MARKET-BASED REDISPATCH IN THE DISTRIBUTION GRID

WHY IT WORKS!

NODES AS

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Objective:

The objective of this report is to explain why market-based redispatch in the distribution grids will work in practice. The concerns about inc-dec bidding are important and requires attention to design, operation and monitoring of local flexibility markets. The report explains why the benefits of a market-based approach are important, and how mitigating measures as well as embedded incentives and uncertainties of distribution networks will ensure local flexibility markets are effective.

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1 INTRODUCTION

In Europe, there is a heated debate about how to manage grid congestions in the electricity network. The regulated approach currently ruled by the German regulator BNetzA and applied by German TSOs has been questioned by different stakeholders for quite some time, as the general European attitude is 'pro market' and European electricity legislation generally supports market-based solutions.

While the key arguments against market-based redispatch focus on the potential for inefficient outcomes of such market designs, it is worthwhile to reflect on the traditional understanding of the energy sector and the management of energy production and electricity demand. This will also add the relevant context for understanding the long and complicated process of developing demand side flexibility as a resource and paving the way for such flexibility in e.g. balancing and congestion management at both transmission and distribution level.

Three decades ago, the process of transforming the principles for governance in the electricity sector started. The underlying view was that it was the responsibility of the sector to satisfy the demand for electricity – in all situations and under all circumstances, regardless the costs. The sector consisted of companies operating an integrated and inseparable set of tasks, typically enjoying monopoly privileges within a defined geography, against obligations to serve all end users within the designated area.

One cornerstone of the transformation process was a clearer separation of tasks and responsibilities, better known as liberalization of the electricity sector at the end of the 90´s. Nowadays, a further cornerstone relies on introducing competitive forces whenever applicable and tighter economical and technical regulation of the remaining monopolies, both on transmission and specifically on distribution level.

A fundamental principle for the EU regulation of the electricity sector is the equal, non-discriminatory, and transparent treatment of all resources. Another principle is the recognition of market mechanisms as the natural first choice for allocation of resources. These principles collide with the traditional view on the role of electricity demand and what we today refer to as demand side resources.

This transformation process, however, is not yet complete – if it ever will be. Some important milestones are achieved, while others are still under preparation. One important milestone that is not yet reached is the full recognition of demand for electricity as comparable with demand for other goods: how much an end user would like to consume at a given point in time depends on numerous factors. The costs for the consumer, of which electricity prices are a key element, are one of those factors. The implications of this 'new' perception of end use are several and include that the traditional distinction between supply and demand in the electricity sector is not as useful as it was. Satisfaction of end users' demand is no longer the sole responsibility of producers and network operators, the former utilities. One end user's demand can be met not only by means of traditional efforts from utilities (like increased production or expansion of the network), but also by means of changes in consumption by other consumers, or by market agents combining the interests of multiple resources and customers. Network constraints can be relieved also by non-wire alternatives, including demand response, specifically at the distribution level While previously the electricity sector adapted supply so that it always matched the consumption, the new perspective is that we might as well also adapt consumption that it fits with supply and (m)any network constraints. Eventually, it will of course be a combination of the two.

2 MARKET-BASED REDISPATCH

Since the 1990ies, most of the debate about congestion management focused on the overall market design of the wholesale market, at the transmission level. Europe has developed a zonal approach, in contrast to the nodal market design applied in several US markets. With few exceptions (Scandinavia and Italy), European bidding zones follow national borders, and thus some of these are very large with an increasing number of internal congestions due to fast growth in intermittent renewable electricity production.

During the past decade, the debate has extended to the emerging question about how to deal with local congestions in the various distribution networks. Here, the causes for congestions can essentially be similar to those at the transmission level, but it can also be related to changes in the demand for and use of electricity.

In response to the (increasing) internal congestion issues in the large bidding zones, where Germany is the most prominent example, TSOs have changed how they calculate network capacity to be made available for the day-ahead and intraday markets, and they have increased their use of so-called redispatch. Redispatch means that the TSO asks market participants to adjust production or consumption at each side of a congestion – simultaneously and in or shortly before real-time. One side of the congestion is a surplus area; here the aim would be to reduce production and/or increase consumption from what is determined after the day-ahead and intraday markets. The other side of the congestion is a deficit area; here producers may be asked to increase production while consumers may be encouraged to reduce consumption. Such redispatch actions are normally compensated by the TSO.

The detailed approach to redispatch has been different from country to country. While numerous countries rely on market-based methods based on voluntary participation, the German approach has always been a regulated approach based on mandatory participation for (some) producers. German authorities have initiated significant analyses about whether to introduce market-based approaches. The final report from the project "Beschaffung von Redispatch" (Procurement of redispatch) commissioned by the Federal Ministry for Economic Affairs and Energy identifies more risks than chances for market-based redispatch (Hirth, Schlecht, Maurer, & Tersteegen, 2019). Hirth & Schlecht (2020) provides a pedagogical explanation of market-based redispatch and associated challenges using graphics and stylised bid-/ask-curves for supply side assets. The results of these analyses are widely known via various articles and discussions about strategic behaviour in relation to congestion management and so-called increase-decrease gaming or bidding, hereinafter referred to as inc-dec bidding. A good overview of other relevant publications in this context is given by Brunekreeft et al. (2020), which provides a balanced and nuanced economic analysis of this topic and includes the demand side in their illustrations.

While these papers are analysing congestion management at transmission level, their conclusions are by many considered relevant also for local congestions, regardless the technical cause of congestion, being it a thermal constraint, voltage etc. This paper adds to this discussion by focusing on the key assumptions for 'successful' inc-dec bidding, potential mitigating efforts and why market-based congestion management is likely to be a preferred approach, at least in distribution networks.

2.1 Key benefits of market-based redispatch

The aim of organising market-based redispatch, or more general applying market mechanisms for congestion management as well as for balancing and ancillary services (Pollit & Anaya, 2019), is to mitigate technical constraints and to improve the efficiency of the electricity sector. With efficiency, we refer to the relation between total costs and total benefits, for the society at large. The static dimension of efficiency refers to how resources are allocated at a given point of time. Because technology and preferences change over time, an allocation of resources that is efficient today is not necessarily efficient tomorrow. The dynamic dimension thus refers to development over time. From a societal perspective, we are obviously interested in both.

Markets are generally and under the right conditions, superior to other allocation mechanisms in terms of achieving short- and long-term efficient allocations. 'Other' mechanisms normally mean some sort of regulated and/or centrally planned allocation. In the case of congestion management, the expected benefits are related to easier and better utilisation of demand side resources and thus potentially lower costs, as demand side flexibility often and at least to some extent is cheaper than changing electricity production. As an example, using the demand side flexibility of an end user who is willing to postpone (slow) charging of EVs from early evening to after midnight is already facilitated by most makes of EVs and will for most EV owners not imply any loss of comfort. Hence, in many cases, demand response may be a faster, more flexible and cheaper approach than increasing the network capacity .While network changes normally will take months if not years, automation and adapted use of heating or cooling facilities can be achieved within days or weeks (unless major changes in the heating or cooling infrastructure is necessary, of course).

The key reason for the difference is that market approaches does not require a regulator or a central planner to have (full) overview of costs and opportunities for all potential suppliers; it generally suffices that market participants know about their own costs. Market-based approaches are thus frequently classified as decentralised decision systems. If the potential providers are limited to a few power producers, with a limited number and/or types of power plants, it can be feasible for a regulator to assess costs. In such cases, centralised decision systems may work quite well. As marginal costs of production at traditional power plants are not directly dependent on the state of the power market, the regulator may choose recent bids to e.g. the day-ahead market as a proxy for the marginal costs for such plants.

But if all end users are also potential service providers, the regulatory overview is a different ball game. First, there is a vast number of potential sources, and these sources are quite different. Further, their cost structure for changing load may be highly dependent on e.g. expected market prices in the near future (opportunity cost), which implies that past prices are not that relevant. It is then very hard for a centralised decision maker to have sufficient overview of the costs of various resources. Additionally, a centralised system with low remuneration of flexible load (e.g. because the opportunity cost really is quite low, regardless the state of the power market) also runs the risk of not attracting sufficient participation from demand side. These challenges are likely to disappear or diminish with a market-based approach, and it is then feasible to attract the lower cost resources for the purpose of congestion management.

Markets are also perceived as more responsive and faster to adopt innovative technologies. While the cost of utilising demand side resources previously tended to prevent efficient utilisation of such resources (except for very large industrial end users, typically at transmission level), advances in communication and data processing technologies have paved the way for large scale utilisation of flexibility on the demand side, even in the low-voltage segments of the networks. The implications are that demand side resources also can compete with traditional grid investments – at all grid levels. However, a regulated or centrally planned approach in the low voltage levels is hardly conceivable.

The practical implementation of market-based redispatch at the DSO level will inevitably require some sort of power exchange like setup, especially when the markets mature with time. The nature of the task of setting up and operate such mechanisms is quite different from the more electro-technical challenges in operating a distribution network. From a competence perspective and regarding the required neutrality of such mechanisms, it is thus natural to seek a type of organisation not very different from that between TSOs and Nominated electricity market operators (NEMOs) when it comes to operating the existing wholesale electricity markets. An independent operator of such flexibility markets will facilitate efficient economic regulation of both buyers and sellers and prevent opportunistic activation of assets within vertically integrated utilities.

Simply put, the efficient use of distributed energy and demand side resources for congestion management requires some sort of decentralised organization and market-based decision making, rather than enabling DSOs to apply some sort of regulated redispatch using tariffs in their networks.

2.2 Key concerns of market-based redispatch

A key objective of all electricity markets is to help ensuring the power system is balanced between production and consumption, subject to grid constraints. In order to prevent or solve such constraints a second market is run to relieve the constraints that remain after the first market by reducing production and/or increasing consumption in an area with surplus of supply (upstream the constraint) and opposite regulation at the other side of the congestion (downstream, an area with surplus consumption). Such simultaneous and opposite regulation is often called redispatch.

Unfortunately, there are a few issues with congestion management and the way it is organised in European markets that complicate the picture. German authorities have focused on these issues and are so far reluctant to open for market-based redispatch. The arguments are spelled out in various reports, papers and academic articles over the past few years, most of which authored or co-authored by the German analyst Lion Hirth (Hirth et al (2019), Hirth & Schlecht (2020)). The issues are, however, well known and described since the 1990ies at least.

The main points of critique are that a setup with two consecutive markets, where the preceding market deliberately ignores an important characteristic of the system and an objective of the second market is to repair the damage caused by ignoring that particular trait, is like an open invitation to market participants to create problems.

Hence, although redispatch is proved to effectively ensure the integrity and balance of the power system, there are two concerns that can be observed throughout all markets: a phenomenon called inc-dec bidding and locational market power.

2.2.1 Inc-dec bidding

Inc-dec bidding describes the behaviour of a market participant in two consecutive markets, e.g. a zonal market followed by a regional/local market, who considers the opportunities in the second market when bidding in the first and aiming to increase his financial gain. In a concrete example this means that a producer (or a consumer) purposefully adjusts his bids in the (uncongested) day-ahead market to ensure that he will be competitive and asked to regulate up or down in the following congested redispatch market. The idea is that by doing so, they can trade energy at more attractive prices and/or collect the price spread between the markets without any energy delivery at all.

In case of a producer with relatively high marginal costs in a surplus area, he would ask a low price in the first market (underbidding) to ensure he is able to sell and receive the market price in that market, only to offer to purchase the same quantity for a low price in the second market. He will then actually not produce at all but collect the spread between the first (unconstrained) market and the second market. A producer at the other side of the congestion, the strategy would be opposite and might be called overbidding in the first market.

The illustration below from Hirth & Schlecht 2020 summarises the strategy: producers in the surplus area (north) offer below cost in the day-ahead market (underbidding), as they are convinced, they will be regulated downwards in real time. Producers in the deficit area (south) overbid, anticipating they will be regulated upwards in real time for a price of 60 EUR/MWh so that their opportunity cost when bidding in the day-ahead market is 60 EUR/MWh. (Note that the numbers here are for illustrative purposes only.)

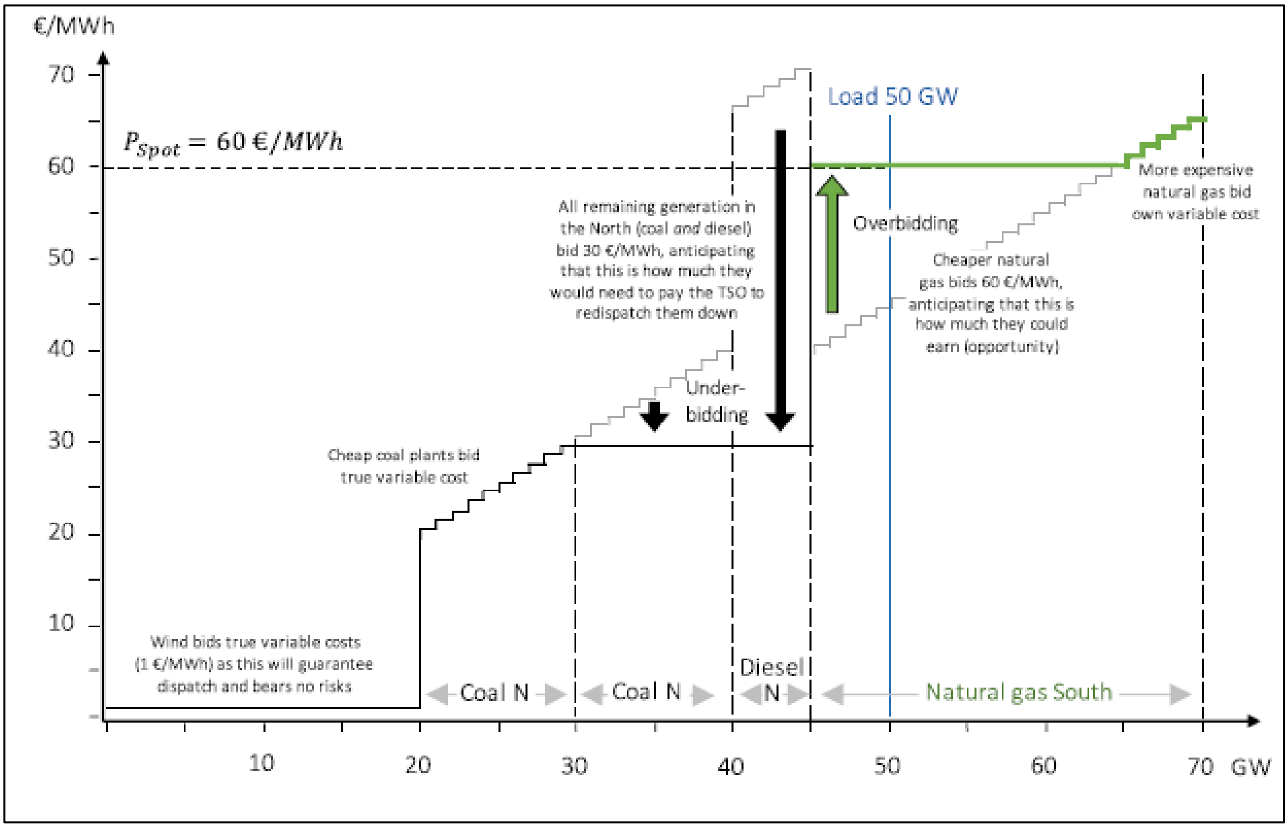

Figure 2-1 Illustration of inc-dec bidding (source: Hirth & Schlecht (2020))

This behaviour, which follows straight from the market design if the conditions are met, will exaggerate the need for redispatch, increase the profit for successful bidders at the expense of those covering the costs of the network, dilute the price signals (in particular for the first market), but will not impact the physical obligation of the buyer and seller. Depending on investment behaviour, such imperfect competition opportunities might also create false investment incentives (e.g. incentivising further production assets at the surplus side of the constraint or wrong perception of demand for grid capacity).

2.2.2 Locational market power

The concern about locational market power is related to the diverse features of heterogenous electricity networks in Europe and elsewhere. Assets with different locations will likely have a different impact on particular constraints. This can be described by a sensitivity factor, explaining to what extent a specific change in production or consumption by an asset relieves (or creates) a constraint. The higher the sensitivity, the more efficient the asset is in relieving a constraint. Numerical analyses of this phenomenon indicate that producers may gain an extra 15 to 50 EUR/MWh by using locational market power in redispatch markets (Hirth, Schlecht, Maurer, & Tersteegen, 2019). However, these calculations only consider the largest producers as potential suppliers of redispatch in transmission grids.

Nonetheless, the electricity demand is not totally inelastic, the producers' incentives to exercise market power in 'their' nodes are limited. Incentives are further reduced by uncertainty about the sensitivity of each assets and uncertainty about how competitors behave.

In the context of redispatch markets, the view is that demand for up- and downward regulation (demand for redispatch) is less elastic (Hirth, Schlecht, Maurer, & Tersteegen, 2019). If the network operator has no choice but to accept the offers, the incentives to take advantage of a good location is obviously much stronger.

3 ANALYSING INC-DEC BIDDING STRATEGIES

It is important to note that both inc-dec bidding and locational market power represent real, serious threats to reduce economic efficiency and therefore social welfare. The most famous examples of inc-dec bidding are presumably the unlucky events in California that peaked in 2000 and 2001 ((Wolak & Bushnell (1999), Stoft (1998) and Harvey & Hogan (2001)) and was solved when California introduced nodal pricing in 2009. Inc-dec bidding is observed in numerous other markets as well, including Great Britain, Norway, Australia and the border between Germany and Denmark (NODES, E-Bridge and Pöyry, 2019).

Applying market-based redispatch, without proper attention to these issues will most likely result in problems that prevent efficient congestion management (Hirth, Schlecht, Maurer, & Tersteegen, 2019). This can cause massive economic transfers from consumers to power producers via too high electricity prices and network charges. Costs of local networks may also be unnecessary high. And while some consumers might afford this or can find ways to reduce the impact of too high costs, e.g. by investing in rooftop PV, it can cause serious harm to consumers on tighter budgets. It can also reduce the speed of the energy transition, away from fossil fuels and towards renewable energy, and harm the reputation of market-based instruments.

There is simply too much at stake to ignore the concerns about market-based redispatch. But on the other hand, the benefits of market-based redispatch are so evident, that it is worthwhile to explore the impacts of these concerns in further detail.

Hence, it is equally important to note that the published papers spelling out the concerns about market-based redispatch often understate arguments in the opposite direction or downplay the key assumptions for ‘successful’ inc-dec bidding. The role and impact of uncertainty for success for market participants who consider such strategic bidding is one example. The impact of demand side flexibility on such strategic incentives is another example. A third example is the assumption that analyses studying constraints at the transmission level are transferable and valid also for local networks, where the technologies providing flexibility as well as the nature of the network constraints may be very different from the transmission level. But most importantly, analyses of mitigating actions are often missing or poor.

3.1 Key assumptions for inc-dec bidding

Details matter. The incentives to such strategic bidding depend on two crucial factors; 1) the potential profit if the strategy is successful and 2) the probability that it actually is successful (or the probability for congestion). The profit, in turn, depends on the extra profit per MWh and the number of extra MWh traded at the favourable price instead of the initial price. We will have a closer look at these factors in the following.

3.1.1 Potential profit for a successful strategy

The potential profit per MWh for a successful inc-dec strategy depends on the difference between the unconstrained zonal price and the respective local, constrained prices. In the hypothetical case with an almost horizontal supply curve in the first market, this difference would be close to zero. The same applies if the demand curve is horizontal. The steeper these curves are, the higher is the potential extra profit per unit. With reference to the examples used by Hirth & Schlecht (2020) Figure 2-1, we can think of the units setting the prices in the redispatch markets at 30 and 60 EUR/MWh respectively, as the competitors, or the reference bidders. If it was likely that the local redispatch markets in that example were cleared at e.g. 49 and 51 EUR/MWh respectively, the potential gain of strategic bidding would have been much smaller.

Furthermore, the potential volume depends partly on the costs and capacity of relevant suppliers, and similarly, on the willingness to pay and capacity to consume for the demand side. But the potential volume also depends on the strategies of other participants. It is important to recognise that some market participants may be so inflexible or for other reasons not considering strategic bidding and hence they simply submit non-strategic, competitive offers in the first market and behave as if there was no gaming at all. Other participants are so competitive that they are anyway allocated (upstream) or have such a high willingness to pay that they will not at all participate in the downstream regulation.

Brunekreeft et al (2020) demonstrates that if the competition from such competitive 'reference' participants (Referenzanbieter) is sufficiently high, the game becomes risky also for the strategic participants. The expected profit from gaming is negative if the competitive pressure is sufficiently high. Under such circumstances, it is not obvious that inc-dec bidding will happen at all.

We can interpret the combination of the impacts from the slope of the supply and demand curves and presence of reference participants as the competitive pressure. We can identify two scenarios where the competitive pressure is insufficient:

1. Congestion-relevant assets: If the competitive (reference) participants have insufficient capacity to solve the congestion, one or more assets become strategic and can potentially enjoy market power. The existence and impact of such assets are well known from theoretical and empirical analyses.
2. Uncompetitive competitors: If the opportunity costs of e.g. competitive participants in a surplus region are sufficiently high, their bids in the physical spot market will be less relevant and provide for potentially higher premiums for successful strategic bidders.

3.1.2 Probability for success of inc-dec bidding strategies

If the market participants are unable to predict if congestion materialise, there is no expected profit from inc-dec bidding. The argument thus goes that for structural congestions, market participants may not know exactly the margin, but they do know, or can fairly correctly forecast, the probability for success. If so, inc-dec bidding is likely to be a profit maximising strategy for market participants.

The logic of a zonal market design is that structural congestions are exactly what the zonal design should address. Bidding zones should reflect the physics of the electricity transmission network, not e.g. national borders. If bidding zones are defined despite the presence of structural congestions, and not reflecting these structural congestions, efficiency issues like inc-dec bidding or alternatively under-utilisation of demand-side resources are unavoidable: with a market-based approach we will incentivise inc-dec bidding, with a regulated redispatch we will not employ all relevant and competitive resources. CREG (2017) and (2019) provide clear explanation and evidence of these efficiency concerns.

But designing bidding zones such that all structural congestions were addressed does not make the remaining congestion issues completely unpredictable. It is indeed likely that some of the 'remaining' constraints are easily predictable while others appear as more random events.

The necessity to forecast at least the direction of a congestion for successful inc-dec bidding is, however, a good starting point for some important mitigating actions, as will be explained below.

3.2 Impact of demand side participation

From a theoretical or structural point of view, the incentives are identical for supply and demand with respect to inc-dec bidding. In practice though, there are some important differences when it comes to the details between the supply and demand side participation as explained below.

3.2.1 Impact on prices

Firstly, demand has impact on prices in both markets and thus also on the potential premium from successful gaming. Let us consider a producer with costs well above expected clearing prices, pushing down the price in the first market by lowering the price in his offer to the day-ahead market. Let us assume this producer is located in the surplus region, so that eventually, it is looking forward to be regulated down in the redispatch market, at a price lower than the day-ahead price. Unless we consider the role of demand, the premium for this producer, if successful, is determined by the most expensive unit allocated for local production (and the day-ahead price).

However, when we also consider demand, we must note that if there is some price sensitivity in demand, there is unsatisfied local demand at the day-ahead. If this demand can participate in the local market, it serves to tighten the gap between the local redispatch price and the day-ahead price, thus effectively reducing the potential profit for the strategic producer.

If we alternatively look at a surplus area, the conclusion is the same: the potential contribution from demand is to reduce the spread between the day-ahead price and the local redispatch price. This limits the potential profit for the strategic player, if they are successful.

3.2.2 Impact on ability to forecast

As mentioned above, the ability to forecast congestion is a key factor for successful inc-dec bidding. The current energy transition makes demand for electricity more price sensitive and less easy to forecast. A few examples serve to illustrate the point. The demand for electricity to operate heat pumps is obviously closely related to actual outdoor temperatures, but with some thermal storage capacity, the demand is also sensitive to price. If the remuneration of flexibility is sufficient or if the final cost of consumption is sufficiently volatile, price sensitivity will also apply to e.g. demand for electricity for ventilation systems and (commercial) freezers. And even if demand for transport by car is predictable, it can be hard to predict when car owners will decide to charge their electrical vehicles.

And while these events may be forecasted with respect to the impact on the transmission network (e.g. the north/south congestion in the German transmission network), it can be harder to predict precisely how the local network will be affected and where in the local network different voltage or temperature constraints will appear. While all production in a region with surplus of supply contributes to a transmission constraint, it is conceivable that only some of this production also contributes to a distribution constraint. Hence, for a random production unit in the surplus region, it will eventually be evident that it is facing a demand for downward regulation, but it is not certain that it also will trigger a congestion in the distribution network.

3.2.3 Other incentives and different risk perception

Furthermore, to the extent the demand side is considering inc-dec bidding, it must be noted that their bids have an 'opposite' logic; power producers are essentially concerned about the difference between a market price and their production or fuel costs, while end users (or suppliers or aggregators serving end-users) are concerned about the value of using an additional unit of energy and its market price. Industrial or commercial end users of electricity also have customers on their own to consider; not using electricity during a period might negatively impact their ability to supply their own customers with the industrial products or commercial services. The consequences of a failed inc-dec attempt can be quite significant ranging from financial loss in the best case to loss of confidence from customers and as such the risk for their own business). This type of risk is less relevant for electricity producers. The strategic interest in participating in inc-dec bidding is thus more complex for the demand side than that of producers.

Consequently, it is harder to predict the bidding behaviour of demand, and thus harder to forecast congestion, in particular at the distribution level.

From an operational perspective, the fundamental difference in the mechanics of an inc-dec strategy for a producer and a consumer also gives rise to a point relevant for operators of flexibility markets. The baseline for a producer is zero quantity; without any (accepted) offers, the producer will not (be able to) produce. Inc-dec bidding thus implies changing the offer price based on anticipated equilibrium prices in the redispatch market. If the strategy fails, the producer will not be able to produce all (not dispatched) or will have to produce at prices below actual costs. For a consumer, the baseline is normally not zero, but typically related to a 'normal' consumption for this consumer under the prevailing conditions. If his inc-dec strategy fails, he may need to buy the difference at a much higher price or face severe consequences for his own business. Hence, the risks involved are not only quite different, but this also offers better opportunities for a market monitoring mechanism to detect inc-dec bidding as outlined in chapter 4.

3.3 Distribution vs. transmission

There are several important differences between distribution and transmission networks when discussing market-based mechanisms to deal with various network constraints.

At transmission level, congestion is often the result of aggregation of multiple underlying reasons or sources for congestion, such as numerous wind farms producing more than the network can transport, or peaking demand from numerous end-users. Even if there are local differences, e.g. between the individual wind farms, the aggregated numbers will quickly become systematic and thus cause structural and easily predictable congestions. At distribution level, the aggregation effect will necessarily be smaller or less important; the heterogeneity of the grid customers will tend to dominate. It can perfectly well be the case that one DSO struggles with too much wind at the same time as their neighbour struggle with peak demand, or indeed that the same DSO has both problems at the same time in different parts of his network. This complicates inc-dec bidding in local markets, as it will have to be tailored to the specific network.[1]

[1] It should be noted that even if multiple DSOs cooperate and together operate flex markets via a joint platform, e.g. for the whole country, congestions and their potential solutions are per definition local issues. The notion of a national market for DSO flexibility fails to indicate that in reality, there can be multiple locations, and thus sub-markets, even within each DSO area.

While the transmission level is, in most countries, operated by a single TSO, in close cooperation with other TSOs in capacity calculation regions, there are no such coordination (yet) at distribution level. The practices of one DSO might be completely different from that of a neighbouring DSO. This adds to the difficulties in forecasting DSO congestions and DSO actions to relieve the constraints. Heterogeneity among DSOs is likely to reduce any incentive to inc-dec bidding at the DSO level as it directly applies to the probability for successful inc-dec bidding.

There are also important technical differences between transmission and distribution grids. Lead times for grid reinforcements are typically lower at the distribution level. The consequences of an overload are normally smaller, or less severe, in distribution networks. DSOs may in fact implement a demand for redispatch with decreasing willingness to pay for larger regulations. All these factors weaken any business case for inc-dec bidding in distribution network congestion management.

As a parallel to the aggregation effect at transmission level, the size of an individual congestion will typically be much smaller at distribution level. This obviously limits the potential profit per transaction of inc-dec bidding. It also means that ultimately, congestion management at DSO level will have to be automated, even if manual procedures for bidding and bid selection might be the normal situation for the many flexibility pilots we currently see around in Europe. There are ongoing efforts among TSOs also to automate bid selection and activation, so this difference is perhaps less important in the future. However, the issue of automation will be important when considering mitigating measures.

3.4 Taxes and network charges

Grid tariffs and taxes may also play a significant role in shaping the incentives to inc-dec bidding. Grid-tariffs are generally more important for the demand side than for producers – in some countries (e.g. Germany), producers are not charged for grid access and utilisation at all. Grid tariffs normally vary between different types of end users, but a common feature is often (but not always) that the charges are somewhat proportional with load (peak-load pricing). For an end-user considering inc-dec bidding, the impact on grid tariffs is a complicating factor that a rational end-user will take into account. As the end-users are a quite heterogenous group, the impact of grid charges makes the behaviour of end-users less predictable and inc-dec bidding riskier for potential ‘players’. However, we return to the issue of tariffs under mitigating measures.

Taxes levied on energy use may play a similar role, contributing to more heterogenous incentives for end-users and increased risks of inc-dec bidding, depending the details of tax schemes. There are normally no similar taxation factors on the supply side.

4 THERE ARE EFFICIENT MITIGATING MEASURES

As explained above, inc-dec bidding is a potentially profitable strategy, for suppliers as well as end-users, when congestion is forecastable and there is insufficient competition from participants that are not playing the game. Mitigation strategies thus typically focus on ability to forecast, competition and the potential profit if gaming is successful.

Two situations are particularly important, as mentioned in section 3.1: congestion relevant assets and uncompetitive competitors. The efficiency of potential mitigating measures can differ in these two situations, but as both situations are likely, regulators, network operators and flexibility market operators should consider all suggested measures.

Before going into details, it is worthwhile to notice that inc-dec bidding is a violation of competition law or sector-specific regulation, alternatively of participation clauses of flexibility markets. It depends, however, on the actual case and the circumstances. As demonstrated by Hirth et al (2019), traditional market power or collusion is not always necessary.[2] But as explained by Brunekreeft et al (2020), it is lack of sufficient competing resources not playing the game that makes inc-dec bidding possible and profitable. Even if it might be possible to demonstrate that a particular action is a violation of law, it is nevertheless also a question if the relevant authority will prioritise the matter. For local congestions in local DSO networks, it is not obvious that competition authorities will spend time and resources on such matters.

Congestion management at distribution level will most likely involve three parties, or categories of participants – buyer, seller and market operator. The buyer of congestion management services will be a DSO, but unlike TSOs, DSOs are, as pointed out in chapter 2 not likely operators of a local market for flexibility. There are already several providers of platforms for local markets; NODES is only one of these. It is then a joint task and challenge for the network operator and a market operator to attract sufficient flexibility providers. These can be (large) end users, DSO-connected generators, suppliers, aggregators, etc.

Successful implementation of non-wire alternatives requires that all three parties work together with mutual respect of and confidence in each other. If one of the parties fails to understand this, the flexibility efforts can quickly collapse. The mitigating measures discussed below focus on what network operators and/or market operators can do. It goes without saying that flexibility providers also can do a significant effort and refrain from inc-dec bidding.

As flexibility markets become more common and mature, we will learn more about mitigating measures and how useful the various measures are. However, clever market participants will also learn more about how they might fool the system. Flexibility suppliers should ideally understand that trust is a vital asset in this business and that any attempt to strategic behaviour will have severe consequences ranging from financial punishment to exclusion from market participation. Ultimately, it may even end up losing their business cases.

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[2] Interestingly, there are also claims that regulated redispatch not only contradicts most EU regulations, but also that the outcome of a redispatched market is effectively a violation of market abuse regulations and competition law (CREG, 2019).

4.1 Network operators have alternatives

It is important to bear in mind that ultimately, network companies might also consider reinforcing their network. Appropriate grid reinforcements will not only reduce or remove incentives and opportunities to inc-dec bidding. They will also destroy potential business cases built on inc-dec biding.

While it takes time and is increasingly complex at higher voltage levels, reinforcement also represents a limitation for the network operator's willingness to pay. This is particularly the case at lower voltage levels as constraints tend to be 'softer' than at transmission level. Violation of transmission constraints is quickly an issue of violating N-1 or similar criteria and is typically a no-go option. Constraints at DSO level are more often an issue about e.g. increased temperature for longer than preferred or too high or low voltage than required. Violations of such constraints tend to be less critical than the constraints at transmission level, and thus the 'threat' from grid reinforcement more relevant.

Network operators may also reduce the scope for inc-dec bidding by tailoring their network charges, such that congestion caused by regular, repeated incidents, like peak load or peak production, are essentially mitigated by the tariff rather than a flexibility market. While it is impossible in practice to device network charges that solve all the 'problems' for a network operator, it can make sense to ensure that solutions to structural, repeated issues are incentivised by the grid charges.

Finally, the strategic position of a network operator may improve as a result of sector coupling. Sector coupling offers more flexibility resources and potentially more tariffs to adapt to ensure proper incentives. The more options at the hand of the DSO, the riskier an inc-dec strategy will be for the flexibility providers.

4.2 Long-term contracts

An obvious choice when there are few relevant suppliers are long-term contracts. The buyer of up- or downward regulation can tender and/or negotiate a long-term contract with the only relevant supplier(s). Assuming the buyer is a network operator with proper requirements on neutrality and facing a reasonable regulation of its revenue, a long-term contract can strike the balance between the network operator's need for sufficiently predictable access to resources at sufficiently attractive prices, and the supplier's need for a profitable business case.

The contract could either determine prices for specified flexibility actions or specify a calculation formula or principles for the prices. Eventually, the formula could incorporate caps or floors. The contract can also limit the potential ability of the contractor to create congestions, by obligating the contractor to bid or behave in a certain way.

Depending on price and performance regulations in the contract, there must also be relevant rules about transparency. Somehow, the buyer must be able to verify if the behaviour of the seller is according to contract or not. Such contracts would thus require some sort of supervision or monitoring from the buyer. Hence, the contract must also specify how the contractor can demonstrate compliance. Also, the consequences of non-compliance must be laid out in such contracts.

Long-term contracts are suitable when there are few relevant assets or participants. A long-term contract with a sufficiently flexible supplier can also ensure other suppliers are always met with a reasonable competition.

An open question is which duration of a long-term contract should be preferred. In a fully competitive context, with ample competitive suppliers and no inc-dec incentives and no need for long-term contracts, regular competitive auctions would be the normal way of resource allocation. Absent these conditions, a long-term contract represent the negotiated outcomes that ideally should deliver the same resource allocation. Obviously, one would not negotiate the conditions daily, as that would essentially be like trying to arrange a daily auction without the proper incentives on the seller side in place. On the other hand, a contract for a very long period, e.g. a decade, would probably not be sufficient flexible for both parties. Depending on the actual situation, the constraints at hand, the presence of existing and potential suppliers, a reasonable duration could be anything between some weeks and some years.

4.3 Bid caps and floors

With few relevant assets and an increased risk of locational market power, a cap (or floor) on bids can be efficient. If the redispatch is part of a regulated domain or activity, e.g. for congestion management at transmission level, the cap would presumably be incorporated in the relevant regulation. To the extent the congestion management principles do not require a regulatory consent, as might be the case for local congestions, the cap would presumably be implemented as part of a long-term contract or as conditions set by the buyer, specifying what the network operator intends to accept or not.

While numeric bid caps, and the suppliers' compliance with these, are easy to monitor, it is not obvious this approach will eliminate inc-dec bidding. Particularly when prices are volatile, it can be difficult to define caps that are always efficient.

A system of caps and floors can be understood as a kind of combination of market-based and regulated mechanisms. The Norwegian regulation for congestion management at transmission (and to some extent regional distribution) level offers a relevant and telling example and might inspire regulators, buyers of flexibility or market operators to design rules or contract conditions with similar objectives. Norwegian regulations include an obligation for producers to offer all available capacity to a reserve market. End users and smaller producers are entitled to offer in this market. The regulation includes a special rule that can be interpreted as a bid cap:

- Under this regulation, the TSO is, under specified conditions, entitled to accept a bid without the obligation to remunerate it according to the bid.
    - The conditions are essentially that there is only one or few relevant assets that can resolve the constraint and that the bids and asks are clearly not reflecting actual costs.
    - When the conditions are met, the remuneration will be set to the prevailing price in the day-ahead market, and thus the profit margin of gaming is effectively set to zero.
    - It is within the discretion of the TSO to decide whether to apply the rule in any specific case. Affected providers may complain to the NRA (the national regulator).
    - This implies that whenever a producer is able to forecast that a specific power plant has locational market power, the TSO can, if it makes similar forecasts, 'catch' the asset in its market surveillance.

Due to this rule, the Norwegian TSO does not experience any significant problems with inc-dec bidding. However, every now and then the rule is in fact applied. And when it is applied, it also serves as a 'constant' reminder and mitigating measure against inc-dec bidding in general.

Just as market participants who considers inc-dec bidding would need to monitor the situation and try to forecast the congestion in order to be successful, the TSO can and will also monitor the behaviour of market participants. This implies that when the conditions for successful inc-dec bidding are present, then the TSO is also aware of these options and incentives. The market monitoring of the TSO takes this into account.

4.4 Market monitoring

In line with the expected automated features of bidding, selection and activation of accepted flexibility offers, an obvious service from operators of market platforms will be to cater for automated market monitoring. Just like the operators of day-ahead and intraday markets already employ algorithms continuously monitoring the bids and offers in their markets, flexibility market operators should develop and offer a selection of algorithms and routines to verify that bids are reasonable, reflecting the realities and not part of an inc-dec strategy.

Regardless if REMIT or similar apply or will apply for a flexibility market, the operator of a flexibility market may of course decide to employ similar conditions. The operator might not be able to enforce such 'private' rules with similar remedies and force as a regulated power exchange or its regulator(s), but such private regulation may still be quite effective.

Likely efforts by market operators/market platforms include defining the baseline methodology, monitoring the baselines (see section 3.2) as well as the quantities and prices offered, and analysing historical data. Keeping a central registry of previous bids and trades will be an important basis for such monitoring. At the same time, other fundamental data must be recorded, e.g. temperature and other weather information, economic and activity indicators etc. that might help to explain variations in baselines over time.

The details of the monitoring activities will ultimately depend on what resources are relevant and the needs of the network operator, as well as which other mitigating measures are employed.

4.5 Randomised bid selection

When there are more than sufficient bids, the participation risk can be increased by introducing some randomness in the procedure for selecting which bids to accept and making sure the flexibility providers are aware of this. This directly reduces the ability for those intending to play the inc-dec game to forecast congestion, and thus reduces their incentives.

This approach can be understood as a selection algorithm resembling a market situation with relatively flat supply curve. Introducing some randomness will inevitably come at a cost, as it implies every now and then accepting offers that are not in the money. The potential benefit is of course that it makes application of a market-based approach feasible while reducing incentives to inc-dec bidding.

4.6 Alternative resources

Alternative resources are e.g. mobile flexible resources like mobile batteries and might be particularly relevant in local congestion management. A mobile storage facility can be employed locally instead of accepting adverse bids from gaming participants. Eventually, that will reduce the probability for a player to be called upon in the redispatch phase and thus reduce the incentive to strategic behaviour.

The 'ultimate' alternative is reinforcement of the network. This will obviously not eliminate the incentives immediately, but it can effectively reduce what players eventually consider as a 'safe' margin.

5 CONCLUSIONS

The concerns about market-based redispatch and the inherent and unavoidable incentives to inc-dec bidding cannot be ignored. However, the benefits of market-based mechanisms are too large to neglect. Hence, the challenge is to find practical ways to introduce flexibility markets for congestion management – in particular at the distribution level – to ensure secure and cost-effective grid management in the future (Pollit & Anaya, 2019).

The key benefits of (local) flexibility markets to pursue are lower network costs, better utilisation of network capital, potential for faster response to demands for increased network capacity, and stronger incentives for innovation. A potential indirect effect of local flexibility markets is also the potential for increased competition in the overall wholesale markets. Ultimately, the market-based approach will help to accelerate the successful transition from fossil to renewable energy and reduce the costs of decarbonisation, hence essentially contribute to the goals of the CEP.

Our brief analysis demonstrates that for typical congestions at distribution level, market-based approaches are fit for purpose. The key assumptions for successful inc-dec strategies at transmission level are not directly applicable to distribution networks. The predictability of the congestion will tend to be relatively low, as compared to the classical cases from e.g. the north-south issue in Germany and the Danish-German border. Efficient mitigating measures are readily available; long-term contracts can be tailored to the specific situation and ensure flexibility providers have their incentives aligned with the network operator. Monitoring efforts and routines from a market operator can ensure compliance with both contracts and behaviour rules defined by the buyer (the network operator) or the market operator. The challenge is to implement sufficient mitigating measures to prevent inc-dec bidding, but not so much or strict that the business case for the flexibility providers disappear.

Our recommendation is thus to continue the work for developing local flexibility markets and help network operators find alternatives to traditional network measures. This requires pilots where not only technology, but also commercial conditions and arrangements are tested and studied, as well as market monitoring routines. There is still a significant scope for financial and commercial engineering in this field, and the only way to gain the necessary experience is to continue testing.

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