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Abstract

As redispatch costs and their associated distributional impacts continue to rise, the discussion on reconfiguring bidding zones in European power markets persists. However, determining an appropriate bidding zone configuration is a non-trivial task, as it must prove beneficial under varying weather conditions, load situations, and an uncertain future, essentially necessitating persistent benefits. This paper uses the German-Luxembourg market area as an example to investigate the impact of uncertain factors, such as short-term weather patterns and long-term system changes, on the potential reduction of redispatch costs resulting from a two-zone split. Employing hierarchical clustering on hourly time series of Locational Marginal Prices for multiple historical weather and future scenario years, the paper derives bidding zone splits and assesses their robustness regarding redispatch cost reduction. Sensitivities to uncertain factors such as grid and renewable expansion, demand development, and fuel prices are investigated. The results indicate that a north-south split of the German-Luxembourg market area can robustly reduce redispatch costs. The impact on the reduction potential of yearly weather fluctuations is limited, owing to the structural nature of grid bottlenecks. However, the long-term transformations within the power system, coupled with their associated uncertainties, can significantly diminish the potential for cost reduction through a bidding zone split.

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

JEL classification: D47, C61, Q40, Q48

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1. Introduction

The liberalization of electricity markets resulted in the unbundling of former vertically integrated utilities into separate companies for power generation and grid operation. Nevertheless, to ensure grid stability, there is a need for coordination between the dispatch decisions of power generators and given grid constraints. Different approaches exist, such as the nodal pricing approach used in markets like PJM in the United States, where Locational Marginal Prices (LMPs) are assigned to each grid node. Differences in LMPs are explicit scarcity signals for transmission. In contrast, markets in Europe use a zonal pricing approach, in which intra-zonal constraints, i.e., grid constraints within zones, are neglected in the market clearing. With a few exceptions, e.g., the Nordics and Italy, these zones largely correspond to national borders. Violations of transmission constraints within zones are administratively handled via remedial actions by a Transmission System Operator (TSO), e.g., by adjusting the dispatch schedule of power plants (a so-called redispatch) or the trade balance (so-called countertrading) post-market clearing.

With increasing capacities of volatile renewable power generation, the German nuclear phase-out, decreasing fossil generation capacities, closer integration of European power markets, and slow grid expansion, the need for remedial actions rose significantly: in Germany, nominal costs for redispatch, countertrading, and compensation payments for renewable curtailment, increased from 200 million Euros in 2014 to 3.7 billion euros in 2022 (BNetzA, 2023). It is important to note that these costs do not necessarily imply static inefficiency. In theory, assuming full participation in redispatch and no additional readjustment costs, zonal pricing and subsequent redispatch can lead to optimal power plant dispatch and maximize social surplus (c.f. Bjørndal et al., 2013).[1] However, the zonal pricing leads to distributional effects if structural bottlenecks are not considered in the zonal market clearing. For instance, if high demand in one region requires costly power generation adjustments through redispatch, the associated costs are socialized by being passed on to consumers via the grid tariffs. Essentially, regions with favorable energy conditions may cross-subsidize those with higher power generation costs. As redispatch costs continue to rise, so do these distributional

[1] However, these theoretical assumptions do not hold in practice, resulting in inefficiencies. Conversely, in reality, the nodal pricing approach also has disadvantages, such as increased complexity, price volatility, and uncertainty. Therefore, it remains a matter of active discussion on which option is the more favorable one.

effects. Besides issues of fairness, this system obscures the true local electricity supply costs and lacks efficient allocation signals for investors of generation and demand capacities and could thus lead to dynamic inefficiency (c.f. Jeddi and Sitzmann, 2021). Consequently, there is a growing call to revise the current bidding zone configuration to better reflect structural grid bottlenecks within Europe and, thereby, reduce redispatch costs (e.g., Höffler, 2009).

In line with Article 34 of the EU capacity allocation and congestion management (CACM) guideline (European Union, 2015), the efficiency of the bidding zone (BZ) configuration has to be assessed every three years by the Agency for the Cooperation of Energy Regulators (ACER), an umbrella organization of European regulators. As part of this process, in 2016, ACER requested the European Network of Transmission System Operators (ENTSO-E) to draft a first bidding zone review, which was published in 2018 (ENTSO-E, 2018) but did not include quantitative analyses. ACER then required the TSOs to submit proposals on a methodology, assumptions, and the alternative BZ configurations to be considered (ACER, 2020). As the TSOs could not agree on alternative configurations, ACER decided on the bidding zone configurations to be reviewed based on a Locational Marginal Price analysis provided by the TSOs (ACER, 2022; ENTSO-E, 2022).

The bidding zone review process highlights the complexity of finding an appropriate bidding zone configuration. First of all, there is no optimal number of bidding zones, as any reconfiguration requires a trade-off between, e.g., complexity and correctness of prices. Increasing the number of zones substantially and, thus, moving towards nodal pricing increases the informational transparency in the market. Therefore, prices reflect actual grid constraints more properly and set incentives for system-friendly investments. Yet, larger bidding zones might be beneficial in practice. In particular, in forward markets, nodal pricing lacks efficiency if the market participants have inadequate expectations about the prices, transaction costs are high, or the limited number of participants leads to low liquidity (e.g., Bartholomew et al., 2003; Kristiansen, 2004; Siddiqui et al., 2005; Deng et al., 2010; Adamson et al., 2010).

ACER's proposal does not aim to drastically increase the number of zones. For Germany, which received most configurations for review, a division into two to a maximum of four zones is being considered (c.f. ACER, 2022).[2]

Even with a given number of bidding zones, it is difficult to determine a suitable bidding zone split. Grid bottlenecks and, hence, the most effective bidding zone configuration might change frequently as volatile renewable generation and demand alter the grid load. In the long run, the commissioning and decommissioning of new generators, consumers, and transmission capacities as well as changing fuel prices, might affect the optimal bidding zone configuration. However, bidding zones should not be adjusted frequently because the reconfiguration increases uncertainty and involves high transaction costs. For example, it requires the transformation of existing forward and long-term contracts. Thus, if a new bidding zone configuration must be stable over time, it should be beneficial under different weather conditions, load situations, and future scenarios – in other words, it must be robust.

This paper addresses the robustness of a bidding zone reconfiguration under stochastic weather patterns and structural changes in the power system over time, e.g., demand and capacity development. It uses a two-zone split of the current German-Luxembourg bidding zone as a case study. To determine suitable BZ split configurations of the German-Luxembourg bidding zone, hourly LMPs are calculated within a linear market and grid model for 24 weather years and the scenario years 2021, 2025, 2030, and 2035. The hourly LMPs are then clustered hierarchically based on Ward's criterion. For the resulting bidding zone splits, the effect on redispatch costs is analyzed. Furthermore, this paper sheds light on how uncertain factors impact the efficiency of a bidding zone reconfiguration by investigating sensitivities regarding grid and renewable expansion as well as fuel prices.

The results show that a north-south division of the German-Luxembourg market area is beneficial in terms of reduced redispatch costs largely independent of weather conditions. However, the cost reduction depends highly on the period for which the bidding zone split is held stable and the future scenario. The sensitivities show that uncertain factors greatly affect the bidding zone

[2]If TSOs cannot allocate generation and load units to a single bidding zone for any of the initially proposed BZ configurations, they may consider fallback options with up to five zones instead.

split's effectiveness in reducing redispatch costs. If the system properties change strongly, e.g., if a substantial part of grid congestion is driven by solar power generation, the redispatch costs reduction from splitting the bidding zone decreases significantly.

The paper is organized as follows. Section 2 presents relevant literature on determining suitable bidding zone reconfigurations. Section 3 introduces the numerical model, relevant input data, and scenario assumptions. Section 4 presents and discusses the results, by comparing redispatch costs for different bidding zone configurations, weather conditions, and scenarios. Section 5 summarizes the main findings and draws conclusions.

2. Related Literature

This research builds on extensive literature applying mathematical models to find suitable bidding zone configurations. The bulk of existing research uses LMPs as an indicator for determining bidding zones, following Stoft (1997), who states that the definition of bidding zones should be based on price differences between nodes, as these contain all relevant information on network-related costs. Exceptions are, e.g., Kumar et al. (2004); Kang et al. (2013); Kłos et al. (2014), who cluster power transfer distribution factors (PTDFs) due to a lack of information available to calculate LMPs or to reduce complexity. ENTSOE-E applies both PTDF and LMP clustering in its first bidding zone review but does not use the results of clustering PTDFs due to the high sensitivity regarding some input assumptions (c.f. ENTSO-E, 2018, p. 30). Most research on LMP clustering focuses on a specific load situation, e.g., Imran and Bialek (2008), who test geographical, fuzzy-c-means, and price differential clustering. Bovo et al. (2019) provide a comprehensive review of this kind of work. A smaller sub-strand of literature considers multiple time steps in clustering LMPs to analyze the impact of stochastic factors such as weather and/or exogenous factors such as capacity and demand development. Burstedde (2012) uses a simplified 72-node model of the European transmission grid to calculate LMPs for the scenario years 2015 and 2020 and applies a hierarchical algorithm based on Ward's criterion to evaluate suitable amounts and shapes of bidding zones. Her results suggest that redefining bidding zones can increase the static efficiency of the system, even without increasing the number of bidding zones. Furthermore, the results show that the clustered bidding zones vary in time. This result is confirmed by Breuer et al. (2013), who apply a more detailed model of the European electricity grid to calculate LMPs for 2016 and 2018. Yet, the authors do not evaluate redispatch costs or volumes. Wawrzyniak et al. (2013) investigate the impact of different wind conditions on optimal bidding zone splits of the Polish market. The authors propose a two-step methodology: first, they apply hierarchical clustering based on Ward's criterion for every load situation (i.e., time step) individually and then use consensus clustering to determine a suitable bidding zone split for all modeled load situations. Although the authors include comparatively little installed wind capacity (1.4 GW) in their analysis, they find that wind conditions affect the clustering results. Breuer and Moser (2014) examine the appropriate amount of bidding zones, taking into account the level of competition and network security. Furthermore, they analyze the cost savings for various reconfiguration frequencies and find that a bidding zone reconfiguration after three years almost halves the benefits compared to a yearly reconfiguration. Felling and Weber (2018) determine bidding zone configurations that are robust to six scenarios for the future development of the electricity system in Central Western Europe. In a follow-up paper, Felling et al. (2019) expand the analysis by calculating redispatch costs and welfare effects. The authors find that an optimized bidding zone configuration can reduce total system costs by 1.8%. This cost reduction is confirmed by the authors in a recent publication for the year 2020 (Felling et al., 2023). In addition, the authors emphasize the distributional effects resulting from the reconfiguration of bidding zones. In another recent publication, Brouhard et al. (2023) cluster bidding zone configurations based on 600 grid load situations for the scenario year 2025. The authors find that the resulting BZ configuration can reduce the need for redispatch significantly in 2025 but leads to increased redispatch volumes in 2030 and 2040 compared to the status quo configuration. They conclude that multiple time horizons have to be considered when creating a robust market design.

Research gap and contribution

Reviewing current literature reveals a lack of systematic analysis of the fundamental drivers that determine the impact of a bidding zone split. This paper seeks to close the gap between existing publications focusing on stochastic factors such as wind power generation (e.g., Wawrzyniak et al., 2013) and publications investigating suitable BZ configurations for specific scenarios (e.g., Burstedde, 2012; Felling and Weber, 2018). For this purpose, the present study analyzes splitting the German-Luxembourg market area into two separate bidding zones. This bidding zone split is done by clustering LMPs obtained from running simulations over 24 weather years for the scenario years 2021, 2025, 2030, and 2035. The resulting bidding zone splits are then analyzed with regard to redispatch costs. Subsequent sensitivity analyses investigate the robustness of the determined bidding zone configuration to uncertain scenario-related factors.

3. Methodology, input data and scenario design

This paper applies a three-step methodology to find and evaluate bidding zone splits. First, SPIDER (Spatial Investment of Distributed Energy Resources, c.f. Schmidt and Zinke, 2023; Czock et al., 2023), a detailed electricity system model of the Central European transmission grid, is applied to derive Locational Marginal Prices for one reference scenario under 24 different weather years. Secondly, these LMPs are clustered to determine bidding zones. In the third step, SPIDER is used to model the market results and redispatch costs for the obtained bidding zone configuration for the reference scenario and sensitivities. The following presents the applied model, the underlying assumptions, the clustering algorithm, and the reference scenario. Throughout this work, the notation presented in table A.4 is used. To distinguish (exogenous) parameters and optimization variables, the latter are written in capital letters.

3.1. Spot market and grid modeling

SPIDER is a model of the European power sector that considers a detailed depiction of the central European transmission grid. In the present work, the commissioning and decommissioning of transmission, generation, and demand capacities are exogenous. Hence, SPIDER is applied as a pure dispatch model, minimizing the variable costs of electricity generation. Variable costs are the product of electricity generation GEN in each market zone z, timestep t and per technology i and the technology-specific variable operating costs γ:

$$min!\ VC = \sum_{z \in Z, i \in I, t \in T} GEN(t,z,i) \cdot \gamma(t,i). \tag{1}$$

3.1.1. Nodal modeling

For calculating LMPs and when modeling redispatch, each grid node constitutes a market zone z, and all transmission grid constraints are considered within a linear optimal power flow problem

(LOPF). To keep the problem linear, DC power flow constraints are used to approximate non-linear AC power flow restrictions. Thereby, the model neglects grid losses and reactive power (c.f. Van den Bergh et al., 2014). The implementation of DC power flows is based on the cycle-based Kirchhoff formulation, which has been proven to be an efficient formulation (c.f. Hörsch et al., 2018). For a thorough description of the LOPF implementation, the underlying model, and its characteristics, the reader is referred to Schmidt and Zinke (2023) and Czock et al. (2023).

3.1.2. Zonal modeling

In addition to the initial model of Schmidt and Zinke (2023), the model formulation is extended to consider different bidding zone configurations in the European spot market by applying the so-called flow-based market coupling (FBMC). Flow-based market coupling was introduced in Central Western Europe (CWE) in 2015 and has since been extended to neighboring markets. In contrast to the Net Transfer Capacity (NTC) approach used before, TSOs determine flow-based parameters, and the actual use of cross-zonal capacities is decided within the market clearing algorithm. A short, general introduction to FBMC modeling is given in the following. For a more detailed description, the reader is referred to Van den Bergh et al. (e.g., 2014), Müller et al. (2018), or Felten et al. (2019).

In every timestep t, the system-wide electricity load and supply must be in equilibrium (2). A market's net position ($SALDO$) is the delta of supply (GEN) and consumption ($CONS$) (3) and, consequently, equals the sum of flows ($FLOW$) from one market to its neighbors (4). The coefficient $\kappa_{z,l}$ depicts the flow direction (1 if line l starts in zone z, -1 if line l ends in zone z, 0 else).

$$\sum_{z \in Z} SALDO(t,z) = 0 \qquad \forall t \in T \qquad (2)$$

$$SALDO(t,z) = \sum_{i \in I} GEN(t,z,i) - \sum_{j \in J} CONS(t,z,j) \qquad \forall t \in T, \forall z \in Z \qquad (3)$$

$$SALDO(t,z) = \sum_{l \in L} \kappa(z,l) \cdot FLOW(t,l) \qquad \forall t \in T, \forall z \in Z \qquad (4)$$

The FBMC approach accounts for the fact that AC-flows between two zones are influenced by the trades between other zones via the zonal Power Transfer Distribution Factors ($zPTDF$) (5). The zonal PTDF is a linear sensitivity between the net position of each zone and the power flows on each AC line. The flows on lines identified as critical lines L are restricted by the tradeable line capacity, the Remaining Available Margin (ram^{-}/ram^{+}), in positive and negative flow direction (6):

$$FLOW(t,l) = \sum_{z \in Z} zPTDF(t,z,l) \cdot SALDO(t,z) \qquad \forall t \in T, \forall l \in L \tag{5}$$

$$ram^{-}(t,l) \leq FLOW(t,l) \leq ram^{+}(t,l) \qquad \forall t \in T, \forall l \in L \tag{6}$$

The parameters ram and $zPTDF$ are called FBMC parameters and have to be defined prior to the market clearing. The zonal PTDF is defined as the sum of the nodal PTDF, which can be calculated from the line reactances (see, e.g., Van den Bergh et al., 2014), weighted with Generation Shift Keys (gsk).

$$zPTDF(t,l,z) = \sum_{n \in N} nPTDF(n,l) \cdot gsk(t,n,z) \qquad \forall t \in T, \forall l \in L, \forall z \in Z \tag{7}$$

The GSKs are an assumption on how the changes in the net position of a market zone are distributed among the nodes. There are different ways to calculate GSKs (c.f. Wyrwoll et al., 2018). In this study, GSKs are calculated for each hour as the proportion of a node's generation of the total zone's generation.

The ram parameter is the remaining line capacity available for commercial exchange without endangering grid security. It is defined as follows:

$$ram(t,l) = f^{max}(t,l) - f^{ref}(t,l) - frm(l) - fav(l) \qquad \forall t \in T, \forall l \in L \tag{8}$$

f^{max} is the maximal power flow per line, determined by the line's physical thermal limit. f^{ref} is the reference flow representing loop and transit flows. In addition, safety margins (the Flow Reliability Margin (frm) and Final Adjustment Value (fav)) are subtracted from the line capacity. In contrast to AC lines, DC lines allow controlling power flows. In this paper, DC lines are modeled via the so-called "Advanced Hybrid Market Coupling" such that the impact of DC flows on AC flows is considered. For an in-depth introduction to the coupling of DC and AC modeling, see, e.g., Müller et al. (2018).

In this study, the frm is set to 10% of the line capacity and the fav is set to zero (c.f. Müller et al., 2018). Reference flows are determined in a preceding model run in which all trade is set to zero (*base case*). Furthermore, only cross-border lines are considered critical lines in this study. Thus, all other intra-zonal transmission restrictions are not taken into account.

3.1.3. Redispatch modeling

The scheduled dispatch after zonal market clearing might violate intra-zonal physical grid restrictions and require remedial redispatch measures. The costs for increasing and decreasing the dispatch of power plants are calculated in a subsequent simplified redispatch run. Within this run, a LOPF is calculated while holding the zonal net trade positions fixed. Therefore, only adjustments in the generation distribution within each zone are possible. Additionally, it is assumed that wind, solar, battery, and electrolysis dispatch determined in the zonal market-clearing can only be curtailed in redispatch, not increased. Differences in generation costs between the zonal and redispatch runs are interpreted as redispatch costs.

The resulting redispatch costs tend to be higher than in reality because of model simplifications: Countertrading, which is not considered in the modeling, can be advantageous over intra-zonal redispatch. Furthermore, the flow-based, zonal results can be more efficient in reality, as TSOs draw on many years of experience when setting flow-based parameters such as the ram and frm or choosing critical lines.

Modeling a detailed representation of grid constraints is computationally challenging.[3] The model is, therefore, subject to several limitations: As mentioned above, investments in transmission, generation, and demand capacities are exogenous assumptions. Ramping and minimum load constraints are approximated to avoid a mixed-integer optimization and the model does not include combined heat and power plants.

[3]The model run time depends on the specific weather and scenario year. On a Windows Azure cloud machine with eight AMD EPYC 7763 cores @2.44GHz each and 128 GB RAM, nodal model runs take about 2:05 hours on average. A full zonal model run, including base case and redispatch, takes about 2.1 hours. For this work, 96 nodal and 118 zonal model runs were evaluated, which add up to a runtime of more than 18 days.

3.2. Clustering algorithm

The SPIDER model is applied to calculate LMPs for all nodes, time steps, and scenarios. Subsequently, nodes are grouped into zones using hierarchical agglomerative clustering based on the LMP time series. The clustering process is initiated by considering each node as an individual zone. Then, following a bottom-up approach, pairs of zones are systematically merged by adhering to Ward's minimum variance criterion (c.f. Ward, 1963). This criterion aims to minimize the sum of squared differences among all LMP time series within the zones during the merging process. This iterative procedure continues until all nodes are grouped into zones, resulting in a hierarchical structure representing the relationships between the LMP time series across the power system. The penultimate iteration holds particular significance in this study, as it represents the definition of two German bidding zones.

In the context of this paper, agglomerative clustering has some advantages. Foremost, existing connections between nodes can easily be considered within the clustering procedure as a prerequisite for merging two zones. This ensures that every node is electrically connected to any of the other nodes within a bidding zone. Second, the cluster method is deterministic, i.e., unlike the commonly used heuristic k-means algorithm, the result does not depend on the starting point. Thirdly, the results of agglomerative clustering based on Ward's criterion tend to form clusters of similar size, which is beneficial for defining sufficiently large markets. Hierarchical agglomerative clustering of LMPs is applied and described in more detail, e.g., by Burstedde (2012) and Wawrzyniak et al. (2013).

3.3. Assumptions and data

Scope and Transmission Grid

The regional focus of the model is central Europe with a spatial resolution at transmission grid node level, i.e., 220 kV to 380 kV voltage levels. The transmission grid model includes 13 European countries that are part of the "Core Flow-Based Market Coupling project" and is based on the published grid information of the Joint Allocation Office (JAO, 2022). Grid extensions follow the German grid development plan (c.f. 50Hertz et al., 2023), and ENTSO-E's Ten-Year Network Development Plan (c.f. ENTSO-E and ENTSOG, 2022). To reduce complexity, a grid reduction algorithm proposed by Biener and Garcia Rosas (2020) is applied to reduce the initial grid from 1063 nodes to 533 nodes and 859 lines in 2021. Important neighboring countries outside the core FBMC region, i.e., Italy, Switzerland, Denmark, Norway, and Sweden, are depicted as singular nodes without intra-country grid restrictions. Interconnectors to these markets are approximated via net transfer capacities (NTC).

The regional scope and the depiction of the reduced transmission grid are visualized in Figure 1.

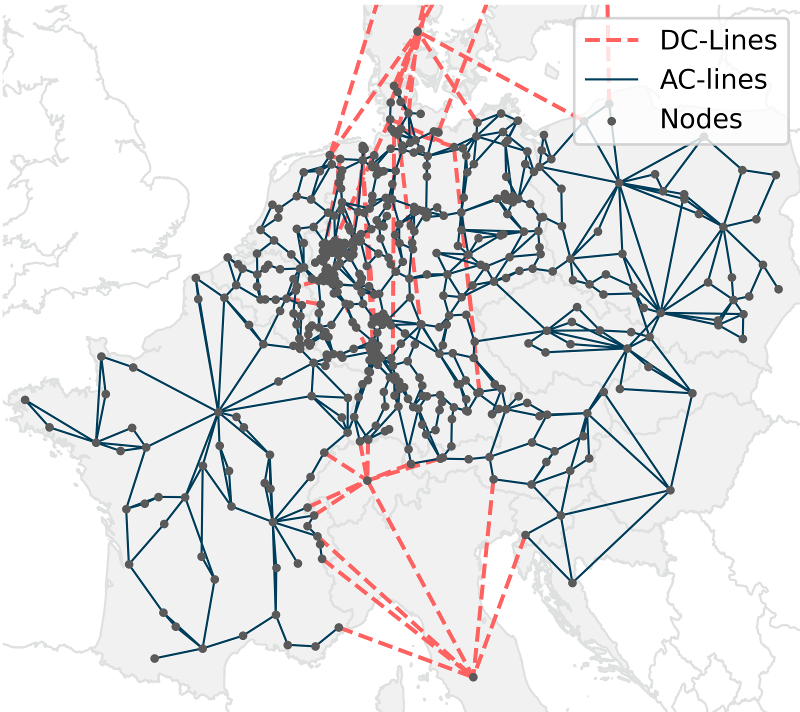

Figure 1: Modeled transmission grid after grid reduction

Input data: Regionalization and Time-series

Existing power plant capacities and their distribution across Europe are based on Bocin et al. (2019) and updated by own research. Data on German conventional power plants is derived from the power plant list of the German grid regulator (BNetzA, 2022a), and data on renewables is the *Marktstammdatenregister* (BNetzA, 2022b). Power plants are allocated to the geographically nearest transmission grid node.

The analysis covers the years 2021, 2025, 2030, and 2035, each in hourly resolution. The country-specific demand time series are taken from ENTSO-E and ENTSOG (2022). The German demand is distributed by sectoral demand shares on the federal state level (c.f. LAK, 2020). For residential demand, the distribution is assumed to follow population shares, while industrial and commercial electricity demand is distributed in proportion to the regional gross value added (c.f. EUROSTAT, 2020). This approach is similar to the one used by 50Hertz et al. (2022). For all other countries, the assumed demand distribution follows the population per local administrative unit (EUROSTAT, 2023).

The hourly onshore wind and solar generation potential dataset comprises 24 climate years (1995 to 2018). These time series are computed based on a reanalysis of meteorological data from the COSMO-REA6 model in a regional resolution of 48x48 km. To match the data to the nearest nodes, Voronoi cells were employed. The generation potential of offshore wind regions (hourly) and hydropower (weekly) is provided by Copernicus Climate Change Service (2020).

3.4. Scenario

For Germany, the assumed capacity development reflects the legal and political situation. The expansion of Wind and solar follows the legal targets of the EEG (2023) and WindSeeG (2023), while the capacities of hydrogen (H2) electrolyzers follow the political targets of BMWK (2023). The phase-out of German nuclear, lignite, and coal power plants is implemented according to the path defined in the Act to Reduce and End Coal-Fired Power Generation (KAG, 2020). In addition, the announced phase-out of lignite-fired power generation by 2030 is considered for the state of North Rhine-Westphalia (BMWK et al., 2022). New onshore wind, solar, and gas capacities are distributed across the federal states, according to 50Hertz et al. (2023). Within the federal states, wind and solar capacities are assigned to nodes based on existing capacities, while the distribution of new gas power plants aligns with the decommissioning of coal-fired and nuclear power plants until 2035. The future distribution of offshore wind farms is given by 50Hertz et al. (2023). To reduce computational costs, new batteries are exclusively positioned at the 30 nodes with the highest demand. Electrolyzers are allocated according to existing German hydrogen projects. The demand development, the capacity development for all other countries, and the expansion of batteries in Germany follow the *Global Ambition* scenario in ENTSO-E and ENTSOG (2022). Table 1 shows Germany's assumed capacity and demand development.

Table 1: Assumptions on installed capacities [GW] and electricity demand development [TWh] in Germany

Technology [GW]	2021	2025	2030	2035
Wind Onshore	54.5	76.0	115.0	157.0
Wind Offshore	7.8	10.9	29.6	35.6
Solar	53.3	108	215.0	309.0
Hard Coal	23.5	14.0	8.4	0.6
Lignite	20.5	14.9	8.9	7.9
Gas	31.9	36.2	47.0	48.0
Nuclear	8.1	-	-	-
Batteries	-	2.8	14.6	22.0
Others	27.5	27.5	27.5	27.5
H2 Electrolyzer	-	0.9	10.0	17.5
Demand [TWh]	532	595	652	686

Additional flexible demand exists from hydrogen electrolyzers, which are assumed to consume electricity when electricity prices are below a certain threshold. The threshold price is assumed to be 70 EUR/MWh.[4] Fuel price assumptions are based on IEA (2022). Appendix B discloses fuel and carbon prices as well as further assumptions on technology parameters and demand development per country.

4. Results and Discussion

4.1. Short-term robustness to weather conditions

Locational Marginal Prices depend on transmission constraints and the distribution of generation and demand. In Germany, electricity demand is concentrated in the densely populated and industrialized regions of Western and Southern Germany, while wind power generation is abundant in the north. If grid bottlenecks occur in high wind power generation situations, LMPs are lower in Northern than Western and Southern Germany. As wind speeds and solar radiation fluctuate, potential bottlenecks can change from hour to hour. A bidding zone split needs to be robust to such variations in weather conditions. Therefore, LMPs are calculated for many weather years (1995 to 2018) in hourly resolution (210,240 load situations per scenario year) and used as input to

[4] This threshold leads to about 3500 full-load hours in 2030, which is in line with the assumptions of the German hydrogen strategy BMWI (2020)

the clustering algorithm. Figure 2 shows the resulting LMPs for the reference year 2021 averaged across all weather years and the bidding zone split obtained from the clustering.

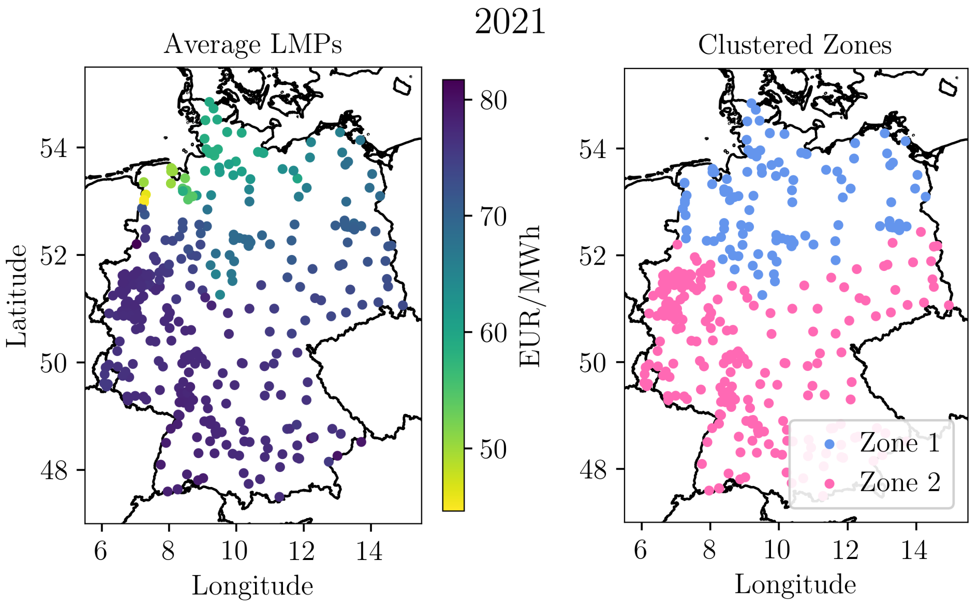

Figure 2: Spatial distribution of LMPs averaged across all weather years (left) and resulting bidding zone split (right) in 2021

In 2021, the annual average LMPs in Northwest Germany are up to 30 EUR/MWh lower than LMPs in Southwest Germany, indicating a structural bottleneck between the North and the South. The LMP clustering results in a bidding zone split approximately along the 53 latitude. Average LMPs in the northern price zone are about 18.5 EUR/MWh lower than in the larger, southern high price zone.

The robustness to weather conditions is evaluated by comparing the resulting redispatch costs for the presented bidding zone split (*all weather year split*) to bidding zone splits, clustered for each individual weather year (*weather year-specific split*), as an upper bound, and to a single bidding zone, i.e., without split (*single BZ*), as a lower bound. Note that the *weather year-specific splits* are rather hypothetical benchmarks since weather conditions are uncertain and unpredictable in the long term. Table 2 depicts the resulting redispatch costs for Germany.

Table 2: Resulting redispatch costs in Mio. EUR per weather year. The relative reduction [%] relates to the *single BZ* case.

weather year	single BZ	all weather year split	[%]	weather year-specific split	[%]
2018	2061.7	877.8	-57.4%	626.2	-69.6%
2017	1854.4	284.8	-84.6%	99.5	-94.6%
2016	1536.4	220.9	-85.6%	58.9	-96.2%
2015	2768.3	811.6	-70.7%	621.6	-77.5%
2014	1886.8	333.0	-82.4%	153.1	-91.9%
2013	1681.5	287.3	-82.9%	105.0	-93.8%
2012	1772.1	278.6	-84.3%	112.4	-93.7%
2011	2351.2	567.9	-75.8%	427.5	-81.8%
2010	1406.0	266.1	-81.1%	88.6	-93.7%
2009	1687.8	431.0	-74.5%	200.9	-88.1%
2008	2096.8	373.6	-82.2%	112.6	-94.6%
2007	2130.9	287.8	-86.5%	99.0	-95.4%
2006	1859.1	549.5	-70.4%	319.9	-82.8%
2005	1851.8	437.0	-76.4%	150.6	-91.9%
2004	1875.6	391.6	-79.1%	188.0	-90.0%
2003	1602.1	332.0	-79.3%	185.3	-88.4%
2002	1786.4	233.8	-86.9%	147.0	-91.8%
2001	1597.2	346.3	-78.3%	208.1	-87.0%
2000	2003.0	267.6	-86.6%	85.9	-95.7%
1999	1643.6	255.7	-84.4%	61.1	-96.3%
1998	2058.1	273.2	-86.7%	100.2	-95.1%
1997	1756.9	351.1	-80.0%	202.8	-88.5%
1996	1450.3	282.2	-80.5%	107.1	-92.6%
1995	1975.9	311.7	-84.2%	206.6	-89.5%
Average	1862.2	377.2	-79.7%	194.5	-89.6%

Without a bidding zone split, the derived redispatch costs for 2021 amount to 1.4 to 2.8 billion EUR depending on the weather year.[5] In the benchmark case of weather year-specific bidding zone configurations, average redispatch costs are about 90% lower than with a single bidding zone, indicating that without weather uncertainty, a yearly two-zone split captures almost all congestion. The *all weather year split* reduces the redispatch costs by about 80% on average. However, redispatch costs are almost twice as high compared to the *weather year-specific split*. For individual

[5]In reality, costs for redispatch, countertrading, and the dispatch of grid reserves amounted to about 1.2 billion EUR in 2021 (BNetzA, 2022c). See section 3.1 for a brief discussion of the underlying drivers of the higher modeled redispatch costs.

weather years, the cost reduction ranges from -57.4% for 2018 to -86.5% for 2007. For 23 out of 24 weather years, the reduction is higher than 70%, and for 14 weather years, it is even higher than 80%. As the redispatch cost reductions are significant for all weather years, it can be concluded that the obtained bidding zone split is robust to weather conditions. However, the deviations in total redispatch costs between weather years are high. Therefore, it seems important to consider different weather years when assessing the impact of a bidding zone split.

This analysis assumes a risk-neutral central planner treating all weather years and events equally in the clustering process. However, a risk-averse central planner might weigh redispatch-intensive weather years higher when determining a bidding zone split. This could potentially reduce the maximum and increase the minimum redispatch costs across all weather years. The result would be a lower weather-related variance in redispatch costs. Moreover, it would be conceivable to adjust the bidding zone within a year to account for structural differences in weather patterns. For instance, applying distinct bidding zone configurations in summer and winter could be beneficial if the structural bottleneck shifts due to different renewable power generation and load patterns. An illustration of such a season-specific split is presented in Appendix C.1; however, assessing the impact on redispatch costs falls beyond the scope of this paper.

4.2. Robustness to system changes

Besides short-term uncertainty, the suitability of a bidding zone split is subject to changes in the electricity system, e.g., new generation capacity, changing electricity demand, and grid extension. Analogous to 2021, LMPs are calculated for 2025, 2030, and 2035 based on the scenario defined in section 3.4. Figure 3 shows the resulting LMP distribution and the clustered bidding zone split per scenario year.

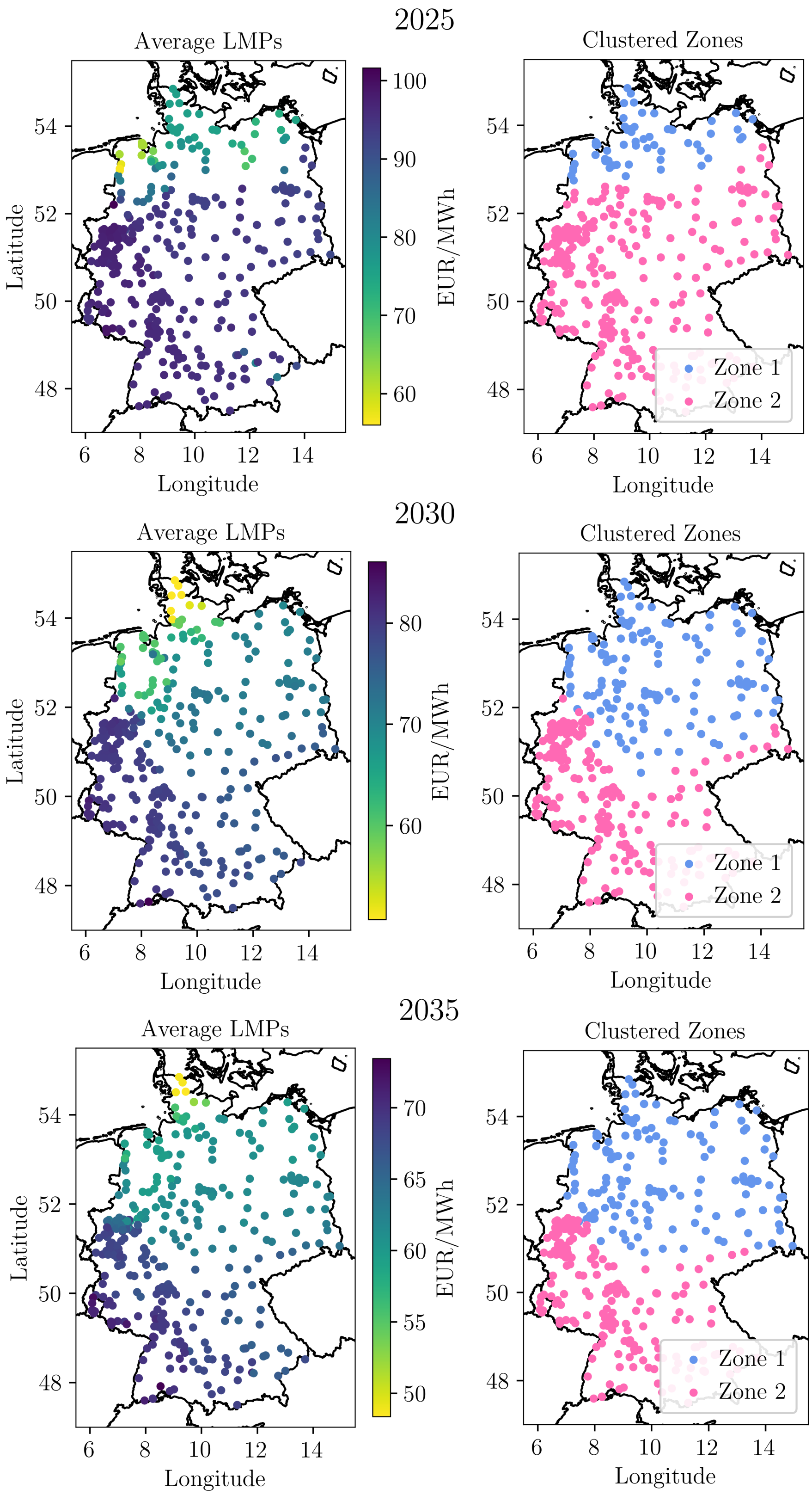

Figure 3: Spatial distribution of LMPs (left) and clustering results (right) for 2025, 2030, and 2035

Several overlapping effects influence the development of the LMP level and distribution. The main drivers of the electricity price level are fuel prices, renewable investments, and electricity demand development. Under the given assumptions, the LMP level increases compared to 2021 due to rising carbon prices and electricity demand. Towards 2030 and 2035, the LMP level declines as large amounts of renewable capacity come into operation. The LMP distribution, in turn, is determined mainly by the distribution of renewable capacity additions and the grid extension (or missing grid extension, i.e., new bottlenecks). Given the assumptions of the reference scenario, new wind power plants in the North, particularly new offshore wind farms, increase the demand for power transmission year by year. Few new AC lines are commissioned by 2025, which hardly changes the resulting bidding zone split. Conversely, substantial grid expansion is planned until 2030, including six new DC projects with a capacity of 2 GW each. As a result, the bottleneck and the boundary between the two clustered bidding zones shift from around the 53rd parallel in 2021 and 2025 southwards towards the 51st parallel in 2030 and 2035.

In practice, frequent adjustments of the bidding zone split would lead to transformation costs and increase complexity and uncertainty for investors and market participants. Determining the future bidding zone configuration well in advance is therefore advantageous. In the following, a *stable* bidding zone configuration until 2035 is examined. To determine such a split, the calculated German-Luxembourg LMPs for all 840,960 time steps (24 weather and four scenario years in hourly resolution) are used as input for the clustering algorithm. The clustering does not incorporate an additional discount factor. Thus, the central planner is assumed to have no time preference.[6] Figure 4 shows the average LMPs across all scenario years and the obtained bidding zone split.

[6]Introducing a discount factor greater than zero would assign a higher weight to the earlier years, potentially changing the clustering result. For example, with a discount rate of 3%, about 4.6% (16 nodes) of the Luxembourg-German nodes are in a different cluster. See Appendix Appendix C.2 for an illustration.

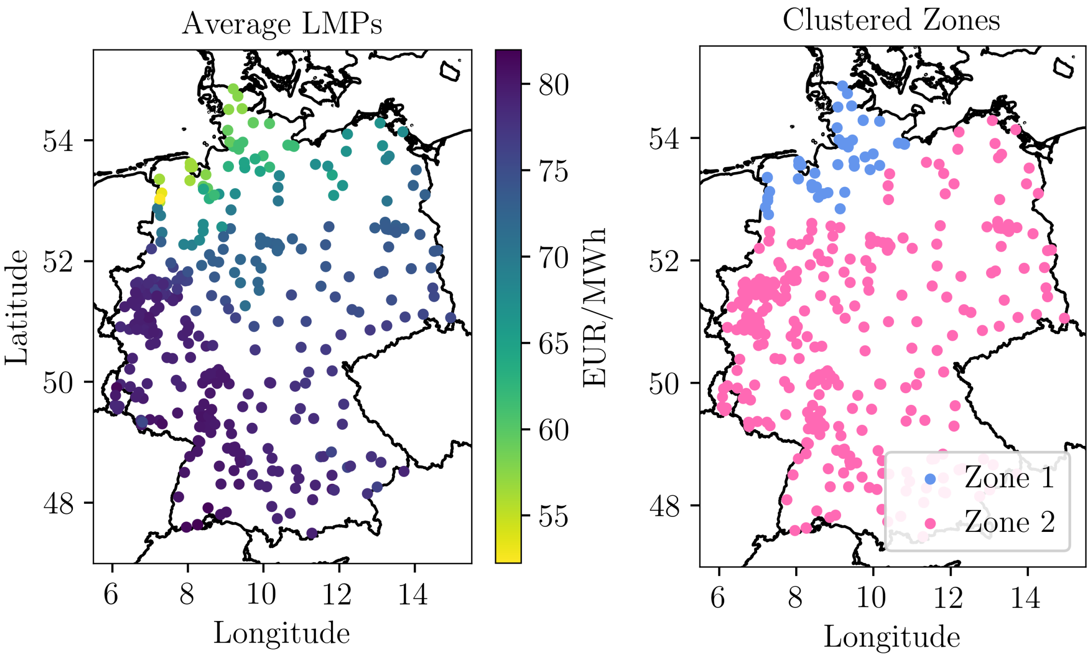

Figure 4: Spatial distribution of average LMPs across all scenario years (left) and resulting bidding zone split (right)

The resulting northern, low-price bidding zone comprises only the Northwest of Germany along the North Sea coast. It is notably smaller in size compared to those derived from scenario year-specific LMPs. This is due to Ward's criterion, which minimizes the in-cluster variance. High wind power generation on- and offshore leads to transmission bottlenecks towards the south and causes low LMPs along the coast in all scenario years. For individual scenario years, other bottlenecks are more prevalent and dominate in the clustering process. Yet, these bottlenecks shift over the scenario years while the bottleneck along the coast remains stable. In addition, the LMPs of the different scenario years are not weighted equally in the clustering. The year 2025 is characterized by the highest LMP levels, resulting in larger Euclidean distances and consequently exerting a stronger influence on the clustering process.[7]

Holding the bidding zone split stable over multiple years decreases the information quality on transmission restrictions in the market. Consequently, the need for redispatch increases in all

[7]This effect could be prevented by normalized time series. However, higher LMPs represent higher system costs, so a higher weighting in the clustering process may make sense. An analysis of different weightings is beyond the scope of this study.

scenario years compared to a yearly split. Table 3 presents the changes in redispatch costs per scenario year compared to the benchmarks of a single bidding zone and the annually changing bidding zone splits presented above. The results are based on 2009 weather conditions as ENTSO-E and ENTSOG (2022) considers these to be the most representative.

Table 3: Resulting redispatch costs in Mio. EUR per scenario year under the weather conditions of 2009. The relative reduction [%] relates to the *single BZ* case.

scenario year	single BZ	stable split	[%]	Year-specific split	[%]
2021	1687.8	548.2	-67.5%	431.0	-74.5%
2025	2595.7	1128.0	-56.5%	315.4	-87.8%
2030	4784.0	1651.0	-65.5%	470.0	-90.2%
2035	7884.8	3773.6	-52.1%	1226.5	-84.4%
Average	4238.1	1775.2	-58.1%	610.7	-85.6%

Without a bidding zone split, the total redispatch costs increase strongly until 2035. This is due to the chosen scenario: a strong increase in renewable generation capacity, growing electricity demand, and comparably slow grid expansion lead to increased redispatch demand, while rising carbon prices increase the costs for (re-)dispatching fossil-fueled power plants. If redispatch costs were equally distributed among all consumers, grid fees to cover the congestion management on the transmission level increase from 0.32 ct/kWh in 2021 to 1.15 ct/kWh in 2035, more than tripling the associated distributional effect.

Splitting the bidding zone once and holding it stable from 2021 to 2035 decreases the yearly redispatch costs by about 58% on average. However, the relative reduction ranges from -56.5% to -67.5% because the *stable split* cannot adequately depict the shifting inner-German bottleneck. In contrast, an annually changing bidding zone configuration (based on LMPs of all weather years) leads to significantly lower redispatch costs. Particularly noteworthy is the decrease in redispatch costs from 2021 to 2025. While redispatch costs in case of a *stable split* are just 27.2% (+127 Mio EUR) higher than with the *year-specific split* in 2021, this ratio increases to factor 3.1 (+2547 Mio EUR) by 2030. Overall, the results show how changing system properties complicate the delimitation of an efficient bidding zone configuration. These findings align with the research by Breuer et al. (2013), who found, for a different scenario setting, that the benefits of a bidding zone split halves if it is held stable over three years instead of an annual reconfiguration.[8] However, dividing the existing bidding zone into two stable market areas is nevertheless beneficial in terms of reducing the distributional effects of redispatch for the assumed reference scenario in each scenario year.

4.3. Sensitivity analysis

The future is uncertain, and the identified bidding zone split might be less efficient or even detrimental if the scenario changes. In the following, a sensitivity analysis is performed to investigate and identify critical parameters that drive the effectiveness of a bidding zone split. To reduce complexity, the sensitivity analysis is done only for the representative weather conditions of 2009 (c.f. ENTSO-E and ENTSOG, 2022). In the following, the *stable* split determined in the previous chapter for the period 2021 to 2035 is considered as the reference case.

4.3.1. System development

The observed grid bottlenecks are largely driven by the assumed substantial development of the electricity system: the renewable generation capacities, particularly wind power, the growth in electricity demand, and the expansion of the transmission capacity.

Delayed wind power expansion: The German expansion targets for renewable energies have been regularly missed in recent years. Therefore, it appears uncertain whether the 2030 targets will be achieved. Within a sensitivity, the effects of splitting the German bidding zone are examined for a scenario with only half the speed of wind power expansion.

Delayed wind power expansion and stable demand: Recent studies on the transition of the German and European energy systems towards climate neutrality show the need for electrification and, hence, growth in electricity demand, as assumed in the reference case. However, the current progress in electrifying the industry, mobility, and heating sectors lags behind those scenarios. Moreover, comparably high electricity prices and limited availability of renewable electricity set incentives

[8] Similar to a season-specific split discussed in section 4.1, the bidding zone split could theoretically be regularly reconfigured without significantly increasing uncertainty. This would require the reconfigurations to be determined well in advance and made transparent, e.g., by publication when implementing the initial split. Potentially, this could lead to the redispatch cost reductions of *year-specific splits*. However, the complexity and transformation costs would be higher than in the case of an *stable split*. Quantifying and weighing both is beyond the scope of this paper.

for industries to move production overseas. A case with delayed wind power expansion and stable demand is analyzed as a second sensitivity.

Delayed grid expansion: To relieve grid congestion and counteract the increasing redispatch costs, TSOs invest in new transmission capacities. However, several of Germany's grid expansion projects are currently delayed (c.f. 50Hertz et al., 2019, 2021, 2023). Further delays in grid expansion would amplify congestion and redispatch costs. To analyze the impact of further setbacks, this sensitivity considers a scenario where projects in Germany set to be operational before 2030 face a one-year delay, while those with later commissioning dates encounter a delay of two years.

The resulting redispatch costs without a bidding zone split in the reference case and the three sensitivities regarding the system development are depicted in figure 5 and described in the following.

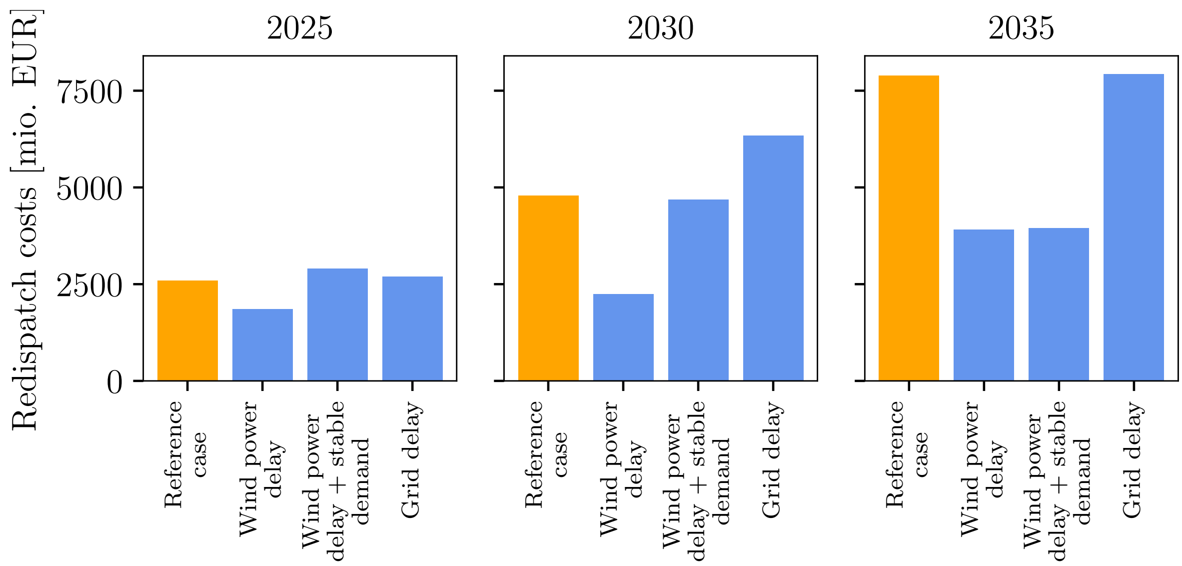

Figure 5: Redispatch costs without a bidding zone split in the system development sensitivities.

Slower wind power expansion reduces grid congestion. As a result, the redispatch costs increase much slower than in the reference case: in 2030 and 2035, these costs are nearly halved compared to the reference case.

If, in addition, the demand remains stable at the level of 2021, the regional surplus generation and, thus, the need for transmission increases. In 2025 and 2030, the level of redispatch costs is similar to the reference case. In 2035, however, the redispatch costs decline due to higher market-driven curtailment: The lower electricity demand leads to more hours of negative residual load, i.e., if wind power generation in Germany exceeds the total demand, renewable power is curtailed already in the market clearing. These market-driven renewable curtailment volumes can be shifted cost-neutral within Germany in redispatch.

Any delay in expanding the transmission capacity increases the need for redispatch and, consequently, redispatch costs. In 2030, redispatch costs are almost 33% higher than in the reference case. By 2035, the difference in redispatch costs diminishes, as all high-capacity DC-lines come into operation, even with the two-year delay.

The absolute redispatch costs and the relative cost reduction in the case of the *stable* bidding zone split is presented in figure 6.

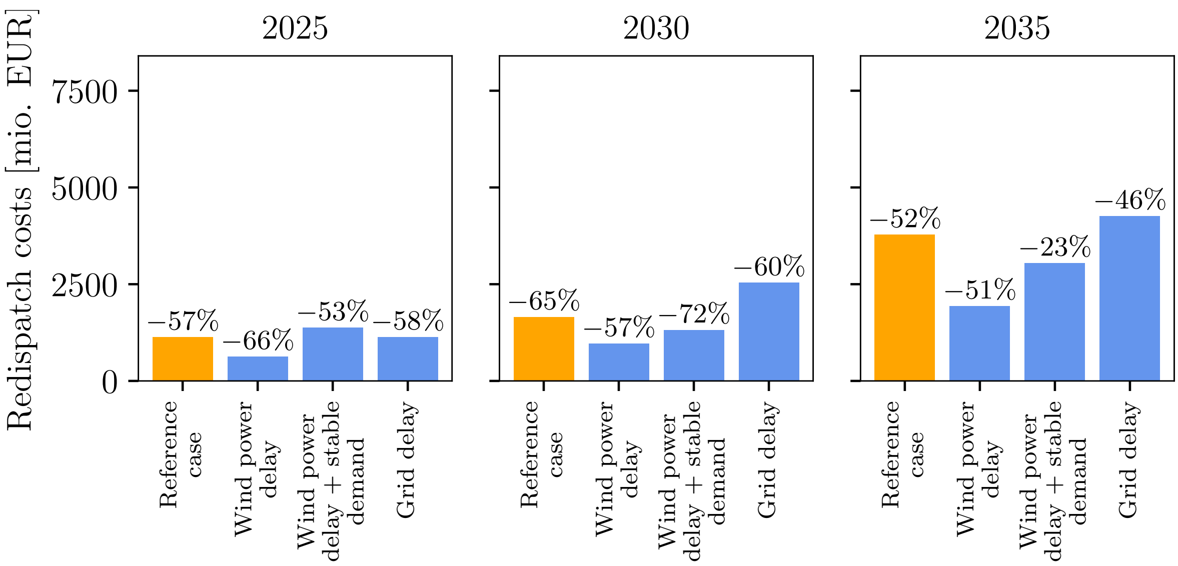

Figure 6: Redispatch costs with a bidding zone split in the system development sensitivities.

The bidding zone split reduces the redispatch costs in all sensitivities substantially, but the effect varies between the sensitivities and scenario years. In case of delayed wind power expansion, the relative reduction amounts to 58% on average, marginally less than in the reference case. The absolute reduction is about 1 billion EUR less on average than in the reference case, indicating that the bottleneck is less severe, but the structure remains similar to the reference case.

If the wind power expansion is delayed and the demand does not increase, the redispatch cost reduction varies much more between years: In 2030, a market split reduces the redispatch costs by about 72%, the highest reduction across all sensitivities and scenario years. This is mainly because cross-zonal trade flows are managed better in the market clearing. Since the power systems of neighboring countries correspond to the reference case, the German electricity system is comparably smaller than in the reference case. The relative importance of cross-country trade increases. In contrast, the cost reduction in 2035 amounts to just 23%, which is the lowest observed across all years and sensitivities. Substantial grid expansion, including new DC lines in the North-South direction, and the higher market-driven wind power curtailment reduce redispatch costs even without a bidding zone split. Instead, high solar power generation leads to local bottlenecks in Southern Germany more often. This is reflected by the additional solar power curtailment of 26 TWh. These local bottlenecks are not captured by the bidding zone split, and hence, redispatch costs are comparably high.

In case of a delayed grid expansion, a bidding zone split reduces the redispatch costs by about 55% on average, with a peak of -60% (3.9 billion EUR) in 2030. Even though the absolute reduction is higher than in the base case, the relative reduction is lower. This is due to a higher absolute level of redispatch costs but a different structure of the grid bottlenecks, which are less well reflected in the studied bidding zone split.

Overall, the sensitivities regarding the system development show that the bidding zone split leads to a robust reduction of redispatch costs as long as the structure of the bottlenecks remains similar. If the system's properties change fundamentally, as in the case of lower wind power expansion and demand in 2035, the effectiveness of a bidding zone split decreases.

4.3.2. Fuel price changes

Assumed fuel prices are based on long-term trends identified by the International Energy Agency (c.f. IEA, 2022, p.110). However, these price trajectories are subject to uncertainty and - as stated by the authors - "do not attempt to track the fluctuations and price cycles that characterize commodity markets in practice." In reality, fuel prices can, and most likely will, deviate from these projections. Fuel prices affect the distribution of electricity generation and, hence, grid bottlenecks if the merit order of power plants changes. The German merit order primarily depends on the gas-coal spread, determined by coal, gas, and carbon prices. Besides the "normal" volatility of global gas market prices, blending low-carbon gases (e.g., hydrogen) could increase the fuel costs of gas-fired power plants. Carbon prices, in turn, depend on regulatory decisions. To achieve its climate goals, the European Union could reduce the number of emission certificates auctioned and increase the carbon price. This would disproportionately increase the electricity generation costs of hard coal and lignite-fired power plants. The effect of doubling gas and carbon prices is calculated in two sensitivities.[9] The resulting redispatch costs for the case of a single German-Luxembourg bidding zone are depicted in figure 7.

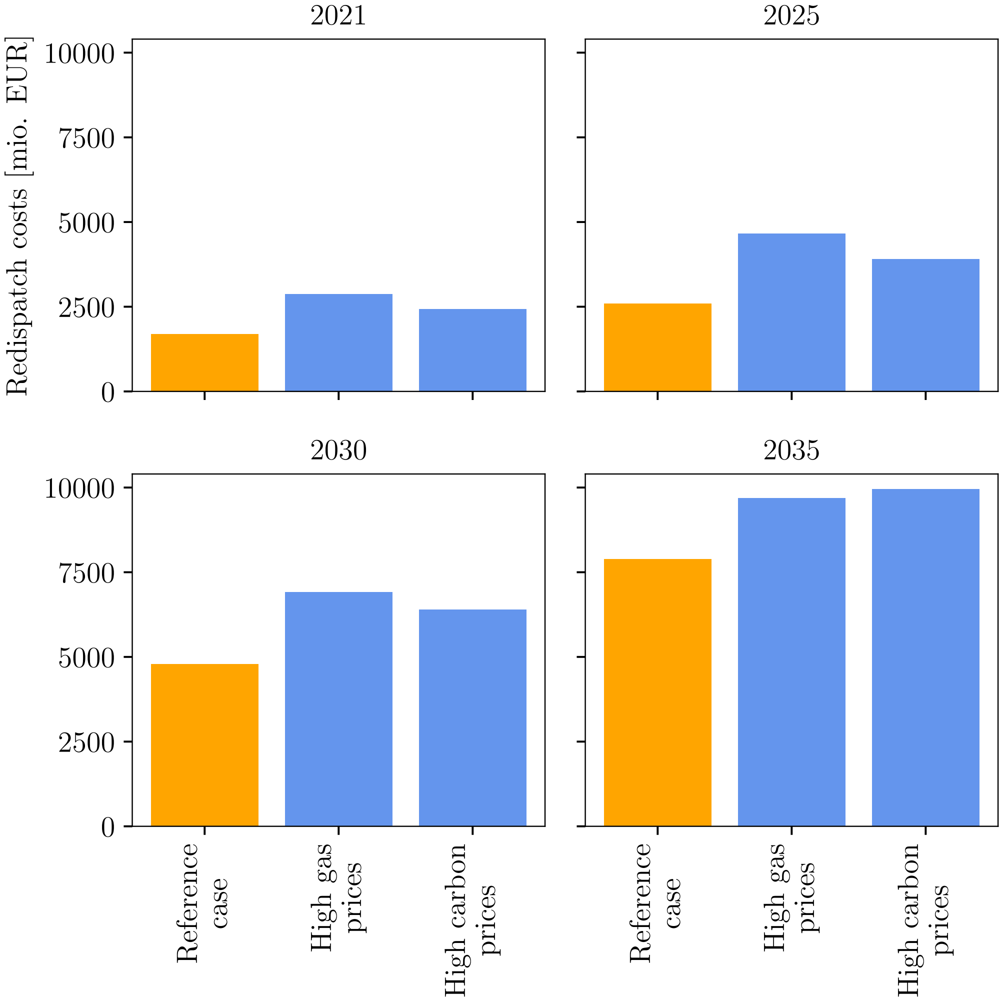

Figure 7: Redispatch costs without a bidding zone split in case of doubled gas and carbon prices.

[9]The fuel price sensitivities focus on changes in the merit order. In fact, rising gas prices might imply higher carbon prices due to increasing emission-intensive coal-fired power generation, and vice versa. Neglecting this potential endogeneity allows for a more isolated examination of changes in the merit order.

Elevated gas and carbon prices increase overall redispatch costs due to higher (re-)dispatchable power generation costs. This, in turn, impacts European trade balances. Higher gas prices lead countries like Italy and the Netherlands, with more gas-fired power generation, to import more electricity. Conversely, countries with significant coal capacities, such as Germany and Poland, export more electricity. This effect diminishes by 2035 as the merit order becomes similar in both sensitivities due to the exogenously assumed coal phase-out.

In contrast, high carbon prices make gas cheaper than coal and lignite for power generation. Consequently, lignite and coal power plants are already priced out in the counterfactual case of 2021, resulting in an overall reduction of German exports, increased flows to the East, and reduced flows to the South. By 2025, however, carbon pricing also renders combined-cycle gas turbines cost-competitive to coal-fired power plants in the reference scenario. Therefore, in later years, higher carbon prices have only minimal additional effects on the merit order of power plants and grid congestion. Elevated redispatch costs, compared to the reference case, stem mostly from increased fuel costs. The effects on the merit order and changed trade flows also determine the impact of the bidding zone split on redispatch costs, depicted in figure 8.

The high imports from Poland and southbound exports, e.g., to Switzerland and Austria, triggered by high gas prices, increase the inner-German grid congestion. However, the bidding zone split studied has a comparably small impact on these trade flows because the countries mentioned all border the Southern zone (see figure 3). This effect decreases over time as the congestion caused by the wind power expansion dominates and coal- and lignite-fired capacities decrease. High gas prices, in turn, increase the German bottleneck due to higher imports to Germany and higher exports to Poland. Splitting the German market reduces imports from the Netherlands and Denmark in particular, resulting in a redispatch cost reduction of 77%. The effect decreases from 2025 as the effect on the merit order disappears.

All in all, fuel prices primarily affect the overall redispatch cost level. To a lesser extent, they influence the effectiveness of a bidding zone split in the short term via the merit order. In the longer term, however, the merit order effect decreases with the decline in coal-fired power plant capacities.

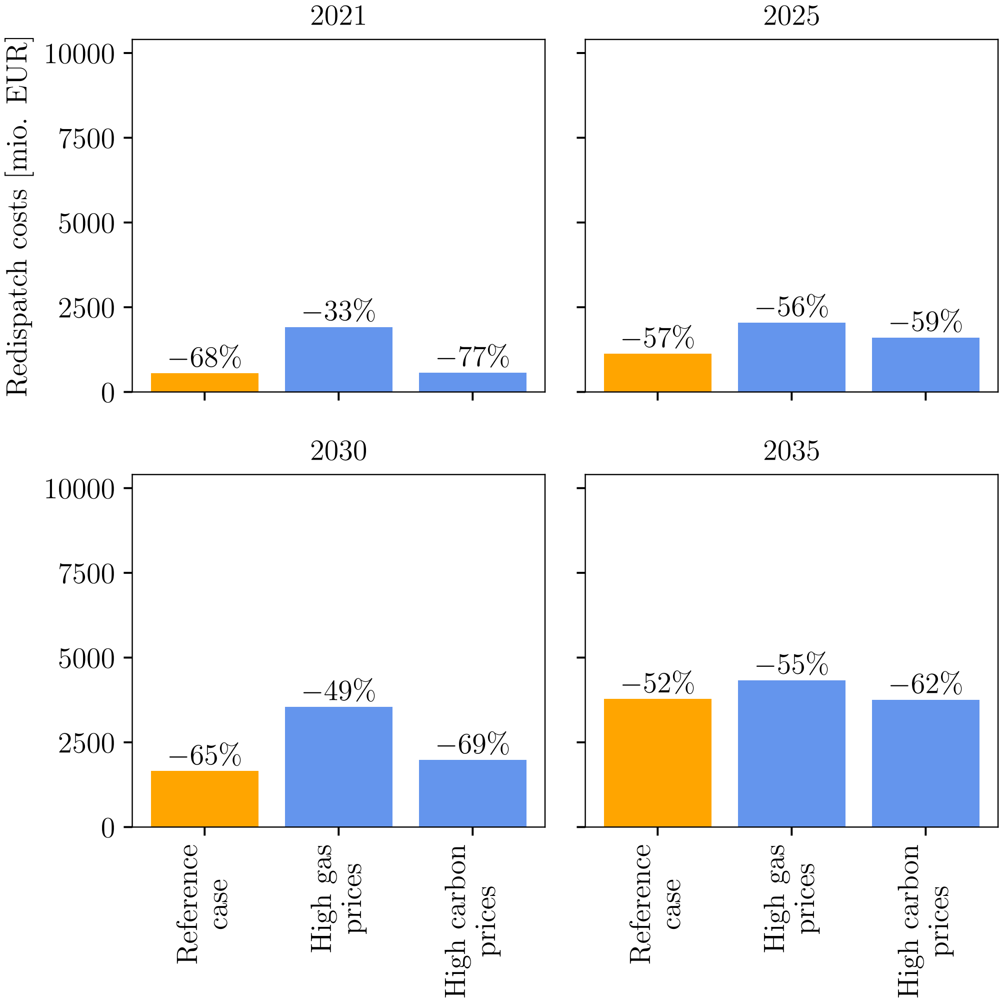

Figure 8: Redispatch costs with a bidding zone split in case of doubled gas and carbon prices.

5. Conclusion

This paper addresses a bidding zone reconfiguration's long- and short-term robustness. Specifically, it analyzes the effects of stochastic weather patterns and, second, structural changes in the power system over time on the redispatch cost reduction due to a two-zone split of the German-Luxembourg market area. For this purpose, Locational Marginal Prices are calculated for 24 weather years and the scenario years 2021, 2025, 2030, and 2035 and used as input for hierarchical clustering based on Ward's criterion to derive a bidding zone split. The robustness of the resulting bidding zone configuration is then analyzed in terms of corresponding redispatch costs. Furthermore, additional sensitivity analyses are performed to investigate the impact of uncertain parameters, such as grid and wind power expansion, as well as fuel prices.

The key findings are threefold: First, the impact of changing weather conditions on the exact bidding zone split is limited if there is a structural bottleneck, such as in Germany. A bidding zone split derived from clustering LMPs of 24 weather years for the reference year 2021 results in a redispatch cost reduction of about 80% on average - 10 percentage points less than the hypothetical benchmark of individual bidding zone splits for each weather year. Second, looking at several scenario years, the structural grid bottleneck shifts southwards over time as the system changes, i.e., transmission, generation capacity, and demand. Annually adjusted bidding zone splits, i.e., obtained from clustering LMPs for each scenario year individually, lead to reductions in redispatch costs of -75 to -90%. If the bidding zone split is stable from 2021 to 2035, the redispatch cost reduction is significantly lower (-52 to -68% per year) for the assumed scenario. Third, deviations in uncertain scenario parameters like the expansion of wind power, transmission capacity, or fuel prices impact the effectiveness of a bidding zone split. If grid expansion projects are delayed, the existing grid bottleneck becomes more structural and severe, increasing the effectiveness of a bidding zone split in reducing redispatch costs. On the other hand, delays in wind power expansion lead to less congestion than in the reference case. Hence, the absolute reduction in redispatch costs is lower. If the congestion is less structural but replaced by local, solar power-driven negative residual loads and associated congestion, the two-zone split studied is less effective. Increases in gas and carbon prices primarily drive up the absolute redispatch costs. To a lesser extent, they impact the bidding zone split's effectiveness due to the altered distribution of fossil power generation within Germany and among neighboring countries. Notably, the impact of fuel prices decreases over time, especially by 2035, as coal and lignite capacities decline.

The results suggest that dividing the German-Luxembourg market area into two stable bidding zones would yield a robust reduction in redispatch costs, mitigating distributional effects. Nonetheless, the sensitivities show that the advantage of a bidding zone split diminishes when the underlying system characteristics change.Considering this dependence on uncertain parameters, the development of novel methods to robustly determine suitable zones is both a relevant and fruitful direction for further research. For instance, the shifting boundaries of the clustered zones over the years could indicate that a third zone may be beneficial. If the northern boundary of this third zone aligns with the existing structural bottleneck, and the southern boundary corresponds to the identified future structural bottleneck, a three-zone setup could significantly enhance the robustness to system developments. Another approach to increase the bidding zone split's effectiveness could involve periodic transitions between configurations, such as switching between summer and winter or day and night. This dynamic adaptation could better reflect the seasonal or daily patterns of renewable power generation and corresponding grid bottlenecks. Furthermore, it may be worthwhile to investigate methods to reduce the weather-induced volatility of redispatch costs. One potential approach could involve assigning higher weights to weather events or years that trigger exceptionally high redispatch costs during the clustering process. Last but not least, this paper uses the German-Luxembourg market area as a case study. In Europe, however, bidding zone splits are discussed for multiple market areas marked by structural bottlenecks, e.g., Great Britain, the Netherlands, or France. The key findings of this study should hold in general for all these market areas, too. However, it should be analyzed in more detail how splitting one bidding zone affects the benefits of splitting another (neighboring) zone.

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Appendix A. Notation

Throughout the paper at hand, the notation presented in table A.4 is used. To distinguish (exogenous) parameters and optimization variables, the latter are written in capital letters.

Table A.4: Sets, parameters and variables

Sets		
$i \in I$, $j \in J$		Electricity generation and consumption technologies
$z \in Z$		Zones
$n \in N$		Nodes
$l \in L$		Transmission Grid Lines
$t \in T$		Timesteps
Parameters		
$f^{max}(l)$	[MW]	Line capacity
$ram(t,l)$	[MW]	Remaining Available Maring (RAM)
$f^{ref}(t,l)$	[MW]	Reference flow in base case
$frm(l)$	[MW]	Flow Reliability Margin (FRM)
$fav(l)$	[MW]	Final Adjustment Value (FAV)
$nPTDF(t,z,l)$	[-]	nodal Power Transfer Distribution Factor
$zPTDF(t,z,l)$	[-]	zonal Power Transfer Distribution Factor
$gsk(t,n,z)$	[-]	Distribution of zonal generation among nodes
$\gamma(t,i)$	[EUR/MWh]	Variable generation cost
$\kappa(m,l)$	[-]	Incidence matrix
Variables		
$GEN(t,z,i)$ / $CONS(t,z,j)$	[MWh]	Electricity generation / consumption
$SALDO(t,z)$	[MWh]	Net position of zone z
$FLOW(t,l)$	[MWh]	Power flow along line l
$VC(y)$	[EUR]	Variable costs

Appendix B. Assumptions on technologies, fuel prices and demand

Table B.5: Considered technologies and their generation efficiency, assumptions based on scenario *Stated Policies* in World Energy Outlook 2021 (IEA, 2022) and Knaut et al. (2016)

Technologies	Efficiency
Nuclear	0.33
Lignite	0.4
Coal	0.45
Combined Cycle Gas Turbines (CCGT)	0.5
Open Cycle Gas Turbines (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 B.6: Assumptions on fuel and carbon prices [EUR/MWh_{th}], based on scenario *Stated Policies* in World Energy Outlook 2022 (IEA, 2022)

Fuel	2021	2025	2030	2035
Uranium	5.5	5.5	5.5	5.5
Lignite	4.5	4.5	5.0	5.0
Coal	15.3	11.5	7.7	7.8
Natural Gas	28.8	27.3	25.8	26.3
Oil	37.7	41.2	44.8	46.5
Biomass	20.0	21.0	22.0	23.0
Carbon [EUR/tCO2]	54.0	90.0	100.0	110.0

Table B.7: Development of demand [TWh], for Germany based on scenario *Global Ambition* in ENTSO-E and ENTSOG (2022)

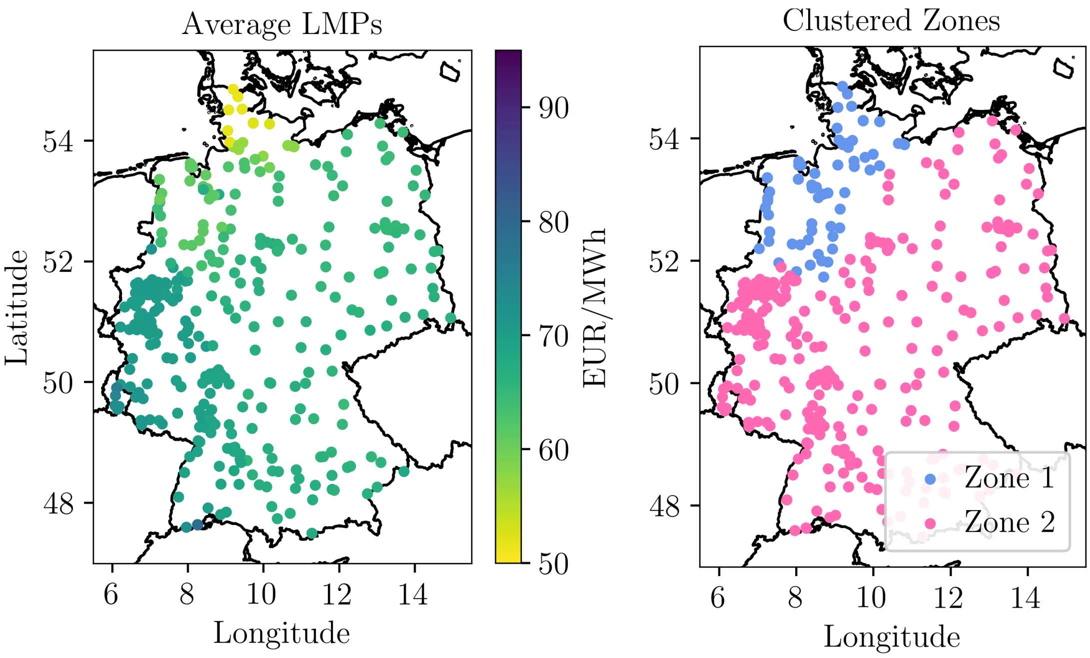
Country	2021	2025	2030	2035
AT	70	78	85	91
BE	88	95	103	108
CH	62	62	62	65
CZ	66	65	65	68
DE	531	592	652	686
DK	35	42	49	52
FR	482	502	523	547
HU	47	46	45	47
HR	19	18	17	17
IT	320	319	317	335
LU	7	7	8	9
NL	119	145	171	182
NO	122	122	122	122
PL	167	169	171	178
SE	142	143	144	148
SI	14	15	15	16
SK	28	30	32	33

Appendix C. Additional results

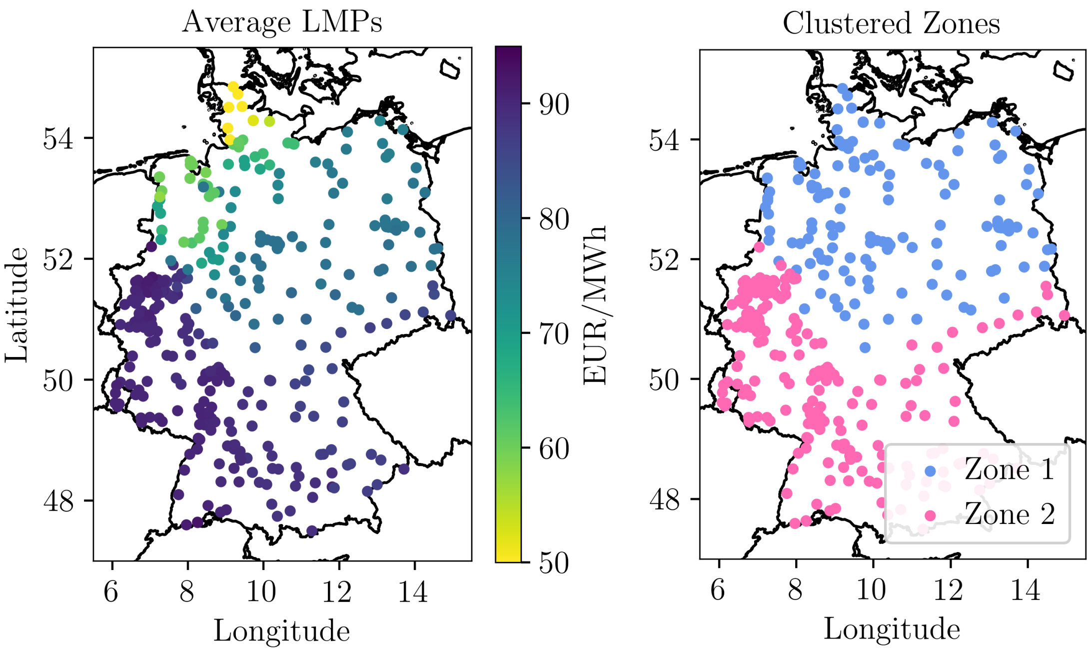
Appendix C.1. Season-specific bidding zone configuration

Changing the bidding zone configuration depending on the time of year could further reduce redispatch costs without increasing uncertainty. This would be particularly beneficial if the structural congestion shifts significantly throughout the year due to different seasonal renewable generation and load patterns. Figure C.9 shows an example of a season-specific split resulting from the separate clustering of the summer and winter season LMP time series for the scenario year 2030.

During the summer season, average LMPs are lower due to higher solar generation and lower electricity demand. In addition, wind generation is lower, especially at greater distances from the North Sea coast. As a result, the low-price summer bidding zone is a smaller area close to the North Sea. In contrast, the winter configuration is the same as that identified for the entire year (see figure 3 in section 4.2). This is because the regional differences in LMPs are higher in the winter months.



(a) Summer (April-September)



(b) Winter (October-March)

Figure C.9: Season-specific split for the scenario year 2030

Appendix C.2. *Discounting in the clustering of a stable split*

In this paper, a discount rate of 0% is assumed for clustering the stable bidding zone split across multiple scenario years, as it simplifies the comparison of the split's impact between scenario years. Considering a discount rate weighs the present higher than the future and thus, the resulting bidding zone configuration changes. For example, a discount rate of 3% would result in a 4.6% (16 nodes) larger northern bidding zone, equivalent to the year-specific one of the year 2025 (see figure C.10).

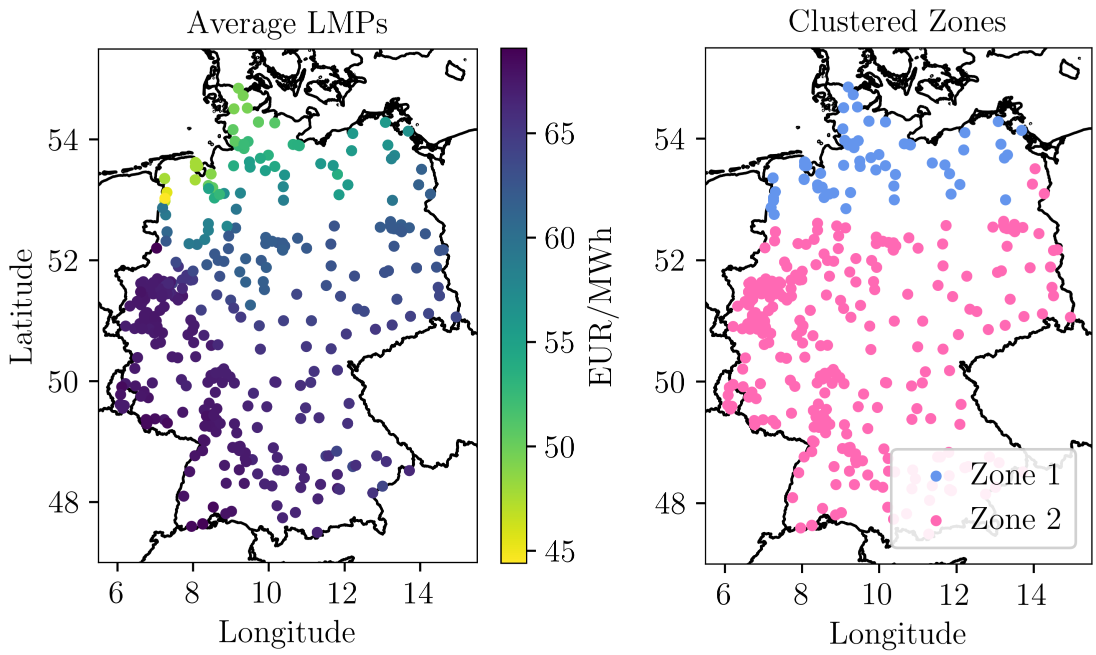


Figure C.10: Spatial distribution of average LMPs across all scenario years (left) and resulting bidding zone split (right) when applying a discount rate of 3% in the clustering