Fighting the wrong battle?

A critical assessment of arguments against nodal electricity prices in the European debate

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Abstract

Contrary to liberalized U.S. electricity markets that apply nodal pricing, EU power markets rely on uniform pricing in bidding zones. The EU's zonal pricing model is challenged by an increasing mismatch between network and generation expansion within existing bidding zones, as well as the complexity of defining adequate new bidding zones. A potential solution is to transition to nodal pricing in the EU. The academic literature provides strong evidence of significant cost savings under nodal pricing as compared to zonal pricing. The question is: Why has nodal pricing persistently been discarded in the EU? It cannot be denied that implementing nodal pricing would require significant changes to the EU market design and potentially also the institutional setup. However, so far, the debate in the EU has mostly focused on perceived flaws of the concept of nodal pricing. In this paper, we identify the main arguments against the concept of nodal pricing brought forward by EU stakeholders. We group the arguments into the six categories: susceptibility to market power, barriers to unlock flexibility, market liquidity concerns, increased investment risks, unmanageable complexity, and political undesirability of locational price differentiation. Our contribution is to critically assess each of the arguments and to demonstrate that they do not explain, nor justify, the opposition to nodal pricing. Instead of devoting attention to mostly misconceived flaws of nodal pricing, we urge a reconsideration of a nodal market.

Highlights

- We identify six main arguments against nodal power markets put forward by EU stakeholders
- We analyze these arguments based on interviews, academic literature, and case studies
- Most perceived challenges have been adequately addressed in systems that implemented a nodal market
- We recommend reconsidering a nodal market and focusing research on the analysis of feasible pathways

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1. Introduction

The concept of nodal electricity pricing[1] and its potential applications were developed more than three decades ago (Schweppe et al., 1988; Hogan, 1992). The transmission network, with its ohmic losses and potential grid constraints, results in diverging costs of electricity supply between nodes. Nodal electricity prices, which are determined at the transmission substation level, reflect these costs and serve as corresponding economic signals to market participants, enabling them to account for losses and possible grid congestion in their operational decisions, while also encouraging future producers, consumers, and storage operators to choose their locations accordingly. Among the electricity wholesale markets implementing nodal pricing are Argentina, Chile, Mexico, New Zealand, Peru, Russia, Singapore, and several regions in the United States (U.S.). Independent System Operators (ISOs) clear the electricity market while considering the thermal and dynamic limits of all transmission network elements.[2]

By contrast, zonal pricing is in place in all EU countries.[3] Under this design, wholesale markets are cleared as if the power system were free of network constraints within each bidding zone. This implies that the hourly day-ahead power price is the same for all grid users within a bidding zone. In the EU, most bidding zones are equivalent to national territories.[4] Under zonal pricing, the market clearing may result in infeasible power flows within bidding zones. Transmission System Operators (TSOs) manage this via redispatch measures, i.e., market participants contributing to network constraints are ordered to alter their generation/consumption after the day-ahead market clearing. These interventions were supposed to be infrequent and irrelevant but have intensified as generation capacity has grown faster than the transmission capacity, and increasingly at remote locations. This has led to higher and more volatile flows, and increasing redispatch costs (ACER and CEER, 2021a). In addition, at times of significant intra-zonal congestion, zonal balancing energy prices and the imbalance price can provide perverse incentives to grid users in real-time, which can endanger system security (Chaves-Ávila et al., 2014). Consequently, a reconfiguration of bidding zones has been discussed for many years.

An alternative to reconfiguring bidding zones is transitioning to a nodal market. The academic literature provides evidence that this could provide significant operational cost savings. Direct (i.e., static) cost savings result from improved scheduling of generators, storage, and load due to more accurate price signals. To analyze these benefits, studies on U.S. markets compare the observed nodal market outcome with the counterfactual of a zonal market. Among them, Wolak (2011) estimates the impact of the Californian Independent System Operator's (CAISO) transition from a zonal to a nodal market design to be 2.1% of the operational costs. A regression analysis by Zarnikau et al. (2014) finds that nodal prices in ERCOT are about 2% lower than under zonal markets. For ERCOT, the Texan system, Triolo and Wolak (2021) value the operational costs of thermal generators 3.9% lower than in the hypothetical zonal counterfactual. By contrast, European authors analyzed the operational benefits from a transition to nodal pricing: Neuhoff et al. (2013) estimate cost reductions between 1.1% and 3.6% for the EU, and Aravena and Papavasiliou (2016) find savings of 2.8% for Central Western Europe. In summary, the direct benefits of nodal pricing have been estimated as between 1-

[1] Also known as locational marginal pricing (LMP).

[2] Nodal pricing at the distribution level (DLMP) is out of the scope of this paper.

[3] PSE, the Polish TSO, seriously considers transitioning towards a nodal market for a few years already, and Ofgem launched several studies evaluating the benefits of nodal pricing in the UK.

[4] As of 2021, exceptions are Sweden (4 bidding zones), Denmark (2 bidding zones) and Italy (7 bidding zones). Norway (5 bidding zones) is outside of the EU but part of the internal electricity market. Conversely, Germany shares a bidding zone with Luxembourg, as well do the Republic of Ireland and Northern Ireland.

4% of operational costs, which would translate into savings of several billion Euro per year in the EU. In the U.S. markets that transitioned from zonal to nodal markets, these savings exceeded the implementation costs within one year of operation (Neuhoff and Boyd, 2011).

In light of these findings, the introduction of nodal pricing in the EU electricity market appears to be an attractive way of dealing with the unavoidable mismatch between generation and transmission expansion. It is obvious that this would require significant changes to the EU market design and potentially also to the institutional setup. However, instead of discussing what these changes would entail, the debate among practitioners has mostly focused on perceived flaws of the concept of nodal pricing.

The contribution of this paper is to identify and assess the main arguments brought by European stakeholders opposed to nodal pricing. We categorize the arguments into six groups: susceptibility to market power, barriers to unlock flexibility, market liquidity concerns, increased investment risks, unmanageable complexity, and undesirability of locational price differentiation for consumers and (renewable) generators. We discuss these concerns using existing literature, interviews, and case studies from nodal markets. We find that most of the claims against nodal pricing are either unfounded or can be addressed via specific regulatory or policy measures. Instead of allowing perceived flaws in the functioning of nodal markets to monopolize the debate, we recommend refocusing the debate on a feasibility analysis of a transition to nodal pricing.

We provide background information on the EU's zonal markets and their challenges in the following section. In Section 3, we identify and briefly introduce the arguments used against nodal pricing in the EU. In Section 4, we analyze the identified arguments and show how they can be addressed via specific market design, regulatory, or policy measures. In Section 5, we summarize and discuss the findings. We conclude with policy recommendations in Section 6.

2. Background: Zonal pricing in the EU's electricity market

The zonal market design was implemented in the 1990's and early 2000's in the transition from vertically integrated monopolies to competitive wholesale markets. Although the concept of nodal pricing was known at that time, and nodal prices were already implemented in places like New-Zealand (1997) and the Pennsylvania-New Jersey-Maryland (PJM) Interconnection (1998), the EU opted for zonal pricing. An important argument behind the more simplistic representation of the network in the market clearing was that it facilitated horizontal integration across formerly national markets (Meeus et al., 2005). Indeed, the EU market became the world's largest electricity market in terms of traded volumes. The often regional ISO markets in the U.S. have so far been less successful at integrating. For comparison, PJM, the largest U.S. ISO, serves an annual load similar to that of Germany, the Netherlands, Belgium, and Austria combined. The EU-27 is about 3.5 times larger. On the other hand, one single price clears the German or French territory for each hour in the day-market—each of these countries is larger than the ERCOT system in Texas, which has more than 4,000 pricing nodes.

In the early days of European market liberalization, national transmission networks were relatively well developed as power systems (transmission and generation) were centrally planned for a long time. However, partly driven by the vertical unbundling resulting from liberalisation, grid development increasingly lagged behind the connection of new generators and new loads (Joskow, 2008a). The increasing deployment of intermittent renewable energy sources (RES) at places where there previously was no generation further aggravated this problem and is expected to increasingly do so due to the geographical distribution of wind and solar resources within Europe (Janda et al., 2017).

Consequently, congestion within national networks is becoming even more prevalent.[5] These developments challenge the appropriateness of zonal pricing, especially under the current bidding zone delineation, which is a legacy rather than a reflection of physical reality.

For several years, the European Commission and the Agency for the Cooperation of Energy Regulators (ACER) have expressed their concern about the negative consequences of the current bidding zone configuration. ACER triggered the first bidding zone review in 2016, specifying Central Europe as the relevant region (ACER, 2016). The outcome of the study was published in 2018 by the European Network of Transmission System Operators for Electricity (ENTSO-E, 2018). Four alternative bidding zone configurations were qualitatively compared to the status quo along three main criteria: network security, market efficiency, and robustness (European Comission, 2015). The result of the study was inconclusive because no alternative configuration consistently outperformed the status quo in all criteria. In consequence, Regulation (EU) 2019/943 refined the bidding zone review procedure. As of 2021, a second bidding zone review is ongoing according to the revised procedure. It is not unlikely that the second bidding zone review study will lead to some adjustments in the bidding configuration. However, the lengthy process and quickly changing flow patterns may result in an outdated configuration by the time of its implementation. As shown by Ambrosius et al. (2020), continuous bidding zone reconfigurations are highly disruptive and increase investment uncertainty, especially for capacity intensive technologies.

The current bidding zone configuration also leads to frequent intra-zonal network congestion. To limit the high need for national redispatch measures, some TSOs lower cross-zonal network capacities for trade (ACER & CEER, 2019).[6] By doing so, TSOs discriminate against cross-zonal, resulting in welfare losses. This practice has been continuously criticized by ACER and CEER, but with little effect.[7] In response, the so-called "70% rule" was introduced in Regulation (EU) 2019/943. It mandates that TSOs offer at least 70% of their interconnector capacity for cross-border trade.[8] ACER reports that the implementation of this 70% rule has been a failure so far (ACER, 2021a).

The difficulties and risks associated with a redefinition of bidding zone borders, and the fact that the implementation of this 70% rule is a failure, indicate that the zonal model may reach its limits. An alternative way to represent the network in the power market should hence be considered.

3. Identification of arguments put forward against nodal pricing

Despite the issues with zonal pricing and the overall positive experiences with the implementation of nodal pricing in several parts of the world, a nodal market is largely contested by EU stakeholders. To identify the arguments against the concept of nodal pricing, we reviewed position papers, conference contributions, and whitepapers from a wide range of relevant stakeholders in Europe between 2013 and 2021.[9] As the scope of this paper is a comparison between zonal and nodal market design, we

[5] Redispatch volumes and the associated costs have been increasing over the last years. In Germany, for example, redispatch quantities rose from less than 3 TWh in 2010 to more than 23 TWh in 2020 (BDEW, 2021).
[6] The incentives for TSOs to lower cross-zonal capacities for trade are discussed by Glachant and Pignon (2005).
[7] Exceptions are the two antitrust cases by the Directorate-General for Competition against Svenska Kraftnät in 2010 and against TenneT DE in 2018. For more background, see e.g., Meeus and Schittekatte (2020).
[8] For a detailed discussion on how the 70% margin shall be calculated consult ACER (2019a).
[9] The reviewed stakeholders include BMWi (German Federal Ministry of Economics and Technology), EFET (European Federation of Energy Traders), Energinet (Danish Transmission System Operator), ENTSO-E (European Network of Transmission Systems for Electricity), Epex Spot (Power Exchange), Eurelectric (Federation for the European Electricity Industry), Europex (European Association of Power Exchanges), JRC (Joint Research Centre of the European Commission), IFIEC (International Federation of Industrial Energy Consumers), Nordic TSOs

concentrate on arguments related to structural characteristics of nodal pricing and not on context-specific challenges related to the transition from one price system to another. In our comparison, we focus on the nodal day-ahead market as typically implemented in the liberalized U.S. power systems, unless specified otherwise.[10]

We clustered the identified arguments in the six groups shown in Table 1: susceptibility to market power, barriers to unlock flexibility, market liquidity concerns, increased investment risks, unmanageable complexity, and locational price differentiation. With the exception of the perceived issues with unlocking flexibility, similar arguments were raised against smaller bidding zones in the bidding zone review study (ENTSO-E, 2018). The following discussion thus also provides insights on how these challenges can be coped with, learning from the experience of nodal pricing.

Table 1: Arguments against nodal pricing from relevant European stakeholders

	Argument against nodal pricing	
1	Market power	EFET (2016), ENTSO-E (2021), Eurelectric (2016a), IFIEC (2013), JRC (2020), RAP (2018)
2	Barriers for unlocking flexibility	ENTSO-E (2021) , RTE (2019), EPEX SPOT (2019)
3	Market liquidity	EFET (2020), ENTSO-E (2021), JRC (2020), RAP (2018), THEMA (2021)
4	Investment risk	Eurelectric (2016a), Nordic TSOs (2019), RTE (2019)
5	Complexity	ENTSO-E (2021), RAP (2018), EUROPEX (2021), EPEX SPOT (2019)
6	Locational price differentiation	EDF (2021), Energinet (2020), ENTSO-E (2021), EPEX SPOT (2019), Nordic TSOs (2019)

First, the presence of market power in wholesale markets is the most often mentioned argument against nodal pricing (ENTSO-E, 2021; Eurelectric, 2016a; JRC, 2020; RAP, 2018). Because market prices are determined at each node, stakeholders fear that strategically located grid users can exercise a stronger influence on the more spatially granular (wholesale) electricity prices. As such, some stakeholders argue that the nodal model precludes the development of a competitive market (EFET, 2016; Eurelectric, 2016a; IFIEC, 2013).

Second, some stakeholders see in nodal pricing an increased barrier to unlocking all flexibility potential in the power system. Three peculiarities of nodal markets are claimed to hinder the integration of flexible resources and impede the integration of RES. First, it is argued that nodal pricing precludes continuous trading in intraday markets as is currently implemented in the EU (Europex, 2021). The possibility to continuously initiate trades in the intraday timeframe is claimed to be especially valuable to match flexible resources with RES generators updating their forecasts near real-time delivery (ENTSO-E, 2021; RTE, 2019). Second, the dispatch in nodal markets is typically centrally determined by the Independent System Operator (ISO). This setup is claimed to hinder the participation of demand response and storage in wholesale markets—resources that are deemed crucial to integrate higher shares of RES (ENTSO-E, 2021; EPEX SPOT, 2019; Europex, 2021). Third, it is deemed not possible to account for the possibility of topological changes in nodal pricing algorithms (ENTSO-E, 2021; EPEX SPOT, 2019; RTE, 2019). Not utilizing the flexibility inherent in the grid topology would lead to welfare losses (ENTSO-E, 2021).

Third, a concern with nodal pricing is that market liquidity in forward markets (1-3 years ahead) is low, leading to higher costs of hedging. Short-term nodal price signals are intrinsically more volatile than

(Danish, Finnish, Norwegian, and Swedish Transmission System Operators), RAP (Regulatory Assistance Project), RTE (French Transmission System Operator), and THEMA (Norwegian consultancy group).

[10] We provide more background on the most important differences between the nodal ISO/RTO markets in the U.S. and zonal day-ahead power market in the EU in Annex A.

zonal prices as they more accurately represent possibly fast-changing local conditions (ENTSO-E, 2021). Forward markets are crucial to hedge these volatile short-term price signals; however, it is argued that nodal pricing implies low market liquidity due to a limited number of trading counterparties at each node (EFET, 2020; JRC, 2020; RAP, 2018; THEMA, 2021).

Fourth, in the long-term (> 3 years), stakeholders argue that nodal prices increase the investment risk for new generation, leading to higher risk premia or the deferment of investments (Eurelectric, 2016a; Nordic TSOs, 2019; RTE, 2019). The rationale behind this statement is that under nodal pricing, unanticipated new generation, load, or transmission lines have a stronger impact on local prices than under zonal pricing.

Fifth, the complexity of the operation of nodal markets is argued to be higher than for zonal markets (ENTSO-E, 2021; EPEX SPOT, 2019; Europex, 2021; RAP, 2018). Currently, Euphemia, the algorithm behind the day-ahead clearing in the EU, is already running to its limits. Nodal markets would even be more complex and require advanced solving techniques.

Sixth, nodal pricing leads to locational price differentiation, which is deemed socially undesirable. With regard to consumers, nodal pricing typically implies a higher price for large industrial electricity consumers and residents that are located near demand centers (EPEX SPOT, 2019). This reduces industry competitiveness and asset values in the affected regions (Nordic TSOs, 2019). Having diverging prices per high-voltage node might lower public and political acceptability (ENTSO-E, 2021). This might be perceived as “unfair” as it impacts the costs of living differently within a country (EDF, 2021).[11] With regard to renewable generators, nodal prices in RES surplus regions decline more strongly than they would in a zonal market due to the high temporal correlation of generation in each pricing area. This lowers the market value of RES (Energinet, 2020).

4. Analysis of the arguments against nodal pricing

In this section, we analyze the arguments against nodal pricing identified in the previous section one by one. We base our analysis on theoretical reasoning, recent literature, empirical evidence from relevant case studies, and expert interviews.

4.1. Market power in the wholesale market

Market power is defined as the ability to profitably raise prices above competitive levels. It is a false statement that nodal pricing is generally more prone to market power or gaming than zonal markets. Structural weaknesses in the network can be exploited both under zonal and nodal pricing, but the strategies that are used to exercise market power differ. We briefly highlight how generators can make use of their pivot position in the two pricing systems.[12]

Under zonal pricing, the market clearing may result in infeasible power flows due to network congestion. A market-based redispatch incentivizes gaming between the wholesale market and the market for ancillary services to resolve network constraints. In the so-called “inc-dec game,” generators behind the network constraint increase their bids knowing they will still be dispatched, and generators before the constraint decrease their bids to ensure they will be compensated for downward redispatch (Holmberg and Lazarczyk, 2015). Hirth and Schlecht (2020) highlight that such gaming is even possible without market power, but market power further enhances the magnitude of the problem. Empirical research on the Italian power market by Graf et al. (2020) shows that such

[11] In France, for example, the principle of nationally uniform tariffs „la péréquation tarifaire“ is meant to show solidarity between regions (Observatoire de l’Industrie Électrique, 2017).
[12] For a more extensive discussion, see Harvey and Hogan (2010).

strategic behavior significantly increases the cost of power generation. The gaming potential in other zonal markets is even larger because Italy is—unlike most other EU countries—structured in seven bidding zones. Alaywan et al. (2004) explain that increased costs due to inc-dec gaming was one of the main reasons to move from zonal to nodal markets in CAISO. Generally, market-based redispatch is more prone to gaming and the exercise of market power than cost-based redispatch (also known as "regulatory," "mandatory," or "administrative" redispatch). Yet, the European Commission mandates market-based compensation because it allows the provision of system services from a more diverse set of market participants, including flexible demand and storage. Gaming is, to a lesser degree, also possible under cost-based redispatch by false reporting of costs or capabilities. Because compensation is based on declared costs, the information asymmetry between the regulator and market parties has a larger impact.

Under nodal pricing, inc-dec gaming is not possible as there is no inconsistency between the area of trade and the physics of the transmission network.[13] Yet, the relevant (day-ahead and real-time) market area changes according to the distribution of power flows. When the network is constrained, market concentration can be high in a node or collection of nodes, i.e., one or few generators own large shares of the generation capacity in the (temporarily) small relevant market area. This concentrated ownership of generation units creates a price setter opportunity. The exercise of market power in nodal markets therefore directly affects wholesale electricity prices in day-ahead and real-time markets. The risk of abuse of market power is well known in U.S. nodal markets, and market power mitigation mechanisms were introduced. The general principle behind such a mechanism is an automatic assessment of potential market power issues before the market clearing.[14] This assessment can result in constraining bids of generators that are deemed to be strategically located and have the potential to exercise market power.[15]

Table 2 summarizes the opportunities and risks of the market designs. While inc-dec gaming is potentially not specifically unlawful (Hirth and Schlecht, 2020), the abuse of market power in wholesale markets is a clear breach of competition law. Importantly, Graf et al. (2021) argue that monitoring market power in nodal pricing might be easier than in the redispatch markets in zonal systems.[16]

Table 2: Potential for strategic behavior under different market designs

	Nodal pricing	**Zonal pricing + market-based redispatch**	**Zonal pricing + cost-based redispatch**
Opportunity	No redispatch required	Accounts for small-scale, decentralized flexibility options in redispatch	Lower gaming potential
Risk	Market power in day-ahead and real-time markets	Inc-dec gaming between day-ahead and redispatch markets	Discrimination of small-scale flexibility options Information asymmetry between regulator and market parties

[13] At least in theory, inc-dec gaming is not possible. In practice, it may occur when not all network constraints are accounted for in the market clearing (c.f. Section 4.5)

[14] Graf et al. (2021) provide a good overview on the differences in market power mitigation mechanisms between ISOs.

[15] Note that the harder the regulator intervenes to avoid market power, e.g., through the introduction of price-caps, the more the door is open for capacity mechanisms.

[16] Also, as discussed in Section 3.5 and Annex A, bidding formats in nodal markets differentiate various cost-components, making offers more transparent and easier to monitor. In zonal markets with simple price-quantity bids, deviations from marginal cost can be justified by (undisclosed) start-up and minimum-energy running costs.

4.2. Barriers to unlock flexibility

Some stakeholders argue that nodal prices inhibit flexibility, and as such, the transition towards a cost-efficient decarbonized power system. We disentangle three concerns in this regard: (i) the lack of continuous intraday trading in nodal markets prevents the near-real time trade of flexibility and increases the need for costly, last-minute corrective measures; (ii) central dispatch of flexible demand and storage creates a challenge to provide the right incentives; and (iii) the missed-out benefit of grid flexibility as nodal pricing renders the use of topology changes more difficult. We address these concerns one by one.

No continuous intraday trading

It is claimed that continuous intraday trading is impossible under nodal pricing. Yet, nothing prevents the implementation of continuous intraday trades after a nodal day-ahead market clearing (although this is not what we would recommend). The intraday trades would depart from the feasible positions as cleared in the day-ahead auction. Before the clearing of each trade, the ISO would need to confirm that the trade does not violate network elements. Alternatively, the system operator could communicate how much transmission capacity is available to trade continuously between different nodes after the day-ahead clearing in a nodal market. Transmission capacity would then be allocated on a first-come-first-served basis. The latter is similar to how cross-zonal capacity is allocated in the current single intraday market coupling in the EU.

Auctions have several advantages over continuous trade including a higher transparency, an efficient allocation of network capacity, a level-playing field between smaller and bigger market players, and the pooling of liquidity.[17] The EU therefore decided to introduce three daily pan-European intraday auctions in 2019 (ACER, 2019b). Introducing a locational component in the intraday auctions seems a natural next step given the limited time for system operators to guarantee a feasibility of dispatch after clearance.[18] Auctions can easily be implemented in nodal pricing systems. Herrero et al. (2018) propose a multi-settlement system consisting of several intraday auctions in the U.S. to strengthen the intraday market.

Demand response and storage under central dispatch

Several European stakeholders argue that the central dispatch, which is applied in existing nodal power markets, hinders the participation of demand response and storage in wholesale markets.

There are two main ways for storage and flexible demand (individually or aggregated) to participate in nodal markets as implemented today. First, providers of flexible demand can submit multi-part bids just like generators would. Herrero et al. (2020) and Helman (2021) show how specific bidding formats for resources such as storage and demand response (via aggregators) are being introduced and continuously improved in U.S. markets. Second, self-scheduled market parties can submit an operation schedule to the system operator and become a price-taker (Cramton, 2017).

Empirical evidence shows high participation of demand response and storage in nodal power markets. In the U.S., for example, total demand response capacity in ISO and RTO systems fluctuated around 30 GW between 2011 and 2018 (Helman, 2021). Demand response capacity varied between 0 and 11% of total peak demand depending on the power system and year, with an average of 6% over all

[17] For an extensive discussion of continuous trade versus auctions, see Section 4.3.1 in Schittekatte et al. (2020).

[18] Continuous trading within a bidding zone up to real-time imposes severe operational challenges for transmission operators. For example, in the German bidding zone, covering the control areas of four TSOs, the gate closure for bilateral trades is 15 minutes before real time, while trading within each of the TSO's control areas is possible until real-time. In other words, the German bidding zone is split into four in the last 15 minutes of continuous trading.

ISOs and the considered timeline. Yet, most revenue for demand response comes from capacity markets (Monitoring Analytics, 2021) due to favorable participation rules (Bowring, 2021). The participation of storage in liberalized U.S. wholesale markets is also steadily increasing (Ela and Singhal, 2020). For example, in CAISO, supported by an energy storage procurement mandate at state-level, battery capacity rose to about 3,000 MW in 2021 (CAISO, 2021). This corresponds to about 6% of peak demand.

Topology changes

Last, a criticism of nodal pricing is that it fails to harness the flexibility of grid topology measures, such as switching of lines, which could lead to a more efficient dispatch. Indeed, topology control can significantly reduce congestion management costs under a zonal market design (Little et al., 2021), and is estimated to have limited utility under nodal pricing (Han and Papavasiliou, 2015); however, this is because nodal pricing already optimises trade within the network, while a large share of the benefits from topology changes in zonal markets resulting from correcting the day-ahead market schedule. Moreover, embedding grid topology changes in a nodal pricing algorithm is not excluded by design, although it may be more difficult than under a zonal clearing.

4.3. Market liquidity

In the short run, nodal prices are more volatile than zonal prices. This short-term price volatility reflects the state of the power system, but it also increases the price risk for market participants. To stabilize their cash flows, generators, retailers, and large consumers typically engage in hedging. Yet, the complexity and cost of hedging may be high in nodal markets due to the small number of counterparties and limited amount of trading at each node, creating the potential for greater price volatility than in zonal markets.

This concern deserves a nuanced response. Market participants willing to hedge do not necessarily need to find a counterparty at the same node. Instead, hedging future price uncertainty often occurs in trading hubs. A trading hub is a subset of nodes over which a price index is calculated as the weighted average nodal price, which is typically very liquid. In 2018, electricity futures and options for 5,900 TWh were traded on organized markets in the U.S. In addition, 5,000 TWh of physical forward contracts were traded, and there was an unknown volume of non-cleared financially settled swaps. For comparison, the total physical load was 3,000 TWh (PJM, 2020), which implies an average churn rate of at least 3.6 for the RTO/ISO systems.[19] Much higher numbers can be expected for the most liquid trading hubs. This is higher than the churn rates in EU countries, except for Germany (ACER and CEER, 2021a). It is therefore a false claim that overall market liquidity would be low in nodal markets.

What is true, however, is that market parties with long-term contracts settled at a trading hub remain exposed to the basis risk, i.e., the price differences between the contract node and the hub. We present two types of financial instruments that allow hedging this basis risk. The prevailing financial instruments for hedging the basis risk are the financial transmission rights (FTRs) (Hogan, 1992). The pay-out of an FTR is the price difference between its two predefined nodes. Depending on the direction of the power flow, they can have a positive or a negative value. The counterparty of FTRs is the ISO, who also determines—based on the available network capacity—how many FTRs are issued. Another form of hedging the locational basis risk does not involve the transmission system operator: Market participants can trade locational forward products to take off the locational risks of other market participants (Deng and Oren, 2006). For example, locational basis swaps are traded at a fixed price and settled at the spot price differences between two locations. While they generally work well,

[19] The churn factor is calculated as the volume of all future and forward contracts over the total physical demand.

risk management through both instruments may be challenging at peripheral nodes, and some locational risk remains.

For example, in the PJM power system, the ISO auctions FTRs on a regular basis. The liquidity in FTR markets is relatively high, and most market participants are able to hedge their locational risks (Monitoring Analytics, 2021).[20] However, it cannot be denied that there are several practical implementation issues as discussed by Risanger and Mays (2022). We briefly describe the three most relevant ones. First, FTRs often do not have a long duration: FTR auctions take place at most three years into the future. Yet, limited lengths of forward energy contracts and transmission rights is not unique to nodal markets, and they also arise in EU zonal markets (ACER and CEER, 2021a). Second, it is challenging to estimate the required fixed contract quantity of FTRs, particularly for renewable energy sources with varying output. This issue is not specific to FTRs but can also apply to Power Purchase Agreements (PPAs) in nodal or zonal markets, depending on their exact design. Solutions are proposed in the literature, e.g., by Hesamzadeh and Biggar (2021) and Kim et al. (forthcoming). Third, payouts to FTR holders often exceed the revenues of FTRs auctions. This implies an implicit subsidy for FTR holders at the expense of the rate payer (Monitoring Analytics, 2021). Possible reasons are inefficiencies in the auction design (Olmstead, 2018) and risk premiums for traders (Opgrand et al., 2022). Also this issue is not specific to nodal markets as discussed in Batlle et al. (2014), but rather exacerbated in them due to the more important role of FTRs.

4.4. Investment risk

Investments in assets participating in the power market face uncertain electricity prices in the long-term, i.e., longer than three years. Nodal pricing is deemed to further increase investment uncertainty because of the additional locational risk: Transmission, generation, or load investments have a larger impact on local prices compared to when the impact of these changes is diffused over a bigger zone. Ambrosius et al. (2022) show that risk aversion therefore has a higher welfare impact under nodal pricing compared to zonal pricing.

In zonal markets, the locational risk is socialized among end users, while in nodal markets, it is allocated to market parties. A key feature of an efficient market design is to allocate risks among those who can better manage them. Allocating the locational risk to market parties seems reasonable. First, they are supposed to be better informed than end users to forecast the future expansion of both generation and transmission; and second, they can at least partly mitigate this risk and impact it via their siting decisions. A downside is that the additional locational risk increases the cost of capital. In Section 4.3, we presented some of the financial instruments to hedge the locational risk in the short- and medium-term. However, FTRs are, for example, only available for up to three years. This may be the main reason why FTRs have not been used to support project finance, but rather to stabilize cash flows of existing assets (Eberhardt and Brozynski, 2017). This missing market problem (for long-term hedging) is an issue faced both in zonal and nodal markets (Joskow, 2008b; Newbery, 2016). Yet, the impact of exposing market parties to this locational risk is likely to be small. For example, Eurelectric (2016b) describes that from an investment perspective, the forward market may be relevant for investment decisions with rapid implementation (e.g., buying an existing asset), but is generally not relevant for investment decisions for new assets. Investors primarily assess the physical and regulatory risks over the lifetime of an asset, which is a much longer period.

[20] In Annex B, we provide a summary of liquidity implications of smaller bidding zones for two case studies: the Nordics and the split of the German-Luxembourgish-Austrian bidding zone.

For the same reason, the impact of nodal prices on guiding investors to locations that are more beneficial for the power system should also not be overstated. Brown et al. (2020) suggest that other factors than nodal prices drive location decisions for utility-scale generation investments. In addition, nodal price signals only reflect the short-run and not the long-run network costs. Pérez-Arriaga et al. (1995) state that nodal prices only recover about 30% of the network costs in practice, which is mostly due to lumpiness in network investment. This implies that investment decisions based on nodal prices underestimate the network costs, leading to a placement of generators too far from consumption centers. The use of additional instruments that affect the spatial distribution of generators, such as predictable transmission charges, might thus be a required complement to all market designs (Eicke et al., 2020).

4.5. Complexity

Stakeholders claim that the determination of market prices is more complex in nodal markets than in zonal markets because the internal network constraints are also considered in the market clearing process.

It is true that Euphemia, the market clearing algorithm that is currently used in the EU, would be unable to calculate nodal prices in a reasonable runtime. Already today, Euphemia is severely challenged in terms of computational complexity with 40 bidding zones (NEMO Committee, 2021). In contrast, PJM clears a wholesale market consisting of 11,000 nodes. Rather than the number of locational prices that are calculated, the main drivers for computational complexity are the clearing rule, the bidding formats and the number of network elements that are considered in the market clearing. We split the remainder of this discussion into three parts: the pricing rule, the bidding format, and the modeling of the transmission network under nodal pricing.

First, it is often impossible to compute marginal prices in the presence of non-convexities that arise due to start-up costs, indivisibilities of bids, and minimal load requirements. In the presence of non-convexities, it may become equivocal which bids to accept and to reject. The approach taken by Euphemia is to enforce strictly linear pricing, i.e., all transactions in the same trading period are settled at the same price.[21] This necessitates an additional constraint, and the market solution consequently deviates from the welfare maximizing solution. Strictly linear pricing also comes at the cost of paradoxically rejected bids, i.e., bids are rejected despite being below the clearing price. The additional constraints render the market clearing computationally difficult under this pricing rule (Van Vyve, 2011). The opposite of strictly linear pricing is non-linear pricing. Under non-linear pricing, the volumes accepted in the market are those of the welfare maximizing solution. However, some generators that are committed make a loss because their non-convex costs are not reflected in the market clearing. These generators are compensated via uplift payments. This approach sacrifices uniform prices for short-term welfare maximization. Non-linear prices are easier to compute because the market clearing is decoupled from the pricing. However, Herrero et al. (2015) highlight that non-linear prices do not fully reflect operational costs and thus do not provide efficient investment signals. Also, the uplifts payments, which only occur under non-linear pricing, can lead to gaming opportunities and are hard to allocate without creating distortions at the demand-side. Meeus et al. (2009) show that the welfare losses of linear pricing are comparatively small when compared to the magnitude of uplifts that need to be paid under welfare optimal prices. Because of these limitations of both pricing rules, current U.S. nodal markets apply a wide range of pricing rules in between strictly linear and non-linear pricing (Herrero, 2018; Hobbs and Oren, 2019). Not all non-convex costs are

[21] Also called uniform price-based clearing.

reflected in the clearing prices, and the pricing algorithm minimizes uplift payments, limiting the discrepancies to strictly linear prices.

A second source of complexity arises from the bidding formats in place in the EU (NEMO Committee, 2021). Simple price-quantity bids are complemented by block bids. A classic block bid is an all-or-nothing order of a given amount of electric energy in multiple consecutive hours. Block bids were introduced because the simple bidding format does not allow generators to account for non-linear costs; in particular, startup costs and minimum run levels. In that regard, the current market clearing algorithm may not be able to support all of these bidding formats when additional bidding zones are coupled or when the usage of certain formats is increased (ACER, 2020). Multi-part bids are a computationally less complex alternative to block bids and are applied in the U.S. nodal markets. Under multi-part bids, non-convex costs are explicit in the bid, and block bids can therefore be avoided.[22] Multi-part bids limit the ability of strategic firms to abuse market power, as Reguant (2014) shows. In the presence of uncertainty in electricity markets, Richstein et al. (2020) demonstrate that multi-part bidding is more efficient than simple and block bids.[23]

Third, the EU coupled power market is the world's largest, and it is difficult to replicate the same computational performance as the significantly smaller ISO systems in the U.S. However, the complexity resulting from the representation of the transmission network under nodal pricing may be reduced. To reduce complexity, U.S. markets only account for the most relevant network constraints in the market clearing.[24] In addition, the day-ahead market clearing is often simplified through proxying network flows in direct current (DC).[25]

4.6. Locational price differentiation

The spatially varying market prices for electricity under nodal pricing affect consumers and generators. We first discuss the effects of this on consumers, which are politically the most delicate, and then on generators. Among the latter, the impact is particularly relevant for renewable generators; they are most frequently affected by network constraints because they are often sited in remote areas.

Effects on consumers

Some stakeholders find it politically undesirable that wholesale electricity prices vary between regions within one country or state. In addition, nodal prices typically increase electricity prices around demand centers due to the concentration of demand, which might reduce industrial competitiveness. These effects may create public resistance to nodal prices.

The political desire for uniform prices for electricity consumers diverges from the economic principle of cost-reflective pricing. When discussing the effect of locational price differences on household consumers, it is important to recognize that energy commodity costs on average only account for 31% of the electricity household bill in the EU, the remainder being network charges, taxes, and levies (ACER and CEER, 2021b).[26] Hence, the distributional impact of nodal pricing on household consumers would be limited. By contrast, industrial consumers are more strongly affected by these distributional

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[22] Background information on the bidding formats in Europe and the U.S. is given in Annex A.

[23] For an extensive discussion of simple, block bids and multi-part bids, see Section 4.2.1 in Schittekatte et al. (2020).

[24] This even implies limited potential for inc-dec gaming on lines that have not been accounted for in the day-ahead stage (Monitoring Analytics, 2021).

[25] The day ahead clearing involves a multi-hour optimization, and therefore is more complex than the real-time clearing. One exception is CAISO, which also has an AC model at the day-ahead stage.

[26] Electricity commodity prices were especially low in 2020 due to COVID-19. The average share of energy commodity costs in the EU has been lower than 40% of the final bill in the last years (ACER and CEER, 2021c).

effects because they are at least partially exempted from network tariffs and taxes. Further, it should be acknowledged that within-country variation of end-user electricity prices is not new; prices already differ by region in some European countries because charges for the distribution network also diverge significantly (ACER, 2021b). In Germany, for example, distribution charges varied in 2021 between 13 EUR/MWh and 251 EUR/MWh depending on the DSO area (Bundesnetzagentur / Bundeskartellamt, 2021), this variation is very similar to estimated average annual nodal prices, ranging between -54 and 221 EUR/MWh (vom Scheidt et al., 2022).

Three options can be applied to ease the effects of nodal pricing on the demand-side. A first option is the allocation of revenues from FTRs—the auction revenue rights—to consumers (Kunz et al., 2016; Opgrand et al., 2022). A second approach is to average consumer prices in load zones. This reduces price volatility while maintaining nodal generator prices and is common practice in many nodal markets in the U.S. In CAISO, for example, there are three load pricing zones, while generators receive nodal prices (EMCSG, 2021).[27] The downside of this approach is that it weakens locational price signals for the demand-side. The U.S. regulator FERC therefore encouraged the disaggregation of such load zones (FERC, 2014). Third, it is possible to compensate consumers without affecting the locational marginal signals, e.g., through a lower fixed charge in network tariffs, or specific policy measures targeted at energy poverty or industries.

Effects on renewable generators

Under nodal pricing, generators receive lower (local) electricity prices if electricity injection at their node increases the flow on lines with binding network constraints. Due to siting constraints, renewable energy sources are most often affected (Millstein et al., 2021), and would therefore suffer most from the introduction of nodal pricing (Gorman et al., 2019; Seel et al., 2021).

In Europe, this discussion is particularly relevant for offshore wind energy, given that the European Commission advocates for offshore bidding zones. These would constitute a meshed offshore grid with small new market zones, much like a nodal market. For these offshore zones, the Commission expects that generators would receive lower prices compared to when included in national zonal markets (the so-called "home market" solution) (European Commission, 2020). Grandfathering congestion income to offshore project developers is one possible remedial action to mitigate lower market incomes (European Commission, 2020).

An alternative would be allowing for higher subsidies with renewable project developers embedding these estimated revenue impacts in their bids for renewable support. Such higher (explicit) renewable support costs, due to more granular spatial pricing, do not increase the final costs for end users. In contrast, including offshore wind generators in a national onshore bidding zone implies a cross-subsidy at the expense of increased redispatch costs. In a meshed offshore grid, the coordination between cross-border power flows would also be sub-optimal. These implicit subsidies for offshore wind developers are likely to exceed the increase in explicit subsidies or awarded revenue from the sale of transmission-rights.

5. Summary and discussion

Table 3 summarizes the six identified arguments against nodal pricing and our findings. It shows that all claimed shortcomings of nodal pricing are either ungrounded or can be addressed by specific market design, regulatory, or policy measures.

[27] A similar approach is used in Italy which currently has seven zonal prices for generation, but one weighted average price for load.

Table 3: Summary of the arguments against nodal pricing and possible mitigation options

	Argument against nodal pricing	Main finding and possible mitigation options
1	Market power	Market power may arise in zonal redispatch markets and in nodal wholesale markets. The wholesale market is easier to monitor, and ex-ante market power mitigation tools have been successfully implemented in nodal markets.
2	Barriers for flexibility a. No continuous ID trading b. Demand and storage participation c. Topology changes	a. Continuous ID trading is possible under zonal and nodal pricing, but requires trade limitations or subsequent redispatch. Intraday auctions are the preferred option. b. Demand and storage can participate in a central dispatch model. Self-scheduling is possible and bidding formats evolve. More volatile prices improve their business case. c. The value of topology changes is lower, and embedding the grid topology in the market clearing is not excluded by design.
3	Market liquidity	More price volatility will create liquidity in forward markets. Long-term hedging can be done in hubs. Locational risk is not excluded, but can be to a large extent mitigated with FTRs or basis swaps.
4	Investment risk	Locational risk that is socialized under zonal pricing is borne by market parties under nodal pricing. This improves incentives for siting decisions, but hedging the locational risk is hard.
5	Complexity	The spatial granularity of prices is one driver of computational complexity next to the pricing rule and bidding formats.
6	Locational price differentiation a. For consumers b. For renewable generators	a. The impact on average energy prices is limited in most cases because the wholesale power prices make up only one third of household consumers' electricity bills. The impact for industry is larger. Mitigation tools include the grouping of nodes for consumers, the allocation of congestion rents to end users, and targeted energy poverty and industrial policy-related measures. b. Zonal markets provide implicit subsidies to renewables. Explicit financial support to renewables might increase, but its costs would be more than offset by lower redispatch costs.

Among the six identified concerns, we consider market power issues and potential barriers to unlocking flexibility to be unsubstantiated. Market power arises independently of the market design. Under nodal pricing, market power is likely easier to monitor, and by using the transmission network more efficiently, we expect on average more competition, and therefore a reduction in the overall potential for market power abuse. Similarly, there is no evidence that the implementation of nodal pricing would be a barrier for demand response and storage. Instead, it might even improve their economic viability: More volatile local-specific prices have a positive impact on their business cases.

More nuanced is our view on hedging and future price risks, which are related to the issues of market liquidity in forward markets and investment uncertainty. In the short- to medium-term, the locational price risk in nodal markets can mostly be hedged with well-designed financial instruments and designated trading hubs, as the U.S. experience shows. Only in isolated nodes might it be costly or even impossible to find the perfect hedge. This is disadvantageous, but only affects a small share of market participants. Importantly, more volatile nodal prices stimulate more hedging activity and therefore might even improve forward liquidity. In the long run, the locational basis risk is not socialized, as it is under zonal pricing. Instead, under nodal pricing this risk is borne by those most likely able to manage it, which creates locational incentives. Besides the price risk, investors account for the physical and regulatory risks over the lifetime of an asset. The implementation of nodal pricing may lower the regulatory risk compared to the threat of frequent bidding zone revisions.

It is true that nodal pricing comes with increased computational complexity. That said, the pricing rule and bidding formats are also important drivers of computational complexity. In the EU, strictly linear pricing and multiple bidding formats are in place, including simple bids, block bids, and variants thereof. By contrast, U.S. nodal markets apply pricing rules in between strictly linear and non-linear pricing and use multi-part bidding formats. These design choices are not specific to the spatial granularity of the power market (Herrero et al., 2020), but the pricing rule and bidding formats in the U.S. are computationally less complex and thus better compatible with nodal pricing. Independent of whether the EU introduces nodal pricing, the pricing rule and bidding formats will need to be revised to allow for having also 15-minute products, instead of solely hourly products, as stipulated in Regulation (EU) 2019/943. Besides these changes, applying nodal pricing in the world's largest interconnected power market would necessitate simplifications in the way the network is represented. Although imperfect, the market clearing will still be much more efficient than under the zonal setup. More research is required on how significant the simplifications need to be to render a nodal EU power system solvable; after all, it would exceed the size of PJM—the world's currently largest nodal system—by a factor of 3.5 in terms of served load.

Last, electricity prices with a fine spatial granularity, as under nodal pricing, are cost-reflective and necessary to provide adequate incentives. The impact on the final bill for household consumers would be limited. Local price differentiation is not new in electricity, and already enters, for example, via regional distribution tariffs. Local price differentiation for load could be mitigated and should therefore not be used as an argument against the introduction of nodal pricing. Examples of mitigation measures are the allocation of congestion rent to disadvantaged grid users, the bundling of demand-side nodes into an aggregate price node (which is not a preferred long-term solution), and most importantly, targeted measures for energy poverty or industrial competitiveness that do not distort price signals at the margin. Regarding renewables, higher explicit financial support might be needed in the short run to counteract lower market values of renewable energy sources under nodal pricing.[28] This reflects the removal of an implicit subsidy (for network externalities) when transitioning from zonal to nodal pricing. The explicit support can come in the form of (temporary increased) subsidies or the allocation of congestion rent. The more efficient operational incentives compensate for the higher support costs, and result in an increase of overall welfare. Yet, the need for increased explicit financial support in the short run might politically be hard to defend.

6. Conclusions and policy implications

The academic literature provides strong evidence that the cost savings of nodal pricing are significant. Case studies from both sides of the Atlantic estimate saving potentials of 1% to 4% of the operational costs when transitioning from zonal to nodal markets. For the EU system, this corresponds to savings of a few billion Euro per year. Why has nodal pricing not yet been seriously considered in the EU?

We identified six main arguments that stakeholders put forward against the concept of nodal pricing. By discussing the validity of these arguments, we clarified prevailing misconceptions of nodal power markets. We showed that these concerns can be sufficiently addressed as it is done in systems that have a nodal market for many years or even decades.

Because the above-discussed arguments have dominated the European debate so far, our main policy recommendation is to reconsider nodal pricing in the EU. Further, our analysis also contributes to the ongoing discussion on the bidding zone review in the EU, where similar arguments are brought up

[28] Due to the higher nodal price volatility, baseload plants may get replaced in the longer run by more flexible peaking plants, which may benefit renewables. No literature is found on these long-run effects of nodal markets.

against smaller bidding zones. The experiences from nodal markets discussed in this paper can also help to design regulatory tools for coping with many of the challenges that small bidding zones face. Moreover, our findings inform the debate on market design options in countries that intend to introduce a wholesale power market.

We see two avenues for further research to support the decision of whether the EU should transition to a nodal market. First and foremost, we strongly encourage future research to investigate what changes a transition from zonal to nodal prices in the EU would entail in term of market design and the institutional setup, e.g., as explored by the SYNERGIE consortium (Ashour Novirdoust et al., 2021). A detailed comparison of the implementation of nodal markets around the world could inspire the design options. Second, we recommend analyzing the welfare benefits of nodal pricing compared to zonal pricing in a fully decarbonized power system. While available studies mostly focus on current power systems, we expect the gains of nodal pricing to be even greater at higher shares of variable renewable energy sources and more flexible demand. These two streams of research can help answer the key question: whether the difficulties that would need to be overcome when transitioning to nodal pricing justify coping with the inefficiencies induced by the zonal market design.

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Annex A: Main differences between U.S. nodal and EU zonal pricing

In this paper, we discuss differences between nodal and zonal markets. As a reference for design choices, we use U.S. ISO/RTO design for nodal markets and the zonal design currently applied in European countries. We focus on the day-ahead (DA) market as it is still the reference market today. We touch upon forward markets and closer to real-time markets in Section 3. Table 4 lists five main differences. Please note that market designs on each side of the Atlantic are not at all uniform.

Table 4: High-level comparison of the nodal U.S. style and zonal-EU style day-ahead market

Characteristic	Nodal (U.S. RTO/ISO style)	Zonal (EU style)
Dispatch decisions	Mostly central dispatch, self-scheduling of some assets	Self or central dispatch
DA market operator	ISO	Power exchange
Bid design	Multi-part bids	Mostly simple and block, possibly multi-part bids
Market clearing rule	Linear pricing	Strictly linear pricing
Balancing responsibility	Unit-based	Portfolio or unit-based
Reserve procurement	Co-optimized	Sequential

In the U.S., nodal markets are operated under centralized dispatch. The independent system operator (ISO) decides on the dispatch of operators, which thus also termed integrated market. In several U.S. systems, some assets and loads are eligible for self-scheduling, implying they submit operation schedules to the system operator. The self-scheduled resource is a price-taker for energy at the scheduled quantity. The ISO also clears the market based on the submitted multi-part bids that reflect besides the variable energy costs (in $/MWh), as well as other operation costs, including start-up and no-load costs (Mansur and White; 2012; Ahlqvist et al., 2019). Not strictly linear pricing is in place, which means that each cleared bid and offer receive the clearing price plus possibly limited side-payments (if solely relying on the clearing price would be loss-making). In nodal markets, deviations from the schedule are settled at the nodal-level and therefore are typically unit-based. Finally, in the U.S. implementation of nodal markets, the procurement of balancing reserves is co-optimized with the day-ahead clearing.

By contrast, most European power systems operate under self-dispatch, where each balancing responsible party (BRP) decides on its own dispatch. A few European countries apply a centralized dispatch, including Greece, Italy, Ireland, and Poland (ENTSO-E WGAS, 2021). Wholesale markets are operated by power exchanges. Most countries with self-dispatch use a simple bidding format, consisting of a volume and a price for energy per hour or in blocks of several hours, to determine the market clearing price. This simple format obliges agents to internalize all production costs and technical constraints in their bids. The lack of intertemporal constraints exposes market participants to the risk of unfeasible or uneconomic scheduling, which can be adjusted through subsequent trades. Intraday markets are thus particularly important in these markets. Strictly linear pricing is in place in the day-ahead market, i.e., there are no side-payments. Instead, the market clearing price results in loss-making bids by allowing for the possibility to reject block bids that would have been in the money for the given clearing price. These rejected block bids are called paradoxically rejected blocks. In European zonal markets, balancing responsibility applies often on a portfolio-level[29] and sometimes at the level of individual units. Finally, auctions for the procurement of balancing capacity are organized before the day-ahead clearing. Balancing service providers must estimate their opportunity costs for not offering their capacity in the day-ahead market when bidding in the balancing reserve auctions.

[29] Portfolio-based balancing responsibility facilitates balancing for larger utilities. Yet, in the case of network constraints, it may impose major challenges on network operators.

Annex B: Forward liquidity with smaller bidding zones

In this annex, we briefly discuss the experiences with liquidity of smaller bidding zones in the Nordics and the implications on forward liquidity of the split of the German-Austrian-Luxembourgish bidding zone.

The experience from the Nordic market on hedging the locational risk is mixed. Electricity Price Area Differentials (EPADs) are forward contracts on the difference between a zonal price and the Nordic system price.[30] Different from FTRs, EPADs are not sold by the TSO; instead, they are traded between market participants on an exchange (Spodniak and Collan, 2018). As such, the revenue loss issue with FTRs in PJM is not possible under EPADs, but there is no guaranteed counterpart for each EPAD. EFET (2016) shows that liquidity of forward and EPAD contracts is low in the Nordic region. One plausible reason is the very high price correlation between zones (between 2015-2019: 92%-100%), leading to a low need for hedging (while the number of hedging products increased due to the split of market zones in 2011). An alternative explanation for this decrease is that hedging needs for market parties declined due to the rise of PPAs in the Nordic region during those years (THEMA, 2021). Spodniak and Collan (2018) suggest that transaction costs and the product's complexity may be barriers for liquidity in the EPAD market. Since 2020, the correlation between Swedish zonal prices declined (ENTSO-E, 2021), while liquidity in the EPAD market increased (THEMA, 2021).

The split of the German-Austrian-Luxembourgish bidding zone in 2018 is an interesting case to study the effect of smaller zones on market liquidity. In the German-Luxembourgish bidding zone, liquidity in the forward markets reduced slightly before the split, but quickly picked up again after (Figure 1). By contrast, liquidity of the new Austrian forward market fell sharply. However, the correlation between monthly average day-ahead prices in Germany and Austria is very high with 94% (ACER and CEER, 2019b). Hence, Austrian market participants can use a German product as a proxy for hedging, or combine a forward contract traded in the German bidding zone with an FTR.

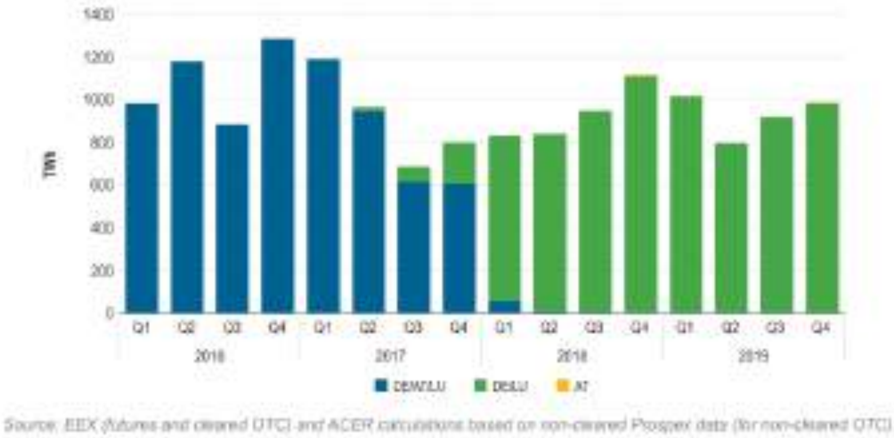

Figure 1: Quarterly forward traded volumes in Germany, Luxemburg, and Austria per bidding zone (ACER 2020)

The two highlighted European examples show that a high cross-zonal price correlation creates little demand for cross-zonal hedges. Consequently, the respective financial products are not necessarily well developed, but their importance soars in the case of smaller bidding zones or when the price-correlation declines. It can take some time for these markets to develop, but there are no indications not to believe that increased short-term price volatility will lead to more liquidity, and as such, this chicken-egg problem will resolve itself.

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[30] The Nordic system price is calculated as the price that would have resulted if the Nordic network was a copper plate.