant fleet could have covered roughly two-thirds of the resulting 6.9 TWh supply gap arising from the nuclear phase-out in 2022. The remaining 1.3 TWh would have been supplied by additional imports from the European market.

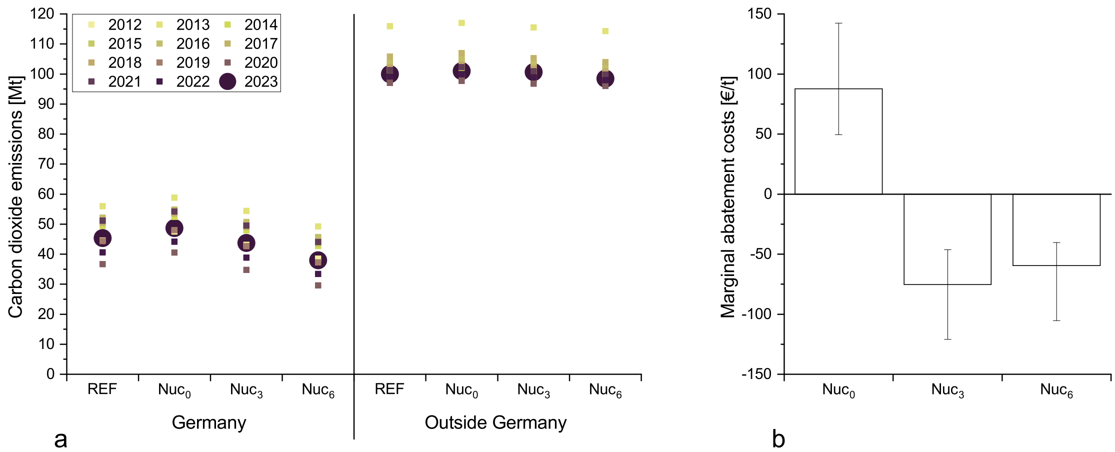

Figure 6: GHG emissions by weather year (a) and marginal abatement costs of GHG emissions (b) in the model period.

The analysis of all scenarios illustrates how nuclear capacity in Germany primarily reduces domestic coal-fired generation and natural gas-fired generation in demand spike hours, but does not have the potential for significant shifts in the European electricity mix. In no scenario is the nuclear capacity in Germany sufficient to displace lignite or hard coal-based generation in Europe on a similar scale; instead, it primarily reduces import demand and the more expensive natural gas-fired generation in the European neighbors. It is important to note that a full replacement of gas or coal is not possible due to combined heat-and-power coefficients and other must-run conditions of thermal power plants used to cover heat demand.

Through the substitution of fossil fuel-fired plants, the additional nuclear capacity reduced GHG emissions in Germany by 3.3 Mt

As shown in Figure 6, the delayed nuclear phase-out reduced GHG emissions in Germany by 6.9% in the model period. Compared to the preliminary estimate of [5] for the emissions in 2023 at 177 Mt, the reduction amounts to only 1.9% of the annual emissions.

In Figure 6 the abatement costs have been calculated for the whole model area. Without the nuclear power plants in the Nuc_0 scenario the abatement cost for reducing GHG emissions by one ton compared to REF would have been at €88, while the scenarios with higher nuclear capacity would have further reduced both emissions and system costs. The marginal benefit, expressed by negative abatement costs, declines with increasing nuclear capacity, as less costly GHG-emitting power plants are gradually substituted by the additional nuclear capacity.

Additional nuclear capacity drives storage utilization

Apart from fossil fuel-based generation, generation from hydro power plants varies across the scenarios. The deviations can be traced back to the activity of pumped-storage power (PSP) plants. In instances of electricity oversupply caused by the inflexibility of nuclear power plants, PSP stored excess electricity, which was later fed into the grid during periods of high residual load. As a result, power generation from PSP plants consistently rises with the increasing availability of nuclear power.

This increased utilization of PSP in central and southern Germany, as well as neighboring countries in the Alps region and Luxembourg, together with the nuclear power plant capacity ensured a more balanced distribution of generation between North and South, effectively reducing congestion in the North-South Transmission Corridor. Therefore, 0.1 TWh (+3.2%) less curtailment of RES to alleviate grid congestion was necessary in 2023 compared to the Nuc_0 scenario, with an additional reduction of almost 0.4 TWh (11.2% in total) being possible in the scenario Nuc_3.

The operation of all last six nuclear plants in Germany would have increased hours of overloads by 15%, exposing challenges for congestion management

However, the increased capacity and the geographical distribution of the other three nuclear power plants in Nuc_6 would negatively impact grid congestion and increase curtailment of RES. Due to increased feed-in of nuclear power plants in Northwest, the Nuc_6 scenario has the highest curtailment, the highest number of overloaded lines and more grid congestion compared to the REF scenario. As nuclear plants are dispatched at available capacity on the market [cf. 6], they reduce generation from other controllable conventional plants in the North in the market dispatch, limiting the flexibility for negative redispatch prior to the congestion points. Furthermore, the geographic distance of nuclear power plants from the congestion points means that they cannot alleviate congestion by reducing their output, leaving curtailment of regional RES as the only congestion management option. Compared to the REF scenario, the Nuc_6 scenario shows an increase in curtailment of 9.1% of the actual RES curtailment corresponding to 0.4 TWh. This situation, exemplified by the Nuc_6 scenario, underscores the challenges in a system with large capacity blocks like nuclear power plants rather than more distributed flexible capacity when trying to integrate RES.

Conclusion and implications

In retrospect, the decision to extend the operation of Germany's last three nuclear power plants was pragmatic. Without nuclear power plants, the mean power price in the first quarter of 2023 would have been approximately €8.61 per MWh higher, with Germany and Europe relying more on natural gas for electricity generation. The postponement of the nuclear phase-out decreased grid congestion and ensured a higher security of supply. This would have been the case regardless of the conditions in 2023, even though weather years have a much more significant impact and even conflicting effects on the security of supply from the market (capacity adequacy) and grid perspective (transmission adequacy). The welfare trade-off between countries resulted in marginal overall welfare gains in Europe. However, accounting for the impact of gas savings in the electricity sector on the gas market, the overall welfare effect could also be positive in countries not directly benefiting from the nuclear phase-out postponement and its effects on the integrated European electricity market. Future research should explore this aspect further.

While postponing the nuclear phase-out in Germany proved to be a positive contribution to tackling the immediate energy challenges, this study also exposed potential limitations in aligning nuclear power with the characteristics of the future energy system, evident in increased grid congestion and less grid congestion management options in the scenario with the maximum nuclear capacity. Furthermore, we find that although prices were high during the energy crisis in the first months of 2023, they alone will not provide sufficient incentives for investments in new flexible and decentralized capacity blocks allowing for more effective management of regional grid congestions.

Finally, the decision to postpone the nuclear phase-out not only contributed to the reduction of GHG emissions in the electricity sector in Germany, which is subject to annual targets, but also led to a short-term reduction of GHG emissions across Europe. In the context of the EU Emissions Trading System (EU ETS), the removal of free allowances attributed to the nuclear capacity from the market could ensure a permanent effect.

Methods

Model description

We use the ELTRAMOD-ELMOD model family developed by the Chair of Energy Economics at TU Dresden. The typical time horizon in the models is one year in hourly resolution. For this paper, we adapted the model to 2,520 hours to represent the time horizon affected by the decision to extend the operation of the three German nuclear power plants. With one node per region, mostly corresponding to the countries included, ELTRAMOD determines the cost-optimal dispatch of the European power plant fleet based on marginal generation costs. Net transfer capacities (NTC) restrict the power trade between the regions. The market results determined by ELTRAMOD are then transferred to ELMOD to analyze the physical feasibility of the market results within the transmission grid. ELMOD has a very high spatial resolution, as it includes all substations in Germany and all interconnection points with its electricity neighbors as individual nodes. For model performance reasons, the national grids of all other regions and interconnection points between them are represented as one aggregated virtual node per region. The power flow between the nodes is restricted by the thermal capacity of the transmission system using a direct current (DC) approximation. For the virtual interconnection points between the other regions, the model considers the aggregated physical interconnection capacity. If the physical capacity does not allow the power flows resulting from the market dispatch, the model determines redispatch activities, increasing or decreasing the output of the plants so that the resulting power flows are feasible given the thermal limits of the transmission grid. Again, the target function ensures that the model achieves cost-optimal adjustments in the generation schedule of the power plants from the market results (redispatch) for removing grid congestions on the basis of marginal costs. For further information on the dispatch-redispatch models used, the authors refer to [7, 8].

Data

This section provides an overview of the dataset used for the analysis, explaining the sources and the pre-processing steps. For modeling the electric market in hourly resolution for the period from 1st of January to 15th of April 2023, following data were essential: techno-economic power plant data, availability of the power plant fleet, load data, fuel prices and the historical NTC values limiting the cross-border electricity exchanges within the European power grid. Model validation and calibration were based on historical Day-Ahead prices, generation records for different technologies, and historical congestion management demand represented by redispatch volumes.

The standard model database, documented by [8, 9], provided the core data for the European power plant park and grid in our analysis. We meticulously cleaned and updated the power plant fleet dataset to cover all operating power plants in the European market in the period from January to 15th of April 2023 and to align the aggregated installed capacity for different technology types with the data published on the Transparency Platform of the European Network of Transmission

System Operators for Electricity (ENTSO-E) [1]. The most recent data for the power plant fleet in Germany was obtained from the list provided by the Bundesnetzagentur [2], the country's official electricity grid regulator. As Great Britain's generation capacity information is not available on the Transparency Platform, the data was downloaded from the Balancing Mechanism Reporting Service (BMRS) application programming interface (API) [10].

Availability time series of RES were calculated as the ratio of actual generation in an hour to installed capacity. Feed-in data for PV, wind, and biomass capacities were acquired from ENTSO-E for most countries. For Great Britain, the aforementioned source was utilized. Italy's availability of renewable capacity was obtained from the official website of the Transmission System Operator [11].

Historic hourly load time series data spanning from 1st of January to 15th of April 2023, for European countries, were extracted from the ENTSO-E Transparency platform [1]. Load data of Great Britain was provided again by the BMRS API [10]. The data of the island of Ireland was retrieved from the Transmission System Operator's official website [12]. Similarly, actual generation time series needed to evaluate the model's quality were obtained from the ENTSO-E Transparency platform, except for Great Britain. Further time series data necessary for model calibration and validation, such as Cross Border Commercial Schedule Exchanges for Electricity Exports and Day Ahead Prices were scrutinized from [1]. The historic Net Transfer Capacities (NTC) data were also sourced from [1]. When NTC were not published for Day-Ahead trade, Week-Ahead or Month-Ahead data were used, subsequently broken down to hourly resolution for the simulation spanning 1st of January to 15th of April 2023.

For the blocks in Germany exceeding an installed capacity of 100 MW, we used the actual historic availability based on the unavailability data derived from the ENTSO-E-Transparency Platform [1] in hourly resolution. For smaller power plants in Germany as well as for the power plants in the European neighbours we determined the hourly mean availability of each technology type in the country based on the data from [1].

Fuel prices, critical for cost calculations, were obtained from various subscription platforms with commodity exchange data. Natural gas [13] and oil prices [13] were already available on an hourly basis, while coal was available in monthly resolution and uniformly assigned to the hours within the respective months [14]. Uranium and lignite prices were derived from [9] and remain constant throughout the analysis period. In addition to fuel prices, CO_2 -prices from EU ETS auctions [15] were imported as daily time series and assigned to the hours of each day of the analysis period.

The validation of the grid model is based on the quarterly report of the Bundesnetzagentur as official authority and grid regulator [16] in Germany. In the grid congestion report for the first quarter of 2023, which also covers the period of our analysis, Bundesnetzagentur publishes data on positive and negative redispatch, curtailment of renewables and total grid congestion, as well as the Top 25 most overloaded grid elements. This allows a thorough validation, including the regional distribution of grid congestion in our model results.

Model validation

To assess the quality of a power system model, it is common to compare the model results of the base period with a couple of indicators derived from the statistics covering the same time horizon [cf. 8, 17, 18]. The comparison of model results with the statistical data considers deviations in generation volumes, metrics of the power prices (averages, mean absolute error, correlation, standard deviation), as well as discrepancies of the model's ability to reproduce trade activities, positive and negative redispatch.

Figure 7 gives an overview of the generation structure of Germany, some candidate countries and the whole area investigated. Overall, the model represents the generation volumes very well. The deviation of the German overall power generation is 0.6% only and the deviation of the modeled overall generation volume in all countries considered from the actual sum is merely 0.3%. As can be seen in Figure 7, also the modeled shares of the single energy carriers in the candidate countries and the whole model region are well in line with the actual proportions. This paper focuses primarily on the situation in Germany and therefore examines the other countries from a rather high-level perspective; the minor deviations are not considered critical since the model's ability to reproduce the German generation mix and the generation mix of the entire model area is highly satisfactory.

Also the modeled net exports of Germany match the real net scheduled exchanges of power pretty well. The deviation is 1.6 TWh only. As the literature shows deviation of this value referring to a whole base year of up to 7.0 TWh [cf. 9, 19], the deviation for the modeled period is considered to be in a good range.

With an average value of €113.73 per MWh, the modeled German power prices matches the actual mean of €113.73 per MWh. The standard deviation of the modeled German power prices is €43.50 per MWh. With €47.39 per MWh, the actual standard deviation is larger. The difference of €3.89 per MWh is a good outcome considering the range for the standard deviation discrepancy between

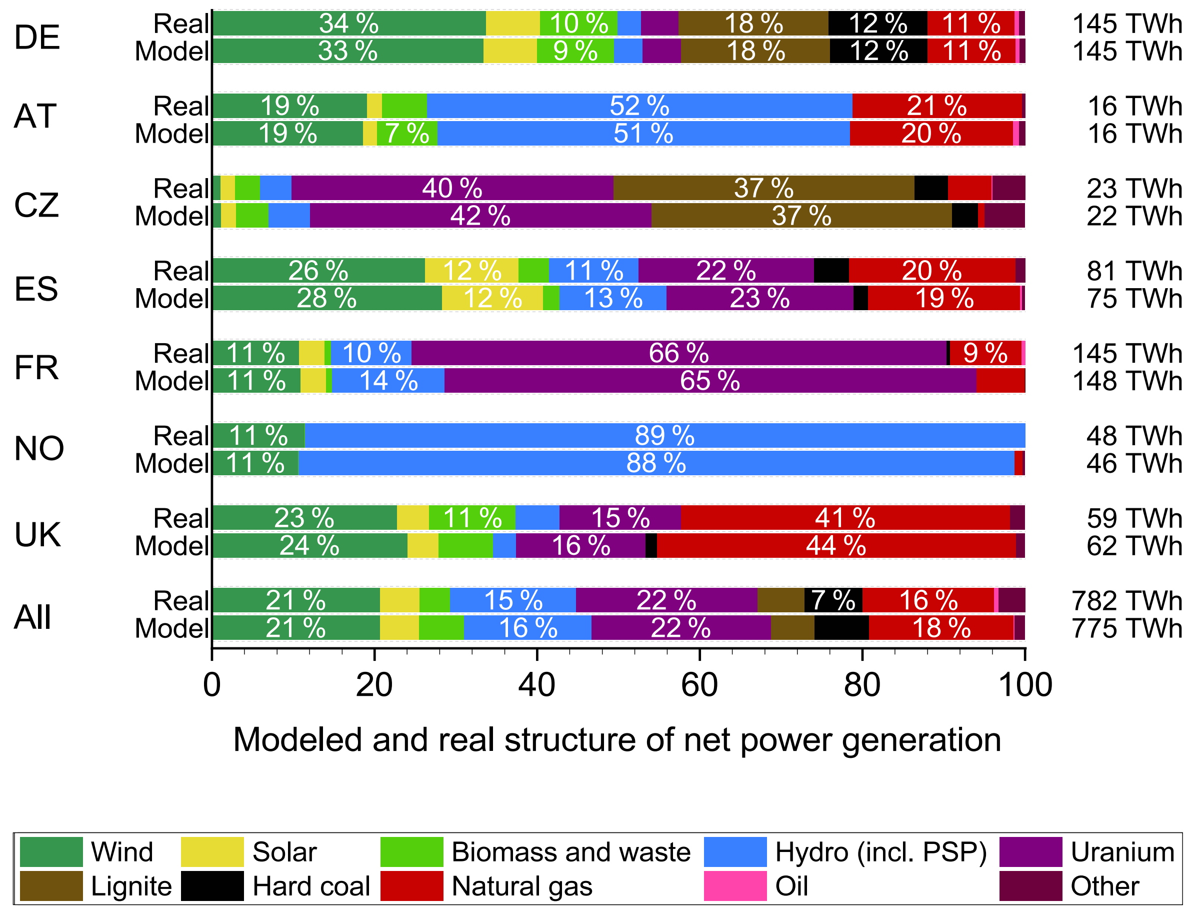

Figure 7: Actual and modeled generation mix for candidate countries and the whole region considered.

modeled prices and real price time series in the literature, for instance [18] who reproduces price time series for 2012. Between the modeled unsorted prices and real day-ahead prices, the correlation coefficient is 82.8%, and 98.7% for the sorted prices. These values are higher than the correlation coefficients of [18] and also of the values of other models [cf. 20] and therefore a good outcome as well. The mean absolute error (MAE) of the modeled sorted price duration curve from the actual one of the German power prices is with €4.10 per MWh also satisfying considering the mean absolute errors of other models that range between €2.28 and €5.93 per MWh [cf. 3, 17, 18, 20].

To sum up, although the time horizon examined only covers 28.5% of a normal model period challenging the model's ability to reproduce the actual conditions, the model shows a sufficient quality for the investigation intended within this paper. There are some deviations in relevant indicators when it comes to the comparison of international model outcomes with the statistical values. Nevertheless, we anticipate that these discrepancies will have minimal impact on the scenario results due to the model's focus on the German electricity system and the total generation

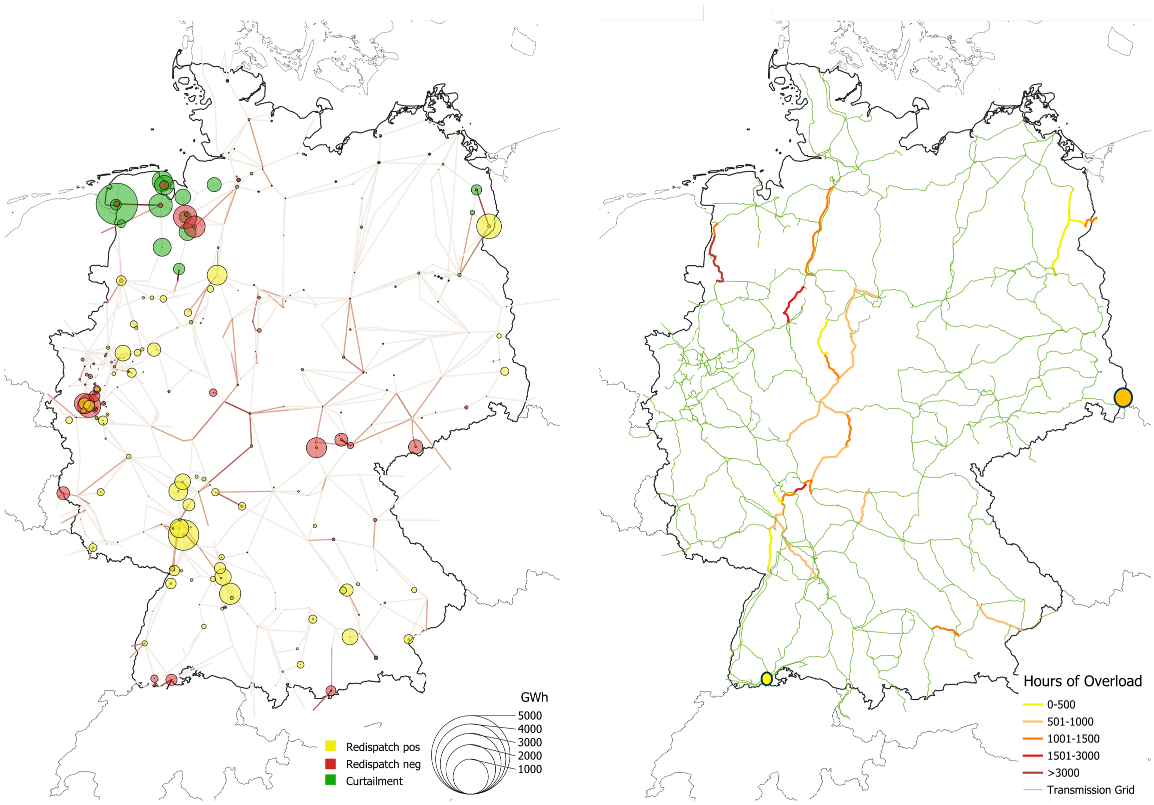

Figure 8: Grid Congestion in Germany and Redispatch Activity in ELMOD on the left and visualization of the Top 25 congested grid elements in the first Quarter of 2023 as published in the grid congestion report of the Bundesnetzagentur [16]

mix in Europe. The outcomes for Germany, as well as for the entire modeled area, align satisfactorily with the historic data.

The grid model produces reliable and realistic results that align well with figures from the official authorities. For the analysis period, the modeled positive and negative redispatch, and curtailment stand at 6.4, 3.3, and 4.3 TWh, respectively. The total grid congestion is estimated at 14 TWh, and its regional distribution is depicted in Figure 8. In comparison, the Bundesnetzagentur's quarterly report, covering a period two weeks shorter than our analysis, reports positive redispatch at 5.2 TWh, negative redispatch at 2.6 TWh, RES curtailment at 3.6 TWh, with grid congestion reaching 11.4 TWh. Overall, despite the 17.8% longer reference period, the modeled grid congestion is only 22.8% higher, affirming the validity and accuracy of the model.

While the model may slightly overestimate grid congestion due to assumptions about thermal limits and the inability to replicate the real-world preventive congestion mitigation measures applied by the grid operators that reduce grid congestion, it effectively reproduces the proportion and level of curative congestion measures. The visualization and comparison of model results with the Top 25 congested elements in Q1 2023 from the Bundesnetzagentur report in Figure 8 also underscores its ability to accurately identify main congestion corridors and the overloaded grid elements.

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Declarations

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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