Three Zones Fix All? Analyzing Static Welfare Impacts of Splitting the German Bidding Zone under Friction

AUTHOR

Berit Hanna Czock

EWI Working Paper, No 04/25

May 2025

Institute of Energy Economics at the University of Cologne (EWI)
www.ewi.uni-koeln.de

Institute of Energy Economics
at the University of Cologne (EWI)

Alte Wagenfabrik
Vogelsanger Str. 321a
50827 Köln
Germany

Tel.: +49 (0)221 277 29-100
Fax: +49 (0)221 277 29-400
www.ewi.uni-koeln.de

CORRESPONDING AUTHOR

Berit Hanna Czock
berit.czock@ewi.uni-koeln.de

ISSN: 1862-3808

Three Zones Fix All? Analyzing Static Welfare Impacts of Splitting the German Bidding Zone under Friction

Berit Hanna Czock[a]

[a] *Institute of Energy Economics, University of Cologne, Vogelsanger Strasse 321a, 50827 Cologne, Germany.*

Abstract

This study examines the static market and welfare effects of splitting the German bidding zone, comparing a two-zone and a three-zone configuration for a 2030 scenario. Using a state-of-the-art grid and market model with explicit representation of frictions in flow-based market coupling and redispatch, the analysis finds that the investigated two-zone split results in a 1.6% static welfare loss as redispatch cost savings do not overcompensate the negative effect of more transmission constraints in the electricity market. Contrarily, three zones lead to a 4.4% static welfare gain, as redispatch cost decrease further than with two zones and trade between German zones is enhanced due to a reduction of loop flows on interconnectors between Germany's North and South. However, both bidding zone split options lead to significant distributional effects, with higher consumer costs and increased subsidy expenditures for renewable energy sources (RES), though these effects are less pronounced with three zones. Additionally, welfare effects are sensitive to scenario definition and representation of frictions. All in all, policymakers should carefully assess the uncertain welfare gains against the transition costs of a bidding zone split, while also considering distribution effects and interactions with existing policies such as the RES subsidy scheme. Reducing frictions in redispatch, albeit with new coordination challenges, could potentially achieve similar objectives with lower transaction costs and fewer distributional impacts.

Keywords: Market Design, Electricity Markets, Nodal Pricing, Energy System Modeling, Renewable Energies, Bidding Zones

JEL classification: D47, D61, C61, Q40

E-mail address: berit.czock@ewi.uni-koeln.de

1. Introduction

Germany's electricity transmission grid is consistently congested between the North, where the majority of wind power plants are located, and the South, where demand is concentrated. Consequently, redispatch[1] costs have risen from 1 bn EUR in 2019 to 4 bn EUR in 2022 (Bundesnetzagentur and Bundeskartellamt, 2023). Additionally, grid congestion in Germany results in unintended loop flows[2] through neighboring countries, thereby diminishing cross-border trading capacities (ACER, 2024). These issues have positioned Germany at the center of attention in the most recent bidding zone review (BZR), a periodic formal evaluation of bidding zone configurations in the European electricity market conducted by the European Union Agency for the Cooperation of Energy Regulators (ACER) and the European Network of Transmission System Operators for Electricity (ENTSO-E). The BZR, which was conducted between 2019 and 2025, assessed several potential reconfiguration options for the German[3] bidding zone for the target year 2025, but did not arrive at a definite recommendation - mainly due to the fact that main assumptions were outdated by the time the review was published (ENTSO-E, 2025). Still, the six year long process ignited an extensive debate on splitting the German bidding zone among academics and affected market participants.

A key argument in favor of splitting the German bidding zone is that a split would internalize congestion into market prices, thereby enabling market participants to react to congestion. This could reduce redispatch costs, which are ultimately borne by consumers through grid fees (Zachmann, 2024). However, concerns have been raised that smaller zones might diminish market liquidity and increase the risks of market power (Brouhard et al., 2020). Additionally, opposition is emerging from stakeholders in the South of Germany, who are likely to face negative distributional effects, with higher electricity prices following the split (Baden-Württemberg Association of Chambers of Commerce and Industry e.V. et al., 2024).

[1] Redispatch refers to the practice of reducing the output of generators located before a grid bottleneck and increasing generation behind the bottleneck. Generators involved in redispatch are compensated for their costs and foregone profits.

[2] Loop flows are unintended power flows that occur when electricity, due to physical grid constraints, takes indirect or parallel routes through neighboring transmission networks.

[3] Germany and Luxembourg form a bidding zone together, which is referred to as the "German bidding zone" for simplicity.

Looking at static welfare implications, although it might imply distributional effects, a bidding zone split should be welfare neutral - in theory and if there are no frictions. In reality, however, several types of friction may lead to changes in static welfare when splitting the German bidding zone:

1. **Liquidity and market concentration:** Smaller zones may lead to lower liquidity, which in turn may reduce market efficiency by limiting price discovery and increasing transaction costs in the face of higher volatility and increased bid-ask spreads. Additionally, smaller zones may have higher market concentration, making them more vulnerable to market power. At the same time, reduced loop flows on interconnectors may enhance trade between zones, potentially improving liquidity or at least the option to (proxy-)hedge on markets in neighboring zones (Compass Lexecon, 2024).
2. **Inefficient redispatch:** A fully efficient redispatch without frictions leads to the same dispatch regardless of the zonal configuration and zonal market outcome. In fact, the final outcome after redispatch is equivalent to the first best result under nodal pricing where each market constitutes a market and all physical grid constraints are reflected in prices. In reality, ramping constraints and restricted participation of certain power plant types, storage, and demand prohibit redispatch from reaching the efficient market outcome, causing frictions (c.f. Bjørndal et al., 2003).
3. **Approximative allocation of transmission capacity:** Transmission capacity between most bidding zones in Europe is allocated via flow-based market coupling (FBMC), an algorithm designed to allocate transmission capacity between zones in a welfare-maximizing manner during market clearing. FMBC is based on an ex ante approximation of physical grid properties. In light of potential approximation errors, transmission capacity is reduced by fixed security margins to avoid line overloading (c.f. Felten et al., 2021). Increasing the number of bidding zones adds more transmission constraints subject to approximation and security margins, thus limiting trade and potentially market efficiency.

Setting aside potential liquidity and market power effects[4], it is the interplay of redispatch and transmission capacity allocation frictions that determines the static welfare impact of a bidding zone split. It is clear that there exists a trade-off between reducing redispatch volumes by internalizing congestion versus imposing trade restrictions by adding more approximation-based constraints. The trade-off hinges on redispatch efficiency: If redispatch is inefficient, reducing redispatch volumes may lead to higher cost savings, thus increasing welfare. If redispatch is efficient, the effect dwindles, putting more emphasis on the market losses from additional trade restrictions - though it has to be kept in mind that a fully efficient redispatch can in theory mitigate welfare losses in the market regardless of the zonal configuration, leaving only distributional effects.

This paper analyzes static market and welfare effects of a bidding zone split in Germany in 2030. Adding to the large body of research existing on the subject, it makes the following contributions: It employs a state-of-the-art grid and market model to represent frictions in redispatch and transmission capacity allocation under FBMC. Additionally, while relevant existing research has primarily focused on two-zone configurations, this paper is the first to investigate a three-zone setup, providing insights into the implications of more granular market structures. The analysis includes prices, rents (consumer, producer, and congestion), redispatch costs, and subsidy expenditures for supporting RES as according to German policy, to give a full picture of welfare and distributional effects. Sensitivity analyses explore the influence of scenario specification and frictions in redispatch.

The following main findings could be derived: From a German perspective, for the investigated 2030 scenario, and under the considered frictions - approximative transmission capacity allocation under FBMC and redispatch inefficiencies -, splitting the German bidding zone leads to modest static welfare changes. The direction of welfare changes depends on the bidding zone configuration: While static welfare increases by 4.4 % in the case of three zones, it decreases by 1.6 % in the case of two zones. Thus, welfare losses due to more transmission constraints in the market cannot be compensated by redispatch cost savings in the investigated two-zone setup. Three zones reflect the physical properties of the grid more closely, resulting in additional cost savings for redispatch and an increase in overall static welfare. Still, both investigated bidding zone split scenarios lead to

[4] Liquidity and market power effects of bidding zone configuration are discussed in detail in Compass Lexecon (2024) as part of the BZR process.

significant distributional effects with the majority of consumers being exposed to higher prices and increased subsidy expenditure for renewables - especially in the two-zone setup where prices diverge significantly.

Three sensitivity analyses show that the impact of a bidding zone split depends on the scenario choice and the representation of frictions. Lower congestion in the case of delayed wind capacity expansion diminishes positive effects of a bidding zone split, while higher congestion in the case of delayed grid expansion leads to significant welfare gains to be made by splitting the German bidding zone. Reducing frictions in redispatch via a full participation of batteries renders bidding zone splitting less efficient.

All in all, the analysis shows that splitting the German bidding zone does not guarantee static welfare gains and welfare outcomes depend on the exact configuration of the zones, the scenario and frictions in redispatch and transmission capacity allocation. Policymakers must be aware of these effects when deciding on a bidding zone split. Furthermore, splitting the German bidding zone implies significant distributional effects, e.g. by increasing the costs of the RES subsidy scheme. In any case, welfare effects must be weighed against implementation costs, potential effects of lower liquidity in smaller zones, and dynamic welfare effects in the face of changing power systems.

The remainder of this paper is structured as follows: Section 2 reviews the existing literature and highlights this study's contribution. Section 3 describes the model, evaluation methods, and the scenario. Section 4 presents the results, which are discussed in Section 5. Finally, Section 6 concludes on the findings.

2. Literature Review and Contribution

Numerous studies assess the market and welfare implications of splitting the German bidding zone (c.f. Table 1). Most studies consider a North-South split into two zones, though exact delineations differ. Most researchers focus on electricity prices, redispatch costs and welfare in a static settings, though some researchers incorporate capacity expansion and quantify dynamic efficiency. Most researchers employ numerical optimization models simulating market dispatch and redispatch. However, scenario assumptions such as demand, fuel prices and renewable energy expansion vary and models differ in the consideration of frictions in redispatch and transmission capacity allocation.

Redispatch modelling methods vary from fully efficient redispatch, and different representations of frictions, e.g. excluding certain generator types or imposing cost penalties on redispatch. Regarding transmission capacity allocation frictions, it has to be noted that many papers employ simplified models with only a few representative grid nodes and ex-ante determination of transmission capacity between zones, which cannot represent frictions due to inaccuracies and security margins in FBMC procedures. Table 1 summarizes the literature and lists analyzed parameters, considered frictions, and scenario years.

	Analysis					**Frictions**		
Citation	Prices	Redispatch	Static welfare	Subsidies	Dynamic welfare	Redispatch inefficiency	FBMC	Scenario years
Burstedde (2012)	✓	✓	✓			✓		2015, 2020
Breuer and Moser (2014)	✓	✓	✓			✓		2016, 2018
Trepper et al. (2015)	✓	✓	✓			✓		2012, 2020
Egerer et al. (2016)	✓	✓	✓					2012, 2015
Plancke et al. (2016)	✓							2020
Van den Bergh et al. (2016)		✓					✓	2013
Ambrosius et al. (2018)	✓	✓	✓		✓	✓		2035
Grimm et al. (2021)	✓	✓	✓	✓	✓	✓		2035
Fraunholz et al. (2021)	✓	✓	✓		✓	✓		2025, 2035
Felling et al. (2023)	✓	✓	✓				✓	2020
Zinke (2023)	✓	✓				✓	✓	2021-2035
Brouhard et al. (2023)	✓	✓	✓					2030, 2040
Dobos et al. (2024)	✓						✓	2025
Knörr et al. (2024)	✓	✓					✓	2025
Frontier Economics (2024)	✓							2025, 2030
Tiedemann et al. (2024)				✓			✓	2030

Table 1: Literature on splitting the German bidding zone

Studies that assess the impact of a bidding zone split for the years 2025 to 2035 are most relevant to this work. These studies come to different conclusions regarding market and welfare effects. For example, price levels for the single German bidding zone in 2030 range from 56 EUR/MWh (Tiedemann et al., 2024) to 80 EUR/MWh (Fraunholz et al., 2021). North-South price differences are found to lie between 5 and 15 EUR/MWh across scenarios and years from 2025 to 2035, with a decreasing tendency in later years when (planned) grid expansion reduces grid bottlenecks (c.f Knörr et al., 2024; Frontier Economics, 2024, who provide an overview of existing literature).

Redispatch costs generally decrease under zone splitting but vary widely, from savings of 117 million EUR (Fraunholz et al., 2021) to over 2 bn EUR in Zinke (2023) for 2025 and over 4 bn EUR in 2030.

It has to be noted that the consideration of frictions in redispatch varies significantly across studies. For example, Brouhard et al. (2023) assume a fully efficient redispatch solving all inefficiencies after the market clearing, which leads to the same supply costs regardless of the zonal configuration. In contrast, in Zinke (2023), the participation of demand and certain generator types in redispatch is restricted. Ambrosius et al. (2018), Fraunholz et al. (2021), and Grimm et al. (2021) impose penalties so that redispatch only changes market outcomes that actually violate physical transmission constraints instead of optimizing the whole dispatch.

In terms of distributional effects, i.e. changes in consumer, producer and congestion rents, results differ as well. Some report higher electricity costs and reduced consumer rents, such as 1–3 bn EUR in Fraunholz et al. (2021), while Grimm et al. (2021) find slight increases in consumer rents. It has to be noted that the zonal configuration considered in Grimm et al. (2021) splits Germany below North-Rhine-Westphalia, which is in the South zone in most other approaches. This allocates more demand in the low-price zone.

Producer surplus findings are mixed, with increases reported in Grimm et al. (2021) and Brouhard et al. (2023) and mixed results in Fraunholz et al. (2021).

As market prices influence generator revenues, splitting the German bidding zone may also affect subsidy expenditures. Only few studies address this. For example, Grimm et al. (2021) find slightly increased RES fees in case of a North-South bidding zone split, which they calculate as the difference between investment costs and market revenues, split equally across consumers.[5] Similarly, Tiedemann et al. (2024) find slightly increased subsidy expenditures for PV and wind onshore for a North-South split under exemplary market premiums and current installation costs. However, their analysis excludes historical installations still in the subsidy scheme and subsidy expenditures for them.

Lastly, congestion rents are generally found to increase under a bidding zone split.

Assessments of total static welfare for future scenarios, especially under friction, are scarce. In Brouhard et al. (2023), where redispatch is frictionless, the bidding zone split is welfare neutral - this also means that frictions in transmission capacity allocation do not matter for overall welfare.

[5] Until 2021, subsidy costs were recovered via a levy on electricity prices, the RES fee. Grimm et al. (2021) do not report absolute subsidy expenditure.

Instead of static welfare, several studies project dynamic welfare for future scenarios, modelling endogenous capacity expansion for grid or power plants(Fraunholz et al., 2021; Ambrosius et al., 2018; Grimm et al., 2021). In these studies, there are different representations of frictions, although their effect is entangled with the dynamic development of the power sector. All three consider frictions in redispatch, with Ambrosius et al. (2018) excluding generators in other zones and Fraunholz et al. (2021) and Grimm et al. (2021) imposing redispatch penalties to minimize redispatch volumes. Regarding frictions in transmission capacity allocation, it has to be noted that all of the approaches considering dynamic efficiency have to rely on simplified load flow representation to keep models computationally tractable. This includes ex-ante determination of transmission capacity between zones, and, in the case of Ambrosius et al. (2018) and Grimm et al. (2021) reduced grid resolution with only 16 nodes in Germany. Thus, they are unable to address frictions arising in FBMC. This friction is analyzed explicitly only in Felling et al. (2023), who optimize bidding zone configurations across Europe (regardless of national borders) for a 2020 scenario and analyze static welfare. They find that static welfare increases with more zones, as redispatch (frictions are modelled via a penalty) is reduced further. However, the welfare increase is non-monotonic. They attribute this to the mathematical properties of the flow-based domain[6], the negative effect of additional load flow constraints and approximation errors inherent to FBMC. This result highlights that static welfare is determined by the interplay of the exact zonal configuration, and frictions in redispatch, and FMBC.

In summary, the literature lacks consensus on the effects of bidding zone splitting, with variations likely driven by scenario differences and the considerations of frictions - which are often not made explicit. Additionally, among recent studies, none provides a comprehensive static welfare analysis of a bidding zone split in a post 2020 scenario and none considers a three-zone setup. This paper addresses this gap by analyzing 2030 static market and welfare impacts of a German bidding zone split, including subsidy expenditure. To explicitly consider frictions, it uses a state-of-the-art model with inefficient redispatch and FBMC.

[6] For a detailed discussion the reader is referred to Felten et al. (2021)

3. Methods

3.1. Grid and Market Model and Representation of Frictions

This study uses a detailed model of the central European electricity market, including frictions in redispatch and transmission capacity allocation via FMBC, to derive the effects of a bidding zone split in Germany on electricity prices, static welfare and distribution effects, and renewable energy subsidy expenditure.

The model was first developed in Schmidt and Zinke (2023) and further extended in Czock et al. (2023) and Zinke (2023). The model is an optimization-based framework that simulates electricity market clearing by minimizing the cost of electricity supply, considering demand, available power plant and transmission grid capacity, and storage constraints. It relies on the assumption of perfect markets and perfectly inelastic demand, which allows for duality between cost minimization (i.e., welfare optimization by a social planner) and market outcomes.

The FBMC implementation requires a multi-step modelling procedure. It is described in detail in Zinke (2023), but the following outlines the key features relevant to this study, which are also illustrated in Figure 1.

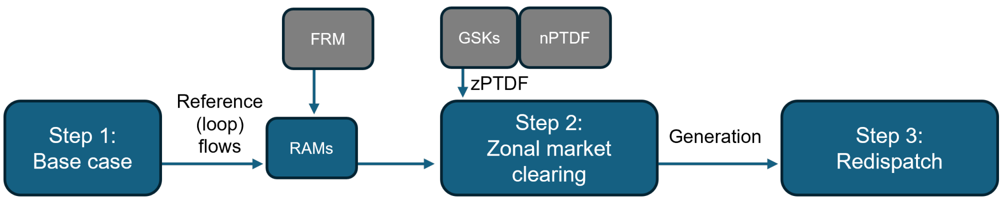

Figure 1: Grid and market modelling procedure

Under FBMC, transmission capacity between zones is allocated during the market clearing stage in a welfare-maximizing manner. To achieve this, trade is subject to several constraints. First, trade between zones is restricted by the *remaining available margins* (RAMs), determined ahead of market clearing. The RAMs are based on line capacity but account for loop flows caused by intra-zonal transmission and typically include security margins (e.g., the *flow reliability margin* (FRM), which is deducted from line capacities). Additionally, market clearing includes constraints representing the sensitivity of power flows on each line regarding the net positions of the zones, considering that flows between two zones may impact flows between other zones (c.f. e.g. Van den Bergh et al., 2016).

To determine RAMs, the first modeling step is computing a *base case* that quantifies reference flows, i.e., loop flows caused by intra-zonal transmission. In this study, the base case is a model run without trade between zones. The second step is the *zonal run*, which models market clearing and trade between zones under the consideration of RAMs derived from line capacities, reference flows, and the FRM, which is set to 10 % in this study (c.f. Zinke, 2023). The sensitivity of flows on each line regarding changes in the net position of a zone (i.e., changes in flows on other lines) is modeled via zonal power transfer distribution factors (PTDFs). Zonal PTDFs (zPTDFs) are derived as the zonal sum of nodal PTDFs, which can be computed from line reactances, weighted by generation shift keys (GSKs). GSKs represent assumptions on how net changes in the zonal saldo are distributed among nodes within a zone and are based on the proportion of a node's hourly generation in the total generation of a zone for this study. Both, the default reduction of line capacity by the FRM and potential approximation errors in the GSKs introduce frictions into the model, closely resembling real world FMBC procedures. The effect of the FRM is straightforward as it reduces RAMs and essentially trade between zones and therefore the efficiency of the market clearing. The effect of approximation errors in the GSKs is more complex, as they translate into inaccuracies in the load flow constraints (compared to the actual physical constraints). If RAMs are underestimated, trade is inaccurately restricted again. If RAMs are overestimated, redispatch volumes increase (c.f. Felten et al., 2021, who provide a detailed assessment of the impact of errors in the flow-based parameters).

The final modelling step, the *redispatch run*, simulates the adjustment of power plants to solve intra-zonal congestion after the market clearing. The redispatch run considers all physical transmission constraints, represented by a linear DC load flow based on a cycle-formulation of Kirchhoff's laws. The following frictions are applied to approximate frictions in real-world redispatch: Trade between zones remains fixed, as TSOs cannot access power plants outside their zones for redispatch. This approach neglects countertrading, which currently plays a minor role. Intermittent RES and batteries are only allowed to reduce supply during redispatch, while other generation technologies can be dispatched flexibly. In reality, batteries with a capacity > 100 kW can be accessed for both positive and negative redispatch but there is no mechanism that ensures that they are charged for positive redispatch ahead of time.

Market and Static Welfare Effects

The results from the zonal run can be used to analyze the static efficiency effect of a bidding zone split. First, wholesale electricity prices can be derived as the marginal cost of electricity generation. Second, changes in consumer rents between bidding zone configurations can be derived from the wholesale electricity prices. Consumer rents refer to the difference between consumers' willingness to pay and market prices. Changes in consumer rents, called ΔCR, equal the difference in wholesale electricity costs, i.e. wholesale electricity prices weighted with hourly demand. For the calculations of ΔCR, only inflexible demand is considered.[7] Similarly, zonal dispatch results allow the calculation of producer rents. Producer rent refers to the difference between generation costs and electricity market prices. Producer rent changes between bidding zone configurations are denoted as ΔPR.

Finally, congestion rent (or congestion income) can be derived. Congestion rent is a revenue stream for TSOs arising from price differences between electricity trading zones with limited transmission capacity. When demand for imports exceeds transmission capacity, markets decouple, creating price differences. Electricity traded from a lower-cost to a higher-cost zone is sold at the higher price, but generators in the lower-cost zone receive only their local price. The price difference constitutes congestion rent, collected by TSOs. Under European legislation, TSOs are required to use congestion rent income to fund grid expansion or ensure system reliability. Thus, congestion rent is often considered as welfare-relevant on the consumer side because it should reduce grid fees if used to refinance TSO activities. The change in congestion rent between two bidding zone setups is called ΔCI.

[7]Electrolysis and storage, like batteries or pumped storage, generate additional electricity demand, but they are regarded as generators in the analysis of rents.

Subsidy Expenditure

The zonal dispatch results also allow analyzing the impact of bidding zone splitting on subsidy expenditure. The *German Renewable Energy Sources Act* (EEG) subsidy scheme supports renewable energy generation by paying fixed feed-in tariffs or market premiums to producers. Market premiums emerge from renewable capacity auctions, held several times per year, and electricity market prices. In these auctions, generators bid a per kWh asking price, the so-called *reference value*, and lowest bids are selected up to the predetermined capacity. Some renewable energy projects, such as pilot units or community energy initiatives ("Bürgerenergieanlagen"), do not participate in the auctions and have reference values fixed by regulators.[8] Generators sell their electricity on the markets and receive market premiums, calculated as the difference between their reference value and the average market value of their technology.

Subsidy expenditure, i.e. the cost of the subsidy scheme, thus varies with reference values and, more significantly, electricity prices. Part of the renewable capacity is subsidized using fixed feed-in tariffs instead.[9] The energy generated by producers under fixed feed-in tariffs is marketed by TSOs, so that subsidy expenditure equals the difference between market prices and fixed tariffs. These costs are recovered through the federal budget, effectively passed on to consumers via taxes.

For this study, subsidy expenditure is calculated as the difference between investment and fixed operation and maintenance (FOM) costs and revenue from electricity markets. Costs are annualized over 20 years, reflecting the duration of EEG subsidies.

Next to RES, there are plans to subsidize backup capacity (SPD et al., 2025). The design of the subsidy scheme is still under discussion. Therefore, subsidy expenditure for backup capacity is calculated as the difference between revenues from electricity markets and investment, FOM and variable costs.

Differences in subsidy expenditure between scenarios are denoted as ΔS_{RES} and ΔS_{BU} for RES and backup generators respectively. It is important to note that changes in subsidy expenditure represent transfers between consumers and producers, not changes in total supply costs or welfare.

[8] Additionally, the reference yield model ("Referenzertragsmodell") adjusts reference values for onshore wind based on location-specific productivity. It compares a turbine's projected energy yield over five years to a standardized reference yield, with less productive locations receiving higher subsidies to incentivize wind in southern Germany.

[9] For example, capacity built before 2014 under an earlier version of the EEG or units below 100 kW.

Redispatch Costs

Redispatch costs are calculated as the difference in supply costs between redispatch and zonal runs. Thus, capital depletion and opportunity costs which generators are reimbursed for in redispatch in reality, are neglected. Changes in redispatch costs between scenarios, denoted as ΔRD, are welfare-relevant on the consumers' side if they are passed on via grid fees.[10]

3.2. Bidding zone configuration

In addition to simulating zonal markets and redispatch, the model is also used to derive the bidding zone reconfiguration scenarios. As a basis for zonal delineation, hourly marginal supply costs, or locational marginal prices (LMPs) are calculated, considering all transmission constraints and corresponding load flows. LMPs are identical for nodes within fully coupled markets, i.e., where connections are unconstrained. When congestion arises, nodal markets decouple, resulting in different LMPs. Providing an insight regarding the location of transmission bottlenecks, LMPs are widely used in the literature as a basis for deriving zonal delineations. It should be noted that Grimm et al. (2016) demonstrated that zones derived from LMPs do not necessarily lead to optimal, i.e., welfare-maximizing, configurations. Nevertheless, this approach remains prevalent due to its simplicity[11] and is used by ACER to propose zonal reconfiguration candidates in the BZR process.

To cluster nodes into zones based on LMPs, this study employs Ward's criterion, which minimizes the sum of squared differences among the LMP time series for all nodes. Nodes with similar hourly LMPs are grouped into the same clusters. Following Felling and Weber (2018), the clustering algorithm is constrained to only cluster nodes that are physically connected.

3.3. Scenario

The market and grid model represents the 13 European countries integrated into FBMC, along with important neighboring countries such as Denmark, Sweden, Norway, Italy, and Switzerland,

[10] Redispatch costs in this study differ from those reported annually by the German grid regulation agency, as the latter report compensation payments for down-regulated units as redispatch costs. In the present analysis, these compensation costs are accounted for in the consumer wholesale costs from zonal market clearing.

[11] The computational complexity of endogenously optimizing zone delineation is demonstrated, for example, in Lété et al. (2022).

which are coupled via NTCs. The model includes the transmission grid (220 kV and 380 kV), reduced from 1,063 to 533 nodes (as of 2021) using a grid reduction algorithm developed by Biener and Garcia Rosas (2020). Transmission grid capacity expansion is exogenous and follows the *Ten Year Network Development Plan 2022* (TYNDP) published by European electricity and gas grid operators (ENTSO-E and ENTSO-G, 2022) and the *Grid Development Plan* (NEP) published by the German TSOs (50Hertz et al., 2022). Note that countries connected by NTCs are modelled as single nodes, without intra-zonal grid restrictions. The transmission grid is depicted in Figure 2.

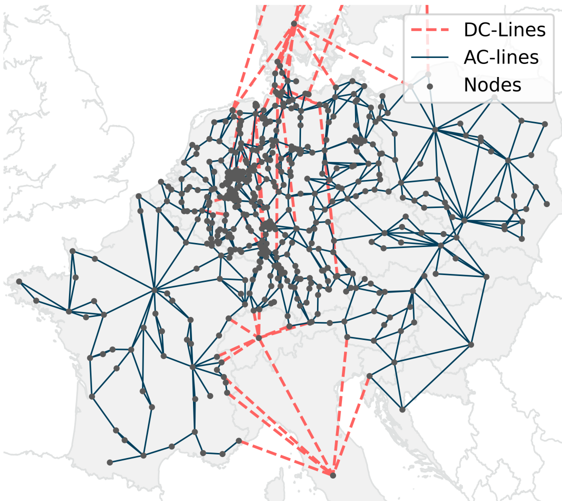

Figure 2: Map of the transmission grid (Zinke, 2023)

The model is initialized with data for 2021, as described in Zinke (2023), and applied in this study for the year 2030. It simulates the zonal dispatch and redispatch at an hourly resolution for the weather year 2009, which is considered a typical weather year according to ENTSO-E and ENTSO-G (2022). Demand and power plants in all countries except Germany follow the *National Trends* scenario from the the TYNDP (ENTSO-E and ENTSO-G, 2022).

The scenario for Germany reflects current legislation where applicable, such as renewable energy capacity targets. The regional distribution of renewables is based on assumptions from 50Hertz et al. (2022). Furthermore, the scenario accounts for the phase-out of coal and nuclear power plants as according to *Act to Reduce and End Coal-Fired Power Generation* (KohleAusG) and government plans to phase out lignite in North-Rhine Westphalia by 2030 (BMWK et al., 2022). Electrolyzer capacity aligns with the German Hydrogen Strategy, while regional distribution reflects announced electrolyzer projects. The capacity for large-scale batteries is taken from the TYNDP scenario, with batteries distributed to the largest demand nodes where sufficient grid connections are likely in place (see Zinke (2023)). Capacity additions for open-cycle gas turbines (OCGT) follow recent proposals to add 5 GW until 2030 (BMWK, 2024). Additionally, it is assumed that 15 GW of combined cycle gas turbines (CCGT) are added, which corresponds to capacity "in planning" or "under construction" in the scenario for the upcoming new grid development plan Bundesnetzagentur (2024).

Given the uncertainty regarding siting, the new gas-fired capacities are assumed to be connected at sites where coal, lignite, and nuclear power plants are phased out, utilizing existing grid capacity. Annual demand for Germany is based on the TYNDP's *National Trends* scenario and distributed according to population shares (residential) and gross value added (industrial and commercial). Demand in other countries is distributed based on population. Table A.7 in Appendix A depicts demand assumptions.

Assumptions on fuel price development follow the *Stated Policies* scenario in IEA (2022) and are listed in Table A.8 in Appendix A. Carbon is priced at 100 EUR/t.

4. Results

4.1. Bidding zone configuration

Figure 3 presents the three considered bidding zone configurations. Figure 3 (a) shows the single German bidding zone as it is today. Clustering locational marginal prices into two zones, a split between the North (N) and the South (S) emerges around the 53rd latitude (Figure 3 (b)). In the case of three zones, shown in Figure 3 (c), the North zone is split into a North-Western (NW) and a North-Eastern (NE) zone, while the South zone is the same as in the two-zone setup. Notably, the two-zone and three-zone setups closely align with options *DE2 1* and *DE3 12* discussed in ACER's bidding zone review (ACER, 2022).

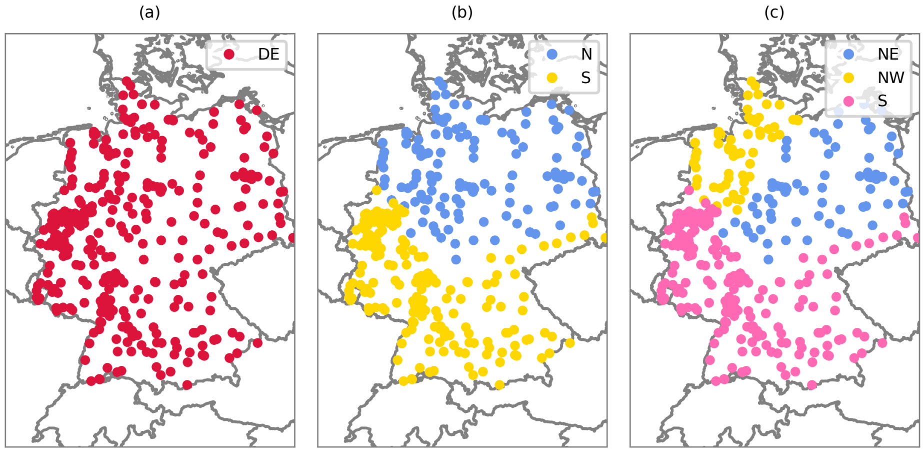

Figure 3: Zonal configuration for (a) the single bidding zone (b) two bidding zones and (c) three bidding zones

4.2. Electricity Prices and Consumer Rents

Splitting the German bidding zone introduces additional transmission constraints into the market, restricting trade between market participants. As a result, electricity wholesale costs for inflexible consumers increase significantly, with net cost rises of 1.6 bn EUR and 1.8 bn EUR, for two and three zones respectively. These cost increases correspond to reductions in consumer rents[12]. The effect entails both, the desired transmission capacity reduction implemented to reduce congestion, and frictions from inaccuracies and security margins in the approximative transmission capacity allocation under FBMC.

The cost changes vary across zones, as prices differ between them. Table 2 lists demand-weighted average wholesale electricity prices for inflexible consumers alongside ΔCR. Compared to the single zone setup, both splitting scenarios reduce prices in the North while increasing prices in the South. This leads to higher consumer rents in the North and lower rents in the South. Since most demand is concentrated in the South, the overall effect is a rent decrease.

Under the three-zone configuration, which further divides the North into a North-East and a North-West zone, price increases in the South are less pronounced. At the same, prices in the North are higher than under a two-zone split. This is especially the case for the North-East zone, where prices

[12]As mentioned in Section 3, costs for flexible demand, such as storage and electrolysis, are excluded from consumer surplus calculations and instead considered in producer rents.

almost converge with the South. This occurs because resolving internal congestion in the North frees up transmission capacity for trade with the South by reducing loop flows on interconnectors. As a result, more consumers face higher prices, reducing consumer rents further.

		Electricity price [EUR/MWh]	ΔCR [bn EUR/a]
Single zone	DE	66.9	-
Two zones	DE	68.2	-1.6
	N	56.5	2.5
	S	76.5	-4.1
Three zones	DE	68.7	-1.8
	NE	70.0	-0.2
	NW	56.9	1.0
	S	72.3	-2.5

Table 2: Average demand-weighted electricity prices and ΔCR compared to the single bidding zone in 2030

Regarding effects on an individual household level, it is crucial to note that wholesale electricity prices account for only a fraction of household electricity prices. Table 3 illustrates electricity wholesale cost changes for average households with more than three persons and single-person households.[13] For them, the wholesale cost changes are negligible. However, for industrial consumers wholesale prices constitute a larger share of total costs, and consumption volumes are substantially higher, making price increases more impactful (c.f. Tiedemann et al., 2024).

		> 3 persons [EUR/a]	single person [EUR/a]
Two zones	DE	7.5	4.7
	N	-56.0	-35.0
	S	52.5	32.8
Three zones	DE	10.2	6.3
	NE	17.0	10.6
	NW	-54.1	-33.8
	S	29.5	18.4

Table 3: Exemplary wholesale electricity cost changes by consumer group and bidding zone setup in 2030 compared to the single bidding zone setup

[13] Average consumption data for 2021 is taken from Statistisches Bundesamt (2023) and amounts to 5.411 kWh/year for households with more than three persons and 3.383 kWh/year for single-person households.

4.3. Producer Rents

Total producer rents decline when splitting the bidding zone, by 2.6 bn EUR and 1.9 bn EUR for the two-zone and three-zone splits, respectively. However, the impacts vary across zones and technologies. Figure 4 shows producer rent changes under both split scenarios compared to a single bidding zone. Producer rent decreases in the North, driven by lower prices, while it increases in the South. This reflects the assumed distribution of power plants, with wind power rents in the North negatively impacted and those of conventional power plants and PV in the South rising.

Producer rent losses for wind are highest under the two-zone setup, as the majority of wind generation is concentrated in the North, resulting in price cannibalization - high simultaneous generation exceeding demand causing prices to drop and market-based curtailment to increase. Table 4 lists market-based curtailment of renewables across the different zonal configurations. Splitting the North into two zones in the three-zone setup enhances North-South trade, reducing market-based wind curtailment and increasing generation and revenues. Consequently, wind producer rents improve under the three-zone split compared to the two-zone split, partially mitigating producer rent losses. PV rents, however, benefit slightly more from the two-zone setup due to higher prices in the South, where most PV capacity is located.

		PV [TWh/a]	Wind onshore [TWh/a]	Wind offshore [TWh/a]
Single zone	DE	6.9	16.3	4.6
Two zones	DE	9.0	27.6	6.5
	N	3.7	24.6	6.5
	S	5.2	2.9	-
Three zones	DE	14.3	20.5	2.3
	NE	8.1	10.1	1.2
	NW	1.5	7.1	1.1
	S	4.7	3.3	-

Table 4: Market-based curtailment of RES by bidding zone setup in 2030

For storage technologies, price volatility and the opportunity for arbitrage determines surpluses. Both bidding zone split configurations decrease volatility in the South, where prices are less influenced by wind intermittency in case of the split. Therefore, rents achieved by pumped storage facilities, which are only located in the South zone, decrease compared to a single bidding zone.

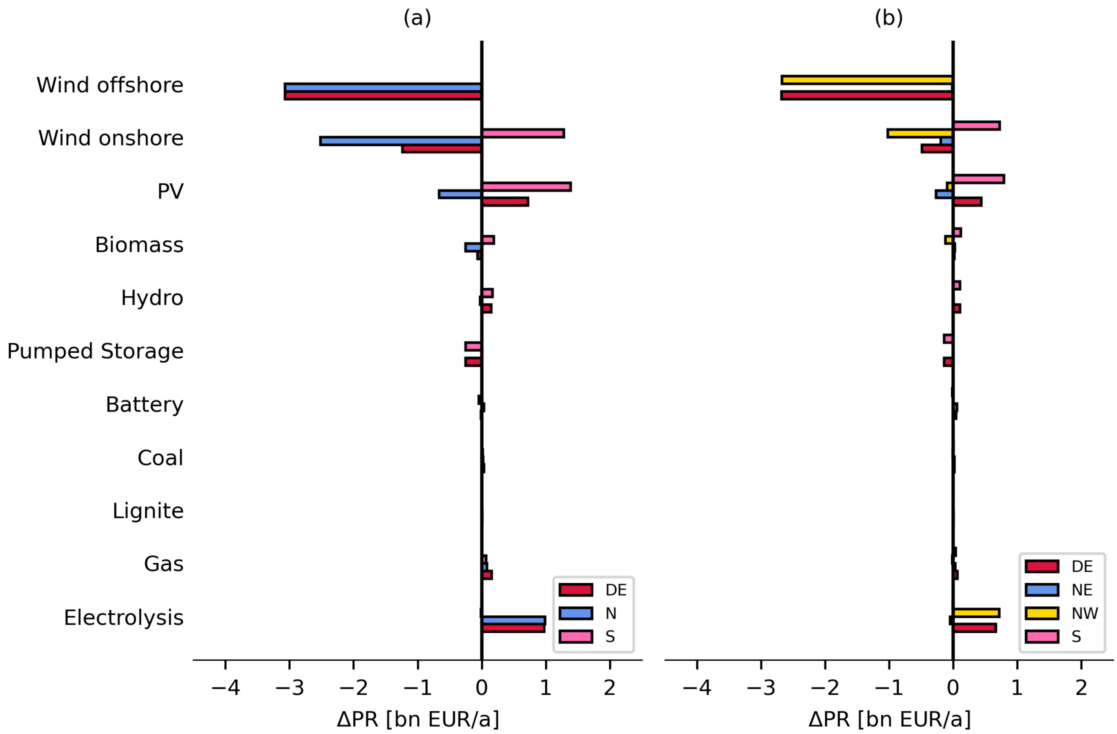

Figure 4: ΔPR for (a) two zones and (b) three zones compared to the single bidding zone setup by technology in 2030

Batteries, which are located at the nodes with the highest demand, benefit from increased volatility in the North and suffer from decreased volatility in the South compared to the single bidding zone setup. Total rents achieved by batteries decrease in the two-zone setup because rent decreases in the South zone overcompensate rent increases in the North zone. Contrarily, batteries benefit in the three-zone setup. This is related to changed price dynamics in the North-East zone: Since there is access to inexpensive wind energy, batteries can charge there at low prices. The North-Eastern zone also has high demand around the capital region so that batteries can discharge at high prices. Additionally, there is a certain convergence[14] of prices between the South and the North-East zone, as trade increases. This leads to batteries in the South zone selling electricity at higher prices while still charging at low prices.

[14]North-South price correlation lies at 0.61 in the two-zone setup, while price correlation between the North-Eastern and Southern zones lies at 0.86 in the three-zone setup. Correlation between the North-West and the South is at 0.7. Correlation between North-West and North-East is 0.79.

Electrolyzers, which are included in producer rents even though they produce hydrogen instead of electricity, benefit in both bidding zone split scenarios because they are assumed to be located in the North, where prices are lower. Naturally, they benefit more from one Northern price zone with low prices than from a East-West split in the three-zone setup, which leads to higher prices in the North-East.

All in all, producer rent effects are largely driven by RES, which constitute the majority of capacity in the 2030 scenario. Price cannibalization, influenced by regional allocation, significantly impacts RES producer rents.

4.4. Subsidies

Renewable technologies and newly installed gas power plants are subsidized to incentivize investment, with subsidy expenditure closely tied to producer rents. However, subsidies also account for the recovery of annualized investment costs, including historical RES installations that still fall under the subsidy scheme.

For the single bidding zone, subsidy expenditure for renewables amounts to 24.1 bn EUR. For both bidding zone split scenarios, renewable subsidy expenditure increases by 3.5 bn EUR and 2.9 bn EUR for the two-zone and three-zone setups, respectively, compared to the single bidding zone. This is primarily due to lower revenues for wind power plants in the North, where concentrated capacity leads to price cannibalization. The three-zone setup mitigates this slightly, as increased North-South trade raises prices in the North East zone. For PV, subsidy expenditure decreases under a bidding zone split since most capacity is located in the South, where higher prices increase revenues. This effect is most pronounced in the two-zone configuration.

Subsidy expenditure for newly installed gas power plants amounts to 2 bn EUR under the single bidding zone setup, decreasing by 40 million EUR and 17 million EUR in the two-zone and three-zone splits, respectively. This reflects assumptions that new gas plants will be added mainly in the South.

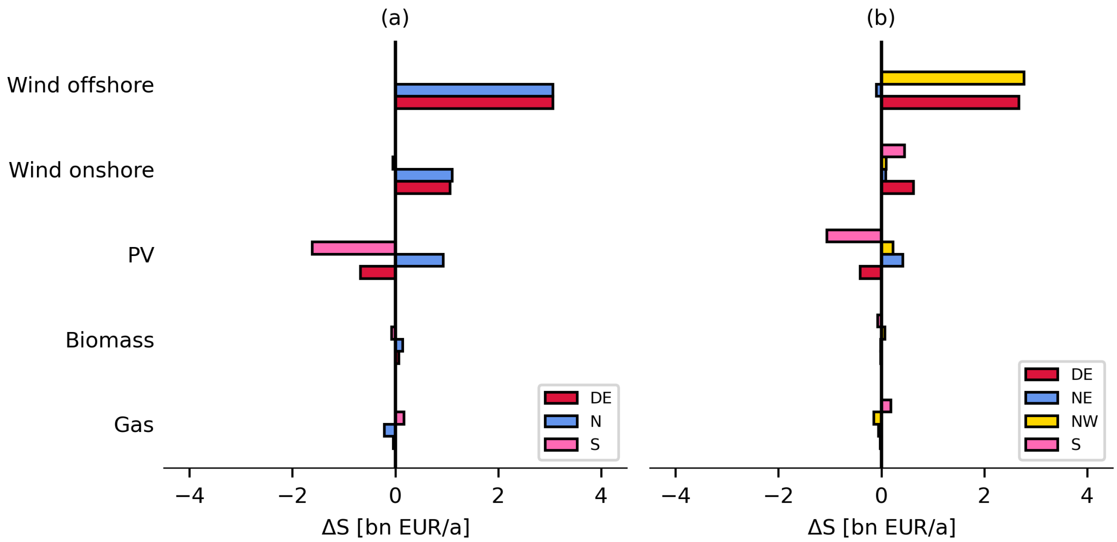

Figure 5: ΔS for (a) two zones and (b) three zones compared to the single bidding zone setup by technology in 2030

Overall, splitting the German bidding zone increases subsidy expenditure, with a greater increase in the two-zone configuration compared to the three-zone setup. Policymakers should also consider the potential interaction between subsidy scheme design and a bidding zone split.

4.5. Congestion Rent

Splitting the German bidding zone generates significant congestion rent in the market clearing, amounting to 2.3 bn EUR and 2.8 bn EUR for the two- and three-zone configurations, respectively, in the 2030 scenario. Most of this revenue arises within today's single German bidding zone, while congestion rents at cross-border lines contribute only a small share. Notably, congestion rents in the rest of Europe decrease as internalizing intra-German congestion reduces congestion on Germany's cross-border lines. Under Regulation (EU) 2019/943, revenues from cross-zonal transmission capacity allocation must be used for congestion management and grid expansion, suggesting that these rents could be used to lower network fees and thus electricity consumption costs.

4.6. Redispatch

The bidding zone split significantly reduces redispatch and grid-based renewable curtailment, leading to lower redispatch costs. Table 5 summarizes the results.

		ΔRD [bn EUR/a]	Curtailment Wind [TWh/a]	Curtailment PV [TWh/a]
Single zone	DE	-	12.8	7.7
Two zones	DE	-1.0	5.5	6.1
	N	-	4.3	1.5
	S	-	1.2	4.6
Three zones	DE	-1.7	4.7	4.7
	NE	-	0.3	0.4
	NW	-	3.2	0.3
	S	-	1.2	4.0

Table 5: Redispatch costs and curtailment by bidding zone setup in 2030

Most redispatch cost savings are realized in the two-zone split as the primary bottleneck between Northern and Southern Germany is internalized in the market. Additional reductions in redispatch costs occur with a three-zone split, particularly addressing congestion between the North-West and North-East. The enhanced North-South trade in this configuration also alleviates PV curtailment in the South zone during sunny hours when electricity is traded from South to North, as already found in Czock et al. (2023). All in all, the results show that the three-zone setup reflects the transmission grid better than the two-zone setup.

4.7. Static Welfare Balance

Figure 6 summarizes the results on rents and subsidy expenditure presented in the previous sections and illustrates the resulting total static welfare impact of the two bidding zone split scenarios for the year 2030 and for the given representation of frictions. Total static welfare changes are modest. Static welfare decreases by 0.2 bn EUR/a and increases by 0.7 bn EUR/a for the two-zone and the three-zone setup, respectively. This corresponds to 1.6 % and 4.4 % of total supply costs in the single German bidding zone. In the face of frictions in redispatch and transmission capacity allocation, welfare gains (increased congestion rents and reduced redispatch costs) in the two-zone setup cannot offset the losses in consumer and producer rents induced by the new transmission constraints. Figure 6 illustrates the overall welfare balance.

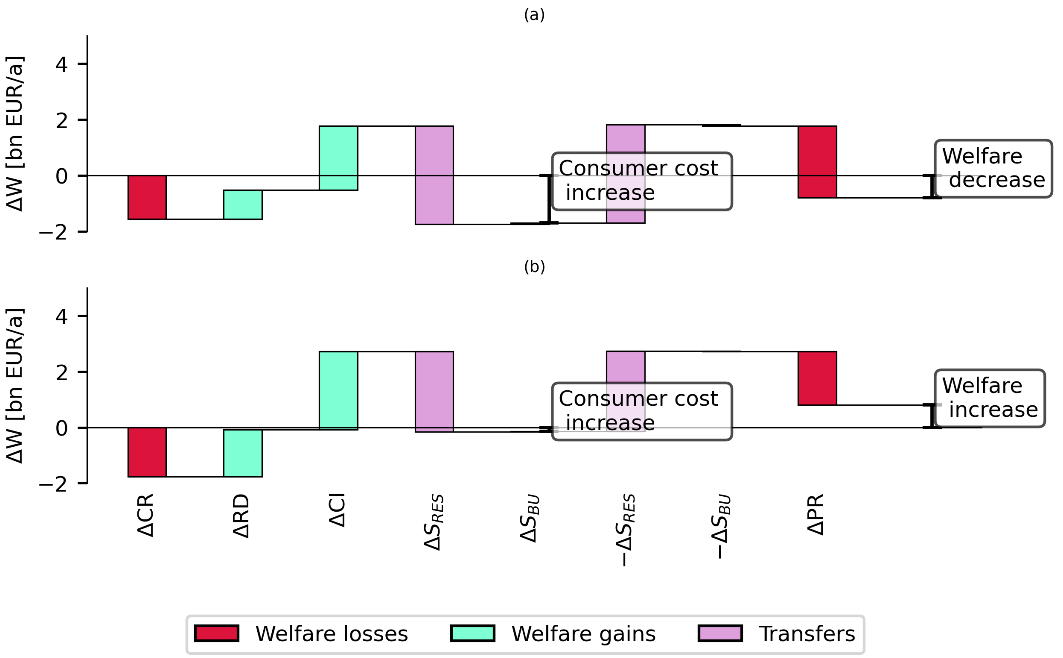

Figure 6: Static welfare balance for (a) two zones and (b) three zones compared to the single bidding zone setup by technology in 2030

Additionally, Figure 6 highlights the distribution effects of the considered bidding zone split scenarios. In both setups, consumer costs consisting of consumer rents (CR), redispatch costs (RD), congestion income (CI), and subsidies (S), increase. Especially in the two-zone setup, rising wholesale costs and subsidy expenditure under a bidding zone split cannot be offset by redispatch savings and increased congestion rents. In the three-zone setup, decreased redispatch costs and increased congestion income mitigate consumer cost increases from rising wholesale costs and subsidy expenditures almost completely. Producers benefit from subsidies, which compensate the losses in producer rents (PR) in both considered bidding zone setups. However, individual consumer cost and producer rent vary significantly between zones, as well as (in the case of producer rent) between technologies, as detailed in earlier sections.

4.8. Sensitivity Analyses

As discussed in section 2, there is no consensus in existing literature on the effects of splitting the German bidding zone, with variations likely driven by differences in scenarios and the representation of frictions. To illustrate the influence of these factors, three sensitivity analyses are conducted.

The first two analyses focus on scenario choice and consider slower wind energy and grid expansion respectively, reflecting Germany's historical challenges in meeting grid and capacity expansion targets (c.f. Zinke, 2023, who conduct similar sensitivity analyses on redispatch costs). Specifically, wind capacity expansion between 2021 and 2030 is halved and all grid expansion projects are delayed by one year to account for these delays. The third analysis examines the effects of changes in redispatch frictions, analyzing a setup where batteries are fully integrated into redispatch, thereby decreasing frictions in redispatch.

Figure 7 illustrates the static welfare changes (relative to the respective single bidding zone case) under these sensitivity analyses.

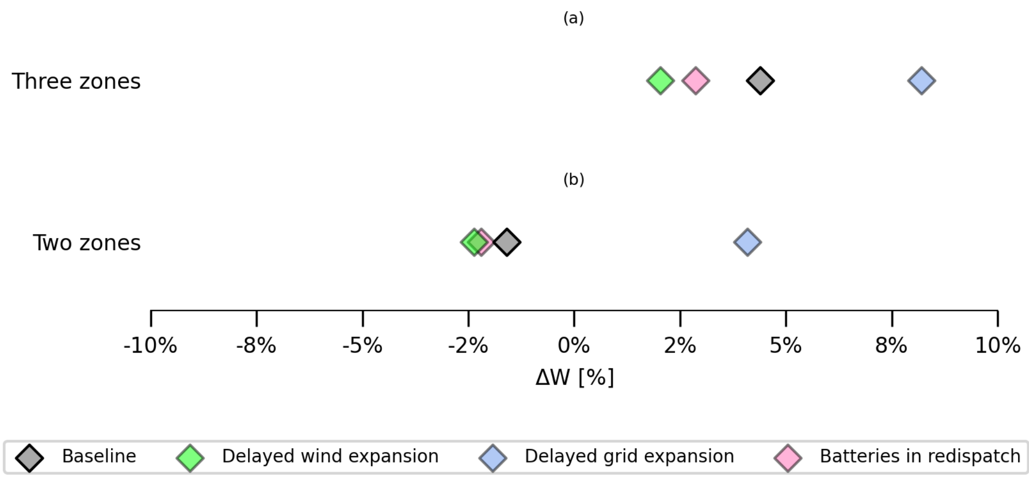

Figure 7: Welfare changes in sensitivity analyses for (a) two zones and (b) three zones, compared to the respective single bidding zone setup in 2030

In the scenario with delayed wind capacity expansion, welfare losses in the two-zone setup are higher, while welfare gains in the three-zone setup are lower than in the baseline scenario. Comparing with the respective single-zone setup, welfare decreases by 2.4 % in the two-zone setup and increases by 2.0 % in the three-zone setup. This is due to the fact that with reduced wind energy capacity, grid congestion is less severe to begin with, and a split cannot decrease redispatch costs as much as in the baseline scenario. Contrarily, in the case of delayed grid expansion, congestion is exacerbated, and the introduction of a bidding zone split can result in significant redispatch cost savings. Overall, welfare improves for both the two-zone and three-zone splits, with the three-zone split proving to be far superior due to its ability to address both North-South congestion and congestion between the North-East and the North-West.

The third sensitivity analysis investigates the effect of removing frictions from redispatch by assuming full participation of batteries in redispatch. This reduces the static welfare gains from bidding zone splitting: The static welfare gain under the three-zone setup diminishes, while the welfare loss under the two-zone split increases. The reason is that in the single bidding zone setup, redispatch costs are already lower because redispatch is more efficient. Consequently, by partially removing frictions in redispatch, the potential redispatch cost savings are reduced, while other welfare parameters remain unchanged from the baseline.

5. Discussion

5.1. Market results

When comparing the results of this study with existing literature, one notable difference relates to electricity prices in the two-zone setup. The price differences between zones in this study reach up to 20 EUR/MWh, which is higher than what has been reported in existing literature. Price differences are impacted by the aforementioned choices in exact bidding zone delineation and FBMC parameters including frictions. Conclusively, direct comparisons with other studies are limited by differences in grid modeling methods and scenario years and no prior study examines a 2030 scenario with a high-resolution FBMC grid model of the European electricity sector. Key factors driving the price differences in this scenario include the high concentration of wind power in the North zone(s), leading to low prices there. In the South zone, high marginal costs of gas power plants (exceeding 120 EUR/MWh for OCGTs) lead to high prices when PV is unavailable. In the case of three zones, prices between the zones converge. Comparing the modelled electricity prices to future power product trades on EEX spot, the results generally seem well in range. For trades carried out in 2024, a volume-weighted average price of 67 EUR/MWh emerges for base products and 79 EUR/MWh for peak products.

Another difference to existing studies concerns the subsidy expenditures for RES. The findings on subsidy expenditure generally align with EWI (2024), which forecasts 19.4 bn EUR in subsidy expenditure for 2029 under a single bidding zone, compared to 24.1 bn EUR for 2030 in this study.

Regarding the impact of a bidding zone split, Tiedemann et al. (2024) report trends of increased subsidy needs for wind in a scenario with two bidding zones in 2030. However, by using exemplary reference values and by omitting past installation costs, they arrive at significantly lower subsidy expenditures. They do not investigate offshore wind subsidies. While offshore wind investors have recently bid reference values of zero, this study indicates that steep capacity increases by 2030, combined with a bidding zone split, exacerbate price cannibalization, necessitating significant subsidies. However, Tiedemann et al. (2024) raise the important point of coordinating price incentives from a potential bidding zone split with the design of the EEG subsidy scheme. While this study essentially assumes that renewable producers are compensated for the difference between zone-specific market values and their reference values, Tiedemann et al. (2024) argue that to maintain price signals and to incentivize renewable capacity in high-price zones, applying a uniform market value across zones would be necessary. They show that applying a uniform market value would potentially increase subsidy expenditure even further.

5.2. Welfare and frictions

The quantitative results indicate that, in the presence of frictions in redispatch and transmission capacity allocation, splitting the German bidding zone does not guarantee static welfare increases. Instead, static welfare depends on the bidding zone configuration, scenario and the frictions. For the 2030 baseline scenario, the considered two-zone configuration leads to slight losses, while the three-zone configuration results in welfare gains. The static welfare losses associated with the two-zone split may seem counterintuitive at first. The North-South split internalizes a significant transmission bottleneck, significantly reducing redispatch volumes and, consequently, costs, which supports one of the main arguments in favor of splitting the bidding zone. However, compared to the single bidding zone, trade within Germany is restricted by the new transmission constraint. This results in increased generation costs in Germany, leading to lower welfare in the zonal market clearing. Redispatch cost reductions cannot fully compensate for the welfare losses in the zonal market clearing in the investigated two-zone split scenario. In contrast, the three-zone setup increases static welfare for two reasons: first, intra-zonal congestion between the North-East and the North-West is internalized in the market, and redispatch costs decrease further. Second, loop flows on the lines connecting the North and the South are alleviated as congestion in the North decreases. This allows for more trade between the South and the North(-East), lowering total generation costs and increasing welfare.

The results are contingent on the considered bidding zone configurations and how well they reflect the transmission grid and the distribution of generation and demand, i.e. congestion. This is also highlighted by the sensitivity analyses, where changes in wind generation capacity and grid expansion lead to significant changes in static welfare. This finding aligns with results in Zinke (2023), who shows that redispatch cost reductions are significantly higher if bidding zones are regularly adjusted to reflect changing grid constraints in the face of transmission capacity expansion. This poses several challenges for policymakers looking to increase welfare by splitting bidding zones: Although it may enhance static efficiency, regular reconfiguration of zones may potentially prevent meaningful investment signals and may therefore impact dynamic welfare. This is aggravated by the fact that bidding zone reconfiguration has an estimated lead-time of three to five years, whereas the most recent formal BZR process took over five years from the definition of assumptions in 2020 to the publication of the quantitative results in 2025. Indeed, the lengthy process prohibited a clear recommendation: Although they find that from a European perspective, splitting the German bidding zone marginally increases static welfare[15], the authoring TSOs refrain from recommending a split because assumptions on fuel prices and demand and generation development were outdated by the time of publication. Additionally, the calculated target year (2025) is regarded to not be meaningful for potential implementation years (around 2030) (c.f. ENTSO-E, 2025). To enable informed decision-making, further research should therefore address the dynamic impact of bidding zone splitting in the face of power system changes, such as planned transmission capacity expansion.

Next to zone configuration, the results presented in this paper are specific to the representation of frictions in the model. First, this relates to frictions in redispatch, which are modeled by limiting the participation of intermittent RES, demand, batteries, and other zones to approximate real-world redispatch procedures. If redispatch were more efficient, for example, with the participation of additional technologies or demand, a split might be less favorable. This is highlighted by the sen-

[15]Static welfare increases with the number of zones Static welfare increases are less than 1% of European supply costs.

sitivity analysis modeling full battery participation in redispatch. If batteries were fully integrated into the redispatch process, the benefits of a split would diminish. However, it is important to note that the effects of battery participation are highly sensitive to their location in the transmission grid, as demonstrated by Czock et al. (2023). Furthermore, it is unclear how efficiency gains from integrating batteries into redispatch can be achieved in practice. The model used in this study assumes optimized charging and discharging decisions for redispatch. In reality, although TSOs receive day-ahead generation schedules, they currently lack the means to preemptively coordinate these decisions. Instead, efficient coordination of batteries with regard to congestion management would require regionally differentiated price signals reflecting grid constraints. A potential solution could involve the creation of a redispatch market, although this would expose the market to "inc-dec gaming," as discussed by Hirth and Schlecht (2018). A bidding zone split, too, creates differentiated price signals that allow batteries to react to congestion. These price signals can only reflect those transmission constraints internalized by the split and are subject to frictions in transmission capacity allocation (see below). Nonetheless, when interpreting the welfare changes highlighted in the sensitivity analysis with full participation of batteries, it must be kept in mind that efficiency gains from battery participation may not fully materialize in the single bidding zone case due to lack of coordination.

Moreover, the results are contingent on the chosen redispatch modelling method. This study employs an ex-post optimization of the nodal dispatch, whereas other studies, such as Fraunholz et al. (2021), apply artificial penalties to ensure that only physical violations of grid infrastructure are resolved. The approach adopted here may potentially overestimate redispatch volumes. However, it should be noted that while penalty-based methods minimize redispatch volumes, determining the appropriate penalty is a non-trivial task. Additionally, the modelling approach used in this paper does not account for the proportional depreciation of capital and opportunity costs that generators incur due to redispatch. These factors, which are accounted for in real-world redispatch and reimbursed to generators, are not reflected in the redispatch cost calculations here. As a result, the simplified representation of redispatch in this study likely overestimates redispatch volumes and underestimates associated costs. A more detailed evaluation of various redispatch modelling approaches and their respective impacts is warranted. This paper offers preliminary insights into the impact of varying redispatch efficiencies, but further research should explore this topic more comprehensively, both in terms of modeling techniques and the potential efficiency gains achievable by real-world redispatch.

Second, regarding frictions in transmission capacity allocation, it must be noted that the representation of FBMC employed in this study also involve several simplifications, which are common in quantitative studies. For instance, this paper assumes fixed security margins and generalized assumptions regarding GSKs. In reality, TSOs have more detailed information about the grid and derive GSKs and security margins from flow forecasts two days ahead (Creos et al., 2020). Further research should address the impact of flow-based parameter choice and grid modelling methods in general on welfare effects of a bidding zone split.

Finally, this study does not assess frictions associated with potentially limited liquidity in smaller bidding zones. Further research on the potential welfare impact is needed, considering opportunities for (proxy-)hedging on neighboring markets, i.e. by analyzing covariance of prices while accounting for effects of zone configuration on interconnector capacity.

5.3. General limitations

Additionally, several limitations inherent to optimization-based electricity market modelling have to be considered when interpreting the numerical results obtained in this study. First, the market and grid model used to simulate zonal markets relies on the following assumptions: perfect foresight, no transaction costs, perfect markets, and inelastic demand. Only if these assumptions hold, the mathematical duality between a central planer problem and the profit-maximization of symmetric firms, which allows for the quantification of welfare, holds.

6. Conclusion

This study contributes to the ongoing debate on splitting the German bidding zone. Existing literature, which lacks consensus on welfare and price effects has so far been limited to the analysis of two zones and frictions have not been considered explicitly. The research gap is addressed by a detailed quantitative analysis of static market and welfare impacts using a state-of-the-art grid and market model with flow-based market coupling for a 2030 scenario. The model is used to investigate a North-South split into two zones and a three-zone split, which splits the North-East and North-West. Key quantitative findings are:

- Given frictions in transmission capacity allocation and redispatch, static welfare increases by 4 % for the three-zone split, while it decreases by 2 % for the investigated two-zone split.
- Consumer wholesale costs decrease in the North while they increase in the South, leading to overall consumer rent decreases.
- Splitting the bidding zone reduces redispatch costs and increases congestion income, thus partially mitigating consumer cost increases if cost changes are passed on via grid fees.
- Price cannibalization in the North zone(s) leads to decreased revenues for wind power, which increases subsidy expenditure and therefore consumer costs.
- Static welfare is highly sensitive to scenario choice and representation of frictions.

All in all, total static welfare impacts of a bidding zone split in 2030 are modest, while distribution effects are significant. Especially in the two-zone setup, consumers are exposed to higher costs than in the single bidding zone setup. Higher market granularity with three zones improves static welfare and mitigates distribution effects compared to two zones.

Conclusively, splitting the German bidding zone does not guarantee welfare gains and welfare outcomes depend on the exact configuration of the zones, the scenario and frictions in redispatch and transmission capacity allocation. Additionally, policymakers should weigh the (uncertain) static welfare effects against transition costs of a bidding zone split, which have been estimated to lie around 1.5 bn EUR (one-off costs) in Compass Lexecon (2023). Additionally, they should consider potential impacts on market liquidity, which are uncertain according to Compass Lexecon (2024). Especially in the case of three zones, which is found to be favorable over a two-zone split in this study, smaller markets may potentially lead to lower liquidity. Furthermore, the interplay with existing policies such as the RES subsidy scheme or the planned capacity mechanism need to be analyzed. Finally, policy-makers need to consider dynamic effects of bidding zone splitting given the trade-off between accurate representation of congestion and defining stable bidding zones.

In light of the complexity, policymakers should evaluate whether alternative mechanisms such as increasing redispatch efficiency, albeit with new coordination challenges, could serve a similar purpose as a bidding zone split - potentially at lower transaction costs and distribution effects.

Further research is needed to assess the market and welfare impacts of splitting the German bidding zone from a pan-European perspective. Still, this study highlights the importance of thorough analysis for any bidding zone reconfiguration, including ongoing discussions for e.g. Italy, France, and Sweden, as static welfare gains cannot be assumed automatically.

Acknowledgements

The author appreciates helpful comments and suggestions by Marc Oliver Bettzüge, Fabian Arnold, Merit Dressler, Oliver Ruhnau, Erik Schrader, Felix Schäfer, Amelie Sitzmann, and Jonas Zinke. Additionally, the author gratefully acknowledges the feedback received from the participants of the workshop of the "GOR Arbeitsgruppe Umwelt und Energie" at the FernUniversität in Hagen, where the results were first presented.

The author gratefully acknowledges the funding provided by the Federal Ministry for Economic Affairs and Climate Action (BMWK), supervised by the project management organization Projekttträger Jülich (PtJ) (grant number 03EI4048AV - 03EI4048A). The contents of this paper reflect the opinions of its author only.

References

50Hertz, Amprion, TenneT and TransnetBW (2022). Szenariorahmenentwurf zum Netzentwicklungsplan Strom (Scenarios for the Grid Development Plan Power) 2037/45, Version 2023. Tech. rep., Bundesnetzagentur.

ACER (2022). DECISION No 11/2022 on the alternative bidding zone configurations to be considered in the bidding zone review process - ANNEX I - List of alternative bidding zone configurations to be considered for the bidding zone review. Tech. rep., European Union Agency for the Cooperation of Energy Regulators.

ACER (2024). Transmission capacities for cross-zonal trade of electricity and congestion management in the EU: 2024 Market Monitoring Report.

Ambrosius, M., Grimm, V., Sölch, C. and Zöttl, G. (2018). Investment incentives for flexible demand options under different market designs. *Energy Policy* 118: 372–389, doi:10.1016/j.enpol.2018.01.059.

Baden-Württemberg Association of Chambers of Commerce and Industry e.V., IHK Working Group Rhineland-Palatinate and Chamber of Commerce, Industry of Saarland, Bavarian Association of Chambers of Commerce and Industry e.V., Amprion GmbH, TransnetBW GmbH and Economic Advisory Council of Bavaria (2024). Germany must remain a unified electricity price zone!

Bergh, K. Van den, Wijsen, C., Delarue, E. and D'haeseleer, W. (2016). The impact of bidding zone configurations on electricity market outcomes. In *2016 IEEE International Energy Conference (ENERGYCON)*. IEEE, 1–6.

Biener, W. and Garcia Rosas, K. R. (2020). Grid reduction for energy system analysis. *Electric Power Systems Research* 185: 106349, doi:10.1016/j.epsr.2020.106349.

Bjørndal, M., Jørnsten, K. and Pignon, V. (2003). Congestion management in the nordic power market—counter purchases and zonal pricing. *Journal of Network Industries* : 271–292.

BMWK (2024). Kraftwerkssicherheitsgesetz - Neue Ausschreibungen für wasserstofffähige Gaskraftwerke und Langzeitspeicher für Strom -Konsultation nach Ziffer 4.1.3.4 der Leitlinien für staatliche Klima-, Umweltschutz- und Energiebeihilfen 2022.

BMWK, MWIKE and RWE (2022). Politische Verständigung zwischen dem Bundesministerium für Wirtschaft und Klimaschutz, dem Ministerium für Wirtschaft, Industrie, Klimaschutz und Energie des Landes Nordrhein-Westfalen und der RWE AG zum vorgezogenen Kohleausstieg 2030 im Rheinischen Revier.

Breuer, C. and Moser, A. (2014). Optimized bidding area delimitations and their impact on electricity markets and congestion management. In *11th International Conference on the European Energy Market (EEM14)*. IEEE, 1–5.

Brouhard, T., Hennebel, M., Petit, M. and Gisbert, C. (2020). Bidding Zones of the European Power System: Benefits of a Multi-Dimensional Approach to the Evaluation of Possible Delineations. In *2020 17th International Conference on the European Energy Market (EEM)*. IEEE, 1–6.

Brouhard, T., Hennebel, M., Petit, M. and Gisbert, C. (2023). A clustering approach to the definition of robust, operational and market efficient delineations for european bidding zones. *IET Generation, Transmission & Distribution* 17: 2687–2702.

Bundesnetzagentur (2024). Kraftwerksliste zum Szenariorahmen Strom.

Bundesnetzagentur and Bundeskartellamt (2023). Monitoringbericht 2023.

Burstedde, B. (2012). From nodal to zonal pricing: A bottom-up approach to the second-best. In *2012 9th International Conference on the European Energy Market*. IEEE, 1–8.

Compass Lexecon (2023). Transition costs of bidding zone reconfigurations - A study for ENTSO-E.

Compass Lexecon (2024). The Impact of Bidding Zone Changes on Liquidity Transaction Costs- A study for ENTSO-E.

Creos, Tennet, Amprion, RTE, TransnetBW, Elia, RTE, 50Hertz and APG (2020). Documentation of the CWE FB MC solution - July 2020 – version 5.0, applicable as of DD MM 2020. Accessed: 2025-03-26.

Czock, B. H., Sitzmann, A. and Zinke, J. (2023). The place beyond the lines-efficient storage allocation in a spatially unbalanced power system with a high share of renewables.

Dobos, T., Bichler, M. and Knörr, J. (2024). Finding stable price zones in european electricity markets: Aiming to square the circle? *arXiv preprint arXiv:2404.06489* .

Egerer, J., Weibezahn, J. and Hermann, H. (2016). Two price zones for the german electricity market—market implications and distributional effects. *Energy Economics* 59: 365–381.

ENTSO-E (2025). Bidding zone review of the 2025 target year.

ENTSO-E and ENTSO-G (2022). Ten year network development plan 2022.

EWI (2024). Mittelfristprognose zur deutschlandweiten Stromerzeugung aus EEG - geförderten Kraftwerken für die Kalenderjahre 2025 bis 2029. Tech. rep.

Felling, T., Felten, B., Osinski, P. and Weber, C. (2023). Assessing improved price zones in europe: Flow-based market coupling in central western europe in focus. *The Energy Journal* 44: 71–112.

Felling, T. and Weber, C. (2018). Consistent and robust delimitation of price zones under uncertainty with an application to central western europe. *Energy Economics* 75: 583–601.

Felten, B., Osinski, P., Felling, T. and Weber, C. (2021). The flow-based market coupling domain-why we can't get it right. *Utilities Policy* 70: 101136.

Fraunholz, C., Hladik, D., Keles, D., Möst, D. and Fichtner, W. (2021). On the long-term efficiency of market splitting in germany. *Energy Policy* 149: 111833.

Frontier Economics (2024). Auswirkungen und Folgemaßnahmen einer Trennung der einheitlichen deutschen Stromgebotszone für Baden-Württemberg - Studie für das Ministerium für Umwelt, Klima und Energiewirtschaft Baden-Württemberg.

Grimm, V., Martin, A., Weibelzahl, M. and Zöttl, G. (2016). On the long run effects of market splitting: Why more price zones might decrease welfare. *Energy Policy* 94: 453–467, doi: 10.1016/j.enpol.2015.11.010.

Grimm, V., Rückel, B., Sölch, C. and Zöttl, G. (2021). The impact of market design on transmission and generation investment in electricity markets. *Energy Economics* 93: 104934.

Hirth, L. and Schlecht, I. (2018). Market-based redispatch in zonal electricity markets. *USAEE Working Paper* Version 2019-03-21.

IEA (2021). World Energy Outlook 2021.

IEA (2022). World Energy Outlook 2022.

Knaut, A., Tode, C., Lindenberger, D., Malischek, R., Paulus, S. and Wagner, J. (2016). The reference forecast of the German energy transition - An outlook on electricity markets. *Energy Policy* 92: 477–491.

Knörr, J., Bichler, M. and Dobos, T. (2024). Zonal vs. nodal pricing: An analysis of different pricing rules in the german day-ahead market. *arXiv preprint* 2403.09265.

Lété, Q., Smeers, Y. and Papavasiliou, A. (2022). An analysis of zonal electricity pricing from a long-term perspective. *Energy Economics* 107: 105853.

Plancke, G., De Jonghe, C. and Belmans, R. (2016). The implications of two German price zones in a european-wide context. In *2016 13th International Conference on the European Energy Market (EEM)*. IEEE, 1–5.

Schmidt, L. and Zinke, J. (2023). One price fits all? on inefficient siting incentives for wind power expansion in germany under uniform pricing. *The Energy Journal* 44, doi: 10.5547/01956574.44.4.lsch.

SPD, CDU and CSU (2025). Koalitionsvertrag 2025: Zusammen für ein modernes Deutschland. Accessed: 2025-04-11.

Statistisches Bundesamt (2023). Stromverbrauch der privaten Haushalte nach Haushaltsgrößenklassen. Accessed on April 4, 2024.

Tiedemann, S., Stiewe, C., Kratzke, C., Hirth, L., Jentsch, M., Damm, N., Gerhardt, N. and Pape, C. (2024). Gebotszonenteilung: Auswirkungen auf den marktwert der erneuerbaren energien im jahr.

Trepper, K., Bucksteeg, M. and Weber, C. (2015). Market splitting in germany–new evidence from a three-stage numerical model of europe. *Energy Policy* 87: 199–215.

Zachmann, G. (2024). Strommarkt: Einheitliche gebotszone aufteilen. *Wirtschaftsdienst* 104: 514–515.

Zinke, J. (2023). Two prices fix all? On the robustness of a german bidding zone split. *EWI Working Paper* 07/23.

Appendix A. Assumptions on technologies, demand and fuel prices

Table A.6: Considered technologies and generation efficiency, assumptions based on scenario *Stated Policies* in World Energy Outlook 2021 (IEA, 2021) and Knaut et al. (2016)

Technologies	Efficiency
Nuclear	0.33
Lignite	0.4
Coal	0.45
CCGT	0.5
OCGT	0.38
Oil	0.4
Biomass	0.3
PV	1
Wind Onshore	1
Wind Offshore	1
Hydro	1
Pumped Storage	0.78
Battery Storage	0.95

Table A.7: Development of demand [TWh] based on the *National Trends* scenario in ENTSO-E and ENTSO-G (2022)

Country	2019	2030
AT	67	83
BE	85	95
CH	62	64
CZ	63	74
DE	524	595
DK	35	53
FR	456	485
NL	114	139
PL	156	182

Table A.8: Development of fuel prices [EUR/MWh_{th}], based on scenario *Stated Policies* in World Energy Outlook 2022 (IEA, 2022)

Fuel	2019	2030
Uranium	3.0	5.5
Lignite	3.9	5
Coal	7.9	7.7
Natural Gas	13.6	25.0
Oil	33.1	44.8
Biomass	21.0	22.0