KURZGUTACHTEN

Regional wholesale prices

What problems does the uniform price zone entail, and how do nodal or zonal prices solve them

This is a machine-translated version of a study originally published in German. The original is available at neon.energy/regionale-großhandelspreise

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Neon Neue Energieökonomik is an energy consulting firm based in Berlin. As a boutique firm, we have specialized in sophisticated quantitative and economic-theoretical analyses of the electricity market since 2014. Through consulting projects, studies, and training courses, we support decision-makers in addressing the current challenges and future issues of the energy transition. Our clients include governments, regulatory authorities, grid operators, energy suppliers, and electricity traders from Germany and Europe.

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Summary

Background. Germany is a uniform price zone in wholesale electricity trading: the same wholesale price applies everywhere. This creates the "copper plate illusion": power plants, storage facilities, and consumers act as if unlimited grid capacity were available everywhere. In reality, lines are often at full capacity, but the electricity market remains blind to these grid bottlenecks.

Problems. This results in three key problems. First, dispatch decisions are often inefficient and must subsequently be corrected by redispatch, which drives up grid fees. With more electric cars, heat pumps, and large batteries, the problem is exacerbated because these flexibilities can hardly be integrated into redispatch. Second, the uniform price zone distorts cross-border trade: exports and imports are determined on the basis of the Germany-wide wholesale price and often exacerbate domestic bottlenecks. Thirdly, as short-term flexibility increases, so does the risk of grid bottlenecks that are difficult to control: flexible systems (e.g., batteries) react so quickly to intraday price signals that emerging bottlenecks cannot always be alleviated in time by redispatch. To prevent this, there is a threat of regulatory intervention in the operation of flexible systems – this is already evident today in the case of large batteries.

Solutions. Differentiating the wholesale market into regional or local prices offers a systematic solution. If Germany were divided into several price zones ("zonal pricing") or if local electricity prices were introduced ("nodal pricing"), bottlenecks in the transmission grid would be reflected in the price: electricity would be cheaper in regions with a surplus and more expensive in regions with a shortage. These price differences would vary every quarter of an hour and reflect the current supply and demand situation. Market participants would thus already factor grid bottlenecks into their dispatch and investment decisions. Misguided incentives for storage facilities, flexible consumers, producers, and foreign trade would be reduced. Since such a reform would also extend to the intraday market, short-term flexibility would automatically be activated where it does not cause bottlenecks.

Distribution effects. Regional prices would have distribution effects for consumers and producers. On an annual average, wholesale prices in the north would tend to fall and in the south to rise. However, the increase is likely to be small; most studies expect 0.5 ct/kWh or less. At the same time, grid fees would fall across Germany because redispatch costs would decline and intra-German congestion rents would arise. Overall, electricity costs would fall for most consumers. Particularly price-sensitive consumers (e.g., export-oriented heavy industry) could be specifically compensated from the congestion rents. EEG-subsidized producers would be protected against revenue losses if the market premium and CfDs were designed appropriately. Overall, the advantages of regional electricity prices outweigh the disadvantages; the remaining challenges can be solved. Introduction is therefore recommended.

1 Introduction

Status quo. The wholesale market price for electricity is the same throughout Germany. Consumers in northern Germany pay the same price for electricity on the wholesale market as those in southern Germany, even though there are significantly more wind turbines in northern Germany. This is also the case when wind power from northern Germany cannot be transported to the south due to bottlenecks in the transmission grid. This is because the wholesale market for electricity is organized in a single price zone for Germany and Luxembourg. This single price zone allows unlimited trading between players within Germany at the same price. Grid bottlenecks are not taken into account. This creates the "illusion of a copper plate," as if electricity could be transmitted to any location at any time in unlimited quantities.

Redispatch. However, the use of electricity generators and consumers resulting from the wholesale market is often not feasible with existing grid capacities. In this case, the grid operators correct the use of plants from the wholesale market through congestion management ("redispatch"): they shut down generation plants "before" the grid congestion and ramp them up "behind" it. The scope and costs of congestion management have risen sharply in recent years (Figure1). In the transmission grid, congestion management has accounted for around 60% of total costs in recent years. Congestion management is therefore currently the main driver of the sharp rise in grid fees, which are placing a burden on households and businesses. Due to the uneven regional distribution of renewable energy expansion and the increasing flexibility of consumers in the context of the energy transition, electricity flows in the German transmission grid are expected to continue to rise. In addition, grid bottlenecks are becoming increasingly short-term due to the increasing forecast errors in wind and solar generation associated with installed capacity and the associated growing importance of the intraday market. This tends to lead to greater challenges in the operation of electricity grids.

Volume and costs of congestion management in Germany

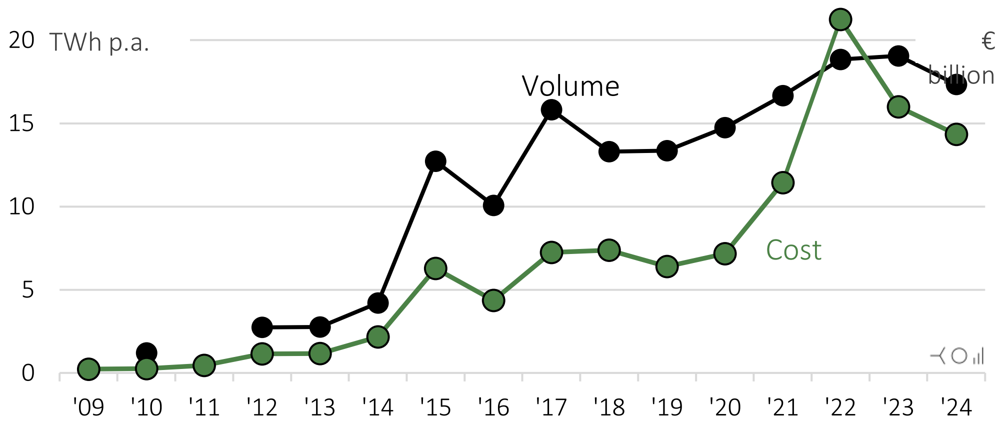

Figure1 : The volume and costs of congestion management have increased fivefold over the last ten years.

This study. This brief report has three objectives. First, we discuss the problems caused by uniform wholesale prices in the transmission grid. Second, we show how regional wholesale prices avoid these problems. They reflect bottlenecks in the transmission grid and therefore vary within Germany. Third, we discuss the implications of introducing regional wholesale prices for consumers, producers, and the futures market, and what accompanying measures would be necessary and sensible.

2 The problems of the uniform price zone

In this section, we discuss three problems for the operation of the German transmission grid that result from the uniform price zone:

- Dispatch on the day-ahead market ignores grid bottlenecks
- Cross-border electricity trading primarily takes into account grid bottlenecks between bidding zones and often exacerbates bottlenecks within the country
- Short-term trading decisions by flexible plants jeopardize the stability of grid operation

2.1 Day-ahead dispatch ignores grid bottlenecks

Problem. Generators, consumers, and storage facilities initially make their decisions based on prices on the day-ahead market. Since the electricity price is uniform throughout Germany, they cannot take grid bottlenecks into account. Due to the market design, players on the electricity market are blind to the grid. In economic terms, the effects on grid bottlenecks are externalities. This leads to economically costly misjudgments by storage facilities, producers, and flexible consumers.

Exemplary grid situation. We illustrate exemplary wrong decisions using a situation with strong winds in the North Sea region. Strong winds have two consequences: on the one hand, low electricity exchange prices and, on the other hand, north-south bottlenecks in the transmission grid (Figure2). This leads to a series of individually rational but economically wrong decisions, as the following examples illustrate.

North-south bottleneck in the German transmission grid

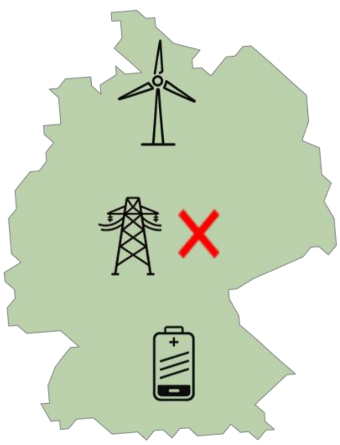

Figure2 : Illustrative example of a north-south bottleneck in Germany. This can occur, among other things, when there is high wind generation on the German coast.

Storage. Due to low wholesale prices, a pumped storage power plant in the Black Forest begins pumping water uphill. The additional demand on the electricity market means that fewer wind farms are curtailing their output. However, due to north-south bottlenecks in the transmission grid, this additional wind power from northern Germany cannot be transported to the south. Therefore, the grid operators have to curtail the wind farms after all and ramp up a redispatch power plant in southern Germany. So the pumped storage plant "thinks" it is storing cheap, clean wind power, but physically, more expensive electricity from fossil fuel power plants that have been started up specifically for this purpose is being used – the copper plate is just an illusion.

Renewables. It is not only in the use of storage that wrong decisions are made in such a windy situation. Price-driven curtailment of renewables can also be counterproductive. When the electricity price falls below zero, solar parks outside the EEG remuneration system are curtailed. If such a solar park is located in Franconia, for example, there is a shortage of electricity there. This is because, contrary to what the uniform electricity price suggests, the electricity surplus is limited to northern Germany. The curtailed solar park in Franconia must therefore be replaced by fossil fuel redispatch power plants.

Flexible consumers. In this situation, a fleet of flexibly charging electric cars in Munich would also respond to the electricity price signal and draw electricity from the grid. The market also signals to these electric cars that surplus wind power can be used. In reality, however, the wind power does not flow to Munich; instead, a gas-fired power plant in Bavaria has to be started up. The more flexible consumers respond to the price signals of a uniform price zone, the more serious the consequences of these misguided incentives become.

Consequence. In the coming years, millions of electric cars and heat pumps will be connected to the grid, more and more of which will be optimized by aggregators. At the same time, the ramp-up of large-scale batteries is gaining momentum (Figure3). However, these three examples show that flexible electricity consumption, the expansion of electricity storage facilities, and the market-based curtailment of renewable energies on a large scale are not compatible with the uniform bidding zone. It is difficult to imagine secure transmission grid operation in which several hundred gigawatts of smart-charging electric cars or even just 50 GW of large batteries are guided by the uniform German electricity price without regard to grid bottlenecks. The integration of flexible consumers and storage facilities into the redispatch mechanism is hardly possible in the current cost-based redispatch system: unlike with generators, it is not objectively possible to determine appropriate compensation for additional or reduced electricity consumption.

Installed flexible capacity for generation and consumption

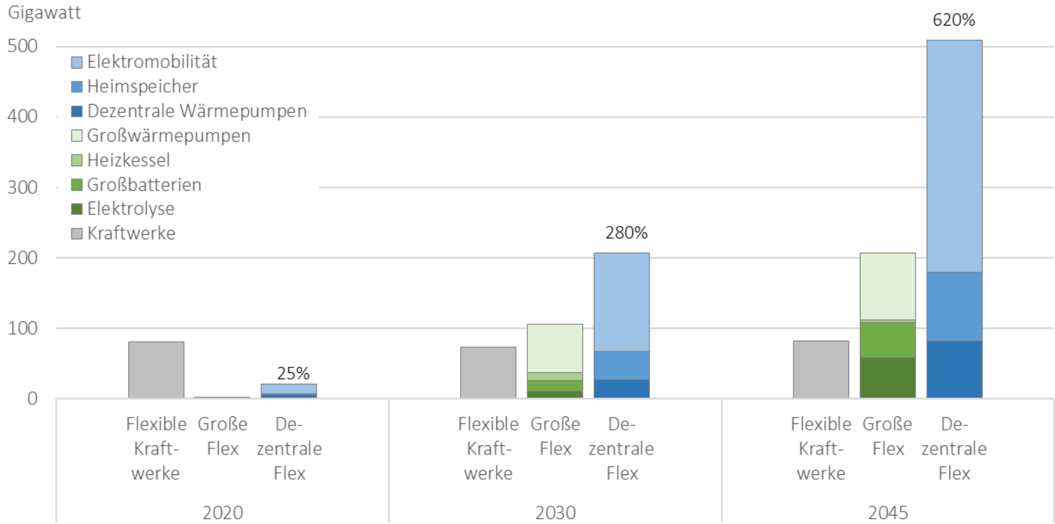

Figure3 : The installed capacity of flexible consumers and storage facilities will exceed the capacity of flexible power plants many times over in just a few years. Only regional price incentives could prevent this from creating new problems in the power grid and in power generation. Own representation based on the 2037/2045 electricity grid development plan and the BMWK long-term scenario "T45-Strom." The electric mobility connection capacity was calculated as 11 kW for 75% of the expected electric cars; the capacity of large batteries and residential battery systems follows the assumptions of the grid development plan.

2.2 Distorted foreign trade

Problem. One problem that is often neglected in the German debate is the "false" trade flows between Germany and its neighboring countries that are favored by the uniform bidding zone. Under normal conditions, imports and exports of electricity are currently possible in Germany up to around 12 GW each. The "leverage" of market coupling on Germany is therefore 24 GW, which is very significant compared to the average load of 60 GW. The extent to which and the direction in which cross-border lines are utilized is determined within the framework of implicit market coupling. Only some of the grid bottlenecks within Germany are taken into account when determining foreign trade flows in flow-based market coupling (FBMC). In addition, the 70% rule under European law obliges transmission system operators to make at least 70% of the transmission capacity of each critical grid element available for cross-border trade – even if these lines are already almost fully utilized by domestic German electricity flows. The correction of "incorrect" foreign trade flows is currently not taking place in practice, as cross-border redispatch does not actually occur in reality.

Take Austria, for example. This problem can also be illustrated by a windy hour with low prices and north-south bottlenecks. The negative electricity exchange price in Germany means that electricity is exported from Germany to its southern neighbors with less wind power, e.g., to Austria. However, since the electricity cannot physically be transmitted from to the south, the

German transmission system operators must in turn request redispatch to resolve the bottlenecks within Germany caused by these trade flows. If there are not enough power plants available, grid reserve power plants that are kept in reserve specifically for this purpose are brought online. Because there are not enough of these in Germany either, grid reserves are regularly contracted in Austria. This then results in the absurd situation that German transmission system operators pay grid reserve power plants in Austria to physically generate the electricity that Germany has sold to Austria at negative electricity prices. If this happens often enough, transmission system operators have to contract additional reserve power plants and pay for them again. Germany then pays for the provision of reserve power plants in Austria, their activation, and (in the case of negative prices) also for the purchase of electricity in Austria. These costs are passed on to German electricity consumers in the form of grid fees.

2.3 Short-term trading decisions

Problem. Dispatch decisions made the day before (day-ahead schedules) can be resolved through congestion management if sufficient redispatch capacity is available. Although this incurs costs that increase grid fees, it is a proven and robust process. However, very short-term schedule changes a few hours or minutes before delivery cannot be corrected by redispatch. These are communicated to the TSO, but often cannot be included in the redispatch process because it requires several hours of lead time – for example, for load flow calculations to identify congestion points, determining countermeasures, notifying plant operators, and balancing the books. As a result, short-term electricity trading, e.g., in the continuous intraday market, leads to irremediable grid bottlenecks. This jeopardizes the secure operation of the electricity system.

Example: wind forecast. The problem of short-term bottlenecks can be illustrated using the example of wind energy. If it becomes clear shortly before real time that even more wind power than previously expected will be generated in windy conditions, the price of electricity on the intraday market falls shortly before delivery. A large battery responds by purchasing and storing the electricity. In doing so, it helps to compensate for this forecast error – exactly as batteries should behave. However, if this battery is located in southern Germany, it exacerbates the north-south grid bottleneck. Network operators would normally respond with redispatch measures, but this may not be feasible in such a short time, meaning that in the worst case scenario, network overload cannot be prevented. If grid operators anticipate such effects, they must operate the grids with more buffer capacity, i.e., preventively curtailing more than is actually necessary. TSOs are discussing this problem with increasing urgency under the heading of "system stability" (Amprion 2025, Energate Messenger 2025).

Interventions. Addressing this problem with a uniform price zone is difficult and only conceivable with major collateral damage. Network operators recently proposed a whole series of measures to restrict market players' freedom of action in the short term, for example in the form of "feasibility ranges" or "central dispatch elements." In effect, such proposals are aimed at closing electricity trading earlier (while at the same time European reforms are shortening the gate closure for international trading). Apart from obstacles under European law, this would also entail considerable welfare losses: short-term forecasting errors in wind and PV generation could no longer be offset by trading transactions and would thus be absorbed by balancing reserves. This would lead to an increase in balancing power calls and reserves. These proposals highlight the real danger that the successes of the German electricity market will be reversed in order to prevent short-term flexibility, ignoring grid bottlenecks. This can already be observed today with the grid connection of large batteries. The main reason for the reluctance to grant grid connections is concern that the response of storage operations to short-term price signals will lead to grid bottlenecks. In the worst case, the expansion of this future technology will be stifled out of concern for short-term grid congestion. The long-term costs of the uniform bidding zone are therefore even greater than just the visible redispatch costs, but consist primarily of missed opportunities, innovations, and investments.

3 Regional wholesale prices

Approach. The three problems outlined in the previous section arise because the wholesale price is uniform throughout Germany. They can be solved by making the wholesale market more spatially granular, i.e., by introducing regional or local prices (Figure4).

Regional prices. With regional prices or "small price zones," the exchange-based electricity market would function exactly as it does today, except that Germany would consist of three to seven price zones instead of a single one. These would be interconnected within the framework of load flow-based market coupling, which organizes cross-zone electricity trading on forward, day-ahead, intraday, and balancing power markets. From a technical perspective, price zone division is a manageable reform because today's pricing and market coupling mechanisms can all continue to be used. Various European countries have divided their price zones in recent years, including Sweden, Norway, Italy, and Germany with the separation of Austria from the common price zone.

Local prices. With local prices or "nodal pricing," a separate price can be formed at each node in the transmission grid, i.e., for each substation. This would mean that around 300 different prices would be possible in Germany. Nodal markets have been firmly established in most US electricity markets for around 15 years under the term "locational marginal pricing." Local prices also relate to the transmission grid—spatially differentiated electricity prices within distribution grids appear unrealistic in the foreseeable future.

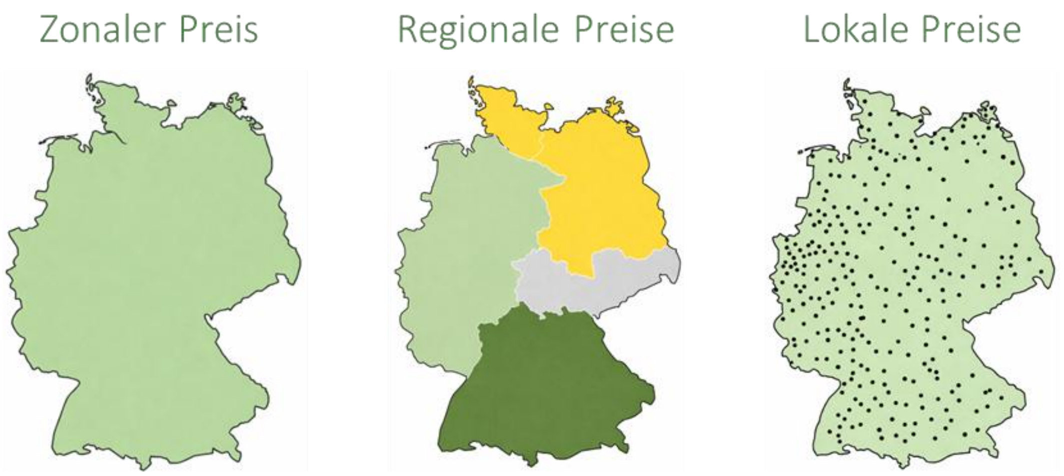

Figure4 : With a zonal price, the electricity price is the same everywhere in Germany, making the market "blind" to grid bottlenecks (left). After dividing the bidding zone, there would be around 2 to 7 price zones with regional prices (middle). With local prices, each substation in the transmission grid would have its own electricity price (right). Illustrative representation.

Grid bottlenecks in day-ahead dispatch. Regional and local wholesale prices reflect grid bottlenecks: the electricity price would be lower before a bottleneck and higher after it. Market participants would therefore already take the grid bottlenecks shown into account in their dispatch decisions. In a strong wind situation, prices in northern Germany would thus be lower than those in southern Germany. Regional prices would avoid the errors of the uniform bidding zone. The pumped storage power plant in the Black Forest would generate electricity instead of consuming it. Instead of the solar park in Franconia, a wind farm in the north would be curtailed. The electric car in Munich would postpone charging until a later time when the grid is free of congestion. Exports to Austria would be reversed to imports.

Short-term trading. Regional price differences would not only occur in the day-ahead market. In intraday trading, imbalance energy, and balancing reserves, different prices per price zone would also result in the event of grid bottlenecks. Therefore, short-term flexibility would also take grid bottlenecks into account. If, for example, more wind power than expected can be generated in the north at short notice, only the intraday price there will collapse, so that instead of the battery in the south, a battery in the north will step in to absorb the additional generation.

Grid expansion requirements. The need for expansion in the transmission grid will decrease with spatially differentiated wholesale prices because flexible consumers, storage facilities, and foreign trade cause fewer internal German grid bottlenecks. Regional wholesale prices may also help with grid-friendly regional control of investments: consumers have an incentive to settle in regions with lower prices and producers in regions with higher prices. However, in most cases, other factors play a greater role in the choice of location, such as the availability of land, skilled labor, or wind or solar potential. Nevertheless, even with spatially differentiated wholesale prices, further expansion of the transmission grid will be necessary, as the spatial distribution of generation and its fluctuating geographical potential over time will continue to increase.

4 Impact on consumers and producers

Effect on wholesale prices. The introduction of regional or local wholesale prices has financial implications for all market participants. In some areas, exchange prices would fall compared to today's prices, while in others they would rise. Price differences would be very high in individual quarter-hours with severe grid congestion, but low or zero in the many hours without significant grid congestion. While prices in northern and eastern Germany would fall during windy periods, they might be lower in southern Germany than in the north during sunny hours.

Distribution effects. On an annual average, electricity prices in northern Germany would tend to fall slightly and in southern Germany rise slightly. Consumers in northern Germany and producers in southern Germany would tend to benefit from this, whereas consumers in the south and producers in the north would tend to lose out. At the same time, the costs of grid operation would fall, benefiting all consumers who pay grid fees.

Magnitude. For regional wholesale prices, modeling studies show a very slight increase in the average wholesale price in southern Germany. The average electricity price in Bavaria would rise by less than €/MWh compared to the uniform bidding zone if the zone were divided (Table1). For private households, this corresponds to an increase in the electricity price of less than 2%. The increase is small compared to the regional differences in grid fees that exist today, some of which exceed €30/MWh. Agora Energiewende estimates that wholesale prices in southern Germany would rise by a maximum of €7/MWh in 2023 if local prices were applied (Agora Energiewende 2024).

Table1 : Wholesale prices in Bavaria would rise in the event of bid zone division. However, according to current models, this increase would be small compared to maintaining the uniform bid zone.

	Number of price zones	Price increase in Bavaria in 2030
Ariadne (2023)	2 3	+ €5/MWh + €3/MWh
Frontier (2024)	2 4	+ €2.9/MWh + €3.3/MWh
EWI / Topic (2023)	2	+ €4/MWh

4.1 Impact on consumers

End customer prices. End customer prices for electricity are made up of procurement costs (wholesale prices), grid fees, taxes, and levies. For households, procurement costs account for roughly 40% of total costs, grid fees for around 30%, and taxes and levies for another 30%. The regionally varying effects on wholesale prices would therefore have only a limited impact on the total bill for private consumers. For industrial consumers, who generally pay little or no grid fees, a change in wholesale prices would have a greater impact on total electricity costs.

Grid fees. The introduction of regionally differentiated wholesale prices would reduce the grid fees paid by consumers. There are two reasons for this:

- lower redispatch costs
- Additional congestion rents

Lower redispatch costs. Because grid congestion between price zones is already taken into account in plant dispatch, redispatch is no longer necessary for these zones. In addition, there would be significant efficiency gains because storage facilities and other flexible assets take grid bottlenecks in the transmission grid into account in their operation, whereas in the current system, their incorrect operation from a grid perspective cannot even be compensated for by redispatching these market participants. This allows for better utilization of the grid, reducing redispatch costs and thus grid fees.

Congestion rents. Congestion rents arise at Germany's external borders: because electricity is transmitted from a low-price zone to a high-price zone via the interconnectors, added value is created. This results from the amount of the price difference and the amount of electricity transmitted. The congestion rents are divided between the respective grid operators. They thus contribute to the financing of grid costs and thereby reduce grid fees. If spatially differentiated wholesale prices were introduced, congestion rents would also arise within Germany. These would then benefit German grid operators exclusively and could be used to reduce grid fees for all consumers. Alternatively, these revenues could also be used to provide targeted relief for sensitive electricity consumers, such as energy-intensive industries competing internationally.

Quantitative estimate. If the German bidding zone were divided into 4 to 5 zones, the intra-German congestion rent would be in the order of around €2 billion per year. Adding to this the falling redispatch costs of €1 billion would result in a reduction in grid fees in the order of €6/MWh for total German electricity consumption. The introduction of local prices would cause grid fees to fall even further.

Distribution effects. While all households benefit from reduced grid fees, the impact on wholesale prices varies from region to region. However, it is expected that the net effect of changed wholesale prices and reduced grid fees will be positive for most households, meaning that only in a few exceptional cases will electricity costs increase . Those consumers who already pay hardly any grid fees today—such as heavy industry, which is largely exempt under Section 19(2) of the Electricity Network Access Ordinance (StromNEV)—will hardly benefit from falling fees and would therefore be worse off than in the status quo without additional compensation.

Equivalent living conditions. In public debate, it is sometimes argued that the price of electricity should be the same throughout Germany, sometimes with reference to Article 72 of the Basic Law. This argument overlooks the fact that end customer prices for consumers have varied greatly from region to region for years and decades because distribution network charges differ. For households in Germany, there are already 900 price zones, so to speak. The regional differences here are sometimes 10 ct/kWh and more, which is an order of magnitude above the expected price effects of regional wholesale prices.

Regional differences in end customer prices for households in 2025

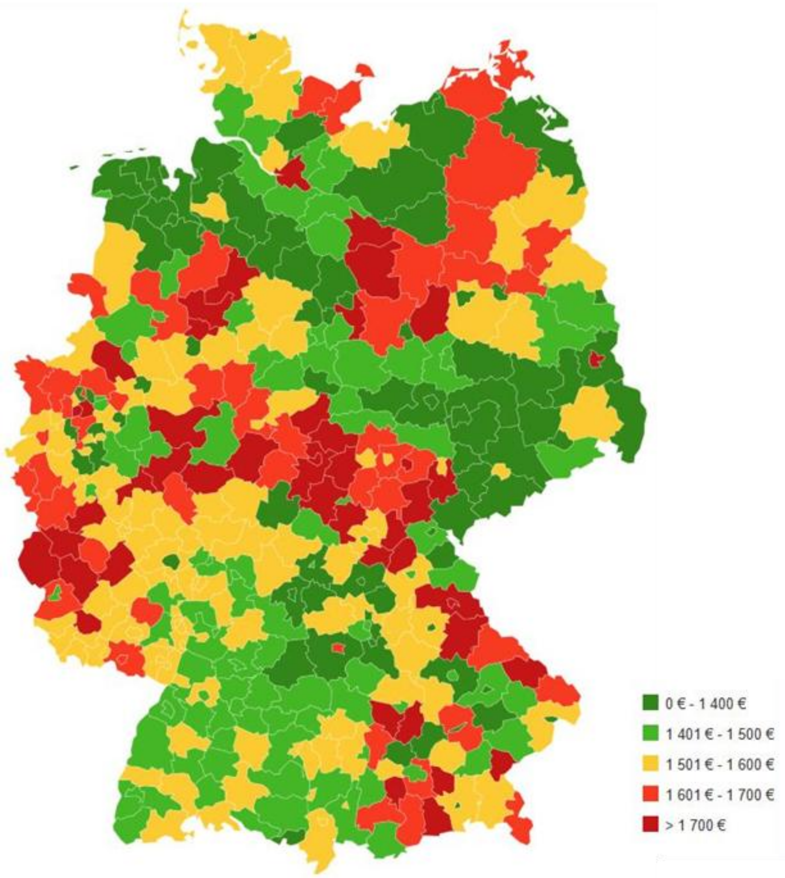

Figure5 : Source: Stromauskunft.de

4.2 Effects on producers

Distribution effects. The division of the uniform bidding zone would also have an impact on producers. Producers in northern Germany in particular face lower market revenues, while producers in southern Germany are likely to benefit from higher market prices. For example, wind turbines in northern Germany would have to fear losses in their electricity marketing revenues: since their generation profile correlates strongly with bottlenecks in the transmission grid, the electricity they generate would be worth less on the wholesale market. In the event of future south-north bottlenecks at midday caused by the expansion of PV capacity in southern Germany, PV plants in southern Germany would also suffer financial losses due to spatially differentiated wholesale prices.

Actors not affected. However, many producers are isolated from these distribution effects. For example, the majority of wind turbines in Germany are directly marketed. With an appropriate market premium structure, these plants would not have to fear financial losses due to regional wholesale prices, as lower revenues on the electricity market would be offset by a higher market premium. The market premium is calculated from the difference between the plant-specific "value to be applied" and the monthly market value of the respective technology. If the monthly market value in each price region were to be calculated in future on the basis of the respective regional wholesale prices, the market premium would completely offset changes in the wholesale price. The same applies to contracts for difference (CfDs), as long as the underlying reference price is the wholesale price applicable to the respective plant. All smaller and older wind turbines would also be isolated from the distribution effects of regional wholesale prices, as they receive a fixed feed-in tariff.

4.3 COMPENSATION FOR LOSERS

Compensation. In addition to the many winners of the introduction of spatially differentiated wholesale prices, there will also be losers from such a reform. In principle, there is financial leeway to compensate them, due to the new intra-German congestion rents and efficiency gains. How this leeway is used is primarily a political question. There is a tension between relieving the burden on consumers, in particular by reducing grid fees, and compensating producers who face lower revenues as a result of the reform. The latter would be particularly important in order to maintain confidence in secure framework conditions for investment.

4.4 IMPACT ON FUTURES TRADING

Status quo. In addition to these distributional effects with winners and losers, the impact on futures trading is cited as a further challenge for producers. It is important for electricity producers to market part of their future production at an early stage, especially if their costs are incurred primarily at the time of plant construction, as is the case with renewable energies. Long-term electricity marketing allows producers to reduce their financial risks, which makes it easier to borrow money. Currently, futures trading for electricity is concentrated in the German bidding zone, mainly because it is much larger than all other bidding zones in Europe. Due to the high liquidity, market players from all over Central Europe conduct the majority of their futures trading in Germany. German market participants in particular benefit from the status quo, as they have a highly liquid long-term market and, unlike foreign players, do not face the risk of price differences compared to the domestic market.

Concern. Dividing up the German bidding zone could break up the concentration of European futures trading in Germany, as there would no longer be a single large price zone in which trading activity is concentrated. However, this is far from certain. For historical reasons, natural gas trading in Europe is concentrated in the small Dutch market, so a large market area is not essential for bundling trading activities. If the futures market were to become more distributed, liquidity in Germany would decline sharply. This would make it more difficult for

German market participants in particular to find counterparties for long-term trading transactions. This would increase the cost of risk management for companies and thus lead to economic costs.

Solution: Virtual trading hubs. Virtual trading hubs are a conceivable approach to facilitating liquid long-term trading even without a uniform German bidding zone. A virtual trading hub is not a physical market location, but a price index. This can serve as the basis for purely financial forward products such as forwards, futures, or spreads. The underlying price index could be defined in the settlement as a weighted average of several zonal spot prices or node prices. For many small zones, a well-defined regional hub could correlate better with domestic forward prices than the German zone price does today; for Germany itself, however, the hedging quality would tend to decline.

5 Alternatives to regional wholesale prices

The introduction of regional or local wholesale prices makes sense from an energy industry perspective, as is widely agreed among academics. However, there are major political concerns about such a reform. We therefore discuss alternatives in this section. These include, in particular, regionalized grid fees and local flexibility markets.

5.1 Spatially and temporally differentiated grid fees

Idea. Today, grid fees are calculated separately for each distribution system operator's grid area. However, grid fees do not usually differ within a distribution grid area. In the transmission grid, a uniform grid fee applies throughout Germany. The idea of spatially and temporally differentiated grid fees is to adjust fees to grid bottlenecks. Grid fees for electricity consumers would therefore be low in regions and at times when electricity cannot be fully transported away. Conversely, they would be high where electricity can only be provided to a limited extent due to grid bottlenecks. Consumers would thus have an incentive to adjust their electricity demand to grid utilization.

Distribution vs. transmission grid. Regional and local wholesale prices only ever have an effect at the transmission grid level. Even with the introduction of nodal pricing, bottlenecks in the distribution grid therefore remain invisible to the market. Within the distribution grid, dynamic grid fees are therefore not an alternative to price zone division, but rather a supplementary measure. However, in view of the political desire for a uniform price zone, dynamic charges *at the transmission grid level* are also being proposed (Neon 2025, BNetzA 2025).

Disadvantages. The concept of time-variable network charges in the transmission grid has two major disadvantages compared to regional wholesale prices: they only affect consumers and they are rigid in the short term.

Only consumers. Grid fees currently only affect consumers. Regionalized grid fees provide an incentive for electricity consumers to behave in a way that benefits the grid, but they do not affect:

- Storage facilities (which are currently exempt)
- Future electrolysis (which is also exempt)
- Energy-intensive industry (which is also largely exempt)
- Producers (who do not pay grid fees in Germany)
- Imports and exports (which are also not subject to grid fees)

Grid fees therefore only affect a small part of the electricity market. Although the introduction of grid fees for producers and storage facilities is currently under discussion, imports and exports will not be affected by grid fees in the long term.

Rigid in the short term. The second limitation of differentiated grid fees is that they must be set at a specific point in time and cannot be changed afterwards. This requires a forecast of load flows, which is always subject to error, but above all, it makes it impossible to react to short-term events. Although regional grid fees can tend to alleviate foreseeable grid bottlenecks, short-term market changes (weather) would continue to lead to short-term decisions (curtailment, storage) that change load flows in the short term, to which grid operators cannot respond with redispatch in such a short time. In other words, regional grid fees do not solve the problem of short-term grid congestion (section2.3).

"Third best." The introduction of time-variable grid fees for the lower grid levels makes sense in principle, especially because the introduction of regional wholesale prices does not appear realistic there. For the reasons mentioned above, time-differentiated grid fees are clearly inferior to spatially differentiated wholesale prices when it comes to eliminating grid congestion in the transmission grid. This is also the view of the Monopolies Commission's current sector report, which considers spatially and temporally differentiated grid fees to be the third-best option after local electricity prices ("first-best") and price zone division ("second-best") – but still better than the status quo (Monopolies Commission 2025).

5.2 Market-based redispatch

European regulation. The European Commission plans to publish a Network Code Demand Response in the first quarter of 2026. This stipulates that grid operators must procure redispatch competitively. Market players are no longer obliged to participate in redispatch – as is currently the case in Germany – but can offer redispatch services on a voluntary basis. Remuneration is based on the bids submitted rather than on cost estimates. The aim of local flexibility markets is, in particular, to use storage facilities and flexible loads in redispatch.

Problems. However, market-based redispatch creates incentives for market players to change their behavior on the spot market: so-called Inc-Dec gaming. Rationally acting players exploit price differences between the local flexibility market and the national wholesale market. For example, a consumer in a surplus area with a foreseeable grid bottleneck would not purchase electricity on the wholesale market, but on the local flexibility market at much lower prices. However, by refraining from purchasing, the consumer exacerbates the grid bottleneck because this further increases the regional electricity surplus. A flexibility market thus creates systematic incentives to exacerbate the congestion problem that it is actually supposed to solve. In the worst case, the flexibility market only solves the problems it has created itself – and costs money in the process. Scientific studies and pilot projects are currently investigating whether long-term contracting of capacity for redispatch can sufficiently address the misguided incentives to make meaningful use of flexibility markets (DataFlex 2025). However, the misguided incentive resulting from the different geographical granularity of the parallel markets remains a fundamental problem. Regional or local wholesale markets avoid precisely this problem.

6 Conclusion

The public debate on price zone division is often reduced to the question of winners and losers. However, these distribution effects are rather minor and there are sensible and easily financeable compensation mechanisms. It is often overlooked that the status quo is becoming increasingly problematic. The main costs of the uniform price zone do not even lie in rising redispatch costs, but primarily in growing system risks and missed opportunities for innovation and investment. Collateral damage from the uniform price zone therefore threatens to restrict short-term electricity trading, which would cause high costs and system risks. Alternatives to price zone division, such as time-variable regionalized grid fees in the transmission grid, are better than no local incentives at all, but they only address part of the problems and are significantly inferior to regional or local prices in terms of economic efficiency and operational system security. Without regional wholesale prices, we believe that extensive flexibilization of consumption and the expansion of large-scale storage facilities are not compatible with secure grid operation. And without flexible consumption and storage, electricity supply will become significantly more expensive.