Market-based redispatch is a necessary complement to the current German re-dispatch regime

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The need for redispatch actions to manage congestion is increasing

Network operators face an increasing need for congestion management.

Over the last 4 years the cost of congestion management was almost 5 billion EUR in Germany. The first quarter of 2019 saw the highest level of RES curtailment – 3.3 TWh [BNetzA 2019a]. The forecast for distribution network expansion cost of the largest distribution network operators has continuously been updated over the last years (from 6.6 billion EUR in 2014 to 11.1 billion EUR in 2018 for the next ten years) [BNetzA 2019b], which underlines the urgency for effective congestion management solutions.

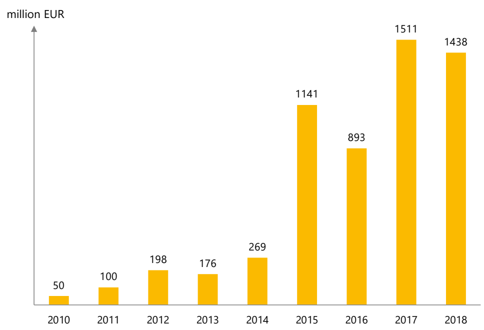

Figure 1: Increasing costs for redispatch in Germany between 2010 and 2018[1]

The continuous expansion of RES and the simultaneous phasing out of coal, combined with likely delays in network reinforcement, suggest that a significant amount of redispatch actions will continue to be necessary and cost of redispatch may increase even further in Germany.

Network and RES investment need to be coordinated, and the congestion management processes have to help deliver efficient outcomes.

Several steps have been taken by the European Commission to increase the flexibility of the electricity system and help with efficient congestion management. A market-based approach is promoted by the EU's Clean Energy Package to make the entire flexibility potential available for redispatch, increase competition and encourage innovation.

Market-based pricing reveals and rewards the real value of energy – including network congestion – at a given time and location. It increases transparency and incentivizes a wider range of market participants (including demand side providers, distributed generation and storage) to provide redispatch volume beyond the minimum volume obligation under the current regulated scheme. Market-based pricing fosters innovation to deliver new products and solutions for efficient electricity market operation.

The business case for new flexibility providers is typically built from stacking revenue from a series of services, including energy, various ancillary services and transmission and distribution congestion management.

Market-based congestion management can be realized through dynamic, time- and location-dependent network tariffs, nodal pricing or market-based redispatch.

The European Union sets market-based mechanisms as the standard for congestion management (Clean Energy Package[2]). Non-market-based mechanism may only be used "where the current grid situation leads to congestion in such a regular

[1] Source: Network and systems security report of the Federal Network Agency Germany (BNetzA)

[2] Regulation (EU) 2019/943 of the European Parliament and of the council of 5 June 2019 on the internal market for electricity - Article 13

and predictable way that market-based redispatching would lead to regular strategic bidding which would increase the level of internal congestion."

The German government appears to be opposed to move towards a market-based congestion management system

The regulated process in Germany for congestion management relies on:

1. **An obligation** to offer available capacities for redispatch capacities "at cost" to the network operator.

2. **Network reserves**: Generators that retire have to continue to deliver redispatch services to the network operator at cost, when necessary for security of supply.

3. **New dedicated network generation assets** are being developed by the network operator to increase N-1 security.

A substantial and increasing part of the generation capacity will be subject to a heavily regulated German redispatch regime.

The number of redispatch providers will increase significantly once all generators above 100 kW have to provide their services under the new NABEG legislation – from approx. 80 power plants currently to over 60,000 generators by 2021 (see Fig. 2).

	< 100 kW	100 kW – 10 MW	> 10 MW
Production (conventional producers, RE plants, CHP plants)	Covered in the future by NABEG (only RE systems) Not covered	Covered by NABEG in the future	Covered by NABEG in the future Already covered today (only for conv. Producers)
Storage (batteries, electrolysis, e-cars, etc.)	Not covered	Covered by NABEG in the future	Already covered today
Demand (Industry, commerce, households, heat applications, etc.)	Not covered	Not covered	Not covered

Potential for market-based redispatch

Figure 2: NABEG increases the number of flexibilities available for redispatch, but still left-out demand-side flexibilities and small-scale generators

The regulator BNetzA expects that the required capacity to be contracted as "network reserves" will increase from 5.1 GW in 2019/20 to 10.6 GW in 2022/23 resulting from increasing cross-border trade and decommissioning of power plants in southern Germany.

The justification of regulated redispatch based on a theoretical example alone is insufficient

The decision for a regulated system is justified by the potential threat of gaming and assumes away all advantages of market-based approaches.

The so-called inc-dec game has been used as an argument by the German BMWi for retaining a cost-based regime.

The key advantage of a cost-based approach is the removal of incentives to engage in inc-dec-gaming, which has been furiously discussed in academic circles. We acknowledge that when trading electricity across various timeframes – day ahead, intraday and balancing – market participants will always attempt to exploit arbitrage opportunities to maximize the value of their production and consumption flexibility. A similar principle applies to redispatch.

There are, however, various caveats in the simplistic analysis put forward that aim at discrediting a market based redispatch approach:

- The examples assume the presence of perfect foresight of pricing and redispatch volumes.
- Demand is assumed to be inelastic.
- The system is assumed to be static without investment needs.

Gaming always involves risks under real-world market conditions. Neglecting these risks will inevitably lead to overestimating the threat of gaming.

Inc-dec gaming involves risks for the market participants. Such risks arise from the difficulty to anticipate the interdependencies between bidding strategy and network operator actions, as well as the reputational risk in the event that there is price transparency.

With respect to the inc-dec gaming with a market-based mechanism, the main risks include the following:

- The effect of different bidding strategies on congestion is highly influenced by network characteristics.
- These, in their turn, are influenced by network operators' actions, e.g. through switching measures and topology changes.
- More active network assets are available to optimize network operation, which increases significantly the complexity of forecasting possible congestions (phase shifters, onload tap-changing transformers, reactive power provision from decentralized RES).
- Allowing demand side providers to actively support redispatch through a market-based scheme would further increase these risks.

It would be naive to neglect these risks when assessing the gaming potential.

Risks and gaming opportunities are influenced by market design and corresponding regulatory measures (such as price caps, restrictions to vary prices between markets, etc.). The evaluation of a market-based redispatch mechanism as performed by Hirth et al. neglects these risks and is therefore incomplete.

Real-world experience shows a moderate relevance of gaming - clearly below the theoretical potential

A discussion of different design or regulatory options to quantify risks is certainly beyond the scope of this paper. However, some relevant international examples shall help illustrate the importance of considering actual risks faced by participants.

Other European countries have implemented market-based congestion management. Thus, three examples are analyzed to see if gaming has actually taken place.

Example 1: Congestion management in the Netherlands

On a transmission system level, the Dutch TSO TenneT can use balancing energy bids with a geotag and a full activation time of more than 30 min. or contract redispatch resources with regulatory oversight (not regulated costs) to solve congestions [TenneT 2019].

Additionally, a system has been put in place to use market-based congestion management as an alternative to bridge delays in network expansions. If a TSO or DSO foresees congestion, congestion management, as it is laid down in the Dutch Grid Code, may be applied. Here, requirements are formulated that specify a cost-benefit-analysis to demonstrate the need for (temporary) congestion management. Furthermore, the network operator must present realistic grid investment plans that resolve the congestion over time. The Energy Supply Consultation group (OTE) – an industry roundtable – has even suggested that market-based congestion management can replace network reinforcements under the given grid code [OTE 2018]. Such a mechanism is also introduced by the CEP as an alternative to building assets.

To limit gaming, the market-based regime can only be applied, if within the congested area at least three or more competitors exist, else negotiated contracting must be applied, with regulatory oversight. Market parties have been well educated on risks they incur for themselves and for society when trying to game. Regulatory intervention, penalties and bidding zone splitting are proposed as threats to limit gaming. As a result, market parties watch each other carefully and inform the regulator if suspicious behavior occurs. The inclusion of demand side providers is a key limitation on the potential for generators to benefit from gaming.

So far, a recognizable increase in network congestion, resulting from a gaming behavior of market parties, has not been observed in the Netherlands – despite the theoretical potential.

Example 2: Experiences on the Danish-German border

In case of physical congestion at the Danish-German border, the TSOs on each side of the border conduct countertrades. Here, a possible gaming opportunity emerges as the Danish TSO Energinet uses mFRR for redispatch as the so-called special regulation [Energinet, TenneT 2019]:

- Balancing responsible parties (BRP) for generators could bid with high generation on the spot market in such events. At the same time, these BRPs could offer downward regulation in regulating power market. Thus, they would receive payments for a problem they caused.
- BRPs for consumption purchase less electricity than needed and offer upward regulation at the same time, thus under-schedule.

These actions rely on the predictability of time and volume for special regulations. Energinet and TenneT analyzed if market parties engage in such behavior and concluded the following [Energinet, TenneT 2019]:

- "Energinet sees no indications that it [price arbitrage] is occurring. Thermal units have supplied an increasing volume of downward regulation (special regulation) over the past three years but looking at the scope of supply over the year etc., it is not possible to identify any atypical operations."
- To identify under-scheduling Energinet monitors BRPs' total purchases/sales and final imbalances in

relation to the used special regulation. “From this monitoring it has been found that certain players actually do buy much less than their requirements during certain periods of special regulation. However, **they do not exhibit consistent and systematic behaviour**, and this is probably because **it can be difficult to predict the scope of special regulation with sufficient precision**” [Energinet, TenneT 2019]. However, only 10% of imbalances during hours of special regulation can be allocated to under-scheduling.

This Danish border example shows that theoretical gaming opportunities exist, but the impact seems not to be material.

Example 3: The British experience

In Great Britain three core aspects ensure efficient operation with a market-based regime:

1. The TSO is incentivized to manage the cost of congestion. It is given freedom to conduct contracting in a range of timeframes and contract forms, rather than being a forced buyer in one mechanism alone. This means that the TSO can choose freely how to contract with generators and market actors. This includes the usage of balancing offers for congestion and other purposes within a single balancing market.

2. The GB TSO has been highly innovative and successful in seeking out alternative sources of flexibility especially from the demand side (dating back to the 1990s), and (more recently) from batteries in the form of Enhanced Frequency Response tenders. Although not all these providers are well placed to deal with locational issues; some are.

3. Despite a strongly pro-market philosophy the regulator has substantial powers, including the right to fine companies up to 10% of their global turnover in case of a breach of competition law. Thus, the backstop of competition law is taken seriously.

GB is not a one-sided story in favor of a blind market-based approach. The introduction of the BETTA market in 2005 (in which Scottish generators were granted the right – in return for ongoing payment of locational network fees – to access the wider GB network) was compounded by introduction of the 'connect-and-manage' regime, which facilitated new wind generation in Scotland before network upgrades were complete.

These two factors exacerbated the existing export transmission constraints from Scotland to England, after years of slow investment and planning delays. Ofgem perceived the potential for unacceptable bidding behavior by generators behind the transmission constraint but felt that under the previous regulator’s regime it did not have clear enough grounds to intervene.

Seven years after Scotland joined the trading arrangements in 2012, Ofgem introduced the Transmission Constraint License Condition (TCLC) on generators, which sets out a definition of circumstances in which their behavior would be deemed unacceptable. It states that “the licensee must not obtain an excessive benefit from electricity generation in relation to a Transmission Constraint Period.” This condition is very far from being a cost-based bidding rule. It is essentially a confirmation that the market should be allowed to work but that abuse of a transmission constraint would not be permitted. There remains the ultimate backstop of competition law that precludes the abuse of a dominant position in a market, which might be defined in terms of location and time.

Ofgem has estimated that the TCLC has delivered a £156m cost saving since its introduction [Ofgem 2017]. There has been only a single enforcement action since its introduction in 2012. A less restrictive and 'targeted' regulatory measure has allowed for the continuation of a market-based approach and removed gaming incentives.

The British example shows the effectiveness of light-touch regulatory measures allowing market-based redispatch and limiting gaming opportunities at the same time.

The common denominator of all these examples for a successful implementation of a market-based solution is to allow a substantially market-based solution that relies on a regulated regime as a backstop. In reformulating the license condition in 2017, it was reduced in scope, as the relevant circumstance is already covered in the REMIT legislation.

The regulated redispatch regime neglects significant economic and environmental benefits in the short and medium term

Cost-based regulation has proved to be the second-best to real competition in electricity and other markets across the globe. The nature of competitive market forces drives efficiency over various timeframes, including incentives to maintain and improve existing capacity and to invest in new capacity. Under a short run marginal cost-based regime, this dynamic efficiency tends to be lost as actors attempt to optimize their regulated revenue without the ability to cover the entire opportunity costs.

Increasing the competition by switching to a market-based regime allows storage systems and the demand side to offer their flexibility services. Cost-based regimes fail to properly include demand flexibilities as – depending on the way in which 'marginal cost' is calculated – there would be no commercial value for the provider to set up or activate the arrangements. This would not be the case with a market-based regime.

Increasing the 'pool' of potential redispatch volumes, especially by properly including and valuing demand, should significantly improve the system operators' options for solving congestion.

The untapped flexibility potential that can be reached with a market-based approach is enormous. The potential of decentralized load flexibilities (EV, electrical heating, batteries) can be up to 22.5 GW by 2030 – and this may even be a conservative estimate [E-Bridge, IAEW 2019].

Including large-scale load customers further improves the effectiveness of congestion management. Various pilot projects have demonstrated that using resources closer to the congestion area reduces the need for activating generators far away from the congested area. This results in lower redispatch volumes [Deuchert 2019]. However, the true potential will only be revealed once a level playing field between generation and demand has been established.

Distribution companies need effective congestion management tools to support the continued energy transition.

As the penetration of small-scale RES will continue to grow and as the electrification of transport, heating and industry continues, we will face increasing congestion at distribution level. Unless effective local markets for flexibility can be delivered, electrification and decarbonization will be delayed and there will be huge unnecessary spend on distribution infrastructure. The need for local congestion management will not diminish over time.

A study of IAEW and E-Bridge analyzed the Germany-wide distribution network with more than 1.8 million simulations to evaluate the effect of considering demand-side flexibilities and storage on network reinforcements.

If the distribution system operator gets access to this additional flexibility, the additional distribution network investment needs could be reduced by 55% from 36.8 billion to about 16.8 billion EUR by 2035. Even when considering activation costs for flexibility and costs for ICT in distribution networks, the annual costs can be reduced by 1.6 billion EUR per annum.

As well as the material economic savings, significant environmental benefits are expected. By making the additional flexibility available to the network operators, the curtailment of RES can be reduced by up to 65 % and CO_2 emissions can be saved [E-Bridge, IAEW 2019].

We suggest supplementing the existing regulated congestion management scheme with a market-based one

Considering that congestion will continue to exist in the German transmission and distribution networks for many years or even decades, the efficiency of a chosen congestion management scheme over time becomes increasingly important for the success of the "Energiewende".

A sustainable and effective congestion management scheme must therefore capture the advantages of a market-based approach while limiting the impact of gaming.

The market-based redispatch shall only be applied to those flexibilities, which are left out of the current regulated regime – namely small-scale generators and the entire demand portfolio. Here, both mechanisms – the regulated and the market-based one – can complement each other.

Particularly, by keeping the regulated regime intact, the gaming risks of the market-based mechanism can effectively be capped and controlled.

This "hybrid" model allows the introduction of a market-based congestion management, to increase the number of available flexibility resources and enhance competition without jeopardizing economic efficiency.

Such a hybrid system can be introduced leaving the single price zone in Germany intact. The approach is complementary to the existing markets and may even assist to strengthen them. The mechanism implemented in the Netherlands demonstrates how the flexibility market can be integrated with the existing intraday market.

While a market-based redispatch regime would certainly increase the efficiency of congestion management within Germany, it may also help to improve the cross-border redispatch.

The design of the market-based redispatch arrangements should be carefully developed to allow the market-based approach to expand into and replace parts of the regulated regime while valuable experience will be gained and trust into the market-based mechanism grows. Ultimately, non-market regimes, which rely on forced pricing as well as block market exit and TSO-led procurement of capacity, may be removed.

Conclusions

Given the lack of coordination between grid and renewable energy expansion, the increasingly difficult implementation of infrastructure measures as well as the continuing electrification of transport, heating and industry, the need for congestion management will continue to grow and lead to higher costs linked to redispatch in the long term. **Efficient approaches for managing congestion are a central component of the "Energiewende" and its importance will increase as distribution networks support further electrification of transport and heating and new types of load.**

Despite the Clean Energy Package requirements, BMWi regards a regulated approach as the only viable option for congestion management. This decision is based on the perception of potential gaming arising from market-based congestion management. This assessment is based solely on simplified theoretical analyses and selective evidence from elsewhere.

However, BMWi's theoretical analyses do not seem to reflect the actual risks faced by market participants in practice. **An analysis of real-life examples from the Netherlands, Denmark and Great Britain shows that 'misconduct' is in practice much less relevant than what the theory would suggest, and far less restrictive regulatory backstops can be used.**

The benefits of a market-based approach seem to be ignored, and it is only the alleged costs associated with gaming that are put forward. The assessment of and comparison between market- and cost-based approaches should be complete and objective.

By opting for the regulated approach, a high proportion of the available flexibility is blocked from congestion management. The economic and environmental benefits of this additional flexibility in combination with its innovative nature outweigh the downsides. **IAEW and E-Bridge estimate the additional potential at around 25 GW by 2030, which could save up to 20 billion EUR in network investments and reduce the RES curtailment by up to 65%.**

A market-based redispatch solution is used in other countries. Why not also in Germany? The generator-centric view of electricity systems is becoming obsolete and arrangements (such as the cost-based approach) that are built around generators shall slowly be abandoned. We recommend the introduction of a market-based regime to run in parallel with the regulated system. The design of the market-based regime must ensure that the advantages are fully exploited, and gaming risks are minimized. In time, all stakeholders should start feeling more comfortable without a regulated redispatch process, and the market-based approach can be fully embraced.

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