DIW Weekly Report 12 2026

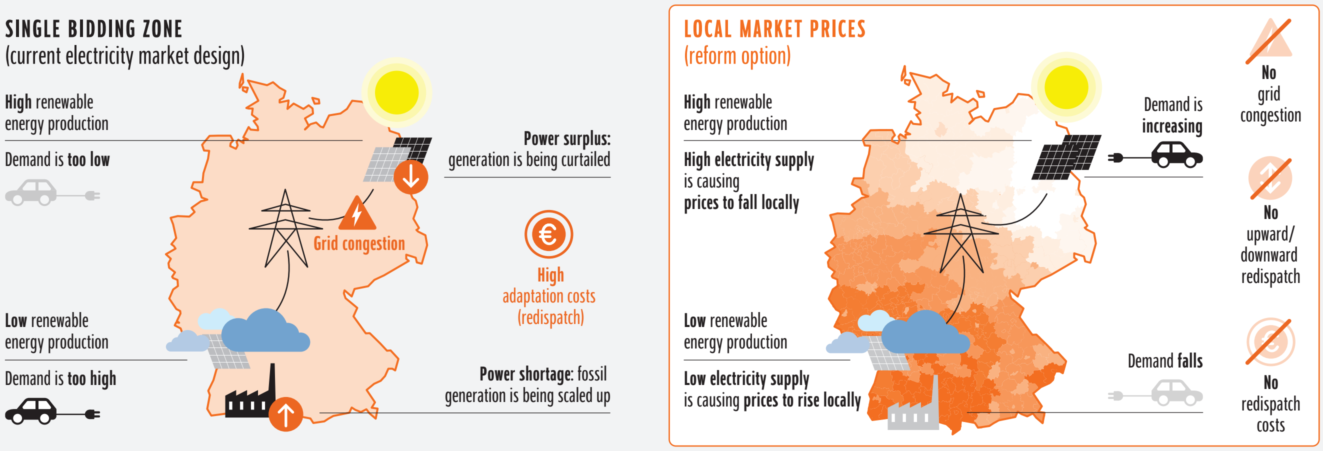
AT A GLANCE

Local market prices can reduce electricity costs

By Karsten Neuhoff and Leon Stolle

- The single bidding zone for Germany does not take into account regional differences in supply and demand, which vary significantly over time with renewable production
- To resolve grid congestion, electricity generators are instructed to adjust their output – this costs just under four billion euros annually
- Local market prices avoid these costs and generate congestion revenues. They also reduce the need for grid expansion
- Congestion revenues can be used to hedge electricity customers against local price risks and secure investment by electricity consumers across Germany
- Extensive international experience should be utilized to rapidly implement local market prices in Germany and other European countries

The single bidding zone leads to grid congestion and costs – local market prices balance supply and demand regionally



Source: Own representation.

FROM THE AUTHORS

*"The German electricity market urgently needs reform because the single bidding zone results in high costs for congestion management and grid expansion. Alternatives such as bidding zone splits and dynamic network tariffs can only partially solve the problem. Local market prices, on the other hand, can save costs on grid expansion and the resolution of grid congestion" — **Karsten Neuhoff** —*

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ABSTRACT

With the liberalization of the electricity markets in 1998, Germany opted for a single, nationwide wholesale price. Regional differences in supply and demand are not taken into account. In the event of grid congestion, electricity generators are paid to adjust their output. This leads to rising costs, an overestimation of grid expansion requirements and increased bureaucracy. Reforms are therefore currently under discussion, in particular the division of the single bidding zone, local market prices and dynamic network tariffs. Whilst a division into large bidding zones only partially resolves the problems, local market prices can save the costs of resolving grid congestion whilst simultaneously generating congestion revenues. These can be used to hedge market participants against local price risks. To determine locally differentiated dynamic network tariffs, as recently proposed by the German Federal Network Agency, forecasts of supply and demand would be required with unattainable precision. Local market prices, on the other hand, are set in real time and do not rely on such forecasts. The extensive international available experience should be utilized to rapidly implement local market prices in Germany and other European countries.

For a long time, energy suppliers built most of their power stations close to where demand was concentrated or connected them to high-capacity transmission and distribution networks. Thanks to this network, labeled as 'copper plate', there were few operational grid bottlenecks. Building on this consistently robust network, the liberalization of the electricity market in 1998 saw the introduction of a single, nationwide wholesale price across Germany. With the expansion of renewable energies and the increased demand for electricity from e-mobility, heat pumps and electrified industrial production, connected load is multiplying. As a result, grid expansion costs of around 650 billion euros are currently forecast by 2045,[1] to eliminate bottlenecks in the distribution and transmission grids.

If the grid expansion fails to eliminate all grid bottlenecks, the German single electricity price leads to market distortions: the price is too low in regions where there is currently little wind and sunshine – local generation and imports from other regions cannot meet the high demand. At the same time, it is then too high for other regions, leading to a surplus of electricity there which cannot be exported due to limited transmission capacity.

During such periods, grid operators instruct power stations in regions with a shortage to increase their output, whilst asking generators in other regions to reduce theirs (Box). All parties affected receive payments for this. This so-called redispatch most recently cost just under four billion euros annually (Figure 1) and leads to an increase in network tariffs of around eight to ten euros per megawatt hour (MWh). This corresponds to around ten per cent of total costs for very large electricity consumers.[2] German grid operators forecast that the maximum redispatch volume will double from 25 gigawatts (GW) at the start of the decade to over

1 Tom Bauermann, Patrick Kaczmarczyk and Tom Krebs (2024): Ausbau der Stromnetze: Investitionsbedarfe. Institut für Makroökonomie und Konjunkturforschung (in German; available online, accessed on February 23, 2026. This applies to all online sources in this report, unless stated otherwise).

2 In 2026, network tariffs will receive a one-off subsidy of 6.5 billion Euro from the Climate and Transformation Fund; see Federal Government (2025): Entlastung bei Energiekosten: Niedrigere Stromkosten (in German; available online).

 DOI: https://doi.org/10.18723/diw_dwr:2026-12-1

50 GW by 2030.[3] Across Europe, redispatch volumes could increase sixfold by 2040.[4]

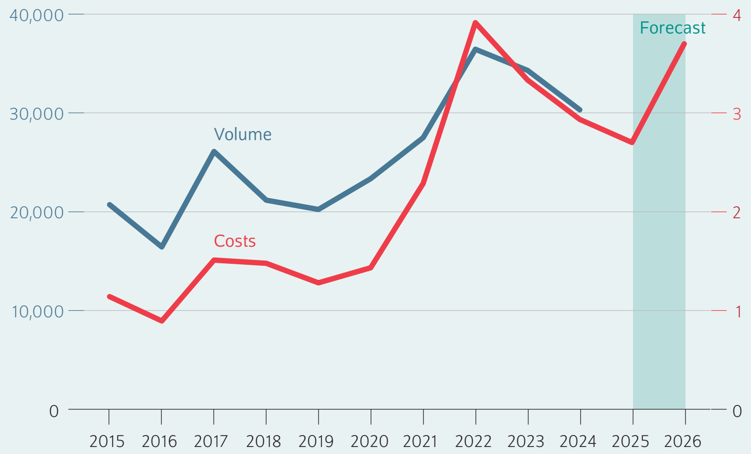
Increasingly more power stations must be kept on standby as a reserve for redispatch. The potential for power station capacity for this purpose has largely been exhausted.[5] Across Europe, an additional power station capacity of around 60 GW is forecast for redispatch by 2040; this corresponds to around 15 per cent of current electricity demand.[6]

Prompted by a Europe-wide review of price zones, often referred to as bidding zones, and new recommendations from the research community, the Monopolies Commission and the Federal Network Agency (*Bundesnetzagentur*), three electricity market reforms are currently being discussed in Berlin and Brussels with regard to resolving market distortions: local market prices, a bidding zone split and dynamic network tariffs.[7] This weekly report focuses primarily on analyzing the structure of local market prices for Germany and comparing them with the other two options.

Figure 1

Development of costs and volumes for congestion management in Germany

Volume in gigawatt-hours (left axis); costs in billions of euros (right axis)



Note: In addition to redispatch, which is the largest factor, countertrading and feed-in management also form part of congestion management. The costs for 2025 and 2026 are forecasts.

Source: Federal Network Agency (Smard; workshop on January, 14th, 2026); Energate newsletter; own representation.

The volume and costs of congestion management have risen sharply and, without electricity market reform, will lead to higher network tariffs.

Local market prices prevent grid bottlenecks and save costs

As the price of electricity can vary significantly from region to region at any given time depending on supply and demand, many countries already have local market prices for each major city or rural region. The local price reflects the situation in each region: when solar and wind generation is high, the price is low, thereby encouraging the charging of heat and battery storage systems, for example; conversely, when demand is high and generation is low, the price is high. This ensures that generation, storage and load behave in a manner that benefits the grid, avoids grid bottlenecks and saves costs by utilizing a broader range of flexibility.

All local markets are integrated into the European electricity market. As before, prices are determined on the exchange through collaboration between exchange operators and grid operators, who combine their commercial and technical expertise. An algorithm determines the local electricity price in such a way that supply and demand are balanced regionally. The pricing process takes available transmission capacities into account, so that electricity flows from regions with low prices to regions with higher prices. This avoids redispatch. During hours without congestion, local electricity prices converge with one another.

By making efficient use of flexibility and networks, local prices reduce the need for expansion of the transmission grid. They also support congestion management in the distribution grid, reducing the need for expansion there. There is no need to further differentiate prices within the distribution grid, as wind, sunshine and temperature are very similar across a region. Thus, for example, when there is plenty of wind and sunshine, a low local price encourages charging of batteries and heat storage systems throughout the city. This helps the entire distribution network. Local market prices can thus create scope and, consequently, time to use the digitalization of distribution networks to record actual network utilization and to tailor expansion requirements or active congestion management accordingly.[8]

Local market prices were introduced in most liberalized electricity markets outside Europe when growing redispatch requirements in large electricity bidding zones led to high

3 Florian Dinger and Marius Klemm (2026): Dynamische Netzentgelte. Presentation by the 4TSOs at the AgNes expert workshop on 14 January 2026 at the Federal Network Agency (in German; available online).

4 Assuming an ambitious grid expansion under the German Grid Expansion Plan, see Georg Thomassen et al. (2024): Redispatch and Congestion Management. European Commission (available online).

5 Karsten Neuhoff, Marion Ott and Paula Prakash (2025): Welcher Reformbedarf besteht im Engpassmanagement? (in German; available online).

6 Georg Thomassen and Andreas Fuhrmanek (2025): Locational price signals in Europe. Publications Office of the European Union (available online); demand data on the website of the European Network of Transmission System Operators for Electricity (ENTSO-E) (available online).

7 European Network of Transmission System Operators for Electricity (2025): Bidding Zone Review (available online); Veronika Grimm et al. (2024): Der deutsche Strommarkt braucht lokale Strompreise. Frankfurter Allgemeine Zeitung, 10 July (in German; available online); Monopolies Commission (2025): 10th Sector Report Energy: Competition and Efficiency for a Sustainable Energy System (available online); Federal Network Agency (2025): Dynamische Netzentgeltkomponente. Festlegungsverfahren der Netzentgeltsystematik Strom (in German; available online).

8 Karsten Neuhoff, Jörn Richstein and Carlotta Piantieri (2018): TSO-DSO-PX Cooperation II. Report on key elements of debate from a workshop of the Future Power Market Platform (available online).

Box

Redispatch: cost-based or market-based

In Germany, redispatch generates costs of just under four billion euros per year. These costs arise when grid operators, in order to resolve grid congestion, instruct power stations to adjust their electricity generation. All parties affected receive payments for this. Until 2017, the costs were considered to be of little relevance to Germany.[1] For this reason, the only discussion was a switch from cost-based to market-based redispatch.[2] Under cost-based redispatch, plant operators receive a regulator-approved reimbursement of their costs for adjusting their electricity generation. Under market-based redispatch, power stations submit bids to adjust their output. The grid operator selects the most cost-effective bids. Prices are therefore determined through competition between bidders rather than through regulatory scrutiny. This is intended to enable both storage facilities and demand-side flexibility technologies to participate in redispatch. These cannot participate in cost-based redispatch, partly because their opportunity costs cannot be verified by the regulator.

However, international experience and economic analyses show that profits made by market participants in market-based redispatch can lead to significant perverse incentives.[3] They first increase production so that they can then be paid in redispatch to reduce production again. Ultimately, this only resolves bottlenecks caused by their own incentives – the overall grid situation may deteriorate.[4]

1 In workshops, the view was that differences between redispatch and local market prices are minimal when systems are optimally designed, cf. Consentec and Neon (2018): Nodale und zonale Strompreissysteme im Vergleich. Brief study for the Federal Ministry for Economic Affairs and Energy (BMWE). Final report (in German; available online).

2 See the statement by the German Association of Energy and Water Industries (BDEW), February 23, 2017 (in German; available online).

3 See 'Belden's experiment' in Adam Nix, Stephanie Decker and Carola Wolf (2022): Enron and the California energy crisis: The role of networks in enabling organisational corruption. Business History Review, 95(4), 765–802 (available online).

4 Karl-Martin Ehrhart et al. (2025): Analysis of a capacity-based redispatch mechanism. Energy Economics (available online).

costs and system risks.[9] This change has not been reversed in a single instance; instead, it served as a model for neighboring regions that also switched to local market prices, particularly in North America.[10]

The real-time market ensures that supply and demand are in balance and enables the short-term procurement of electricity. At the same time, the day-ahead market allows large generators, such as power stations, and large consumers, such as industry, to plan their operations for the following day. Finally, futures markets offer the opportunity to hedge prices in the long term.

Real-time trading enables flexible electricity procurement

Many electricity customers decide at short notice how much electricity they need and when – for example, when small businesses run their machinery and households charge their electric cars. At the same time, an increasing number of electricity customers can feed electricity into the grid or use it at short notice thanks to energy management systems and batteries or heat storage units. To do so, they need transparent, attractive prices and unbureaucratic procedures.[11]

As local market prices eliminate the need for redispatch and thus trading no longer needs to be halted prematurely, it is possible to react to the electricity price in real time. To this end, electricity customers are informed of the local electricity price at five-minute intervals.[12] Of course, only few monitor these electricity prices directly; for this purpose, there are energy management systems from, for example, heat pumps or smart electric car charging stations. These systems can use the electricity price to determine energy consumption or feed-in. Local prices are only relevant for customers with smart meters, who already have greater flexibility through storage systems, electric vehicle charging stations or heat pumps. For all other customers, a Germany-wide average price can remain in place. Together, all customers benefit from falling prices thanks to grid-friendly behavior by all market participants.

To enable electricity customers to react to these prices at short notice, they need dynamic electricity tariffs. However, they do not need to expose their entire electricity demand to the spot price; instead, they can hedge their expected electricity demand and pay the spot price only for any deviations from that. It is important that dynamic electricity tariffs are based not on the German single price, as has been the case to date, but on local market prices. Otherwise, they will increase rather than reduce bottlenecks, redispatch requirements and system costs.[13]

Planning production and securing prices the day before

Unlike private electricity customers and small businesses, large industrial customers and power stations plan their production processes in advance. An electricity auction at noon of the previous day currently serves as the central marketplace (day-ahead market) in Germany.

9 For the historical context, see Ignacio Aravena et al. (2021): Transmission capacity allocation in zonal electricity markets. Operations Research, 69(4).

10 See webinar on the introduction of nodal prices in North America (available online).

11 Karsten Neuhoff et al. (2024): How can nodal prices engage consumers? Future Power Market Platform – Workshop Report June 2024 (available online).

12 To ensure resilience, internet communication can be supplemented by remote control via the electricity grid or radio signals.

13 Neuhoff, Ott and Prakash (2025), ibid.

Also in countries with local market prices, there is a day-ahead auction. In such auctions, bidders must specify in their bid the location of the power plant or consumer they are bidding on behalf of.[14] Bids at power plant level spare power plant operators the previous effort of aggregating their power plant capacities, creating complex block bids for these, and, after the auction, drawing up schedules for each individual power plant to be communicated to the system operators. Instead, they can submit bids directly for each power plant. This facilitates market access for smaller market participants.[15] The integration of the markets for energy, balancing energy products and transmission capacity simultaneously increases liquidity and the intensity of competition.[16] At the same time, bids at the local power plant level rather than at portfolio level improve transparency, enabling effective market monitoring.[17]

In the day-ahead auction, market participants secure a price for the volumes of electricity determined in the auction. They therefore effectively only pay or receive the local real-time price for deviations from these volumes. International experience shows that the sum of a large number of small deviations can be accurately predicted using weather forecasts and price elasticities, thereby helping to ensure the reliability of the grid. This 'law of large numbers' does not apply to large power stations and large batteries. Consequently, they may only adjust their feed-in or load gradually (ramping constraints) or must coordinate deviations from the previous day's auction results with system operators. To this end, generators submit bids for adjustments during the course of the day.[18]

Long-term contracts: hedging cost and revenue risks

Suppliers and large generators use futures markets to hedge electricity prices over the longer term for periods ranging from several months to a few years, both currently in Germany and in markets with local market prices. There, however, the futures contracts do not refer to individual local prices, but to the average local price of a region (so-called trading hubs). With futures contracts based on the trading hub price, a local price risk (`basis risk') remains, arising from the difference between the hub price and the local price at a plant's node.

To hedge against these local price risks, congestion revenues are utilized in the context of local market prices; these arise instead of redispatch costs.[19] Congestion revenues arise when electricity is fed into the grid in a region with a low local electricity price and withdrawn in another region with a higher electricity price. They already arise today in international electricity trading between countries and are used, in accordance with current regulatory requirements, to finance grid expansion and reduce network tariffs. In North America, these congestion revenues are distributed to electricity suppliers via Financial Transmission Rights (FTRs) for their electricity customers, in order to hedge them against local price risks.[20]

One challenge here is the generation profiles of wind and solar plants, which cannot be forecast over the long term. In North America, these are hedged within the utility's portfolio alongside a portfolio of FTRs. This would be less suitable for smaller utilities competing in the end-customer market. A promising approach here is the tripartite energy contracts proposed by the European Commission.[21] Under this scheme, wind and solar projects can hedge their revenues with long-term contracts for differences (CfDs): the pooled CfDs are then issued to electricity customers. The congestion revenues are used to offset the price differences between the locations of the wind and solar plants and those of the electricity customers.[22] This ensures that electricity customers across Germany receive reliable and affordable renewable energy.[23]

Local market prices could be implemented quickly

The introduction of local market prices entails one-off costs for market operators and participants, for example, to adapt software and processes. Experience in North America shows that these costs can be recovered within the first few years through efficiency gains (Figure 2). Additional savings arise from reduced investment in generation capacity and grid expansion. For Europe, annual savings of twelve billion euros are forecast, rising to as much as 42 billion euros by 2040.[24]

Experience shows that a transition is possible within a few years.[25] Established software solutions for this already exist from internationally active companies such as Siemens, Hitachi and General Electric. Delays have occurred, for

14 The bid specifies start-up costs, warm-up times and flexibility potential – as has been the case to date for redispatch.

15 Jörn Richstein, Casimir Lorenz and Karsten Neuhoff (2020): An auction story: How simple bids struggle with uncertainty. Energy Economics (available online).

16 Karsten Neuhoff (2003): Integrating transmission and energy markets mitigates market power. Cambridge Working Papers (available online).

17 Paul Twomey et al. (2005): A Review of the Monitoring of Market Power. The Possible Roles of TSOs in Monitoring for Market Power Issues in Congested Transmission Systems. Center for Energy and Environmental Policy Research (available online).

18 Karsten Neuhoff et al. (2025): EU power market reform towards locational pricing: Rewarding flexible consumers for resolving transmission constraints. Energy Policy, 207, 114808.

19 Leon Stolle et al. (2026): Designing Hedging Instruments for Locational Price Risks – Lessons from North American Financial Transmission Rights. DIW Discussion Paper No. 2156 (available online, accessed on February 26, 2026).

20 The holder of an FTR receives payment for a defined volume of electricity based on the price difference between local markets and trading hubs. Together with a forward contract on the trading hub, this hedges the price risk; see webinar on experience with FTRs (available online).

21 Announcement of tripartite energy contracts: European Commission press release of 5 September 2025: Commissioner Jørgensen announces first 2 sectorial tripartite contracts (available online). For the concept, see Karsten Neuhoff et al. (2024): A renewable energy pool brings benefits of the energy transition to consumers. DIW Weekly Report No. 15, 227–234 (available online).

22 For an assessment of the price effects, see Silvana Tiedemann et al. (2024): Auswirkung einer Gebotszonenteilung auf den Marktwert der Erneuerbaren Energien im Jahr 2030. Kopernikus Project Ariadne (in German; available online).

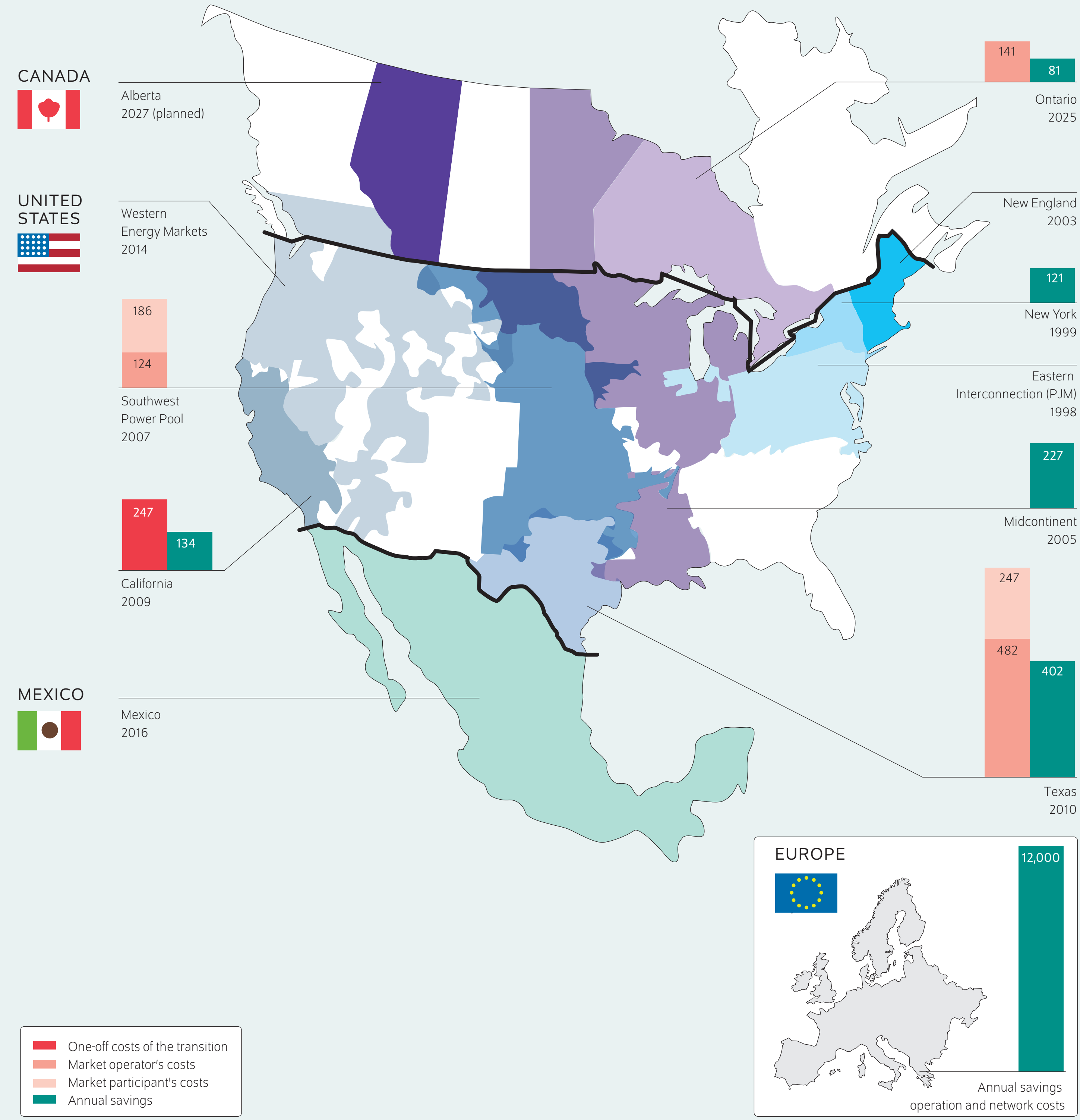
23 Karsten Neuhoff et al. (2025): Contracting Matters: Hedging Producers and Consumers with a Renewable Energy Pool. The Energy Journal (available online).

24 Assuming an ambitious grid expansion, see Thomassen and Fuhrmanek (2025), ibid.

25 See webinar on the introduction of nodal prices in North America (available online).

Figure 2

One-off transition costs and annual savings from the introduction of local electricity prices in North America
In millions of euros; year of transition



Notes: All values have been converted to 2024 prices in euros using the World Bank's GDP deflator and the European Central Bank's exchange rates. As the transition in Ontario did not take place until 2025, the figures are ex-ante forecasts for the average of the expected ten-year savings. Europe represents a forecast of savings for the year 2030, assuming an ambitious grid expansion.

Sources: Author's own presentation based on several reports on ex-post evaluations: Analysis Group (New York); Brattle Group (Midcontinent); FTI Consulting (Southwest Power Pool); FTI Consulting & Wolak (California); FTI Consulting & Triolo, Wolak (Texas), IESO (Ontario); JRC (Europe).

The one-off costs of the transition are incurred only once and are quickly recouped through the annual savings generated.

example in California, due to unsuitable governance structures.[26] Simple governance is thus important. Rather than a Europe-wide coordinated transition to local market prices, a step-by-step approach is therefore recommended.[27] Experimental clauses could be introduced into EU electricity market regulation to allow countries or groups of countries to implement local market prices without Europe-wide coordination on every design detail. This would build on positive experiences with regional pilot projects in European electricity market integration and with the gradual introduction of local market prices in North America.

Bidding zone splits still result in high redispatch requirements

There is also currently a debate about dividing the existing single bidding zone. Dividing it into northern and southern bidding zones sounds plausible at first glance, as periods of high electricity generation in the windy north lead to transmission bottlenecks from north to south. However, this simplification ignores, firstly, the wide variety of different weather conditions. Simulations of the electricity grid show that a division into two or a few bidding zones cannot resolve structural bottlenecks in the transmission grid (Figure 3). Costs for redispatch requirements and the provision of reserves remain.

Secondly, in the event of a bidding zone split, in continuous trading between bidding zones, transmission capacity is allocated free of charge to those traders who submit a request first.[28] Once transmission capacity has been allocated, trading, liquidity and competition remain confined to the respective bidding zone and decrease accordingly in smaller zones.

Thirdly, the energy market remains fragmented between energy, various balancing energy products, different forms of collateral for balancing energy products, congestion management energy and various reserves.[29] This reduces transparency, creates barriers to market entry for market participants and thus further restricts liquidity, efficiency and competition.[30]

Fourthly, although on a smaller scale, there is still a risk of excessive grid expansion. This is because expansion planning would be geared towards avoiding all congestion, now within the bidding zones.

Figure 3

Reduction in redispatch costs and volumes by number of bidding zones

Savings (white) relative to the status quo (single bidding zone = 100)

Study	Unit	Single bidding zone	Bidding zones: Two	Three	Four	Five	Local market prices
Knörr et al. (2024)	Costs in Germany	100	93	95	95		0
Diers et al. (2023)	Volume in Germany	100	65				
Bidding Zone Review (2025)	Volume in Central Europe	100	49	48	51	51	
Agora Energiewende (2025)	Volume in Germany	100		80			0

Note: Agora Energiewende uses a simplified network model with 22 nodes. A model comprising 22 zones thus corresponds to local prices without the need for redispatch. The values for the Bidding Zone Review and Agora Energiewende are calculated as averages of the respective modelled weather years.

Sources: Johannes Knörr, Martin Bichler and Teodora Dobos (2024): Zonal vs. Nodal pricing: An analysis of different pricing rules in the German day-ahead market (available online); Hendrik Diers et al. (2023): Price effects of a German bidding zone division. Expert report by EWI and Thema (available online); Entso-e (2025): Bidding Zone Review of the 2025 Target Year (available online); Agora Energiewende and Fraunhofer IEE (2025): Local electricity prices. How integrating grid realities into the electricity market succeeds and reduces costs (available online).

A bidding zone split could reduce the need for redispatch. But only local market prices would reduce it to zero.

Local prices are better for hedging price risks than a bidding zone split

Local market prices can hedge price risks more effectively than a bidding zone split for three reasons (Table): Firstly, under local market prices, the entire transmission capacity is managed through auctions, meaning that the scarcity rent is captured as congestion revenue. With a bidding zone split, however, part of the transmission capacity must be withheld to reduce congestion within zones, whilst a portion continues to be allocated free of charge in continuous trading. This reduces congestion revenues.

Secondly, with local market prices, it is difficult to predict whether a local market price will, on an annual average, be above or below the Germany-wide average level. Consequently, all electricity customers have an interest in hedging if it is structured as a fair insurance scheme, that is one that includes both payouts and repayments. For large bidding zones, most models forecast lower prices for northern Germany than for southern Germany, at around ten Euros/MWh.[31] This reduces the interest of electricity customers

26 Christopher Weare (2003): The California Electricity Crisis: Causes and Policy Options. Public Policy Institute of California (available online).

27 Neuhoff et al. (2025), ibid.

28 Karsten Neuhoff, Jörn Richstein and Nils May (2016): Auctions for Intraday Trading: Impacts on efficient power markets and secure system operation (available online).

29 Karsten Neuhoff et al. (2015): Flexible Short-Term Power Trading: Gathering Experience in EU Countries. DIW Discussion Paper 1494 (available online).

30 See Anselm Eicke and Tim Schittekatte (2022): Fighting the wrong battle? A critical assessment of arguments against nodal electricity prices in the European debate. Energy Policy, 170, 113220 (available online).

31 See EWI (2025): Gebotszonensplit in Deutschland: Worum geht es? EWI Policy Brief (in German; available online).

Table

Comparison of the advantages and disadvantages of the single bidding zone and reform options

	Redispatch	Flexibility	Liquidity and competition	Price transparency	Grid expansion	Local price risks	Resilient network operation
Single bidding zone	Just under four billion euros a year, increases grid charges by 8–10 euros/MWh (and rising), >25 GW of reserves	May exacerbate bottlenecks	Market segmentation (e.g. energy, congestion, balancing energy)	Low due to portfolio based bidding with complex bids	Significantly increased need to avoid nation-wide bottlenecks	No risks at present, but uncertainty regarding adjustments remains	Rising risks in redispatch
Bidding zone split	Less redispatch, up to 50 per cent savings	More localized prices reduce congestion risks	Market segmentation, liquidity and competition remain limited to zones	Low due to portfolio based bidding with complex bids	Increased need for congestion within zones	Prices for northern Germany forecast to be around 10 euros/MWh lower	Moderate risks in redispatch
Local market prices	No redispatch required	Effectively deployed and remunerated	High liquidity and competition	High due to unit-based bidding with multi-part bids	Hardly any grid expansion required, as grid usage is efficient	Hedged with congestion revenues	No redispatch risks, opportunity for modular operation of the grid

Source: Own illustration.

in northern Germany in participating in long-term hedging. Without their contribution, a bidding zone split would require higher congestion revenues to hedge local price risks.

Thirdly, various studies show that there is no perfect division into stable bidding zones.[32] Further divisions or bidding zone adjustments would therefore be necessary in the future. Any reorganization would lead to conflicts of interest, as electricity customers always insist that they should not be worse off as a result of the adjustment. To ensure that no reform measure puts market participants at a disadvantage, additional funds would be required to hedge local price risks.

Dynamic network tariffs require precise forecasts

A third reform option is dynamic network tariffs. Network tariffs distribute the fixed costs of investment and operation of the network across electricity customers. This inadvertently creates disincentives to investment and the use of flexibility. For this reason, some countries, such as Sweden and France, have introduced time-varying network tariffs, which are generally announced several months in advance. For example, reduced network tariffs at midday encourage increased electricity consumption during periods of high solar production.[33]

In Germany, the Federal Network Agency has recently proposed generating a local price signal through dynamically varying network tariffs that differ across regions.[34] This initiative signals that local price signals are considered, whilst at the same time upholding the political requirement for a single electricity bidding zone.

There are two reasons why dynamic network tariffs are not used anywhere to manage structural bottlenecks.[35] Firstly, grid operators cannot predict regional generation and demand with sufficient precision.[36] A storm front may be delayed, or early morning fog may clear later than expected. Grid operators therefore assume short-term forecasting errors of 14 to 17 GW.[37] Consequently, there is always a risk that dynamic network tariffs will lead to an incorrect local price signal, thereby exacerbating rather than reducing grid bottlenecks. An accurate forecast the day before would be necessary, as dynamic network tariffs would have to be set by the morning of the previous day at the latest in order to provide a basis for electricity trading. Local market prices, on the other hand, can be updated in real time.

Secondly, with increasing demand elasticity, quantity steering is better suited to the allocation of scarce resources than price steering.[38] Storage increases demand flexibility. This argues against setting prices the day before in the form of dynamic network tariffs and instead in favor of setting transmission capacity (quantity), which is then implicitly allocated in auctions at local market prices.

Conclusion: Local market prices for long-term, reliable electricity costs

Despite falling costs for the expansion of solar and wind energy, electricity costs in Germany remain high. A key cost driver is the single bidding zone, which fails to take account of local fluctuations in supply and demand, thereby leading to rising redispatch costs, high grid expansion costs and bureaucracy. This is increasingly jeopardizing industrial

32 Teodora Dobos, Martin Bichler and Johannes Knörr (2025): Challenges in finding stable price zones in European electricity markets: Aiming to square the circle? Applied Energy, 382, 125315 (available online).

33 Anke Weidlich et al. (2025): Dynamic network tariffs and their possible design for Germany (available online).

34 See Federal Network Agency (2025), ibid.

35 See Weidlich et al. (2025), ibid.

36 See Tagesspiegel Background (2026): Dynamische Netzentgelte laut ÜNB keine Lösung für kurzfristige Engpässe. Issue of January 15 (in German; available online).

37 Dinger and Klemm (2026), ibid.

38 Martin Weitzman (1974): Prices vs. Quantities. The Review of Economic Studies 41(4), 477–491.

investment and makes a fundamental reform of the electricity market design urgently necessary.

Three options are being discussed as potential reforms. A bidding zone split would only partially address the constantly changing grid congestion. This would result in a continued high need for redispatch, a decline in liquidity and the intensity of competition, and local price risks would be difficult to hedge. Dynamic network tariffs, as a second option, could remove flexibility barriers arising from the current allocation of fixed costs in the electricity market. However, this approach would reach its limits when it comes to resolving structural network congestion. A more suitable approach, on the other hand, would be the concept of local market prices for every major city and rural region. These would enable grid bottlenecks to be managed efficiently and would contribute to liquidity, competition and transparency. Local market prices would increase the efficiency of the electricity system both during the transition phase and in a future fully renewable energy system. Dispatchable capacity for extreme situations would remain part of security of supply, though demand for it would be reduced through an efficient market design.

Many countries outside the EU have already introduced local market prices. Their experience refutes three frequently expressed concerns. Firstly, it is claimed that incomplete digitalization and a lack of smart meters would be an obstacle. In fact, when the first schemes were introduced in North America around 25 years ago, computers were even slower than they are today and smart meters were unknown. Secondly, local market prices are said to be a purely theoretical concept. However, this is refuted by the many successful implementation examples in North America and New Zealand. Thirdly, local prices are said to jeopardize investment by electricity customers and renewable energy producers. In reality, however, the introduction of such prices also generates congestion revenues. Globally, regulations have always stipulated how congestion revenues are passed on to electricity customers. This safeguards against local price risks and thus refutes the argument that local market prices lead to location risks.

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JEL: Q41, Q48, D47, L51

Keywords: Locational pricing, zonal pricing, grid tariffs, congestion management, redispatch, electricity market design

LEGAL AND EDITORIAL DETAILS

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DIW Berlin — Deutsches Institut für Wirtschaftsforschung e. V.
Anton-Wilhelm-Amo-Straße 58, 10117 Berlin
www.diw.de
Phone: +49 30 897 89–0 Fax: –200
Volume 15 March 25, 2026

Layout
Roman Wilhelm; Stefanie Reeg; Eva Kretschmer, DIW Berlin

Cover design
© imageBROKER / Steffen Diemer

Composition
Satz-Rechen-Zentrum Hartmann + Heenemann GmbH & Co. KG, Berlin

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ISSN 2568-7697